April 1, 2019

Ms. Trisha Osborne, Assistant Commission Secretary
Public Utilities Commission of Nevada
Capitol Plaza
1150 East William Street
Carson City, Nevada 89701-3109

RE: Docket No. 19-04___ - Joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of First Amendment to 2018 Joint IRP, a **Distributed Resource Plan**.

Dear Ms. Osborne:

Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (the "Companies") hereby submit for approval their First Amendment to the 2018 Joint Integrated Resource Plan (approved by the Commission on February 15, 2019 in Docket No. 08-06003. The subject matter of this First Amendment is the Companies' first Distributed Resources Plan.

Amendments to NRS § 704.741 made by the 2017 Legislature in Senate Bill 146 ("SB146") establish a requirement that Nevada Power and Sierra prepare and file with the Commission "Distributed Resources Plans." SB146 includes transitory language requiring that the Companies file their first Distributed Resources Plan ("DRP") on or before April 1, 2019, as an amendment to their existing Commission-approved integrated resource plan ("IRP"). As an amendment to the Companies' 2018 Joint IRP, NRS § 704.751(2)(a) (as amended by SB146), requires that that Commission issue an order accepting or modifying the Distributed Resources Plan, or specifying any portions of the amendment deems to be inadequate, within 165 days after its filing. Thus statutory period within which this matter must be resolved therefore runs on Friday, September 13, 2019.

SB146 defines Distributed Resources as "distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies." To ensure a thoughtful and structured approach to this new planning paradigm, NV Energy has adopted a "walk-jog-run" philosophy to work through the development of the various elements of Nevada's first Distributed Resources Plan. This approach, and the comprehensive analyses used to prepare this Distributed Resources Plan were developed through significant collaboration with stakeholders, many of whom have participated in developing DRP techniques in other jurisdictions.

To aid the Commission in considering this first Distributed Resources Plan, the Companies have included with this Application and incorporated herein by reference the following Application Exhibits:

> **Application Exhibit A** is a proposed notice of the Application as required by NAC § 703.162.
>
> **Application Exhibit B** is a copy of the "As Enrolled" version of Senate Bill 146 (2017 Legislature).
>
> **Application Exhibit C** is a copy of the "Temporary Regulations" approved by the Commission and submitted to the Legislative Counsel Bureau and the Office of the Secretary of State on November 15, 2018.
>
> **Application Exhibit D** is a complete narrative version of the Distributed Resources Plan (the "DRP Narrative").

The form of Exhibit D, the DRP Narrative, was selected because it is the form used in IRPs and IRP amendments to provide the Commission and stakeholders with detailed and technical information regarding the inputs, in-depth descriptions of the analytical techniques applied to the questions to be answered in IRP filings, as well as clear communication of the results of integrated resource plan filings and the recommendations for Commission approval. The DRP Narrative is supported by the testimony of the following four witnesses:

> **James R. Saavedra**, Director, Distributed Energy Resources Planning.
>
> **Joseph V. Sinobio**, Manager, Major Projects – Delivery.
>
> **Casey Baker**, Transmission Planning Engineer II.
>
> **Anita Hart**, Director, Demand-Side Management.

The DRP Narrative is presented in twelve sections, following the basic outline of the distributed resources planning process set out in the Temporary Regulations.

> **Section 1 – Executive Summary**. This section of the narrative is sponsored by Mr. Saavedra, and provides an overview of the contents in the DRP Narrative.
>
> **Section 2 –Introduction**. Also sponsored by Mr. Saavedra, this section of the narrative describes the principles and processes NV Energy followed in developing the Distributed Resources Plan, and includes definitions and acronyms used in the filing.
>
> **Section 3 – Distributed Resource Plan Elements**. The analytics used to prepare the various components of the DRP are described here. The analytical framework used by the distribution system planners are supported by Mr. Sinobio. The analytical framework used by the transmission system planners are supported by Mr. Casey Baker. Also in Section 3 are discussions of the use of tariffs to incentivize the adoption of

electric vehicles and other storage devices, as well as the coordination of DRP process and existing Commission-approved programs encouraging the adoption of Distributed Resources. These discussions are supported by Ms. Hart.

Section 4 – Barriers to Deployment of DER. Supported by Mr. Saavedra, this part of the DRP Narrative describes the barriers that NV Energy has identified that might be a deterrent to the deployment of Distributed Resources and means of addressing those barriers.

Section 5 – Coordination with Integrated Resource Plan and Other Legislative Actions. This section of the DRP Narrative discusses the impact of the DRP on the evaluation of load forecasts, demand-side, supply-side and transmission assets in the resource planning process. This discussion is sponsored by Mr. Saavedra.

Section 6 – Data Sharing, Access and Security Issues. Sponsored by Mr. Saavedra, this part of the DRP Narrative provides the details, challenges overcome, and the solutions that NVE developed to identify the data that stakeholders want to see and how it will be shared.

Section 7 – Publicly-Accessible Web Portal. Also sponsored by Mr. Saavedra, this part of the DRP Narrative details the web portal that NVE developed to share the outputs from the DRP with stakeholders and the public.

Section 8 – Refining Distributed Resources Plan Elements. This part of the DRP Narrative, sponsored by Mr. Sinobio, describes the Companies' present plans to refine the methods and tools used in the performing the various analyses required to develop the DRP, as well as development of procurement processes over approximately the next two years.

Section 9 – Incremental Investment in Tools, Systems or Technologies to Integrate Distributed Resources. This part of the DRP Narrative, sponsored by Mr. Sinobio, describes the Companies' existing, recently-developed, and potential future tools, systems, or technologies used, or which could be used in the future, to develop the DRP, and any incremental investment that may have been identified to develop, acquire, or implement these.

Section 10 – Pilot and Demonstration Projects. This part of the DRP Narrative, sponsored by Mr. Sinobio, describes the proposed pilot and/or demonstration projects that the Companies may be proposing to conduct in support of the analyses or tools, systems, or technologies used to support the DRP.

Section 11 – Specific Requests for Commission Approval. This part of the DRP Narrative, sponsored by Mr. Sinobio, describes the specific requests that the Companies are making of the Commission in this DRP, including requests for the Commission's approval of various elements of the DRP, and any variances requested by the Companies with respect to the temporary DRP regulations.

> **Section 12 – Roadmap to 2021**. This part of the narrative, sponsored by Mr. Saavedra, provides the details on the steps the Companies will be taking to refine distributed resources planning inputs and analytics in time for the June 2021 filing.

In addition to the DRP Narrative, technical appendices have been prepared to assist the Commission and stakeholders in reviewing the inputs, analytic framework, models and methods applied in preparing the DRP. Each is described below.

> **Technical Appendix DRP-1**, sponsored by Mr. Sinobio, this technical appendix shows peak loads from 2014 through 2018 on NV Energy's substation transformers and feeders.

> **Technical Appendix DRP-2,** also sponsored by Mr. Sinobio, shows Forecasted peak loads from 2019 to 2025 on NV Energy's substation transformers and feeders.

> **Technical Appendix DRP-3,** sponsored by Mr. Sinobio, is a flow diagram outlining how distribution feeder level data was gathered and analyzed in order to support NV Energy's performance of the HCA.

> **Technical Appendix DRP-4**, sponsored by Mr. Sinobio, is a table indicating which data sources were used to create the loading profiles for each of the feeders analyzed in the HCA.

> **Technical Appendix DRP-5** contains screen shots from the Publicly-Accessible DRP Web Portal. Mr. Saavedra supports the discussion regarding the Web Portal and the information portrayed in Technical Appendix DRP-5.

Should you have any questions regarding this filing, please contact me at 775-834-5692 or mgreene@nvenergy.com.

Sincerely,

/s/ Michael Greene
Michael Greene
Senior Attorney

APPLICATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval of First Amendment to 2018 Joint Integrated Resource Plan, a Distributed Resources Plan prepared and filed pursuant to NRS § 704.751(5) as amended by SB146 (2017 Legislature)	)))))) /	Docket No. 19-04_____

APPLICATION TO APPROVE FIRST AMENDMENT TO
2018 TRIENNIAL INTEGRATED RESOURCE PLAN

Nevada Power Company, d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and together with Nevada Power, the "Companies" or "NV Energy"), make this Application, pursuant to Nevada Revised Statute ("NRS") § 704.741 *et seq*., and Nevada Administrative Code ("NAC") § 704.9005 *et seq*. for approval by the Public Utilities Commission of Nevada ("Commission") of the Companies' First Amendment to their 2018 joint triennial integrated resource plan ("2018 Joint IRP"). Amendments to NRS § 704.741 made by the 2017 Legislature in Senate Bill 146 ("SB146") establish a requirement that Nevada Power and Sierra prepare and file with the Commission "Distributed Resources Plans." SB146 includes transitory language, found in Section 3 of the "As Enrolled" version, requiring that the Companies file their first Distributed Resources Plan on or before April 1, 2019, as an amendment to their existing Commission-approved integrated resource plan ("IRP").[1] Therefore this Application has been prepared as an amendment to the Companies' 2018 Joint IRP, addressing one item only: the Companies' first Distributed Resources Plan ("DRP"). As an amendment to the Companies' 2018 Joint IRP, NRS § 704.751(2)(a) (as amended by SB146),

[1] The "As Enrolled" version of SB146 is included in this filing as Application Exhibit B. Subsection 2 of Section 3 of SB146 reads in its entirety:

> Any public utility required to file a plan pursuant to NRS 704.741 that would not otherwise be required to file a new plan before July 1, 2018, shall, on or before April 1, 2019, *submit an amendment to its existing plan that complies with the provisions relating to a distributed resources plan* in subsection 5 of NRS 704.741, as amended by section 1 of this act. (Emphasis added).

requires that that Commission issue an order accepting or modifying the Distributed Resources Plan, or specifying any portions of the amendment it deems to be inadequate, within 165 days after its filing. The statutory period within which this matter must be resolved therefore runs on Friday, September 13, 2019.

I.
SUMMARY AND INTRODUCTION

SB146 defines Distributed Resources as "distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies." This filing represents the culmination of NV Energy's efforts to timely comply with the schedule set forth in SB146. The comprehensive analyses used to prepare this DRP were developed through significant collaboration with stakeholders, many of whom have participated in developing distributed resources planning techniques in other jurisdictions.

To ensure a thoughtful and structured approach to this new planning paradigm, NV Energy has adopted a "walk-jog-run" philosophy to work through the development of the various elements of Nevada's first DRP. This philosophy was discussed in detail throughout the stakeholder workshops to establish a baseline and understanding of the evolutionary process of each of the DRP elements.

The purpose of SB146 is not expressly stated in the legislation, but based on its language, NV Energy is of the view that the 2017 Nevada Legislature expected that a formal DRP process would aid in the cost-effective integration of Distributed Resources into the utilities' distribution and transmission planning processes and, ultimately, the NV Energy utilities' electricity grid. The Companies have embraced the DRP concept, and have prepared one of the first comprehensive and complete distributed resources plans in the nation. Keeping with the "walk-jog-run" philosophy and drawing from models and hypotheses being discussed and debated in other jurisdictions, as well as the regulations established by the Commission to implement SB146, the Companies have prepared a potentially transformational process for planning transmission and distribution systems, and for accelerating the cost-effective integration of Distributed Resources with the Companies' electric grid.

II.
THE APPLICANTS

Nevada Power and Sierra are Nevada corporations and wholly-owned subsidiaries of NV Energy, Inc. Nevada Power and Sierra are public utilities as defined in NRS § 704.020, and are subject to the jurisdiction of the Commission. Nevada Power is engaged in providing electric service to the public in portions of Clark and Nye counties, Nevada pursuant to a certificate of public convenience and necessity issued by this Commission. Sierra provides electric service to the public in portions of fourteen northern Nevada counties, including the communities of Carson City, Minden, Gardnerville, Reno, Sparks, and Elko. Sierra owns and operates a certificated local gas distribution company engaged in the retail sale of natural gas to customers in the Reno-Sparks metropolitan area.

Sierra's primary business office is located at 6100 Neil Road in Reno, Nevada and Nevada Power's primary business office is located at 6226 West Sahara Avenue in Las Vegas, Nevada. All correspondence related to this Application should be transmitted to the Companies' counsel _and_ to the Manager of Regulatory Services, as set forth below:

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

III.
APPLICATION EXHIBITS

To aid the Commission in considering this first DRP, the Companies have included with this Application and incorporated herein by reference the following Application Exhibits:

- **Application Exhibit A** is a proposed notice of the Application as required by NAC § 703.162.
- **Application Exhibit B** is a copy of the "As Enrolled" version of Senate Bill 146 (2017 Legislature).
- **Application Exhibit C** is a copy of the temporary regulations approved by the Commission in an order in Docket No. 17-08022 dated October 8, 2018 and submitted to the Legislative Counsel Bureau and the Office of the Secretary of State on November 15, 2018 (the "Temporary Regulations").
- **Application Exhibit D** is a complete narrative version of the Distributed Resources Plan (the "DRP Narrative").

The form of Exhibit D, the DRP Narrative, was selected because it is the form used in IRPs and IRP amendments to provide the Commission and stakeholders with detailed and technical information regarding the inputs, in-depth descriptions of the analytical techniques applied to the questions to be answered in IRP filings, as well as clear communication of the results of integrated resource plan filings and the recommendations for Commission approval. Because the 2017 Legislature directed that distributed resources plans be filed within IRPs or as IRP amendments, the narrative form has been adopted for this DRP.

IV.
SUPPORTING MATERIAL

NAC § 704.9321(1) provides that a utility's resource plan must be based on substantially accurate data, adequately demonstrated and defended, and adequately documented and justified. NAC § 704.922 provides that a utility's resource plan must include technical appendices containing sufficient detail to enable the technically proficient to understand how the IRP was prepared, and to evaluate the validity of the assumptions and accuracy of the data used. NAC §

704.5664 requires that a utility's resource plan must include written testimony in support of the resource plan.

Consistent with these directives included in this First Amendment to the 2018 Joint IRP and incorporated herein by reference, the reader will find all material required to adequately demonstrate and defend the substantially accurate data supporting the analysis and the requests for affirmative relief set forth herein. A summary of this information, which references the DRP Narrative, technical appendices, and prepared direct testimony making up this filing, is set forth by general topic below. The DRP Narrative has been presented in twelve sections, following the basic outline of the distributed resources planning process set out in the Temporary Regulations.

Section 1 – Executive Summary. This section of the narrative is sponsored by Mr. James R. Saavedra, and provides an overview of the contents in the DRP Narrative.

Section 2 –Introduction. Also sponsored by Mr. Saavedra, this section of the narrative describes the principles NV Energy followed in developing the DRP, how the DRP meets the requirements of SB146, the stakeholder process used to develop not only the Temporary Regulations but the analytical tools and methods used to prepare the DRP, and definitions and acronyms used in the filing.

Section 3 – Distributed Resources Plan Elements. The analytics used to prepare the various components of the DRP are described here. The analytical framework used by the distribution system planners are supported by Mr. Joseph V. Sinobio and include the following:

1. Load and Distributed Resources Forecasting. This part of the DRP Narrative generally describes how load forecasting is performed at the distribution feeder level for the Companies, and discusses the effect of Distributed Resources on distribution load forecasting;

2. Hosting Capacity Analysis ("HCA"). This part of the DRP Narrative describes how the distribution substation and feeder models were prepared utilizing the Companies' distribution power flow software, Synergi, how the loading profile data for the Companies' distribution feeders was developed, the analytical method for the HCA,

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the results of the HCA, and a discussion of "real-time" hosting capacity and NV Energy's progress in that regard;

3. <u>Grid Needs Assessment ("GNA")</u>. This part of the DRP Narrative describes how the Companies identified 10 existing and forecasted constraints on their distribution systems for the years 2020 through 2025, the identifying information and parameters of those constraints in terms of the deficiencies involved, and the identified traditional wired capital upgrade solutions for addressing those constraints;

4. <u>Non-Wires Alternative Analysis ("NWA")</u>. This part of the DRP Narrative describes the Companies' NWA Suitability/Screening Criteria to determine which of the 10 identified constraints could be suitable for a potential NWA solution, the method and the NWA Sizing Model that the Companies used to perform the NWA analyses, and the results of the NWA analyses, including the sizing of the Distributed Resources technologies (demand response, energy efficiency, solar PV, and battery storage) used in the potential NWA portfolio;

5. <u>Locational Net Benefits Analysis ("LNBA")</u>. This part of the DRP Narrative describes the Present Worth of Revenue Requirements ("PWRR") analyses that were performed by the Companies, which compared the costs of traditional wired capital upgrade solutions against the costs and potential system-level and locational benefits of NWA solutions;

6. <u>Interconnection Issues for Distributed Resources</u>. This part of the DRP Narrative briefly mentions the Companies' Rule 15 and the changes to the interconnection process that are being considered in discussions with regulators and stakeholders;

7. <u>Tools, Systems, and Technologies</u>. This part of the DRP Narrative briefly discusses some of the vendors and software that NV Energy is aware of which could help support DRP-related analyses in the future.

The analytical framework used by the transmission system planners are supported by Mr. Casey Baker and include the following:

1. Load and Distributed Resources Forecasting. This part of the DRP Narrative generally describes how the transmission planning group forecasts native load and control area load forecasting;

2. GNA for the NV Energy Transmission System.

a. Transmission Constraints and Projects Identified. This part of the DRP Narrative describes how the transmission planning group identifies transmission system constraints and traditional wired capital upgrades.

b. NWA Solution Analysis. This part of the DRP Narrative describes how the transmission planning group utilizes the NWA Suitability/Screening Criteria to identify constraints that could be suitable for a potential NWA solution, the method and the NWA Sizing Model that the Companies used to perform the NWA analyses, and the results of the NWA analyses for the transmission system;

3. LNBA. This part of the DRP Narrative describes the PWRR analyses that were performed by the Companies, which compared the costs of traditional wired capital upgrade solutions against the costs and potential system-level and locational benefits of NWA solutions;

Also in Section 3 are discussions of the use of tariffs to incentivize the adoption of electric vehicles and other storage devices, as well as the coordination of DRP process and existing Commission-approved programs encouraging the adoption of Distributed Resources. These discussions are supported by Ms. Anita Hart.

Section 4 – Barriers to Deployment of Distributed Resources. Supported by Mr. Saavedra, this part of the DRP Narrative describes the barriers that NV Energy has identified that might be a deterrent to the deployment of Distributed Resources and the means of addressing those barriers.

Section 5 – Coordination with IRP and Other Legislative Actions. Picking up on the discussion of existing Commission-approved Distributed Resources begun in Section 3, this section of the DRP Narrative discusses the impact of the DRP on the evaluation of load forecasts, demand-side, supply-side and transmission assets in the resource planning process. This discussion is sponsored by Mr. Saavedra.

Section 6 – Data Sharing, Access and Security Issues. Sponsored by Mr. Saavedra, this part of the DRP Narrative provides the details, challenges overcome, and the solutions that the Companies developed to identify the data that stakeholders want to see and how it will be shared.

Section 7 – Publicly-Accessible Web Portal. Also sponsored by Mr. Saavedra, this part of the DRP Narrative details the web portal that the Companies developed to share the outputs from the DRP with the public.

Section 8 – Refining DRP Elements. This part of the DRP Narrative, sponsored by Mr. Sinobio, describes the Companies' present plans to refine the methods and tools used in the performing the various analyses required to develop the DRP over approximately the next two years.

Section 9 – Incremental Investment in Tools, Systems or Technologies to Integrate Distributed Resources. This part of the DRP Narrative, sponsored by Mr. Sinobio, describes the Companies' existing, recently-developed, and potential future tools, systems, or technologies used, or which could be used in the future, to enhance the analytics in performing several of the elements in the DRP, and any incremental investment that may have been identified to develop, acquire, or implement these.

Section 10 – Pilot and Demonstration Projects. This part of the DRP Narrative, sponsored by Mr. Sinobio, describes the proposed utilization of pilot and/or demonstration projects that the Companies may be proposing to conduct in support of the analyses or tools, systems, or technologies used to support the DRP.

Section 11 – Specific Requests for Commission Approval. This part of the DRP Narrative, sponsored by Mr. Sinobio, describes the specific requests that the Companies are making of the Commission in this DRP, including requests for the Commission's approval of various elements of the DRP, and any variances requested by the Companies with respect to the Temporary Regulations.

Section 12 – Roadmap to 2021. This part of the narrative, sponsored by Mr. Saavedra provides the details on the steps the Companies will be taking to refine distributed resources planning inputs and analytics in time for the June 2021 filing.

In addition to the DRP Narrative, technical appendices have been prepared to assist the Commission and stakeholders in reviewing the inputs, analytic framework, models and methods applied in preparing the DRP. Each is described below.

Technical Appendix DRP-1, sponsored by Mr. Sinobio, shows historical peak loads from 2014 through 2018 on NV Energy's substation transformers and feeders.

Technical Appendix DRP-2, also sponsored by Mr. Sinobio, shows forecasted peak loads from 2019 to 2025 on NV Energy's substation transformers and feeders.

Technical Appendix DRP-3, sponsored by Mr. Sinobio, is a flow diagram outlining how distribution feeder level data was gathered and analyzed in order for NV Energy to perform the HCA.

Technical Appendix DRP-4, sponsored by Mr. Sinobio, is a table indicating which data sources were used to create the loading profiles for each of the feeders analyzed in the HCA.

Technical Appendix DRP-5 contains screen shots from the Publicly-Accessible DRP Web Portal. Mr. Saavedra supports the discussion regarding the Web Portal and the information portrayed in Technical Appendix DRP-3.

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V.

CONFIDENTIALITY

None of the information set forth in the DRP, Technical Appendices or Prepared Direct Testimony is commercially confidential and/or trade secret information subject to protection pursuant to NRS § 703.190.

VI.

REQUEST FOR DEVIATION FROM REGULATION

NAC § 704.0097 provides that the Commission may allow deviation from any provision of NAC Section 704 if:

(1) Good cause for the deviation appears;

(2) The person requesting the deviation provides a specific reference to each provision of the chapter from which the deviation is requested; and

(3) The Commission finds that the deviation is in the public interest and is not contrary to statute.

NV Energy is seeking deviation from two categories of the regulations. As is set forth above, SB146 requires that this first DRP be filed as an amendment to the NV Energy utilities' 2018 Joint IRP. However, rather detailed regulations governing amendments to the long term planning forecast, fuel and purchased power pricing forecasts, demand-side, or supply-side plans have no applicability to this single-issue DRP. Thus, the Companies are requesting waiver of the following regulations, which are intended to apply to IRP amendments that do not exclusively deal with the DRP. These regulations include:

- NAC § 704.9517(1)(b), a section that specifies any changes in assumptions or data that have occurred since the utility's last resource plan was filed. This first-ever Distributed Resources Plan by definition cannot include changes from prior distributed resources plans.

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- NAC § 704.9517(1)(c), as applicable, information required by NAC 704.9489, selected requirements for the action plans of a resource plan filing. This first-ever Distributed Resources Plan does not include requests to amend the demand-side or supply-side action plans approved by the Commission.
- NAC § 704.9517(1)(d), as applicable, data and information required in selected sections NAC 704.9422 to 704.948. This first-ever DRP does not include requests to amend the supply-side action plan approved by the Commission and so does not include Technical Appendices showing the impact of the DRP on the selection of resources in the approved supply-side plan. It does, however, include five detailed technical appendices specifically addressing the inputs to and information regarding the analyses performed to establish elements of the DRP including the HCA, the GNA and the LNBA.
- NAC § 704.9517(1)(e), a current peak demand forecast. This first-ever DRP is based on distribution-level and transmission-level forecasts of both load and distributed resources. A system-level peak demand forecast does not provide any information relevant to the types of forecasts used in preparing the DRP.
- NAC § 704.9517(1)(f), a table indicating the current loads and resources. A distributed resources plan is not intended to solve for the differences between system loads and system resources—that is the function of a supply-side analysis. Thus, a system-level loads and resources table provides no information relevant to the determination of distribution feeder-level needs or options, whether traditional or non-wires solutions, to fill that need.
- NAC § 704.9517(1)(g), where the utility seeks an amendment related to a renewable energy contract or energy efficiency contract, information about the imputed debt mitigation. This provision is not applicable to distributed resources plans.

Good cause appears for each of the above requests for deviation from the general (and in the case of an IRP amendment addressing only a DRP, the irrelevant) provisions governing the contents of an amendment to an IRP. Deviation from the specific provisions set forth above is not contrary to statute and deviation is in the public interest.

The Companies also request deviation from certain specific provisions of the Temporary Regulations adopted in November 2018. Each of these requests is set forth below.

- Section 8.2 of the Temporary Regulations states in part that *"The net distribution system load and distributed resource forecast will include system, substation, and feeder level net load projections and energy and demand characteristics for all distributed resource types."* The Companies utilized net distribution feeder, substation transformer, and transmission forecasts to determine the constraints on the T&D systems. While system-level forecasts for Distributed Resources types were filed with the Commission in Docket No. 18-06003, and this DRP does not alter those forecasts in any way, the Companies were not able in the time provided between filings to disaggregate those system-level forecasts to the substation and feeder level. As noted in Section 8.A of this DRP, the Companies plan to complete this disaggregation by the summer of 2019 as a prerequisite for conducting future years HCA for the years 2018-2025 (to be completed by October 2019).
- Section 8.3 of the Temporary Regulations states in part that the *"Hosting Capacity Analysis shall be performed using a load flow analyses and forecasted distribution facilities and their capacity, configuration, loading and voltage data gathered at the substation, feeder, and primary node levels."* Although the Companies were not able to complete the HCA using forecasted conditions on the distribution system, as noted in Section 8.B of this DRP, they plan to include these elements for the years of 2018 through 2025, inclusive, by October 2019. These refinements to the HCA will be

reported in an update to this DRP to be filed with the Commission on or before September 1, 2020.

- Section 8.3 of the Temporary Regulations further states regarding HCA that *"Scenario analysis will be performed to evaluate hosting capacity under normal and planned and unplanned contingency conditions."* The Companies completed the HCA under normal system operating conditions, but were not able in the time provided or with the resources that they were able to acquire, to perform scenario analysis around planned or unplanned contingency conditions. As noted in Section 8.B of this DRP, the Companies plan to acquire the resources and to complete the HCA including these elements by July 2020, and to report on that analysis and the results in an update to this DRP to be filed with the Commission on or before September 1, 2020.
- Section 8.4 of the Temporary Regulations states in part that the *"Grid Needs Analysis shall be based on the net distribution system load and distributed resource forecast …."* As set forth above, the Companies plan to disaggregate its existing system-level Distributed Resource forecasts down to the substation and feeder level by this summer 2019, and to perform a study later this year to determine the potential magnitude of the effects of Distributed Resources on the distribution planning load forecasting process by the end of this year. "Propensity to adopt" forecasting techniques will be explored by the end of October 2020. Future GNAs will then be based upon Distributed Resource forecasts at the substation and feeder levels.

Good cause appears for each of the above requests for deviation from the most advanced but not as yet technically achievable portions of the Temporary Regulations. Keeping with the "Walk-Jog-Run" approach adopted by the Companies and the stakeholders, work continues on the technical aspects of the HCA and work on two of the four requested deviations will be completed by October 2019, while the remaining two will be completed in time for the

Companies' next DRP filing. Deviation from the specific provisions set forth above is not contrary to statute and deviation is in the public interest.

VII.
PRAYER

WHEREFORE, the Companies requests that the Commission:

(1) Accept this First Amendment to the 2018 Joint IRP, the Companies' first-ever Distributed Resources Plan under SB146 (2017 Legislature), and based upon the information provided in this Application, including the Narrative, Technical Appendices and prepared direct testimony, make the following specific findings.

(2) The load and distributed resource forecasting methods as discussed in Section 3.A.1. of this DRP are prudent and in compliance with Section 8.2 of the Temporary Regulation, subject to the request to waive certain aspects of Section 8.2 of the Temporary Regulations as noted above.

(3) The Hosting Capacity Analysis methods as discussed in Section 3.A.2 of this DRP are prudent and in compliance with Section 8.3 of the Temporary Regulations, subject to the request to waive certain aspects of Section 8.3 of the Temporary Regulations as noted above.

(4) The Grid Needs Assessment methods for the distribution system as discussed in Section 3 of this DRP are prudent and in compliance with Section 8.4 of the Temporary Regulations, subject to the request to waive certain aspects of Section 8.4 of the Temporary Regulations as noted above. This includes the following elements:

a. The identification of distribution constraints and projects as discussed in Section 3.A.3.a.;

b. The Non-Wires Alternative analysis as discussed in Section 3.A.3.b.;

c. The Locational Net Benefits Analysis as discussed in Section 3.A.3.c.; and

d. The traditional upgrade projects and NWA solution recommendations as discussed in Section 3.A.3.d.

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(5) The Grid Needs Assessment methods for the transmission system as discussed in Section 3 of this DRP are prudent and in compliance with Section 8.4 of the Temporary Regulations. This includes the following elements:

a. The identification of transmission constraints and projects as discussed in Section 3.B.2.a.;

b. The Non-Wires Alternative analysis as discussed in Section 3.B.2.b.;

c. The Locational Net Benefits Analysis as discussed in Section 3.B.2.c.; and

d. The analysis of traditional upgrade projects and NWA solutions recommendations as discussed in Section 3.B.2.

(6) The identification of tariffs approved by the Commission that address deployment of Distributed Resources discussed in Section 3.C of this DRP is in compliance with Section 3.3 of the Temporary Regulations.

(7) The identification of existing programs approved by the Commission that address the deployment of Distributed Resources and the methods of effectively coordinating these programs to maximize the locational benefits and minimize the incremental costs of DERs discussed in Sections 3.D and 3.E of this DRP is in compliance with Section 3.5 of the Temporary Regulations.

(8) The identification of barriers to the deployment of DERs discussed in Section 4 of this DRP is in compliance with Section 3.5 of the Temporary Regulations.

(9) The development and deployment of a publicly-accessible Web Portal that provides maps and accessible electronic data, discussed in Section 7 of the DRP, was prudent and in compliance with Section 8.3 of the Temporary Regulations.

(10) The incremental utility investment and expenditures discussed in Section 9.B of the DRP and set forth the table below are approved as prudent and in compliance with Section 3.4 of the Temporary Regulations.

INCREMENTAL INVESTMENT TO DEVELOP DRP

Project	Nevada Power	Sierra	Total
DER Data Integration & Automation	$100,138	$100,137	$200,275
Publicly-accessible Web Portal	$193,324	$193,323	$386,647
Consultant Labor to Develop DRP	$85,466	$85,466	$170,932
DER Analytics Dashboard	$162,157	$99,961	$262,118
		GRAND TOTAL	**$1,019,972**

(11) The recommendations for the construction of traditional upgrade projects and associated estimated expenditures discussed in Section 3.A.3.d of the DRP are approved as prudent.

(12) Grant such additional other relief as the Commission may deem appropriate and necessary.

Dated this 1st day of April, 2019.

Respectfully submitted,

NEVADA POWER COMPANY
SIERRA PACIFIC POWER COMPANY

<u>*/s/ Michael Greene*</u>
Michael Greene
Senior Attorney
Nevada Power Company
Sierra Pacific Power Company
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<u>*/s/ Timothy Clausen*</u>
Timothy Clausen
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APPLICATION EXHIBIT A

DRAFT NOTICE

PUBLIC UTILITIES COMMISSION OF NEVADA
DRAFT NOTICE
(Applications, Tariff Filings, Complaints, and Petitions)

Pursuant to Nevada Administrative Code ("NAC") 703.162, the Commission requires that a draft notice be included with all applications, tariff filings, complaints and petitions. Please complete and include **ONE COPY** of this form with your filing. (Completion of this form may require the use of more than one page.)

A title that generally describes the relief requested (see NAC 703.160(4)(a)):

> **Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy, seeking approval of the First Amendment to 2018 Joint Integrated Resource Plan, a Distributed Resources Plan prepared and filed pursuant to NRS § 704.751(5) as amended by SB146 (2017 Legislature)**

The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (see NAC 703.160(4)(b)):

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

A brief description of the purpose of the filing or proceeding, including, without limitation, a clear and concise introductory statement that summarizes the relief requested or the type of proceeding scheduled **AND** the effect of the relief or proceeding upon consumers (see NAC 703.160(4)(c)):

> **Nevada Power Company and Sierra Pacific Power Company are seeking approval of their first amendment to their 2018 Joint Integrated Resource Plan, which addresses the first Distributed Resources Plan prepared according to Senate Bill 146 (2017 Legislature). Distributed Resources are defined as "distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies," and the Distributed Resources Plan demonstrates how to evaluate and ensure the cost effective incorporation of Distributed Resources into the utilities' distribution and transmission planning functions.**

A statement indicating whether a consumer session is required to be held pursuant to Nevada Revised Statute ("NRS") 704.069(1)[1]:

No. A consumer session is not required by NRS § 704.069.

If the draft notice pertains to a tariff filing, please include the tariff number **AND** the section number(s) or schedule number(s) being revised.

Not Applicable

[1] NRS 704.069 states in pertinent part:

> 1. The Commission shall conduct a consumer session to solicit comments from the public in any matter pending before the Commission pursuant to NRS 704.061 to 704.110 inclusive, in which:
> (a) A public utility has filed a general rate application, an application to recover the increased cost of purchased fuel, purchased power, or natural gas purchased for resale or an application to clear its deferred accounts; and
> (b) The changes proposed in the application will result in an increase in annual gross operating revenue, as certified by the applicant, in an amount that will exceed $50,000 or 10 percent of the applicant's annual gross operating revenue, whichever is less.

APPLICATION EXHIBIT B

"AS ENROLLED"

Senate Bill No. 146–Senator Spearman

CHAPTER..........

AN ACT relating to energy; requiring certain electric utilities in this State to file with the Public Utilities Commission of Nevada a distributed resources plan; prescribing the minimum requirements of such a plan; revising provisions governing the filing of a plan by one electric utility to increase the supply of electricity or reduce demand; increasing the period by which the Commission must issue an order accepting or modifying certain portions of such a plan or amendments to such a plan; and providing other matters properly relating thereto.

Legislative Counsel's Digest:

Existing law requires an electric utility with an annual operating revenue of $2,500,000 or more in this State to submit to the Public Utilities Commission of Nevada, on or before July 1 of every third year, a plan to increase its supply of electricity or decrease the demands made on its system by its customers. (NRS 704.741) **Section 1** of this bill requires certain affiliated utilities to file a joint plan. Under **sections 1 and 3** of this bill, each utility is required to file a plan on or before June 1, 2018, and on or before June 1 of every third year thereafter.

Section 1 of this bill also requires an electric utility to submit to the Commission, on or before July 1, 2018, a distributed resources plan as part of the plan to increase its supply or decrease the demands on its system. A distributed resources plan must: (1) evaluate locational benefits and costs of distributed resources; (2) propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources; (3) propose cost-effective methods of effectively coordinating existing programs approved by the Commission; (4) identify additional spending necessary to integrate cost-effective distributed resources into distribution planning; and (5) identify barriers to the deployment of distributed resources. Under **section 3**, each utility must submit its first distributed resources plan on or before April 1, 2019.

Existing law requires the Commission to convene a public hearing on the adequacy of a plan to increase supply or reduce demand and to issue an order accepting the plan or specifying any portions of the plan it deems to be inadequate. (NRS 704.746, 704.751) **Section 2** of this bill authorizes the Commission to accept a distributed resources plan that complies with the provisions of **section 1** after such a hearing. **Section 2** also increases from 180 days to 210 days the period by which the Commission must issue an order approving or modifying any portion of a plan to increase supply or reduce demand that does not relate to the energy supply plan of the utility and increases from 135 to 165 days the period by which the Commission must issue an order accepting or modifying an amendment to such a plan.

EXPLANATION – Matter in ***bolded italics*** is new; matter between brackets ~~[omitted material]~~ is material to be omitted.

THE PEOPLE OF THE STATE OF NEVADA, REPRESENTED IN SENATE AND ASSEMBLY, DO ENACT AS FOLLOWS:

Section 1. NRS 704.741 is hereby amended to read as follows:

704.741 1. A utility which supplies electricity in this State shall, on or before ~~[July]~~ ***June*** 1 of every third year, in the manner specified by the Commission, submit a plan to increase its supply of electricity or decrease the demands made on its system by its customers to the Commission. ***Two or more utilities that are affiliated through common ownership and that have an interconnected system for the transmission of electricity shall submit a joint plan.***

2. The Commission shall, by regulation:

(a) Prescribe the contents of such a plan, including, but not limited to, the methods or formulas which are used by the utility ***or utilities*** to:

(1) Forecast the future demands; and

(2) Determine the best combination of sources of supply to meet the demands or the best method to reduce them; and

(b) Designate renewable energy zones and revise the designated renewable energy zones as the Commission deems necessary.

3. The Commission shall require the utility ***or utilities*** to include in ~~[its]~~ ***the*** plan:

(a) An energy efficiency program for residential customers which reduces the consumption of electricity or any fossil fuel and which includes, without limitation, the use of new solar thermal energy sources.

(b) A comparison of a diverse set of scenarios of the best combination of sources of supply to meet the demands or the best methods to reduce the demands, which must include at least one scenario of low carbon intensity that includes the deployment of distributed generation.

(c) An analysis of the effects of the requirements of NRS 704.766 to 704.775, inclusive, on the reliability of the distribution system of the utility ***or utilities*** and the costs to the utility ***or utilities*** to provide electric service to all customers. The analysis must include an evaluation of the costs and benefits of addressing issues of reliability through investment in the distribution system.

(d) A list of the utility's ***or utilities'*** assets described in NRS 704.7338.

(e) A surplus asset retirement plan as required by NRS 704.734.

4. The Commission shall require the utility *or utilities* to include in ~~[its]~~ *the* plan a plan for construction or expansion of transmission facilities to serve renewable energy zones and to facilitate the utility *or utilities* in meeting the portfolio standard established by NRS 704.7821.

5. ***The Commission shall require the utility or utilities to include in the plan a distributed resources plan. The distributed resources plan must:***

(a) Evaluate the locational benefits and costs of distributed resources. This evaluation must be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits and any other savings the distributed resources provide to the electricity grid for this State or costs to customers of the electric utility or utilities.

(b) Propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources that satisfy the objectives for distribution planning.

(c) Propose cost-effective methods of effectively coordinating existing programs approved by the Commission, incentives and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

(d) Identify any additional spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding a net benefit to the customers of the electric utility or utilities.

(e) Identify barriers to the deployment of distributed resources, including, without limitation, safety standards related to technology or operation of the distribution system in a manner that ensures reliable service.

6. As used in this section:

(a) "Carbon intensity" means the amount of carbon by weight emitted per unit of energy consumed.

(b) ***"Distributed generation system" has the meaning ascribed to it in NRS 701.380.***

(c) "Distributed resources" means distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies.

(d) "Renewable energy zones" means specific geographic zones where renewable energy resources are sufficient to develop generation capacity and where transmission constrains the delivery of electricity from those resources to customers.

Sec. 1.5. NRS 704.746 is hereby amended to read as follows:

704.746 1. After a utility has filed its plan pursuant to NRS 704.741, the Commission shall convene a public hearing on the adequacy of the plan.

2. The Commission shall determine the parties to the public hearing on the adequacy of the plan. A person or governmental entity may petition the Commission for leave to intervene as a party. The Commission must grant a petition to intervene as a party in the hearing if the person or entity has relevant material evidence to provide concerning the adequacy of the plan. The Commission may limit participation of an intervener in the hearing to avoid duplication and may prohibit continued participation in the hearing by an intervener if the Commission determines that continued participation will unduly broaden the issues, will not provide additional relevant material evidence or is not necessary to further the public interest.

3. In addition to any party to the hearing, any interested person may make comments to the Commission regarding the contents and adequacy of the plan.

4. After the hearing, the Commission shall determine whether:

(a) The forecast requirements of the utility ***or utilities*** are based on substantially accurate data and an adequate method of forecasting.

(b) The plan identifies and takes into account any present and projected reductions in the demand for energy that may result from measures to improve energy efficiency in the industrial, commercial, residential and energy producing sectors of the area being served.

(c) The plan adequately demonstrates the economic, environmental and other benefits to this State and to the customers of the utility ~~[,]~~ ***or utilities*** associated with the following possible measures and sources of supply:

(1) Improvements in energy efficiency;

(2) Pooling of power;

(3) Purchases of power from neighboring states or countries;

(4) Facilities that operate on solar or geothermal energy or wind;

(5) Facilities that operate on the principle of cogeneration or hydrogeneration;

(6) Other generation facilities; and

(7) Other transmission facilities.

5. The Commission may give preference to the measures and sources of supply set forth in paragraph (c) of subsection 4 that:

(a) Provide the greatest economic and environmental benefits to the State;

(b) Are consistent with the provisions of this section;

(c) Provide levels of service that are adequate and reliable; and

(d) Provide the greatest opportunity for the creation of new jobs in this State.

6. The Commission shall:

(a) Adopt regulations which determine the level of preference to be given to those measures and sources of supply; and

(b) Consider the value to the public of using water efficiently when it is determining those preferences.

7. The Commission shall:

(a) Consider the level of financial commitment from developers of renewable energy projects in each renewable energy zone, as designated pursuant to subsection 2 of NRS 704.741; and

(b) Adopt regulations establishing a process for considering such commitments including, without limitation, contracts for the sale of energy, leases of land and mineral rights, cash deposits and letters of credit.

8. The Commission shall, after a hearing, review and accept or modify an emissions reduction and capacity replacement plan which includes each element required by NRS 704.7316. In considering whether to accept or modify an emissions reduction and capacity replacement plan, the Commission shall consider:

(a) The cost to the customers of the electric utility ***or utilities*** to implement the plan;

(b) Whether the plan provides the greatest economic benefit to this State;

(c) Whether the plan provides the greatest opportunities for the creation of new jobs in this State; and

(d) Whether the plan represents the best value to the customers of the electric utility ~~[.]~~ ***or utilities.***

Sec. 2. NRS 704.751 is hereby amended to read as follows:

704.751 1. After a utility has filed the plan required pursuant to NRS 704.741, the Commission shall issue an order accepting or modifying the plan or specifying any portions of the plan it deems to be inadequate:

(a) Within 135 days for any portion of the plan relating to the energy supply plan for the utility for the 3 years covered by the plan; and

(b) Within ~~[180]~~ ***210*** days for all portions of the plan not described in paragraph (a).

➥ If the Commission issues an order modifying the plan, the utility ***or utilities*** may consent to or reject some or all of the modifications by filing with the Commission a notice to that effect. Any such notice must be filed not later than 30 days after the date of issuance of the order. If such a notice is filed, any petition for reconsideration or rehearing of the order must be filed with the Commission not later than 10 business days after the date the notice is filed.

2. If a utility files an amendment to a plan, the Commission shall issue an order accepting or modifying the amendment or specifying any portions of the amendment it deems to be inadequate:

(a) Within ~~[135]~~ *165* days after the filing of the amendment; or

(b) Within 180 days after the filing of the amendment for all portions of the amendment which contain an element of the emissions reduction and capacity replacement plan.

➥ If the Commission issues an order modifying the amendment, the utility ***or utilities*** may consent to or reject some or all of the modifications by filing with the Commission a notice to that effect. Any such notice must be filed not later than 30 days after the date of issuance of the order. If such a notice is filed, any petition for reconsideration or rehearing of the order must be filed with the Commission not later than 10 business days after the date the notice is filed.

3. All prudent and reasonable expenditures made to develop the utility's ***or utilities'*** plan, including environmental, engineering and other studies, must be recovered from the rates charged to the utility's ***or utilities'*** customers.

4. The Commission may accept ~~[a]~~ ***:***

(a) A transmission plan submitted pursuant to subsection 4 of NRS 704.741 for a renewable energy zone if the Commission determines that the construction or expansion of transmission facilities would facilitate the utility ***or utilities*** meeting the portfolio standard, as defined in NRS 704.7805.

(b) A distributed resources plan submitted pursuant to subsection 5 of NRS 704.741 if the Commission determines that the plan includes each element required by that subsection.

5. The Commission shall adopt regulations establishing the criteria for determining the adequacy of a transmission plan submitted pursuant to subsection 4 of NRS 704.741.

6. Any order issued by the Commission accepting or modifying an element of an emissions reduction and capacity replacement plan must include provisions authorizing the electric utility ***or utilities*** to construct or acquire and own electric generating plants necessary to

meet the capacity amounts approved in, and carry out the provisions of, the plan. As used in this subsection, "capacity" means an amount of firm electric generating capacity used by the electric utility ***or utilities*** for the purpose of preparing a plan filed with the Commission pursuant to NRS 704.736 to 704.754, inclusive.

Sec. 3. 1. Notwithstanding any other provision of law and except as otherwise provided in this subsection, any public utility required to file a plan pursuant to NRS 704.741, as amended by section 1 of this act, shall file a plan pursuant to that section, as amended by section 1 of this act, on or before June 1, 2018. The plan filed by a public utility pursuant to NRS 704.741, as amended by section 1 of this act, on or before June 1, 2018, is not required to include the distributed resources plan required by subsection 5 of NRS 704.741, as amended by section 1 of this act.

2. Any public utility required to file a plan pursuant to NRS 704.741 that would not otherwise be required to file a new plan before July 1, 2018, shall, on or before April 1, 2019, submit an amendment to its existing plan that complies with the provisions relating to a distributed resources plan in subsection 5 of NRS 704.741, as amended by section 1 of this act.

Sec. 4. This act becomes effective on July 1, 2017.

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APPLICATION EXHIBIT C

"TEMPORARY REGULATIONS"

BRIAN SANDOVAL
Governor

STATE OF NEVADA

PUBLIC UTILITIES COMMISSION

November 15, 2018

VIA INTEROFFICE MAIL

Office of the Secretary of State
101 North Carson Street, Suite 3
Carson City, Nevada 89701

RE: Public Utilities Commission of Nevada
LCB File No. T001-18 (Docket No. 17-08022)

To Whom it May Concern:

On October 8, 2018, the Public Utilities Commission of Nevada ("Commission") voted to adopt as temporary the proposed regulation in the above-referenced matter. The regulation implements Senate Bill 146 (2017).

Enclosed are the following: a copy of the Commission's Order regarding the analysis required pursuant to NRS 233B.0608(1); a copy of the Commission's Order adopting the proposed regulation as temporary that includes the final copy of the regulation; an informational statement, the Secretary of State's form for filing administrative regulations; and a notice of adoption of regulation.

Additionally, pursuant to recent LCB requests regarding submittal of permanent regulations, a Statement Regarding Small Business Impact as contemplated by NRS 233B.0608(2), signed by the Executive Director of the Commission as required by NRS 233B.0609(2), is also included. Accompanying the Statement Regarding Small Business Impact are the referenced attachments, the Report by the Regulatory Operations Staff of the Commission filed on August 10, 2018, and the Order of the Commission issued August 16, 2018.

Although the Statement Regarding Small Business Impact is included, such inclusion should not be interpreted as Commission concurrence that inclusion of such is required. A clear reading of NRS 233B.0608 indicates that ***only if*** an agency makes an initial determination, pursuant to subsection (1), of a direct or significant economic burden upon small business, or a direct restriction of the formation, operation or expansion of a small business, ***then*** the agency must conduct the broader analysis contemplated by subsection (2). In this case, the Commission made a well-reasoned finding that the proposed regulations will cause no significant impact on small businesses and so evidenced this conclusion in the Informational Statement submitted pursuant to NRS 233B.066.

The adopted temporary regulation and accompanying materials are also being submitted to the Legislative Counsel Bureau in accordance with NRS 233B.070(2). Please return a copy of the temporary regulation to the Commission bearing the stamp of the Secretary of State, indicating it has been filed with the Secretary of State. This will enable the Commission to comply with NRS 233B.070(6), which directs the agency to submit a file-stamped copy to the State Library and Archives Administrator.

Should you have any questions or concerns, please contact me at 775-684-6121.

Sincerely,

Donald Lomoljo
Utilities Hearing Officer
dlomoljo@puc.nv.gov

Enclosures

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Investigation and rulemaking to implement Senate Bill 146 (2017).	)))	Docket No. 17-08022

At a general session of the Public Utilities Commission of Nevada, held at its offices on September 26, 2018.

PRESENT: Chairman Ann Wilkinson
Commissioner Ann Pongracz
Commissioner Bruce H. Breslow
Assistant Commission Secretary Trisha Osborne

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

The Commission opened an investigation and rulemaking, designated as Docket No. 17-08022, to implement Senate Bill ("SB") 146 (2017).

II. SUMMARY

The proposed regulation, attached hereto as Attachment 1, is adopted as a temporary regulation.

III. PROCEDURAL HISTORY

- On September 15, 2017, the Commission opened an investigation and rulemaking to implement SB 146 (2017).
- The Commission is conducting this investigation and rulemaking in accordance with Chapters 703 and 704 of the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), including but not limited to NRS 703.025 and 704.210.
- On September 15, 2017, the Commission issued a Notice of Rulemaking, Notice of Request for Comments, and Notice of Workshop.
- On October 13, 2017, the Attorney General's Bureau of Consumer Protection ("BCP"); the Energy Storage Association ("ESA"); Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (together, "NV Energy"); Tesla, Inc. ("Tesla"); Vote Solar; and the Regulatory Operations Staff ("Staff") of the Commission filed comments.

- On October 26, 2017, BCP, NV Energy, Tesla, Vote Solar, Western Resource Advocates ("WRA"), and Staff filed reply comments.
- On November 7, 2017, the Hearing Officer held a Workshop. BCP, the Interstate Renewable Energy Council ("IREC"), NV Energy, Tesla, WRA, and Staff made appearances. The participants discussed the comments and reply comments.
- On November 9, 2017, the Hearing Officer issued a Procedural Order, adopting a procedural schedule.
- On February 21, 2018, the Hearing Officer held a Continued Workshop. BCP, IREC, NV Energy, Tesla, Vote Solar, WRA, and Staff made appearances. The participants discussed the informal meetings held by the participants.
- On February 22, 2018, the Hearing Officer issued Procedural Order No. 2, adopting a procedural schedule.
- On February 22, 2018, the Commission issued a Notice of Workshop.
- On June 1, 2018, BCP; IREC jointly with WRA and Vote Solar; and NV Energy filed comments and proposed language.
- On June 8, 2018, BCP, IREC, NV Energy, Tesla, and Staff filed comments.
- On June 14, 2018, the Hearing Officer held a Workshop. BCP, IREC, NV Energy, Tesla, WRA, and Staff made appearances. The participants discussed the proposed language filed by the various participants.
- On July 25, 2018, the Commission issued a Notice of Intent to Act Upon a Regulation, Notice of Workshop, and Notice of Hearing for the Adoption, Amendment and Repeal of Regulations of the Commission.
- On July 25, 2018, the Hearing Officer issued Procedural Order No. 3 with a proposed regulation attached. Staff was directed to conduct an investigation pursuant to NRS 233B.0608 to determine whether the proposed regulation is likely to: (a) impose a direct and significant economic burden upon a small business; or (b) directly restrict the formation, operation or expansion of a small business.
- On August 9, 2018, the Hearing Officer sent a letter to the Legislative Counsel Bureau ("LCB") with the proposed regulation attached, requesting that the regulation be assigned an LCB file number.
- On August 10, 2018, Staff filed a briefing memorandum regarding the small business impact statement required to be considered pursuant to NRS 233B.0608(2).

- On August 16, 2018, the Commission issued an Order finding that the proposed regulation does not impose a direct and significant burden upon small businesses, nor does it directly restrict the formation, operation, or expansion of a small business.

- On August 23, 2018, BCP; NV Energy; Staff; and IREC, WRA, and Vote Solar (the "Joint Commenters") filed comments.

- On August 30, 2018, the Hearing Officer held a workshop. BCP, IREC, NV Energy, and Staff made appearances and discussed the proposed regulation.

- On September 5, 2018, the Hearing Officer held a hearing. BCP, NV Energy, IREC, WRA, and Staff made appearances and discussed the proposed regulation.

IV. SUMMARY OF PUBLIC RESPONSE[1]

1. BCP, the Joint Commenters, NV Energy, and Staff filed comments regarding the proposed regulation. Each participant generally supported the proposed regulation. BCP suggested a modification to limit the scope of the "Grid Needs Assessment" to distribution rather than transmission resources as well as a modification to add a supply side comparison. The Joint Commenters generally recommended additional requirements for the hosting capacity analysis including iterative monthly improvements in the analysis, additional formatting requirements such as color coding and downloadable files, and an extended forecast period. NV Energy suggested deleting the requirement that a distributed resources plan include a narrative describing the utility's progress toward publicly available real-time hosting capacity. Staff noted a typographical error and suggested insertion of language allowing for Commission modification of a DRP in accordance with the authority granted in SB 87 (2015).

V. REGULATION

2. The attached regulation implements SB 146 (2017) by setting forth the filing, content, update and approval requirements for a distributed resources plan ("DRP"). The regulation was developed in large part through a collaborative process resulting in a regulation that is consistent with SB 146 and, for the most part, a consensus document. The regulation

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[1] This section only summarizes public response to the proposed regulation issued on July 25, 2018.

allows for stakeholder input into development of the DRP process including moving towards a common goal of establishing needs-based hosting capacity information for distributed resource developers; requiring a cost/benefit analysis that compares DRP resources to conventional resources; and facilitates Commission directives for improvements to the DRP process.

THEREFORE, it is ORDERED:

1. The proposed regulation attached hereto as Attachment 1 is ADOPTED AS TEMPORARY.

By the Commission,

ANN WILKINSON, Chairman

ANN PONGRACZ, Commissioner

BRUCE H. BRESLOW, Commissioner

Attest:
TRISHA OSBORNE
Assistant Commission Secretary

Dated: Carson City, Nevada
10/8/18

(SEAL)

PUBLIC UTILITIES COMMISSION OF NEVADA
PUC

ATTACHMENT 1

PROPOSED REGULATION OF THE
PUBLIC UTILITIES COMMISSION OF NEVADA

Docket No. 17-08022

September 26, 2018

Explanation -- Matter in *italics* is new; matter in brackets [~~omitted material~~] is material to be omitted

Section 1. Chapter 704 of the NAC is hereby amended by adding thereto the provisions set forth as sections 2-11 of this regulation.

Sec. 2. NAC 704.905X. "Distributed Resources" defined. "Distributed resources" means distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies, which can be in front of or behind the meter.

Sec. 3. NAC 704.905X. "Distributed Resources Plan" defined. "Distributed resources plan" means a plan which:

1. Identifies and evaluates the locational benefits and costs of distributed resources. The evaluation of locational benefits and costs of distributed resources must be based on:

a. reductions or increases in local generation capacity needs,

b. avoided or increased localized investments in distribution infrastructure,

c. reductions to or increases in safety benefits of the electric grid,

d. reductions to or increases in the reliability benefits of the electric grid,

e. other localized savings that distributed resources provide to the electric grid; and

f. other costs that distributed resources impose on customers of the electric utilities.

2. Identifies, evaluates and, in order to maximize locational benefits and minimize the incremental cost of distributed resources, may propose standard tariff offerings, bilateral contracts, competitive solicitations and/or other mechanisms pursuant to which cost-effective distributed resources will be deployed.

3. Identifies existing programs approved by the Commission that address deployment of distributed resources, including tariffs and incentives, and proposes cost-effective methods for effectively coordinating deployment of distributed resources with existing programs in order to maximize locational benefits and minimize the incremental cost of distributed resources.

4. Identifies and evaluates any necessary incremental utility investment or expenditures to be funded to integrate cost-effective distributed resources into the distribution planning process consistent with the goal of yielding a net benefit to the customers of the electric utility or utilities.

5. Identifies and evaluates potential barriers to the deployment of distributed resources, including, without limitation, safety standards related to technology or operation of the distribution system. Any recommendations regarding accepting or overcoming identified potential barriers will ensure the safety of the distribution grid and reliability of service.

Sec. 4. NAC 704.910X. "Grid Needs Assessment" defined. "Grid Needs Assessment" means a summary that includes the constraints on a utility's electric grid and solutions to those constraints. It includes all analysis of non-wires alternatives' suitability to mitigate identified constraints, results of locational net benefit analyses and recommendations for the deployment of utility infrastructure upgrade solutions and non-wires alternative solutions to identified constraints.

Sec. 5. NAC 704.910X. "Locational Net Benefit Analysis" defined. "Locational Net Benefit Analysis" means a cost benefit analysis of Distributed Resources that incorporates the location-specific net benefits to the electric grid.

Sec. 6. NAC 704.905X. "Non-Wires Alternative" defined. "Non-Wires Alternative" means a solution to an identified constraint(s) on the utility's electric grid that may include the deployment of a distributed resource or suite (package) of distributed resources.

Sec. 7. NAC 704.905X. "Hosting Capacity Analysis" defined. "Hosting Capacity Analysis" means the analysis to determine the amount of distributed resources that can be accommodated on a particular feeder section of the distribution system at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

Sec. 8. NAC 704.948X Requirements for distributed resources plan; consistency with action plan; annual filings.

1. The resource plan of a utility must contain a distributed resources plan for the 3 years covered by the action plan of the utility. The distributed resources plan of a utility must be consistent with the action plan of the utility.

2. The distributed resources plan must be developed by a utility using a forecast of net distribution system load and distributed resources. The forecast period shall be a 6-year period, at minimum, beginning with the year after the distributed resources plan is filed. The net distribution system load and distributed resource forecast will include system, substation and feeder level net load projections and energy and demand characteristics for all distributed resource types. Updates to the net distribution system load and distributed resource forecast will be filed at least annually in accordance with Section 10 of this regulation.

3. As part of its distributed resources plan, a utility shall develop a Hosting Capacity Analysis of the distribution system. The Hosting Capacity Analysis shall be performed using a load flow analyses and forecasted distribution facilities and their capacity, configuration, loading and voltage data gathered at the substation, feeder and primary node levels. Scenario analyses will be performed to evaluate hosting capacity under normal and planned and unplanned contingency conditions. The utility shall provide a detailed description of the methods and outcomes it used to perform the Hosting Capacity Analysis. Until otherwise ordered by the Commission, updates to the distribution system Hosting Capacity Analysis shall be made publicly available at least bi-annually, or two times a year, once as filed in accordance with Section 10 of this regulation, and at least one additional time via the utility's public internet website. The utility's website shall contain a portal that provides maps and accessible electronic data suitable for distribution to the public. The distributed resources plan shall include a *narrative describing the utility's progress toward providing publicly available real-time hosting capacity.*

4. As part of its distributed resources plan, the utility shall develop a Grid Needs Assessment. The Grid Needs Assessment shall be based on the net distribution system load and distributed resource forecast and the facilities capacity analysis and shall include the Hosting Capacity Analysis, the results of a Non-Wires Alternative and a Locational Net Benefits Analysis to compare utility infrastructure upgrade solutions and distributed resource solutions to forecasted transmission and distribution system constraints. Updates to the Grid Needs Assessment will be filed at least annually in accordance with Section 10 of this regulation.

5. The distributed resources plan shall include recommendations for: new cost-effective distributed resources, utility infrastructure upgrade solutions which have been determined to be the preferred solution to constraints on a utility's electric grid on the basis of the analysis in the Grid Needs Assessment, and sourcing of distributed resource solutions. Recommendations will be based on the Locational Net Benefit Analysis of resource options to utility customers.

6. The utility shall identify and justify any change in methodology of forecasting, Hosting Capacity Analysis or Grid Needs Assessment from that used in the utility's previous resource plan.

7. The distributed resources plan shall include forecasted loads and distributed resources growth for the distribution electric grid over a 6-year period, at minimum, beginning with the year after the distributed resources plan is filed.

8. The distributed resources plan shall include a summary that explains how distributed resources have affected the need for supply side resources in the resource planning process. The summary shall include but not be limited to: the effect of distributed resources on the need for new generation and transmission resources; and how distributed resources are integrated into the transmission planning and supply side planning portions of the resource planning process.

9. The distributed resources plan shall include a summary that describes the results of an informal stakeholder process to discuss recommendations for improvements to the Hosting Capacity Analysis. The informal stakeholder process shall occur not less than 120 days prior to the filing of a distributed resources plan and be organized by the utility.

10. The distributed resources plan of a utility must include a technical appendix that conforms to NAC 704.922.

Sec. 9. NAC 704.950X Deviation from and amendment of distributed resources plan.

1. Notwithstanding the approval by the Commission of the distributed resources plan of a utility, the utility may deviate from the approved distributed resources plan to the extent necessary to respond adequately to any significant change(s) in circumstances not contemplated by the distributed resources plan. A significant change in circumstances includes, without limitation:

(a) A material change in net system, feeder or nodal customer load or demand;

(b) A material difference between the estimated and actual locational net benefit results for any or all resources analyzed in the Grid Needs Assessment;

(c) A material difference between estimated and actual in-service dates or performance of distributed resources analyzed and selected pursuant to the distributed resources plan;

(d) Any other circumstance that the utility demonstrates to the Commission warrants a deviation.

2. If the utility deviates from its approved distributed resources plan, the utility shall include in the rate proceeding in which costs associated with the deviation are first sought to be recovered a description and justification for the deviation.

3. The utility may seek authority from the Commission to deviate prospectively from the distributed resources plan in an update filed pursuant to Section 10 of this regulation, or by filing an amendment to the distributed resources plan in accordance with subsection 4.

4. An amendment to the distribution resources plan of a utility must contain:

(a) A section that identifies the specific approvals requested by the utility in the amendment;

(b) A section that specifies any changes in assumptions or data that have occurred since the utility's last resource plan was filed; and

(c) As applicable, information required in Section 8 of this regulation.

The Commission will conduct its evaluation of the amendment of the distributed resources plan in accordance with Subsection 4 of Section 15 of this regulation and issue an order approving the amendment as filed, modifying the amendment, or specifying those parts of the update that the Commission considers inadequate.

Sec. 10. NAC 704.950XX Update of distributed resources plan: Filing; requirements.

1. Beginning in calendar year 2020, on or before September 1 of the first and second years after the action plan of a utility is filed, the utility shall file an update of the distributed resources plan that will be applicable for each year remaining in the period covered by the action plan.

2. The update of the distributed resources plan must comply with the requirements of Section 8 of this regulation.

Sec. 11. NAC 704.950XXX Update of distributed resources plan: Action by Commission.

1. The Commission will conduct a hearing within 60 days after a utility files an update of its distributed resources plan and issue an order within 120 days after the filing of that update by the utility.

2. The Commission will conduct its evaluation of the update of the distributed resources plan in accordance with Subsection 4 of Section 15 of this regulation and issue an order approving the update as filed, modifying the update, or specifying those parts of the update that the Commission considers inadequate.

Sec. 12. NAC 704.9156 is hereby amended to read as follows:
Resource plan" means the plan that a utility is required by NRS 704.741 to submit every third year to the Commission, that consists of, and provides an integrated analysis of:

1. A load forecast;
2. A demand side plan;
3. A supply plan;
4. A financial plan;
5. An energy supply plan;
6. *A distributed resources plan; and*
7. An action plan.

Sec. 13. NAC 704.9215 is hereby amended to read as follows:

1. A utility's resource plan must be accompanied by a summary that is suitable for distribution to the public. The summary must contain easily interpretable tables, graphs and maps and must not

contain any complex explanations or highly technical language. The summary must be approximately ~~[30]~~ ***40*** pages in length.

2. The summary must include:

(a) A brief introduction, addressed to the public, describing the utility, its facilities and the purpose of the resource plan, and the relationship between the resource plan and the strategic plan of the utility for the duration of the period covered by the resource plan.

(b) The forecast of low growth, the forecast of high growth and the forecast of base growth of the peak demand for electric energy and of the annual electrical consumption, for the next 20 years, commencing with the year following the year in which the resource plan is filed, both with and without the impacts of programs for energy efficiency and conservation and an explanation of the economic and demographic assumptions associated with each forecast.

(c) A summary of the demand side plan listing each program and its effectiveness in terms of costs and showing the 20-year forecast of the reduction of demand and the contribution of each program to this forecast.

(d) A summary of the preferred plan showing each planned addition to the system for the next 20 years, commencing with the year following the year in which the resource plan is filed, with its anticipated capacity, cost and date of beginning service.

(e) A summary of renewable energy showing how the utility intends to comply with the portfolio standard and listing each existing contract for renewable energy and each existing contract for the purchase of renewable energy credits and the term and anticipated cost of each such contract.

(f) A summary of:

(1) The energy supply plan for the next 3 years setting out the anticipated cost, price volatility and reliability risks of the energy supply plan;

(2) The risk management strategy;

(3) The fuel procurement plan; and

(4) The purchased power procurement plan.

(g) A summary of the distributed resources plan for the next 3 years covered by the action plan of the utility setting out:

(1) The locational benefits and costs of distributed resources, which may include benefits and costs for the electric grid.

(2) Identified barriers and recommendations to accept or overcome these barriers to the deployment of cost-effective distributed resources and proposed mechanisms pursuant to which cost-effective distributed resources will be deployed, in coordination with existing Commission-approved programs.

(3) Incremental utility investment or expenditures to be funded for the next 3 years to identify, evaluate and integrate cost-effective distributed resources into the distribution planning process.

(4) A summary of the methods and outcomes of the Hosting Capacity Analysis described in Section 8 of this regulation.

(5) A summary of forecasted loads and DER growth for the electric grid over a 6-year period, at minimum, beginning with the year after the distributed resources plan is filed.

(*h*) A summary of the activities, acquisitions and costs included in the action plan of the utility.

(*i*) An integrated evaluation of the components of the resource plan which relates the preferred plan to the objectives of the strategic plan of the utility, and any other information useful in presenting to the public a comprehensive summary of the utility and its expected development.

Sec. 14. NAC 704.9489 is hereby amended to read as follows:

1. Each resource plan of a utility must include a detailed action plan based on an integrated analysis of the demand side plan and supply plan of the utility. In its action plan, the utility shall specify all its actions that are to take place during the 3 years commencing with the year following the year in which the resource plan is filed. The action plan must contain:

(a) An introductory section that explains how the action plan fits into the longer-term strategic plan of the utility.

(b) A list of actions for which the utility is seeking the approval of the Commission.

(c) A schedule for the acquisition of data, including planned activities to update and refine the quality of the data used in forecasting.

(d) A specific timetable for acquisition of options for the supply of electric energy and for programs for energy efficiency and conservation.

(e) If changes in the methodology are being proposed, a description fully justifying the proposed changes, including an analysis of the costs and benefits. Any changes in methodology that are approved by the Commission must be maintained for the period described in the action plan.

(f) A section describing any plans of the utility to acquire additional modeling instruments.

(g) A section for the utility's program for energy efficiency and conservation, including:

(1) A description of continued planning efforts;

(2) A plan to carry out and continue selected measures for energy efficiency and conservation that have been identified as desirable; and

(3) Any impacts of imputed debt calculations associated with energy efficiency contracts in the preferred plan.

(h) A section for the utility's program for acquisition of resources for the supply of electric energy for the period covered by the action plan, including:

(1) The immediate plans of the utility for construction of facilities or long-term purchases of power;

(2) The expected time for construction of facilities and acquisition of long-term purchases of power identified in subparagraph (1);

(3) The major milestones of construction; and

(4) Any impacts of imputed debt calculations associated with renewable energy contracts or energy efficiency contracts in the preferred plan.

2. The action plan must contain an energy supply plan ***and a distributed resources plan***.

3. The action plan must contain a budget for planned expenditures suitable for comparing planned and achieved expenditures. Expenses must be listed in a format that is consistent with the categories and periods to be presented in subsequent filings. The budget must be organized in the following categories:

(a) Forecasting of loads;

(b) Energy efficiency and conservation;

(c) ***Distributed Resources;***

(d) Plan for supply; and

(e) Financial plan.

4. The action plan must contain schedules suitable for comparing planned and actual activities and accomplishments. Milestones and points of decision committing major expenditures must be shown.

5. The action plan must contain a renewable energy zone transmission action plan for serving one or more of the renewable energy zones designated by the Commission or an explanation of why no renewable energy zone transmission action plan is contained in the action plan. In addition to the other action plan requirements set forth in this section, the renewable energy zone transmission action plan must include, with supporting data and documentation, for each action item recommended by the utility:

(a) For permitting, routing study and right-of-way acquisition expenses, evidence addressing:

(1) How such expenditures will facilitate compliance with NRS 704.7821 in a manner consistent with NAC 704.8901 to 704.8937, inclusive; and

(2) All other benefits Nevada retail ratepayers will derive from the expenses;

(b) For proposed construction and expansion of transmission facilities:

(1) Evidence of how the proposed construction and expansion will facilitate compliance with NRS 704.7821 in a manner consistent with NAC 704.8901 to 704.8937, inclusive;

(2) A listing and description, including detailed cost estimates and development schedules, of the transmission facilities recommended by the utility for construction or expansion;

(3) A listing and description of transmission alternatives that were considered by the utility, including transmission development partnerships;

(4) Data and economic analysis that supports the transmission projects recommended by the utility, including, without limitation, a comparison of the levelized cost, including transmission, of procuring renewable resources from the renewable energy zones proposed to be served by the utility's recommended transmission projects to other renewable resource options, including those that are located in and out of renewable energy zones designated by the Commission;

(5) Evidence of the financial commitments from developers of renewable energy projects located in the affected renewable energy zones;

(6) An estimate of the level of capacity and energy that the utility expects to utilize from the affected renewable energy zones in the next 20 years, commencing with the year following the year in which the resource plan is filed; and

(7) The estimated time frame to fully utilize the capacity of the construction and expansion of transmission facilities recommended by the utility; and

(c) In addition to the renewable energy zone transmission action plan requirements set forth in paragraph (b), for construction and expansion of transmission infrastructure that will serve both Nevada retail ratepayers and export markets outside of Nevada:

(1) Evidence that any renewable energy developers wishing to export energy outside of Nevada have a buyer for their energy and that the buyer has a means of delivering the energy from the transmission system of the Nevada utility to the point of delivery;

(2) A strategic plan to mitigate the potential financial risks to Nevada retail ratepayers associated with stranded investment and infrastructure that is not intended to provide service to Nevada retail ratepayers, including, without limitation, safeguards to monitor the financial risk to Nevada's retail ratepayers and criteria to trigger an amendment to the renewable energy transmission action plan should changes in circumstance occur which could expose Nevada retail ratepayers to such risks; and

(3) Identification of the potential resources in the renewable energy zones, including the resources under contract, resources under development, known completion dates and the known amount of capacity and energy to be produced by renewable energy projects in the affected renewable energy zones for customers outside of Nevada.

Sec. 15. NAC 704.9494 is hereby amended to read as follows:

1. The Commission will issue an order:

(a) Approving the action plan of the utility as filed; or

(b) If the plan is not approved as filed, specifying those parts of the action plan the Commission considers inadequate.

2. Approval by the Commission of an action plan constitutes a finding that the programs and projects contained in that action plan, other than the energy supply plan ***and distributed resources plan***, are prudent, including, without limitation, construction of facilities, purchased power obligations, programs for energy efficiency and conservation and impacts of imputed debt calculations associated with renewable energy contracts or energy efficiency contracts. If the Commission subsequently determines that any information relied upon when issuing its order approving the action plan was based upon information that was known or should have been known by the utility to be untrue or false at the time the information was presented, the Commission may revoke, rescind or otherwise modify its approval of the action plan.

3. If, at the time that the Commission approves the action plan of the utility, the Commission determines that the elements of the energy supply plan are prudent, the Commission will specifically include in the approval of the action plan its determination that the elements contained in the energy supply plan are prudent. For the Commission to make a determination that the elements of the energy supply plan are prudent:

(a) The energy supply plan must 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.

(b) The energy supply plan must optimize the value of the overall supply portfolio for the utility for the benefit of its bundled retail customers.

(c) The utility must demonstrate that the energy supply plan 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.

Failure by a utility to demonstrate that its energy supply plan is prudent in accordance with this subsection does not otherwise affect approval of the action plan, including the energy supply plan, and the utility may subsequently seek a determination that the energy supply plan is prudent in the appropriate deferred energy proceeding.

4. At the time that the Commission approves the action plan of the utility, the Commission shall make a determination as to whether the elements of the distributed resources plan are prudent. The Commission shall specifically include in the approval of the action plan its determination that the elements contained in the distributed resources plan are prudent. For the Commission to make the determination that the elements of the distributed resources plan are prudent, the Commission must determine that:

(a) The net distribution system load and distributed resource forecasts, Hosting Capacity Analysis, Grid Needs Assessment, and the Non-Wires Alternative and Net Locational Benefits Analyses have been prudently performed, and

(b) The selections of new distributed resources set forth in the distributed resources plan are reasonable.

5. A utility may recover all costs that it prudently and reasonably incurs in carrying out an approved action plan in the appropriate separate rate proceeding. ***A utility may recover all costs it***

prudently and reasonably incurs in carrying out an approved distributed resources plan, in the appropriate separate rate proceeding. A utility may recover all costs that are prudently and reasonably incurred in carrying out the approved energy supply plan, including deviations pursuant to subsection 1 of NAC 704.9504 approved by the Commission in the appropriate deferred energy application filed pursuant to NAC 704.023 to 704.195, inclusive.

Sec. 16. NAC 704.9208 is hereby repealed.

TEXT OF REPEALED SECTION

NAC 704.9208 Dates for certain utilities to file resource plans.

1. The resource plans required to be submitted by Nevada Power Company pursuant to NRS 704.741 must be filed on July 1, 1988, and every 3 years thereafter.

2. The resource plans required to be submitted by Sierra Pacific Power Company pursuant to NRS 704.741 must be filed on July 1, 1989, and every 3 years thereafter.

LEGISLATIVE REVIEW OF ADOPTED REGULATIONS--NRS 233B.066
Informational Statement
LCB File No. T001-18

1. **A clear and concise explanation of the need for the adopted regulation.**

   The regulation implements Senate Bill ("SB") 146 (2017).

2. **Description of how public comment was solicited, a summary of public response, and an explanation of how other interested persons may obtain a copy of the summary.**

   (a) Copies of the proposed regulation, notice of intent to act upon the regulation and notice of workshop and hearing were sent by U.S. mail and email to persons who were known to have an interest in the subjects of noticing and interventions. These documents were also made available at the website of the PUCN, http://puc.nv.gov, mailed to all county libraries in Nevada, published in the following newspapers:

   Ely Times
   Las Vegas Review Journal
   Nevada Appeal
   Reno Gazette Journal
   Tonopah Times-Bonanza,

   and posted at the following locations:

Public Utilities Commission 1150 East William Street Carson City, Nevada 89701	Public Utilities Commission 9075 West Diablo Drive, Suite 250 Las Vegas, Nevada 89148

   (b) The Attorney General's Bureau of Consumer Protection ("BCP"); the Energy Storage Association ("ESA"); the Interstate Renewable Energy Council, Inc. ("IREC"); Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (collectively "NV Energy"); Tesla, Inc. ("Tesla"); Vote Solar; Western Resource Advocates ("WRA"); and the Regulatory Operations Staff ("Staff") of the Commission filed comments in the matter. The commenters generally supported the proposed regulation with some suggestions for modification of specific provisions as summarized at ¶1 of the October 8, 2018, PUCN Order adopting the regulation as temporary.

   (c) Copies of the transcripts of the proceedings are available for review at the offices of the PUCN, 1150 East William Street, Carson City, Nevada 89701 and 9075 West Diablo Drive, Suite 250, Las Vegas, Nevada 89148.

3. **The number of persons who:**

   (a) **Attended each hearing:** 5

   (b) **Testified at each hearing:** 5

   (c) **Submitted written comments:** 6

4. **For each person identified in paragraphs (b) and (c) of number 3 above, the following information if provided to the agency conducting the hearing:**

   (a) Name;

   (b) Telephone number;

   (c) Business address;

   (d) Business telephone number;

   (e) Electronic mail address; and

   (f) Name of entity or organization represented.

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5. **A description of how comment was solicited from affected businesses, a summary of their response and an explanation of how other interested persons may obtain a copy of the summary.**

Comments were solicited from affected businesses in the same manner as they were solicited from the public.

The summary may be obtained as instructed in the response to question 2(c).

6. **If the regulation was adopted without changing any part of the proposed regulation, a summary of the reasons for adopting the regulation without change.**

Proposed revisions to the regulation proposed by the participants were generally incorporated in the regulation.

7. **The estimated economic effect of the regulation on the business which it is to regulate and on the public. These must be stated separately, and in each case must include: both adverse and beneficial effects, and both immediate and long-term effects.**

(a) Estimated economic effect on the businesses which they are to regulate.

The regulation does not impose any economic effect on the businesses the regulation is to regulate.

(b) Estimated economic effect on the public which they are to regulate.

The regulation does not regulate the public.

8. **The estimated cost to the agency for enforcement of the proposed regulation:**

Any costs associated with the regulation are considered incremental in nature.

///

9. **A description of any regulations of other State or governmental agencies which the regulation overlaps or duplicates and a statement explaining why the duplication or overlap is necessary. If the regulation overlaps or duplicates a federal regulation, the name of the regulating federal agency.**

The regulation does not overlap or duplicate other State of federal regulations.

10. **If the regulation includes provisions that are more stringent than a federal regulation that regulates the same activity, a summary of such provisions.**

N/A

11. **If the regulation provides a new fee or increases an existing fee, the total annual amount the agency expects to collect and the manner in which the money will be used.**

N/A

12. **If the proposed regulation is likely to impose a direct and significant burden upon a small business or directly restrict the formation, operation or expansion of a small business, what methods did the agency use in determining the impact of the regulation on a small business?**

The Regulatory Operations Staff ("Staff") of the Commission conducted a Delphi Method exercise to determine the impact of this proposed regulation on small businesses. The Delphi Method is a systematic, interactive, forecasting method based on independent inputs of selected experts. In this instance, the participants were members of Staff. Each participant in the exercise used his background and expertise to reflect upon and analyze the impact of the proposed regulation on small businesses. Based upon Staff's analysis, Staff recommended to the Commission that the Commission find that the proposed regulation will not impose a direct and significant economic burden on small businesses or directly restrict the formation, operation or expansion of a small business. The Commission accepted Staff's recommendation and found that the proposed regulation does not impose a direct or significant economic burden upon small businesses, nor does it directly restrict the formation, operation, or expansion of a small business, and therefore a small business impact statement pursuant to NRS 233B.0608(2) is not required. This finding was memorialized in an Order issued in Docket No. 17-08022 on August 16, 2018.

SECRETARY OF STATE FILING DATA	Form For Filing Administrative Regulations **Agency: Public Utilities Commission**	FOR EMERGENCY REGULATIONS ONLY **Effective date** __________ **Expiration date** __________ __________ **Governor's signature**

Classification: ☐ **PROPOSED** ☒ **ADOPTED BY AGENCY** ☐ **EMERGENCY**

Brief description of action: Rulemaking to amend, adopt, or repeal regulations to implement Senate Bill 146 (2017). Specifically, the regulation sets forth the filing, content, update, and approval requirements for a distributed resource plan.

Authority citation other than 233B: This matter is being conducted by the Public Utilities Commission pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code Chapters 703 and 704, including but not limited to NRS 703.025 and 704.210.

Notice date: July 25, 2018.

Hearing date: September 5, 2018.

Date of Adoption by Agency: October 8, 2018.

NOTICE OF ADOPTION OF REGULATION

On October 8, 2018, the Public Utilities Commission of Nevada adopted a temporary regulation, assigned LCB File No. T001-18 (Docket No. 17-08022), which pertains to Chapter 704 of the Nevada Administrative Code. A copy of the adopted temporary regulation is attached.

STATEMENT REGARDING SMALL BUSINESS IMPACT (NRS 233B.0608)

LCB File No. T001-18 (PUCN Docket No. 17-08022)

1. **A description of the manner in which comment was solicited from affected small businesses, a summary of their response and an explanation of the manner in which other interested persons may obtain a copy of the summary.**

   N/A. *See* Informational Statement accompanying the Regulation, Question Nos. 2-5 and 12.

   Pursuant to NRS 233B.0608 (1), the Regulatory Operations Staff ("Staff") of the Public Utilities Commission of Nevada ("PUCN") conducted an investigation to determine whether the proposed regulation is likely to: (a) impose a direct and significant economic burden upon a small business; or (b) directly restrict the formation, operation or expansion of a small business. In a Memorandum filed on August 10, 2018, Staff memorialized its conclusion that the proposed regulation does not impose a direct and significant economic burden upon small businesses nor does it directly restrict the formation, operation or expansion of a small business. *See* Attachment 1 hereto.

   On August 16, 2018, the PUCN issued an Order adopting the findings of Staff and specifically found that the proposed regulation does not impose a direct and significant economic burden upon small businesses, nor does it directly restrict the formation, operation or expansion of a small business. *See* Attachment 2 hereto.

   NRS 233B.0608 (2)(a) only requires an agency to consult with owners and officers of small businesses "*if* an agency determines pursuant to subsection 1 that a proposed regulation *is* likely to impose a direct and significant economic burden upon a small business or directly restrict the formation, operation or expansion of a small business …." (emphasis added). Given the PUCN's determination that the proposed regulation does not impose a direct and significant economic burden upon small businesses or directly restrict the formation, operation or expansion of a small business, the PUCN is not statutorily mandated to make this inquiry, as no such "affected" small businesses exist.

2. **The manner in which the analysis was conducted.**

   See Attachments 1 and 2. Staff used a version of the Delphi method that incorporates elements of the Staff Delphi method to determine the potential impact of a regulation on small businesses.

3. **The estimated economic effect of the proposed regulation on the small businesses which it is to regulate, including, without limitation:**
   (a) Both adverse and beneficial effects; and
   (b) Both direct and indirect effects.

See Informational Statement accompanying the Regulation, Question No. 7. *See also* Attachments 1 and 2.

4. **A description of the methods that the agency considered to reduce the impact of the proposed regulation on small businesses and a statement regarding whether the agency actually used any of those methods.**

N/A. *See* Attachments 1 and 2.

Pursuant to NRS 233B.0608 (1), Staff conducted an investigation to determine whether the proposed regulation is likely to: (a) impose a direct and significant economic burden upon a small business; or (b) directly restrict the formation, operation or expansion of a small business.

On August 16, 2018, the PUCN issued an Order adopting the findings of Staff and specifically found that the proposed regulation does not impose a direct and significant economic burden upon small businesses nor does it directly restrict the formation, operation or expansion of a small business. *See* Attachment 2.

NRS 233B.0608 (2)(c) only requires an agency to consider methods to reduce the impact of a proposed regulation on small businesses "*if* an agency determines pursuant to subsection 1 that a proposed regulation *is* likely to impose a direct and significant economic burden upon a small business or directly restrict the formation, operation or expansion of a small business ...." (emphasis added). Given the PUCN's determination that the proposed regulation does not impose a direct and significant economic burden upon small businesses or directly restrict the formation, operation or expansion of a small business, the PUCN is not statutorily mandated to make this inquiry as there are no impacts on small businesses and no methods that were considered for reducing the non-existent impacts.

5. **The estimated cost to the agency for enforcement of the proposed regulation.**

See Informational Statement accompanying the Regulation, Question No. 8. *See also* Attachment 1.

6. **If the proposed regulation provides a new fee or increases an existing fee, the total annual amount the agency expects to collect and the manner in which the money will be used.**

N/A. *See also* Informational Statement accompanying the Regulation, Question No. 11.

7. **If the proposed regulation includes provisions which duplicate or are more stringent than federal, state or local standards regulating the same activity, an explanation of why such duplicative or more stringent provisions are necessary.**

See Informational Statement accompanying the Regulation, Questions Nos. 9 and 10. *See also* Attachment 1.

8. **The reasons for the conclusion of the agency regarding the impact of a regulation on small businesses.**

The PUCN complied with NRS 233B.0608 by making a concerted effort to determine whether the proposed regulation imposes a direct and significant economic burden upon small businesses or directly restricts the formation, operation, or expansion of a small business. The PUCN concluded that no such impacts would occur from the adoption of the proposed regulation based upon the well-reasoned investigation of Staff.

I, STEPHANIE MULLEN, Executive Director of the PUCN, certify that, to the best of my knowledge or belief, a concerted effort was made to determine the impact of the proposed regulation on small businesses and the information contained in the statement was prepared properly and is accurate.

DATED this 1'+ day of November, 2018.

STEPHANIE MULLEN,
Executive Director
PUBLIC UTILITIES COMMISSION OF NEVADA

ATTACHMENT 1

PUBLIC UTILITIES COMMISSION OF NEVADA
MEMORANDUM

DATE: August 8, 2018

TO: The Commission
Via: Anne-Marie Cuneo, DRO AMC

FROM: Meredith Barnett, Assistant Staff Counsel MB/MCQ

SUBJECT: Small Business Impact Report
Agenda No. 15-18; Item No. 5B ; Docket No. 17-08022;
Investigation and rulemaking to implement Senate Bill 146 (2017).

I. Summary:

The Public Utilities Commission of Nevada ("Commission") opened an investigation and rulemaking to implement Senate Bill ("SB") 146 (2017). This matter was designated as Commission Docket No. 17-08022. The rulemaking sets forth provisions governing distributed resources planning.

On September 15, 2017, the Presiding Officer issued a Notice of Rulemaking, Notice of Request for Comments, and Notice of Workshop.

On October 13, 2017, comments were filed by the Regulatory Operations Staff ("Staff") of the Commission; Vote Solar; Tesla, Inc. ("Tesla"); the Energy Storage Association; and Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy ("NV Energy").

On October 26, 2017, Staff, Vote Solar, Tesla, Western Resource Advocates ("WRA"), the Nevada Attorney General's Bureau of Consumer Protection ("BCP"), and NV Energy filed Reply Comments.

On November 7, 2017, a Workshop was held.

On February 21, 2018, a Continued Workshop was held.

Multiple Informal Workshops were held between the participants.

On June 1, 2018, NV Energy filed proposed regulations; Interstate Renewable Energy Council, Inc. ("IREC"), WRA and Vote Solar jointly filed proposed regulations; and BCP filed alternative language to NV Energy's proposed regulations.

On June 8, 2018, IREC, Tesla, NV Energy, BCP and Staff each filed Comments on the proposed regulations.

On June 14, 2018, a Workshop was held.

On July 25, 2018, the Presiding Officer issued Procedural Order No. 3 directing Staff to conduct an investigation pursuant to Nevada Revised Statutes ("NRS") 233B.0608(1) regarding whether the proposed regulations, attached as Attachment 1 to that Procedural Order, are likely to:

(a) impose a direct and significant economic burden upon small businesses; or
(b) directly restrict the formation, operation or expansion of small business.

Procedural Order No. 3 directed Staff to conduct an investigation into whether the proposed regulations are likely to affect small businesses as contemplated in NRS 233B.0608(1) and to present a report of the results of this investigation, including all information required by NRS 233B.0609(1), along with a statement identifying the methodology used in determining the impact on small business. Staff was further directed to place the report on a Commission agenda meeting not later than the open meeting of the Commission scheduled for August 15, 2018.

NRS 233B.0608(1) requires an agency to make a concerted effort to determine whether a proposed regulation is likely to:

(a) impose a direct and significant economic burden upon small businesses; or
(b) directly restrict the formation, operation or expansion of small business.

A small business is defined in NRS 233B.0382 as a business conducted for profit which employs fewer than 150 full-time or part-time employees. NRS 233B.0608 (1) further requires that the assessment must be made prior to conducting a workshop regarding the proposed regulation.

NRS 233B.0608(3) requires that an agency considering a proposed regulation "shall prepare a statement identifying the methods used by the agency in determining the impact of a proposed regulation on a small business and the reasons for the conclusions of the agency."

One Staff Financial Analyst, one Staff Economist and two Staff Engineers, all of whom were involved in the rulemaking in this Docket and who are most knowledgeable about the proposed regulations, participated in this analysis.

This briefing memo constitutes the Staff Report regarding the small business impact of the proposed regulations.

II. Investigation and Analysis:

In accordance with NRS 233B.0608 (3), Staff used a version of the Delphi method that incorporates elements of the Policy Delphi method to determine the potential impact of a regulation on small businesses. The Delphi method is a systematic interactive forecasting method based on independent inputs of selected experts. It recognizes the value of expert opinions, experience and intuition and allows the use of limited information when full scientific knowledge is lacking.

In this instance, the participants were members of Staff, all four of whom are involved in the rulemaking and who are most familiar with the subject matter of the rulemaking. Specifically, one Staff Financial Analyst, one Staff Economist, and two Staff Engineers, participated in this analysis. Each participant in the exercise used the participants' background and expertise to reflect upon and analyze the impact of the regulations on small businesses. Following the written responses the Delphi participants engaged in a critique of the other participant's responses, arriving at a consensus position.

The proposed regulations apply to public utilities in the business of supplying electricity which has an annual operating revenue in this state of $2,500,000 or more. Prior to SB 146 each electric utility filed an integrated resource plan ("IRP"). SB 146 requires two or more utilities that are affiliated through common ownership and that have interconnected systems for transmission of electricity to file a joint IRP and extends the time the Commission has to issue an order on an IRP or IRP amendment.

On or before April 1, 2019, SB 146 requires that an IRP or IRP amendment include a distributed resources plan ("DRP"). SB 146 defines a "Distributed Resource" as "distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies". SB 146 requires that the distributed resource plan evaluate the locational benefits and costs of distributed resources; identify mechanisms for the deployment of cost-effective distributed resources; propose cost-effective methods for coordinating with existing programs; identify any additional spending necessary to integrate cost-effective distributed resources; and identify barriers to the deployment of distributed resources. The proposed regulations specify the analyses and information to be included in the DRP in order to fulfill the requirements of SB 146.

Immediate Adverse Effects:

The proposed regulation will not have an immediate adverse effect on small businesses. Electric utilities must file an IRP or IRP amendment that includes a DRP on or before April 1, 2019. The utility will incur costs associated with modeling, software and associated hardware necessary to obtain the information and do the analysis required by the proposed regulations. These costs will be reviewed and potentially passed on to utility customers as part of a future general rate case proceeding. Therefore, these costs cannot have an immediate adverse effect on utility customers, including small businesses. Further, it is unknown if these costs will ultimately result in higher energy costs for utility customers. Any increase in energy costs caused by these utility expenditures will be a result of SB 146, not the proposed regulation.

The proposed regulation may have an immediate adverse effect on a utility. As discussed above, the utility will incur costs associated with modeling, software and associated hardware necessary to obtain the additional information and do the additional calculations required by the regulation. Additionally, the regulation requires that additional information and calculations be included in an IRP and/or IRP amendment. Therefore, a utility may experience an increase in time required to prepare and litigate an IRP and and/or IRP amendment that includes a DRP because of the additional information and calculations required by the proposed regulation. Any additional costs a utility incurs to prepare and/or litigate an IRP and/or IRP amendment that includes a DRP is a result of SB 146, not the proposed regulation. The regulations also require a utility file annual updates to parts of the DRP that will require additional utility time and resources and are not specifically required by SB 146. It is unknown if any additional utility time and/or resources will impact the rates of utility customers.

Immediate Beneficial Effects:

The proposed regulation will not have an immediate beneficial effect on small businesses. Any potential immediate impact on a small business would be to small businesses that contract with a utility to install new software and hardware necessary to conduct the analysis and obtain the information needed to provide a DRP. However, these benefits would be a result of SB 146, not the proposed regulation.

Long-Term Adverse Effects:

Similar to the immediate adverse effects outlined above, the proposed regulation will not have any long-term direct or significant adverse effect on small businesses. The utility will incur costs associated with modeling, software and associated hardware necessary to obtain the information and do the analysis required by the proposed regulations. These costs will be reviewed and potentially passed on to utility customers as part of a future general rate case proceeding. It is unknown if these costs will ultimately result in higher energy costs for utility customers and any increase in energy costs caused by these utility expenditures will be a result of SB 146, not the proposed regulation.

The proposed regulation may have long-term adverse effects on a utility because the regulation requires additional information and calculations be made in an IRP and/or IRP amendment. A utility may experience an increase in time required to prepare and litigate an IRP and and/or IRP amendment that includes a DRP based on the additional information and calculations required by the proposed regulation. Any additional costs a utility incurs to prepare and/or litigate an IRP and/or IRP amendment that includes a DRP is a result of SB 146, not the proposed regulation. The regulations also require a utility file annual updates to parts of the DRP that will require additional utility time and resources and are not specifically required by SB 146. It is unknown if any additional utility time and/or resources will impact the rates of utility customers.

Long-Term Beneficial Effects:

The regulation will not have long-term beneficial effects on utility customers, including small businesses. The requirement of a DRP may result in a more reliable distribution grid as the utility will have a complete understanding of its distribution grid and will have a guide for procuring cost-effective distributed resource solutions. Additionally, to the extent that the DRP identifies cost-effective distributed resource solutions, the utility and potentially its customers may benefit from cost savings as compared to other infrastructure solutions. However, any potential benefits are a result of SB 146, not the proposed regulation.

Cost to the Commission to enforce or administer the proposed regulation, including start-up and ongoing costs.

Under the proposed regulation the Commission may incur costs to review the additional information and calculations required by the proposed regulations that must be made in an IRP and/or IRP amendment. The Commission and Staff may experience an increase in time required to litigate an IRP and/or IRP amendment that includes a DRP based on the additional information and calculations required by the proposed regulation.

As a result of the investigation, Staff has concluded that the proposed regulations are not likely to: (a) impose a direct and significant economic burden upon small business; or (b) directly restrict the formation, operation, or expansion of small business. Therefore, a small business impact statement pursuant to NRS 233B.0608 (2) is not required.

III. Notice and Subsequent Action:

On July 25, 2018, the Presiding Officer issued Procedural Order No. 3, attaching the proposed regulations. Procedural Order No. 3 directed Staff to conduct an investigation pursuant to NRS 233B.0608(1) to determine whether the proposed regulations were likely to (a) impose a direct and significant economic burden upon a small business; or (b) directly restrict the formation, operation or expansion of a small business.

IV. Conclusion:

Staff recommends that, in accordance with NRS 233B.0608(1), the Commission find that the proposed regulations are not likely to impose a direct or significant economic burden on a small business, or to restrict the formation, operation or expansion of a small business.

Staff further recommends that, pursuant to NRS 233B.0608 (3), the Commission state that the Delphi method was used in the determination of the impact of the proposed regulations on small business.

ATTACHMENT 2

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Investigation and rulemaking to implement Senate Bill 146 (2017).	)))	Docket No. 17-08022

At a general session of the Public Utilities Commission of Nevada, held at its offices on August 15, 2018.

PRESENT: Chairman Joseph C. Reynolds
Commissioner Ann C. Pongracz
Commissioner Bruce H. Breslow
Assistant Commission Secretary Trisha Osborne

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

The Commission opened an investigation and rulemaking, designated as Docket No. 17-08022, to implement Senate Bill ("SB") 146 (2017).

II. SUMMARY

The proposed regulation in Docket No. 17-08022 does not impose a direct and significant economic burden upon small businesses, nor does it directly restrict the formation, operation, or expansion of a small business. Therefore, a small business impact statement pursuant to the Nevada Revised Statutes ("NRS") 233B.0608(2) is not required.

III. PROCEDURAL HISTORY

• On September 15, 2017, the Commission opened an investigation and rulemaking to implement SB 146 (2017).

• The Commission is conducting this investigation and rulemaking in accordance with Chapters 703 and 704 of the NRS and the Nevada Administrative Code ("NAC"), including but not limited to NRS 703.025 and 704.210.

• On September 15, 2017, the Commission issued a Notice of Rulemaking, Notice of Request for Comments, and Notice of Workshop.

• On October 13, 2017, the Attorney General's Bureau of Consumer Protection ("BCP"); the Energy Storage Association ("ESA"); Nevada Power Company d/b/a NV Energy and Sierra

Pacific Power Company d/b/a NV Energy (together, "NV Energy"); Tesla, Inc. ("Tesla"); Vote Solar; and the Regulatory Operations Staff ("Staff") of the Commission filed comments.

- On October 26, 2017, BCP, NV Energy, Tesla, Vote Solar, Western Resource Advocates ("WRA"), and Staff filed reply comments.

- On November 7, 2017, the Hearing Officer held a Workshop. BCP, the Interstate Renewable Energy Council ("IREC"), NV Energy, Tesla, WRA, and Staff made appearances. The participants discussed the comments and reply comments.

- On November 9, 2017, the Hearing Officer issued a Procedural Order, adopting a procedural schedule.

- On February 21, 2018, the Hearing Officer held a Continued Workshop. BCP, IREC, NV Energy, Tesla, Vote Solar, WRA, and Staff made appearances. The participants discussed the informal meetings held by the participants.

- On February 22, 2018, the Hearing Officer issued Procedural Order No. 2, adopting a procedural schedule.

- On February 22, 2018, the Commission issued a Notice of Workshop.

- On June 1, 2018, BCP; IREC jointly with WRA and Vote Solar; and NV Energy filed comments and proposed language.

- On June 8, 2018, BCP, IREC, NV Energy, Tesla, and Staff filed comments.

- On June 14, 2018, the Hearing Officer held a Workshop. BCP, IREC, NV Energy, Tesla, WRA, and Staff made appearances. The participants discussed the proposed language filed by the various participants.

- On July 25, 2018, the Commission issued a Notice of Intent to Act Upon a Regulation, Notice of Workshop, and Notice of Hearing for the Adoption, Amendment and Repeal of Regulations of the Commission.

- On July 25, 2018, the Hearing Officer issued Procedural Order No. 3 with a proposed regulation attached. Staff was directed to conduct an investigation pursuant to NRS 233B.0608 to determine whether the proposed regulation is likely to: (a) impose a direct and significant economic burden upon a small business; or (b) directly restrict the formation, operation or expansion of a small business.

- On August 9, 2018, the Hearing Officer sent a letter to the Legislative Counsel Bureau ("LCB") with the proposed regulation attached, requesting that the regulation be assigned an LCB file number.

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• On August 10, 2018, Staff filed a briefing memorandum regarding the small business impact statement required to be considered pursuant to NRS 233B.0608(2).

IV. SMALL BUSINESS IMPACT REPORT

1. Staff conducted a Delphi Method exercise to determine the impact of this proposed regulation on small businesses. The Delphi Method is a systematic, interactive forecasting method based on independent inputs of selected experts. In this instance, the participants were members of Staff. Each participant in the exercise used their background and expertise to reflect upon and analyze the impact of the proposed regulation on small businesses. Staff made the following observations:

Immediate Adverse Effects

2. Staff states that the proposed regulation will not have an immediate adverse effect on small businesses. Electric utilities must file an integrated resource plan ("IRP") or IRP amendment that includes a distributed resources plan ("DRP") on or before April 1, 2019. The utility will incur costs associated with modeling, software and associated hardware necessary to obtain the information and do the analysis required by the proposed regulation. These costs will be reviewed and potentially passed on to utility customers as part of a future general rate case proceeding. Therefore, these costs cannot have an immediate adverse effect on utility customers, including small businesses. Further, it is unknown if these costs will ultimately result in higher energy costs for utility customers. Any increase in energy costs caused by these utility expenditures will be a result of SB 146, not the proposed regulation.

3. The proposed regulation may have an immediate adverse effect on a utility. As discussed above, the utility will incur costs associated with modeling, software and associated hardware necessary to obtain the additional information and do the additional calculations required by the regulation. Additionally, the regulation requires that additional information and calculations be included in an IRP and/or IRP amendment. Therefore, a utility may experience an increase in time required to prepare and litigate an IRP and/or IRP amendment that includes a DRP because of the additional information and calculations required by the proposed regulation.

Any additional costs a utility incurs to prepare and/or litigate an IRP and/or IRP amendment that includes a DRP is a result of SB 146, not the proposed regulation. The regulation also require a utility file annual updates to parts of the DRP that will require additional utility time and resources and are not specifically required by SB 146. It is unknown if any additional utility time and/or resources will impact the rates of utility customers.

Immediate Beneficial Effects

4. Staff states that the proposed regulation will not have an immediate beneficial effect on small businesses. Any potential immediate impact on a small business would be to small businesses that contract with a utility to install new software and hardware necessary to conduct the analysis and obtain the information needed to provide a DRP. However, these benefits would be a result of SB 146, not the proposed regulation.

Long-Term Adverse Effects

5. Similar to the immediate adverse effects outlined above, Staff opines that the proposed regulation will not have any long-term direct or significant adverse effect on small businesses. The utility will incur costs associated with modeling, software and associated hardware necessary to obtain the information and do the analysis required by the proposed regulations. These costs will be reviewed and potentially passed on to utility customers as part of a future general rate case proceeding. It is unknown if these costs will ultimately result in higher energy costs for utility customers and any increase in energy costs caused by these utility expenditures will be a result of SB 146, not the proposed regulation. The proposed regulation may have long-term adverse effects on a utility because the regulation requires additional information and calculations be made in an IRP and/or IRP amendment. A utility may experience an increase in time required to prepare and litigate an IRP and and/or IRP amendment that includes a DRP based on the additional information and calculations required by the proposed regulation. Any additional costs a utility incurs to prepare and/or litigate an IRP and/or IRP amendment that includes a DRP is a result of SB 146, not the proposed regulation. The regulation also require a utility file annual updates to parts of the DRP that will require additional

utility time and resources and are not specifically required by SB 146. It is unknown if any additional utility time and/or resources will impact the rates of utility customers.

Long-Term Beneficial Effects

6. Staff states that the regulation will not have long-term beneficial effects on utility customers, including small businesses. The requirement of a DRP may result in a more reliable distribution grid as the utility will have a complete understanding of its distribution grid and will have a guide for procuring cost-effective distributed resource solutions. Additionally, to the extent that the DRP identifies cost-effective distributed resource solutions, the utility and potentially its customers may benefit from cost savings as compared to other infrastructure solutions. However, any potential benefits are a result of SB 146, not the proposed regulation.

7. Based on the foregoing, the Commission determines that the proposed regulation in Docket No. 17-08022 is not likely to: (a) impose a direct and significant economic burden upon small business; or (b) directly restrict the formation, operation, or expansion of a small business. Therefore, a small business impact statement pursuant to NRS 233B.0608(2) is not required.

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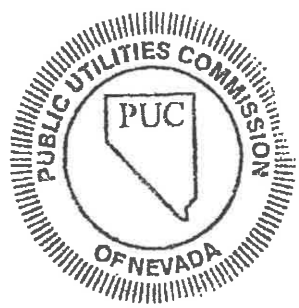
THEREFORE, it is ORDERED:

1. The proposed regulation is not likely to impose a direct and significant economic burden upon small businesses, nor is it likely to directly restrict the formation, operation, or expansion of a small business.

By the Commission,

Trisha Osborne

TRISHA OSBORNE,
Assistant Commission Secretary
on behalf of the Commissioners



Certified: ____________________
STEPHANIE MULLEN,
Executive Director

Dated: Carson City, Nevada

8/16/18

(SEAL)

APPLICATION EXHIBIT D

DRP NARRATIVE

NV Energy's

Distributed Resources Plan

April 1, 2019

Table of Contents

Section 1. Executive Summary

In 2017, the Nevada Legislature enacted Senate Bill 146 ("SB146"), which introduced and established requirements for Distributed Resources Planning in Nevada. SB146 requires the State's two largest electric utilities, Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra"),[1] to periodically prepare and include in their integrated resource plans ("IRPs"), a Distributed Resources Plan ("DRP"). SB146 defines Distributed Resources as "distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies."[2] SB146 also requires that the NV Energy utilities begin to prepare joint IRPs beginning on or before June 1, 2018, and that together the NV Energy utilities file their first joint DRP on or before April 1, 2019. This filing represents the culmination of NV Energy's efforts to timely comply with the schedule set forth in SB146. The comprehensive analyses used to prepare this DRP were developed through significant collaboration with stakeholders, many of whom have participated in developing DRP techniques in other jurisdictions.

To ensure a thoughtful and structured approach to this new planning paradigm, NV Energy has adopted a "walk-jog-run" philosophy to work through the development of the various elements of Nevada's first DRP. This philosophy was discussed in detail throughout the stakeholder workshops to establish a baseline and understanding of the refinement process of each of the DRP elements.

The purpose of SB146 is not expressly stated in the legislation, but based on its language, NV Energy is of the view that the 2017 Nevada Legislature expected that a formal DRP process would aid in the cost-effective integration of Distributed Resources (also referred to as "DERs") into the distribution planning process and, ultimately, the NV Energy utilities' electricity grid. NV Energy has embraced the DRP concept, and has prepared one of the first comprehensive and complete DRPs in the nation. Keeping with the "walk-jog-run" philosophy and drawing from models and hypotheses being discussed and debated in other jurisdictions, as well as the temporary regulations established by the Public Utilities Commission of Nevada ("Commission") to implement SB146,[3] NV Energy has prepared a potentially transformational process for incorporating DERs into the transmission and distribution planning processes, and for accelerating their cost-effective integration with the Companies' electric grid.

Even before the temporary regulations implementing SB146 were finalized, NV Energy began investing in equipment and systems (*e.g.*, an Automated Metering Infrastructure ("AMI") smart meter system, Plant Information ("PI") system, and intelligent line sensors) that have enabled the NV Energy utilities to gather significantly more granular data regarding the loading on each of their distribution feeders, distribution substations and transmission lines. Now that it has been collected, using cutting-edge informational technology resources, this massive amount of 15-minute data is being used to refine distribution feeder-level forecasts of load and loading.

[1] Together, Nevada Power and Sierra are referred as "NV Energy," the "NV Energy utilities," or the "Companies."

[2] SB 146, Section 1.6(c).

[3] The Commission conducted a rulemaking to implement SB146 through Docket No. 17-08022. The Commission adopted temporary regulations for the implementation of SB146 in an Order dated October 8, 2018 in Docket No. 17-08022 (the "Temporary Regulations.") The Commission submitted the Temporary Regulations to the Legislative Counsel Bureau and the Office of the Secretary of State on November 15, 2018. This filing was constructed to comply with both SB146 and the Temporary Regulations.

Consistent with the Temporary Regulations, NV Energy developed a six-year load and DER growth forecast for their electric grids beginning with the year after this report is filed (2020-2025). The load growth forecasts for distribution feeders came from the normal forecasting process of the Companies' Distribution Planning Department, and the forecast of Distribution Resources came from Volume 5 of 18 and Technical Appendix Item LF-1 of NV Energy's Joint IRP filing with the Commission in Docket No. 18-06003. Using this information, the NV Energy utilities have identified potential Non-Wires Alternative ("NWA") solutions for mitigating constraints on their electric grid identified by these forecasts, and compared their costs to traditional utility infrastructure investment.

To understand the locational capabilities and needs of the distribution grid and the potential locational benefits of Distributed Resources, a comprehensive analysis of the grid was required. This work entailed identifying where Distributed Resources can be integrated into the grid with minimal impact or cost, where Distributed Resources cause impacts and costs to interconnect and integrate, and where Distributed Resources can solve or mitigate the forecasted need for grid enhancements.

Developed with the assistance of stakeholders, the analysis in this DRP begins by identifying the capabilities and needs of the existing system by means of a Hosting Capacity Analysis ("HCA"). The HCA is a nearly ubiquitous feature of a DRP in those jurisdictions thinking about or adopting some version of distributed resource planning. In California, for instance, debate regarding and refining of the HCA has taken priority over the larger DRP process. The HCA determines the amount of capacity from Distributed Resources that can be accommodated on a particular feeder section without adversely impacting safety, power quality, reliability, or other operational criteria. The HCA performed by the Companies for this proceeding relies on advanced electrical simulation software to model the distribution system and calculate the level of Distributed Resources that can be accommodated without violating any of the established criteria. This methodology is more analytically efficient than using an iterative approach, and is bolstered by the substantial volume of 15-minute data discussed above. Analytical cases for distributed generation, solar photovoltaic ("PV") generation, and load were used to identify the potential hosting capacity for Distributed Resources on the grid. The results of the HCA reveal that certain distribution feeders have limited hosting capacity, and are fed into the established process for identifying constraints on the electric system, and ultimately for identifying and determining solutions.

Next, for the period from 2020 through 2025, NV Energy performed a Grid Needs Assessment ("GNA") to identify constraints on the Companies' electric grid and the consequent traditional or "wired" capital upgrade solutions that would otherwise be required to address these constraints. Following a suitability and screening process, potential NWA solutions were identified and analyzed using a spreadsheet-based tool that quantifies the needs of the system and identifies a NWA solution portfolio that satisfies those needs.

NV Energy then performed a "ballpark" cost comparison between traditional wired solutions and NWA solutions to identify NWA options that are candidates to defer or displace traditional wired investments. Where potential opportunities were identified, a more detailed Present Worth of Revenue Requirement ("PWRR") analysis was performed comparing the traditional and NWA options. The PWRR analysis looks at potential benefits in addition to costs, and serves as the location-specific economic analysis of costs and benefits (Locational Net Benefits Analysis, or

“LNBA”). The result of the LNBA is a determination of the most cost-effective solutions for meeting the needs of the transmission and distribution systems.

Consistent with SB146 and in working through this first DRP, NV Energy identified barriers to the cost-effective integration of Distributed Resources, and has included recommendations to overcome these barriers in Section 4.

The framework developed for this DRP also ensures coordination with the IRP process as well as other legislative actions. The details on this coordination are outlined in Section 5.

The data required to be shared by the NV Energy utilities with stakeholders has been reviewed with a broad stakeholder group. This vetting process has included not only what data would be shared, but how it would be shared, how the safety and security of the data would be ensured, and how customer-specific information would be protected from disclosure. Several informal workshops served as a forum for NV Energy to update stakeholders on the progress of the DRP development, and for stakeholder to provide input into its development, including the publicly-accessible web portal discussed in Section 7.

As was discussed with the stakeholder group over the last 18 months, many of the DRP elements are still evolving. In keeping with a “walk-jog-run” approach, some of these elements represent only the initial stage in how NV Energy will eventually complete the necessary analyses and the information that will be provided in the DRP. The Companies will continue to refine these elements, and Section 8 outlines the refinement timeframe and activities regarding them. This serves as the basis for a roadmap through 2021, which is outlined in Section 12.

In working through the DRP elements, the Companies have identified several areas that may benefit from investment in new tools, systems and/or technologies. The timeframe for this investigation and determination of which elements will be impacted are detailed in Section 9.

The Companies also investigated and attempted to identify which elements would benefit by conducting a pilot and/or a demonstration project. The results of this investigation for the respective elements are detailed in Section 10.

Finally, any incremental utility investment for which approval of funding through 2021 is being requested of the Commission is described in Section 11.

Section 2. Introduction

A. Distributed Resources Plan Policy and Vision

As NV Energy worked with stakeholders in developing the DRP, the Companies sought to ensure that the effort adhered to the highest standards in the industry and aligned with NV Energy's Core Principles. These principles are outlined in Figure 1 below:

FIGURE 1:
DRP OBJECTIVES ALIGN WITH NV ENERGY CORE PRINCIPLES

Core Principle	Definition	DRP Alignment
Customer Service	• Focus on delivering reliability, dependability, fair prices and exceptional service	• Continue to provide value to our customers, adapt to customer expectations and deliver quality service at a fair price. • Enhance the reliability and resiliency of the distribution system. Maintain high levels of security and safety for customers and employees. • Minimize customer rate impact. • Support DER integration in the locations that provide net value to our customers.
Employee Commitment	• Equip employees with the resources and support they need to be successful. Encourage teamwork and provide a safe, rewarding work environment. No compromise when it comes to safety.	• Achieve coordination between NV Energy business units in order to plan for greater DER penetration. • Allocate internal resources in business units to effectively plan for greater DER penetration.
Environmental Respect	• Committed to using natural resources wisely and protecting our environment.	• Integrate cost-effective DER onto the grid where it provides net benefits for NV Energy's customers, including contributing to achieving state and federal Greenhouse Gas and renewable goals and policies.
Regulatory Integrity	• Adhere to a policy of strict compliance and pursue frequent, open communication with regulators.	• Collaborate with stakeholders to advance established energy policies. • Look for opportunities where multiple legislative/regulatory directives can meet a single regulatory goal.
Operational Excellence	• Strive for excellence in every aspect of our work. Meet or exceed our customers' expectations, perform our work safely, and preserve our assets.	• Adopt a proactive approach and take the lead on shaping conversations as they relate to an enhanced distribution planning activity. • Ensure safety and reliability of the grid for the benefit of customers and employees.
Financial Strength	• We are excellent stewards of our financial resources. Invest in hard assets and focus on long-term opportunities that will contribute to the future strength of the company.	• Strive to accurately forecast DER adoption. • Invest in cost-effective DER (*i.e.*, DR and EE programs) that defer traditional distribution infrastructure investments and reduce costs for customers. • Make prudent investments that help ensure distribution network optimization. • Maximize the utilization of existing assets. • Incorporate and combine existing programs and regulatory requirements where applicable.

B. Overview of Plan Contents

This DRP meets all of the requirements of SB146 and the Temporary Regulations implementing this legislation, with the exception of a few areas noted in Section 11.B.[4] Although this plan has been NV Energy's responsibility to prepare, the Companies took care to include and collaborate with interested stakeholders throughout the development process to increase understanding of the methods and data used to generate this DRP, to reduce or eliminate areas of contention, and to ensure the greatest possible benefits to NV Energy's customers. Stakeholder input has been invaluable in informing and refining the details of this DRP. It is anticipated that this first-ever DRP will deliver the following benefits, among others:

- When filed on April 1, 2019, this narrative will initially be an amendment to the Companies' Joint IRP and going forward will be included as a separate volume in the IRP filing for the three years covered by the IRP action plan.
- A more granular and time-variant forecast of net distribution system load and distributed resources. The forecast period shall be a six-year minimum, beginning with the year after the DRP is filed. The net distribution system load and DER forecast on the various components of the distribution system, substation and feeder level will assist NV Energy to better accommodate DER, plan for needed distribution and transmission capacity, calibrate locational benefits, and assess non-wires alternatives.
- A thorough and complete baseline HCA that can be periodically updated, used to speed technical screening for interconnection, and assist in identifying where to reinforce the system to accommodate additional DER.
- Development of a GNA that is based upon the net distribution system load, DER forecast and the facilities capacity analysis. This will include the HCA, results of a NWA and LNBA that compared the NWA to a traditional wires solution to determine a least cost infrastructure upgrade solution to the transmission and/or distribution constraints.
- An update to the interconnection processes to speed interconnection across technologies, especially for energy storage.
- An LNBA analysis that incorporates known and measurable benefits and costs of location-specific opportunities to use DERs as NWAs to traditional wired solutions. The current list of benefits and costs will be updated as the menu of known and measurable benefits and costs grows.
- Identification and justification of any change in methodology of forecasting, HCA or GNA from that used in any previous filing.
- A summary that explains how DERs have affected the need for supply side resources in the IRP process including the effect of DERs on the need for new generation and transmission resources. This will include an explanation of how DERs are integrated in the transmission planning and supply side planning portions of the IRP process.

[4] Pursuant to NAC § 704.0097, the Companies seek specific waivers from portions of the Temporary Regulations in the Application.

- A summary that describes the results of an informal stakeholder process to discuss recommendations for improvements to the HCA and a technical appendix that conforms to NAC 704.922.
- The collection and storage of a robust data set, and access to new information displays through a website portal to help stakeholders make more informed market decisions and allow them to better serve our shared customers.

Establishing a formal DRP process as part of an IRP required the Companies to modify their transmission and distribution planning paradigms and to develop new planning processes, procedures and tools, and coordinate amongst several departments, including: Distribution Planning, Integrated Grid Planning, Demand Side Management, Resource Planning, Legal, Rates & Regulatory, Renewable Energy & Smart Infrastructure, Transmission Planning, IT, Operations, Project Management and Distributed Energy Resource Planning.

Based upon the elements of SB146 and through internal research and discussion, informal stakeholder workshops and formal workshops convened to develop regulations implementing SB146, the Companies have learned from the efforts of utilities in other jurisdictions. As was discussed in detail in the stakeholder workshops, the Companies have adopted a "walk-jog-run" approach to implement the five elements of SB146 (listed below).

This first joint DRP is focused on developing expertise in four foundational elements of the DRP process. First is the publication of the HCA, which relies on robust data to determine the loading profile of feeders and the amount of DERs that can be installed on a feeder section without requiring significant upgrades. The HCA takes into account many factors to allow for multi-scenario analysis. Accuracy of load forecasts as well as the penetration and characteristics of interconnected Distributed Resources are essential. Forecasting techniques and accuracy at the local level using time-differentiated data was essential to support the HCA. Industry stakeholders have emphasized that the results of the HCA must have a level of transparency to guide stakeholders to the areas of the NV Energy system where Distributed Resources can be cost effectively integrated and in what amounts.

Second is development of a robust GNA that analyzes the constraints on the transmission and distribution portions of the electric grid. Third, the GNA identifies NWAs suitable to mitigate constraints, which will be used to perform the fourth foundational element, the LNBA. The economic analysis performed through the LNBA ensures that a least cost solution is recommended and implemented to the benefit of NV Energy's customers.

C. Plan Meets Requirements of SB146

Over the past few years, several states including California, Hawaii and New York have initiated distributed resources plan processes, either through new legislation or new regulatory requirements. Nevada joined this effort in 2017 with SB146, which requires the NV Energy utilities to file their first joint DRP by April 1, 2019.

Section 1.6(c) of SB146 defines Distributed Resources as "distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies." Distributed generation systems are defined in Nevada Revised Statutes ("NRS") § 701.380 3(a) as:

[A] facility or system for the generation of electricity that is in close proximity to the place where the electricity is consumed:

1) That uses renewable energy as defined in NRS 704.7811 to generate electricity;
2) That is located on the property of a customer of an electric utility;
3) That is connected on the customer's side of the electricity meter;
4) That provides electricity primarily to offset customer load on that property; and
5) The excess generation from which is periodically exported to the grid in accordance with the provisions governing net metering systems used by customer-generators pursuant to NRS 704.766 to 704.775, inclusive.

Section 1.5 of SB146 sets forth five elements that must be included in a DRP. Specifically, a DRP must:

(a) Evaluate the locational benefits and costs of distributed resources. This evaluation must be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits and any other savings the distributed resources provide to the electricity grid for this State or costs to customers of the electric utility or utilities.

(b) Propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources that satisfy the objectives for distribution planning.

(c) Propose cost-effective methods of effectively coordinating existing programs approved by the Commission, incentives and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

(d) Identify any additional spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding a net benefit to the customers of the electric utility or utilities.

(e) Identify barriers to the deployment of distributed resources, including, without limitation, safety standards related to technology or operation of the distribution system in a manner that ensures reliable service.

Each of the above requirements is addressed in this DRP.

D. Stakeholder Engagement

NV Energy adopted an active, focused stakeholder engagement process in the course of preparing this DRP, modeling efforts that have worked well in other states such as California, Hawaii and New York. Based on lessons learned in these states, a successful stakeholder process has a well-designed organizational structure with clearly defined objectives and outcomes, and is open and accessible to a diverse and representative set of stakeholders. These steps ensure that discussions are focused on specific issues and decision points and solicit a wide range of meaningful input. An effective stakeholder process that engages subject matter experts on technical issues fosters constructive working relationships among stakeholders, regulators, and utilities, and builds common ground on key issues and vocabulary, bridging different positions earlier than in a formal regulatory proceeding. This fosters transparency, predictability, and buy-in from the different stakeholder groups. Experience elsewhere suggests that often, getting all parties to adopt common definitions and understanding of the scope of a given issue is itself a valuable accomplishment, reducing misunderstanding and defining areas of mutual agreement.

NV Energy established a utility-led multi-tier structured process that led to a more efficient, collaborative regulatory proceeding in which outcomes were understood by all parties involved.

NV Energy worked with stakeholders to propose new regulations for the consideration of the Commission that provided more specific direction and guidance in the development of the DRP. The Commission adopted the Temporary Regulations in an Order dated October 8, 2018 in Docket No. 17-0802. Section 8.9 of the Temporary Regulations requires NV Energy to describe the results of the informal stakeholder process to discuss recommendations for improvements to the HCA.

Although a deeper dive into the specific elements of the DRP occurred in some of the informal workshops, the stakeholder engagement process focused on "what" would be included in the DRP and not necessarily "how" the elements needed to be developed.

To illustrate the scope and robustness of the stakeholder process, the following outlines the schedule of 16 workshops that were held to work through the development of this first DRP:

- November 7, 2017 – Commission Stakeholder Workshop
- January 24, 2018 – Informal Stakeholder Workshop
- February 7, 2018 – Informal Stakeholder Workshop
- February 21, 2018 – Commission Continued Stakeholder Workshop
- March 15, 2018 – Informal Stakeholder Workshop
- March 29, 2018 – Informal Stakeholder Workshop
- April 12, 2018 – Informal Stakeholder Workshop
- April 26, 2018 – Informal Stakeholder Workshop
- May 3, 2018 – Informal Stakeholder Workshop
- June 14, 2018 – Commission Continued Stakeholder Workshop
- August 16, 2018 – Informal Stakeholder Workshop
- August 30, 2018 – Commission Continued Stakeholder Workshop
- October 11, 2018 – Informal Stakeholder Workshop
- November 29, 2018 – Informal Stakeholder Workshop – Recommendations for improvements to the Hosting Capacity Analysis per Section 8.9 of the new regulations.
- December 13, 2018 – Informal Stakeholder Workshop
- February 21, 2019 – Informal Stakeholder Workshop

1. Informal Workshop Dedicated to Hosting Capacity Analysis

Per Section 8.9 of the Temporary Regulations, on November 29, 2018, NV Energy hosted an informal workshop to discuss recommendations for improvements to the HCA. The Companies prepared and presented specific information regarding the status of the current HCA, and a timeline for the next phases of HCAs and refinement. As many of the stakeholders had been included in the stakeholder engagement process over the prior 18 months, stakeholders expressed a solid understanding of the HCA methodology being used.

The participants in the November 29th workshop also discussed an upcoming December 19, 2018, meeting that NV Energy had scheduled with the Electric Power Research Institute ("EPRI") to discuss modeling of smart inverter technology when performing HCA. NV Energy committed to provide an overview of this discussion at a subsequent informal stakeholder workshop to be held on February 21, 2019.

Participants also discussed whether it would be necessary to modify the Companies' Rule 15 in their respective tariffs, NV Energy's interconnection rule, based upon information obtained from the HCA. NV Energy informed stakeholders that it would be reviewing Rule 15 for the Companies to determine potential modifications in the 3rd and 4th quarters of 2019 to specifically address changes to IEEE 1547. [5]

As NV Energy stepped through the phasing timeline for the refinement of HCA (see Section 8.B.), participants asked about the rationale for waiting to add the protection, operation, and reliability criteria to the HCA analysis. The Companies explained that the distribution system model in the software being utilized to prepare the HCA, DNV-GL's Synergi program, does not presently model protection-related elements. The proper modeling parameters will have to be added in the future in order to include potential protection-related limitations to the HCA. A significant discussion of the capabilities of tools to determine operational and reliability characteristics followed.

Finally, the participants discussed the definition and requirements of "real-time" hosting capacity. As stated in NV Energy's August 23, 2018 Comments in Docket No. 17-08022, the Companies viewed real-time as being reflective of system conditions in the timeframe of seconds temporally; normally applied to an operational paradigm, which is different than the planning paradigm.

E. Definitions and Acronyms

ADMS – Advanced Distribution Management System

AMI – Advanced Metering Infrastructure

ANSI – American National Standards Institute

DERMS – Distributed Energy Resource Management System

[5] The Companies subsequently delayed the scheduled review of Rule 15 to Q3 and Q4 of 2020 to ensure adequate time for advanced (smart) inverters to become generally commercially-available.

Distributed Energy Resources (DERs) – Distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies, which can be in front of or behind the meter.

DG – Distributed Generation

DR – Demand Response

DRMS – Demand Response Management System

DSM – Demand Side Management

EE – Energy Efficiency

EPRI – Electric Power Research Institute

EV – Electric Vehicle

Feeder (*i.e.*, Circuit) – A medium voltage (*e.g.*, 4 kV, 12 kV or 25 kV) line, either overhead or underground, that provides service from a substation transformer to a low voltage electric system or directly to the customer.

GIS – Geographic Information System

Grid Needs Assessment (GNA) – A summary that includes the constraints on a utility's electric grid and solutions to those constraints. It includes all analysis of non-wires alternatives' suitability to mitigate identified constraints, results of locational net benefit analysis and recommendations for the deployment of utility infrastructure upgrade solutions and non-wires alternative solutions to identified constraints.

Hosting Capacity Analysis (HCA) – The analysis to determine the amount of distributed resources that can be accommodated on a particular feeder section of the distribution system at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

IEEE – Institute of Electrical and Electronics Engineers

IEEE Standard 1547 – The IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. The 2003 version of this standard was updated in 2018 to, among other revisions, allow DERs to actively participate in voltage regulation through approval of the area's electric system operator.

kV – kilovolt

kWh – kilowatt-hours

Locational Net Benefit Analysis (LNBA) – A cost benefit of Distributed Resources that incorporates the location-specific net benefits to the electric grid.

Model Forge – The process that pulls data from NV Energy's GIS mapping system into a MS Access database with the appropriate schema required by the Synergi Electric software.

Non-Wires Alternative (NWA) – A solution to an identified constraint(s) on a utility's electric grid that may include the deployment of a distributed resource or suite (package) of distributed resources.

OMAG – Operation, Maintenance, Administrative, and General expense.

PI – Plant Information system from OSIsoft.

PV – Photovoltaic

"Real-time" Hosting Capacity Analysis – For the purposes of this DRP; updating hosting capacity values, (1) on a monthly basis within a reasonable time after the utility determines that a parameter has changed that would appreciably affect a feeder section's hosting capacity value, and (2) within a reasonable time, but no more than a month, after a specific distributed energy resource interconnection applicant of sufficient capacity has submitted an application to the utility that would appreciably affect a feeder section's hosting capacity value.

Substation – Location at which one or more substation transformers steps down power from a transmission voltage to a distribution voltage.

T&D – Transmission and Distribution

Thermal Rating – The maximum amount of electrical current that an electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements. This is one of the limiting categories in the HCA.

TOU – Time-of-Use

Volt-VAR Optimization/Conservation Voltage Reduction (VVO/CVR) – An operational approach in which voltage- and VAR-controlling devices at the substation and on the distribution system work in concert to manage the voltage on the system within defined limits, specifically, to flatten the voltage profile along the distribution feeder so that the operating voltage can be lowered to achieve peak load, energy consumption, or loss reduction.

Section 3. Distributed Resources Plan Elements

A. Distribution Planning

NV Energy's Distribution Planning department provides support to the electric distribution systems at both the Nevada Power and Sierra. The Distribution Planning department has a two-fold responsibility. First, the department is responsible for determining the distribution system construction requirements to economically and reliably accommodate new load additions to the distribution system. Second, the department ensures that these load additions do not detrimentally affect the existing system and service to existing customers.

The department's major tasks include:

- Determining the distribution service requirements for new distribution load additions;
- Recommending distribution capital improvement projects;
- Producing short, mid, and long range distribution facility (feeder and medium-power substation transformer) load forecasts;
- Developing short, mid, and long range distribution master plans; and
- Developing distribution power flow system models.

1. Load and DER Forecasting

a. Distribution Load Forecasting

NV Energy has a rigorous process for forecasting electric load growth on its distribution feeders and medium-power substation transformers. The Distribution Planning department generates short-term distribution facility (transformer and feeder) load forecasts for five years, which are mainly driven by submitted Applicant service requests on the electric distribution system. The proposed load additions are assigned to a specific distribution feeder(s), given an estimated in-service date based upon the requested date in the Applicant's Project Information Sheet, and an estimated time frame for the proposed load to fully come on-line on the system (ramp-up period). Each feeder in Distribution Planning's internal database system is assigned to a substation transformer, and thus a substation transformer-level forecast is also generated. The substation transformer and distribution feeder forecasts serve as the main drivers for the determination of service requirements for Applicants' service requests, and proposal of capital improvement projects generated from the department.

Distribution Planning considers all of the following pieces of information when generating its distribution facility load forecasts:

- Historical distribution facility peak loading, normalized for temperature, and adjusted for abnormal switching,
- Reserved Load values reflective of service requirements memos (Planning Memos) that have been written to reserve capacity on distribution facilities in association with Applicants' service requests,

- Planned switching in association with Applicants' service requests, capital improvement projects, or for other reasons, and
- Ramp-up period based upon information provided in Applicants' service requests, Metrostudy residential survey data, and experience.

To support a 10-year horizon for corporate capital planning, forecasts for distribution feeders and substation transformers can be generated which cover that timeframe. However, given the uncertainty in forecasting at such a local level, the latter five or six years of the 10-year forecast horizon is extremely variable and experience begets a lower confidence level in its accuracy.

In this manner, distribution load forecasting at NV Energy is accomplished at a local level and aggregated up to the substation level, rather than based upon a system-level load forecast that is disaggregated down to a regional level, and then substation and feeder levels, which is a technique used at some other utilities.

No specific or new distribution facility load forecasts were produced for this DRP. Since the load forecasts for substation transformers and distribution feeders are continually updated by NV Energy's Distribution Planning department, a 'snapshot' of the forecasts from January 18, 2019 served as the basis for the GNA analyses, and covered the minimum six-year timeframe following the year of the filing of this DRP required by the Temporary Regulations. Peak loads from 2014 through 2018 on NV Energy's substation transformers and feeders are provided in **Technical Appendix Item DRP-1**. Forecasted peak loads from 2019 to 2025 on NV Energy's substation transformers and feeders are provided in **Technical Appendix Item DRP-2**.

b. Distributed Resources' Effect on Distribution Load Forecasting

NV Energy understands that DERs have an effect on the loading of distribution facilities. Some of these technologies are energy generating, like solar PV or traditional induction or synchronous generators, and some are load modifying, like Energy Efficiency or Demand Response. The use and proliferation of these technologies affects the net loading as measured at points along the feeder, at the feeder breaker at the substation, or elsewhere in the substation. Presently, the Companies' validation process determining past distribution feeder peak loading does not specifically account for any of these effects, nor does the feeder load forecasting process.

Energy Efficiency has a different effect than some other Distribution Resource technologies in that it provides a reduction to a customer's gross load on a more continuous basis. Other Distribution Resources like private solar PV installations and the Demand Response program are more variable, and can measurably affect the net loading of the Companies' distribution feeders. Presently, the distribution load forecasting process does not make any adjustment for the potentially different effects. However, they are embedded in the net loading data utilized in the forecasting process. As discussed below in Section 8.A., NV Energy will perform a study later in 2019 to determine the potential magnitude of these effects, and whether or not it is appropriate to make adjustments or seek refinements for these inputs to the distribution planning load forecasting process.

c. Distributed Resources Forecasting

Distributed resource forecasting is performed by the NV Energy departments mainly responsible for the programs under which the variety of Distributed Resource technologies are made available to customers (*i.e*., not by the Distribution Planning Department). Presently, Distributed Resource forecasts are developed and presented at the system level for both Nevada Power and Sierra, and are not disaggregated to the region, substation, or distribution feeder levels.

Therefore, this DRP does not present new or updated forecasts of penetration or potential load impacts for Demand Response, Energy Efficiency, electric vehicles, customer-owned generation, or energy storage. Instead, the forecasts used for this DRP and the support behind them were included in the Companies' Joint IRP filing with the Commission in Docket No. 18-06003, and were specifically discussed in Volume 5 of 18 and Technical Appendix Item LF-1 of that filing.

As discussed elsewhere in this narrative, the verification of historical distribution feeder peak loading and the feeder load forecasting processes do not specifically account for the effects of these technologies. However, the Companies will be performing work during 2019 to determine the methods for doing this. Additionally, as noted below in Sections 8.A. and 8.B., the Companies plan to complete the work necessary to disaggregate the system-level Distributed Resource forecasts to the distribution feeder level by summer 2019, in time to support the next iteration of the HCA scheduled to be completed by October 2019 (future year 2018-2025 studies).[6] This will be followed with an investigation of new methods of forecasting Distributed Resources at the customer level. The Companies are targeting October 2020 for integrating new techniques into the Companies' Distributed Resources forecasting process.

2. Hosting Capacity Analysis

Generally, the hosting capacity of a distribution feeder is a measure of its ability to accommodate Distributed Resource capacity before a technical, operational, or safety limitation is reached. It will then be used in several ways:

- As shown on the publicly-accessible Web Portal, the results of the HCA will provide information pointing customers, Distributed Resource providers, and vendors to locations on the distribution system where additional Distributed Resources might be installed without potentially incurring interconnection upgrade costs;
- As an input to the GNA process, the HCA results will add another criteria by which constraints on the distribution system can be identified. Constraints identified on the basis of limited hosting capacity and the requisite traditional wired solutions to those constraints will feed into the GNA, similar to how traditional thermal, voltage, or reliability constraints are already relied upon; and

[6] NV Energy's Hosting Capacity Analysis studies for this filing were based upon 2017 feeder loading profile and peak loading data. Refer to Section 3.A.2.a below. The upcoming studies that NV Energy plans to conduct that will extend that analysis to 2025 will include all years beyond 2017, beginning with 2018. So, for the purposes of the Hosting Capacity Analysis, although the 2018 year has already past and this filing is in the 2019 year, NV Energy considers the studies for the years 2018-2025 as future year studies at this point in time.

- The output of the HCA also can be used as an input to a Distributed Resource interconnection process that the Companies and stakeholders are currently working on to replace one of the Initial Review technical screens in the Companies' current interconnection rules (*i.e.*, Rule 15).

The HCA analysis performed by NV Energy utilizes two distinct systems. DNV-GL's Synergi Electric electrical simulation software ("Synergi") is used to model and analyze the NV Energy's electric distribution systems. The electrical connectivity models of the distribution systems from NV Energy's Geographic Information System ("GIS") mapping system is used as the source for the connectivity models in Synergi.

Preparation of the models in Synergi was the most resource-intensive and time-consuming aspect of performing the HCA. At a high level, this consisted of preparing a correct model of the distribution feeders and substations themselves in Synergi, and preparing the feeder loading profile data which would be an input into Synergi.

<u>a. Substation and Feeder Model Preparation</u>

The process by which the components of the distribution system (*e.g.*, cables, conductors, transformers, fuses, switches, regulators, capacitors, reclosers, meters, dead-ends, pull boxes) and the connectivity model of the distribution system are populated from NV Energy's GIS mapping system into Synergi is referred to as the Model Forge process. The Model Forge process pulls data, which includes GIS and existing Distributed Resource data on feeder sections, from a custom database in the GIS mapping system into a MS Access database with the appropriate schema required by Synergi. Several scripts[7] are then run to perform a model clean-up process which allows the GIS mapping elements and distribution equipment unique to NV Energy's system to be properly used by Synergi (*e.g.*, construction types, conductor or cable type/size, specific switch or fuse types/sizes, and proper connectivity of laterals), as well as any missing data to be flagged and filled in.

Synergi requires three main data source files to build a complete model: a feeder model, a substation model, and an equipment warehouse. Once these files were loaded, the clean-up scripts were run. To perform the initial HCA analysis for this filing, the preparation of NV Energy's distribution system models for use in Synergi required several clean-up scripts to be run to ensure proper functioning of the Synergi software, among them, one to fix any loops detected, correct substation data, correct the naming of substation transformers in the Sierra territory, and correct demand profiles.

Following this, Synergi contains a feature that allows the user to preview any remaining errors that may cause an unsuccessful load flow run. This "view info panel" was accessed and either gave an indication that the model was valid or provided warnings and error details. These were corrected prior to running the model.

Additionally, Synergi requires the peak loading of the feeders to be provided in order to provide the reference for the feeder loading profile data (*i.e.*, what value of load is 100 percent). Historical

[7] Python scripting in Synergi builds script routines. Scripts are programs that automate the execution of tasks which alternatively would be executed one-by-one by a user of the software.

peak load readings from 2017 data provided by NV Energy's Distribution Planning Department were imported into the Synergi model.

One final model preparation step was to adjust the settings in Synergi for the distribution line capacitors so that they operated on the basis of 124 V high voltage and 118 V low voltage settings. These settings determined whether the capacitors were modeled as being energized (or "turned on") or not during the initial load allocation process in Synergi. For example, if a voltage of 117 V was calculated in Synergi at the location of a distribution line capacitor, that capacitor was modeled as "on" since it was on a section that was under 118 V, which would then aid in increasing the voltage on the feeder during the load flow analysis.

b. Feeder Loading Profile Data Preparation

One of the main inputs that Synergi requires in order to run a time-series analysis is loading profile information for the modeled distribution feeders. In Synergi, the data in these loading profiles are in the form of a percentage of the peak loading on the feeder (noted above).

NV Energy acquired information from several sources to develop the feeder loading profile data used in the HCA studies. The general process for creating the necessary data was:

- First, loading data for the year 2017 was acquired for distribution feeders with metering data in the PI system. Generally, this consisted of kW and kVAR data, and in some cases, current data in amps along with either an actual or assumed power factor. The data used represented an hourly average based upon the 5- to 10-second load read data available in PI.[8] Invariably, not all the loading data for all of the feeders represented normal or accurate telemetry. Some "0" values, repeated data values, or data gaps were encountered. For 0 data values, these were adjusted to the last known "good" value in the data set before the 0 value. Where these issues involved six hours or less of data, linear interpolation was used to replace the 0 or repeated values to create loading values more in line with what should be expected in the load profile. Where more than six hours of suspicious data were flagged, further analysis was performed. In this manner, the loading profile data for every feeder was examined for outlying values that were likely the result of outages or abnormal switching, and corrections were made so that abnormal values were not selected for the HCA maximum or minimum loading. If a month of missing data was found, then that month's loading data, or load profile, from the year 2018 was used to fill in the missing data.
- Next, where feeder or substation transformer loading data was absent in PI, data from NV Energy's installed intelligent line sensors was acquired to attempt to fill in gaps. The sensor data mainly consisted of current (in amps), phase angle, and voltage information, as available. Typical sensor data consisted of 15-minute average readings. Due to the technical limitations of different sensor types, some sensors recorded information all year long, some only in the summer months, some only when communication issues did not create data gaps in the sensor data, and some did not record data every 15 minutes. Consequently, a few programs were written to develop the available sensor data for use in

[8] Generally, older Remote Terminal Units ("RTUs") in NV Energy's substations provided 10-second telemetry data, while newer RTUs provided 5-second data.

the feeder loading profiles. Depending upon the available sensor data, an average hourly reading was produced based upon anywhere from one to four readings for the hour. In some cases, one or two of the phases had readings, but the other phase had missing information. In these cases, an attempt was made to approximate the missing phase information based on the available phases. As with the available PI data, if 2017 sensor data was missing, then an attempt was made to acquire 2018 sensor data for the same time period to help fill in the feeder loading profile data gaps.

- Next, if loading data did not exist in PI for a selected feeder, and there was no intelligent line sensor data available to utilize, then loading data for the substation transformer from which the feeder was served was acquired to attempt to create the feeder loading profile. If more than one feeder was served from the transformer in question, this transformer loading data was compared to the loading data for the other feeder(s) it serves and was scaled to properly reflect the loading of the feeder in question so that all of the feeders' loading data combined properly reflected the transformer loading data. As required, the loading profile of the substation transformer data was used to establish the loading profile for the missing feeder loading data.
- If all of the above techniques to acquire or develop accurate feeder loading data did not produce complete results, or there simply was no available data from a feeder, substation transformer, or intelligent line sensor to draw from, then generic loading profiles for commercial, residential, or mixed feeders were used. Ten feeders within each category were selected from both the Nevada Power and Sierra territories that had good data, and an average loading profile was created for each feeder type (resulting in a total of six profiles; three for Nevada Power and three for Sierra). This generic loading profile was then used for the feeder loading profile.
- Finally, a 12-month view of the feeder loading profile was graphed in order to visually inspect the profile to identify any remaining errors in the data.

The above feeder loading profile data preparation process spanned about 6 months and involved a great deal of effort to acquire data from several sources, manage the inconsistencies of the data, and fill in data gaps. However, techniques were developed over the course of the process which should expedite the development of feeder loading profile data in the future.

Technical Appendix Item DRP-3 provides a diagram of the above-described process for developing the feeder loading profile data for use in Synergi (shown in four graphics to aid in clarity).

The result of the feeder loading profile data preparation process was that the data for the entire 2017 year was used to determine the 24-hour loading on the peak and minimum loading days in each month of the year (*i.e.*, 24 loading data points for the highest load (peak) day and 24 loading data points for the lowest load (minimum) day for each month, resulting in 48 data points for each month, or 576 data points each for both kW and kVAR for the whole year). Since the data was for both kW and kVAR, these 576 x 2 loading data points were provided to Synergi to complete the information required to run time-series analysis.

Technical Appendix Item DRP-4 provides a table indicating which data sources referenced above were used to create the loading profiles for each of the feeders analyzed. About 67 percent of the feeder loading profiles utilized data from the PI system, 15 percent utilized data from the generic load profiles, 14 percent utilized data based upon scaling from substation transformer data, and 7 percent utilized intelligent line sensor data.[9]

c. HCA Analytical Method

NV Energy utilized the Incremental HCA capability and the Engineering Analysis ("EA") automation capability in Synergi to perform the initial HCA for this filing. EA Automation is a tool in Synergi that allows multiple analyses to be automated and carried out sequentially. This improves the efficiency of the analysis process, as the user is no longer required to repeat the same process for each portion of the system to be analyzed. The Incremental HCA tool calculates the limiting criteria on each feeder section being modeled for all defined analysis hours, and considers existing generation in calculating this limit. The result is the additional amount of capacity that could be added to each section, in addition to existing customer generation, without exceeding one of the technical criteria. Incremental HCA uses a calculation approach in order to allow results to be produced in a practical timeframe. What this means is that Synergi runs a baseline load flow analysis, and then, using calculations based on impedances in the system, calculates the different limits. Synergi models the electric distribution system in sections. Thus, the HCA was run for each section Synergi models, thereby producing the most granular result possible. Distribution Resource capacity is set at 100 percent for the HCA generation calculations, and OFF for the load capacity calculations.

NV Energy's initial approach to determining the Hosting Capacity of its distribution feeders included the following scenarios:

- Uniform Generation – This analysis case was designed to simulate the effects of distributed generation on the distribution feeder line sections; essentially, any Distribution Resource technology that provides energy into the distribution system. Technologies could include inverter-based generation like solar PV, wind, and the discharging of battery energy storage systems, or traditional distributed diesel generators. Simulating this case as uniform generation across the analysis timeframe accounts for the potential myriad of actual future situations where Distribution Resources could be generating (or discharging) at a variety of levels and times throughout the day or year, which at this point in time cannot be determined with any certainty.
- Uniform Load – This analysis case was designed to simulate the effects of additional load being imposed on the distribution feeder line sections, potentially from the charging of battery energy storage systems, the charging of electric vehicles, or the effects of Demand Response programs. Essentially, this case reflected what traditional Distribution Planning load studies might endeavor to determine regarding the limitations of the distribution system in the face of load growth. Simulating this case as uniform load across the analysis timeframe accounts for the potential myriad of actual future situations where Distribution Resources could simultaneously be charging and load modifying programs could be

[9] These percentages will not equal 100 percent because the loading profile data for several feeders utilized more than one data source.

interacting with each other in a manner that at this point in time cannot be determined with any certainty.

- Solar PV – This analysis case was designed to simulate the effects of solar PV being added to the distribution feeder line sections. Although solar PV output varies throughout the daylight hours, the analysis assumed a constant output of the solar PV at rated capacity across the hours of 10:00 a.m. through 4:00 p.m. The logic for this assumption is that it is possible that solar PV output could be at its full rated capacity any time within these hours. By running the analysis at full output (instead of using irradiance curves, for example), it can be ensured that no practical limits have to be placed on solar PV operation, and that results are valid for any level of output up to full rated output.

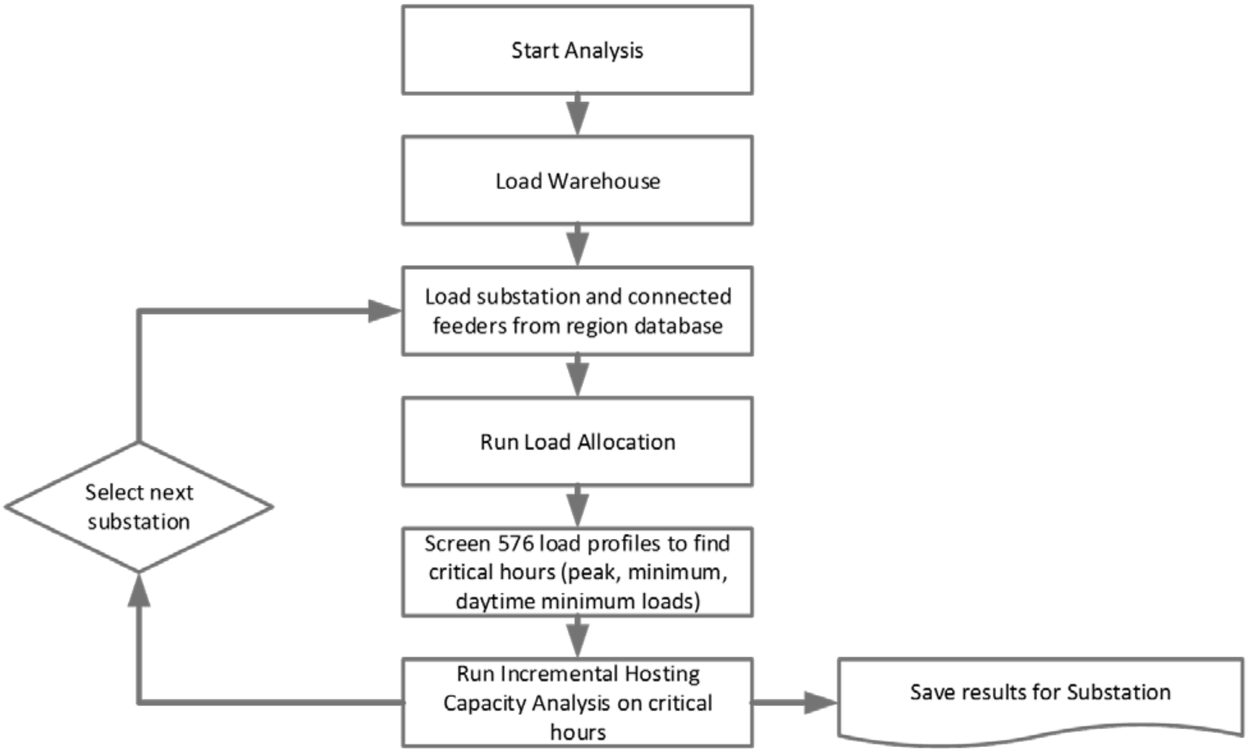
The initial HCA utilized the following criteria to determine technical limitations:

- Steady-State Voltage – A limitation was imposed for steady-state voltage on the distribution feeder sections, with limits established as a maximum of 126 V and a minimum of 116 V,[10] in line with the American National Standards Institute ("ANSI") Standard C84.1 Range A limits.
- Voltage Variation – A 3 percent limitation was imposed for steady-state voltage to vary from its initial level to its final level, either on the basis of the addition or removal of distributed generation capacity or load. Note that this limitation was not meant to simulate or reflect transient voltage fluctuations or harmonics.
- Thermal Loading – A limitation was imposed when the normal continuous thermal ratings of the equipment modeled on the distribution feeders was reached in the simulations.
- Reverse Power Flow (Feeder) – A limitation was imposed that there must be no reverse power flow at the feeder breaker at the substation. However, this analysis was for informational purposes only with a view towards future HCA where system protection-related limiting criteria will be considered, and was not considered as a limiting criteria in the initial HCA for this filing.
- Reverse Power Flow (Section) – A limitation was imposed that there must be no reverse power flow on any feeder sections. Similarly, this analysis was for informational purposes only with a view towards future HCA where system protection-related limiting criteria will be considered, and was not considered as a limiting criteria in the initial HCA for this filing.

Figure 2 below provides a high-level view of the process, including part of the model preparation process.

[10] Voltages are on a 120 V base. ANSI Standard C84.1 Range A voltage allows a minimum of 114 V at the customer's service entrance, but since the Companies' distribution systems are modeled in Synergi down to the primary voltage side of the service transformers only (*i.e.*, the service transformer itself and the secondary/service cable to the customer's meter is not modeled), an allowance for additional voltage drop between that point and the service entrance of 2 V was assumed.

FIGURE 2:
HIGH-LEVEL MODEL PREPARATION AND HCA PROCESS



To help more efficiently run the HCA, a "recipe" was created that directed Synergi to perform the desired HCA scenarios, which substation transformers and feeders to analyze, and what technical criteria to use to establish limitations. A recipe provides the sequence of commands for Synergi to set up and execute the required analysis and report results, and ensures that when analyses are performed by multiple users, they are performed consistently and the results files have identical structures. For any given HCA run, the feeders and substation transformers that were to be part of the run, the electronic folder to which the results were to be written, and any other required scripts were added to the recipe. The recipe includes a settings file which ensured that the same settings were used for all the HCA runs. The recipe then ran the substation and feeder models for a selected transformer, ran load allocation,[11] ran incremental HCA, saved the results file in MS Access format, and then moved to the next transformer.

In order to reduce analytical time in Synergi, the NV Energy distribution system was separated into eight regions: three for Sierra and five for Nevada Power. Most often, the recipe was set to run an entire region of substations and feeders, but sometimes running certain substations and feeders within a region produced results more quickly. Depending upon how many sections were

[11] Load allocation is the process by which Synergi allocates the given maximum (peak) loading at the head-end of the feeder down to the sections of the feeder on which loads are modeled. This is accomplished via a weighted disaggregation of the peak loading on the basis of the capacity ratings of the service transformers.

modeled for each feeder and substation[12] that were part of any individual HCA run, the analysis and production of results took anywhere from a few days to a few weeks to complete.

In several instances, the HCA run did not progress, hanging up on a particular substation transformer, or simply producing results that did not include certain of the transformers that should have been part of the run. In these instances either the run was terminated and investigated, or the missing transformers were investigated for the cause of the problem. When corrections were found to be necessary, they were made, and the run either was re-started, or a new run of just the missing transformers was performed.

d. HCA Results

The HCA results files generated from Synergi were saved in MS Access format and contain the following pertinent information for each feeder section:

- Region of NV Energy's service territory
- Substation Name
- Substation Transformer ID
- Feeder ID
- (Feeder) Section ID
- Analysis Year
- Season (Month)
- Day Type (peak day, minimum load day)
- Hour of Day (1 to 24)
- Maximum Generation (MW)
- Maximum Load (MW)
- Maximum Generation based upon steady-state maximum voltage criteria (MW)
- Maximum Generation based upon delta voltage criteria (MW)
- Maximum Generation based upon thermal criteria (MW)
- Maximum Generation based upon reverse power flow criteria (MW)
- Maximum Generation based upon steady-state minimum voltage criteria (MW)
- Load based upon steady-state minimum voltage criteria (MW)
- Load based upon thermal criteria (MW)

[12] The GIS mapping model of the Nevada Power distribution system contained 1,174,250 sections, or an average of approximately 1,200 sections per feeder. The model of the Sierra distribution system contained a total of 517,175 sections, or an average of approximately 1,400 sections per feeder.

When the MS Access results files were completed for a HCA run, the results were checked via a program that NV Energy created to identify anomalous results: zeros, voltage or thermal issues that created a limitation, if a hosting capacity limitation occurred during a non-peak daytime hour, or not during summer or winter. In this manner, additional errors were found and corrected and the HCA was re-run. Ultimately, the results were posted to an internal site for quality control review prior to publication to the publicly-accessible Web Portal (refer to Section 7), and a review was performed of the red-amber-green color coding to identify any remaining anomalies prior to publication.

Regarding the HCA results themselves, several issues resulted in initial hosting capacity values of "0" for certain feeder sections. Prominent among them was baseline voltages on some feeder sections in the powerflow runs were already below 116 V. For the Uniform Load analysis case in particular, this meant that any increase in load whatsoever would violate the minimum 116 V criteria and yield a "0" result for not only that feeder section, but all sections of that feeder, and additionally for all sections of feeders that are served from the same substation transformer. In this respect, Synergi yielded a correct result for the analysis parameters and constraints it was given; any increase in load anywhere on the feeder in question or on any feeder served from the same substation transformer would reduce the voltage on the subject feeder section to varying degrees, in many cases only very slightly. Although the Companies deemed the HCA results for the Uniform Generation and Solar PV analysis cases to be of higher importance at this stage, this is a situation that NV Energy will examine for future HCA runs and determine if there is a way to eliminate this result in the Uniform Load case.

NV Energy completed the HCA and generated results for all eight regions in its service territory. As of March 8, 2019, the Companies estimated that approximately 50 percent of those results were verified as accurate; meaning that the accuracy checks performed did not reveal incorrect or inaccurate results. The Companies will continue the process of data verification of the HCA results, and will post verified results to the publicly-accessible Web Portal as they become available.

Given the volume of data associated with the HCA results, the publicly-accessible Web Portal presents the best opportunity for interested parties to view these results, which are color-coded (red-amber-green) by feeder section. This web portal will be accessible directly at **https://drp.nvenergy.com** by the end of April 2019. For security and tracking purposes, users must register to access the results. Once on the HCA results site, a user can click on feeder sections to reveal popup boxes containing the results information, and download the results data files.[13] While results for the feeders served from specific substation transformers can be provided, the volume of data associated with the analysis performed on the totality of NV Energy's distribution system does not allow for the results to be provided in the form of a Technical Appendix to this DRP.

[13] As of the date of this filing, the data file download feature of the Web Portal is not functional due to unforeseen technical issues. Refer to the discussion below in Section 7.

e. Progress Toward "Real-time" Hosting Capacity

The concept of "Real-Time" Hosting Capacity Analysis comes from the Commission's Temporary Regulations. Subsection 3 of Section 8 of the Temporary Regulations requires that the Companies include in this and all DRPs "a narrative describing the utility's progress toward providing publicly available real-time hosting capacity." As discussed above in Section 2.E.1., the Companies continue to seek clarity amongst Nevada stakeholders regarding the meaning of the "real-time hosting capacity" requirement, so that they and the Commission can consistently gauge NV Energy's progress towards such. In its August 23, 2018 comments in Docket No. 17-08022, the Companies stated that they viewed the term "real-time" as being reflective of system operating conditions within a timeframe of seconds. The Companies discussed this temporal concept in terms of an operational paradigm, rather than a planning paradigm. Assuming that the term "real-time," as used in the Temporary Regulations, is intended to apply to the planning process generally, and the hosting capacity analysis specifically, the available hosting capacity on sections of distribution feeders would need to be updated and made available publicly on a virtually continuous basis (temporally in a matter of seconds, minutes, or hours) because the values will change continuously based upon changing system conditions. NV Energy expressed concern that there would be significant cost associated with the additional resources required (*e.g.*, software, staffing, training, data sharing, etc.) to achieve and maintain this capability to planning, rather than operational, schemes. Further, depending upon the use case(s) that stakeholders believe necessitates planning information in "real-time," the question of cost responsibility in relation to who is requesting and benefiting from this capability would need to be addressed.

Based upon the discussion at and after the November 29, 2018 stakeholder workshop, it seemed that the stakeholders' expectations for an eventual "real-time" HCA are not aligned with NV Energy's initial interpretation. Rather, they were more akin to ensuring that in short order NV Energy will update its existing DER capacity totals as soon as possible after any application to install a Distributed Resource is received through the interconnection process, and consequently, that a feeder's hosting capacity is updated at the same time.

NV Energy has continued to engage stakeholders on this "real-time" hosting capacity definition, and based upon this discussion, the Companies presented a proposed definition for 'Real-time Hosting Capacity' in the February 21, 2019 informal stakeholder workshop. That definition is very similar to the one contained in Section 2.E above.[14] Although consensus on the issue has not been reached, and some of the stakeholders expressed their belief that establishing a definition was not necessary, NV Energy is of the view that given the requirement in the Temporary Regulation, this is an important enough concept on which there appears to be divergent views, that it should be addressed straightforwardly through a definition. The definition proposed by the Companies in Section 2.E reflects a definition of the concept as used in a planning versus operational paradigm.

The discord described above reflects two different visions of the goal; making the results of an HCA publicly-available and to whom and for what purpose. In short, is the HCA a planning tool, or an operational tool? In the Companies' view, the HCA is clearly a planning tool, and so should

[14] Differing in that on February 21st the definition referred to the signing of a service agreement as one of the triggers for determining if a feeder section's hosting capacity required updating, while in this DRP, in response to subsequent comments from the stakeholders, that was changed to when applications are received rather than when a service agreement is signed.

be subject to the temporal standard of a planning analysis. If it is to be treated as an operational tool, and thus subject to an operational definition of "real time," who is benefiting from that effort? Stated differently, what stakeholder use cases will be enabled or enhanced by "real time" information from the HCA? As used in the operational context, the term "real-time" is generally known in the electric utility industry as referring temporally to cycles up to minutes. If defined in this context the term would require that hosting capacity values would change continuously within that timeframe, as well as seasonally. This definition is incompatible with the interconnection processes both in place and under development, which are based upon forward-looking analysis using set values that, in accordance with Rule 15, would allow for days and months for review and approval of Distributed Resource interconnection applications, construction, inspection, and ultimately, energization. As the term "real-time" is applied in the interconnection context, it must refer to how frequently the hosting capacity values used in the analysis of new interconnection applications are updated. As review of this filing proceeds, the Commission may find that certain of the stakeholders' expectations regarding "real-time" hosting capacity analysis continue to differ from NV Energy's interpretation of the term.

Essentially, the above-mentioned discussions with stakeholders constitute NV Energy's current progress towards the goal of publicly-available "real-time" hosting capacity at the time of this filing. However, the Companies' present plans for reducing the interval involved with updating the hosting capacity of sections of feeders is discussed below in Section 8.B, Phase IV of NV Energy's refinement plan for HCA. That plan includes establishing criteria by the end of January 2020 aimed at targeting feeders in need of updated HCA and ensuring that analysis takes place on a monthly basis or any time a large capacity Distributed Resource application is received by NV Energy, with the results uploaded to the publicly-accessible Web Portal directly following the updated analysis. This targeting of feeders would eliminate the need to continually update hosting capacity on feeders where no change in the value should be expected and represents an efficient, cost-effective method given the amount of new DER capacity applications that NV Energy receives on any given distribution feeder in a month's time.

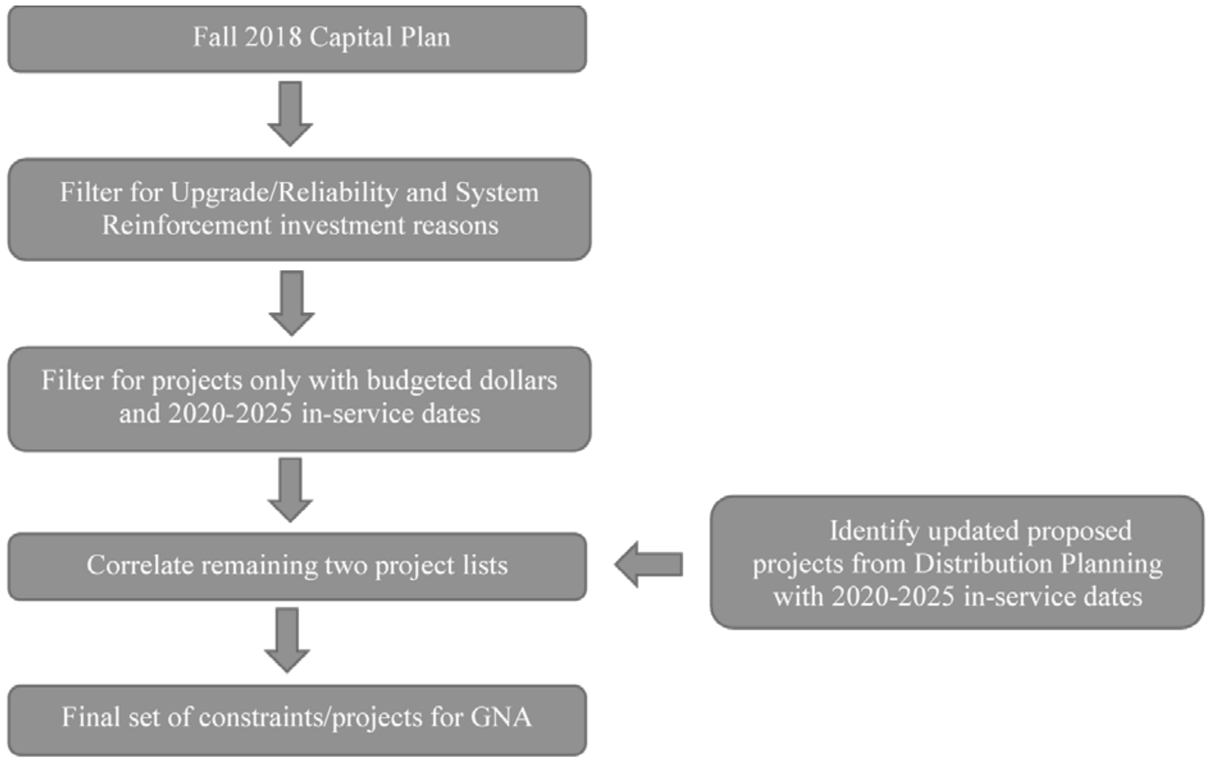
3. Grid Needs Assessment

NV Energy's GNA encompasses the constraints on the Companies' electric grid, traditional and NWA solutions to those constraints, determination of NWAs' suitability to mitigate identified constraints, results of locational net benefit analyses, and recommendations for the deployment of utility infrastructure upgrade solutions and NWA solutions to identified constraints.

a. Distribution Constraints and Projects Identification

NV Energy utilized its 2018 Capital Plan as the source to identify what traditional capital upgrade projects the Companies plan to fund and complete in the coming years. The GNA includes constraints reflected in the Companies' 2018 Capital Plan, which are those that have been deemed as high enough priority or risk to mitigate through funding of a proposed capital upgrade project. Figure 3 below depicts the high-level process that the Companies used to identify constraints for the GNA:

FIGURE 3:
GNA CONSTRAINTS/PROJECTS IDENTIFICATION



Updated information from NV Energy's Distribution Planning department regarding proposed 2020-2025 projects was used to further refine the set of system constraints.[15] The resulting final set of distribution constraints and traditional capital upgrade projects for the 2020-2025 timeframe included a total of 10 projects; five in the Sierra territory, and five in the Nevada Power territory. The forecasted constraints consisted mainly of distribution substation transformer thermal overloads under normal operating conditions, with a few reliability-related constraints under unplanned contingency conditions.

Figure 4 below summarizes the pertinent information for each situation. The data shown is for the year 2025, as this is the ending year of the analysis period. The table is broken into several graphics for ease of viewing, with Columns A through E repeated for identification purposes. The first graphic shows the identifying information, the second shows the deficiency information, and the third shows the traditional capital upgrade project information for each situation.

[15] The vintage of the information obtained from Distribution Planning regarding proposed traditional capital upgrade projects, their planned in-service dates, and load forecast information, was from January 18, 2019. All the analyses in this DRP are based upon information from January 18, 2019 and do not account for any changes that may have occurred after that date.

FIGURE 4:
SUMMARY FORECASTED DISTRIBUTION CONSTRAINT AND TRADITIONAL CAPITAL UPGRADE SOLUTIONS TABLE

A	B	C	D	E	F	G	H	I
Year	Company	Region	Substation	Facility ID	Facility Type	Constraint Type	Operational Condition	Seasonal Identification (Peak, Off-Peak, All)
2020	SPPC	SPPC-NW	Silver Springs	SIL BK 1	Transformer	Reliability	Unplanned Contingency	All
2020	SPPC	SPPC-TM	Silver Lake	SLK BK 2	Transformer	Thermal	Normal	Peak
2020	NPC	NPC-NE	Speedway	SPD BK 2	Transformer	Thermal	Normal	All
2020	SPPC	SPPC-TM	Sugarloaf	SLF BK 1	Transformer	Thermal	Normal	Peak
2020	NPC	NPC-STRIP	Swenson	SWN BK 2	Transformer	Thermal	Normal	Peak
2021	NPC	NPC-SW	Tomsik	TOM BK 2//3	Transformer	Thermal	Normal	Peak
2021	NPC	NPC-NW	Village	VLG BK 1	Transformer	Thermal	Normal	Peak
2022	NPC	NPC-NW	Beltway	BLT BK 4	Transformer	Thermal	Normal	Peak
2022	SPPC	SPPC-NE	Ray Couch	RYC BK 2	Transformer	Reliability	Unplanned Contingency	Peak
2025	SPPC	SPPC-NE	Golconda	GOL 1202	Feeder	Reliability	Unplanned Contingency	All

A	B	C	D	E	J	K	L	M	N	O	P	Q
Year	Company	Region	Substation	Facility ID	Total Estimated Duration of Deficiency in 2025	Total Estimated Days of Deficiency in 2025	Estimated Duration of Deficiency on Peak Day in 2025	Deficiency Start Time on Peak Day in 2025	Deficiency End Time on Peak Day in 2025	Criteria (Ratings)	Initial Deficiency	Estimated Maximum Deficiency in 2025
2020	SPPC	SPPC-NW	Silver Springs	SIL BK 1	8,760.00 hours	365 days	24.00 hours	12:00 AM	12:00 AM	9,350 kVA	7,000 kVA	7,300 kVA
2020	SPPC	SPPC-TM	Silver Lake	SLK BK 2	199.25 hours	48 days	9.50 hours	12:30 PM	10:00 PM	46,700 kVA	1,100 kVA	9,900 kVA
2020	NPC	NPC-NE	Speedway	SPD BK 2	3,313.25 hours	301 days	24.00 hours	12:00 AM	12:00 AM	37,300 kVA	6,500 kVA	22,300 kVA
2020	SPPC	SPPC-TM	Sugarloaf	SLF BK 1	41.75 hours	14 days	4.00 hours	2:15 PM	6:15 PM	60,000 kVA	300 kVA	10,100 kVA
2020	NPC	NPC-STRIP	Swenson	SWN BK 2	4,005.00 hours	231 days	24.00 hours	12:00 AM	12:00 AM	37,300 kVA	3,500 kVA	19,100 kVA
2021	NPC	NPC-SW	Tomsik	TOM BK 2//3	76.75 hours	20 days	7.50 hours	1:15 PM	8:45 PM	74,600 kVA	1,700 kVA	12,100 kVA
2021	NPC	NPC-NW	Village	VLG BK 1	9.00 hours	4 days	4.50 hours	3:15 PM	7:45 PM	37,300 kVA	300 kVA	2,200 KVA
2022	NPC	NPC-NW	Beltway	BLT BK 4	118.25 hours	30 days	9.00 hours	12:30 PM	9:30 PM	37,300 kVA	2,300 kVA	9,100 kVA
2022	SPPC	SPPC-NE	Ray Couch	RYC BK 2	588.00 hours	89 days	12.00 hours	10:30 AM	10:30 PM	7,000 kVA	2,800 kVA	3,000 kVA
2025	SPPC	SPPC-NE	Golconda	GOL 1202	8,724.75 hours	365 days	24.00 hours	12:00 AM	12:00AM	5,724 kVA	2,200 kVA	2,200 kVA

A	B	C	D	E	R	S	T
Year	**Company**	**Region**	**Substation**	**Facility ID**	**T&D Infrastructure Upgrade Project Name**	**Estimated Cost**	**T&D Infrastructure Upgrade Reserve Margin in 2025**
2020	SPPC	SPPC-NW	Silver Springs	SIL BK 1	Silver Springs 2nd Transformer Addition-Bank 2	$3,200,000	2,050 kVA
2020	SPPC	SPPC-TM	Silver Lake	SLK BK 2	Silver Lake Transformer #1 Upgrade	$3,100,000	50,100 kVA
2020	NPC	NPC-NE	Speedway	SPD BK 2	Speedway 138x69/12 kV Bank 1	$2,900,000	15,000 kVA
2020	SPPC	SPPC-TM	Sugarloaf	SLF BK 1	Sugarloaf #2 Transformer Addition	$5,900,000	49,900 kVA
2020	NPC	NPC-STRIP	Swenson	SWN BK 2	Swenson 138/12 kV Bank 3 Addition	$2,800,000	33,900 kVA
2021	NPC	NPC-SW	Tomsik	TOM BK 2//3	Tomsik 138/12 kV Bank 1	$1,800,000	13,300 kVA
2021	NPC	NPC-NW	Village	VLG BK 1	Village Bank 2	$2,300,000	35,100 kVA
2022	NPC	NPC-NW	Beltway	BLT BK 4	Beltway Bank 3	$2,000,000	28,200 kVA
2022	SPPC	SPPC-NE	Ray Couch	RYC BK 2	Ray Couch Bank 2 Upgrade	$1,700,000	4,000 kVA
2025	SPPC	SPPC-NE	Golconda	GOL 1202	Kramer Hill Bank 2 and 1205 Breaker	$2,200,000	4,800 KVA

The columns in Figure 4 above are explained below:

- Column A: Year – The year in which the constraint is forecasted to occur.
- Column B: Company – The territory in which the constraint is forecasted to occur; either Sierra ("SPPC") or Nevada Power ("NPC").
- Column C: Region – The region within each Company's territory in which the constraint is forecasted to occur. There are five regions designated in the Nevada Power territory: NVE-NE (Northeast), NVE-NW (Northwest), NVE-SE (Southeast), NVE-SW (Southwest), and NVE-Strip (Las Vegas Strip area). There are three regions designated in the Sierra territory: SPPC-TM (Truckee Meadows), SPPC-NE (Northeast), and SPPC-NW (Northwest).
- Column D: Substation – The name of the substation in which the constrained distribution system facility is located or is served from.
- Column E: Facility ID – The unique identifier for the constrained distribution system facility, which begins with either a two- or three-character abbreviation for the substation, the abbreviation "BK" if the facility is a substation transformer, and a number identifying either the position of the substation transformer in the substation or the feeder breaker number if the facility is a distribution feeder. The symbol "//" means that two substation transformers are normally operated in parallel with each other.
- Column F: Facility Type – The type of constrained distribution facility, *e.g.*, (substation) transformer or feeder.
- Column G: Constraint Type – The type of constraint, including, reliability, thermal, or voltage.

- Column H: Operational Condition – The operating condition in which the constraint occurs, including, normal operating, unplanned contingency, or planned abnormal conditions (*e.g.* during scheduled maintenance or construction).
- Column I: Seasonal Identification – Identifies the season of the year in which the constraint mainly occurs, including, Peak (generally, June through September), Off-Peak (generally, October through May), or All (occurs almost throughout the year). This is subjectively based the Total Estimated Duration of Deficiency in 2025 and the Total Estimated Days of Deficiency in 2025.
- Column J: Total Estimated Duration of Deficiency in 2025 – Based upon forecasted annual 15-minute load curve information, this is the estimated total number of hours in the year 2025 that the forecasted loading will be above the established limit (*i.e.*, there will be a deficiency). The year 2025 is chosen for this and other parameters as it is the last year in the six-year timeframe from the year of this filing, and the last year covered by the GNA.
- Column K: Total Estimated Days of Deficiency in 2025 – Based upon forecasted annual 15-minute load curve information, this is the estimated total number of days in the year 2025 that the forecasted loading will be above the established limit at any time during the day.
- Column L: Estimated Duration of Deficiency on Peak Day in 2025 – Based upon forecasted annual 15-minute load curve information, this is the estimated total number of hours on the forecasted peak load day in the year 2025 that the forecasted loading will be above the established limit.
- Column M: Deficiency Start Time on Peak Day in 2025 – Based upon forecasted annual 15-minute load curve information, this is the time of the day on the forecasted peak load day in the year 2025 that the forecasted loading will begin to be above the established limit.
- Column N: Deficiency End Time on Peak Day in 2025 – Based upon forecasted annual 15-minute load curve information, this is the time of the day on the forecasted peak load day in the year 2025 after which the forecasted loading will cease to be above the established limit.
- Column O: Criteria (Ratings) – This is the criteria used to establish the constraint (*i.e.*, the established limit). Most often, this is the normal continuous rating of the distribution facility on which the constraint occurs.
- Column P: Initial Deficiency – In kW, this is the amount of the constraint, as compared to the Criteria or Rating, that either exists today, or is forecasted to exist in the first year of the constraint.
- Column Q: Estimated Maximum Deficiency in 2025 – In kW, this is the amount of the constraint, as compared to the Criteria or Rating, which is forecasted to exist in 2025. In comparison to the Initial Deficiency, this figure can help to gauge how the constraint may be increasing or decreasing over time.
- Column R: T&D Infrastructure Upgrade Project Name – The name of the approved traditional T&D capital upgrade project in the Companies' 2018 Capital Plan which is meant to address the constraint.

- Column S: Estimated Cost – The estimated cost in today's dollars for the approved traditional T&D capital upgrade project in the Companies' 2018 Capital Plan which is meant to address the constraint.
- Column T: T&D Infrastructure Upgrade Reserve Margin in 2025 – The estimated amount of incremental capacity that the traditional T&D capital upgrade project will install in 2025, above what is necessary to accommodate the Estimated Maximum Deficiency in 2025.

Brief descriptions of the 10 constraint situations are provided below.

2020

Five constraints on the Companies' distribution system were identified that are planned to be mitigated through traditional capital upgrade projects in 2020:

- In the Northwest region of the Sierra territory, Silver Springs 60/12 kV Substation provides service to some of the customers along State Highway 50 between Carson City and Fallon, Nevada. The distribution primary voltage at the substation is 12 kV, while the primary voltage from distribution substations and feeders surrounding the Silver Springs Substation service territory is 25 kV. This creates an operational constraint when service to all or a portion of the two existing distribution feeders from Silver Springs Substation or the single existing 9.35 MVA transformer at the substation is lost for any amount of time. Restoring service by switching load (customers) to adjacent in-service distribution facilities is not possible due to the difference in primary voltage.

  Entitled "Silver Springs 2nd Transformer Addition-Bank 2," with an in-service date of June 1, 2020, the planned traditional capital upgrade project for mitigating this constraint involves installing a second transformer at the substation (60/25x12 kV, 10.5 MVA) capable of carrying all of the substation's load. The dual low-side configuration would allow initial primary voltage service at 12 kV, and conversion to 25 kV in the future.

- In the Truckee Meadows region, northwest of Reno, Nevada, the existing 120x60/25 kV, 46.7 MVA transformer #2 at the Silver Lake 60/25 kV Substation is forecasted to exceed its normal thermal capacity rating during the 2020 peak season. The Silver Lake transformer #1 has a 13.3 MVA capacity.

  Entitled "Silver Lake Transformer #1 Upgrade," with an in-service date of June 1, 2020, the planned traditional capital upgrade project for mitigating this constraint involves replacing transformer #1 at the substation with a 120x60/25 kV, 60 MVA transformer.

- In the Northeast region of the Las Vegas Valley, the existing 138x69/12 kV, 37.3 MVA transformer #2 at the Speedway 69/12 kV Substation is forecasted to exceed its normal thermal capacity rating during the 2020 peak season

  Entitled "Speedway 138x69/12 kV Bank 1," with an in-service date of June 1, 2020, the planned traditional capital upgrade project for mitigating this constraint involves installing a second 138x69/12 kV, 37.3 MVA transformer at the substation.

- In the Truckee Meadows region, north of Sparks, Nevada, the existing 120/25 kV, 60 MVA transformer #1 at the Sugarloaf 120/25 kV Substation is forecasted to exceed its normal thermal capacity rating during the 2020 peak season.

Entitled “Sugarloaf #2 Transformer Addition,” with an in-service date of June 1, 2020, the planned traditional capital upgrade project for mitigating this constraint involves installing a second 120/25 kV, 60 MVA transformer at the substation.

- On the Strip, the existing 138/12 kV, 37.3 MVA transformer #2 at the Swenson 138/12 kV Substation is forecasted to exceed its normal thermal capacity rating during the 2020 peak season.

  Entitled “Swenson 138/12 kV Bank 3 Addition,” with an in-service date of June 1, 2020, the planned traditional capital upgrade project for mitigating this constraint involves installing a third 138/12 kV, 37.3 MVA transformer at the substation.

2021

Two constraints on the Companies’ distribution system were identified that are planned to be mitigated through traditional capital upgrade projects in 2021:

- In the Southwest region of the Las Vegas Valley, the existing paralleled 138/12 kV, 37.3 MVA transformers #2 and #3 at the Tomsik 138/12 kV Substation are forecasted to exceed their combined normal thermal capacity rating during the 2021 peak season.

  Entitled “Tomsik 138/12 kV Bank 1” and with an in-service date of June 1, 2021, the planned traditional capital upgrade project that will mitigate this constraint involves installing a third 138/12 kV, 37.3 MVA transformer at the substation.

- In the Northwest region of the Las Vegas Valley, the existing 138/12 kV, 37.3 MVA transformer #1 at the Village 138/12 kV Substation is forecasted to exceed its normal thermal capacity rating during the 2021 peak season.

  Entitled “Village Bank 2” and with an in-service date of June 1, 2021, the planned traditional capital upgrade project that will mitigate this constraint involves installing a second 138/12 kV, 37.3 MVA transformer at the substation.

2022

Two constraints on the Companies’ distribution system were identified that are planned to be mitigated through traditional capital upgrade projects in 2022:

- In the Northwest region of the Las Vegas Valley, the existing 138/12 kV, 37.3 MVA transformer #4 at the Beltway 138/12 kV Substation is forecasted to exceed its normal thermal capacity rating during the 2022 peak season.

  Entitled “Beltway Bank #3 Addition,” with an in-service date of June 1, 2022, the planned traditional capital upgrade project for mitigating this constraint involves installing a second 138/12 kV, 37.3 MVA transformer at the substation.

- In the Northeast region of the Sierra territory, the existing Ray Couch 60/12 kV Substation provides service to an area just to the west of Fallon, Nevada. Two existing transformers are located at the substation. Transformer #1 has a normal continuous rating of 14 MVA, while transformer #2 is rated at 7 MVA. Should transformer #1 go out of service for any reason, transformer #2 does not have the ability to serve all of the load on the substation during peak conditions.

Entitled “Ray Couch Bank 2 Upgrade,” with an in-service date of November 15, 2022, the planned traditional capital upgrade project for mitigating this constraint involves replacing transformer #2 at the substation with a 60/12 kV, 14 MVA transformer. Upon completion, each transformer at the substation would be able to carry the load on the substation should the other transformer go out of service for any reason. An additional linked project entitled “Ray Couch 1207/1208 Tie” is also needed to create a tie between the Ray Couch 1207 and 1208 feeders to facilitate transferring load during a contingency.

<u>2025</u>

One constraint on the Companies’ distribution system was identified that is planned to be mitigated through a traditional capital upgrade project in 2025:

- In the Northeast region of the Sierra territory, the existing Golconda 60/12 kV and Kramer Hill Substations provide service to an area near Winnemucca, Nevada. There is one feeder from Kramer Hill Substation, the 1204, and it ties to both the Golconda 1201 and 1203 feeders. However, the Golconda 1202 feeder is not tied to the Kramer Hill 1204 feeder, and even if it was, there is insufficient capacity on the existing Kramer Hill 60/12 kV, 7 MVA transformer #1 to accept the total load served by the Golconda 1201, 1202, and 1203 feeders combined when that is necessary during an outage at the Golconda Substation.

  Entitled “Kramer Hill Bank 2 and 1205 Breaker,” with an in-service date of December 1, 2025, the planned traditional capital upgrade project for mitigating this constraint involves installing a second 120/12 kV, 7 MVA transformer at Kramer Hill Substation, and also installing a new distribution feeder designated 1205 to tie to the Golconda 1202 feeder so that feeder’s load could be successfully transferred to Kramer Hill Substation when necessary.

<u>b. Non-Wires Alternative Analysis</u>

As discussed above, an NWA is a solution to an identified constraint(s) on the Companies’ electric transmission or distribution systems that may include the deployment of one or more Distributed Resources in lieu of a traditional wired solution.

(1) NWA Suitability/Screening Criteria

Distributed Resources have the potential for deferring, and in unique cases eliminating, the need for traditional infrastructure solutions. However, the services that they provide do not always align with the needs or characteristics of existing or forecasted constraints on the utility electric system. Also, timing issues in the form of short lead times may make potential NWA solutions less viable. Consequently, NV Energy developed NWA Suitability/Screening Criteria (“Suitability Criteria”) in order to filter planned traditional T&D capital upgrade projects and better identify those situations where a NWA solution was a viable alternative to address an existing or forecasted constraint, and thus potentially defer a planned traditional wired T&D capital upgrade project. Figure 5 below shows the Suitability/Screening Criteria:

FIGURE 5:
NON-WIRES ALTERNATIVE SUITABILITY/SCREENING CRITERIA

Non-Wires Alternative Suitability/Screening

		Yes	No	Comment
Critical Suitability Criteria				
A.	Is the constraint anticipated to occur between January 1, 2020 and December 31, 2025?			
B.	Is the constraint based upon thermal loading, voltage, or reliability reasons where a reduction in peak demand loading or energy consumption, or load shifting, on the transmission or distribution facilities involved would eliminate or defer the constraint?			
Red Flag Suitability Criteria				
C.	Is the wired solution still within the planning or design stage, with no major equipment on order, received, or installed?			
D.	Is it reasonable to assume at this time that a Distributed Energy Resources solution will be reliable and safe (i.e., non-critical customers) in this location on the grid?			
E.	Is it reasonable to assume at this time that local residents would accept a Distributed Energy Resources solution in this area?			
F.	Is it reasonable to assume at this time that local governmental agencies would accept a Distributed Energy Resources solution in this area?			
G.	Is it reasonable to assume at this time that there are no environmental concerns which would preclude a Distributed Energy Resources solution in this area?			
H.	Is it reasonable to assume at this time that a Distributed Energy Resources solution would be able to be physically sited in this area?			

1. ***If all of the responses above are Yes, then proceed with the Non-Wires Alternative analysis.***
2. ***If either of the responses in A or B are No, then provide appropriate comment(s) and do not proceed with the Non-Wires Alternative analysis.***
3. ***For the questions in C through H, No responses should only be initially entered if the user has good reason supported by personal knowledge or experience. If any of the responses for C through H are initially entered as No, initiate a discussion with appropriate NV Energy personnel to discuss the specifics of the situation and verify the response. Following this discussion, if it is appropriate for all the responses for C through H to be Yes, proceed with the Non-Wires Alternative analysis, documenting in the Comments area where any responses were changed and why. Do not proceed with the Non-Wires Alternative analysis if any one of the initial No responses presents a supportable reason to not continue. Document the discussions in the Comments area and via a separate attachment if necessary.***

Continue with Non-Wires Alternative Analysis? **Yes** **No** (Highlight the response)

The Suitability Criteria are divided into Critical and Red Flag sections. For the Critical section, there are two criteria:

- Criterion A addresses the issue of timing. NV Energy's NWA analyses included reviewing constraints and planned traditional wired T&D capital upgrade projects within of the 2020-2025 timeframe (a minimum of six years beginning with the year after this DRP was filed).
- Criterion B addresses the characteristics of an existing or forecasted constraint on the utility electric system. If the constraint relates to thermal overload, voltage, or reliability, where a reduction in peak demand or energy consumption, or a temporal shifting of load, would avoid or eliminate the constraint, a NWA technology could be utilized to address the issue.

For the Red Flag section, there are six criteria:

- Criterion C addresses the fact that certain near-term planned traditional wired T&D capital upgrade projects may already be well into their planning, design, or construction phases, with major equipment potentially either ordered, delivered, or installed, and significant capital funds spent. In these situations, it was prudent to forgo further investigation of an NWA and continue with the installation of the wired solution.

- Criterion D addresses the fact that a NWA solution must be considered as reliable and safe in order to be considered as an option to address an existing or forecasted constraint. These tenets cannot be compromised. The criterion refers to ensuring that NWAs are not installed as a substitute for traditional solutions where service to critical customers are involved. Evaluated on a case-by-case basis, under this criterion, critical customers (*e.g.*, emergency services) would not be served from NWAs.
- Criterion E addresses the fact that local residents have expressed opposition to the installation of certain NWA technologies based on their footprint or aesthetics, or simply that they are unfamiliar with or untrusting of the technology in comparison to the wired utility facilities that they are used to.
- Criterion F is similar to Criterion E, but addresses the potential issues from the perspective of local governmental agencies rather than residents.
- Criterion G addresses the fact that certain areas may have restrictive environmental requirements that could preclude the installation of certain DERs (*e.g.*, like wind or diesel generation).
- Criterion H addresses the fact that there may be physical limitations in citing certain NWA technologies in certain areas. For example, an NWA analysis may reveal that a solar PV and battery energy storage system solution may be a viable alternative to a traditional wired solution in a certain locale, but land on which to cite the solution is not available. In practice, for this DRP, NV Energy did not attempt to perform an analysis to determine whether or not certain DER technologies could be sited in certain areas. A blanket assumption was made that any such issue would be addressed later should the results of an NWA analysis reveal that a Distributed Resource solution may be recommended.

The questions posed in each of the criterion were framed so that if all the responses were "Yes," then an NWA analysis should be conducted (see Item 1 in Figure 5). If either of the two Critical Suitability Criteria are failed (i.e., the question answered as a "No"), then an NWA analysis should not be performed (per Item 2). However, the Suitability Criteria also allow for an analysis to be conducted even if one or more of the Red Flag Criteria may initially be failed. Item 3 requires that "justification is required to support the decision based upon personal knowledge or experience" must exist to support any initial "No" response, and further requires that a specific discussion take place amongst the appropriate NV Energy personnel to either verify the initial "No" response and provide reasoning for it, or change the initial "No" response to a "Yes," and so then perform an NWA analysis. This ensures that the Suitability Criteria are as inclusive as possible in that they ensure that for Red Flag NWAs, the reasons to not perform an NWA analysis are verified and documented.

NV Energy also considered a criterion based upon the estimated cost of the planned traditional T&D capital upgrade project, which would have screened out situations where the traditional wired solution was considered to be comparatively low-cost, but this was not adopted, again, in order for the suitability/screening process to be as inclusive as possible.

(2) NWA Analysis Method

To perform the initial NWA analysis for this filing, NV Energy developed a MS Excel-based spreadsheet tool, the NWA Sizing Model,[16] which:

- Captures information about the traditional wired solution,
- Provides the Suitability/Screening Criteria results,
- Provides aerial geographic information in the area of the constraint,
- Provides single-lines of the substations involved,
- Captures 15-minute load data for the constrained electric system facility,
- Provides outage data (if necessary),
- Determines the amount of the constraint (or deficiency) in future years (*i.e.*, the need),
- Determines the ability of Energy Efficiency, Demand Response, Solar PV, and Battery Energy Storage System DER technologies to mitigate the constraint,
- Provides a ballpark cost estimate for the NWA DER portfolio, and
- Compares the ballpark estimated NWA DER portfolio cost to the estimated cost of the traditional wired solution.

Of the 10 distribution constraints identified above and shown in Figure 4, two did not pass the Suitability/Screening Criteria to move forward in the process to the NWA analysis. These were the constraints identified at Sugarloaf Substation and Swenson Substation. Each of these constraints failed Criteria C (see Figure 5 above); the design and construction process had progressed beyond the point at which it would have been reasonable to halt progress in order to consider an alternative method of addressing the constraint (note that the traditional capital upgrade projects involved all have in-service dates in 2020).[17]

The NWA Sizing Model contains a number of tabs as explained below:

- Overview – Provides information with regard to the goal, methodology, potential NWAs, and results sought by the spreadsheet.
- User Guide – Provides brief instructions for each of the tabs in the spreadsheet.
- Wired Solution – Provides information about the planned traditional capital upgrade solution, what is the problem and solution, in-service date and estimated cost, and any relevant comments (optional).

[16] This tool is a functioning model that cannot readily be provided as a Technical Appendix. The Companies welcome the opportunity to demonstrate the model to interested parties.

[17] Despite this fact, both constraints were run through the MS Excel NWA spreadsheet in order to generate the deficiency information required in Columns J, K, L, N, and O, and the reserve margin information in Column R of the summary table in Figure 4.

- Suitability – Provides the Suitability/Screening Criteria analysis for the constraint, indicating if it is passes onto the NWA analysis or not, with comments and reasoning.
- Substation – Provides a single-line diagram of the local transmission and substation system (if available), a single-line diagram of the substation in question, and any diagram of the wired solution (if available).
- Right-of-Way ("ROW") and Permitting – Provides an aerial geographic image of the area in which the constraint lies (generally centered on the substation in question), an aerial geographic image of the substation in question, an aerial geographic image showing any potential permitting issues or considerations (if available).[18] Of note, the NWA analyses did not consider whether land or a potential customer location would be available to site a Distributed Resource solution.
- Load Data – Provides the 15-minute loading data for the constrained electric system facility. The PI Datalink may be used to import the loading information directly into the spreadsheet, or it can be input manually (cut and paste) from a separate file into which the PI data has been placed.[19] For the purposes of this NWA analysis, 2017 loading data was acquired and used. The analysis began in Q4 2018, and 2017 represented the best full year of data available at the time.

  From the MW and MVAR information, the tab calculates the MVA. The tab then scales the current year loading data for successive years (for 10 years) based upon the load forecast information for the electric system facility in question provided by NV Energy's Distribution Planning department, provides forecasted loading data for the identified peak day for each analysis year, and identifies deficiency parameters in terms of MVA, MWh, and 15-minute periods, hours, and days per year over the limit.
- Outage Information – Provides historical outage information for reliability-based constraints, if necessary (not provided for other types of constraints).
- Need – Provides the ability to chart forecasted loading for any day of the year[20] against the asset limit, identifies that most recent peak loading amount, day, and time, allows input of the forecasted peak loading data, displays the annual peak MVA and MWh need in tabular and graphic form, provides the estimated number of days in a year that the forecasted loading will be over the established limit, and provides forecasted overload hours and period on the peak day of all the years of the analysis.
- Portfolio – Provides the user the ability to create a NWA solution portfolio to address the forecasted constraint for any day in the analysis period,[21] and indicates the MW reduction

[18] An aerial geographic image showing any potential permitting issues or considerations is not provided for the 10 distribution constraint situations. The NWA analyses performed did not include such considerations.

[19] This data from PI is the raw data which has not been filtered for anomalies, normalized for temperature, or adjusted for abnormal system configuration.

[20] However, in order to properly size the NWA solution, the Chart Day should be the identified peak day.

[21] However, in order to properly size the NWA solution, the month and day selected should be the forecasted peak month and day, and for the purposes of this analysis, the year should be selected as 2025.

for the various Distributed Resource technologies used in the analysis, which included Energy Efficiency, Demand Response, Solar PV, and Battery Energy Storage Systems.[22]

The analysis technique first used an estimated 2 percent MW demand reduction capability for Energy Efficiency,[23] then used the unique Demand Response Peak MW Reduction potential for the electric grid facility in question, varying the Demand Response start time so as to minimize the NWA portfolio estimated cost. Then a Solar PV generation amount was entered by the user to minimize the NWA portfolio estimated cost. Finally, Battery Energy Storage System MWs and MWhs were automatically calculated by the NWA Sizing Model to address any remaining constraint above the facility rating or limit that was not addressed by the other three Distributed Resource technologies. If using no solar PV minimized the NWA solution portfolio cost, then a zero capacity for this technology was chosen. In this manner, the NWA solution portfolio was established with the goal of minimizing its estimated cost. However, the analysis method was not an optimization, which would require varying multiple inputs simultaneously to achieve the desired cost minimization goal.

Of note, the charging requirements for the battery energy storage system DER are not modeled (this is an item that the Companies plan to address in the next round of NWA analyses in Q4 2019.)

- Solar Analysis – Provides solar profile information reflecting the average 15-minute generation meter data of Net Energy Metering customers (from 2016 for Sierra, and from 2015 for Nevada Power), forecasted solar output on the Chart Day (the day chosen by the user to be viewed; normally the peak day), the effect on the forecasted loading data, and graphical representations of the solar production based upon the solar profile.
- NWA Proposal – Provides the estimated cost for the NWA solution portfolio, along with the cost data assumptions. This cost comparison is not meant to reflect net present value or the potential impact of any benefits attributable to the NWA solution portfolio.
- Results – Provides a comparison of the estimated total cost of traditional wired capital upgrade solution versus the estimated cost for the NWA solution portfolio, along with any comments that may have been entered on other tabs of the spreadsheet.
- Admin – Provides data that is used in other tabs of the spreadsheet for functional purposes.

[22] Demand Response was assumed over a three hour period, customized by hour for both early peak (1PM – 6PM) or late peak (6PM – 9PM), including snapback in a fourth hour, with the potential Peak MW Reduction specific to the distribution facilities in question based upon existing Demand Response capability installed on those facilities as of June 2018. Solar PV and Battery Energy Storage Systems were assumed as in-front-of-the-meter and utility-owned. Conservation Voltage Reduction, while shown in the NWA Sizing Model, was not used for this analysis. NV Energy intends to add this technology to the potential NWA portfolio solution in the next round of NWA analyses scheduled for Q4 2019.

[23] An estimated 2 percent permanent peak MW demand reduction over a span of three to four years was used for Energy Efficiency based upon historical impacts from NV Energy's programs and recent regulatory kWh savings targets in the range of 1.0 percent to 1.25 percent of retail sales.

(3) NWA Analyses Discussion

2020—Silver Springs

A service reliability issue exists in the area of the Silver Springs Substation. When the existing transformer #1 goes out of service for any reason its load cannot be picked up by neighboring feeders due to a difference in the primary voltages. Loading information revealed a 2017 peak of about 6.7 MVA,[24] with very low load growth forecasted through 2027. Given that the installation of a second transformer at the substation would provide reliable service to the load on a continuous basis throughout the year, the NWA analysis was run with an Asset Limit (Rating) of 0 MVA. Thus the NWA solution would need to be available to serve load on a continuous basis in order for a comparable analysis to be made against the traditional wired solution.

In this analysis, Demand Response was not included in the NWA solution portfolio because of an absence of DR capacity in the Silver Springs area. Additionally, solar PV capacity was limited to 7.2 MW-AC in order to not cause reverse powerflow at the substation. Any NWA solution would likely need to be connected to the low-side bus at the substation.

2020—Silver Lake

The loading on the existing Silver Lake transformer #2 is forecasted to exceed its 46.7 MVA rating under normal operating conditions by the summer peak, 2020. Loading information revealed a 2017 peak of 40.2 MVA, with about 20 MVA of growth forecasted over the next 10 years.

In this analysis, 800 kW of Demand Response was included in the NWA solution portfolio, which represents the approximate total installed Demand Response capability on that transformer. Adjusting the start time of the Demand Response to 6:45 PM reduced the estimated NWA portfolio cost. Additionally, a portfolio with no solar PV also minimized that cost. Any NWA solution would likely need to be connected to the low-side bus at the substation, or one of the feeders served from transformer #2.

2020—Speedway

The loading on the existing Speedway transformer #2 is forecasted to exceed its 37.3 MVA rating under normal operating conditions by the summer peak, 2020. Loading information revealed a 2017 peak of 10.2 MVA, but with almost 60 MVA of additional load from several large customer projects planned over the next 10 years.

In this analysis, Demand Response was not included in the NWA solution portfolio because of an absence of DR capacity in the Speedway area. A portfolio with 20.3 MW-AC of solar PV minimized the estimated NWA portfolio cost. Any NWA solution would likely need to be connected to the low-side bus at the substation, or to one of the feeders served from transformer #2.

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[24] Loading for Silver Springs transformer #1 was determined from PI data for the Silver Springs 1211 and 1212 feeders.

2021—Tomsik

The loading on the existing Tomsik transformers #2 and #3 (paralleled) is forecasted to exceed their total 74.6 MVA rating under normal operating conditions by summer peak, 2021. Loading information revealed a 2017 peak of 54.3 MVA,[25] with about 40 MVA of growth forecasted over the next 10 years.

In this analysis, 2,400 kW of Demand Response was included in the NWA solution portfolio as that is the approximate total installed DR capability on those transformers. Adjusting the start time of the DR to 5:30 PM reduced the estimated NWA portfolio cost. Additionally, a portfolio with 2.3 MW-AC of solar PV also minimized that cost. Any NWA solution would likely need to be connected to the low-side bus at the substation, or to one of the feeders served from transformers #2 or #3.

2021—Village

The loading on the existing Village transformer #1 is forecasted to exceed its 37.3 MVA rating under normal operating conditions by summer peak, 2021. Loading information revealed a 2017 peak of 26.6 MVA, with about 15 MVA of growth forecasted over the next 10 years.

In this analysis, 1,200 kW of Demand Response was included in the NWA solution portfolio as that is the approximate total installed DR capability on that transformer. Adjusting the start time of the DR to 4:00 PM reduced the estimated NWA portfolio cost. Additionally, a portfolio with no solar PV also minimized that cost. Any NWA solution would likely need to be connected to the low-side bus at the substation, or on one of the feeders served from transformer #1.

2022—Beltway

The loading on the existing Beltway transformer #4 is forecasted to exceed its 37.3 MVA rating under normal operating conditions. Loading information revealed a 2017 peak of 23.6 MVA, with about 29 MVA of growth forecasted over the next 10 years.

In this analysis, 950 kW of Demand Response was included in the NWA solution portfolio as that is the approximate total installed Demand Response capability on that transformer. Adjusting the start time of the DR to 6:15 PM reduced the estimated NWA portfolio cost. Additionally, a portfolio with 2.4 MW-AC of solar PV also minimized that cost. Any NWA solution would likely need to be connected to the low-side bus at the substation, or on one of the feeders served from transformer #4.

2022—Ray Couch

The area around the Ray Couch Substation is subject to reliability issues because the existing Ray Couch transformer #2 cannot accommodate the load on the substation should transformer #1 go

[25] Loading for the paralleled Tomsik transformers #2 and #3 was determined from the PI data for Tomsik transformer #2 and Tomsik transformer #3.

out of service for any reason. Loading information revealed a 2017 peak of about 9.4 MVA,[26] with less than 1 MVA of load growth forecasted through 2027. Assuming that transformer #2 is not upgraded (*i.e.*, replaced with a transformer of greater capacity), any NWA solution would need to reduce the load on the substation to the current 7 MVA capacity of transformer #2 in order. Thus, the analysis was performed using 7 MVA as the Asset Limit.

In this analysis, Demand Response was not included in the NWA solution portfolio because of an absence of DR capacity in the Ray Couch area. Additionally, a portfolio with no solar PV minimized the estimated NWA portfolio cost. Any NWA solution would likely need to be connected to the low-side bus at the substation, or on one of the feeders served from transformer #2.

<u>2025—Kramer Hill</u>

Service reliability in the Kramer Hill Substation area is at issue because the existing Golconda 1202 feeder does not tie to another feeder, and its load cannot be served from another distribution facility in the event of a loss of service to the feeder. Loading information revealed a 2017 peak of about 2.2 MVA,[27] with virtually no load growth forecasted through 2027. Given that the installation of a second transformer and a new distribution feeder at Kramer Hill Substation would provide reliable service to the Golconda 1202 load on a continuous basis throughout the year, the NWA analysis was run with an Asset Limit (Rating) of 0 MVA, indicative of the fact that the NWA solution would need to be available to serve load on a continuous basis in order for comparable analysis to be made against the traditional wired solution.

In this analysis, Demand Response was not included in the NWA solution portfolio because of an absence of DR capacity in the Golconda area, and the solar PV capacity was limited to 2.6 MW-AC in order to not cause reverse powerflow at the substation. Any NWA solution would likely need to be connected to the Golconda 1202 feeder.

(4) NWA Analyses Results

Figure 6 below summarizes the identifying information, NWA portfolio parameters, and traditional capital upgrade project information for each situation. The data shown is for the year 2025, as this is the ending year of the analysis period. The table is broken into several graphics for ease of viewing, with Columns A through E repeated for identification purposes.

[26] Loading for the combined Ray Couch transformers #1 and #2 was created from the PI data for the Ray Couch 1206, 1207, and 1208 feeders.

[27] Loading data for Golconda 1202 was very fragmented and was assembled from current (amp) and power factor data by extrapolating single-phase loading across all phases, and filling in missing data with existing data (*e.g.*, December data was filled in with October and November data, while January-March data was filled in with April-May data).

FIGURE 6:
SUMMARY FORECASTED DISTRIBUTION CONSTRAINT AND NWA SOLUTIONS TABLE

A	B	C	D	E	F	G	H	I
Year	Company	Region	Substation	Facility ID	Facility Type	Constraint Type	Operational Condition	Seasonal Identification (Peak, Off-Peak, All)
2020	SPPC	SPPC-NW	Silver Springs	SIL BK 1	Transformer	Reliability	Unplanned Contingency	All
2020	SPPC	SPPC-TM	Silver Lake	SLK BK 2	Transformer	Thermal	Normal	Peak
2020	NPC	NPC-NE	Speedway	SPD BK 2	Transformer	Thermal	Normal	All
2020	SPPC	SPPC-TM	Sugarloaf	SLF BK 1	Transformer	Thermal	Normal	Peak
2020	NPC	NPC-STRIP	Swenson	SWN BK 2	Transformer	Thermal	Normal	Peak
2021	NPC	NPC-SW	Tomsik	TOM BK 2//3	Transformer	Thermal	Normal	Peak
2021	NPC	NPC-NW	Village	VLG BK 1	Transformer	Thermal	Normal	Peak
2022	NPC	NPC-NW	Beltway	BLT BK 4	Transformer	Thermal	Normal	Peak
2022	SPPC	SPPC-NE	Ray Couch	RYC BK 2	Transformer	Reliability	Unplanned Contingency	Peak
2025	SPPC	SPPC-NE	Golconda	GOL 1202	Feeder	Reliability	Unplanned Contingency	All

A	B	C	D	E	J	K	L	M	N	O
Year	Company	Region	Substation	Facility ID	NWA Energy Efficiency Capacity in 2025	NWA Demand Response Capacity in 2025	NWA Solar PV Capacity in 2025	NWA Battery Power Capacity in 2025	NWA Battery Energy Capacity in 2025	NWA Portfolio Estimated Cost for 2025
2020	SPPC	SPPC-NW	Silver Springs	SIL BK 1	140 kW	0 kW	7,200 kW	6,610 kW	88,960 kWh	$55,176,085
2020	SPPC	SPPC-TM	Silver Lake	SLK BK 2	1,100 kW	800 kW	0 kW	8,770 kW	48,580 kWh	$25,437,349
2020	NPC	NPC-NE	Speedway	SPD BK 2	1,170 kW	0 kW	20,300 kW	8,710 kW	98,170 kWh	$79,841,855
2020	SPPC	SPPC-TM	Sugarloaf	SLF BK 1	1,370 kW	1,300 kW	0 kW	7,420 kW	12,990 kWh	$8,337,364
2020	NPC	NPC-STRIP	Swenson	SWN BK 2	1,110 kW	0 kW	18,800 kW	16,940 kW	174,010 kWh	$115,508,899
2021	NPC	NPC-SW	Tomsik	TOM BK 2//3	1,700 kW	2,400 kW	2,300 kW	8,640 kW	33,800 kWh	$23,454,303
2021	NPC	NPC-NW	Village	VLG BK 1	770 KW	1,200 kW	0 kW	400 kW	340 kWh	$1,251,861
2022	NPC	NPC-NW	Beltway	BLT BK 4	910 kW	950 kW	2,400 kW	6,730 kW	22,740 kWh	$16,035,737
2022	SPPC	SPPC-NE	Ray Couch	RYC BK 2	200 kW	0 kW	0 kW	2,800 kW	18,670 kW	$9,488,739
2025	SPPC	SPPC-NE	Golconda	GOL 1202	40 kW	0 kW	2,600 kW	2,100 kW	36,000 kWh	$21,857,920

A	B	C	D	E	P	Q	R
Year	**Company**	**Region**	**Substation**	**Facility ID**	**T&D Infrastructure Upgrade Project Name**	**Estimated Cost**	**T&D Infrastructure Upgrade Reserve Margin in 2025**
2020	SPPC	SPPC-NW	Silver Springs	SIL BK 1	Silver Springs 2nd Transformer Addition-Bank 2	$3,200,000	2,050 kVA
2020	SPPC	SPPC-TM	Silver Lake	SLK BK 2	Silver Lake Transformer #1 Upgrade	$3,100,000	50,100 kVA
2020	NPC	NPC-NE	Speedway	SPD BK 2	Speedway 138x69/12 kV Bank 1	$2,900,000	15,000 kVA
2020	SPPC	SPPC-TM	Sugarloaf	SLF BK 1	Sugarloaf #2 Transformer Addition	$5,900,000	49,900 kVA
2020	NPC	NPC-STRIP	Swenson	SWN BK 2	Swenson 138/12 kV Bank 3 Addition	$2,800,000	33,900 kVA
2021	NPC	NPC-SW	Tomsik	TOM BK 2//3	Tomsik 138/12 kV Bank 1	$1,800,000	13,300 kVA
2021	NPC	NPC-NW	Village	VLG BK 1	Village Bank 2	$2,300,000	35,100 kVA
2022	NPC	NPC-NW	Beltway	BLT BK 4	Beltway Bank 3	$2,000,000	28,200 kVA
2022	SPPC	SPPC-NE	Ray Couch	RYC BK 2	Ray Couch Bank 2 Upgrade	$1,700,000	4,000 kVA
2025	SPPC	SPPC-NE	Golconda	GOL 1202	Kramer Hill Bank 2 and 1205 Breaker	$2,200,000	4,800 kVA

The columns in Figure 6 above that are not already explained as part of Figure 4 are explained below:

- Column J: NWA Energy Efficiency Capacity in 2025 – A standard amount of MW reduction from Energy Efficiency was assumed for every portfolio as 2 percent[28] of the maximum MW loading on that selected day.
- Column K: NWA Demand Response Capacity in 2025 – A flexible input where the amount of potential MW reduction that could be achieved by locationally targeting the existing Demand Response assets connected to the distribution facility in question can be entered by the user. This does not necessarily represent the amount of reduction expected through normal operation of the Demand Response program, but what could be achieved through locationally targeting the assets through a specially-designed program. Certain of these figures may be 0 kW if no appreciable Demand Response presently exists on the subject distribution facility.
- Column L: NWA Solar PV Capacity in 2025 – This is a flexible input where a MW amount of solar PV capacity can be entered by the user. Certain of these figures may be 0 kW if this choice minimized the estimated cost of the NWA portfolio in Column O.
- Column M: NWA Battery Energy Storage System Power Capacity in 2025 – Already accounting for any MW reduction from EE, DR, and solar PV, this is the estimated MW power capacity of a Battery Energy Storage System that would be required to address any

[28] Refer to Footnote 24 above. This 2 percent assumption is greater than the annual energy savings targets of at least 1.1 percent statewide in response to new legislation passed through Senate Bill 150 ("SB150") and Assembly Bill 223 ("AB223") by the 2017 Nevada Legislature, and assumes successful locationally-targeted marketing yielding an increased local penetration of Energy Efficiency measures in the areas where demand reduction is needed to potentially defer a T&D wired solution.

remaining MW deficiency amount above the Rating. The spreadsheet used this technology as a final step to address any remaining MW deficiency.

- Column N: NWA Battery Energy Storage System Energy Capacity in 2025 – Already accounting for any MWh reduction from EE, DR, and solar PV, this is the estimated MWh energy capacity of a battery energy storage system that would be required to address any remaining MWh deficiency amount above the Rating. The spreadsheet used this technology as a final step to address any remaining MWh deficiency.
- Column O: NWA Portfolio Estimated Cost for 2025 – This is the total estimated cost for the NWA portfolio necessary to address the forecasted deficiency in 2025.

Importantly, NV Energy did not use the results of the NWA Sizing Model to support a decision of whether or not to implement a traditional wired solution vs. a NWA solution. Rather, it was used as a tool to determine whether to conclude the investigation (*i.e.*, if the estimated cost of the NWA solution was far greater than the traditional wired solution), or to continue the investigation (*i.e.*, if the estimated cost of the NWA solution was relatively close to or lower than the traditional wired solution).

As can be seen by comparison of Columns O and Q in Figure 6 for the eight constraints that passed the Suitability/Screening criteria, only the 2021 scenario at Village Substation offered a capital cost comparison that warranted closer analysis to determine if deployment of an NWA solution could be favorable as compared to a traditional wired solution.

(5) Village Substation NWA Discussion

After performing the analysis described above, NV Energy investigated the situation at Village Substation further and refined the estimated cost of a battery energy storage system at the substation. As opposed to the $500/kWh unit cost figure used in the NWA Sizing Model,[29] which represents an estimate on the low end of what could be expected for such a system, the Companies quickly acquired a more refined, size-specific cost of $643,750[30] for a 0.5 MW / 1 MWh capacity for a lithium-ion battery energy storage system.

A sensitivity was run assuming no contribution from Energy Efficiency, 1.2 MW of peak reduction provided by Demand Response, and no Solar PV contribution to gauge if Demand Response alone could address the forecasted constraint and defer the need to install a battery energy storage system in 2021. This was achieved by varying the year, so that the NWA Sizing Model determined that no battery energy storage system was required. The modeled result indicated that Demand Response could address the forecasted constraint in 2021 and 2022, but that in 2023 a very small amount MW and MWh of capacity shortfall would need to be addressed by some other means. So,

[29] NV Energy chose a $500/kWh unit cost for a lithium-ion utility scale battery energy storage system based upon data in the *LAZARD'S Levelized Cost of Storage Analysis-Version 3.0* report, pgs. 30-31, November 2017. The $500/kWh figure trends towards the lower end of the unit cost ranges in the report.

[30] Consisting of only the $486,750 for the energy storage technology, $125,000 for the inverter, and $50,000 for the power control system. The total cost of these items was used as the cost for a 0.4MW / 0.34MWh system which was the result in the Village Substation NWA Sizing Model. Column O in Figure 6 for the Village Substation utilizes this total estimated cost figure.

this sensitivity indicated that it might be possible to defer the need to install the battery energy storage system until 2023.[31]

Consequently, NV Energy proposes to perform a demonstration of the locational dispatch of Demand Response (discussed below in Section 3.D.6.) on installed assets on the Village transformer #1 during the summer of 2019 in order to verify whether or not the required peak loading and energy reduction necessary to preclude an overload on the transformer could be achieved in 2021 and 2022. If successful, this would defer the installation of the Village Bank 2 at least until 2023, and would also provide additional time to re-examine this situation in the future with the potential of battery energy storage system pricing being reduced to the point where such a system might be more cost competitive.

c. Locational Net Benefits Analysis

The deployment of Distributed Resources at different locations on the electric grid can result in different impacts. This is true for any potential undesirable impact in terms of thermal or voltage limitations on the distribution system, and it is also true for any potential benefit to NV Energy's electric system and customers. This locational value assessment, or LNBA, is essential for several reasons:

- Evaluating the economics of Distributed Resources deployed at different locations on the system, and their potential to defer traditional wired capital upgrade solutions,
- Understanding the impact of Distributed Resources on long-term system needs related to load growth or reliability, and
- Informing the procurement process of a NWA solution.

Electric industry approaches for the economic valuation of Distributed Resources have evolved as new renewable generation deployments continue to increase. The process for determining the net value of Distributed Resources consists of identifying, describing, and valuing their quantitative and qualitative benefits and incremental costs.

In 2015, the Commission identified eleven potential categories of benefits and costs associated with distributed generation (reference Docket Nos. 15-07041 and 15-07042). At the time, only five were considered known and measurable. The Commission has yet to revisit this list of potential benefits and costs for NWAs. Thus, for analysis purposes, the benefit and cost variables used by NV Energy are largely based upon the Commission's eleven variables. At this time, the Companies have applied techniques to quantify eight of the eleven variables:

- Transmission Upgrade Deferral Cost – The value of the deferral of a transmission capital upgrade or asset replacement.
- Distribution Upgrade Deferral Cost – The value of the deferral of a distribution capital upgrade or asset replacement.

[31] This result is highly sensitive to the accuracy of the load forecast for the Village transformer #1 and is dependent upon that forecast not increasing in 2021 and 2022 from what was used in the analysis. Conversely, a reduction in the load forecast would benefit this analysis.

- Transmission Upgrade OMAG Cost – The value of the incremental OMAG associated with a transmission capital upgrade or asset replacement.
- Distribution Upgrade OMAG Cost – The value of the incremental OMAG associated with a distribution capital upgrade or asset replacement.
- Avoided Energy – The value of avoided energy based upon hourly energy prices as estimated by production cost simulation software ("PROMOD").
- Generation Capacity – The value of the avoided additional generation needed at peak demand as determined by optimal dispatch of resources.
- Ancillary Services – The value of avoided ancillary services requirements (*e.g.*, frequency control, reactive power, operating reserves) as estimated by production cost simulation software ("PROMOD").
- T&D Losses – The value of any estimated reduction in losses on the transmission and distribution systems.

The Companies intend to attempt to quantify following three variables into the LNBA prior to the June 2021 filing:

- Renewable Portfolio Standard ("RPS") Integration Cost – The value of avoided costs associated with resource intermittency and uncertainty that must be managed on the power system. Such costs include, but are not limited to, frequency response, voltage regulation, and operating reserves.
- Greenhouse Gas Emissions – The value of avoided costs associated with the emission of any gaseous compound in the atmosphere that is capable of absorbing infrared radiation, thereby trapping and holding heat in the atmosphere.
- Reliability/Power Quality – The value of any quantifiable improvement in the reliability or resiliency of the transmission or distribution system, and potentially providing voltage support to the system.

NV Energy performed the location-specific economic analysis of costs and benefits, the LNBA, using PWRR analysis that compared a traditional wired utility investment solution to a NWA solution to meet the needs of the transmission and distribution systems.

While the LNBA is directed towards helping to guide where Distributed Resources can be most economically sited to defer investment in a T&D wired solution, it is important to understand that the LNBA is an embedded cost and benefit analysis. The LNBA conducted for distribution planning purposes doesn't quantify locational marginal costs or measure locational marginal pricing (as used in energy imbalance market pricing). In the DRP context, the LNBA provides a location-specific total cost and benefit valuation of the NWA solution, which is compared with the location-specific traditional wired utility solution to ensure the utility is developing a least cost solution for its customers.

(1) Village Substation LNBA Discussion

Given the comparative costs of the traditional wired solution ($2,300,000) versus the NWA portfolio solution in this case ($1,251,861), NV Energy performed a PWRR analysis comparing the installation by June 2021 of the Village Bank 2 transformer versus installing a battery energy storage system in June 2021 and deferring the installation of the Village Bank 2 transformer to June 2026. The resulting PWRRs for the two options were $2,419,669 versus $3,540,984, respectively, which supported the installation of the Village Bank 2 transformer in 2021.

d. Traditional Upgrade Projects and NWA Solutions Recommendations

The final aspect of the GNA involves identifying traditional wired solutions that NV Energy is recommending be constructed, or NWA solutions that the Companies are recommending to pursue in lieu of a wired solution, within the three-year 2019-2021 action plan period from the Companies' most recent June 2018 Joint IRP filing. Section 3.A.3.a above contains descriptions of the constraints identified on the Companies' distribution systems in 2020 through 2025 (and the traditional wired upgrade solutions) that could potentially be satisfied by a NWA solution. Section 3.A.3.b above contains descriptions of the NWA analyses performed with respect to those constraints. Section 3.A.3.c contains a description of the one constraint that moved forward to having an LNBA (PWRR) analysis performed.

In Figure 4 above, seven forecasted constraints on the Companies' distribution systems are identified with planned in-service dates in 2020 or 2021, along with the traditional wired upgrade solutions and estimated capital cost for those solutions. Those seven projects are:

1. 2020 – Silver Springs 2nd Transformer Additions-Bank 2;
2. 2020 – Silver Lake Transformer #1 Upgrade;
3. 2020 – Speedway 138x69/12 kV Bank 1;
4. 2020 – Sugarloaf #2 Transformer Addition;
5. 2020 – Swenson 138/12 kV Bank 3 Addition;
6. 2021 – Tomsik 138/12 kV Bank 1; and
7. 2021 – Village Bank 2

For each of the forecasted constraints, Figure 4 also contains information on the constraint type, operational condition, seasonal identification, criteria (*i.e.*, the rating of the forecasted overloaded distribution component), initial deficiency (*i.e.*, the overload in the first year that it is forecasted to occur), and the estimated amount, duration on the peak day, total days, and total duration of the forecasted deficiency in 2025.

As noted above, the traditional wired upgrade solutions at Sugarloaf and Swenson Substations did not pass the initial Suitability/Screening process. Nevertheless, these alternatives were run through the NWA Sizing Model to generate similar information to the other constraints in Figure 4. The results of the NWA analysis are shown in Figure 6 above.

NV Energy is seeking Commission approval to construct the first six traditional wired upgrade solutions listed above with projected cash flows below in Figure 7:

FIGURE 7:
PROJECTED CASH FLOWS FOR DISTRIBUTION TRADITIONAL WIRED SOLUTIONS WITH IN-SERVICE DATES IN 2020 AND 2021

Project	Pre-2019	2019	2020	2021	3-Year Total (2019-2021)
Silver Springs Bank 2	$600,000	$700,000	$1,900,000	$0	**$2,600,000**
Silver Lake Xfmr 1	$100,000	$2,100,000	$900,000	$0	**$3,000,000**
Speedway Bank 1	$0	$600,000	$2,300,000	$0	**$2,900,000**
Sugarloaf Bank 2	$3,900,000	$2,000,000	$0	$0	**$2,000,000**
Swenson Bank 3	$0	$1,100,000	$1,700,000	$0	**$2,800,000**
Tomsik Bank 1	$0	$0	$100,000	$1,700,000	**$1,800,000**
TOTALS	**$4,600,000**	**$6,500,000**	**$6,900,000**	**$1,700,000**	**$15,100,000**

As the constraints on the distribution system and the consequent need for these projects are driven mainly by distribution feeder and substation transformer loading forecasts, the variability of these forecasts over time could accelerate or slow forecasted overloads. As it does for all capital expenditures, NV Energy continually monitors these conditions and adjusts the need for traditional wired solutions and NWA solutions. However, the scopes of the traditional wired solutions themselves change far less often.

4. DER Interconnection

NV Energy's Rule 15 governs the interconnection of DERs of 20 MW capacity or less seeking to connect to the Companies' distribution systems. Rule 15 outlines the interconnection process, technical operating and metering requirements, and testing and certification criteria for distributed generators, including energy storage devices. Through Commission Docket Nos. 17-06014 and 17-06015, Rule 15 was revised to include language specific to energy storage devices.

NV Energy utilizes Clean Power Research's PowerClerk software to facilitate the interconnection process of net energy metering installations, mainly private solar PV. Depending on their size, non-net energy metering Distributed Generation interconnections may be required to submit a different application to interconnect under Rule 15.[32]

[32] Reference NV Energy's standards RE-1 "Design Standard for Parallel Generation 10 MW or Less" and RE-2 "Design Standard for Parallel Generation 10 MW or More". Standard RE-1 contains Attachment 1 "Parallel Generator Interconnection Application for Installations up to 200 kW" and Attachment 2 "Parallel Generator Interconnection Application for Installations with a Capacity of 201 kW to 10,000 kW". Standard RE-2 contains Attachment 1 "Application for the Interconnection of a Generator with a Capacity Greater than 10 MW for Parallel Operation with the Utility System".

NV Energy did not implement any changes to its DER interconnection process to be reported in this filing. However, activities planned to target the interconnection process going forward are discussed below in Section 8.F.

5. Tools, Systems, or Technologies

As discussed above in Section 3.A.3.b(2), NV Energy developed a MS Excel-based tool to perform the initial NWA analyses. Over the course of performing the tasks and analyses for this filing, the Companies met with several software vendors (either via teleconference, webinar, or onsite) to evaluate their products. These meetings were meant to educate the Companies on the capabilities of third-party software tools being marketed or developed that could aid in performing at least some of the many analyses required to develop the elements of the DRP, and potentially support other related activities of the Companies.

Briefly discussed below are some of the vendors and software that the Companies have been made aware of:[33]

- Clean Power Research has developed WattPlan Grid and WattPlan Advisor. WattPlan Grid provides customer-level adoption forecasts for multiple types of DERs. WattPlan Advisor provides tools to manage and improve the effectiveness of a utility's DER customer programs.
- GridUnity provides a platform and a suite of applications which aid in simplifying and automating the renewable interconnection application and technical screening process, publishing and enhancing hosting capacity, and leveraging data across several utility systems through predictive analytics to identify where DERs could be of the most benefit.
- Integral Analytics, Inc. markets a suite of software products, including LoadSEER, DSMore, and IDROP. LoadSEER is a spatial load forecasting tool that produces time-series analysis for future geographically-based load and DER growth. DSMore is a financial analysis tool which evaluates the cost, benefits, and risks of energy efficiency, demand-side management, and demand response. IDROP supports cost-effective dispatching of many types of DERs, both in front of and behind the customer meter.
- Landis & Gyr provides a portfolio of Advanced Grid Analytics to aid in solving power quality, reliability, and operational challenges through leveraging data from multiple sources on the electric distribution system, including planning for and managing DERs through dynamic modeling.
- Opus One Solutions provides its GridOS operating platform for advanced grid analytics, integrated operations, transactive energy functionality, and microgrid management to

[33]This listing of vendors and software is in alphabetical order and should in no way be interpreted as NV Energy endorsing, specifically including or excluding, or showing any preference for any vendor or software, nor should it be construed as a commitment from NV Energy to issue a Request for Proposals in the future for new software from any of the vendors listed. It is simply for informational purposes at this time. The descriptions of the software and their capabilities are NV Energy's interpretation based upon vendor publications and publicly-accessible website information, are not meant to be complete descriptions, and no attempt has been made to properly portray trademarks or registrations. The Companies do plan to discuss the need for software to aid in supporting the DRP activities as noted in Section 8.H. below, and will proceed in the future on the basis of that discussion.

provide real-time distribution system state estimation, hosting capacity, and locational marginal values for DERs.

- ProsumerGrid provides software for simulation, planning, and decentralized operation of multiple types of DERs including the interdependence of grid physics and electricity markets, DER hosting capacity, financial analysis, and valuation.
- Siemens provides its PSS®SINCAL multi-module software which facilitates load and DER modeling, time-series load flow analysis, and power quality analysis of electric transmission and distribution systems, including hosting capacity analysis and locational net benefits analysis.

B. Transmission Planning

The Company's Transmission System Planning Department is responsible for the reliability of the transmission grid consisting of voltages ranging from 55 kV to 500 kV. The criteria for the transmission system reliability is based on applicable North American Electricity Reliability Corporation (NERC) Compliance standards. More specifically, NERC Transmission Planning standard TPL-001-4 outlines transmission system performance requirements under several types of contingency conditions. For each type of contingency, certain performance is required. Where mitigation is required to meet performance criteria, Corrective Action Plans (i.e., traditional utility solutions) are identified and implemented to address the reliability issue and bring performance within acceptable criteria. In addition to identifying existing reliability issues, transmission planning also specifies transmission system upgrades to accommodate both transmission and distribution system load growth. The requirements of these facilities is based on individual transmission interconnections and distribution load forecasting.

1. Load Forecasting

Transmission Planning utilizes the most recently approved extreme weather or 1 in 10 year Integrated Resource Plan native load forecast and control area load forecast for planning purposes. When applicable, the distribution short-term distribution facility load forecast is used for studies on specific lines or substations.

2. Grid Needs Assessment

a. Transmission Constraints and Projects Identification

In the normal course of business, Transmission Planning identifies traditional ("wired") capital upgrades through several continuous and cooperative processes. The primary source for capital upgrade recommendations is the Corrective Action Plan documents identified in the Companies' North American Electric Reliability Corporation (NERC) reliability standard compliance analysis effort. This analysis is performed by modeling various transmission grid scenarios representing specific network assumptions (*e.g.*, season, time of day, neighboring utility operations, etc.) and simulating NERC-defined contingencies while observing the system response. These scenarios are developed to represent stressed conditions on the present system and forecasted system topologies out to 10 years. If the system fails to respond within the NERC (or by extension the Western Electric Coordinating Council or "WECC") defined performance criteria, a Corrective Action Plan to mitigate the issue is prepared. Secondarily, risks to public safety and reliability on transmission assets that are not captured by the NERC analysis are identified by operational teams and communicated to Transmission Planning. Transmission Planning evaluates these risks and recommends solutions in collaboration with functional engineering groups. An example of a reliability risk that would not be captured by NERC analysis would be a load served on a radial transmission line. Under NERC standards, if a disturbance on the line triggers protective relaying and opens the line, the load can be disconnected as a "consequential load loss." While allowable under NERC standards, this result would be looked at by operational teams and likely forwarded to Transmission Planning. Another example of a reliability risk that would be identified by operational teams would include equipment deterioration that does not yet violate a specific standard. Though these issues do not directly violate reliability standards, they nevertheless are reviewed and projects are initiated to minimize risk to safety and increase system reliability. Finally, some transmission capital upgrades are driven by generator interconnections and growth due to major load additions.

To complete the Grid Needs Assessment, Transmission Planning followed a similar methodology as that used by Distribution Planning. All transmission capital upgrades in the NV Energy's Fall 2018 Capital Plan were reviewed and filtered through the NWA Suitability Criteria described in Section 3.A.3.b.(1). The 2018 Fall capital plan contained 107 transmission projects, 42 of which met critical suitability criteria A (constraint anticipated to occur between January 1, 2020 and December 31, 2025), and 26 of which met the critical suitability criteria B (constraint based upon thermal loading, voltage, or reliability reasons where a reduction in peak demand loading, energy consumption, or load shifting would eliminate or defer the constraint). Fourteen projects met both criteria A and B. Prior to the NWA analysis process, two capital upgrades in the original 2018 Fall Capital Plan were deferred from 2024 and 2025 in-service dates until 2030 due to updated assumptions. As a result, 12 Transmission Capital Upgrade projects were evaluated through the Non-Wires Alternative analysis process.

The identification of Transmission grid needs varies from the Distribution Planning process in two important ways:

- Current, widely-used Transmission Planning software does not have the ability to perform time-variant ("temporal") analysis over a 24-hour or annual period. The software is only capable of simulating steady-state "snapshots" of specific system conditions. Grid needs are identified from a series of modeled snapshots ("base cases") that are tuned to determine "worst-case" conditions. These models only identify the size of the overload for that specific condition and do not provide insight into the length of the condition or annual frequency of the condition. As a result, additional assumptions must be made to determine the duration of a grid need and expected frequency (such as, the expected time to restore a line that has suffered an outage, the likelihood of an outage, the typical duration of peak loading conditions, etc.).
- Transmission Planning models must integrate additional data points that have significant impact on the sizing and timing of grid needs. Unlike the distribution system, the transmission system performance is impacted by system-wide conditions including generation dispatch, phase-shifter operation, western interconnection-wide flow patterns outside of NV Energy's balancing area, major generation additions, major

load additions, major topology upgrades and other dynamic variables. As these variables change, the power flow driving the capital upgrade can change significantly.

These two factors underscore the fact that there is significantly more uncertainty in the size, length, and required in-service date of a transmission capital upgrade when compared to a distribution capital upgrade. Historically, this limitation in transmission grid need sizing accuracy has not been an issue because the incremental sizing of a wired capacity upgrade is much larger than that of a custom NWA solution. In addition, a wired-solution asset lifetime (typically 55-70 years) is long enough to ensure that the asset will provide its intended benefit even if the driving variable (such as a 1-10 summer heat wave) does not occur in the year the project goes into service.

Despite these differences, the Transmission GNA was able to describe the 12 grid needs in a similar way to the Distribution GNA as presented in Figure 8.

FIGURE 8:
SUMMARY FORECASTED TRANSMISSION CONSTRAINT AND TRADITIONAL CAPITAL UPGRADE SOLUTIONS TABLE

A	B	C	D	E	F	G	H	I
Year	**Company**	**Region**	**Substation**	**Facility ID**	**Facility Type**	**Constraint Type**	**Operational Condition**	**Seasonal Identification (Peak, Off-Peak, All)**
2020	SPPC	SPPC-NW	Dove	Dove	Capacitor	Voltage	Normal	All
2023	NPC	NPC-NW	Artesian	Artesian	Capacitor	Voltage	Normal	Peak
2023	NPC	NPC-NW	Sinatra	Sinatra	Capacitor	Voltage	Normal	Peak
2023	NPC	NPC-NW	Millers	PE-MW 138 kV	Line Fold	Thermal	Unplanned Contingency	Peak
2023	NPC	NPC-NW	Pecos	PE 230/138 Bank 5	Transformer	Thermal	Normal	All
2024	NPC	NPC-NW	Burnham	Burnham	Capacitor	Voltage	Normal	Peak
2024	NPC	NPC-NW	Northwest	NW 230/138 Bank 3	Transformer	Thermal	Unplanned Contingency	All
2025	NPC	NPC-NW	Mcdonald	McDonald	Capacitor	Voltage	Normal	Peak
2025	NPC	NPC-NW	Tropical	Tropical	Capacitor	Voltage	Normal	Peak
2025	NPC	NPC-NW	Clark	CL-CN 138 kV	Line Upgrade	Thermal	Unplanned Contingency	Peak
2025	NPC	NPC-NW	Mission	Mission 69 kV	New Line	Reliability	Unplanned Contingency	All
2025	NPC	NPC-NW	Flamingo	SP-FL-DE 69 kV	Line Upgrade	Thermal	Normal	Peak

A	B	C	D	E	J	K	L	M	N	O
Year	**Company**	**Region**	**Substation**	**Facility ID**	**Total Estimated Duration of Deficiency in 2025**	**Total Estimated Days of Deficiency in 2025**	**Estimated Duration of Deficiency on Peak Day in 2025**	**Criteria (Ratings)**	**Initial Deficiency**	**Estimated Maximum Deficiency in 2025**
2020	SPPC	SPPC-NW	Dove	Dove	8,760.0 hours	365 days	24 hours	N/A	90 MVAr	90 MVAr
2023	NPC	NPC-NW	Artesian	Artesian	360 hours	90 days	4 hour	N/A	24 MVAr	24 MVAr
2023	NPC	NPC-NW	Sinatra	Sinatra	360 hours	90 days	4 hour	N/A	24 MVAr	24 MVAr
2023	NPC	NPC-NW	Millers	PE-MW 138 kV	4 hours	1 day	4 hour	118.6 MVA	N/A	N/A
2023	NPC	NPC-NW	Pecos	PE 230/138 Bank 5	8760 hours	365 days	24 hours	1209 MVA	N/A	N/A
2024	NPC	NPC-NW	Burnham	Burnham	360 hours	90 days	4 hour	N/A	24 MVAr	24 MVAr
2024	NPC	NPC-NW	Northwest	NW 230/138 Bank 3	25 hours	9 days	2 hours	672 MVA	10 MVA	60 MVA
2025	NPC	NPC-NW	Mcdonald	McDonald	360 hours	90 days	4 hour	N/A	24 MVAr	24 MVAr
2025	NPC	NPC-NW	Tropical	Tropical	360 hours	90 days	4 hour	N/A	24 MVAr	24 MVAr
2025	NPC	NPC-NW	Clark	CL-CN 138 kV	0.5 hours	1 day	0.5 hour	237 MVA	1 MVA	1 MVA
2025	NPC	NPC-NW	Mission	Mission 69 kV	2 hours	1 day	2 hour	91.5 MVA	62 MVA	71 MVA
2025	NPC	NPC-NW	Flamingo	SP-FL-DE 69 kV	360 hours	90 days	4 hours	118.6 MVA	N/A	N/A

A	B	C	D	E	P	Q	R
Year	**Company**	**Region**	**Substation**	**Facility ID**	**T&D Infrastructure Upgrade Project Name**	**Estimated Cost**	**T&D Infrastructure Upgrade Reserve Margin in 2025**
2020	SPPC	SPPC-NW	Dove	Dove	Dove Capacitor Bank	$ 1,200,000	0 kVAr
							0
2023	NPC	NPC-NW	Artesian	Artesian	CAPACITOR SYSTEM ADDNS - TRANS (ARTESIAN)	$ 1,500,000	0 kVAr
							0
2023	NPC	NPC-NW	Sinatra	Sinatra	CAPACITOR SYSTEM ADDNS - TRANS (SINATRA)	$ 1,300,000	0 kVAr
							0
2023	NPC	NPC-NW	Millers	PE-MW 138 kV	LOOP PE-MW138 INTO MILLERS (M5)	$ 12,800,000	N/A
							0
2023	NPC	NPC-NW	Pecos	PE 230/138 Bank 5	PECOS 230/138KV BANK #5	$ 1,100,000	N/A
							0
2024	NPC	NPC-NW	Burnham	Burnham	CAPACITOR SYSTEM ADDNS - TRANS (BURNHAM)	$ 1,200,000	0 kVAr
							0
2024	NPC	NPC-NW	Northwest	NW 230/138 Bank 3	NORTHWEST SUB 230/138KV TRANSFORMER BANK 3	$ 9,800,000	303,700 kVA
							0
2025	NPC	NPC-NW	Mcdonald	McDonald	CAPACITOR SYSTEM ADDNS - (MCDONALD)	$ 800,000	0 kVAr
							0
2025	NPC	NPC-NW	Tropical	Tropical	CAPACITOR SYSTEM ADDNS - TRANS (TROPICAL)	$ 1,200,000	0 kVAr
							0
2025	NPC	NPC-NW	Clark	CL-CN 138 kV	CLARK CONCOURSE 138KV RECONDUCTOR	$ 2,300,000	190,000 kVA
							0
2025	NPC	NPC-NW	Mission	Mission 69 kV	MISSION TRANS UPGRADE: EQUESTRIAN MISSION 69 KV LINES 1&2	$ 12,800,000	20,500 kVA
							0
2025	NPC	NPC-NW	Flamingo	SP-FL-DE 69 kV	SP-FL-DE 138kV LINE CONVERSION	$ 18,200,000	N/A

Each of the columns followed the same format as described in the Distribution GNA with two exceptions. The duration of deficiency was estimated by using 24-hour duration when the driving variable could not be determined, a 4-hour duration when the overload was best characterized as system peak related, or a timeframe based on the estimated time that the grid conditions could be adjusted through generation dispatch or operational fix could be implemented. Several projects resulted in "N/A" for describing the Initial Deficiency, Maximum Deficiency, and Upgrade Reserve Margin. In these cases, the reason these were found to be not applicable is described in Figure 9.

FIGURE 9:
EXPLANATION OF TRANSMISSION GRID NEEDS THAT WERE FOUND TO HAVE A NOT APPLICABLE UPGRADE RESERVE MARGIN

A	B	C	D	E	
Year	**Company**	**Region**	**Substation**	**Facility ID**	**N/A Explanation**
2023	NPC	NPC-NW	Millers	PE-MW 138 kV	This project has been deferred out past 2025 after further review
2023	NPC	NPC-NW	Pecos	PE 230/138 Bank 5	This project is driven by interconnection customers. No active interconnection exists. Until the interconnection contracts are active, sizing cannot be completed
2025	NPC	NPC-NW	Flamingo	SP-FL-DE 69 kV	This project is driven by potential large customer growth and is not currently needed with local area natural load growth. If the large customer load is initiated and this project can be re-evaluated

One constraint on the Companies' transmission system was identified which is planned to be mitigated through a traditional capital upgrade project in 2020:

2020 – Dove Capacitor Bank

A 90 MVAR capacitor bank will be required at Dove 120 kV substation to offset the system voltage issues and mitigate the TPL-001-4 violation. Voltage issues occur in the Tracy area on the 120 kV system when Tahoe Regional Industrial Center loads increase by approximately 100 MW. This load level is expected to be reached by 2020.

Four constraints on the Companies' transmission system were identified which are planned to be mitigated through traditional capital upgrade projects in 2023:

2023 – Artesian Capacitor Bank

A 24 MVAR capacitor bank and one 138 kV PCB will be required at the Artesian 138 kV bus. During peak loading times in Southern Nevada, NV Energy imports approximately 400-500 MVAR of reactive support to ensure adequate voltage performance. Proper system operation requires the capability of providing sufficient reactive support within one's own balancing area or establish contractual rights to secure the needed MVAR capability. This project is one of several proposed capacitor bank additions that will be required to mitigate this MVAR deficiency.

2023 – Sinatra Capacitor Bank

A 24 MVAR capacitor and one 138 kV PCB will be required at the Sinatra 138 kV bus. During peak loading times in Southern Nevada, NV Energy imports approximately 400-500 MVAR of reactive support to ensure adequate voltage performance. Proper system operation requires the capability of providing sufficient reactive support within one's own balancing area or establish contractual rights to secure the needed MVAR capability. This project is one of several proposed capacitor bank additions that will be required to mitigate this MVAR deficiency.

2023 – Pecos – Millers 138 kV – delayed until 2032

The Companies need to construct five new 138 kV PCBs in a six PCB GIS ringbus configuration, loop the existing Pecos-Michael Way 138 kV line into Miller Substation and build associated facilities pursuant to NERC TPL-002. When the Pecos-Tropical 138 kV contingency occurs, three 138/12 kV subs must be picked up from the existing Miller 69 kV system, overloading the Miller-NLV and Artesian – NLV 69 kV lines during forecasted system peak conditions.

2023 – Pecos 230/138 kV Transformer Bank #5 Addition

Additional generation interconnections in northeast Clark County have triggered the need for additional 230/138 kV transfer capacity in northern Las Vegas. This project would add an additional transformer at Pecos substation to provide this capacity. This project is driven by generator interconnection agreements and as a result a firm "in-service date" is not currently available.

Two constraints on the Companies' transmission system were identified which are planned to be mitigated through traditional capital upgrade projects in 2024:

2024 – Burnham Capacitor Bank

A 24 MVAR capacitor and one 138 kV PCB are to be installed at the Burnham 138 kV bus. During peak loading times in Southern Nevada, NV Energy imports approximately 400-500 MVAR of reactive support to ensure adequate voltage performance. Proper system operation requires the capability of providing sufficient reactive support within one's own balancing area or establish contractual rights to secure the needed MVAR capability. This project is one of several proposed capacitor bank additions that will be required to mitigate this MVAR deficiency.

2024 – Northwest 230/138 kV Transformer Bank #2 Addition

The third 336 MVA 230/138 kV transformer is to be installed at the existing Northwest Substation by the summer of 2024 and associated 230 kV and 138 kV breakers for this new transformer. Installation of the third Northwest 230/138 kV transformer (Bank#2) is needed to relieve the overload projected in 2024 on the existing 230/138 kV transformers (Bank#1 & Bank#3).

Five constraints on the Companies' transmission system were identified which are planned to be mitigated through traditional capital upgrade projects in 2025:

2025 – McDonald Capacitor Bank

Install a 24 MVAR capacitor and one 138 kV circuit switcher at the McDonald 138 KV bus. During peak loading times in Southern Nevada, NV Energy imports approximately 400-500 MVAR of reactive support to ensure adequate voltage performance. Proper system operation requires the capability of providing sufficient reactive support within one's own balancing area or establish contractual rights to secure the needed MVAR capability. This project is one of several proposed capacitor bank additions that will be required to mitigate this MVAR deficiency.

<u>2025 – Tropical Capacitor Bank</u>

A 24 MVAR capacitor is to be installed at the Tropical 138 kV bus. During peak loading times in Southern Nevada, NV Energy imports approximately 400-500 MVAR of reactive support to ensure adequate voltage performance. Proper system operation requires the capability of providing sufficient reactive support within the balancing area or establish contractual rights to secure the needed MVAR capability. In addition, the Tropical capacitor is needed to prevent forecasted voltage collapse at Tropical/Gilmore/Leavitt substations following a Pecos-Tropical 138 kV line outage near peak load conditions. This project is one of several proposed capacitor bank additions that will be required to mitigate this MVAR deficiency.

<u>2025 – Clark – Concourse #2 /Reconductor 138 kV</u>

Peak generation at Clark results in high east to west 138 kV flow. Models demonstrate that the Clark - Concourse 138 kV line is the first 138 kV line forecasted to overload in 2025. Reconductor the 4.7 miles of Clark W to Concourse 138 kV to 954 ACSS. This will increase the line rating from 237 MVA to 428 MVA. An alternative solution is to construct a second 138 kV transmission line.

<u>2025 – Equestrian - Mission 69 kV Lines 1 &2</u>

Rebuilding approximately 4.1 miles of the existing Equestrian - Mission 69 kV line to new 954 ACSS double circuit structures designed for 2-69 kV circuits: one for Equestrian - Mission 69 kV line #1 and the other for line #2, convert the Equestrian 69 kV substation to breaker–and-a-half configuration, and install Two 69 kV Line Terminals with breakers, pre-fab control house at Mission substation. This project will improve reliability at existing radial substation. All maintenance on this existing radial 69 kV line and the 69 kV substation bus has to be done with the line energized to keep the Mission customers in-service. This leads to high maintenance costs and longer maintenance periods.

<u>2025 – Spencer – Flamingo – Decatur line conversion</u>

Convert the existing Spencer-Flamingo 69 kV line and existing Flamingo-Valley View-Decatur 69 kV line to 138 kV. Build structures for 954 ACSS. This project is driven by a major load expansion that does not currently have a firm in-service date.

<u>b. Non-Wires Alternative Analysis</u>

As described in the distribution planning context above, a NWA is a solution to an identified constraint(s) on the Companies' electric transmission or distribution systems that may include the deployment of one or more Distributed Resources in lieu of a traditional wired solution.

(1) NWA Suitability/Screening Criteria

The Transmission Grid Needs were subjected to the same suitability criteria described in the Distribution Planning NWA Suitability/Screening Criteria. No transmission projects were eliminated for Red Flag issues.

(2) NWA Analysis Method

The 12 projects that met both critical suitability criteria A & B were subjected to the same MS Excel NWA Sizing Model tool to determine the feasibility of a NWA to cost-effectively defer or replace the proposed wired solution. When projects were found to feasibly replace the traditional wires alternative on the basis of an estimated capital investment cost, the project was reviewed using the second tool, a PWRR analysis on the proposed Non-Wires Alternative.

(3) NWA Analyses Discussion

Six of the projects evaluated were reactive support (capacitor bank additions), and the remaining six projects were triggered by forecasted line and transformer overloads (line reconductors, transformer additions, etc.)

For the analysis of NWA solutions to capacitor bank additions, the size of the proposed capacitor bank became the proxy for the size of the grid need. In the case of the Dove capacitor bank, the duration of the need is known to be more than just during system peak conditions. If the load additions driving the project fully materialize, the grid need could become a 24-our deficiency. For the other capacitor bank projects, the need was assumed to be for the typical 4-hour peak duration, as these projects are aimed at correcting a need observed only during system peak. Using this methodology, none of the capacitor addition projects appear to be effectively deferred or replaced by a NWA. This conclusion is supported by the fact that capacitor additions result in significant MVAR capacity addition with minimal land and equipment costs. To secure equivalent MVAR capability, a relatively large battery energy storage system or solar plus battery energy storage installation would be required to provide the same benefit. Since the issue is not real power (MW) related, the potential NWAs are not able to leverage their main benefit (shifting/reducing load) as a means to be more cost competitive. As a result, none of the capacitor bank projects demonstrated feasibility at being deferred or replaced with a NWA solution.

When evaluating the remaining six identified transmission grid needs, the system base case models and seven-year distribution transformer load forecasts were used to model the loading on the applicable asset. Since in each case the need is triggered by system flows, the asset loading was not directly related to the load forecast at a particular distribution transformer. Thus, certain assumptions were made including using the average load growth rate in the immediate geographic area to simulate growing asset loading. Where possible, additional base cases were used to identify loading levels for various years. However, this methodology proved to be unreliable as different base cases included different system-wide flows (including and outside of NV Energy's area) that did not resemble a steady loading growth rate. In addition, assumptions about the frequency of outages and of future generation had to be made to approximate the grid need to a much tighter accuracy than is typically required for Transmission level analysis. When applicable, the assumptions were noted in the NWA Sizing Model tool for each project. Once the grid need was determined, a NWA portfolio solution was developed to mitigate the grid need using the same methodology described in the distribution planning Grid Needs Assessment.

(4) NWA Analyses Results

The results of the Non-Wires Alternative sizing analysis for each of the 12 Transmission Projects is presented in Figure 10.

FIGURE 10:
RESULTS OF THE NWA SIZING MODEL ANALYSIS

A	B	C	D	E	F	J	K	L	M	N	O
Year	Company	Region	Substation	Facility ID	Facility Type	NWA Energy Efficiency Capacity in 2025	NWA Demand Response Capacity in 2025	NWA Solar PV Capacity in 2025	NWA Battery Power Capacity in 2025	NWA Battery Energy Capacity in 2025	NWA Portfolio Estimated Cost for 2025
2020	SPP	SPPC-NW	Dove	Dove	Capacitor	0	0	0	90,000 kVA	180,000 kWh	$ 90,000,000
2023	NPC	NPC-NW	Artesian	Artesian	Capacitor	0	0	0	24,000 kVA	24,000 kWh	$ 24,000,000
2023	NPC	NPC-NW	Sinatra	Sinatra	Capacitor	0	0	0	24,000 kVA	24,000 kWh	$ 24,000,000
2023	NPC	NPC-NW	Millers	PE-MW 138 kV	Line Fold	N/A	N/A	N/A	N/A	N/A	N/A
2023	NPC	NPC-NW	Pecos	PE 230/138 Bank 5	Transformer	N/A	N/A	N/A	N/A	N/A	N/A
2024	NPC	NPC-NW	Burnham	Burnham	Capacitor	0	0	0	24,000 kVA	24,000 kWh	$ 24,000,000
2024	NPC	NPC-NW	Northwest	NW 230/138 Bank 3	Transformer	7,600 kW	0	0	32,300 kW	124,500 kWh	$ 68,073,000
2025	NPC	NPC-NW	Mcdonald	McDonald	Capacitor	0	0	0	24,000 kVA	24,000 kWh	$ 24,000,000
2025	NPC	NPC-NW	Tropical	Tropical	Capacitor	0	0	0	24,000 kVA	24,000 kWh	$ 24,000,000
2025	NPC	NPC-NW	Clark	CL-CN 138 kV	Line Upgrade	0	0	0	980 kVA	440 kWh	$ 1,585,000
2025	NPC	NPC-NW	Mission	Mission 69 kV	New Line	0	0	0	71,000 kW	156,000 kWh	$ 78,367,000
2025	NPC	NPC-NW	Flamingo	SP-FL-DE 69 kV	Line Upgrade	N/A	N/A	N/A	N/A	N/A	N/A

A	B	C	D	E	F	P	Q	R
Year	Company	Region	Substation	Facility ID	Facility Type	T&D Infrastructure Upgrade Project Name	Estimated Cost	T&D Infrastructure Upgrade Reserve Margin in 2025
2020	SPP	SPPC-NW	Dove	Dove	Capacitor	Dove Capacitor Bank	$ 1,200,000	0 kVAr
2023	NPC	NPC-NW	Artesian	Artesian	Capacitor	CAPACITOR SYSTEM ADDNS - TRANS (ARTESIAN)	$ 1,500,000	0 kVAr
2023	NPC	NPC-NW	Sinatra	Sinatra	Capacitor	CAPACITOR SYSTEM ADDNS - TRANS (SINATRA)	$ 1,300,000	0 kVAr
2023	NPC	NPC-NW	Millers	PE-MW 138 kV	Line Fold	LOOP PE-MW138 INTO MILLER	$ 12,800,000	N/A
2023	NPC	NPC-NW	Pecos	PE 230/138 Bank 5	Transformer	PECOS 230/138KV BANK #5	$ 11,000,000	N/A
2024	NPC	NPC-NW	Burnham	Burnham	Capacitor	CAPACITOR SYSTEM ADDNS - TRANS (BURNHAM)	$ 1,200,000	0 kVAr
2024	NPC	NPC-NW	Northwest	NW 230/138 Bank 3	Transformer	NORTHWEST SUB 230/138KV TRANSFORMER BANK 3	$ 9,800,000	303,700 kVA
2025	NPC	NPC-NW	Mcdonald	McDonald	Capacitor	CAPACITOR SYSTEM ADDNS - (MCDONALD)	$ 1,200,000	0 kVAr
2025	NPC	NPC-NW	Tropical	Tropical	Capacitor	CAPACITOR SYSTEM ADDNS - TRANS (TROPICAL)	$ 1,200,000	0 kVAr
2025	NPC	NPC-NW	Clark	CL-CN 138 kV	Line Upgrade	CLARK CONCOURSE 138KV RECONDUCTOR	$ 2,300,000	190,000 kVA
2025	NPC	NPC-NW	Mission	Mission 69 kV	New Line	MISSION TRANS UPGRADE: EQUESTRIAN MISSION 69 KV LINES 1&2	$ 12,800,000	20,500 kVA
2025	NPC	NPC-NW	Flamingo	SP-FL-DE 69 kV	Line Upgrade	SP-FL-DE 138kV LINE CONVERSION	$ 18,200,000	N/A

Using this analysis, one grid need was found to be near-feasibly deferred or replaced with a NWA: the Clark – Concourse 138 kV reconductor project.

c. Locational Net Benefits Analysis

Based on the needs assessment, the Clark-Concourse 138 kV reconductor project was then entered into the NWA PWRR Worksheet.xlsx tool to model and compared the PWRR of both the traditional wired solution to the proposed NWA. For this project, the PWRR analysis was conducted to determine if a NWA could cost-effectively defer the proposed wired solution for one year, from 2025 to 2026.

The PWRR analysis showed that although the capital cost of the NWA was lower than the cost of the wired solution, the need to install the same wired solution one year later nevertheless caused the total PWRR of the combined project to be approximately 1/3 more than the wired solution alone. The PWRR for the combined project became more competitive with each additional year that the NWA could defer the wired solution. As a result, it was recommended that once the grid need becomes more imminent, the NWA analysis be re-evaluated to determine if designing a NWA that defers the project for several years can make it more cost-competitive.

For all new Transmission based projects, a default field in the Project Portfolio Management software has been added to require consideration of NWAs to meet the need being addressed. Following the annual update to the NV Energy 10-year Capital Plan, Transmission Planning will complete this analysis on any new projects entering the 6-year planning window.

C. Tariffs for Cost-Effective Deployment of DER

1. Tariffs as an Incentive Mechanism for Storage

As a general matter:

- Transactions between the utility and customers that involve programmatic incentives (*e.g.*, demand-side management and demand-reduction) that are approved and overseen by the Commission at the program level are typically not tariff-based. (SB 145 for example)
- Tariff-based incentives for storage have been proposed in compliance with Section 27 of AB405. These tariffs govern the transaction between the utility (seller) and a customer-generator who has installed an energy storage system (buyer), and have been designed to expand and accelerate the development and use of energy storage systems in Nevada. These tariffs are the subject of proceedings (Docket No. 17-07026) that will continue on February 8, 2018.
- Another tariff-based incentive for storage paired with customer-owned renewable generation is available under Section 28.3 of AB405. Under the currently proposed Rule 15, exports from energy storage systems are permitted, and exports of stored renewable energy (*i.e.*, from the customer-generator) qualify for excess energy credits.
- Finally, the Company received approval from the Commission in Docket Nos. 18-09017 and 18-09018 for a new tariff to incentivize fast charging commercial electric vehicles.
- Successive DRPs may identify a need or opportunity for additional tariff-based incentives targeted at distributed energy resources. At this point in time the Companies have not identified:
    - That additional incentives are necessary to expand and accelerate the development and use of energy storage systems in Nevada,
    - That such incentives should be provided to customer-generators with storage systems, and
    - Tariffs are necessary to deliver such incentives.

D. Coordination with Existing Commission-approved DER Programs

1. Overview

NV Energy is itself a leader in providing and supporting DERs in Nevada, from its robust energy efficiency and demand response programs (authorized and supervised by the Commission, governed by Nevada's IRP statutes and regulations), battery energy storage systems and electric vehicle rebate and innovative pricing programs, to its role as program administrator of the Legislature's Renewable Generations Programs, its offerings of time-of-use pricing pilots, and its recently-updated interconnection rules and processes. In accordance with Section 3.3 of the Commission's Temporary Regulation, these Commission-approved programs must be identified in the DRP, and the cost-effective coordination between existing Commission-approved programs addressing deployment of DERs and new DERs within the DRP discussed and proposed.

In this section, the Company briefly describes its extensive obligations and successes in implementing the wide range of DER programs and policies generated by the Nevada Legislature. These include incentive programs and tariff offerings designed to promote customer-owned renewable generation, battery energy storage systems and electric vehicles. The discussion includes descriptions of how these existing programs are coordinated with each other and with grid operations, the very valuable information that these programs provide to assist performance of the NWA and LNBA analyses, and their support of estimates of incremental costs and benefits. Finally, recommendations and proposals are made to further improve the locational benefits of DER programs, reduce the incremental cost of their deployment, and achieve better coordination and alignment across parallel DER efforts and policy goals.

2. Demand-Side Management ("DSM") Programs

A key component of any IRP is the utilities' portfolio of programs for reducing customers' demand on the electrical system (reference NRS § 704.741(1)). In the resource planning context this portfolio of programs is termed the "demand-side plan", and the Commission reviews NV Energy's existing and proposed demand-side portfolios every year, either in a triennial IRP or in an annual update filing. In the context of the DRP, these programs are termed "energy efficiency" and "demand response" resources, and are included in the definition of "distributed generation systems" in NRS § 704.741(6).

a. Energy Efficiency ("EE")

NV Energy maintains a robust portfolio of Commission-approved programs focused on delivering energy savings measured in kWh. This portfolio includes energy education, energy assessments, and rebate programs for energy conservation measures directed across the commercial and residential market segments. In addition to offering cost-effective alternatives to supply-side resources within an IRP, these programs have contributed to achieving Nevada's RPS policy goals. More recently, NV Energy's energy efficiency programs have been structured to achieve a new non-RPS annual energy efficiency savings target of at least 1.1 percent of annual retail electricity sales statewide. The new energy efficiency target was established in 2017 in Senate Bill 150 ("SB150") and Assembly Bill 223 ("AB223"). NV Energy's 2018 Joint IRP (Docket No. 18-06003), which covers the 2019-2021 DSM program years, also includes plans to spend at least 5 percent of the overall DSM budget on low-income measures.

The portfolio of DSM programs approved in the 2018 Joint IRP achieved a benefits-to-cost ratio using the total resource cost ("TRC") test of 2.15, and a non-energy benefits TRC ("NTRC") ratio of 2.42. Approximately 65 percent of the funding is dedicated to energy efficiency programs that primarily save energy (*i.e.*, kWh) but achieve varying degrees of permanent demand (*i.e.*, kW) savings as well. These programs include:

- Energy Education – this program primarily focuses on making all customer segments aware of energy efficiency solutions via presentation, media outreach, community events, professional training, and live educational performances at schools. In addition to these activities, NV Energy will be distributing energy kits to both residential and commercial customers.

- Energy Reports – this program provides periodic energy usage reports to residential and business customers to inform and motivate them to take actions to save energy by using electricity more efficiently.
- Energy Assessments – this program provides a customized energy analysis to residential customers who want to learn more about their energy usage and how their home performs.
- Direct Install – this program provides residential customers with the direct installation of low-cost energy efficient measures in their homes at the time of a Company-provided energy assessment or smart thermostat installation.
- Low Income – this program provides energy efficient appliances and products to low or limited income customers.
- Residential Lighting – this program provides incentives to encourage customers to purchase and install energy efficient lighting products by partnering with manufacturers and retailers to offer discounted pricing on high quality LEDs at participating retail locations.
- Residential Air Conditioning – this program provides incentives to help customers make energy efficiency upgrades to air conditioners and heat pumps.
- Pool Pumps – this program provides incentives for upgrading inefficient single-speed pool pumps to more energy efficient variable-speed pumps.
- Schools – this program provide continuous energy improvement in public schools, including K-12 and higher education. The program offers two types of energy services to school administrators—rebates for energy efficiency projects and technical assistance to facility managers.
- Commercial Energy Services – this program offers energy efficiency technical assistance and incentives to commercial and industrial customers to promote investments in energy efficient retrofit and new construction projects.

Several of these existing Commission-approved programs are capable of reducing or shifting locational grid constraints, particularly those that are thermal or voltage-related. As noted above in Section 3.A.3.b (2), the NWA analyses in this DRP reflect a 2 percent potential reduction in demand (and a consequential reduction in energy usage) via energy efficiency programs.

b. Energy Efficiency Support of Locational Benefits

Energy efficiency programs support long-term planning objectives and deliver "permanent" demand and energy reduction. While such programs do not per se provide operational flexibility to the utility grid or locational dispatch capability in the way that demand response programs can, they can still provide locational benefits. Industry-wide, NV Energy has identified case studies demonstrating the viability of deploying targeted energy efficiency to permanently lower the overall demand of specific locales, making energy efficiency a potentially important NWA resource for utilities across the country. In Nevada, NV Energy successfully deployed concentrated energy efficiency in a target area (Carson City, Dayton, Carson Valley and South Tahoe) while an upgrade to transmission service into the area was deferred (reference Docket Nos. 08-08012 and 08-08013).

Technology-specific energy conservation measures exhibit characteristic energy savings profiles, or savings curves, that can be considered when using energy efficiency to mitigate operational issues on the electric grid. Energy efficiency measures have varying capabilities to offset energy use at times of peak demand, and peak demand at the system level is not necessarily coincident with the peak demand on a particular distribution feeder, which varies depending upon the customer and load types on the feeder. The cost-effectiveness models used by the Companies determine a DSM measure's avoided capacity (*i.e.*, avoided kW) benefits at the system level, not at the feeder level. A generalized cost estimate for avoided transmission and distribution capacity is currently used in DSM planning.

3. Demand Response ("DR")

NV Energy's demand response programs offer customers flexible demand management solutions, and valued-added service components that drive additional energy savings, improve customer convenience and control, and generate actionable information. Technology and services are packaged into portfolios designed to meet the needs of residential and commercial customer segments and various customer and end-use load types. A primary example of this is NV Energy's flagship DR program which offers customers a no cost smart thermostat with installation, mobile app, energy efficiency optimization service, and A/C fault detection service. Additionally, an agricultural load control system has been built out at Sierra that to date has not been considered part of DSM with regulatory asset treatment, but rather as a capital project originally, and now supported by O&M funds.

The DR portfolio is capable of providing dispatched load control for either reliability (*i.e.*, grid emergency) or economic reasons and therefore can be used for peak shaving, peak shaping, and operating reserves. A detailed review of the latest residential and commercial DR programs can be found in the Companies' 2018 Joint IRP.

In aggregate, if all of the NV Energy DR resources were dispatched at the same time on a hot summer day for an hour, the system would provide approximately 250 MW/MWh of system-level emergency load relief. Typically, however, the system is dispatched for economic reasons. In this operational mode, the dispatch of DR resources is spread across the peak hours, flattening out the system peak and reducing reliance on peak-priced purchased energy and fuel. When not scheduled for economic reasons, a portion of the DR resource system can be queued as an operating reserve resource that meets the requirements for 10-min spinning reserves. Below are some key summary statistics of NV Energy's existing DR resources:

- Emergency DR Capacity: 250 MW
- 10-min Spinning Reserve DR: 190 MW
- Typical Peak Offset for Economic/Peak Shaping DR: 150 MW
- Total Customers Enrolled: 92,000

- Total Devices/End-use Loads Under Control: 130,000

Approximately 80 percent of the capacity of NV Energy's current DR portfolio is generated by controlling weather-sensitive air conditioning ("A/C") loads via smart thermostats, paging thermostats, and load control switches. The Companies recognize the need to diversify the customer assets (lighting controls, water heaters, pool pumps, etc.) participating in DR programs in order to provide higher levels of DR capacity and capability outside of the summer months, particularly as more renewable resource capacity comes online. DR resources are expected to be used to help manage the variability of renewable resources and can be used to absorb excess solar generation by control of thermal and electrical storage devices such as grid-interactive water heaters, ice thermal storage for A/C, and electric batteries. As a DER, demand response technologies and methodologies continuing to improve and will enable the control of loads and the integration of other DERs such as PV, EV, and storage onto the grid in the future.

DR approaches vary in complexity and timescales. Price-response, typically delivered through time-of-use and critical-peak pricing tariffs, delivers DR in the months-ahead to day-ahead timeframe. NV Energy's current DR portfolio emphasizes direct load-control techniques to primarily effectuate load control within the timeframe of 1-day-ahead to 10-minutes-ahead. As more asset types capable of operating in the 10-min-ahead to 4-seconds-ahead timeframe proliferate, NV Energy will need to supplement or build out additional DR infrastructure to successfully integrate the larger number of assets.

a. Price Responsive DR and Related Tariffs

DR related tariffs currently offered by the Company come in the form of stand-alone tariffs or tariff riders that effectuate a price-based load response and require no DR technology and infrastructure, and stand-alone tariffs and tariff riders that require varying degrees of DR technology and program management support. The below matrix in Figure 11 provides a simplified overview of DR related tariffs at the company and resource requirements to implement them. A high level description of each tariff type follows.

FIGURE 11:
DR-RELATED TARIFFS AND IMPLEMENTATION REQUIREMENTS

Required Resources	OLM-AS	IS-2	TOU	CPP (+DDP)	EV Rider
Program Administration	X	X		X	
Marketing & Education	X	X	X	X	X
CIS, Metering, Billing, Customer Support	X	X	X	X	X
Utility DR Systems & Communications Infrastructure	X	X		X	
Customer Technology & Support	X	X			

<u>OLM-AS Rate Rider – Optional Load Management – Automation Services</u>: this tariff rider supports residential and certain small commercial A/C load control programs by specifying monthly load control bill credits by device type, as well as performance based credits load control event participation as measured by NV Energy smart meters. The tariff rider also specifies the conditions and characteristics of billing credit transactions and load management periods related to the A/C load control program.

<u>IS-2 Interruptible Irrigation Tariff</u> - this tariff at Sierra is available to eligible agricultural customers who agree to interrupt irrigation pump service during system emergencies. This service is applicable to electricity used solely to pump water to irrigate land for agricultural purposes. Agricultural purposes include growing crops, raising livestock or for other agricultural uses which involve production for sale, and which do not change the form of the agricultural product pursuant to NRS 587.290. Customer participating on this tariff must allow the company to install load control technology on their water pumps, or otherwise be capable of responding to utility load control signals within 30 minutes to curtail water pumping under electricity grid emergency conditions.

<u>Time of Use Tariffs</u> - The NV Energy Time of Use ("TOU") tariffs provide customers with a choice. Customers who are willing to use less electricity during periods when the total demand of energy is highest (the peak), will save money by shifting their usage to times with lower rates. Time of use rates are higher during daytime and early evening hours (peak-usage) and lower during night time hours (off-peak). To help customers who are uncertain about the best rate for their lifestyle, a comparison will be made between the Time of Use Rate and the regular flat rate for the first 12-month period. If the Time of Use Rate was more costly during that period, NV Energy will

credit the difference back to the customer and give the customer the option to move back to the flat rate. NV Energy supports a number of TOU Rate variants including options such as the following:

- Critical Peak Pricing ("CPP") – this is a rate variant of the base TOU rate in which a higher priced time period, or critical peak period, can be dispatched to customers via various customer selected communication channels on a day-ahead basis. Critical peak periods are not known in advance, but are dispatched during times of high wholesale power prices. NV Energy's current version of CPP has a fixed start time (i.e. 1pm) and fixed duration (i.e. 5 hours at Sierra and 6 hours at Nevada Power). There are variants of the CPP rate on offer that are combined with Daily Demand Pricing (discussed below).

- Electric Vehicle Rider - NV Energy offers a special Electric Vehicle ("EV") Time of Use Rate rider for its northern and southern Nevada EV customers. It allows a customer to pay a discounted rate if they charge the vehicle during the utility's off-peak hours between 10 p.m. and 6 a.m. As an added benefit, the discounted rate applies to all of the energy used at a home or apartment during that period of time, not just electricity used to charge an electric vehicle.

b. Demand Response Support of Locational Benefits

NV Energy's DR information technology and communications systems support the locational dispatch of DR resources. As far back as 2008, before the financial crisis hit, the DSM department worked with the Distribution Planning department to identify "hotspots" on the distribution system, where certain feeders had started to exceed their loading limits. The A/C direct load control program—called "Cool Share" at the time—was target marketed into these hotspots with success during the 2008 program year. However, the continuing decline in the housing market and the financial crisis cooled off these hotspot, and since that time, there has not been any specific locational targeting of the program. However, the project demonstrated successful target marketing and the programming of the load management systems to be able to dispatch load control in the hotspot areas.

The Company leveraged the statewide NV Energize smart meter project, and the US DOE Smart Grid Investment Grant (part of the American Reinvestment and Recovery Act) to specify, procure, and implement a Demand Response Management System ("DRMS") in the 2010-2012 timeframe. Core functionality of the DRMS allows the grouping of load control devices into discrete resource groups to accommodate locational dispatch by geographic zones, or by substation, bank, or feeder. There is a role type in DRMS that allows distribution operators to log into the system to see how much load curtailment is available down to the feeder level, and to dispatch an event to a substation, bank, or feeder. DRMS was originally setup to accommodate larger geographic zones, such that if an event is launched to a specific feeder, all of the devices on that feeder will be dispatched, but also the other devices in that particular zone.[34] Locational dispatch testing was

[34] The load management system supervising NV Energy's fleet of two-way paging programmable communicating thermostats—the Carrier Comfort Choice ("CCM") system—is limited to a maximum of 14 operational groups. Hence, the CCM groups are mapped according to larger zones. Devices on a particular feeder can still be dispatched, but the other CCM devices in the zone would also be dispatched. NV Energy's other load management systems were similarly mapped; however, they can be remapped and regrouped on a more granular basis.

performed in 2018 to verify expected operating characteristics and in preparation for new IT systems integrations between the DRMS, the Advanced Distribution Management System ("ADMS"), and the GIS. The DSM technical services team is currently reconfiguring the resource groups in DRMS from larger geographic zones to a more granular set of resources to enable more accurate dispatch at the feeder level. A new integration to ADMS will allow distribution operators to dispatch DR events from within ADMS to assist with distribution system management; and, a new integration to the GIS system will update the distribution system network topology within DRMS on a daily basis, as opposed to the historical practice of once a year before the start of the load control season.

Despite these improvements, due its age and the original specifications, the DRMS device management and optimization function set and its supporting database architecture do not well support "fast DR" or the "shimmy DR" as described in the LBNL CA Demand Response Potential Study that uses load management for ancillary services down to the 4 second timeframe. [35] The database does not natively support retrieval and storage of device state information for devices such as smart inverters for PV systems or storage devices, along with more modern command sets related to voltage support or frequency regulation.

However, its support for the OpenADR 2.0 standard allows the DRMS to be used to dispatch peak shaving and peak shaping load control events to storage devices. Due to its participation in another US DOE grant—the Renewable and Distributed System Integration grant awarded in 2009—with partners Pulte Homes and UNLV, the Company is leveraging BTM battery energy storage systems installed at a residential neighborhood in Las Vegas called Villa Trieste for ongoing DER technical integration activities with inverters and storage devices. The DRMS can accomplish simple dispatch of battery energy storage systems via a vendor cloud and via a local gateway using protocol translation. Additional systems and software are required for more advanced and more optimal dispatch of PV and Storage systems for "fast DR" support of distribution system operations and renewable energy volatility management.

That said, the Company's current DR operational capability exceeds its DER valuation and cost-effectiveness modeling capability. As mentioned above, current cost-effectiveness models use a system level generalized avoided cost of transmission and distribution. Calculation of more granular locational benefits and marginal cost of distribution can in turn be used to better target DR deployment and dispatch. Additionally, the current set of deterministic models do not support the calculation of extrinsic values related to DERs, such as the insurance value of DR. Migration from deterministic modeling toolsets to probabilistic models for the 2021 DRP filing is a common theme that is also discussed earlier in the Load and DER Forecasting section.

As mentioned before, in the context of the EE regulatory treatment of AB223/SB150, DR is included within the definition of energy efficiency in the NAC regulations, but currently the avoided capacity (i.e. kW), and avoided T&D locational benefits are not specifically addressed in

[35] Fast DR is used here for grid services responsive within the range of four seconds to five minutes such as regulation and load-following services.

Alstone et al. (Lawrence Berkeley National Laboratory), Final Report on Phase 2 Results: 2025 California Demand Response Potential Study: Charting California's Demand Response Future (Mar. 1 2017) at 5-56, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452698.

statutes or regulations. Avoided energy, avoided capacity and system average T&D costs are included in the cost-effectiveness modeling for DSM programs. DR provides more flexible grid operational benefits than EE, and is an important component of potential NWA solutions. Thus, the Company's portfolio of DSM programs balances both EE and DR focused programs. Although, SB146 and AB223/SB150 goals may not be fully aligned the Company recognizes and supports the balanced EE and DR approach.

c. Demand Response Coordination to Minimize the Incremental Cost of Distributed Resources

Starting in 2012, the Company launched new versions of its DR programs focused on an Integrated Demand Side Management ("IDSM") format. IDSM programs are an effort to minimize the deployment costs of multiple DER measures, thereby improving the cost-effectiveness of DSM programs and the customer experience. To date, the Company IDSM offerings have been focused on deploying DR infrastructure and devices types that also provide native energy efficiency benefits, or can be incrementally upgraded to provide additional EE savings and operational information. With improved coordination across customer programs, the IDSM format can be extended to PV, thermal storage, and electrical storage. As mentioned above, the Company is already working to include battery energy storage systems as a DR asset in the residential sector. It is also working on program design and incentive offers to incorporate commercial electrical storage in direct response to inquiries about the new Large Storage Incentive Program (further described below). For example, the Company is working with the Governor's Office of Energy to assist with developing DR event incentives and technical integration for a planned storage installation at the State of Nevada Grant Sawyer building in Las Vegas.

With respect to improved coordination across existing DER programs, it is important to note that current regulations related to cost recovery of DSM programs tracks expenditures in accounts separately from the legislatively sponsored DER programs, as the cost recovery mechanisms are different. Hence, the regulations promote clear and trackable separation of DER program activities with respect to funding and reporting categories. This tends to support organizational and activity separation; [36] hence, existing regulatory and management paradigms are not necessarily in full alignment with DRP goals to foster improved coordination of existing programs and the minimization of the incremental costs to deploy DER technologies.

The next section turns to a discussion of non-DSM programs and activities focused on implementing the fair distribution of renewable energy, storage, and EV infrastructure incentives authorized by the Nevada State Legislature.

4. Clean Energy Programs

NV Energy is responsible for delivering clean energy customer incentive programs for emerging technologies in the renewable and distributed energy resource space that include renewable energy, energy storage and electric vehicle technologies. The renewable energy technologies include solar, solar thermal, wind, and hydro. The flagship program has historically been the Solar Incentives program for behind-the-meter solar rooftop installations which is a contributor to NV Energy's

[36] Potter, Jennifer, Stuart, Elizabeth, and Cappers, Peter. (Lawrence Berkeley National Laboratory), "Barriers and Opportunities to Broader Adoption of Integrated Demand Side Management at Electric Utilities: A Scoping Study" (February 2018), https://emp.lbl.gov/publications/barriers-and-opportunities-broader

requirement to meet the RPS. Currently, the renewable energy programs combined contribute over 9 percent of the total NV Energy renewable generation resource and has helped NV Energy exceed the RPS requirement that states that 20 percent of our energy supply should come from renewable sources in 2018.

These Clean Energy programs are legislated in NRS 701B and regulated through NAC 701B. These programs provide education, community outreach, and incentives to install energy storage, electric vehicle infrastructure, small scale solar, wind, and hydro generation. Most customers that adopt distributed private generation do so through these programs. As such, the department provides expert advice, data tracking, and regulatory support for distributed resources for both internal and external customers.

NRS 701B established the solar energy systems, wind energy systems, and waterpower energy systems programs and provided $255,270,000 for solar incentives and a combined $40,000,000 for wind and waterpower incentives. The statute further established a goal of achieving 250 megawatts of installed solar capacity, with no corresponding goals for the wind and waterpower programs. These programs are managed by NV Energy and are funded through the Renewable Energy Programs Rate (“REPR”), which is a volumetric rate rider paid for by NV Energy’s electric customers.

In 2018, six new EV and two new energy storage programs were introduced to comply with the requirements from 2017 Nevada Senate Bill 145. These programs include the small energy storage program, large energy storage program, multifamily EV charging program, workplace EV charging program, electric fleet charging program, technical advisory services, EV custom grant program, and the Nevada electric highway.

The key mission of the clean energy programs is to offer customers support for new technologies, ensure that the implementation of the clean energy programs is conducted in a prudent and effective fashion, and provide technical expertise on Rule 15 interconnections related to distributed energy resources.

a. Net Energy Metering (“NEM”) Tariff

The NEM tariff applies the deployment of renewable DERs, more specifically solar PV. Under this tariff, the customer receives a bill credit for excess energy that is exported to the grid. Net metering allows customers to use the energy generated by their renewable energy system to offset their monthly power bill. Customers may participate in net metering even if they choose not to participate in the clean energy incentive programs.

b. NV GreenEnergy Rider

Customers can choose to “go green” by participating in the NV GreenEnergy Rider (“NGR”). The Northern NV Green Energy Choice program offers customers the option of taking 100 percent or 50 percent of their energy from renewable resources by electing to pay an additional amount on their monthly bill (based on your usage).

The NV GreenEnergy Rider requires a minimum commitment of 12 months, or until service on a customer account is discontinued. Customers will receive a renewal notice for additional 12-month periods. The monthly amount will be listed on monthly bills as the NGR charge.

Commercial customers may also participate through negotiated terms, which are subject to approval by the Commission.

c. Renewable Generations Support of Locational Benefits

Customer-sited solar PV installations are the most common form of distributed generation deployments. Although solar PV represents a small fraction of our electric generation capacity in Nevada, it has grown rapidly in recent years and could continue to grow in future years if downward installed system cost trends continue. The value of solar (VOS) analysis and recent studies conducted among multiple states in the U.S. have demonstrated the challenge in quantifying the benefits or costs that result from customer-sited solar PV systems as their impacts on the distribution system are fundamentally local, requiring a high degree of analytical granularity. Groundbreaking work such as the Electric Power Research Institute (EPRI) in collaboration with Con Edison and SCE have developed a framework and applied analysis on distribution circuits with multiple configurations. The study, "Time and Locational Value of Distributed Energy Resources (DER): Methods and Applications (EPRI #3002008410)," provides preliminary insights about the locational value benefits DERs can offer under certain operating conditions in different distribution system types and configurations. Other analytical tools such as the distributed energy resource avoided cost (DERAC) calculator developed by E3 has been enhanced to incorporate locational benefits and avoided costs at the distribution feeder level. The DERAC calculator represents avoided costs associated with T&D, including capacity deferrals, relieved congestion, and avoidance of losses. This tool has been approved by the California Public Utilities Commission as part of SCE and SDG&E's DRP filings.

Similar to energy efficiency and demand response resources, customer-sited solar PV displaces traditional centralized generation which must use the utility T&D network to deliver electricity to customer sites. Distributed solar resources generate power that is consumed on that distribution system. On homes equipped with customer-sited solar PV systems, the solar output serves the on-site load first and its green electrons never flow through the utility grid, unless there is excess generation, thus reducing loads on the utility's T&D network. Typically, the excess power generated and pushed into the grid is consumed at the local distribution system by the solar customer's neighbors, reducing loads on the upstream portions of the distribution system while minimizing T&D losses. The key factors that would impact distribution avoided costs and benefits from distributed solar PV include the following:

- Specific characteristics of the utility feeders such as length, size, installed protection, voltage regulating equipment, etc.
- Location of the distributed solar PV system on the electric grid feeder.
- Saturation of distributed solar PV capacity on the feeder as compared to the load.
- Daily and seasonal feeder load shape compared to the distributed solar PV load shape.
- Reactive power requirements and flows on the feeder.

- Capabilities of the utility to communicate with the distributed solar PV advanced smart inverters and dispatch to adjust the real or reactive power.

Solar PV systems interconnected to the grid include DC to AC inverter devices. In 2018, the Institute of Electrical and Electronics Engineers (IEEE) published the IEEE Standard 1547-2018 for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, which specifies how DERs interact with and function on the electric distribution system. This standard represents a major update since the last 2013 version. The standard requires DERs to be capable of providing specific grid supportive functionalities including voltage and frequency ride-through, voltage and frequency regulation, as well as communications and control functionality. These capabilities can help increase the amount of DERs that can be interconnected on the grid, improve power quality and ensure that DERs can be a reliable and optimized resource as DER penetration increases. The new inverters certified to IEEE Standard 1547-2018, known as advanced smart inverters, can support two-way communications with the utility and can be monitored and controlled remotely. This capability allows the ability to configure operational functions and customize unique inverter trip and functional settings based on locational needs during the inverter commissioning, as well as allowing settings to be adjusted over time. For example, different locations on a circuit will have different voltage levels. Locations closer to a substation would experience higher voltages, and locations further away from the substation would have a lower voltage. Moreover, the standardization of smart inverter communications protocols such as SEP2.0, DNP3 or SunSpec Modbus can facilitate the integration with the utility's supervisory control and data acquisition (SCADA) systems and distributed energy resource management systems (DERMS). However, the level of readiness and sophistication of back office integrations to empower an effective utility DER management platform is key in leveraging the full potential and benefits of DERs.

5. Electric Vehicle Infrastructure Demonstration Program

Following establishment by the 2017 Nevada Legislature in Senate Bill 145 to support the acceleration of EV deployment and the expansion of vehicle charging infrastructure statewide, the NV Energy launched a number of Electric Vehicle Infrastructure Demonstration ("EVID") programs during the 2018-2019 program year. These programs include EV Charging Station Incentives, the Nevada Electric Highway, EV Custom Grant Program and Technical Advisory Services.

These programs were strategically designed to expand the EV charging infrastructure across the state of Nevada by providing incentives to offset the cost of engineering, procurement and installation of the electric vehicle charging stations.

a. Electric Vehicle Tariff

As mentioned above, NV Energy offers a special EV Time of Use Rate rider. Time of use rates are higher during daytime and early evening hours (peak-usage) and lower during night time hours (off-peak). To help customers who are uncertain about the best rate for their lifestyle and electric vehicle charging needs, a comparison will be made between the EV Time of Use Rate and the regular flat rate for the first 12-month period. If the EV Time of Use Rate was more costly during that period, NV Energy will credit the difference back to the customer and give the customer the option to move back to the flat rate.

6. EV Infrastructure Programs Coordination with DR

Following establishment by the 2017 Nevada Legislature in Senate Bill 145 to support the acceleration of EV deployment and the expansion of electric vehicle charging infrastructure statewide, NV Energy launched a number of Electric Vehicle Infrastructure Demonstration (“EVID”) programs in September 2018. These programs include the Nevada Electric Highway, EV Custom Grant Program, Technical Advisory Services, and EV Charging Station Incentives for multi-family, fleet, and workplace charging. These programs were strategically designed to expand the EV charging infrastructure across the state of Nevada by providing incentives to offset the cost of hardware, engineering, procurement and installation of the electric vehicle charging stations. Under these programs EV charging stations are required to be network enabled for potential future DR/DER programs. At present, a DR/DER program has not been developed to manage these assets, but discussions around optimal program structure have begun.

Considerations around an effective program design include incentive structures and possible locational benefits. EV charging consumption that is incentivized during peak solar generation, and that is curtailed during late afternoon demand peaks, would be ideal. Coordination with vendors will be required to ensure the necessary charging station management software is available to enable time variant charging control strategies.

Moreover, bi-directional charging stations and EVs supporting "vehicle-to-grid" (V2G) applications to enable the use of idle car batteries as a source of power have potential to provide grid services such as demand response. Awareness for V2G technology and the impact it can have for the electricity grid is gaining momentum through field pilot demonstrations and collaborations with a few EV manufacturers. However, there are still challenges and barriers to overcome such as impacts of the stress on the batteries, manufacturer warranties, consensus support from major EV manufacturers, and lack of industry standardization on advanced remote communications protocols for EV charging equipment, among others, before V2G technologies become mainstream beyond pilot projects as critical assets to effectively balance peak demands on the electricity grid.

NV Energy also offers a special EV time-of-use (TOU) rate rider. TOU rates are higher during daytime and early evening hours (peak-usage) and lower during night time hours (off-peak). To help customers who are uncertain about the best rate for their lifestyle and electric vehicle charging needs, a comparison will be made between the EV TOU rate and the regular flat rate for the first 12-month period. The customer is given a guarantee for the lowest rate and NV Energy credits the difference back to the customer if the TOU rate yielded a higher cost. The customer then has the option to move back to the flat rate.

The EV TOU rate is designed for residential EV charging, but is less well suited to commercial charging with DR. Commercial sites may have other large loads that would cost more during late afternoon, including process loads that may well exceed EV demand during peak hours. The best approach to effective commercial EV charging DR is to couple it with storage and to establish charging schedules for EV fleets.

Commercial sites that are supporting public charging would want to provide a reasonably uniform cost to avoid having to manage customer complaints. Storage is the best way to approach either public access or high demand charging that is characteristic of DC fast charging. There is also a locational benefit to the storage, as high EV traffic areas that include fast chargers would not create peak demand issues when coupled with storage.

7. Energy Storage Programs

Senate Bill 145 ("SB145"), approved during the 79th (2017) Session of the Nevada Legislature, established as part of the Solar Energy Systems Incentive Program, a program for the payment of incentives for the installation of residential and commercial energy storage systems. The Energy Storage Incentives program offers financial incentives to lower the upfront capital costs and shorten the payback period of energy storage systems. The program was created to promote and advance the market adoption of emerging energy storage technologies and their innovative use cases and applications in Nevada including reducing peak demand for electricity, avoiding or deferring investment by the utility in assets for the generation, transmission or distribution of electricity, or improving the reliability of the operation of the transmission or distribution grid.

The Energy Storage Incentives program is available to NV Energy customers who have previously installed a renewable energy system or are currently installing one alongside their energy storage system. Applications are submitted online through the online application portal accessible through the NV Energy website. Registration and access to the NV Energy application portal is available to homeowners, business owners, and contractors associated with a customer project and authorized to represent the customer on their behalf.

a. Storage Related Tariffs

Assembly Bill 405 ("AB405") passed in 2017 and included a requirement for NV Energy to establish a new time variant rate offering that is designed to expand and accelerate the development and use of energy storage systems in the state of Nevada. As a result, NV Energy established optional time variant rate treatments that include time-of-use rates, a critical peak pricing schedule, a daily demand charge based schedule, and a schedule that allows for the combination of critical peak pricing and the daily demand charge.

b. Storage Programs Coordination with DR

NV Energy was one of the first electric utilities in the U.S. to begin installing and testing behind-the-meter residential battery energy storage system technologies in 2011. The company's efforts in this space began with small pilots focused on peak demand reduction and optimization, and more recently have evolved into the assessment of advanced battery dispatch use cases and integrations with NV Energy's demand response management system (DRMS). The integration with the DRMS has been primarily based on the latest Open Automated Demand Response (OpenADR) protocol, currently OpenADR 2.0.

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Section 1.2 of SB145 established the Small Energy Storage Incentives program component and up to $5,000,000 in incentive funding for residential and non-residential customers pursuing energy storage systems with a nameplate capacity less than 100 kilowatts. Currently, customers eligible for the program may receive a larger incentive by electing to enroll in a time-of-use (TOU) rate. This rate-based measure helps satisfy the requirement in the law that the energy storage systems provide a minimum level of benefit to customers of the utility, including, without limitation:

- Reducing peak demand for electricity;
- Avoiding or deferring investment by the utility in assets for the generation, transmission or distribution of electricity; or
- Improving the reliability of the operation of the transmission or distribution grid.

Section 1.3 of SB145 established the Large Energy Storage Incentives program component and up to $5,000,000 in incentive funding for non-residential customers pursuing energy storage systems with a nameplate capacity of at least 100 kilowatts but not more than 1,000 kilowatts. This program is intended to prioritize installations that serve critical infrastructure facilities. The program requires a collaborative process to establish criteria for the identification and selection of customers participating in this program. The collaborative process will include representatives from state and local agencies that provide critical infrastructure, as well as experts from the Commission and the industry.

In addition, and prior to, the launch of the above described Energy Storage Incentives program, NV Energy had implemented pilot programs involving the installation of residential battery energy storage systems at homes with existing rooftop solar panels. The primary objective of these pilots has been to demonstrate the feasibility of peak demand reduction in the residential space by establishing communication between NV Energy and remote battery energy storage management systems and testing direct load control through demand response (DR) strategies. The battery energy storage systems have been deployed into a new housing development called Villa Trieste located in Las Vegas, which contains state of the art energy efficient homes. The homes at the Villa Trieste development are ‘Leadership for Energy and Environmental Design’ (LEED) platinum certified and are equipped with rooftop solar PV systems.

The first pilot was implemented through collaborative efforts with the University of Nevada Las Vegas (“UNLV”), NV Energy, and Pulte Homes, based on a Department of Energy (“DOE”) research development and systems integration (RDSI) grant. Upon the launch of this pilot in 2008, it was one of a handful of projects across the country that were aiming to test the use of several technologies, including battery energy storage, to achieve demand reduction for homes. At the start of the project, the partners considered the potential installation of a single large battery energy storage system (approximately sized at 1.5 MW/6 MWh) at an NV Energy substation. Such an installation could serve many customers and enable distribution level grid benefits. However, this option was ruled out due to its high capital cost around 2009. The installation of several 'neighborhood' batteries at Villa Trieste was also considered with each battery energy storage system serving a number of homes. But this approach was also ruled out due to high implementation costs associated with the requirement to partially bury the batteries and because the high-density Villa Trieste development could not accommodate the installation of batteries near sidewalks or shared curbside areas.

The project team successfully installed the first battery energy storage system at a home in the Villa Trieste development in November 2012. The system, which was called the OnDemand Energy Appliance ("ODEA"), was purchased from Silent Power, Inc. Ultimately, five ODEA units were installed and tested at Villa Trieste homes. Five additional battery energy storage systems, called Sunverge Integration System (SIS), were purchased from Sunverge and installed at other Villa Trieste homes. While the DOE funded portion of this pilot ended in 2015, testing has continued. The ODEA units have been removed due to failure of SilentPower to remain a viable business entity, but five Tesla Powerwall 1.0 units have also been installed in Villa Trieste homes to enable continued testing of communications between NV Energy and the energy storage systems to implement DR strategies. Using existing customer sites that had participated in the 2017 – 2018 pilot, an extension is being offered to further test demand response events at these homes. This pilot extension will demonstrate the feasibility of communication between NV Energy and remote inverters (installed at customers' homes) to dispatch demand response events to battery energy storage systems. This will be achieved using OpenADR2.0b, SunSpec, and Smart Energy Profile (SEP) 2.0 protocols. The DRMS can accomplish simple dispatch of battery energy storage systems via a vendor cloud or via a local communicating gateway device performing protocol translation.

In addition to ongoing activities working to include battery energy storage systems as a DR asset in the residential sector, NV Energy is also working on program design and incentive offering to incorporate commercial electrical energy storage in direct response to inquiries about the Large Storage Incentives program. As the first customer application filed, NV Energy is working with the Governor's Office of Energy to assist with developing DR incentives and technical integration for a planned 160 kW/840 kWh lithium-ion energy storage installation at the State of Nevada Grant Sawyer building in Las Vegas.

E. Recommendations for Cost-Effective Coordination of Existing DER Programs

The Company recognizes the need to strategically coordinate the joint implementation of multiple DERs which: 1) are required by different administrative code and regulations; 2) are approved in separate PUCN filings; 3) have different cost recovery mechanisms; and 4) are managed by different departments within NV Energy. Technically, NV Energy has a great deal of knowledge from the Villa Trieste and the State of Nevada Grant Sawyer building projects that provide lessons learned and best practices for future projects. Functionally, NV Energy will be focusing on strategic areas that could greatly benefit from continued collaboration including how to use existing programs, systems and tariffs to most cost effectively achieve the goals of AB223/SB150, SB145, SB204, and of course SB146. The Company will be evaluating a variety of activities and/or tools for efficient utility operations and coordinated program efforts.

Section 4. Barriers to Deployment of Distributed Resources

As set forth in Section 1.5.(e) of SB146 and in more detail in Section 3.5 of the new DRP regulations, one of the required elements of a DRP is a discussion of potential barriers to the deployment of Distributed Resources. The Company has identified several potential barriers to the deployment of Distributed Resources during the development of this initial DRP. They can be grouped into three categories:

- Integration/Interconnection of Distributed Resources with the Distribution Grid:
  - As the number of requests to interconnect Distributed Resources increases, additional resources and modification of the interconnection process may become necessary.
  - As the types of Distributed Resources technologies increase, interconnection tariffs may need to be modified.
  - Where an individual Distribution Resource fails to deliver its anticipated benefits at the anticipated costs, the entire portfolio of Distributed Resources may be impacted.
- Market Limitations on the ability of Distributed Resources to deliver promised benefits:
  - DER participation in the wholesale energy marketplace is in its infancy.
  - Resource performance and intermittency is an issue that may have to be addressed contractually.
  - Ability of Distributed Resources to fulfill market demand as well as local reliability needs.
  - Potential cost of Distribution Resource technologies, including integration costs.
- Distribution system operational and infrastructure capability to handle Distributed Resource Value:
  - High penetrations of Distributed Resources can lead to poor voltage regulation, utility equipment overloads and reliability concerns.
  - Limited visibility of DER locations and impacts to the system operators.
  - Limited ability to granularly forecast Distributed Resources and their impacts to system conditions.
  - Operational constraints should be monitored, communicated and enforced to meet local system needs.

The Companies developed some potential solutions that could address these barriers, which are captured in Figure 12 below:

FIGURE 12:
POTENTIAL BARRIERS TO DER DEPLOYMENT

Barriers to Deployment	How the DRP can help to address	Status
Integration and Interconnection of DER on the Distribution Grid • Individual DER failure impacts entire portfolio of DER • Increasing DER interconnection requests review resources interconnection process. • As the types of Distributed Resources technologies increase, interconnection tariffs may need to be modified.	• Review and modify (if necessary) interconnection process to handle growing number of DER requests • Review and modify (if necessary) interconnection rules/tariffs to accommodate growing number of emerging DER technologies • Provide additional useful information to developers so they are able to customize and target solutions	• Complete • Complete • Complete
Market limitations on the ability of DER to provide benefits • DER may be limited in the ability to participate in the wholesale energy marketplace • Resource performance and intermittency is an issue • Ability of DER to meet market as well as local reliability needs • Potential cost of DER technology and integration costs	• Provide DER forecasting methodology to better evaluate resource availability and intermittency, investments and changes needed to integrate • Develop contracts to mitigate DER performance and reliability issues • Evaluate potential cost of DER technology and integration costs within the context of benefits, services, and alternatives • Provide system value to DER through non-wires alternatives based on Locational Net Benefit Analysis	• On going • To be developed • On going • On going
Distribution system operational and infrastructure capability to handle DER • High DER penetration can lead to poor voltage regulation, utility equipment overloads and reliability concerns • Limited visibility of DER locations and impacts to system operators • Limited ability to granularly forecast DERs and their impacts on system conditions	• The DRP will identify the necessary investments in operational tools, devices and systems to overcome challenges posed by increased DER penetration such as voltage regulation, equipment overloads, protection, reliability and operational constraints and to forecast and study system conditions • Develop pilot and demonstration projects to test technologies and develop a better understanding of forecasting DERs and their impacts on operations and reliability.	• On going • On going

Section 5. Coordination with Integrated Resource Plan and Other Legislative Actions

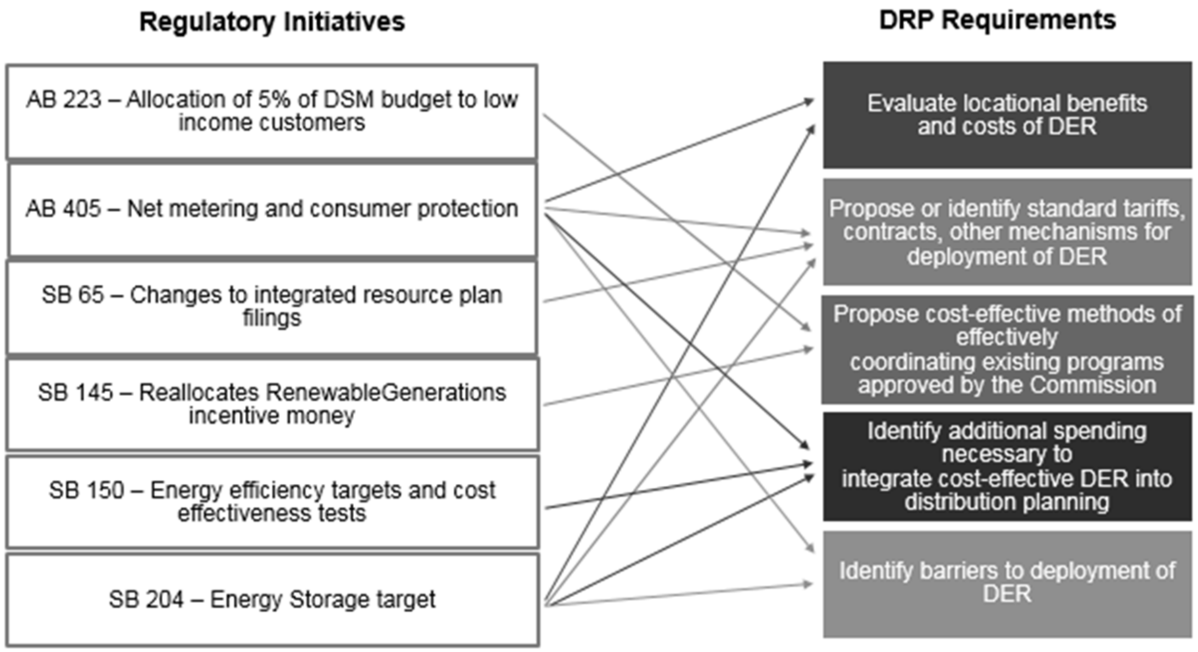
The evaluation of Distributed Resources as alternatives to investment by the utility in traditional wired solutions has not affected the need for the evaluation of load forecasts, demand-side, supply-side and transmission assets in the resource planning process. In developing the IRP, NV Energy incorporates the latest information available to forecast the adoption rates and energy use and savings characteristics of all Distributed Resources. NV Energy will continue to monitor the deployment of Distributed Resources through both existing Commission-approved programs and the DRP process, and will assess the impact of these resources in future IRPs.

In working with the Commission and stakeholders to develop the Temporary Regulation, it was important to recognize the requirements of related bills that were also passed out of the 2017 Nevada Legislative session. Together, six other related bills played a key role in the development of this DRP. As a reminder, these bills were discussed in detail in Sections 3.C., 3.D. and 3.E. They are listed again below for convenience.

- Assembly Bill 223 ("AB223") -- AB223 now requires that energy efficiency programs be evaluated as a group as opposed to individually. This new approach would allow for a program that is uneconomical on a standalone basis to now potentially be justifiable.
- Assembly Bill 405 ("AB405") -- AB405 changes how private generation or net metering is to be compensated for excess energy and provides for consumer protection to rooftop solar customers.
- Senate Bill 65 ("SB65") -- SB65 broadens the participation in the upfront planning process by engaging all interested parties and requires that long term resources be selected taking into consideration the environmental and social attributes of a resource.
- Senate Bill 145 ("SB145") -- SB145 provides for incentives to be paid for storage technologies similar to incentives paid for solar wind and hydro private generation. SB145 also calls for the development of an electric vehicle demonstration program and finally the bill requires the company to fund $1 million from 2018 thru 2023 for low income solar energy systems and distributed generation systems.
- Senate Bill 150 ("SB150") -- Similar to AB223, but in addition calls for the Commission to establish goals for energy efficiency to be included in the integrate resource plan.
- Senate Bill 204 ("SB204") -- SB204 calls for the Commission to establish targets for energy storage by October 2018 if after conducting a study energy storage is deemed to be cost effective.

Together with SB146, these six related energy bills interface or touch each other in some fashion. It was crucial in the development of the Temporary Regulations implementing SB146 that the Commission consider how these other bills overlapped with each other, as illustrated in Figure 13 below:

FIGURE 13:
DRP IMPACT ON AND SUPPORT OF OTHER REGULATORY INITIATIVES



Several of these bills established new mandates. When a particular technology is mandated, the Company's ability to evaluate other potential DRP options is reduced, including those that may be lower cost to solve grid constraints.

To effectuate the changes in the IRP regulations required to implement SB146, a new Section was added that identifies the time-frame for determining the HCA, the requirements for determining the locational benefits and costs of Distributed Resources, and other elements of the DRP. While NAC § 704.9225 requires that the Companies present a 20-year load forecast for long term integrated planning, the DRP requires a shorter timeframe for forecasting, with a minimum of six years beginning with the year after the DRP is filed. Additionally, like the existing IRP process, if there is a need to modify the DRP within the approved three-year action plan, the Company will file an amendment or update to the plan in a similar manner to the method used for an IRP amendment as described in NAC § 704.9503.

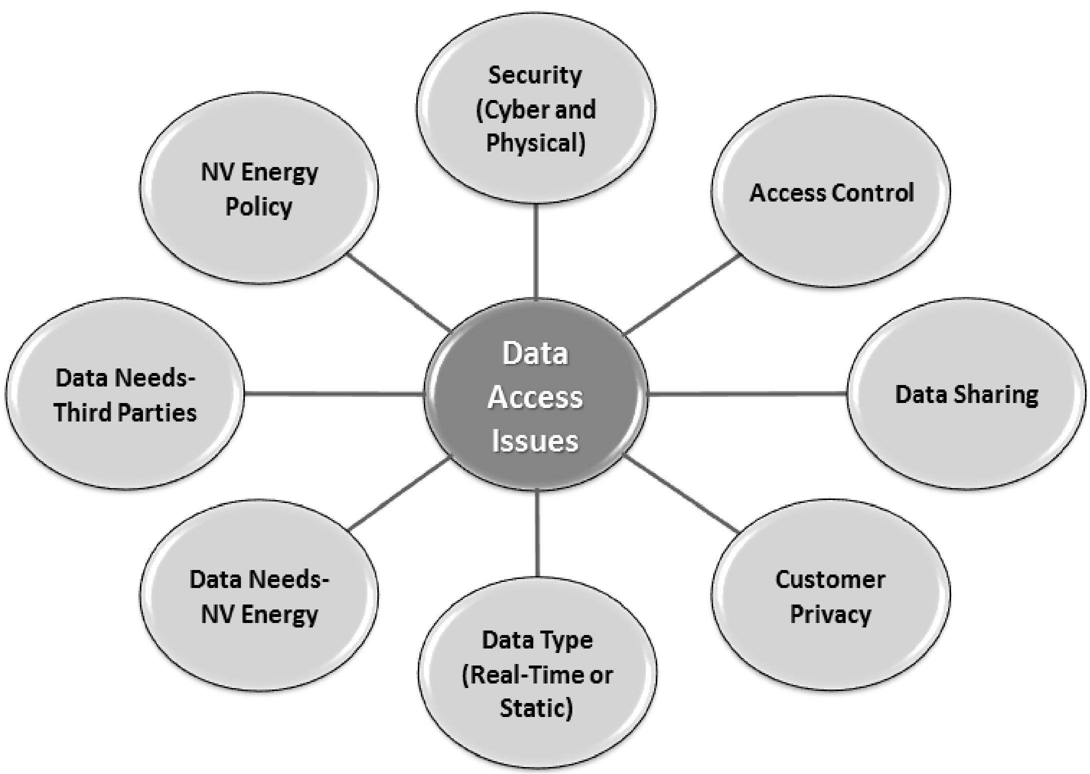
Section 6. Data Sharing, Access and Security Issues

Data sharing, access and security issues are hotly contested in other jurisdictions. Initially, considering the low level of DER penetration today on the Companies' distribution systems, requirements for data sharing, access and security could have been postponed to later DRPs. However, NV Energy ensured that these issues were addressed head-on during the stakeholder process. Now, DER developers will be able to focus on areas of potentially low cost interconnection and integration, thus minimizing their costs of customer acquisition and system costs for customers. This should also minimize the costs of integration as a whole for NV Energy for low penetration conditions. As the program advances, techniques to inform the industry and public of areas to concentrate DER will be developed. Cyber-security, customer information and privacy concerns were core to NV Energy's concerns as this area was developed.

Data sharing is vital to developing least cost DER integration solutions on the distribution system. NV Energy's goal was to provide useful and timely information to all stakeholders while maintaining the data security and confidentiality that customers expect and that is required for the safety and security of the grid. The Companies worked with Stakeholders to ensure their use cases for the available data were understood and how it would best be shared with Stakeholders.

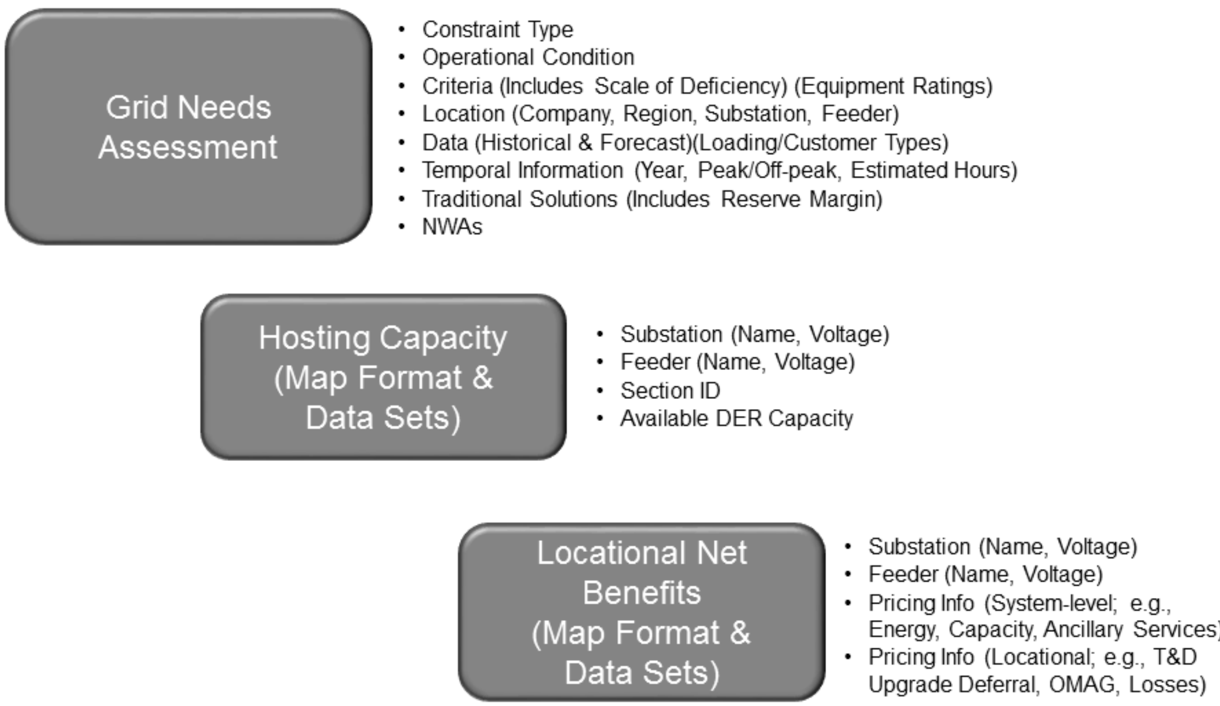
Several challenges in providing the additional transparency and data sharing were evaluated and discussed, as illustrated below in Figure 14:

FIGURE 14:
DATA ACCESS CHALLENGES



In working with stakeholders to understand the data they are seeking in order to promote their distributed resource products and services, the data behind three elements of the analysis were identified as being particularly important to industry representatives: the Grid Needs Assessment, the Hosting Capacity Analysis, and Locational Net Benefit Analysis. Figure 15 below illustrates these three specific areas and the associated data that has been provided to stakeholders through the new DRP publicly-accessible web portal.

FIGURE 15:
WEB PORTAL DATA



The historical and forecast load data will be available for download by clicking on the icon on the upper left of the Web Portal screen (looks like three parallel lines). This data is also provided in **Technical Appendix Items DRP-1 and DRP-2**. Also, the NWA data is available within the GNA Summary Table as a separate worksheet tab in the download file, and is provided above in Figure 6.[37] Finally, the customer type information is not available through the Web Portal. This data will be available through the Web Portal either in the 4th quarter of 2019 or 1st quarter of 2020.

As is discussed below, utilities are vested with the responsibility to ensure safe and reliable service to not only customers within their service territories but also to users of the utility grid. It was thus important to identify the information regarding the electric grid that would need to remain confidential, and thus redacted from the public data sharing effort discussed above. NV Energy

[37] As discussed below in Section 7, as of the date this filing the file download capability is not yet available.

reviewed recent proceeding from California,[38] as well as its internal policies and procedures, to determine what information should be placed into the public domain in Nevada.

Based on this review, it was determined that information regarding feeders that serve a specific customer set identified by specific criteria, and not necessarily the substation and/or other feeders from the substation that do not provide service to this customer set, would be subject to redaction. The following seven criteria were used to determine which facilities would be identified for redaction:

- Distribution Facility necessary for black start, or capability essential to the restoration of regional electricity service and/or subject to North American Electric Reliability Corporation Reliability Standard CIP-014-2 or its successors;
- Distribution Facility that is the primary source of electrical service to a military installation essential to national security and/or emergency response services (may include certain air fields, command centers, weapons stations, emergency supply depots);
- Distribution Facility that serves installations necessary for the provision of regional drinking water supplies and wastewater services (may include certain aqueducts, well fields, groundwater pumps, and treatment plants);
- Distribution Facility that serves a regional public safety establishment (may include County Emergency Operations Centers; law enforcement headquarters; major state and county fire service headquarters; county jails and state and federal prisons; and 911 dispatch centers);
- Distribution Facility that serves a major transportation facility (may include an international airport, and other air traffic control center);
- Distribution Facility that serves a Level 1 Trauma Center(s); and
- Distribution Facility that serves over 60,000 meters.

After reviewing the facilities that met the above criteria, the Companies developed a list of feeders that would be redacted from the DRP public web portal. Utilizing this list, 306 feeders (or approximately 23 percent of all feeders) were redacted from the data set.

[38] California Public Utilities Commission Docket No. 14-08-013 (July 24, 2018).

Section 7. Publicly-accessible Web Portal

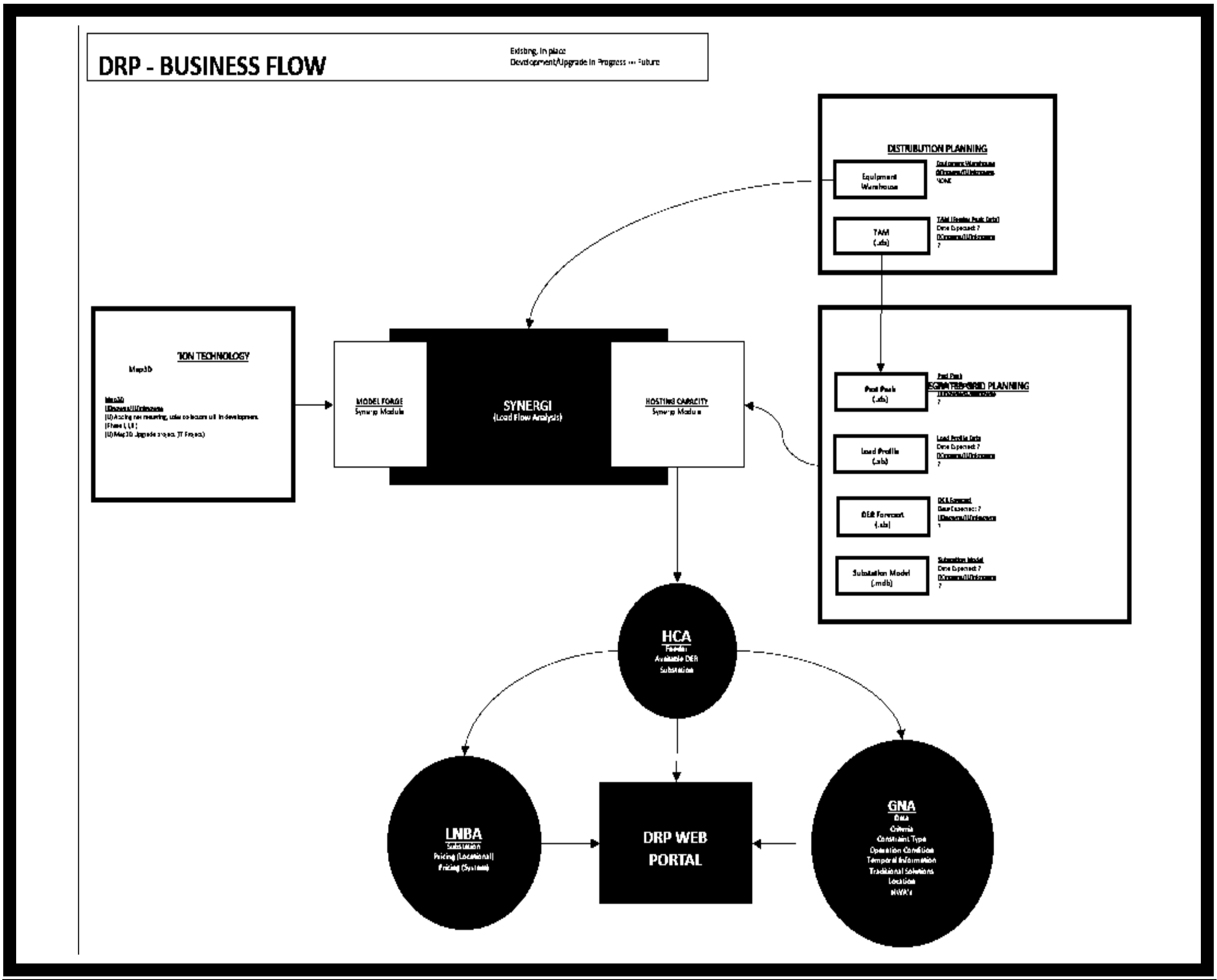
The goal for developing the publicly-accessible web portal was to ensure functionality and user friendliness that would assist third-party participants searching for information to assist them in making quality decisions in siting Distributed Resource solutions. To this end, the Companies reviewed and leveraged the modeling the major California investor-owned utilities ("IOUs") utilized in their web portals, and adopted the same platform (developed by Environmental Systems Research Institute or "ESRI") to display NV Energy's data. The Companies also contracted with Wipro Ltd. to leverage their expertise in building this type of a mapping/web tool.

Understanding current processes, data, technology, and systems gives the Companies and third-parties better visibility into the determination of the HCA results for the Uniform Generation Capacity, Solar PV Capacity, and Uniform Load Capacity analysis cases (discussed in Section 3.A.2 above) for all eight regions of NV Energy's service territory; five in Nevada Power's service territory (NPC-NW, NPC-NE, NPC-SW, NPC-SE, and NPC-Strip) and three in Sierra's service territory (SPPC–TM, SPPC-Carson, and SPPC-Eastern).

During a series of internal technology and process workshops for this DRP web portal project, three flow models emerged as requiring additional analysis: Business Flow, System Flow, and Data Flow. The Business Flow model is outlined below.

The Business Flow diagram in Figure 16 illustrates the understanding that existing feeders, substations, solar net energy metering installations, and service transformers in AutoCAD Map 3D get connected with specific relationships within the utility assets through a Model Forge process within the Synergi load flow program. Recall that Synergi is the load flow analysis software provided by DNV-GL which NV Energy uses to model its distribution system. It reads the Model Forge network established connections and establishes sections of feeders that are connected to specific power transformers at a substation. In the modeling, there are bus bar conductors at the service transformers whose length is negligible when viewed in AutoCAD Map 3D GIS and whose minimal impedance does not affect the Synergi load flow results. It is on these conductors that the local residential or commercial load as well as any existing installed DER is modeled. Upon completion of the HCA, the feeder sections will display the incremental Hosting Capacity when a user clicks the section of interest.

FIGURE 16:
BUSINESS FLOW DIAGRAM



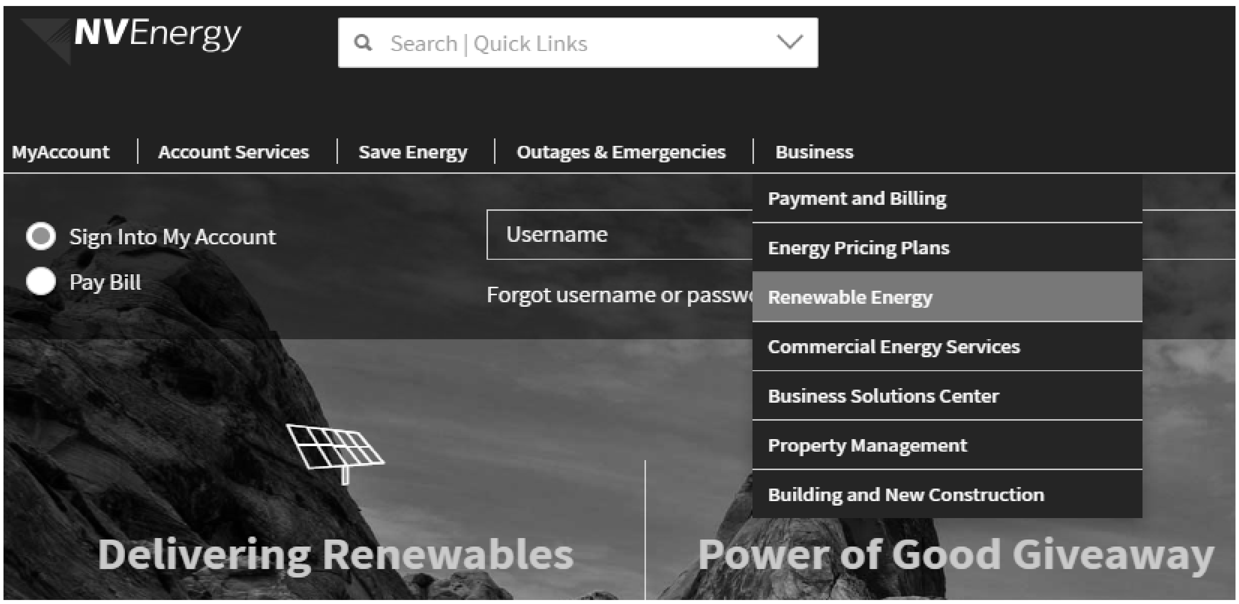
Three key databases are outputs from the HCA in Synergi:

- Transformer/Feeder Model (X, Y, Section ID)
- Results (24 Hours) Uniform Generation/Load
- Results PV (daytime) DER Forecast

In working with stakeholders, the Companies developed three distinct screens to display the results of and data associated with the Grid Needs Assessment, Hosting Capacity Analysis, and Locational Net Benefit Analysis. The data shown on each of these screens was shown on a previous page. The data on these screens also shows color-coded distribution facilities (green, amber, red) to allow users to quickly find areas on the electric grid that have constraints, greater ability to incorporate new DER capacity, or enhanced benefit of locating DERs in a given area.

Regarding the user experience, accessing the DRP Web Portal will have two distinct reference points from the public www.NVEnergy.com website. To ensure compatibility the user will need to use the Chrome web browser. Once users navigate to www.NVEnergy.com, in the top main menu bar, under "Business" they can click "Renewable Energy."

FIGURE 17:
NV ENERGY PUBLIC WEBSITE



On the 'Clean Energy' page displayed, at the bottom, the user will note an area entitled 'Distributed Resource Plan Portal', beneath which there is a "LEARN MORE' button. The second access point will be under Clean Energy after you get to the NV Energy website. Once users click on the 'LEARN MORE' button, the login screen is displayed (which contains additional text about the DRP and the portal itself) along with links to 'Register New User' and 'Forgot Password'. For simplicity, there are no other links to other sites or pages in this login screen.

Multifactor Authentication ("MFA") is a requirement for all external (public) facing applications developed by NV Energy. Since NV Energy's current authentication functionality does not yet support e-mail as an authentication factor, the MFA process uses a smartphone application-based authentication using "Okta Verify." Prior to user registration, the user will need to install the "Okta Verify" application on their smartphone. After successful registration, the user will login with their credentials (username + password), the user will then be prompted to enter an OTP (one-time password) which is provided via "Okta Verify".

The Web Portal will be accessible directly at **https://drp.nvenergy.com** by the end of April 2019. Challenges were encountered in ensuring the Web Portal meets all updated cybersecurity requirements of the Companies. Associated with these requirements, as of the date of this filing, the data download capability is not yet active. The Companies are working diligently to make this capability available as soon as possible.

Screen shots of the Web Portal are provided in **Technical Appendix Item DRP-5**.

Section 8. Refining Distributed Resources Plan Elements

Upon passage of SB146, one of the initial deliverables in developing the path toward this DRP was a gap analysis between the Companies' then-current processes and tools and what capabilities would need to be in order to produce a DRP. Figure 18 below captures this initial analysis:

FIGURE 18:
INITIAL GAP ANALYSIS FOR DRP PROCESSES AND TOOLS

	Current Status	Gaps to Close for DRP
Methodologies	• DER forecasting is top down at the system level • Iterative Hosting Capacity methodology is the preference but no process in place • Non-wires Alternatives (NWA) suitability criteria initial draft is developed	• Make decision on suitable approach for bottom up DER forecasting • Develop process to use iterative Hosting Capacity methodology for representative circuits • Identify elements to inform NWA suitability criteria
Software and Tools	• ADMS capability in place • AMI and SCADA deployment for large parts of the system provides potential for granular data	• Evaluate the need for and timing of additional operational, monitoring and control systems • Make a decision on forecasting software • Make a decision on customer facing web portal to present Hosting Capacity of circuits.
Processes	• Interconnection process is well laid out and documented via Rule 15 • Developing additional NWA criteria and opportunity identification as part of the capital planning process • Mature IRP process developed	• Evaluate the need for modifications of Rule 15 to incorporate elements (i.e., IEEE 1547 advanced inverter functionality) • Preserve IRP regulatory approach and incorporate DRP in that process that forecasts and quantifies customer adoption of DER • Incorporate DER, Hosting Capacity, net benefit analysis into distribution planning "tool box" • Determine pace of Hosting Capacity analysis relative to DER adoptions (actual and forecast)
Timing and Coordination	• Activities currently take place within "silos" • Limited visibility over timeline and impact of activities on other projects and initiatives	• Establish a logical sequence of planning activities that encourage collaboration across teams within the utility • Identify departmental dependencies • Create DRP focused role in each impacted department
Stakeholder Engagement	• Typical engagement through investigatory dockets • No other present forms of stakeholder engagement	• Initiate utility led stakeholder engagement process • Develop overall stakeholder engagement strategy and topic-specific engagement models • Focus on the "what" and don't get bogged down in the "how"

Most of the above-identified gaps are addressed either directly or indirectly in the areas discussed below, but all have been addressed in some manner either during the development of this filing or will be going forward.

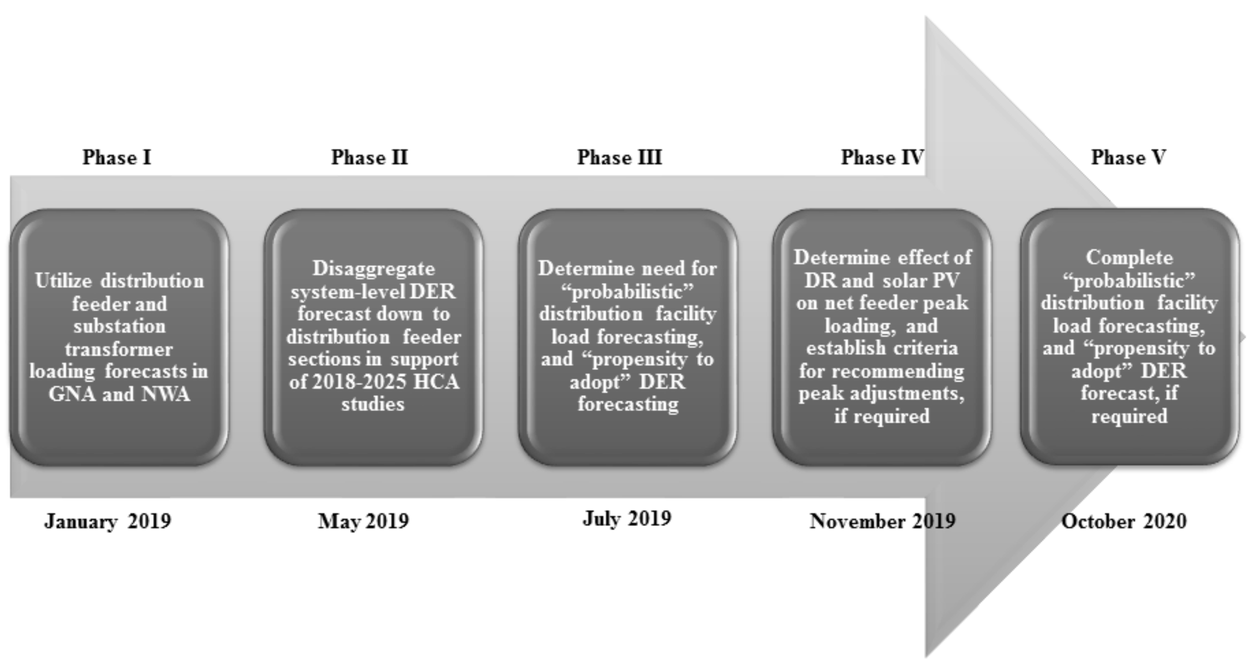
A. Load and Distributed Resource Forecasting

Ultimately, advanced, multi-scenario forecasting methods will be required to forecast load and Distributed Resource adoption at the feeder level. This will necessitate the construction of a bottom-up forecast, as opposed to the top-down system forecasting performed to support triennial IRPs. Advanced forecasting methods will need to account for growth, customer adoption rates, customer consumption profiles, and Distributed Resource profiles at a more granular level (*i.e.*, more precise than the feeder level).

Software tools and methodologies for producing distribution resources plans are evolving and improving. Continued investigation, as discussed in Section 8.H. below, will be vital to advancing the DRP process in Nevada. Stakeholder engagement was helpful in selecting methodologies and refining inputs on initial adoption rates and characteristics. Unlike Hosting Capacity where the tools already exist and only need incremental changes, advanced forecasting will require new software investment, procedures and methodologies. More accurate advanced forecasting should develop as improvements in complexity and thoroughness and actual data refine the models. Incremental improvements will continue as DER adoption rates increase providing more data on load behaviors and DER characteristics.

Figure 19 below depicts the planned refinement of load and DER forecasting:

FIGURE 19
LOAD AND DER FORECASTING REFINEMENT TIMELINE



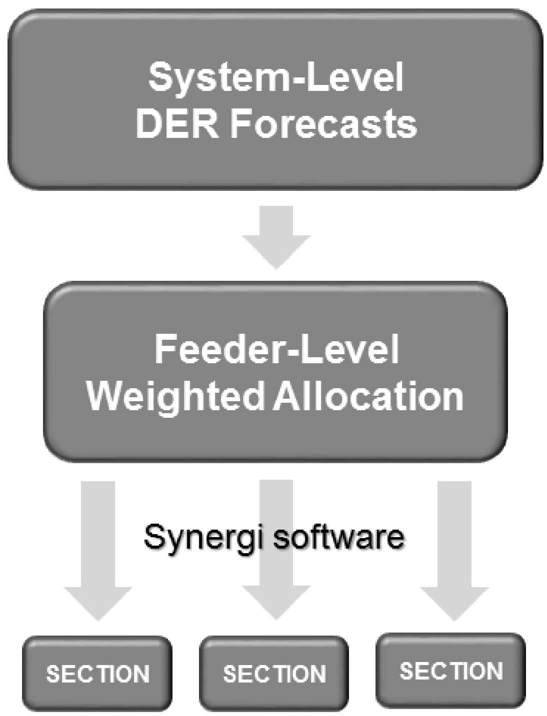
Phase I

This initial phase was completed for this filing, as explained in Section 3.A.1.a above.

Phase II

Presently, NV Energy's DER forecasting is compiled at the system level. In order to support future year HCA studies at the distribution feeder section level, forecasted incremental DER capacity at a more granular (*i.e.*, feeder) level is required. In the next phase of development, NV Energy will move to a method of estimating DER capacity increases in future years on distribution feeder sections by disaggregating the system-level DER forecast down to the primary section (or node) level, as depicted in Figure 20 below:

FIGURE 20:
DER FORECAST DISAGGREGATION



The databases in Synergi will contain the existing DER capacity for each distribution feeder section through the base 2017 HCA. By examining the existing aggregate DER capacity on each feeder, a weighted allocation will be performed to disaggregate the incremental system-level DER forecast amounts down to the feeder level. From there, Synergi is able to perform a weighted allocation of whatever incremental DER capacity is provided at the feeder level down to the section level based upon whether or not the section has existing DER capacity on it and what amount that may be.

The Companies acknowledge that this still represents a top-down approach for determining how incremental DER capacity will be added to distribution feeder sections in future years. However, this phase acts as an initial step in allowing the first set of future year HCA studies to be conducted and initial results provided. A more advanced method of DER forecasting is discussed in Phase III.

Phase III

NV Energy's Distribution Planning department has traditionally performed "deterministic" load forecasting, where a single forecast is produced for each distribution feeder or substation transformer. However, load forecasting by its very nature is a probabilistic endeavor. As such, in Phase III, the Companies will determine if multi-scenario, probabilistic-type distribution load forecasting is necessary to support the advancement of DRP activities. A similar question presents itself for DER forecasting. The Companies will also examine this question, along with the need for a "propensity to adopt" forecasting method for DER.

Phase IV

If there are no DERs on a distribution feeder, then the loading reads for that feeder, normally taken at the feeder breaker at the substation, reflect the gross load (including losses) on that feeder. However, the loading reads for feeders with DERs are reflective of the net loading on those feeders, i.e., reflective of the effect of the DERs in changing the loading of the feeders as seen at the substation. If the effect of the DERs is removed, then the loading on the feeder will reflect the gross load on the feeder. This is important to understand when variable DERs are present on feeders, many or all of which the utility may not have any control over.

The three most prevalent DERs present on NV Energy's distribution feeders are Energy Efficiency, Demand Response, and behind-the-meter solar PV. Energy Efficiency works differently in that it reduces the actual energy requirement of certain components of a customer's load on a continuous basis, and so it affects a customer's gross load. Demand Response and solar PV, however, are variable in that DR is not run continuously and solar PV output varies with time of day, season, and cloud cover or shading.

While the vast majority of NV Energy's distribution feeders have low existing penetration of DERs, there are some where the penetration level may be appreciably affecting the net peak loading of the feeder in an amount that may necessitate adjusting the peak loading value to account for the effect of the DER. In this phase, the Companies will determine what this effect may be, whether or not to recommend adjustment of peak loading values for feeders, and if so, how and when to do that.

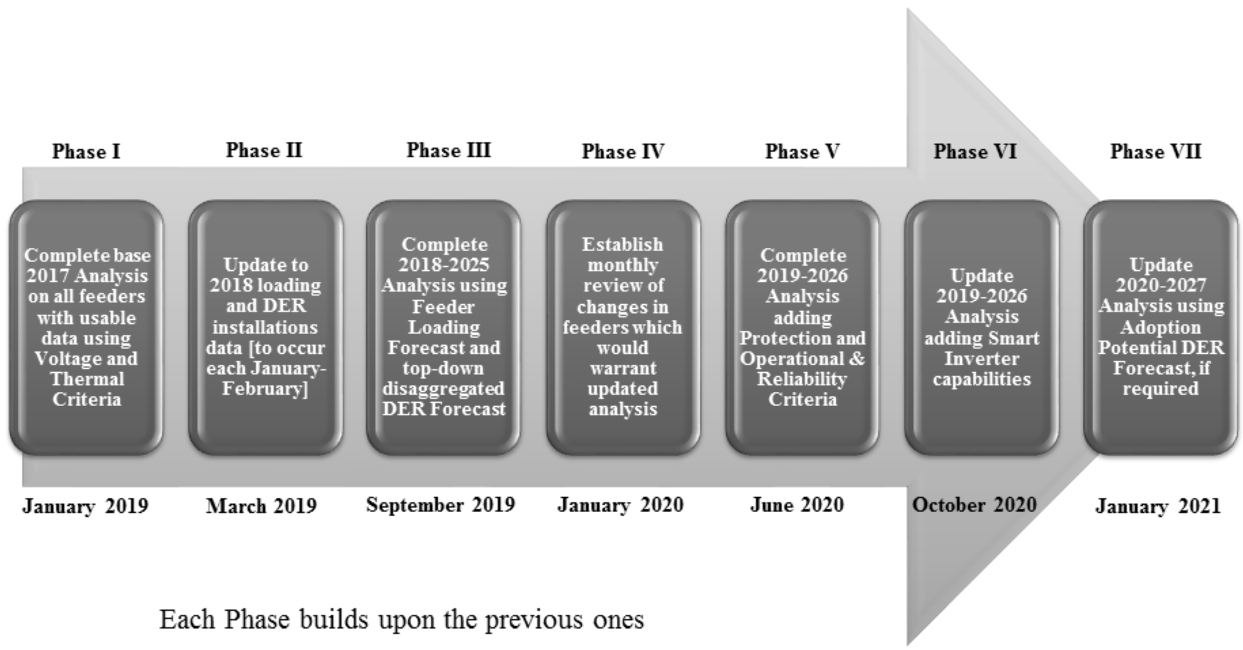
Phase V

Based upon the results of Phase III, if it is determined that NV Energy will transition to probabilistic load forecasting and "propensity to adopt" DER forecasting, this phase will mark when those efforts should be completed.

B. Hosting Capacity Analysis

Throughout the stakeholder process conducted over the last year, NV Energy consistently indicated that the methodology used for the HCA in this DRP filing would be only the initial method used to ultimately perform that analysis. Figure 21 below outlines the growth of the HCA methodology that NV Energy plans to achieve through 2021:

FIGURE 21
HOSTING CAPACITY ANALYSIS REFINEMENT TIMELINE



<u>Phase I</u>

The initial phase of the HCA was completed for this filing, as explained above in Section 3.A.2.

<u>Phase II</u>

NV Energy plans to "reset" the feeder loading data and installed DER data used for the HCA in this second phase. As the initial HCA used a 2017 data set, moving forward, the data set used for the HCA in Synergi should be updated to reflect the most recent year of full annual loading data, installed DER capacity, and feeder topology.

<u>Phase III</u>

Building off Phase II, NV Energy plans to proceed with its HCA for future years in Phase III. Since the initial Phase I analysis was based upon 2017 data, in order to obtain a complete set of information for all years, this phase will begin with 2018 data. Since the HCA must contain information for a minimum of six years beyond the year of this DRP filing, the analysis will extend to and include 2025.

The Companies intend to use the most updated distribution feeder forecasts to create forecasted future year feeder loading data by comparing the 2017 peak loading to a future year forecasted peak loading, and inflating each loading data point by that ratio (percent change in peak loading) for that future year.

Since only system-level DER forecasts are available at this time, for Phase III the Companies will utilize a top-down disaggregation approach to determine forecasted increases in solar PV by distribution feeder for the future years of the analysis by applying increased solar PV capacity to feeder sections that presently have solar PV installed. The Companies understand that this initial disaggregation method does not necessarily well simulate the potential growth of solar PV on distribution feeders and limits forecasted additional solar PV to feeder sections that already have such installations. However, this simple method will only be an interim step towards a more robust and accurate method of forecasting the potential growth of DERs both in terms of capacity and locations that is proposed in Phase VII below.

Phase IV

In Phase IV, to streamline the process of updating the forecasted future Hosting Capacity of feeders, and avoid having to run the HCA on all distribution feeders in all future years, the Companies will develop a method to identify which feeders have had, or are forecasted to have, changes on them that would appreciably affect the Hosting Capacity value. This will target efforts towards only the feeders where the Hosting Capacity value would have reason to change in the future. NV Energy intends to develop a process in which a review would take place monthly to detect which feeders require updated analysis, and updated HCA would be run thereafter.

The preliminary criteria that the Companies are considering to make this determination are:

- Voltage Conversion: Has a voltage conversion of the feeder or on part of the feeder taken place?
- Loading Variation: Does the load forecast for the feeder show a TBD percent or more increase or decrease when compared to the past year's peak loading or compared to any future year's forecasted peak loading within the planning horizon?
- Reconfiguration: Has the feeder been reconfigured through permanent switching?
- Reconductoring/Phasing: Has any section of cables/conductors making up the feeder been reconductored (or phases added)?
- Voltage Controlling/Regulating Devices: Has a device that either directly controls or affects voltage, such as a line voltage regulator and/or capacitor, been installed or removed from the feeder?
- Customer Class Composition: Has the composition of any of the customer classes on the feeder changed by TBD percent or more?
- DER Capacity Additions: Does the total DER capacity of recent interconnection applications on a feeder equal at least X kW or represent TBD percent of the feeder's installed DER capacity?

- Protective Devices/Settings: Has a protective device been installed/removed (e.g., line recloser) or settings been changed?

Phase V

Prior to this phase, the HCA will have been completed utilizing thermal, voltage, and reverse power flow limitations (although any Hosting Capacity results on the basis of reverse power flow limits were initially not used). In this Phase, NV Energy will add_appropriate protection and operational/reliability related criteria. The main reason for conducting the HCA up until this point to provide results based upon reverse power flow limitations was to provide initial information towards the eventual consideration of protection-related criteria. Internal discussion will need to take place in this phase with the Companies' system protection and operations departments to determine the appropriate method of introducing these potential limiting criteria into the HCA.

The HCA for all feeder sections will then be updated, accounting for any additional criteria, once another requisite change to the model of NV Energy's distribution system in Synergi is completed. Since the present system model does not contain the appropriate information for Synergi to properly run protection-related studies, the system model will need to be updated in this phase with the appropriate information (e.g., zero-sequence impedance) for these studies to be run within the HCA.

Phase VI

Currently, the model of NV Energy's distribution system in Synergi does not discreetly model the inverters associated with solar PV installations (or other inverter-based DER technologies). As discussed below in Section 8.F., the integration of smart inverter capabilities into the Companies' Rule 15 and internal standards will to take place within approximately the next two years. NV Energy understands that certain capabilities of smart inverters could improve Hosting Capacity by addressing the limiting factor in the HCA for given feeders. The Companies will attempt to incorporate smart inverter modeling into its Synergi model, and subsequently update the HCA for all feeders.

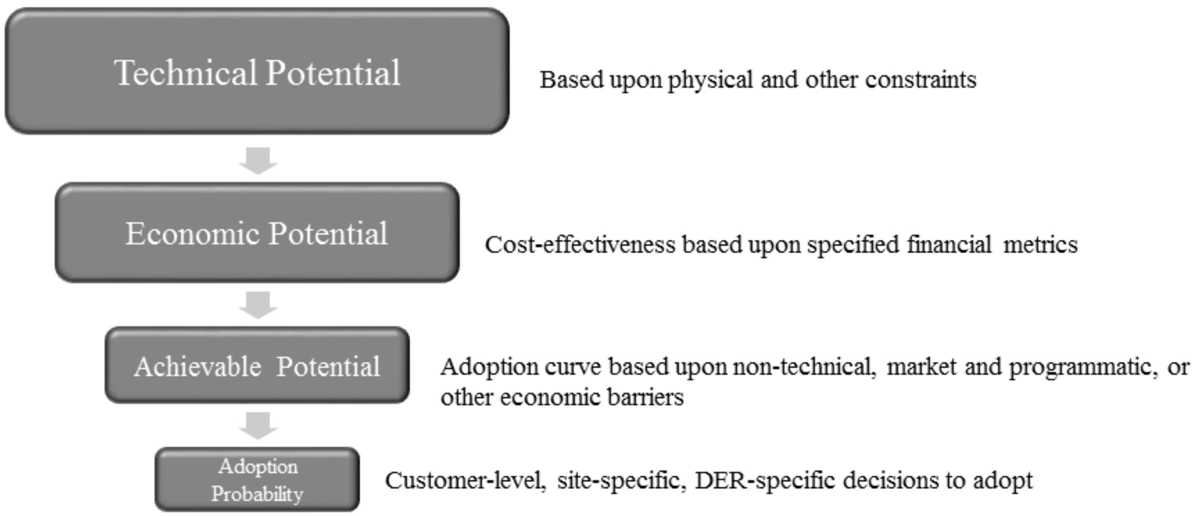
Phase VII

As adoption and penetration of Distributed Resources increases, it will become even more important to forecast how much, when, and where different types of DER will reside. In this Phase, NV Energy may develop a method of "customer adoption forecasting" for at least some Distributed Resource technologies, and so will advance from a top-down disaggregation method of allocating forecasted DER growth down, to a robust bottom-up approach.

There are several aspects to "customer adoption forecasting" which are important to understand. Economic and Achievable Potential are defined relative to the theoretical maximum, which is the Technical Potential. Technical Potential would be the total DER capacity that could be installed in an area based upon available or projected technology, without consideration of cost or willingness of users to adopt the technology. Economic Potential is the subset of Technical Potential in which a cost-effectiveness test would be applied, understanding that not all technically-feasible installations would take place due to cost considerations. Achievable Potential is a subset of

Economic Potential and is what could be realistically achieved given real-world constraints, including market and programmatic barriers, policy goals, and the rate at which homes and businesses could actually adopt the technology. Adoption Probability refers to what level of adoption could be realistically expected on the basis of actual program funding levels and actual marketing programs, and the fact that it is known that not all that is achievable will actually be realized in the form of actual customer decisions to adopt a technology. Figure 22 below illustrates this concept:

FIGURE 22:
CUSTOMER ADOPTION PROBABILITY

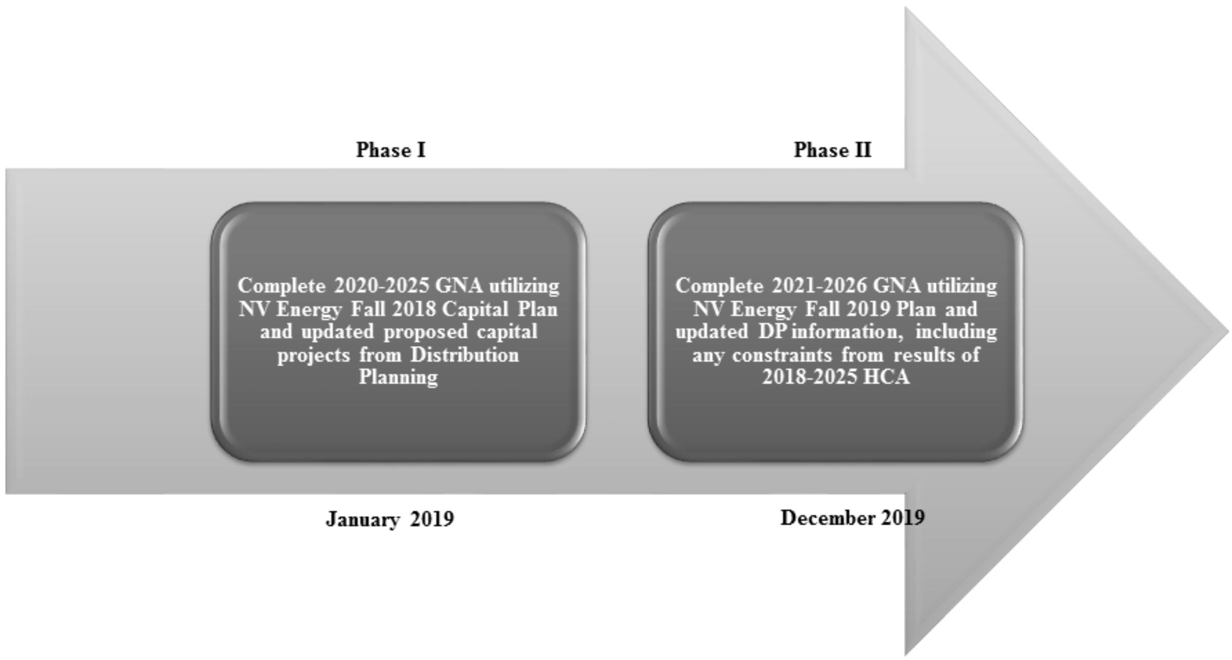


This phase ensures that the DRP that is filed as part of the Companies' required IRP by June 2021 contains a minimum of six years of information beyond the year of the filing. As such, the HCA results should be completed through and including at least the year 2027.

C. Grid Needs Assessment

Although the Grid Needs Assessment process for this DRP filing represented the first time that NV Energy had gathered and presented certain information about the existing or forecasted constraints on its grid (particularly with respect to the estimated number of hours or days that a deficiency was forecasted to exist), the Companies do not foresee significant changes to the method by which the Grid Needs Assessment was developed. The exception is that the Companies plan to include in the GNA any constraints determined on the basis of HCA results, as Figure 23 below simply reflects:

FIGURE 23:
GRID NEEDS ASSESSMENT REFINEMENT TIMELINE



<u>Phase I</u>

The initial phase of the GNA was completed for this filing, as explained above in Section 3.A.3.

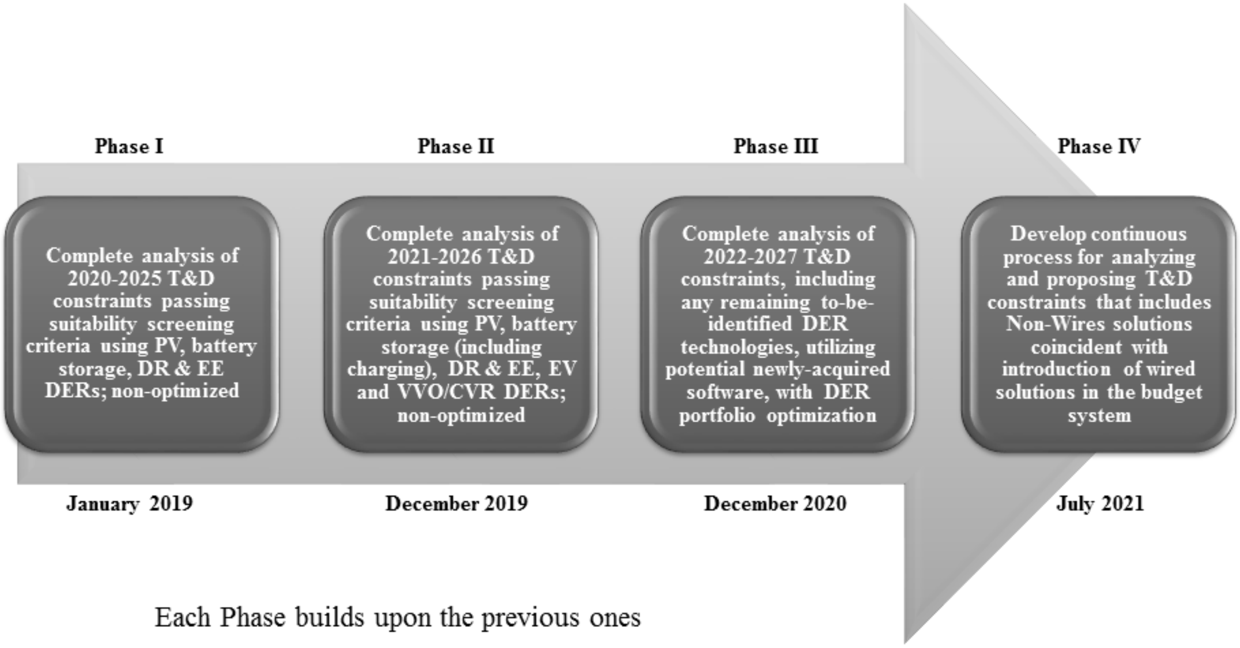
<u>Phase II</u>

This phase represents the next iteration of the GNA, ensuring that the timeframe captures the upcoming six year period of 2021-2026, utilizing the updated NV Energy 2019 Capital Plan, and updated information from the Distribution Planning department. Since the Companies plan to complete future year HCA studies in September 2019 (see Figure 21 above), this iteration of the GNA, and those going forward, will include any identified constraints from that analysis in addition to traditional thermal, voltage, or reliability constraints, and identified traditional wired solutions.

D. Non-Wires Alternative Analysis

While NV Energy has performed Non-Wires Alternative analysis before, this DRP marks a step forward in terms of the Companies' concentrated efforts on both the T&D systems. Several continued improvements to the process have been identified, as illustrated in Figure 24 below:

FIGURE 24
NON-WIRES ALTERNATIVES ANALYSIS REFINEMENT TIMELINE



Phase I

The initial phase of the NWA analysis was completed for this filing, as explained above in Section 3.A.3.b.

Phase II

In this phase, the NWA analysis will move forward by adding potential technologies to the toolkit of options to address existing or forecasted grid constraints. These include electric vehicles and Volt-VAR Optimization/Conservation Voltage Reduction ("VVO/CVR"). For this DRP, the Companies only considered the discharging characteristic of battery energy storage systems (and assumed adequate charging time). Going forward, the effect of charging must be considered in the analysis in order to ensure that loading limits are not exceeded and sufficient charging time is available to allow the necessary discharging kWh to address the constraint. Also, the initial phase utilized an assumption that existing DR and EE could provide a certain amount of peak load and energy reduction. In Phase II, the analysis will analyze whether the existing location-specific capacities of these technologies can be increased to provide incremental benefits that can be captured in a portfolio solution.

Phase III

In Phase III, the Companies will investigate the possibility of further expanding the potential DER technology portfolio to include, for example, fuel cells, micro-turbines, and flywheels. The Companies will also consider aggregated behind-the-meter solar PV and energy storage pairings. Significantly, should the Companies decide to purchase software with the capability of performing

NWA analysis (see Section 9.C.), that software would be utilized to perform Phase III analyses, including cost and siting considerations.

Phase IV

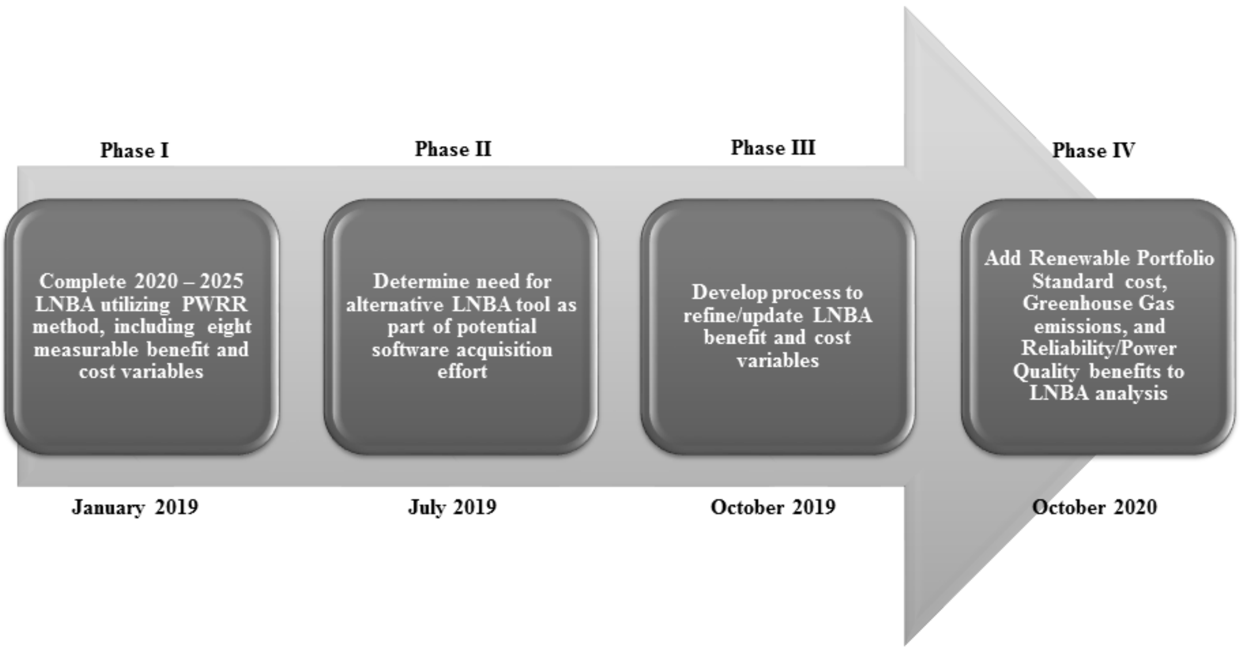
Rather than a NWA process that occurs in a set timeframe annually, NV Energy's goal is to consider non-wires solutions at the same time as traditional wired solutions are developed, and determine the appropriate solution when the capital project is first proposed in the Companies' Project Portfolio Management ("PPM") capital budget system. This process change could result in non-wires solutions being proposed as the solution to identified T&D constraints up front, instead of traditional wired solutions. This would truly integrate non-wires solutions into the planning framework and solution toolkit.

As discussed with the Stakeholder group during the "walk" phase NV Energy will be focused on using utility sponsored NWA solution portfolios. This approach will allow the Utilities to gain experience with NWAs, test technologies and test impacts on operations of the electric grid. As NV Energy moves through the "jog" and "run" phases, it will consider looking to the marketplace to develop the NWA solution based upon NV Energy's internal procurement policies such as issuing a Request for Proposals (RFPs) based upon a detailed constraint requirement. The Planning departments would then use these market driven NWA solutions and compare them to a traditional wired solution to ensure a cost-effective solution is implemented.

E. Locational Net Benefits Analysis

Conceptually, while it is not difficult to postulate that locating DERs at different places on the electric grid could yield different benefits, determining a method to truly and fairly quantify these locational benefits is more elusive. The ability of DERs to potentially provide benefit to the T&D system as well as the energy supply level complicates this exercise. Although there are further-reaching concepts like Distribution Marginal Cost, Figure 25 below illustrates the Companies' plan to refine and enhance the LNBA through 2021:

FIGURE 25:
LOCATIONAL NET BENEFITS ANALYSIS REFINEMENT TIMELINE



Phase I

The initial phase of the LNBA analysis was completed for this filing, as explained above in Section 3.A.3.c.

Phase II

As discussed above in Section 3.A.3.c., the initial LNBA for this filing was performed through the use of an internal spreadsheet tool developed by the Companies. This phase will integrate any needs determined for LNBA into the investigation of potential new software tools to support DRP functions, as discussed in Section 9.C.

Phase III

In this phase, the Companies will develop a process that will ensure continuous updating of the LNBA cost and benefit variables. Ultimately, the NWA process will work as a continuous process within NV Energy, and as the NWA analysis feeds into the LNBA, continuous updating of the LNBA variables will ensure that the best information is available to support integration of these into the integrated planning process.

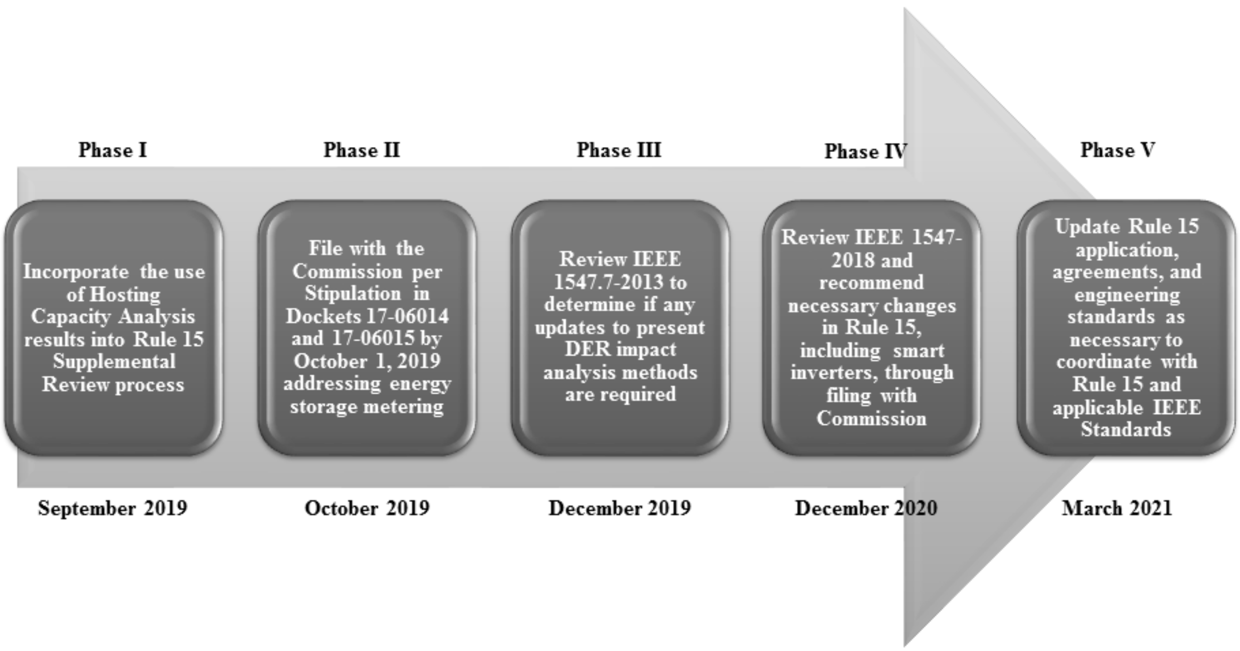
Phase IV

This phase will add any remaining variables to the LNBA, which at present, are defined as Renewable Portfolio Standard cost, Greenhouse Gas Emissions, and Reliability/Power Quality benefits, and would complete the initial 11 cost and benefit variables identified by the Companies as part of the LNBA.

F. DER Interconnection

With NV Energy now performing HCA and in light of the newly-updated IEEE Standard 1547-2018, changes to the Companies' Rule 15 will be required going forward. This is the main thrust of the planned progression shown below in Figure 26:

FIGURE 26:
DER INTERCONNECTION REFINEMENT TIMELINE



Phase I

One of the agreed-upon use cases for the results of the HCA common to both the understanding of the Companies and the stakeholders is to aid in streamlining the interconnection process for DERs. Presently, the Initial Review process in NV Energy's Rule 15 contains a screen in which the aggregate (existing plus newly proposed) generating facility capacity on a line section is compared to the peak loading of that line section, and if that ratio is less than 15 percent then the proposed DER installation passes that screen[39]. Since the Companies plan to review and update their Rule 15 in response to the updated IEEE Standard 1547.2018, including smart inverter issues, in a later Phase, the Companies initially will utilize the results from Phase III of the HCA Refinement Timeline (Figure 21) in the Supplemental Review process if a proposed DER installation fails Screen D in Rule 15 to quickly determine whether or not a technical issue may exist as a result of the proposed installation despite the failure of Screen D. The Companies intend replace Screen D

[39] Refer to Screen D, Sections I.3 and I.4.d of NV Energy's Rule 15.

with one that utilizes the HCA results in the Initial Review rather than the 15 percent screen when filing any recommended updates to Rule 15 with the Commission per Phase III below.

Phase II

Per the Stipulation in Commission Docket Nos. 17-06014 and 17-06015 (Revisions to Rule 15), NV Energy is required to make a filing with the Commission no later than October 1, 2019 in which the Companies *"will report on the results of the Phase I deployment of energy storage device interval meters, including the quality and utilization of the data collected."* NV Energy and the parties to this filing will also address other issues provided in Section 12 of that Stipulation.[40]

This Phase addresses the Companies' filing requirement.

Phase III

IEEE Standard 1547.7-2013 is the "IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection". NV Energy has experienced very few DER installations of a magnitude greater than 1 MW on its distribution system, and does not receive many applications annually for DERs of this magnitude seeking interconnection to the distribution system. Notwithstanding this, NV Energy uses similar impact study analytical processes for interconnection of DER to its transmission and distribution systems. The Companies intend to review IEEE 1547.7 to determine if any change to the present impact study methodology is necessary, and if so, incorporate any changes into the impact study template for proposed interconnections to the distribution system.

Phase IV

IEEE Standard 1547-2018 was completed last year, and represented an all-encompassing review and updating of that standard, which had been last fully updated in 2003. Although updated through Commission Docket Nos. 17-06014 and 17-06015 to include language specific to energy storage devices, NV Energy's Rule 15 is due for a top-to-bottom review and updating to incorporate any appropriate changes from the updated IEEE 1547, including smart inverters, especially given that much of the rule has not be updated since 2003.

Phase V

Once Rule 15 has been updated, the appropriate internal Company application, agreements, and standards should be reviewed and updated to ensure coordination with Rule 15 and applicable IEEE standards, thus completing the review and updating process for proposed interconnection of DERs to the Companies' distribution systems.

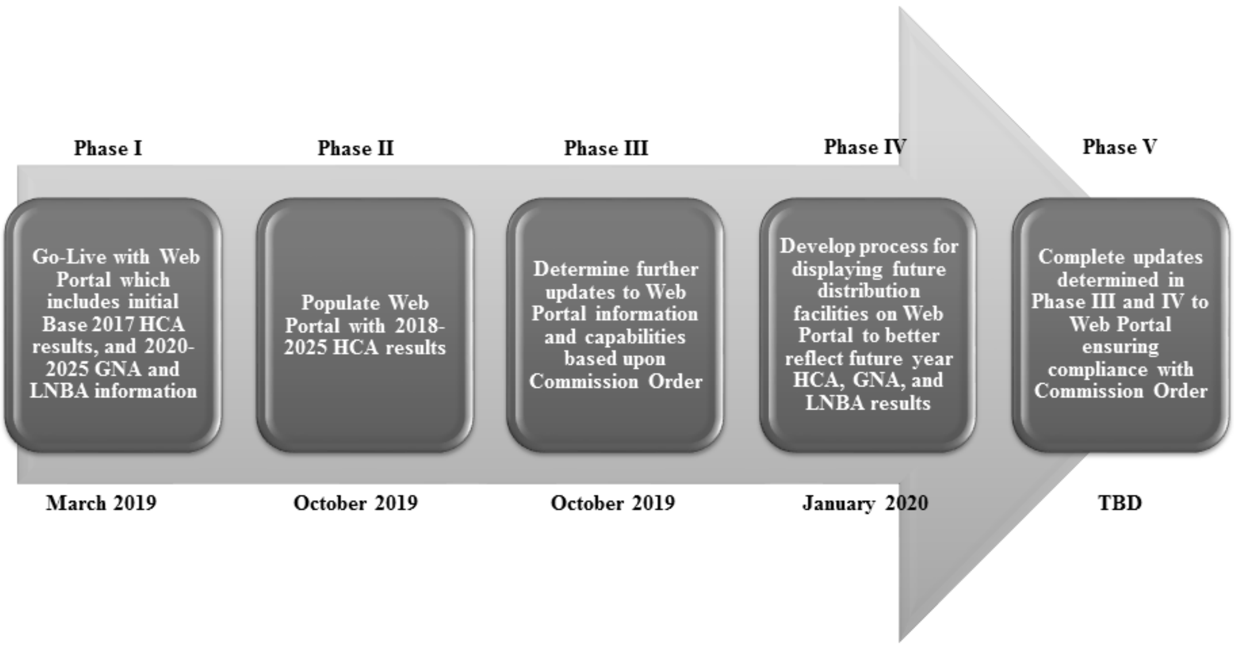
G. Publicly-accessible Web Portal

The initial information provided on NV Energy's Web Portal represents the results of the analyses performed for this DRP filing. Figure 27 below shows that the Companies plan to provide more

[40] Reference Commission Order in Docket Nos. 17-06014 and 17-06015 dated April 13, 2018, Attachment 1, Section 12 of the Stipulation, pgs. 5-6.

information through the Portal, but also to determine future improvements subsequent to the Commission's order in this docket:

FIGURE 27:
PUBLICLY-ACCESSIBLE WEB PORTAL REFINEMENT TIMELINE



<u>Phase I</u>

The initial phase of the publicly-accessible web portal was completed for this filing and went live on March 8, 2019, including information which NV Energy had verified as of that date.

<u>Phase II</u>

In accordance with Phase III in Section 8.B., once the future year HCA results are available for 2018-2025, they will be populated to Web Portal.

<u>Phase III</u>

NV Energy anticipates that the Commission's Order for this filing will certainly contain directives with regard to most, if not all, of the DRP elements presented. Any directives relating to the Web Portal will be examined in this phase, and a determination will be made regarding what changes, improvements, or additions need to be made to the Portal. A schedule and cost for such changes will also be developed.

<u>Phase IV</u>

NV Energy's GIS mapping system displays existing and proposed distribution facilities. The proposed facilities displayed are those contained in an approved design, but haven't yet been constructed. Once constructed, the facilities are shown as existing on the map. However, the GIS mapping system is not designed to, nor has it been its purpose to, display future distribution facilities associated with planned or proposed, approved or unapproved, capital upgrade projects, which in the future, will either alter or add to the existing distribution system. These facilities can be many years from being designed and constructed, and so are not depicted on the map.

Since the Synergi software draws from the GIS mapping system for its topology and connectivity, and additionally so does the Web Portal, this presents a challenge in truly depicting an accurate planned or forecasted distribution system populated with future year HCA, GNA, and LNBA results. Further, while it is possible to model those future changes and additions to the distribution system in Synergi in order to perform proper future year studies, those alterations will not flow to the Web Portal's depiction of the distribution system since the Portal receives its topology information directly from the GIS mapping system.

In this phase, the Companies will develop a process to display future distribution facilities, topology, and connectivity, matching how the system was studied in Synergi, so that all the HCA, GNA, and LNBA results can be properly shown on the Web Portal.

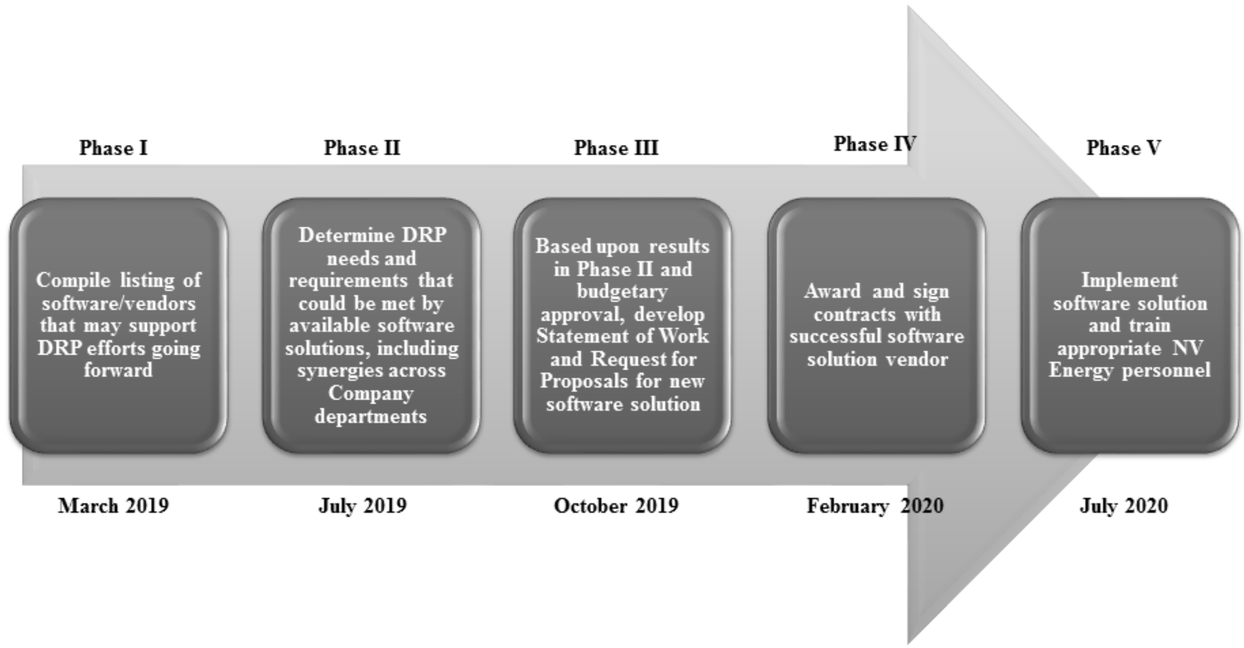
Phase V

In this phase, any of the changes, updates, or additions defined in Phases III and IV will be implemented on the Web Portal. At this time, it is difficult to determine a timeframe for this as any directives in the Commission's Order for this filing cannot be known. Presently, however, the Companies expect that this phase would be completed prior to the subsequent IRP filing in June 2021.

H. Tools, Systems, or Technologies

NV Energy's present plan is to determine the need for new analytical or operational software to support the DRP plan activities, and if so, acquire it. Figure 28 below focuses on this:

FIGURE 28:
POSSIBLE SOFTWARE ACQUISITION REFINEMENT TIMELINE



<u>Phase I</u>

The initial phase of the effort to potentially acquire a new software solution to support DRP efforts is discussed above in Section 3.A.5.

<u>Phase II</u>

While much work has already been done, and NV Energy has met with and learned about the offerings of several vendors, the cross-functional needs and requirements amongst the affected departments within the Companies will need to be gathered and examined for potential synergies. Vendor presentations and demonstrations could also take place. The Companies will make a decision at the end of this phase whether or not to proceed with a Request for Proposals for a new software solution.

<u>Phase III</u>

Assuming that the Companies determine to acquire a new software solution to support DRP efforts, and internal budgetary approval is secured, this phase will develop the Statement (or Scope) of Work and a Request for Proposals for acquisition of the new solution.

<u>Phase IV</u>

This phase allows several months for the Request for Proposals process, and should the Companies deem it appropriate to do so based upon the vendor bids, would culminate in an award and agreement with the successful software vendor.

Phase V

A goal of this phase would be to ensure that the new software solution would be implemented and NV Energy personnel would be trained to begin utilizing it in the load and DER forecasting, HCA, GNA, and NWA analysis processes in Q4 2020. This would ensure that the new solution would be used in support of the DRP as part of the subsequent IRP filing in June 2021.

Section 9. Incremental Investment in Tools, Systems, or Technologies to Integrate Distributed Resources

In accordance with Section 1.5(d) of SB146 and Section 3.4 of the Temporary Regulations, this section discusses any additional (incremental) investment necessary to cost-effectively integrate DERs into the distribution planning process, and extends beyond that to discuss any investment already undertaken by the Companies in the development of this DRP, and potential future investment areas to accommodate increased interconnection and integration of DERs going forward.

With successful EE, DR, and Renewable Generations programs in place for many years, the Companies have extensive experience with DER. Several existing, recently-developed and utilized, and potential future tools will assist in tracking, analyzing, managing and understanding the impacts of DERs on the Companies' electric grid, enabling additional DER penetration in a safe and reliable manner.[41]

A. Existing Tools, Systems, or Technologies

Several of NV Energy's existing systems support DER management and analysis, including:

- **Advanced Distribution Management System –** This system can manage existing distributed generation via telemetry gained through SCADA,
- **Demand Response Management System –** This system is described above in Section 3.D.6,
- **Meter Data Management System –** This system houses the generation data from private solar PV installations with generation (or renewable energy credits) meters,
- **RNI and the Sensus Flexnet meter communication system –** This system comprises NV Energy's Automated Metering Infrastructure smart metering system, providing granular customer billing data, meter voltage, and meter outage notification,
- **Intelligent Line Sensors –** NV Energy has over 600 intelligent line sensors installed throughout the Companies' transmission and distribution systems, providing varying telemetry data and fault measurement and locating capability. The Companies continue to install these sensors,
- **Synergi Electric electrical simulation software –** This power flow simulation software supports analytical studies of the distribution system, and is discussed in more detail above in relation to performing HCA in Section 3.A.2.

[41] Some of the tools, systems, or technologies identified in this DRP are also components of what could generally be considered a Grid Modernization Plan. However, this DRP does not attempt to establish any such plan, nor do the Companies claim that the existing, recently-developed, or potential future tools, systems, or technologies discussed herein constitute the Companies' Grid Modernization Plan. The scope of such a plan is greater than what is discussed in this DRP.

The Companies have not identified additional spending within this DRP at this time with respect to the above items to facilitate expansion of DERs on the distribution system.

B. Recently-Developed Tools, Systems, or Technologies

Over the course of the last two years, NV Energy has taken several steps to develop this first-of-its-kind DRP in Nevada in the form of new tools, and internal personnel and consulting labor resources, as follows:

- **Internal NV Energy Organizational Change** – The Companies organized a formal working group focused on the growing issues and additional workload associated with managing and administering increasing penetration of Distributed Resources in general and this DRP in particular. Six full-time equivalent positions were assigned to the effort, resulting in the following: one position in the Distributed Energy Resource Planning department, one position in the Distribution Planning department, and four positions in the newly-formed Integrated Grid Planning department[42]. A Director was added to the Distributed Energy Resource Planning department, a Planning Technician was added to Distribution Planning, and a Manager, Major Projects-Delivery and three Senior Engineer, Distribution Planning positions were added in Integrated Grid Planning.

- **DER Data Integration and Automation –** The Companies initiated and completed a multi-phased project to augment the distribution system modeling in Synergi to include the substation transformers, ensure the provision of DER data from the PowerClerk system through to the Synergi powerflow software, automate the process of updating the Synergi model from the GIS mapping system (described above in Section 3.A.2.a. as the Model Forge process), and provide consulting services for the HCA studies as required. The phases of the project were:
  - Phase 1 – Update the existing model build process for the Nevada Power distribution system to add the necessary data (*e.g.*, Net Energy Metering installations) required for HCA, including a one-time build of the substation models.
  - Phase 2 – Update the existing model build process for the Sierra distribution system to add the necessary data (*e.g.*, Net Energy Metering installations) required for HCA, including a one-time build of the substation models.
  - Phase 3 – Enhance the overall build solution to permit the area models to be reconstructed in an automated manner nightly (*i.e.*, the Synergi model databases can be refreshed nightly from the GIS mapping system databases if desired, to ensure the most up-to-date distribution system for use in planning studies).
  - Consulting Support – Provide consulting support to facilitate NV Energy's completion of the HCA required in support of the DRP filing.

[42] These new positions did not necessarily result in an increase in overall headcount for the Companies, and so do not necessarily represent incremental cost. They are discussed here for informational purposes to reflect part of the changes that the Companies were required to make as a results of increasing proliferation of DERs on their electric grid and the additional requirement per SB146 to develop and file a DRP.

Figure 29 below provides the costs by Company and general cost categories:

FIGURE 29:
DER DATA INTEGRATION AND AUTOMATION INVESTMENT[43]

Nevada Power Company

Cost Category	As of 2/28/19	Estimated Remaining	Subtotal
Labor	$8,184	$1,202	$9,386
Outside Services	$40,759	$40,903	$81,662
Purchases	$0	$0	$0
Overheads	$7,656	$1,434	$9,090
AFUDC	$1,952	$(1,952)	$0
		TOTAL	**$100,138**

Sierra Pacific Power Company

Cost Category	As of 2/28/19	Estimated Remaining	Subtotal
Labor	$7,745	$1,642	$9,386
Outside Services	$40,759	$40,903	$81,662
Purchases	$0	$0	$0
Overheads	$7,120	$1,970	$9,090
AFUDC	$1,602	$(1,602)	$0
		TOTAL	**$100,137**

- **Publicly-accessible Web Portal –** In accordance with Section 8.3 of the Commission-approved Temporary Regulation, the Companies developed a publicly-accessible Web Portal to provide access to HCA results, and GNA and LNBA information. This new tool is discussed in detail above in Section 7.

  Figure 30 below provides the costs by Company and general cost categories:

[43] The total approved budget for this project is $200,275, so the total estimated expenditures for this project assumes this amount.

FIGURE 30:
PUBLICLY-ACCESSIBLE WEB PORTAL INVESTMENT[44]

Nevada Power Company

Cost Category	As of 2/28/19	Estimated Remaining	Subtotal
Labor	$5,276	$0	$5,276
Outside Services	$127,751	$48,735	$176,486
Purchases	$1,691	$0	$1,691
Overheads	$7,869	$0	$7,869
AFUDC	$2,002	$0	$2,002
		TOTAL	**$193,324**

Sierra Pacific Power Company

Cost Category	As of 2/28/19	Estimated Remaining	Subtotal
Labor	$5,276	$0	$5,276
Outside Services	$83,142	$96,069	$179,211
Purchases	$1,304	$0	$1,304
Overheads	$6,290	$0	$6,290
AFUDC	$1,242	$0	$1,242
		TOTAL	**$193,323**

- **Consulting Labor to Develop DRP Roadmap, Structure, and Stakeholder Engagement –** As this was NV Energy's first DRP, it necessitated a steep learning curve to ensure its completion by the mandated April 1, 2019 due date. Through a competitive bidding process, ICF was selected to assist in developing the structure of the DRP, and to utilize its expertise and experience in creating and managing a robust and collaborative stakeholder process during the DRP development period. Several informal and formal workshops were held with all stakeholders, facilitating open discussion of the various elements of the DRP. These discussions proved valuable in ensuring that the DRP would not only provide maximum benefit to the Companies' customers, but also allowed supporters and vendors of DERs to assist in evaluating methodologies and outputs that would be most beneficial to them.

  Figure 31 below provides the costs by Company and general cost categories, with the expenditures as of February 28, 2019 representing what should be final costs:

[44] The total approved budget for this project is $386,647, so the total estimated expenditures for this project assumes this amount. The estimated remaining expenditures are set to reflect an ultimate 50/50 split in total costs between the Companies.

FIGURE 31:
CONSULTING LABOR TO DEVELOP DRP INVESTMENT

Nevada Power Company

Cost Category	As of 2/28/19	Estimated Remaining	Subtotal
Labor	$0	$0	$0
Outside Services	$85,466	$0	$85,466
Purchases	$0	$0	$0
Overheads	$0	$0	$0
AFUDC	$0	$0	$0
		TOTAL	**$85,466**

Sierra Pacific Power Company

Cost Category	As of 2/28/19	Estimated Remaining	Subtotal
Labor	$0	$0	$0
Outside Services	$85,466	$0	$85,466
Purchases	$0	$0	$0
Overheads	$0	$0	$0
AFUDC	$0	$0	$0
		TOTAL	**$85,466**

- **DER Analytics Dashboard** – Although the penetration of DERs on the Companies' distribution systems is low when viewed at the system level, local penetration on distribution facilities can far exceed that and could potentially result in problematic situations on the distribution system. The Companies developed a DER Analytics Dashboard tool utilizing the Tableau software to visualize the data associated with DERs and to enhance the tracking of installed DERs on specific distribution facilities from service transformers all the way up to the combined company level. This tool allows NV Energy to take a proactive stance in identifying potential areas where analysis and augmentation of the system may be necessary to facilitate increased penetration of DERs.

  Figure 32 below provides the costs by Company and general cost categories, with the expenditures as of February 28, 2019 representing what should be final costs:

FIGURE 32:
DER ANALYTICS DASHBOARD INVESTMENT

Nevada Power Company

Cost Category	As of 2/28/19	Estimated Remaining	Subtotal
Labor	$1,103	$0	$1,103
Outside Services	$154,150	$0	$154,150
Purchases	$0	$0	$0
Overheads	$5,670	$0	$5,670
AFUDC	$1,234	$0	$1,234
		TOTAL	**$162,157**

Sierra Pacific Power Company

Cost Category	As of 2/28/19	Estimated Remaining	Subtotal
Labor	$1,103	$0	$1,103
Outside Services	$94,592	$0	94,592
Purchases	$0	$0	$0
Overheads	$3,433	$0	$3,433
AFUDC	$834	$0	$834
		TOTAL	**$99,961**

C. Potential Future Tools, Systems, or Technologies

- **Analytical Software** – The Companies plan to determine the need for additional software to enhance the various analytical capabilities (*e.g.*, load and DER forecasting, HCA, NWA analysis) necessary to support the DRP now and in the foreseeable future. Section 10.G. below indicates that in 2019 the Companies will decide whether or not to acquire such new tools, and if so, would do so through a competitive procurement process.
- **Operational Software/Systems** – While the existing ADMS and DRMS systems are in place to manage the Companies' distribution systems and the Demand Response programs, respectively, other systems may be required to properly monitor, control, and deliver the various potential values (use cases) of existing and future DERs. Along with analytical capabilities, the Companies will be investigating the need for software and a system to manage and control DERs, often referred to as a Distributed Energy Resource Management System ("DERMS").
- **Grid Edge Technology –** This type of technology includes devices installed at or close to the customer's meter, potentially both behind and in front of the meter. Examples of such devices are smart inverters, and dynamic solid-state controlled VAR sources on either the secondary or primary distribution system. Additionally, although NV Energy has been deploying intelligent line sensors for several years, there may be different products that

could provide additional monitoring and other services to help facilitate DERs on the electric system.

Section 10. Pilot and Demonstration Projects

While NV Energy and some other utilities are involved in thinking about and developing many of the concepts and analyses required to develop a DRP, these concepts and analyses are not yet prevalent in the utility industry. In fact, NV Energy has watched closely the progress of various working groups that were established in California, including demonstration and pilot projects that were initiated after the major California IOUs filed their initial Distribution Resources Plan filings in July 2015.

NV Energy has also proposed demonstration projects of its own, including a combined in-front-of-the-meter solar PV and battery energy storage system project to address continuing service concerns in the Smith Valley area in northern Nevada[45]. Had that project come to fruition, it would have marked the first instance of a non-wires solution being constructed instead of a traditional wired utility solution to a constraint on NV Energy's electric distribution system, and valuable insight would have been gained regarding the endeavor to implement and operate such a solution. Notwithstanding the fact that EE and DR have been employed on NV Energy's system for many years, non-wires DER solutions on the distribution system directed at addressing specific constraints and deferring traditional wired solutions are new to NV Energy, as they are too many other utilities currently in various stages of testing these technologies. The Companies support a measured approach, but also advocate moving forward to vet these technologies in order to ensure that they can accomplish their goals and provide their expected benefits, and do so in a safe and reliable manner under real-world conditions. To this end, the discussion below centers on several elements of and specific technology to support the DRP.

A. Load and DER Forecasting

As the penetration of DER rises, it will become increasingly important to disaggregate the impact of DER to accurately forecast the net load of distribution facilities. Uncertainty and risk will consequently be increased. As discussed above in Section 8.A., NV Energy plans to determine whether or not to transition to multi-scenario load forecasting at the distribution level, and "bottom up" forecasting for DER in the form of "customer propensity to adopt" modeling. These approaches would require a large amount of data, both from inside and outside the Companies.

Should NV Energy decide to move forward with these more advanced load and DER forecasting concepts, a thoughtful approach to this potential transition would be to select certain areas of the distribution system and certain DER technologies to initially attempt to apply these new concepts, define measures of success, and establish a timeframe for the pilot. The Companies are not yet in a position to determine a well-defined scope and budget, and so are only identifying the potential for such a future pilot in this DRP filing. Should the Companies decide to move forward with a pilot project on the aforementioned techniques, it is anticipated that such an effort would be filed with the Commission either as part of an update of this DRP or within the DRP volume in the next planned IRP filing in June 2021.

[45] Refer to Commission Docket No. 16-01013, Comments of Nevada Power Company and Sierra Pacific Power Company dated May 2, 2016, pg. 14.

B. Hosting Capacity Analysis

HCA is extremely time consuming and computation-intensive. Multiple analytical constraints and both generation and load cases are addressed on the approximately 1.7 million distribution feeder sections captured in the Companies' GIS mapping system, and consequently the Synergi power flow model. This is intentional, and reflects NV Energy's view that the most accurate means of determining hosting capacity is to perform the analysis at the most granular level (in this case, feeder sections) across the entirety of the Companies' distribution systems for which data could be obtained or reasonably generated.

As discussed above in Section 8.B., NV Energy plans to refine and enhance the HCA going forward, to add potentially limiting criteria, address smart inverter capabilities, and potentially include Distribution Resource forecasting based upon customer adoption forecasting. Although these activities will require initial testing on small parts of the distribution system prior to rolling out to the entire system, and in a sense this can be viewed as constituting demonstrating the additional criteria or capabilities, the Companies do not expect to develop a specific pilot or demonstration related to HCA at this time.

C. Non-Wires Alternative Analysis

Ultimately, NWAs should no longer be viewed as an "alternative" to a traditional wired capital upgrade solution to an identified T&D constraint, but rather, one of the standard options, or "tools in the toolbox". A number of utilities have been deploying various NWA solutions to address constraints on their electric systems, or simply to pilot the technologies and gain experience with it.

Sections 3.A. and 3.B. above discuss the Companies' NWA analyses for this DRP. From this information, one project appeared to present an opportunity for an NWA option; the forecasted thermal constraint on the Village transformer #1 in 2021. Consequently, the Companies performed some sensitivities and acquired information to generate a more accurate estimated cost.

As discussed above in Section 3.A.3.b(5), although the estimated cost for a battery energy storage system solution in the case of the forecasted constraint at the Village Substation with such a small power and energy requirement was lower than the estimated cost for the traditional wired solution, an NWA solution did not present itself as economically viable as compared to the traditional wired solution from a PWRR standpoint. However, as discussed in that section, in 2019 NV Energy plans to first test and then demonstrate the viability of locationally-targeted operation of existing Demand Response assets on the Village transformer #1 in an attempt to defer the need for the Village Bank 2 at least two years to 2023. The Companies expect to report further on this demonstration project in an update of the DRP which would be required to be filed by September 1, 2020.

D. Locational Net Benefits Analysis

NV Energy does not foresee the need for piloting or demonstrating any aspects of the planned future efforts regarding the LNBA process as discussed above in Section 8.E.

E. DER Interconnection

NV Energy does not foresee the need for piloting or demonstrating any aspects of the planned future efforts regarding the DER interconnection process as discussed above in Section 8.F.

F. Publicly-Accessible Web Portal

NV Energy does not foresee the need for piloting or demonstrating any aspects of the planned future efforts regarding the Publicly-accessible Web Portal as discussed above in Section 8.G.

G. Tools, Systems, or Technologies

As discussed above in Section 8.H, NV Energy plans to discuss and determine the need to potentially acquire a new software solution to support DRP efforts. Should the decision be made to do so, certainly there would be a structured rolling out any new software in terms of its integration with existing NV Energy systems, development of new procedures, and requisite training. Presently, the Companies have not identified a pilot or demonstration regarding the integration of any new software, but if a decision is made to acquire such and a plan is developed for rolling out such a new system, pilots or demonstrations could be part of that plan and would be reflected in future DRP filings.

Section 11. Specific Requests for Commission Approval

A. NV Energy Requests for the Commission

Based on the information provided in the above Narrative, as well as the testimony and the information provided in the Technical Appendices attached hereto, NV Energy requests that the Commission issue the following findings on NV Energy's DRP:

1. The load and DER forecasting methods as discussed in Section 3.A.1. of this DRP are prudent and in compliance with Section 8.2 of the Temporary Regulations, subject to the request to waive certain aspects of Section 8.2 of the Temporary Regulations as noted below in Section 11.B of this DRP.
2. The Hosting Capacity Analysis methods as discussed in Section 3.A.2 of this DRP are prudent and in compliance with Section 8.3 of the Temporary Regulations, subject to the request to waive certain aspects of Section 8.3 of the Temporary Regulations as noted below in Section 11.B of this DRP.
3. The Grid Needs Assessment methods for the distribution system as discussed in Section 3 of this DRP are prudent and in compliance with Section 8.4 of the Temporary Regulations, subject to the request to waive certain aspects of Section 8.4 of the Temporary Regulations as noted below in Section 11.B of this DRP. This includes the following elements:
    a. The identification of distribution constraints and projects as discussed in Section 3.A.3.a.;
    b. The Non-Wires Alternative analysis as discussed in Section 3.A.3.b.;
    c. The Locational Net Benefits Analysis as discussed in Section 3.A.3.c.; and
    d. The traditional upgrade projects and NWA solutions recommendations as discussed in Section 3.A.3.d.
4. The Grid Needs Assessment methods for the transmission system as discussed in Section 3 of this DRP are prudent and in compliance with Section 8.4 of the Temporary Regulations. This includes the following elements:
    a. The identification of transmission constraints and projects as discussed in Section 3.B.2.a.;
    b. The Non-Wires Alternative analysis as discussed in Section 3.B.2.b.;
    c. The Locational Net Benefits Analysis as discussed in Section 3.B.2.c.; and
    d. The traditional upgrade projects and NWA solutions recommendations as discussed in Section 3.B.2.d.
5. The identification of tariffs approved by the Commission that address deployment of DERs discussed in Section 3.C of this DRP is in compliance with Section 3.3 of the Temporary Regulations.
6. The identification of existing programs approved by the Commission that address the deployment of DERs and the methods of effectively coordinating these programs to maximize the locational benefits and minimize the incremental costs of DERs discussed in

Sections 3.D and 3.E of this DRP, is in compliance with Section 3.5 of the Temporary Regulations.

7. The identification of barriers to the deployment of DERs discussed in Section 4 of this DRP is in compliance with Section 3.5 of the Temporary Regulations.

8. The development and deployment of a publicly-accessible Web Portal that provides maps and accessible electronic data discussed in Section 7 of this DRP was prudent and in compliance with Section 8.3 of the Temporary Regulations.

9. The incremental utility investment and expenditures discussed in Section 9.B of this DRP and set forth in Figure 33 below are approved as prudent and in compliance with Section 3.4 of the Temporary Regulations.

FIGURE 33:
INCREMENTAL INVESTMENT TO DEVELOP DRP

Project	Nevada Power	Sierra	Total
DER Data Integration & Automation	$100,138	$100,137	$200,275
Publicly-accessible Web Portal	$193,324	$193,323	$386,647
Consultant Labor to Develop DRP	$85,466	$85,466	$170,932
DER Analytics Dashboard	$162,157	$99,961	$262,118
TOTAL	**$541,085**	**$478,887**	**$1,019,972**

10. The recommendations for the construction of traditional upgrade projects and NWA solutions and associated estimated expenditures discussed in Section 3.A.3.d of this DRP are approved as prudent. Figure 7 above presents the estimated costs for these projects.

B. NV Energy Requests for Waivers of Temporary DRP Regulations

Through its best efforts, NV Energy was able to complete virtually all of the requirements contained in the Temporary Regulations approved by the Commission, with the exception of the items listed below. The Companies request a waiver of certain requirements of the regulations as follows:

- Section 8.2 of the Temporary Regulations states in part that *"The distributed resources plan must be developed by a utility using a forecast of net distribution system load and distributed resources. The forecast period shall be a 6-year period, at minimum, beginning with the year after the distributed resources plan is filed. The net distribution system load and distributed resource forecast will include system, substation, and feeder level net load projections and energy and demand characteristics for all distributed resource types."* NV Energy utilized net distribution feeder, substation transformer, and transmission forecasts to determine the constraints on the T&D systems. While system-level forecasts for DER types were filed with the Commission in Docket No. 18-06003 and this DRP does not alter those forecasts in any way, the Companies did not disaggregate those system-level forecasts to the substation and feeder level. As noted in Section 8.A of this DRP, NV Energy plans to complete this disaggregation by this summer 2019 as a prerequisite for conducting future years

Hosting Capacity Analysis for the years 2018-2025 to be completed by October 2019. Also of note in Section 8.A is that NV Energy plans to investigate alternative methods for developing substation and feeder level DER forecasts and implement any such new methods by October 2020.

- Section 8.3 of the Temporary Regulations states in part that the *"Hosting Capacity Analysis shall be performed using a load flow analyses and forecasted distribution facilities and their capacity, configuration, loading and voltage data gathered at the substation, feeder, and primary node levels."* Although NV Energy did not complete the Hosting Capacity Analysis using forecasted conditions on the distribution system, as noted in Section 8.B of this DRP, NV Energy plans to complete the Hosting Capacity Analysis including these elements for each year of 2018 through 2025 inclusive by October 2019 and to report on that analysis and the results in an update to this DRP to be filed with the Commission on or before September 1, 2020.

- Section 8.3 of the Temporary Regulations further states in part regarding Hosting Capacity Analysis that *"Scenario analysis will be performed to evaluate hosting capacity under normal and planned and unplanned contingency conditions."* NV Energy completed the Hosting Capacity Analysis under normal system operating conditions, but did not under planned or unplanned contingency conditions. As noted in Section 8.B of this DRP, NV Energy plans to complete the Hosting Capacity Analysis including these elements by July 2020 and to report on that analysis and the results in an update to this DRP to be filed with the Commission on or before September 1, 2020.

- Section 8.4 of the Temporary Regulations states in part that the *"Grid Needs Analysis shall be based on the net distribution system load and distributed resource forecast…"* Although NV Energy has not yet developed DER forecasts at the substation and feeder levels, and so the GNA in this DRP filing does not account for those forecasts in the determination of constraints on NV Energy's electric grid, NV Energy plans to disaggregate its existing system-level DER forecasts down to the substation and feeder level by this summer 2019, to perform a study later this year to determine the potential magnitude of the effects DER on the distribution planning load forecasting process by the end of this year, and complete "propensity to adopt" DER forecasting techniques by the end of October 2020 (if the Companies decide to utilize such a method). Future GNAs will then be based upon DER forecasts at the substation and feeder levels.

Section 12. Roadmap to 2021

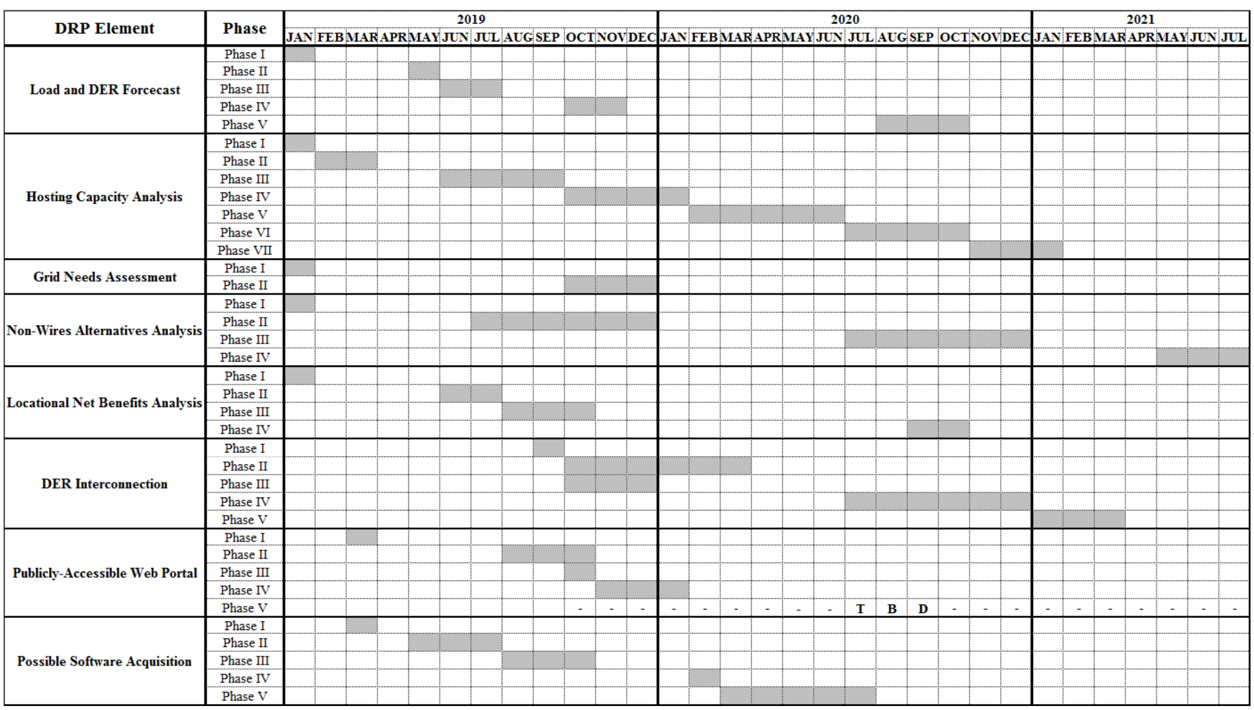
The next steps associated with activities that will drive not only an update to this DRP (to be filed no later than September 1, 2020), but the DRP filing to be filed as part of the Companies' next Triennial Joint IRP filing (no later than June 1, 2021), are set forth below.

NV Energy performs an annual top-down review of its Capital Plan, which incorporates all of the transmission and distribution projects that the Companies plan to fund and construct over the next 10 years. Going forward, this annual review will incorporate any proposed NWA solutions that have been recommended through the transmission and distribution planning processes. Once approved, these NWA solutions will be incorporated into the Companies' Action Plans and Action Plan budgets, as appropriate.

As explained in Section 8 above, NV Energy will also continue to refine and enhance the various elements of the DRP. Collectively, these specific tasks and goals comprise NV Energy's roadmap towards the June 2021 DRP filing mentioned above.

Figure 34 below is the high-level schedule that NV Energy has prepared to guide its DRP efforts through 2021.

FIGURE 34:
HIGH-LEVEL SCHEDULE OF DRP ELEMENTS REFINEMENT



Per Sections 9 and 10 of the Commission-approved Temporary Regulations, NV Energy will identify and justify any changes in the methodology of performing the tasks and analyses in support of the DRP within the update or next complete filing mentioned above.

JAMES R. SAAVEDRA

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to
2018 Joint Triennial Integrated Resource Plan

Distributed Resources Plan

Docket No. 19-04___

PREPARED DIRECT TESTIMONY OF

James R. Saavedra

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

A. My name is James R. Saavedra. I am the Director of Distributed Energy Resource Planning for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6226 W. Sahara Ave. Las Vegas, Nevada. I am filing testimony on behalf of Nevada Power and Sierra.

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

A. I have been continuously employed by NV Energy since March 2000 in several program and leadership roles. I have experience in electric utility distribution planning, substation and technical operations and distributed energy resources. I have Bachelor of Science degrees in Physics and Electrical Engineering, and a Master's degree in Business Administration. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Saavedra-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, DISTRIBUTED ENERGY RESOURCE PLANNING.

A. As the Director of Distributed Energy Resource Planning my responsibilities include leading the effort of developing the Companies' first Distributed Resource Plan ("DRP").

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

A. Yes. I have appeared before the Commission in various dockets including, most recently, the Commission's workshops and hearings in Docket No. 17-08022, the proceeding in which the Temporary Regulations implement Senate Bill 146 ("SB146") were drafted and approved.

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

A. My testimony is in support of certain sections of the DRP narrative, specifically:

- Section 1 – Executive Summary
- Section 2 – Introduction
- Section 4 – Barriers to Deployment of DER
- Section 5 – Coordination with Integrated Resource Plan and Other Legislative Actions
- Section 6 – Data Sharing, Access and Security Issues
- Section 7 – Publicly-Accessible Web Portal

- Section 12 – Roadmap to 2021
- Technical Appendix 5

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring **Exhibit Saavedra-Direct-1**.

7. Q. WHAT HAS BEEN YOUR ROLE IN PREPARING THIS FIRST DRP?

A. I have lead a cross functional team charged with developing this first DRP. I was responsible for putting in place processes to ensure that the vision and strategy for the development and implementation of the DRP were timely developed and carried out. I oversaw the development of the budget, identification of the resources and development of the procedures to effectively and efficiently implement the DRP. I was responsible for developing a regulatory strategy and obtaining approvals from the Commission on new regulations. I also oversaw the drafting of the DRP narrative.

8. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF THE DRP NARRATIVE SECTIONS THAT YOU ARE SUPPORTING IN THIS FILING.

A. **Section 1 –** Executive Summary provides an overview of the contents in the DRP narrative.

Section 2 – Introduction, Subsections A and B provide details on the principles NV Energy followed in developing the DRP.

1. <u>Overview of Plan Contents</u>. This part of the narrative outlines the contents of the Plan and explains the benefits the DRP delivers.

2. Plan Meets Requirements of SB146. This part of the narrative provides background on the legislation that was passed in 2017 and how the DRP meets the requirements of the statute.
3. Stakeholder Engagement. This part of the narrative provides details on the robust stakeholder engagement process that NVE utilized in developing both the regulations implementing SB146 and this first DRP. It includes details on the dedicated workshop that NVE facilitated on hosting capacity analysis.
4. Definitions and Acronyms. This part of the narrative provides definitions of technical terms and explains any of the narratives acronyms.

Section 4 – Barriers to Deployment of DER. This part of the narrative describes the barriers that NV Energy identified that would be a deterrent to the deployment of Distributed Resources and the solutions to remove those barriers.

Section 5 – Coordination with Integrated Resource Plan ("IRP") and other Legislative Actions. This part of the narrative provides the details of how the DRP interacts with the IRP and which other legislative actions have to be taken into consideration when developing this DRP.

Section 6 – Data Sharing, Access and Security Issues. This part of the narrative provides the details, challenges overcome, and the solutions that NV Energy developed to identify the data that stakeholders want to see and how it will be shared.

Section 7 – Publicly-Accessible Web Portal. This part of the narrative details the web portal that NV Energy developed to share the outputs from the DRP with the public.

Section 12 – Roadmap to 2021. This part of the narrative provides the details on the steps NV Energy will be taking to evolve the DRP for the June 2021 filing.

Technical Appendix 5 – Web Portal. Provides details on the DRP website portal as well as various screenshots of the Hosting Capacity Analysis results, Grid Needs Assessment results and the Locational Net Benefit Analysis results.

9. Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications
For
James R. Saavedra

Summary of Qualifications

Over 30 years of electric utility experience, including 17 years of leadership experience, with 19 years at NV Energy (Nevada Power Company and Sierra Pacific Power Company) based in Las Vegas, NV. Experienced in management and leadership techniques, goal-setting, process analysis, capital and operations budgeting and technical writing.

Professional Experience

NV Energy- 6226 W. Sahara Ave., Las Vegas, NV 89151
July 2017 to present
Director – Distributed Energy Resource Planning

- Responsible for leading a cross functional team to develop the vision, strategy and processes for NV Energy's Distributed Resource Plan.
- Develop budget, resources and procedures to effectively and efficiently implement the Distributed Resource Plan.
- Responsible for developing a regulator strategy and obtain approval from Nevada's Public Utility Commission.

NV Energy- 6226 W. Sahara Ave., Las Vegas, NV 89151
January 2014 to July 2017
Director – Substations and Technical Operations Department

- Responsible for managing a department staff of up to 142 employees, manage and direct all business activities related to substation construction and maintenance, system protection and transmission/civil construction.
- Responsible for developing a 10-year business plan including capital and operation and maintenance budgets.
- Responsible for developing a unitized price strategy for my areas of responsibility.
- Direct department in strategic and logistic functions to ensure efficient and effective utilization of all resources.
- Develop department scorecard, goals, objectives and safety policies.

January 2005 to December 2013
Director – Administrative and Property Services Department

- Responsible for managing a department staff of up to 94 employees, manage and direct all business activities related to property services (the sale, leasing, survey and maintenance of company-owned real estate and the acquisition of permits, real estate and right-of-way needed for the construction and maintenance of company-owned generation stations, gas pipelines and electric infrastructure) and administrative services (facilities maintenance, corporate records, support services (interior services, reprographics, food services, mail services and office supplies).

- Responsible for case management and developing legal strategies associated with litigation involving the company's land assets (i.e., condemnation, encroachment and permitting initiatives)
- Direct department in the strategic acquisition of real estate and land rights to support the Company's goal in master planning, routing and sitting of electrical infrastructure and the capital improvement program.
- Designed and implemented organizational design changes to provide a "one-stop shop" concept to better support our internal and external customers.
- Responsible for developing and managing over a $27.5 million O&M budget and ensuring appropriate justifications and resource allocation to support up to a $20 million capital budget.
- Develop department scorecard, goals and objectives. Instituted program to develop and document processes and procedures to ensure accountability and consistencies across both companies.

Nevada Power Company - 6226 W. Sahara Ave., Las Vegas, NV 89151
Supervisor – Distribution Planning Department
February 2002 to December 2004

- Responsible for the supervision of department staff (eight engineers and two technicians), oversee and participate in complex professional engineering work involving master planning, routing and siting of electrical (T&D) infrastructure and the capital improvement program; review engineering plans and specifications; project manager on dozens of projects annually; and perform a variety of technical tasks relative to assigned areas of responsibility.
- Strategic business planning and budgeting
- Responsible for project initiation and justification of $40 to $60 million annually. Provide technical guidance to Planning Distribution team and assure all projects are technically sound/efficient. Overall Project Management; capable of managing complex projects.
- Develop department goals and objectives. Responsible for project tracking, submittals and approvals (municipality requirements), sub-consultant coordination, all related paperwork.
- Provide project design concepts, quality control, budget & schedule control, resulting in policy and procedures to enhance customer service and department standards and continuity.

Senior Planning Engineer – Distribution Planning Department
March 2000 to January 2002

- Team leader of a three-person team: to develop a recommendation for a new load distribution forecasting methodology.
- Develop requirements and justifications for substation and distribution feeder master plans.
- Prepare and prioritize project justifications for distribution system's capital budget.
- Provide support and make recommendations to Company's Planning, Operating and District Personnel on topics and policies relating to distribution design, planning, regulatory rules and Company polices and goals.

Ameren Corporation – 1900 Chouteau Ave, St. Louis, MO 63166
Senior Planning Engineer – Distribution Engineering Department
December 1988 to July, 1999

- Project manager in the development of a comprehensive 20-year, spatial load forecast study and distribution system design for the entire Ameren System, consisting of approximately

1,500,000 customers. This project provides for a multi-scenario, land based load forecast for Ameren's Missouri and Illinois territories.

- Member of the development and implementation team for a new budgeting methodology at Ameren. This methodology instituted a Budget Constrained Planning (BCP) philosophy that not only reduced capital budgeted dollars but prioritized the Operating Departments' projects.
- Prepare, prioritize and review submitting Department's project justifications for Ameren's entire distribution system's capital budget.
- Develop, implement and provide support to Company's Operating Departments on topics and policies relating to distribution design, planning, regulatory rules and Company's goals and objectives.
- Developed compliance requirements for Ameren's budgeting and financial information required by Illinois Commerce Commission's de-regulation legislation.

Customer Service Engineer – St. Louis Metropolitan District

- Engineered, designed, scheduled and budgeted a wide variety of distribution system projects, ranging from substations to customer facility extensions.
- Company liaison for several large St. Louis municipalities. Worked closely with City Administrators, City Engineers, Planning and Zoning, Permit and Public Works Departments to maintain, modify and develop utility infrastructure.
- Represented Ameren in dealing with municipalities, public and private organizations, industrial, commercial and residential customers and their consultants.
- Responsible for industrial, commercial and residential customers' requests and complaints concerning outages, reliability and distribution system concerns.

Project Engineer - Distribution & Customer Substation Design Group

- Plan, budget, schedule, design, coordinate site acquisitions, engineer and supervise construction of multi-million dollar distribution substation projects.
- Engineer, budget, schedule and provide direct construction coordination on customer substation projects, working closely with the customer and customer's consultants.
- Negotiated with City Aldermen and Planning and Zoning Departments in determining site locations, screening requirements and configurations for distribution substations.
- Perform cost comparisons, evaluations and engineering studies, project cash flows, develop material and job specifications and evaluate vendor bids.

Assistant Engineer - Transmission Line Design Group

- Developed engineering designs, justifications, budgeted, and coordinated various transmission line projects (345 kV, 161 kV and 138 kV).
- Developed engineering models and upgraded programs in BASIC and FORTRAN

Education

University of Missouri - St. Louis - Masters in Business Administration - May 1994
Truman State University - Bachelor of Science in Physics - May 1990
University of Missouri - Rolla - Bachelor of Science in Electrical Engineering - December 1988
Villanova University – Six Sigma Green Belt - 2014

Memberships

Board President of The Children’s Free Clinic of Southern Nevada
Board Vice-President of the Global Charity Foundation
Board Secretary of the Family and Child Treatment of Southern Nevada (FACT)
Registered Professional Engineer in Nevada
Member National Society of Professional Engineers (NSPE)
Member Institute of Electrical and Electronics Engineers (IEEE)

Training

Six Sigma Green Belt, Leadership Development Program; Supervisor’s Workshop; Team Building; Lessons in Leadership; Change Management; Project Management, Customer Relations Training; Situational Leadership II; Managers and Supervisors Conference; Utility Finance & Accounting; Replacing Negativity with Enthusiasm; Coaching Skills for Managers & Supervisors; 7 Habits Fundamentals Workshop; Assertive Leadership Skills; The 4 Disciplines of Execution; Creative Leadership Workshop.

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF CLARK)

I, JAMES SAAVEDRA, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

JAMES SAAVEDRA

Subscribed and sworn to before me
This 26th day of March, 2019.

NOTARY PUBLIC

S. MANNSUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023

JOSEPH V. SINOBIO

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to
2018 Joint Integrated Resource Plan

Distributed Resources Plan

Docket No. 19-04___

PREPARED DIRECT TESTIMONY OF

Joseph V. Sinobio

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

A. My name is Joseph V. Sinobio. I am a Manager, Major Projects-Delivery for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6226 W. Sahara Ave. Las Vegas, Nevada. I am filing testimony on behalf of Nevada Power and Sierra.

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

A. I have been continuously employed by NV Energy since September 1988. I have experience in electric utility transmission and distribution planning, and distributed energy resources. I have a Bachelor of Engineering degree in electrical engineering. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Sinobio-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS MANAGER, MAJOR PROJECTS-DELIVERY.

A. As a Manager, Major Projects-Delivery my responsibilities include supporting distributed energy resource planning, interconnection, and impact studies on the Companies' distribution systems, and integrated grid planning.

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

A. Yes. I have provided written testimony and appeared before the Commission in various dockets, most recently the application by the Companies seeking Commission approval of their 2018 Joint Triennial Integrated Resource Plan ("IRP") (Docket No. 18-06003). I have also participated in Commission workshops in various investigatory dockets, most recently the 2017 Investigation and Rulemaking to implement Senate Bill 146 ("SB146") Investigatory Docket No. 17-08022.

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

A. My testimony is in support of certain sections of the Distributed Resources Plan ("DRP") narrative, specifically:

- Section 3, Subsection A – Distributed Resources Plan Elements, Distribution Planning;
- Section 8 – Refining Distributed Resources Plan Elements;
- Section 9 – Incremental Investment in Tools, Systems, or Technologies to Integrate Distributed Resources;
- Section 10 – Pilot and Demonstration Projects;

- Section 11 – Specific Requests for Commission Approval, and
- Technical Appendices DRP-1, DRP-2, DRP-3, and DRP-4.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring Exhibit Sinobio-Direct-1.

7. Q. PLEASE DESCRIBE YOUR ROLE IN PREPARING THIS FIRST DRP.

A. My role was overseeing and completing the technical analyses of NV Energy's distribution systems for the DRP, as well as making recommendations based on those analyses. I was responsible for:

1. Acquiring and developing the distribution load and Distributed Resources forecasts at the substation and distribution feeder levels;
2. Directing completion of the Hosting Capacity Analysis studies, Grid Needs Assessment, Non-Wires Alternative ("NWA") analyses, and Locational Net Benefits Analysis;
3. Developing NV Energy's plan to refine several elements of the DRP;
4. Recommending any traditional wired projects, NWA solutions, pilots, and demonstration projects;
5. Compiling any incremental investment determined by NV Energy as necessary to integrate Distributed Resources; and
6. Compiling any specific requests for Commission approval and requests for deviations from the DRP Temporary Regulations ("Temporary Regulations").

8. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF THE DRP NARRATIVE SECTIONS THAT YOU ARE SUPPORTING IN THIS FILING.

A. Section 3, Subsection A of the DRP narrative describes the Companies' activities, processes, and analyses in support of the DRP in the following areas:

1. Load and Distributed Resources Forecasting. This part of the narrative describes generally how load forecasting is performed at the distribution feeder level for the Companies and discusses the effect of Distributed Resources on distribution load forecasting;

2. Hosting Capacity Analysis ("HCA"). This part of the narrative describes how the distribution substation and feeder models were prepared utilizing the Companies' distribution power flow software Synergi, how the loading profile data for the Companies' distribution feeders was developed, the analytical method for the HCA, the results of the HCA, and a discussion of "real-time" hosting capacity and NV Energy's progress in that regard;

3. Grid Needs Assessment ("GNA"). This part of the narrative describes how the Companies identified 10 existing and forecasted constraints on their distribution systems for the years 2020 through 2025, the identifying information and parameters of those constraints in terms of the deficiencies involved, and the identified traditional wired capital upgrade solutions for addressing those constraints;

4. NWA. This part of the narrative describes the Companies' NWA Suitability/Screening Criteria to determine which of the 10 identified constraints could be suitable for a potential NWA solution, the method and the NWA Sizing Model that the Companies used to perform the NWA analyses, and the results of the NWA analyses, including the sizing of the

Distributed Resources technologies (Demand Response, Energy Efficiency, Solar PV, and Battery Energy Storage) used in the potential NWA portfolio;

5. Locational Net Benefits Analysis (“LNBA”). This part of the narrative describes the Present Worth of Revenue Requirements (“PWRR”) analyses that were performed by the Companies, which compared the costs of traditional wired capital upgrade solutions against the costs and potential system-level and locational benefits of NWA solutions;

6. Distributed Resource Interconnection. This part of the narrative briefly mentions the Companies’ Rule 15 and the changes to the interconnection process that are being considered in discussions with regulators and stakeholders;

7. Tools, Systems, and Technologies. This part of the narrative briefly discusses some of the vendors and software that NV Energy is aware of which could help support DRP-related analyses in the future.

Section 8 of the DRP narrative describes the Companies’ present plans to refine the methods and tools used in the performing the various analyses required to develop the DRP over approximately the next two years,[1] including the seven elements (areas) mentioned above and one additional element; the Publicly-accessible Web Portal, which is described in Section 7 of the DRP narrative.

Section 9 of the DRP narrative describes the Companies’ existing, recently-developed, and potential future tools, systems, or technologies used, or which could be used in the future, to develop the DRP, and any incremental investment that may have been identified to develop, acquire, or implement these.

[1] In support of the Companies’ next Joint Integrated Resource Plan which is scheduled to be filed by June 1, 2021.

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d/b/a NV Energy

Section 10 of the DRP narrative describes any pilot or demonstration projects that the Companies may be proposing to conduct in support of the analyses or tools, systems, or technologies used to support the DRP.

Section 11 of the DRP narrative describes any specific requests that the Companies are making of the Commission in this DRP, including requests for the Commission's approval of various elements of the DRP, and any variances requested by the Companies with respect to the Temporary Regulations.

Technical Appendix DRP-1 contains substation transformer and distribution feeder past peak loads from 2014 to 2018 for both Nevada Power and Sierra.

Technical Appendix DRP-2 contains substation transformer and distribution feeder forecasted peak loads for 2019 to 2025 for both Nevada Power and Sierra.

Technical Appendix DRP-3 contains a flowchart of the process by which NV Energy obtained 2017 loading data on the distribution feeders that were part of the HCA.

Technical Appendix DRP-4 contains a table indicating the sources of loading data for the distribution feeders that NV Energy performed HCA on.

9. Q. IS NV ENERGY MAKING ANY SPECIFIC REQUESTS OF THE COMMISSION AS A RESULT OF THE COMPANIES' ACTIVITIES IN DEVELOPING OR THE ANALYSES CONDUCTED IN THIS DRP?

A. Yes.

10. Q. WHICH SPECIFIC REQUESTS OF THE COMMISSION ARE YOU SUPPORTING IN THIS TESTIMONY?

A. Section 11 of the DRP narrative describes the Companies' specific requests for the Commission to approve as prudent and in compliance with the appropriate sections of the Temporary Regulations approved by Commission Order in Docket No. 17-08022 on October 8, 2018. I support the request for Commission approval of the following:

1. NV Energy's load and Distributed Resources forecasting methods as discussed in Section 3.A.1 of the DRP narrative;
2. NV Energy's HCA methods as discussed in Section 3.A.2 of the DRP narrative;
3. NV Energy's GNA methods as discussed in Section 3.A.3 of the DRP narrative, including the identification of distribution constraints and projects, the NWA analyses, the LNBA, and the traditional upgrade projects and NWA solutions recommendations, as discussed in Sections 3.A.3.a. through 3.A.3.d., respectively; and
4. NV Energy's identification of incremental utility investment or expenditures as discussed in Section 9.B of the DRP narrative.

11. Q. PLEASE DESCRIBE HOW NV ENERGY BUILT THE LOAD AND DISTRIBUTED RESOURCES FORECASTS EMPLOYED IN THIS DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES AS PRUDENT?

A. As stated in Section 3.A.1.a of the DRP narrative, NV Energy utilized updated load forecasts for substation transformers and distribution feeders (as of January 18, 2019), which supported the determination of constraints on the distribution system and the consequent traditional wired upgrade projects (solutions). The load forecasts covered the minimum six-year timeframe following the year of the filing of this DRP as required by the Temporary Regulations.

As stated in Section 3.A.1.c of the DRP narrative, no new or updated forecasts for Demand Response, Energy Efficiency, electric vehicles, net metering solar PV, or energy storage were performed for this DRP. Updates to the forecasts of Distributed Resources were included in the Companies' Joint IRP filing with the Commission in Docket No. 18-06003, and were specifically discussed in Volume 5 of 18 and Technical Appendix Item LF-1 of that filing. These forecasts were approved by Commission in the Modified Final Order issued on February 15, 2019.

The above activities meet the requirements of Section 8.2 of the Temporary Regulations with one exception, which is noted in Section 11.B of the DRP narrative. NV Energy is requesting a waiver of the portion of Section 8.2 of the Temporary Regulations that requires that "*The net distribution system load and distributed resource forecast will include system, substation, and feeder level net load projections and energy and demand characteristics for all distributed resource types.*" Still in the "walk" phase of the "walk-jog-run" approach to implementing the DRP, as of the date of this filing, NV Energy has not yet performed future year HCA studies (discussed below in Q&A 12). Substation- and feeder-level Distributed Resource forecasts serve as an input to support these future year HCA studies. When NV Energy determined that the future year HCA studies could not be completed for this filing, NV Energy redirected available resources toward completing the numerous other analyses presented in this filing. The unavailability of these forecasts does not compromise other analyses in the filing, nor does it appreciably diminish the usefulness of the HCA, and does not impact the results from the DRP.

To meet its obligation in the Temporary Regulation, NV Energy plans to deliver its next iteration of the HCA by the end of the summer, 2019. The Companies plan to complete the work necessary to disaggregate system-level Distributed Resources forecasts down to the feeder level in time to produce that next HCA study.

12. Q. PLEASE DESCRIBE NV ENERGY'S ACTIVITIES REGARDING HCA IN THIS DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES AS PRUDENT?

A. As stated in Section 3.A.2 of the DRP narrative, NV Energy performed its HCA using load flow analyses on models of the Companies' distribution systems via the Synergi Electric power flow software. Capturing normal operating conditions and based upon 2017 feeder loading profiles and feeder configurations, NV Energy completed HCA on more than 1,300 distribution feeders, provided a detailed description of the methods and outcomes of the HCA, developed a publicly-accessible Web Portal to view the HCA results with downloadable electronic data,[2] and provided a narrative describing its progress toward providing publicly-available "real-time" hosting capacity. These activities as described in the DRP narrative meet the requirements of Section 8.3 of the Temporary Regulations, with the exceptions noted below.

[2] Discussion of the publicly-accessible Web Portal is provided in Mr. Saavedra's Direct Testimony and in Section 7 of the DRP narrative.

As noted in Section 11.B of the DRP narrative, NV Energy is requesting waivers of the portions of Section 8.3 of the Temporary Regulations which require that "*The Hosting Capacity Analysis shall be performed using … forecasted distribution facilities and their capacity, configuration, loading and voltage data…,*" and "*Scenario analysis will be performed to evaluate hosting capacity under normal and planned and unplanned contingency conditions.*" HCA is extremely time-consuming and computation-intensive. As explained in the narrative, NV Energy expended great effort to acquire, and in the majority of cases, assemble the load profiles of more than 1,300 distribution feeders from a variety of sources. Also, numerous technical hurdles presented themselves during the course of developing and testing the HCA methods and performing the analysis, to the point of requiring the vendor of the Synergi Electric modeling software to initiate and complete coding changes to the software used by NV Energy to perform these studies. Eventually, it became clear that HCA studies for future years could not be completed in time for this filing. The unavailability of these future year studies does not compromise other analyses in the filing, nor does it have an appreciable effect on or diminish the usefulness of the DRP.

NV Energy plans to complete the future year HCA studies as soon as practical following this filing. The Companies plan to complete the HCA for the years 2018 through 2025 using forecasted loading and Distributed Resource penetration at the feeder section level under normal planned configuration of the distribution system by the end of summer 2019.

The next generation of HCA as currently contemplated will include contingency conditions. This step change will require a significant amount of discussion amongst interested parties to determine a method that balances the interests of performing the HCA that includes contingency conditions, with managing the volume of HCA runs required to address the myriad of potential unplanned operating conditions that could existing in the future on a feeder or set of feeders. It must be determined what unplanned operating conditions may be reasonably anticipated and therefore be included in the set of limiting criteria in the HCA studies (in addition to thermal, voltage, and protection-related criteria). To allow adequate time for this and for completion of the actual requisite updated future year HCA studies, and to meet its obligation in the Temporary Regulation, NV Energy plans to complete the HCA including contingency conditions by the end of June 2020 so that the results can be reported in a planned update to the DRP required to be filed with the Commission by September 1, 2020. The unavailability of future year HCA studies including this additional limiting criteria does not compromise other analyses in the filing, nor does it have an appreciable effect on or diminish the usefulness of the DRP.

13. Q. PLEASE DESCRIBE NV ENERGY'S ACTIVITIES REGARDING THE GNA IN THIS DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES AS PRUDENT?

A. As stated in Section 3.A.3 of the DRP narrative, NV Energy developed its GNA including a HCA, NWA analyses, a LNBA which compares utility infrastructure wire upgrade solutions and DER solutions to forecasted transmission and distribution constraints, and recommendations for traditional upgrade projects and NWA solutions recommendations. These activities as described in the DRP narrative meet the requirements of Section 8.4 of the Temporary Regulations, with the exception noted below.

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As noted in in Section 11.B of the DRP narrative, NV Energy is requesting a waiver of the portion of Section 8.4 of the Temporary Regulations, which requires that the *"Grid Needs Analysis shall be based on the … distributed resource forecast …"* In Q&A 11 above, I note that NV Energy has not yet developed Distributed Resources forecasts at the substation and feeder levels and the reasons for that. Consequently, the GNA in this DRP filing does not account for those forecasts in the determination of constraints on NV Energy's electric grid. The unavailability of Distributed Resource forecasts at the substation and feeder levels does not compromise other analyses in the filing, nor does it have an appreciable effect on diminishing the usefulness of the DRP.

As noted in Q&A 11, to meet its obligation in the Temporary Regulation, NV Energy plans to disaggregate system-level Distributed Resources forecasts down to the feeder level prior to this summer 2019.

14. Q. PLEASE DESCRIBE NV ENERGY'S ACTIVITIES REGARDING IDENTIFYING INCREMENTAL INVESTMENT OR EXPENDITURES TO INTEGRATE DERs IN THIS DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES AS PRUDENT?

A. Section 9.B of the DRP narrative identifies several efforts that NV Energy has recently undertaken to support the analyses and meet the requirements of the DRP. Four specific efforts are identified as incremental investment to facilitate the integration of DERs and support the DRP effort, those being:

1. DER Data Integration and Automation;
2. Publicly-Accessible Web Portal;
3. Consulting Labor to Develop the DRP; and

4. DER Analytics Dashboard.

Section 9.B contains brief descriptions of each of these efforts, the dollars spent by the Companies as of February 28, 2019, and estimated remaining expenditures beyond that date, if any. These activities as described in the DRP narrative meet the requirements of Section 3.4 of the Temporary Regulations.

As of the date of this filing, NV Energy has not specifically identified any other software, hardware, or electric system upgrade projects and costs that would qualify as incremental expenditures to facilitate the integration of Distributed Resources and support the DRP effort. However, as noted in Section 8 of the DRP narrative, as well as other areas of the narrative, NV Energy will be evolving a number of elements of the DRP and may identify additional investment necessary to expand its analytical and operational capabilities.

15. Q. ARE SECTIONS 8 AND 10 OF THE DRP NARRATIVE REQUIRED EITHER BY SB146 OR THE TEMPORARY REGULATIONS?

A. No.

16. Q. WHY ARE SECTIONS 8 AND 10 OF THE DRP NARRATIVE INCLUDED AND WHAT PURPOSE DO THEY SERVE?

A. Section 8 describes the Companies' present plans to refine the methods and tools used in the performing the various analyses required to develop the DRP. NV Energy has indicated to the stakeholder group involved in the process of the developing the DRP that it is employing a prudent "walk-jog-run" approach to developing the methods and analyses required to support the goals of the DRP.

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

Naturally then, this first-of-its-kind DRP filing in Nevada would be representative of the emerging nature of this industry in the state and should be expected to grow and mature over the next few years. In Section 8, NV Energy lays out the progression of a number of the main elements of the DRP through the next triennial filing of the Companies' Joint IRP by June 1, 2021.

In reviewing the progress of DRP in California, the Companies noted that certain "demos" were required of the major California investor-owned utilities, particularly around the topics of hosting capacity and locational benefits. Given the emerging nature of this issue in Nevada, NV Energy is of the opinion that it may be prudent to pilot or demonstrate certain concepts, methods, or technologies prior to a decision to employ them in the first place, how to employ them, or whether or not to apply or deploy them system-wide. Section 10 captures recommendations in this regard.

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

A. Yes, it does.

Statement of Qualifications
For
JOSEPH V. SINOBIO

Summary of Qualifications

Over 30 years of electric utility experience, including 25 years of leadership experience, all for NV Energy (Nevada Power Company and Sierra Pacific Power Company) based in Las Vegas, NV. Highly experienced in electric utility distribution planning. Experienced in management and leadership techniques, goal-setting, process analysis, capital budgeting, technical writing, and providing written and verbal regulatory testimony. Expertise in distributed energy resources, interconnection, impact studies, and integrated grid planning.

Professional Experience

Manager, Major Projects-Delivery June 2016 - Present
Nevada Power Company and Sierra Pacific Power Company (d/b/a NV Energy)

Directly manage a team responsible for supporting distributed energy resource planning, interconnection, and impact studies, and integrated grid planning.

Manager, Distribution Planning January 2005 – June 2016
Nevada Power Company and Sierra Pacific Power Company (d/b/a NV Energy)

Directly managed a team responsible for the regional electric Distribution Planning function.

Director, Distribution Technical Services March 2001 – January 2005
Nevada Power Company and Sierra Pacific Power Company

Directed a team responsible for the regional Distribution Standards, electric Distribution Planning (34.5 kV and below), Central Mapping, and Distribution Operations Technical Support functions.

Manager, Regional Electric Technical Services May 2000 – March 2001
Nevada Power Company and Sierra Pacific Power Company

Managed a team responsible for the regional electric Distribution Planning, Central Mapping, and the Distribution Operations Technical Support functions.

Manager, Regional Electric Distribution Planning September 1999 - May 2000
Nevada Power Company and Sierra Pacific Power Company

Directly managed a team responsible for the regional electric Distribution Planning and Distribution Operations Technical Support.

Manager, Distribution Planning & Analysis January 1998 – September 1999
Nevada Power Company

Directly managed a Distribution Planning team.

Manager, Distribution Planning, Standards & Analysis January 1994 – January 1998
Nevada Power Company

Managed a Distribution Planning and Distribution Standards team.

Engineer II - III, Transmission Planning July 1991 – January 1994
Nevada Power Company

Performed detailed engineering analysis to recommend transmission system capital improvement projects, transmission construction requirements for new load additions, and system transfer capability using WSCC powerflow software. Improved departmental analysis procedures by developing a transmission master plan for the southern Las Vegas Valley (+-100 square mile area).

Engineer I - II, Distribution Planning April 1989 – July 1991
Nevada Power Company

Performed engineering analysis in developing distribution master plans, distribution load forecasts, and in recommending distribution system capital improvement projects, distribution construction requirements for new load additions, and new distribution feeder and substation additions for the northern and western Las Vegas Valley (+-200 square mile area with an average annual growth rate of approximately 5%).

Training, Education, & Memberships

Leadership Development Program; Supervisor's Workshop; Team Building; Lessons in Leadership; Change Management; Project Management; Finance & Accounting for Non-Financial Managers; Management Accounting; Managing Multiple Projects, Objectives & Deadlines; Media Training; Customer Relations Training; Situational Leadership II; Criticism & Discipline Techniques for Managers, Mutual Gains; Seven Management & Planning Tools; Managers and Supervisors Conference; Utility Finance & Accounting; Replacing Negativity with Enthusiasm; Coaching Skills for Managers & Supervisors; 7 Habits Fundamentals Workshop; Spatial Load Forecasting; Assertive Leadership Skills; The 4 Disciplines of Execution; Creative Leadership Workshop.

Bachelor of Engineering Degree in Electrical Engineering; State University of New York @ Stony Brook; Stony Brook, NY; 1988.

I.E.E.E. Power & Energy Society Member

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF CLARK)

I, JOSEPH V. SINOBIO, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

Joseph V. Sinobio
JOSEPH V. SINOBIO

Subscribed and sworn to before me
this 26th day of March, 2019.

S. Mannsur
NOTARY PUBLIC

S. MANNSUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023

CASEY BAKER

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to
2018 Joint Triennial Integrated Resource Plan

Distributed Resources Plan

Docket No. 19-04___

PREPARED DIRECT TESTIMONY OF

Casey Baker

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

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

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS A TRANSMISSION PLANNING ENGINEER?

A. I am responsible for developing electric transmission system models and conducting analysis to assist planning efforts for the Companies' transmission system. I conduct analyses to determine potential risks to system reliability and identify the requirements for mitigation. In addition, I perform studies to determine system upgrades required for the interconnection of proposed power generation facilities to the transmission system.

I am also responsible for all Non-Wires Alternative ("NWA") analysis for transmission projects, which is a focal point of the Distributed Resource Plan ("DRP"). Related to this work, I am responsible for creating and maintaining the current NWA screening tools for the NWA analyses conducted in the DRP.

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

A. I have a Bachelor of Science Degree in Mechanical Engineering and a Master of Business Administration Degree with a focus in Renewable Energy, both from the University of Nevada, Reno. I began my employment with the Companies as a student engineer in 2011. I have experience in transmission planning, project management, renewable energy analysis, and energy storage analysis. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Baker Direct-1**.

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

A. No.

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

A. I was the primary developer of the non-wires alternative ("NWA") analysis tools used to screen traditional investment in distribution and transmission projects for deferral or replacement by NWAs. In addition, I conducted the NWA analysis for Transmission (55kV-500kV) category projects.

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

A. No.

7. Q. PLEASE DESCRIBE THE NWA TOOLS THAT YOU WORKED ON?

A. The two NWA analysis tools that I worked on are the Sizing Template and the Present Worth Revenue Requirement ("PWRR") analysis tool. Both were developed using MS Excel. The purpose of the tools is to create a standardized process for analyzing grid need to determine whether the "wired solution" planned to address the grid need can be cost-effectively deferred or replaced with an NWA.

The first step of the analysis performed using the Sizing Template tool is to evaluate whether the grid need (or system constraint) meets the Critical Suitability Criteria and Red Flag Suitability Criteria. If the grid need meets the criteria, the next analysis step is to define the grid need in terms of the size of the system deficiency, duration of the deficiency, and timing of the deficiency. To a degree, this definition process is already performed in the normal course of evaluating wired solutions. However, NWA design requires characterizing grid needs with a higher resolution than has been done historically because NWAs can be designed to fit the exact size of an identified grid need. In the case of thermal loading grid needs, the size of the grid need is defined by querying one-year's worth of historical asset loading data sampled at 15-minute increments to create a loading curve. The curve is then scaled so that the peak loading in the historical year matches the forecasted peak loading of the asset in future years. This provides a series of curves for each successive year. The series of curves can then be compared to the asset operating limit to determine the forecasted overload size, the duration of the overload, and in what year the overload is forecasted to occur.

For transmission voltage deficiency grid needs, the sizing of the grid need was determined by using the size of the reactive support device identified in the wired solution (typically capacitor banks). In some cases, assumptions of the grid need duration had to be made based on estimated outage duration times and peak loading conditions. These assumptions were noted for each project, if applicable, in the DRP.

Once the grid need is defined, the Sizing Template provides the user the ability to simulate dispatching several NWAs to address the grid need in an effort to eliminate the overload. The NWAs that can be simulated include energy efficiency, demand response, solar photovoltaic power output, and energy storage. The user can manually adjust the sizing of each NWA to develop a portfolio of one or many NWAs to solve the grid need. Because the cost-effectiveness of each technology is dependent on the time of day and character of the grid need, each NWA is selected on a case-by-case basis. The final output of the Sizing Template is a capital cost estimate of the NWA portfolio that can be inserted into the PWRR analysis tool if further financial analysis is required.

The PWRR Analysis Tool is a modified version of the Capital Expense Recovery Model ("CER") workbook that the Companies use in Integrated Resource Plans to compare the revenue requirements associated with different capital investments. The PWRR analysis tool requires the user to input the estimated costs of both the wired solution and NWA, including capital costs, operations and maintenance costs, and owner's costs. Additional financial parameters are inputs to the model, including tax variables, construction cash flow, and inflation rate, to create a side-by-side capital expense recovery model comparison between the wired and NWA solutions. The NWA section includes additional variables related to the desired performance of the NWA, including the maximum power output, maximum energy storage size, and round-trip efficiency. If the variable is not applicable (for instance, round-trip efficiency for energy efficiency), it can be set to zero. These variables are used to estimate the benefit streams for the NWAs in addition to the deferral benefit. Finally, the user inputs the required in-service date of the wired solution, the NWA, and the "deferred wired solution." The deferred wired solution is the same wired solution originally proposed, but with the costs delayed until the year in which the NWA can defer the grid need. Each of these inputs can be approximated by the user using standard, publicly available information and then updated as more accurate information becomes available for the specific project through a bidding process or refined assumptions.

The output of the PWRR analysis tool is a PWRR value for both the wired solution and the NWA solution. The PWRR value for the wired solution is calculated using the CER model, discounted to the present year. The net PWRR value for the NWA solution includes the capital expense recovery model combined with the estimated annual benefits. This net PWRR is then combined with the deferred wired solution PWRR to provide a Net Total PWRR for the combined NWA and deferred wired solution.

By comparing the wired solution PWRR with the Net Total PWRR it can be determined whether a NWA can cost-effectively defer or replace the proposed wired solution.

Both tools allow the user to adjust inputs as new information or new assumptions are made. This allows the user to conduct "what-if" sensitivity analyses to determine whether changes in a specific variable (such as updated load forecasts, cost information, or benefit calculations), result in different outcomes.

8. Q. PLEASE EXPLAIN THE CRITICAL SUITABILITY CRITERIA AND RED FLAG SUITABILITY CRITERIA FOR NWA ANALYSIS.

A. The Critical Suitability Criteria establishes two conditions that must be true for the NWA analysis to continue. First, the project being evaluated must have a planned In-Service Date between January 1, 2020 and December 31, 2025. Second, the constraint must be based upon thermal loading, voltage, or reliability, so that a reduction in peak demand loading or energy consumption, or load shifting, on the transmission or distribution facilities involved would eliminate or defer the constraint.

9. **Q.** **PLEASE EXPLAIN THE RED FLAG SUITABILITY CRITERIA FOR NWA ANALYSIS?**

A. The Red Flag Suitability Criteria includes six conditions that the planner should consider before completing a full NWA analysis. These criteria give the planner opportunity to evaluate potential "red flags" that might make a NWA infeasible beyond the Critical Suitability Criteria. It also allows the planner the opportunity to document related institutional knowledge and discuss nuanced details that may affect a proposed NWA design. Red flags include whether or not major procurement for the wired solution have already been initiated, what land constraints exist, what environmental permitting constraints may exist, and whether the location has specific safety or customer service issues relevant to mitigating the grid need. If a red flag is identified that makes a NWA clearly infeasible, the planner is required to plainly document the reason why. Unlike the Critical Suitability Criteria, failure to pass the Red Flag Suitability Criteria does not mean that the NWA is not feasible, a clear and present reason(s) must be provided to halt further NWA analysis.

10. **Q.** **WHAT ASSUMPTIONS AND DATA SOURCES WERE USED IN DEVELOPING THE SIZING TEMPLATE?**

A. In defining the grid need for thermal loading, it was assumed that future loading curves will be similar to historical loading curves. This assumption was coupled with distribution bank loading forecast data developed by the Companies to define the grid need.

For voltage deficiency related grid needs, it was assumed that a photovoltaic plant or energy storage device rating would need to match the reactive power capability of the proposed wired solution to be feasible. This assumption was based on conversations with renewable energy and energy storage developers who stated that current generation inverters can provide similar voltage support to traditional reactive devices such as capacitors or reactors.

11. Q. WHAT WERE THE SOURCES USED FOR MODELING THE DISTRIBUTED RESOURCES IN THE NWA ANALYSIS?

A. In creating the NWA portfolio, several assumptions were made to model the capability of NWA technologies. For energy efficiency, it was assumed that deployment in a specific load pocket or feeder had a maximum capability of reducing loading by 2 percent of the peak loading for 24-hours a day. This assumption was based on Company analysis of existing energy efficiency program capabilities. To model demand response, average demand reduction curves were used. These curves are developed internally by demand response experts and represent the expected decay in load reduction capability during a demand response event based on opt-out functionality. The curves vary based on the time of day the demand response event is triggered. The solar photovoltaic generation profile used for the analysis was a 15-minute average single family residential distributed generation profile (grouped by either Sierra or Nevada Power customers). This same data was used in the most recent general rate reviews for each company (Docket Nos. 16-06006 and 17-06003), and was provided to stakeholders as part of the Assembly Bill 405 implementation Docket No.17-07026.

The approximated capital, operations, and maintenance cost for energy efficiency and demand response solutions is based on an average $/kW cost estimate created by internal energy efficiency and demand response teams based on an analysis of historical program performance. The cost was net of the technology's deferred generation and T&D capacity benefit as calculated in its respective program.

The approximation of capital costs for solar photovoltaic generation was based on publicly available installed cost information. The National Renewable Energy Resource Lab Photovoltaic System Cost Benchmark Q1 2017 report estimates "$1.11/Wdc (or $1.44/Wac) for one-axis-tracking utility-scale systems" (page 48). Discussions with several solar developers verified the reasonableness of using the publicly available figures and their applicability to Nevada installations specifically. For the purposes of the Sizing Template capital cost estimate, $1.47/Wac was used.

To approximate a capital cost for energy storage, the "Total Initial Installed Cost" figures provided on pages 30-31 of the LAZARD Levelized Cost of Storage report (ver. 3.0 issued November 2017) was used. Energy storage installed cost figures varied from a low of approximately $300/kWh to $1200/kWh. This band of prices was compared to a size-adjusted average price for installed utility scale energy storage ($/kWh) calculated using indicative pricing estimates the Companies received from third party developers. For the purposes of screening the NWAs, a figure of $500/kWh or $500,000/MWh was used.

If a grid need showed potential to be feasibly deferred or replaced with a NWA, the price estimates were refined by consulting with industry partners and indicative pricing estimates for specific sizes and locations of resources.

12. Q. WHY WERE DISTRIBUTED SOLAR PRODUCTION PROFILES COMBINED WITH UTILITY SCALE SOLAR COST ESTIMATES IN THE SIZING TEMPLATE?

A. The purpose of the sizing template is to determine whether a NWA is feasible and if solar photovoltaic generation of any kind (residential, commercial, utility-scale) can provide appreciable benefit towards mitigating the grid need. The distributed solar production profiles were used since they represent historical photovoltaic production data in Nevada, have been evaluated thoroughly by the Companies, and are publicly available. The Companies recognize that the actual production profile of a solar photovoltaic plant in the specific location with a specific panel type and plant design would likely have a somewhat different profile, but the difference does not substantially affect whether or not photovoltaic energy production aligns with the timing of the grid need. The Companies also recognize that the cost of residential and commercial photovoltaic installations are often significantly higher than utility scale installations. However, it was decided to use the lowest reasonable cost estimate for screening purposes so that a particular solar based NWA would not be unfairly eliminated using the residential or commercial estimates.

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13. Q. DESCRIBE HOW THE BENEFITS OF DISTRIBUTED ENERGY RESOURCES ARE INTEGRATED INTO THE NWA ANALYSIS.

A. The main benefit of a NWA is the cost savings resulting from deferring or replacing a wired solution. In addition to savings, other benefit streams can sometimes be captured depending on the technology being deployed. In the case of energy efficiency and demand response, reduction in generation, transmission, and distribution capacity is embedded in the cost estimate of the asset. For utility-scale solar photovoltaic, the energy benefit (the dollar value of the energy delivered) is calculated by multiplying the companies hourly Marginal Energy Cost ("MEC") forecast by the solar production profile. For retail solar photovoltaic generation (residential, commercial, etc.) the energy benefit is assumed to be compensated outside of the NWA analysis through net-metering or another power-purchase agreement and is therefore set to zero.

Both solar photovoltaic and energy storage assets provide a reduction in peak capacity benefit. For solar photovoltaic generation, the peak capacity size is equal to the nameplate output of the generator multiplied by the percentage of generation expected to be available over system peak. This percentage is calculated for solar assets in both northern and southern territories internally by the Companies for resource planning purposes. Analyses of the Companies' peak capacity needs indicate that peak capacity resources must be able to provide four hours of continuous power output to adequately address system peak periods. As a result, the peak capacity size of an energy storage asset is calculated by finding the minimum of either the power output capability of the asset (measured in MWs) or the energy storage capability (measured in MWhs) divided by four. Once the peak capacity size of the asset is determined, it is then multiplied by the Company-developed capacity price forecast (in $/kW-Month) for three months for each year during the life of the asset. This calculation is based on the fact that capacity resources only provide clear system benefits for approximately three months every year in Nevada's electric system.

For energy storage assets, the NWA tool approximates the value of energy arbitrage. Energy arbitrage value was developed by estimating a $/kWh figure for storage based on an analysis of resource planning base cases with and without storage assets. First, a resource planning case was run without energy storage assets and the total yearly production costs for 27 years was forecasted. Then the same case was adjusted to include a 25 MW x 4-hour (100 MWh) energy storage device in Nevada's area set to charge and discharge based on forecasted energy prices. The total yearly production costs were forecasted again using the storage case. The annual difference in production costs between the no-storage case and the storage case was then divided by the storage capacity (kWh) of the modeled storage device to approximate the per unit value of energy storage for energy arbitrage purposes. This figure was then multiplied by the size of the proposed energy storage device to estimate the potential energy arbitrage value of the asset.

The energy value, capacity value, and energy arbitrage values, when applicable depending on technology, are included in the PWRR analysis tool and used to offset the NWA costs for each year in the CER model.

This allows the Net Total PWRR to represent the cost of the asset minus the estimated benefits.

14. Q. IN THE DRP, HOW MANY TRANSMISSION PROJECTS WERE EVALUATED FOR A NON-WIRES ALTERNATIVE?

A. The 2018 Fall Capital Plan included 107 transmission projects with planned capital allocated between 2018 and 2027. Of these 107 projects, 42 projects met the Critical Suitability Criteria A, 26 projects met Critical Suitability Criteria B, and 14 projects met both Criteria A and B. Prior to the NWA analysis process, two capital upgrades in the original 2018 Fall Capital Plan were deferred from 2024 and 2025 in-service dates until 2030 due to updated assumptions. As a result, 12 transmission capital upgrade projects were evaluated using the NWA analysis tools.

15. Q. DID ANY OF THE PROJECTS SHOW POTENTIAL FOR BEING DEFERRED OR REPLACED WITH A NWA?

A. Yes.

16. Q. PLEASE DESCRIBE THE PROJECT AND THE PROPOSED NON –WIRES ALTERNATIVE.

A. The Clark – Concourse 138 kV line in Nevada Power's service territory is currently forecasted to overload in 2025 under unplanned contingency scenarios. The proposed wired solution for this project is to reconductor the existing line to increase the transmission capacity of the circuit from 237 MVA to 428 MVA. The estimated cost of the wired solution is $2.3 million.

In 2025, the forecasted overload is only 0.98 MW and 0.44 MWh. An energy storage device with this capability may be able to be procured, installed and interconnected for approximately $1.59 million based on indicative pricing estimates received from third-party developers. A PWRR analysis was conducted to determine if deferring the wired solution from 2025 to 2026 provided sufficient savings to offset the capital cost of the energy storage device including the energy arbitrage benefit. The PWRR analysis found that the single year of deferral and energy arbitrage benefit did not provide sufficient savings to offset the costs of the asset.

17. Q. WAS THE NON-WIRES ALTERNATIVE PURSUED.

The PWRR analysis concluded that a NWA was not cost-effective to be pursued for this grid need at this time. However, as the need becomes more imminent, the analysis can be rerun by designing the NWA to defer the wired solution for additional years and with updated cost assumptions to determine if at that time a NWA is feasible.

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

A. Yes.

STATEMENT OF QUALIFICATIONS
Casey Baker

My name is Casey Baker. My business address is 6100 Neil Road, Reno, Nevada. I have been employed with Sierra Pacific Power Company ("Sierra" or “the Company”) since 2011. I am currently a Transmission Planning Engineer II in the Transmission System Planning department for NV Energy.

I started my career with NV Energy as a student intern in the Major Projects department. During my two years in this role I was introduced to the capital budgeting process and project scheduling. During my last semester as a student intern, I worked in the Renewable Energy department where I provided public presentations on NV Energy’s RenewableGenerations Incentives program, energy efficiency, electric vehicles, and renewable energy technology.

I began full-time employment with NV Energy in 2013 as a Transmission Planning Associate Engineer. In this role I conducted analysis of NV Energy’s transmission grid. My primary focus was conducting system impact studies for proposed renewable energy generation interconnections to NV Energy’s transmission system. Using company and industry standards, I determined the transmission system upgrades required to safely and reliably interconnect the proposed generation. In this position I was required to understand how new renewable energy technology would affect the Transmission System and implement that knowledge in planning design. In addition, I helped develop a customer reliability improvement plan that focused on identifying transmission system grid needs and prioritizing projects to mitigate them.

In 2014 I became a Transmission Associate Project Manager. In this role I interacted directly with renewable energy developers seeking to interconnect on NV Energy's transmission system. I was required to manage multi-disciplinary teams of engineers to scope and schedule transmission projects required for the interconnection of renewable energy generators.

In 2017 I changed departments to the Renewable Energy and Smart Infrastructure group at NV Energy. The team's purpose was to identify opportunities to deploy renewable energy, energy storage, and Non-Wires Alternatives. In this role, I worked with subject matter experts from several departments to develop the Non-Wires Alternative screening tools.

In 2018 I moved back to Transmission Planning as a Transmission Engineer II. For the Distributed Energy Resource Plan, I was responsible for performing the NWA analysis for grid needs on the transmission system. In this role I also continue to maintain and update the NWA screening tools.

By virtue of my employment, background, experience and education, I am a qualified witness in regard to the NV Energy's NWA screening tool and all transmission NWA analyses associated with the Companies' DRP filings.

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF WASHOE)

I, CASEY BAKER, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

CASEY BAKER

Subscribed and sworn to before me

this 29 day of March, 2019.

LYNN D'INNOCENTI
Notary Public - State of Nevada
Appointment Recorded in Washoe County
No: 13-10786-2 - Expires May 2, 2021

Lynn D'Innocenti

NOTARY PUBLIC

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

ANITA L. HART

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to
2018 Joint Integrated Resource Plan

Distributed Resources Plan

Docket No. 19-04___

PREPARED DIRECT TESTIMONY OF

Anita L. Hart

SECTION I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

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

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

A. My professional experience includes 25 years in the utility industry and I have a Master of Arts in Economics with an emphasis in Public Utility Regulation. I have worked for the Companies since 2008. In addition to Director and Consultant Staff positions in the Demand Side Management organization, I was also assigned to the resource planning organization in the role of Manager of Gas Transportation Planning. In that role I was responsible for the planning and analysis of natural gas transportation needs and ensuring sufficient supply to the generation fleet and Sierra's natural gas customers.

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

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, DEMAND SIDE MANAGEMENT.

A. As the Director of Demand Side Management I am responsible for the development, analysis and implementation of a cost-effective portfolio of electric and natural gas DSM and CEE programs.

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

A. Yes, I have testified in several proceedings before the Commission, in addition to the California Public Utilities Commission and the Arizona Corporation Commission. Most recently, I provided testimony addressing demand side issues before this Commission in Docket Nos. 17-06043, 17-06044 and 18-06003.

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

Exhibit Hart-Direct-1	Statement of Qualifications
Exhibit Hart-Direct-2	DR/PV Interaction Assessment

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

A. I am supporting Section 3-D of the Distributed Resources Plan ("DRP"), which is entitled "Coordination with Existing Commission-approved DER Programs." In this section of the DRP, the Companies review the long list of existing legislatively-mandated programs (including education, incentive and tariff programs) addressing the deployment of distributed resources. As is apparent from this description, through programs already offered and administered by the Companies, customers at Nevada Power and Sierra are highly invested in the success of the distributed resources economy. The discussion highlights the current state of program coordination with grid operations and how these programs support the analysis of locational benefits and costs. Then recommendations and proposals are made to further improve the locational benefits of distributed resource programs, reduce the incremental cost of their deployment, and achieve better coordination and alignment across parallel efforts and policy goals. Finally, in compliance with the directive contained in the stipulation approved by the Commission in Docket Nos. 16-07001 and 16-07007, which required the Companies to report in their 2018 joint integrated resource ("IRP") plan on their assessment of the interaction between demand response programs and photo-voltaic systems, I discuss the results of the assessments completed.

SECTION II: SUMMARY OF ONGOING DISTRIBUTED RESOURCE PROGRAMS

7. Q. PLEASE PROVIDE AN OVERVIEW OF THE EXISTING DISTRIBUTED RESOURCE PROGRAMS NV ENERGY CURRENTLY IMPLEMENTS?

A. The Companies have been proactive in supporting the Nevada Legislature's evolving policies vis-à-vis the adoption of distributed generation, serving as the program administrator charged with managing the funding of customer rebates for solar, wind, and hydropower distributed generation systems. Additionally, in order to effectively implement Senate Bill 145 (2017 Legislature), these programs have been expanded to include customer rebates for energy storage technologies and electric vehicle infrastructure.

In parallel, the Companies have been offering for many years, a portfolio of cost-effective energy efficiency ("EE") and demand response ("DR") programs delivered to customers through Commission-approved DSM

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Plans proposed and approved as part of the IRP process. The currently approved portfolio of DSM programs include: Energy Education, Energy Assessments, Direct Install, Low Income, Residential Lighting, Residential Air Conditioning, Pool Pumps, Schools, Commercial Energy Services, and both residential and commercial DR.

In addition to the programs noted above the Companies offer a variety of DR-related tariffs in the form of stand-alone tariffs or tariff riders that effectuate price-based load response and require no DR technology and infrastructure, as well as stand-alone tariffs and tariff riders that require varying degrees of DR technology and program management support.

8. Q. WHAT TYPES OF SYSTEM BENEFITS DO THE DSM PROGRAMS CURRENTLY OVERSEEN BY THE COMMISSION PROVIDE TO CUSTOMERS?

A. The DSM programs described above flatten the system load shape and improve the system load factor. This effect is driven by two primary factors: permanent peak demand savings and dispatchable peak demand savings. Permanent peak demand savings are derived from the coincident peak demand savings from energy efficiency programs. For example, the Commercial Services programs have a significant impact on system peak demand. Dispatchable peak demand savings are derived from demand response programs. Demand response events avoid the purchase of expensive peak market energy and provide substantial savings for all customers.

With respect to electricity grid benefits, the Companies' residential and commercial demand response programs are currently employed for 10-minute operating reserves. It can also be strategically dispatched by location to reduce congestion on the distribution system or in response to a distribution system emergency. The system can operate in much the same fashion as a supply-side peaking resource, while providing an added suite of customer, environmental and locational dispatch benefits.

9. Q. DO THE COMPANIES HAVE EXPERIENCE WITH DEPLOYING DSM TO PROVIDE A LOCATIONAL BENEFIT?

A. Yes. Energy efficiency programs typically support long-term planning objectives and deliver "permanent" demand and energy reduction. While such programs do not *per se* provide operational flexibility to the utility grid or locational dispatch capability in the way that demand response programs can, they can still provide locational benefits. As an example, the Companies successfully deployed concentrated energy efficiency in a target area (Carson City, Dayton, Carson Valley and South Tahoe) while an upgrade to transmission service into the area was deferred (reference Docket Nos. 08-08012 and 08-08013).

The Companies' DR information technology and communications systems support the locational dispatch of DR resources. As far back as 2008, before the financial crisis hit, the Companies' DSM department worked with their Distribution Planning department to identify "hotspots" on the distribution system, where certain feeders had started to exceed their loading limits. The A/C direct load control program—called "Cool

Share" at the time—was then target marketed into these hotspots with success during the 2008 program year. Continuing decline in the housing market and the financial crisis cooled off these hotspots and the target marketing of DR. However, the project demonstrated successful target marketing and the programming of the load management systems to be able to dispatch load control in the hotspot areas.

Finally, in the 2012 timeframe the Companies leveraged the statewide NV Energize smart meter project, and the U.S. DOE Smart Grid Investment Grant (part of the American Reinvestment and Recovery Act) to specify, procure, and implement a Demand Response Management System ("DRMS"). The DRMS allows the utility to deploy load control devices to accommodate locational dispatch by geographic zones, or by substation, bank, or feeder. Functionality in the DRMS allows distribution operators to log into the system to see at the feeder level how much load curtailment is available, and to dispatch an event to a substation, bank, or feeder. DRMS was originally set up to accommodate larger geographic zones, such that if an event was launched to a specific feeder, all of the devices on that feeder and in that particular zone would be dispatched. The DSM technical services team is currently reconfiguring the resource groups in DRMS from larger geographic zones to a more granular set of resources to enable more accurate dispatch at the feeder level. Locational dispatch testing was performed in 2018 to verify expected operating characteristics and in preparation for new IT systems integrations between the DRMS, the Advanced Distribution Management System ("ADMS"), and the Geographic Information System ("GIS"). A new integration to

ADMS will allow distribution operators to dispatch DR events from within ADMS to assist with distribution system management; and, a new integration to the GIS system will update the distribution system network topology within DRMS on a daily basis, as opposed to the historical practice of once a year before the start of the load control season.

10. Q. WHAT IS THE ROLE OF DSM WITH RESPECT TO THE NON-WIRES ALTERNATIVES ANALYSIS?

A. The Companies are currently deploying DSM programs that are used for permanent peak demand reduction from energy efficiency measures and temporary load management interventions from demand response enabled technologies. General deployment of these programs has an impact at both the system level as well as at the distribution system level. A number of industry case studies highlight the use of energy efficiency and demand response as key components of successful non-wires alternative projects. Hence, within the context of the evolving distributed resource plan elements it will be important to continue work on more fully characterizing the impact of DSM programs at the distribution system level. The Company has already started to include some initial methodologies to estimate the impact of energy efficiency and demand response on certain distribution feeders already identified as requiring additional infrastructure to reliably meet customer load. With a few key changes to existing demand response infrastructure and operations, and incremental energy efficiency in-line with regulatory targets, at least one of the distribution system upgrade projects—a transformer addition at Village Substation—could potentially be deferred.

11. Q. WHICH DSM CAPABILITIES AND OPPORTUNITIES WILL BE FURTHER INVESTIGATED WITH RESPECT TO NON-WIRES ALTERNATIVES?

A. The first capability to be examined in 2019 is a targeted and optimized dispatch of demand response resources installed at premises on Village Substation distribution feeders. This requires re-programming the DRMS to include a larger number of discrete resources at the feeder level for more targeted event dispatch. The second capability will be to develop and test a new optimization algorithm designed to shape the peak load on the distribution feeders. Demand response capacity in the area around Village Substation currently approximates 1.2 MW; however, the estimates are based upon maximum load shed capability using system average load impact factors. It will be important to determine the actual peak shaping capability of these resources. Another opportunity that could be further explored is to specifically target recruitment of additional customers around Village Substation who would have the most impact on reducing the peak load requirements of the feeders. The higher impact programs would include those that address the loads driving peak, such as: residential air conditioning measures; commercial air conditioning measures; and demand response.

12. Q. WHAT IS THE ROLE OF CLEAN ENERGY PROGRAMS WITH RESPECT TO THE NON-WIRES ALTERNATIVES ANALYSIS?

A. Similar to energy efficiency and demand response resources, customer-sited solar PV displaces traditional centralized generation, which must use the utility's T&D network to deliver electricity to customer sites.

Distributed solar resources generate power that is consumed on that distribution system. On homes equipped with customer-sited solar PV systems, the solar output serves the on-site load first. Unless excess generation is produced, a system's "green electrons" never flow through the utility grid, but net loading on the utility's T&D network is reduced. Typically, any excess power generated and pushed onto the grid is delivered through the local distribution system and consumed by the solar customer's neighbors. Net loading in the local area and on upstream portions of the distribution system, as well as T&D losses, are reduced.

13. Q. HOW DO THE COMPANIES PLAN ON IMPROVING THE COORDINATION AND IMPLEMENTATION OF THE CURRENT DISTRIBUTED RESOURCE PROGRAMS?

A. The Companies recognize the need to strategically coordinate the joint implementation of multiple DERs that: 1) are required by different administrative code and regulations; 2) are approved in separate Commission filings; 3) have different cost recovery mechanisms; and 4) are managed by different departments within the Companies. The Companies have a great deal of technical knowledge from the Villa Trieste project that has provided lessons learned and best practices for future projects. Functionally, the Companies will be focusing on strategic areas that could greatly benefit from continued collaboration including how to use existing programs, systems and tariffs to most cost effectively achieve the goals of AB223/SB150, SB145, SB204, and SB146. The Companies will be evaluating a variety of activities and/or tools for efficient utility operations and coordinated program efforts.

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

SECTION III: COMPLIANCE ITEMS AND DIRECTIVES

14. Q. PLEASE DESCRIBE THE DIRECTIVE CONTAINED IN THE STIPULATION APPROVED BY THE COMMISSION IN DOCKET NOS. 16-07001 AND 16-07007, WHICH REQUIRED THE COMPANIES TO REPORT IN THEIR 2018 JOINT IRP ON THEIR ASSESSMENT OF THE INTERACTION BETWEEN DR PROGRAMS AND PHOTO-VOLTAIC SYSTEMS.

A. In Docket Nos. 16-07001 and 16-07007 the Companies agreed in a Commission-approved stipulation to report on their assessment of the interaction, if any, between DR and photo-voltaic systems. Thereafter the legislation establishing the requirement for this DRP, SB146 was enacted. SB146 characterizes both solar PV and DR as Distributed Resources. Regulations implementing SB146 require that DRPs discuss the interplay between Commission-approved Distributed Resources programs. Ultimately, the Companies view the intent of the regulations as requiring the coordination of existing Commission-approved programs promoting the deployment of Distributed Resources, with the projects emerging from the DRP for promoting the deployment of Distributed Resources.

15. Q. PLEASE DESCRIBE THE ASSESSMENT OF THE INTERACTION BETWEEN DR PROGRAMS AND CUSTOMER-SITED PV SYSTEMS.

A. The Companies completed two internal assessments. The first analysis was completed to determine if the peak hour of the system load would shift with the increase in customer-sited PV systems. The results of this Study are contained in **Exhibit Hart-Direct-2.** The second assessment reviewed DR program participant event override behaviors by event phases.

Major findings from the evaluations are listed below:

1. The addition of customer-sited photo-voltaic ("PV") systems does not adjust the forecasted peak hour of uninterrupted system loads. The peak at hour 17 remains for both Nevada Power and Sierra over the 2019-49 period;
2. Customers' overriding behavior did not show significant differences across DR event phases with different start times; and

Based on these results, the Companies will continue to implement demand response as approved by the Commission.

16. Q. DOES THIS COMPLETE YOUR TESTIMONY.

A. Yes, it does.

STATEMENT OF QUALIFICATIONS

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

EDUCATION

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

PROFESSIONAL EXPERIENCE

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

Director – Demand Side Management, Energy Efficiency/Conservation

- Oversight of the Demand Side Management team
- Development and implementation, analysis and cost recovery of cost-effective statewide demand side management programs that provide exceptional service to customers.

Manager – Gas Transportation Planning, Resource Planning and Analysis

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

Consultant Staff – DSM Planning, Customer Strategy & Programs

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

SOUTHWEST GAS CORPORATION – Las Vegas, Nevada (1993 to 2008)

Manager – State Regulatory Affairs/Research, Conservation and DSM

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

Senior Specialist – State Regulatory Affairs

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

Administrator and Specialist – Marketing/Conservation and DSM

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

Regulatory Analyst – Revenue Requirements and Resource Planning

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

PUBLIC SERVICE COMPANY OF NEW MEXICO – ALBUQUERQUE, New Mexico (Summer 1992)

Student Intern – Regulation and Market Communication

- Completion of a retail wheeling study.

BOARDS AND HONORS

SOUTHWEST ENERGY EFFICIENCY PROJECT ("SWEEP")

- 2016 Board of Directors, Member

LAS VEGAS METRO CHAMBER OF COMMERCE FOUNDATION

- 2015 Leadership Las Vegas, Graduate

EXHIBIT HART-DIRECT-2

Customer-Sited Photo-Voltaic and Demand Response Interaction

March 22, 2019

Major Findings

1. The addition of customer-sited photo-voltaic ("PV") systems does not adjust the forecasted peak hour of the uninterrupted system loads. The peak at hour 17 remains for both Nevada Power and Sierra over the 2019-49 period; and
2. Customers' overriding behavior did not show significant differences across demand response ("DR") event phases with different start times.

1. Annual load profile forecast

On March 28, 2019, the load forecasting team at NV Energy provided their final DR-uninterrupted hourly system load forecast from 2019 to 2049 for the Nevada Power Company ("Nevada Power") and the Sierra Pacific Power Company ("Sierra"), respectively. Per communication with the load forecasting team, the system load forecast has taken into account the behind-the-meter distributed rooftop photovoltaic solar generation (customer-sited PV), but it does not include the impact from the must-take purchased or IRP-planned solar and renewable generation from the supply side resources. This analysis was completed to determine if the peak hour of the system load would shift with the increase in customer-sited PV systems.

Using the hourly system load forecast data files provided by the load forecast team, the annual peak load hour is identified and reported in Table 1. The peak day load profiles are plotted and reported in Figure 1 for NPC and Figure 2 for SPPC. Figure 1 shows that the NPC DR-uninterrupted system loads will peak at hour 17 on July 1 for 2019 and at hour 17 on July 5 for 2049 with a peak load of 5,855 megawatts (MW) and 7,224 MW, respectively. While annual system peak loads are forecasted to occur on different days over the 2019-49 period for NPC, the annual loads are always (without exception) projected to peak at hour 17 over the forecast period once must-take solar and renewable generation are excluded from consideration. As can be seen from Figure 2, annual peak loads for SPPC, just like the NPC case, may occur on different days but always at hour 17 over the forecast period of 2019-49, with annual peaks increasing from 1,796 MW in 2019 to 2,074 MW in 2049.

Table 1. Original DR-uninterrupted system peak load hour over 2019 - 2049

Year	Annual Peak Load Hour	
	Nevada Power	Sierra
2019	17	17
2024	17	17
2029	17	17
2034	17	17
2039	17	17
2044	17	17
2049	17	17

Figure 1. Nevada Power Annual Peak Day Load Profile 2019-2049

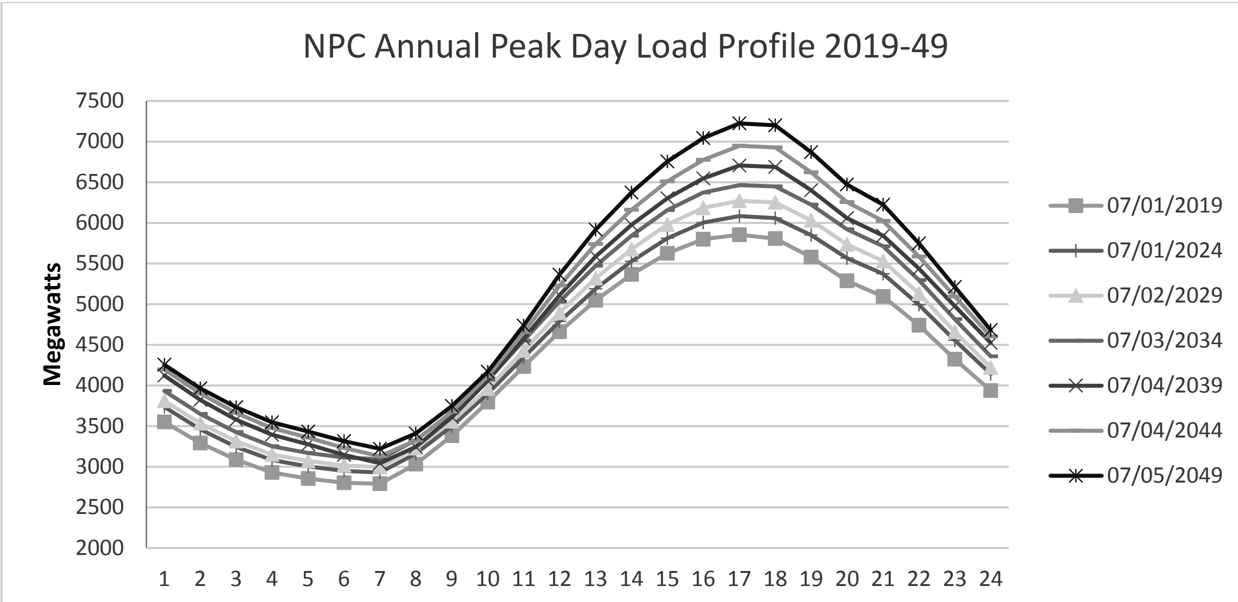
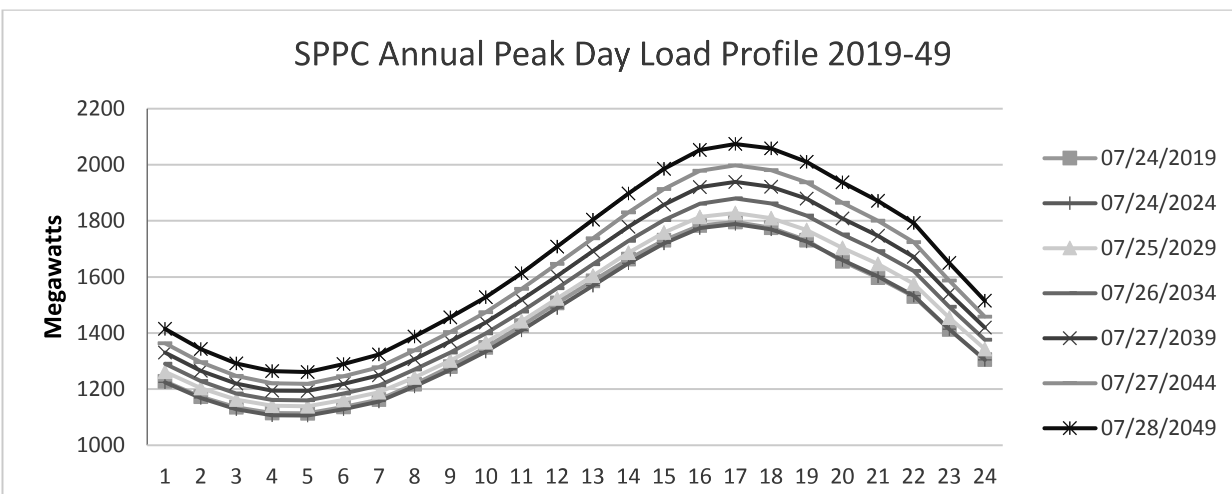


Figure 2. Sierra Annual Peak Day Load Profile 2019-2049



2. Customer DR event overriding behavior

In this section, DR program customers' potential to override DR events, as well as changes in overall event override rates over the last five years (from 2014 to 2018) is revisited based on ADM's multiple year measurement and verification reports. Manual override rates are reported for DR customers with either two-way communicating programmable thermostats (35,058 devices in total in the south by end of 2018) or smart thermostats (66,560 devices in the south and 10,990 devices in the north by end of 2018). These customers can simply adjust their thermostats to override a DR event at any point of time during an event, and customers contribute about 94 percent demand reduction in the DR residential and small commercial resource portfolio. Contributing about six percent of the total DR capacity, customers installed with switches (i.e., direct control units) or one-way communicating programmable thermostats are not included in this report as they need to call our customer service representatives to override a DR event and their event override rates have been consistently much lower than one percent overtime because of the inconvenience.

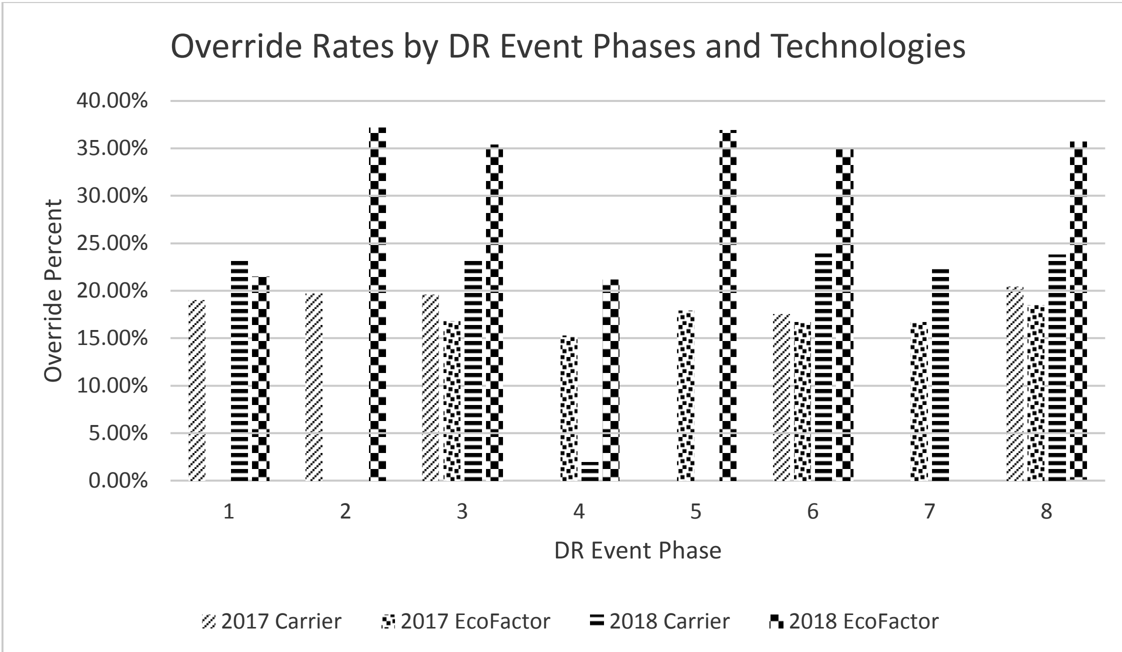
a. Override rates by event phases

In 2017 and 2018, an eight-phase DR event strategy was used in the south with the first phase of the event typically starting at 15:30, the second phase at 15:40 (15:30 plus 10 minutes), and so on with the last phase starting at 16:40. Because DR events in the north started uniformly at 16:00 and ended at 18:00, with all devices being controlled at the same time, analysis of the behaviors of customers in the north was not performed. Override rates by DR event phases in the south are reported in Table 2 and Figure 3. It can be seen that override rate across phases are almost the same, being around 20 percent for customers with Carrier thermostats, while for customers with the EcoFactor smart thermostats, override rates ranging from near 17 percent to 18.5 percent in 2017 and from about 21 percent to 37 percent in 2018, suggesting that customers' overriding behavior did not show statistically remarkable change with the event start time.

Table 2. Override Rates by DR Event Phases in the South

DR Event Phase	Time Difference from the 1st Phase (minutes)	2017		2018	
		Customers with Carrier Thermostats	Customers with EcoFactor Thermostats	Customers with Carrier Thermostats	Customers with EcoFactor Thermostats
1	0	19.0%	NA	23.4%	21.5%
2	10	19.7%	NA	NA	37.2%
3	20	19.6%	16.8%	23.2%	35.4%
4	30	NA	15.3%	1.95%	21.2%
5	40	NA	17.9%	NA	36.9%
6	50	17.5%	16.7%	23.9%	34.9%
7	60	NA	16.7%	22.3%	NA
8	70	20.4%	18.5%	23.8%	35.7%

Figure 3. Customer Overriding Rates by DR Event Phases and Technologies



AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF CLARK)

I, ANITA L. HART, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

Anita Hart

ANITA L. HART

Subscribed and sworn to before me this 25th day of March, 2019.

S. MANNSUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023

NOTARY PUBLIC

DRP-1

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
NE	Allen	ALN BK 1		16.5	16.3	15.8	15.0	14.0	ALN1201		299	280	462	422	375
NE	Allen	ALN BK 1		16.5	16.3	15.8	15.0	14.0	ALN1203		486	489	276	283	275
NE	Allen	ALN BK 1		16.5	16.3	15.8	15.0	14.0	ALN1204		1	1	2	1	1
NE	Allen	ALN BK 2		29.1	29.5	30.7	29.1	27.6	ALN1205		407	437	440	420	420
NE	Allen	ALN BK 2		29.1	29.5	30.7	29.1	27.6	ALN1206		418	420	509	511	479
NE	Allen	ALN BK 2		29.1	29.5	30.7	29.1	27.6	ALN1210		2	2	2	2	2
NE	Allen	ALN BK 2		29.1	29.5	30.7	29.1	27.6	ALN1212		400	344	542	498	461
NE	Allen	ALN BK 2		29.1	29.5	30.7	29.1	27.6	ALN1213		457	501	498	456	442
NE	Allen	ALN BK 3		29.8	29.8	31.7	30.0	28.7	ALN1214		491	531	529	508	483
NE	Allen	ALN BK 3		29.8	29.8	31.7	30.0	28.7	ALN1215		393	384	388	371	336
NE	Allen	ALN BK 3		29.8	29.8	31.7	30.0	28.7	ALN1217		201	204	103	102	102
NE	Alta	AL BK 3		21.4	21.6	22.0	22.2	23.5	AL1202		466	487	483	472	487
NE	Alta	AL BK 3		21.4	21.6	22.0	22.2	23.5	AL1203		280	326	311	353	359
NE	Alta	AL BK 3		21.4	21.6	22.0	22.2	23.5	AL1205		249	267	260	260	350
NE	Alta	AL BK 4		11.5	12.1	12.4	12.0	12.2	AL1208		95	96	104	130	123
NE	Alta	AL BK 4		11.5	12.1	12.4	12.0	12.2	AL1209		463	470	497	471	475
NE	Alta	AL BK 5		27.9	29.0	28.8	28.6	26.0	AL1210		374	385	389	367	367
NE	Alta	AL BK 5		27.9	29.0	28.8	28.6	26.0	AL1212		314	308	304	302	307
NE	Alta	AL BK 5		27.9	29.0	28.8	28.6	26.0	AL1213		328	328	343	345	336
NE	Alta	AL BK 5		27.9	29.0	28.8	28.6	26.0	AL1214		356	356	355	352	251
NE	Alta	AL BK 6		4.7	4.6	4.6	5.6	5.0	AL1217		45	49	43	46	46
NE	Alta	AL BK 6		4.7	4.6	4.6	5.6	5.0	AL1218		188	186	195	224	200
NE	Andrews	AND BK 1		22.1	23.5	22.2	20.3	16.6	AND1203		1	1	1	1	1
NE	Andrews	AND BK 1		22.1	23.5	22.2	20.3	16.6	AND1204		400	387	410	416	373
NE	Andrews	AND BK 2		21.7	23.1	22.1	20.0	16.2	AND1207		406	343	350	335	439
NE	Andrews	AND BK 2		21.7	23.1	22.1	20.0	16.2	AND1209		311	393	400	267	253
NE	Andrews	AND BK 2		21.7	23.1	22.1	20.0	16.2	AND1212		415	391	395	292	234
NE	Andrews	AND BK 2		21.7	23.1	22.1	20.0	16.2	AND1213		180	405	422	414	378
NE	Andrews	AND BK 2		21.7	23.1	22.1	20.0	16.2	AND1214		1	1	1	1	1
NE	Andrews	AND BK 2		21.7	23.1	22.1	20.0	16.2	AND1215		1	1	0	0	0
NE	Andrews	AND BK 2		21.7	23.1	22.1	20.0	16.2	AND1217		412	416	422	356	2
NW	Angel Peak	AP BK 1		0.5	0.5	0.5	0.6	0.6	AP401		22	24	19	17	17
NW	Angel Peak	AP BK 1		0.5	0.5	0.5	0.6	0.6	AP402		16	16	16	15	15
NW	Angel Peak	AP BK 1		0.5	0.5	0.5	0.6	0.6	AP403		34	33	32	90	56
NW	Angel Peak	AP BK 2		0.0	0.0	0.0	0.0	0.0	AP3402		16	16	19	82	60
SE	Anthem	ANT BK 1		30.2	30.3	23.8	26.0	24.9	ANT1201		373	402	159	169	161
SE	Anthem	ANT BK 1		30.2	30.3	23.8	26.0	24.9	ANT1203		144	138	120	136	125
SE	Anthem	ANT BK 1		30.2	30.3	23.8	26.0	24.9	ANT1204		486	578	535	506	503
SE	Anthem	ANT BK 2		30.2	30.7	23.9	26.4	25.0	ANT1205		404	452	344	387	379
SE	Anthem	ANT BK 2		30.2	30.7	23.9	26.4	25.0	ANT1207		442	392	349	366	329
SE	Anthem	ANT BK 2		30.2	30.7	23.9	26.4	25.0	ANT1209		189	197	176	194	187
SE	Anthem	ANT BK 2		30.2	30.7	23.9	26.4	25.0	ANT1212		432	474	443	436	442
SE	Anthem	ANT BK 2		30.2	30.7	23.9	26.4	25.0	ANT1213		367	389	402	385	388
SE	Anthem	ANT BK 3		8.9	8.9	8.3	8.9	8.7	ANT1214		413	412	392	414	404
SW	Arden	AD BK 4		18.2	17.2	15.3	13.3	19.7	AD1202		171	177	1	1	1
SW	Arden	AD BK 4		18.2	17.2	15.3	13.3	19.7	AD1203		401	398	365	356	328
SW	Arden	AD BK 4		18.2	17.2	15.3	13.3	19.7	AD1204		370	345	291	275	437
SW	Arden	AD BK 5		18.2	17.5	15.0	13.2	19.6	AD1205		281	252	379	385	357
SW	Arden	AD BK 5		18.2	17.5	15.0	13.2	19.6	AD1206		122	111	105	98	533
SW	Arden	AD BK 5		18.2	17.5	15.0	13.2	19.6	AD1207		402	399	331	339	328
SW	Arden	AD BK 5		18.2	17.5	15.0	13.2	19.6	AD1208		1				
NE	Artesian	AR BK 2		24.7	24.3	24.3	24.1	23.2	AR1202		213	210	211	212	202
NE	Artesian	AR BK 2		24.7	24.3	24.3	24.1	23.2	AR1203		128	126	129	128	122
NE	Artesian	AR BK 2		24.7	24.3	24.3	24.1	23.2	AR1204		431	430	443	421	425
NE	Artesian	AR BK 2		24.7	24.3	24.3	24.1	23.2	AR1206		431	386	390	399	369
NE	Artesian	AR BK 3		24.4	25.0	25.6	24.6	23.6	AR1208		370	363	501	479	436
NE	Artesian	AR BK 3		24.4	25.0	25.6	24.6	23.6	AR1210		229	231	228	218	224
NE	Artesian	AR BK 4		24.5	25.1	25.6	24.6	23.7	AR1211		477	473	481	481	457
NE	Artesian	AR BK 4		24.5	25.1	25.6	24.6	23.7	AR1213		477	468	364	367	366
NE	Artesian	AR BK 4		24.5	25.1	25.6	24.6	23.7	AR1214		431	435	427	442	392
NE	Artesian	AR BK 4		24.5	25.1	25.6	24.6	23.7	AR1215		417	436	443	443	420
SW	Avera	AVR BK 1		42.6	40.5	40.4	36.2	33.7	AVR1205		460	476	353	357	358
SW	Avera	AVR BK 1		42.6	40.5	40.4	36.2	33.7	AVR1206		298	293	272	248	247
SW	Avera	AVR BK 1		42.6	40.5	40.4	36.2	33.7	AVR1208		429	456	554	484	432
SW	Avera	AVR BK 1		42.6	40.5	40.4	36.2	33.7	AVR1209		381	326	337	310	315

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
SW	Avera	AVR BK 1		42.6	40.5	40.4	36.2	33.7	AVR1210		421	416	501	390	356
SW	Avera	AVR BK 2		33.6	33.5	37.7	32.0	30.0	AVR1215		433	450	538	353	339
SW	Avera	AVR BK 2		33.6	33.5	37.7	32.0	30.0	AVR1216		336	356	521	474	436
SW	Avera	AVR BK 2		33.6	33.5	37.7	32.0	30.0	AVR1217		497	534	537	480	441
SW	Avera	AVR BK 2		33.6	33.5	37.7	32.0	30.0	AVR1221		312	303	340	308	286
SE	Balboa	BL BK 1		18.1	17.0	16.4	15.1	14.6	BL1201		194	190	184	189	188
SE	Balboa	BL BK 1		18.1	17.0	16.4	15.1	14.6	BL1203		459	447	431	403	380
SE	Balboa	BL BK 1		18.1	17.0	16.4	15.1	14.6	BL1204		207	229	187	201	162
SE	Balboa	BL BK 2		16.3	16.3	15.1	15.7	16.5	BL1207		353	350	349	387	373
SE	Balboa	BL BK 2		16.3	16.3	15.1	15.7	16.5	BL1208		384	361	369	403	441
SE	Balboa	BL BK 3		16.4	16.6	15.1	15.5	16.5	BL1209		197	190	168	199	197
SE	Balboa	BL BK 3		16.4	16.6	15.1	15.5	16.5	BL1210		190	203	193	200	199
SE	Balboa	BL BK 3		16.4	16.6	15.1	15.5	16.5	BL1211		408	420	387	394	445
NW	Beltway	BLT BK 4		24.0	22.8	19.6	16.9	15.1	BLT1213		197	172	122	71	
NW	Beltway	BLT BK 4		24.0	22.8	19.6	16.9	15.1	BLT1214		86	65	34	68	
NW	Beltway	BLT BK 4		24.0	22.8	19.6	16.9	15.1	BLT1216	New					
NW	Beltway	BLT BK 4		24.0	22.8	19.6	16.9	15.1	BLT1217	New					
NW	Beltway	BLT BK 4		24.0	22.8	19.6	16.9	15.1	BLT1218		153	102	81	77	51
NW	Beltway	BLT BK 4		24.0	22.8	19.6	16.9	15.1	BLT1219		428	449	454	421	415
NW	Beltway	BLT BK 4		24.0	22.8	19.6	16.9	15.1	BLT1223		255	271	279	264	256
SE	Bicentennial	BCT BK 1		26.4	23.7	21.6	21.1	20.4	BCT1201		41	10	145	126	121
SE	Bicentennial	BCT BK 1		26.4	23.7	21.6	21.1	20.4	BCT1203		393	402	137	141	145
SE	Bicentennial	BCT BK 1		26.4	23.7	21.6	21.1	20.4	BCT1204		361	396	381	382	379
SE	Bicentennial	BCT BK 2		25.7	23.7	21.2	20.8	19.8	BCT1205		454	493	444	439	444
SE	Bicentennial	BCT BK 2		25.7	23.7	21.2	20.8	19.8	BCT1210		221	241	227	227	218
SE	Bicentennial	BCT BK 2		25.7	23.7	21.2	20.8	19.8	BCT1211		261	275	332	327	327
SE	Bicentennial	BCT BK 2		25.7	23.7	21.2	20.8	19.8	BCT1213		8	8	134	106	93
SE	Bicentennial	BCT BK 2		25.7	23.7	21.2	20.8	19.8	BCT1214		285	257	202	196	143
SE	Bicentennial	BCT BK 2		25.7	23.7	21.2	20.8	19.8	BCT1215		178	175	138	104	100
SE	Bicentennial	BCT BK 2		25.7	23.7	21.2	20.8	19.8	BCT1217		218	132	69	24	7
SE	Big Bend	BGB BK 1		6.7	6.7	6.8	6.9	6.9	BGB2501		156	157	159	159	159
SE	Big Bend	BGB BK 2		13.1	13.2	13.4	12.1	12.1	BGB2507		304	307	312	281	281
NE	Blade Runner	BLR BK 1		0.0	0.0	0.0	0.0		BLR1202		24	28			
SW	Blue Diamond	BD BK 2		0.0	0.0	0.0	0.0	0.0	BD401		1	1	1	1	1
SW	Blue Diamond	BD BK 2		0.0	0.0	0.0	0.0	0.0	BD402		1	1	1	1	1
SW	Blue Diamond	BD BK 3		0.0	0.0	0.0	0.0	0.0	BD403		1	1	1	1	1
SW	Blue Diamond	BD BK 3		0.0	0.0	0.0	0.0	0.0	BD404		1	1	1	1	1
SE	Boulder Beach	BB BK 1		0.0	0.0	0.0	0.0	0.0	BB1201		91	89	95	299	144
SE	Burnham	BRN BK 1		26.5	26.3	25.4	26.4	25.6	BRN1201		337	364	321	348	333
SE	Burnham	BRN BK 1		26.5	26.3	25.4	26.4	25.6	BRN1202		448	448	432	463	427
SE	Burnham	BRN BK 1		26.5	26.3	25.4	26.4	25.6	BRN1204		427	434	464	449	426
SE	Burnham	BRN BK 2		26.1	26.0	24.9	26.2	25.0	BRN1205		333	343	303	306	316
SE	Burnham	BRN BK 2		26.1	26.0	24.9	26.2	25.0	BRN1206		309	309	303	299	294
SE	Burnham	BRN BK 2		26.1	26.0	24.9	26.2	25.0	BRN1209		387	412	492	478	437
SE	Burnham	BRN BK 2		26.1	26.0	24.9	26.2	25.0	BRN1210		207	223	216	224	204
SE	Burnham	BRN BK 3		23.6	23.6	23.0	25.0	22.1	BRN1211		386	357	345	358	334
SE	Burnham	BRN BK 3		23.6	23.6	23.0	25.0	22.1	BRN1212		393	388	427	419	392
SE	Burnham	BRN BK 3		23.6	23.6	23.0	25.0	22.1	BRN1214		386	366	376	414	340
SE	Cabana	CB BK 1		27.1	28.1	26.9	26.5	26.7	CB1201		342	325	317	333	384
SE	Cabana	CB BK 1		27.1	28.1	26.9	26.5	26.7	CB1202		410	410	386	414	353
SE	Cabana	CB BK 1		27.1	28.1	26.9	26.5	26.7	CB1204		480	507	476	454	379
SE	Cabana	CB BK 2		27.0	27.9	26.9	27.7	26.7	CB1205		411	411	373	384	366
SE	Cabana	CB BK 2		27.0	27.9	26.9	27.7	26.7	CB1206		133	146	126	188	204
SE	Cabana	CB BK 2		27.0	27.9	26.9	27.7	26.7	CB1209		481	500	484	482	499
SE	Cabana	CB BK 2		27.0	27.9	26.9	27.7	26.7	CB1210		413	427	416	433	408
SE	Cabana	CB BK 3		22.8	24.6	24.3	25.5	24.1	CB1211		434	435	414	466	451
SE	Cabana	CB BK 3		22.8	24.6	24.3	25.5	24.1	CB1212		295	301	298	303	316
SE	Cabana	CB BK 3		22.8	24.6	24.3	25.5	24.1	CB1214		398	463	453	455	423
SE	Cactus	CCT BK 1		17.3	18.0	16.0	17.9	18.0	CCT1201		1	1	1	1	1
SE	Cactus	CCT BK 1		17.3	18.0	16.0	17.9	18.0	CCT1202		295	315	277	283	255
SE	Cactus	CCT BK 1		17.3	18.0	16.0	17.9	18.0	CCT1207		432	421	387	403	381
SE	Cactus	CCT BK 2		16.8	17.9	15.7	17.6	17.8	CCT1209		1	1	1	1	1
SE	Cactus	CCT BK 2		16.8	17.9	15.7	17.6	17.8	CCT1211		377	455	354	484	451
SE	Cactus	CCT BK 2		16.8	17.9	15.7	17.6	17.8	CCT1212		289	305	289	279	272
SE	Cactus	CCT BK 2		16.8	17.9	15.7	17.6	17.8	CCT1214		278	304	301	414	295

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
SE	Cactus	CCT BK 2		16.8	17.9	15.7	17.6	17.8	CCT1216		1	1	1	1	1
SE	Cactus	CCT BK 2		16.8	17.9	15.7	17.6	17.8	CCT1217		1	1	0	0	0
SE	Cactus	CCT BK 2		16.8	17.9	15.7	17.6	17.8	CCT1218		1	1	0	0	0
SW	Camero	CMO BK 2		16.4	17.3	15.3	15.9	16.4	CMO1201		1	1	1	1	1
SW	Camero	CMO BK 2		16.4	17.3	15.3	15.9	16.4	CMO1205		340	334	307	294	276
SW	Camero	CMO BK 2		16.4	17.3	15.3	15.9	16.4	CMO1206		311	370	347	323	392
SW	Camero	CMO BK 2		16.4	17.3	15.3	15.9	16.4	CMO1212		140	149	131	134	127
SW	Camero	CMO BK 2		16.4	17.3	15.3	15.9	16.4	CMO1213		1	1	1	1	1
NW	Canyon	CN BK 1		0.0	0.0	0.0	0.0	0.0	CN3401		19	20	22	93	70
NE	Carey	CA BK 5		5.9	5.3	4.9	4.8	4.4	CA1201		134	126	119	111	118
NE	Carey	CA BK 5		5.9	5.3	4.9	4.8	4.4	CA1203		145	146	144	144	132
NE	Carey	CA BK 5		5.9	5.3	4.9	4.8	4.4	CA1204		1	1	1	0	0
NE	Carey	CA BK 6		14.6	14.5	14.1	13.7	14.2	CA1207		323	343	342	337	388
NE	Carey	CA BK 6		14.6	14.5	14.1	13.7	14.2	CA1208		210	215	207	218	185
NE	Carey	CA BK 7		15.0	14.9	14.4	13.8	14.6	CA1209		199	202	202	191	180
NE	Carey	CA BK 7		15.0	14.9	14.4	13.8	14.6	CA1211		396	386	365	366	349
NE	Carey	CA BK 7		15.0	14.9	14.4	13.8	14.6	CA1212		248	246	218	244	230
NE	Carey	CA BK 8		7.6	7.8	8.0	7.4	7.0	CA1213		260	267	272	278	253
NE	Carey	CA BK 8		7.6	7.8	8.0	7.4	7.0	CA1215		328	338	345	320	287
NE	Carey	CA BK 9		7.7	7.7	7.9	7.7	6.9	CA1220		148	162	165	185	176
NE	Carey	CA BK 9		7.7	7.7	7.9	7.7	6.9	CA1221		3	200	134		
NW	Charleston	CHR BK 1		12.4	13.3	13.7	13.0	13.0	CHR1201		311	366	388	363	350
NW	Charleston	CHR BK 1		12.4	13.3	13.7	13.0	13.0	CHR1202		261	302	280	276	283
NW	Cheyenne	CHN BK 1		26.2	26.6	25.9	26.1	25.7	CHN1202		409	452	449	448	440
NW	Cheyenne	CHN BK 1		26.2	26.6	25.9	26.1	25.7	CHN1204		401	426	468	469	411
NW	Cheyenne	CHN BK 2		26.2	27.0	25.9	26.0	25.7	CHN1205		411	432	380	375	379
NW	Cheyenne	CHN BK 2		26.2	27.0	25.9	26.0	25.7	CHN1207		468	517	506	501	509
NW	Cheyenne	CHN BK 2		26.2	27.0	25.9	26.0	25.7	CHN1208		481	516	480	480	431
NW	Cheyenne	CHN BK 2		26.2	27.0	25.9	26.0	25.7	CHN1210		288	286	303	302	283
NW	Cheyenne	CHN BK 3		19.1	19.6	21.7	19.9	19.5	CHN1211		381	397	518	500	452
NW	Cheyenne	CHN BK 3		19.1	19.6	21.7	19.9	19.5	CHN1212		421	430	498	481	420
NW	Cheyenne	CHN BK 3		19.1	19.6	21.7	19.9	19.5	CHN1214		136	130	130	130	118
STRIP	Claymont	CM BK 1		19.4	20.0	23.7	23.8	23.7	CM1202		115	133	360	381	378
STRIP	Claymont	CM BK 1		19.4	20.0	23.7	23.8	23.7	CM1204		393	415	379	411	383
STRIP	Claymont	CM BK 1		19.4	20.0	23.7	23.8	23.7	CM1205		405	380	360	370	352
STRIP	Claymont	CM BK 2		22.7	23.0	22.5	23.2	21.5	CM1209		431	470	464	489	441
STRIP	Claymont	CM BK 2		22.7	23.0	22.5	23.2	21.5	CM1211		359	349	330	342	311
STRIP	Claymont	CM BK 2		22.7	23.0	22.5	23.2	21.5	CM1212		284	279	281	294	302
STRIP	Claymont	CM BK 3		21.5	20.2	19.4	19.7	18.5	CM1223		304	290	282	300	250
STRIP	Claymont	CM BK 3		21.5	20.2	19.4	19.7	18.5	CM1224		399	399	383	377	383
STRIP	Claymont	CM BK 3		21.5	20.2	19.4	19.7	18.5	CM1225		290	286	294	277	272
STRIP	Claymont	CM BK 4		17.8	18.5	19.3	19.1	18.2	CM1228		341	351	344	339	312
STRIP	Claymont	CM BK 4		17.8	18.5	19.3	19.1	18.2	CM1229		231	238	205	226	232
STRIP	Claymont	CM BK 4		17.8	18.5	19.3	19.1	18.2	CM1230		92	122	68	76	80
STRIP	Claymont	CM BK 4		17.8	18.5	19.3	19.1	18.2	CM1231		249	247	275	279	283
NW	Cold Creek	CC BK 2		5.4	5.5	5.2	4.8	4.8	CC1202		121	125	113	118	148
NW	Cold Creek	CC BK 2		5.4	5.5	5.2	4.8	4.8	CC1206		135	139	136	143	146
STRIP	Commerce	COM BK 1		13.2	13.0	13.2	14.3	14.2	COM1203		1	1	1	1	1
STRIP	Commerce	COM BK 1		13.2	13.0	13.2	14.3	14.2	COM1204		1	1	1	1	1
STRIP	Commerce	COM BK 1		13.2	13.0	13.2	14.3	14.2	COM1205		337	305	329	348	339
STRIP	Commerce	COM BK 1		13.2	13.0	13.2	14.3	14.2	COM1207		311	307	328	370	355
STRIP	Commerce	COM BK 2		18.7	18.2	18.3	16.3	13.5	COM1216		411	409	438	390	275
STRIP	Commerce	COM BK 2		18.7	18.2	18.3	16.3	13.5	COM1218		108	114	104	108	88
STRIP	Commerce	COM BK 2		18.7	18.2	18.3	16.3	13.5	COM1219		413	407	391	365	325
STRIP	Concourse	CON BK 1		22.4	23.4	22.2	21.5	22.8	CON1201		343	362	383	374	346
STRIP	Concourse	CON BK 1		22.4	23.4	22.2	21.5	22.8	CON1203		449	466	399	420	451
STRIP	Concourse	CON BK 1		22.4	23.4	22.2	21.5	22.8	CON1204		255	286	249	278	259
STRIP	Concourse	CON BK 2		19.8	19.0	18.8	18.8	18.4	CON1205		345	349	349	381	399
STRIP	Concourse	CON BK 2		19.8	19.0	18.8	18.8	18.4	CON1206		431	421	409	426	412
STRIP	Concourse	CON BK 2		19.8	19.0	18.8	18.8	18.4	CON1209		161	152	130	140	115
STRIP	Concourse	CON BK 2		19.8	19.0	18.8	18.8	18.4	CON1211		305	314	308	310	307
STRIP	Concourse	CON BK 2		19.8	19.0	18.8	18.8	18.4	CON1212		4	4	4	4	4
STRIP	Concourse	CON BK 2		19.8	19.0	18.8	18.8	18.4	CON1213		228	205	205	196	200
STRIP	Concourse	CON BK 3		19.9	19.2	19.1	19.1	18.8	CON1214		2	2	2	43	43
STRIP	Concourse	CON BK 3		19.9	19.2	19.1	19.1	18.8	CON1215		142	142	138	157	159

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
STRIP	Concourse	CON BK 3		19.9	19.2	19.1	19.1	18.8	CON1217		369	377	352	369	346
NE	Craig	CR BK 1		21.9	20.1	24.2	18.9	18.0	CR1201		319	324	303	296	275
NE	Craig	CR BK 1		21.9	20.1	24.2	18.9	18.0	CR1203		440	406	394	320	316
NE	Craig	CR BK 1		21.9	20.1	24.2	18.9	18.0	CR1204		330	328	325	317	316
NE	Craig	CR BK 2		19.6	17.8	18.2	16.8	15.6	CR1205		345	315	321	285	243
NE	Craig	CR BK 2		19.6	17.8	18.2	16.8	15.6	CR1206		190	168	254	242	209
NE	Craig	CR BK 2		19.6	17.8	18.2	16.8	15.6	CR1208		269	247	243	200	219
NE	Craig	CR BK 2		19.6	17.8	18.2	16.8	15.6	CR1209		199	202	195	199	191
NE	Craig	CR BK 3		28.4	27.3	29.0	28.8	27.9	CR1211		517	496	527	513	499
NE	Craig	CR BK 3		28.4	27.3	29.0	28.8	27.9	CR1212		431	431	428	424	395
NE	Craig	CR BK 3		28.4	27.3	29.0	28.8	27.9	CR1213		423	426	437	451	450
NE	DeBuono	DEB BK 1		14.2	14.7	14.8	13.9	13.0	DEB1203		284	299	304	313	287
NE	DeBuono	DEB BK 1		14.2	14.7	14.8	13.9	13.0	DEB1204		371	383	381	340	329
NE	DeBuono	DEB BK 2		16.2	16.2	15.6	14.8	15.4	DEB1210		306	304	287	296	301
NE	DeBuono	DEB BK 3		16.0	16.4	15.6	15.3	15.5	DEB1214		386	411	403	396	398
NE	DeBuono	DEB BK 3		16.0	16.4	15.6	15.3	15.5	DEB1215		430	436	428	439	418
NE	DeBuono	DEB BK 3		16.0	16.4	15.6	15.3	15.5	DEB1216		386	404	337	319	320
SW	Decatur	DE BK 3		15.5	15.3	14.2	15.2	14.3	DE1201		296	310	292	286	275
SW	Decatur	DE BK 3		15.5	15.3	14.2	15.2	14.3	DE1203		324	312	286	306	288
SW	Decatur	DE BK 3		15.5	15.3	14.2	15.2	14.3	DE1204		407	416	404	417	401
SW	Decatur	DE BK 4		12.0	12.3	11.8	12.0	11.5	DE1205		18	19	19	19	28
SW	Decatur	DE BK 4		12.0	12.3	11.8	12.0	11.5	DE1206		252	278	260	264	290
SW	Decatur	DE BK 5		11.8	12.1	11.5	11.8	11.3	DE1209		423	446	458	418	430
SW	Decatur	DE BK 5		11.8	12.1	11.5	11.8	11.3	DE1212		442	448	433	484	442
SW	Decatur	DE BK 7		16.0	16.5	14.6	15.0	14.3	DE1214		445	443	423	420	412
SW	Durango	DU BK 1		25.5	26.5	22.8	25.1	23.8	DU1201		474	503	488	467	448
SW	Durango	DU BK 1		25.5	26.5	22.8	25.1	23.8	DU1203		496	539	395	551	509
SW	Durango	DU BK 1		25.5	26.5	22.8	25.1	23.8	DU1204		362	361	344	379	359
SW	Durango	DU BK 1		25.5	26.5	22.8	25.1	23.8	DU1205		37	65	64	68	78
SW	Durango	DU BK 2		26.7	27.3	23.6	25.7	24.9	DU1208		486	509	343	361	346
SW	Durango	DU BK 2		26.7	27.3	23.6	25.7	24.9	DU1209		508	551	550	524	501
SW	Durango	DU BK 2		26.7	27.3	23.6	25.7	24.9	DU1210		467	502	502	485	484
SW	Durango	DU BK 3		18.9	18.9	18.0	18.6	18.1	DU1211		402	408	387	394	379
SW	Durango	DU BK 3		18.9	18.9	18.0	18.6	18.1	DU1212		476	476	473	479	471
SW	Durango	DU BK 3		18.9	18.9	18.0	18.6	18.1	DU1215		5	4	5	5	5
NW	El Capitan	ELC BK 1		37.5	35.0	34.6	34.7	33.0	ELC1204		252	258	238	213	216
NW	El Capitan	ELC BK 1		37.5	35.0	34.6	34.7	33.0	ELC1205		220	230	247	232	225
NW	El Capitan	ELC BK 1		37.5	35.0	34.6	34.7	33.0	ELC1208		424	355	339	346	288
NW	El Capitan	ELC BK 1		37.5	35.0	34.6	34.7	33.0	ELC1209		426	422	429	422	418
NW	El Capitan	ELC BK 1		37.5	35.0	34.6	34.7	33.0	ELC1210		436	460	485	455	449
NW	El Capitan	ELC BK 2		41.2	39.5	42.5	40.1	37.9	ELC1215		491	488	494	463	447
NW	El Capitan	ELC BK 2		41.2	39.5	42.5	40.1	37.9	ELC1216		459	457	482	449	424
NW	El Capitan	ELC BK 2		41.2	39.5	42.5	40.1	37.9	ELC1217		419	431	449	521	479
NW	El Capitan	ELC BK 2		41.2	39.5	42.5	40.1	37.9	ELC1218		302	271	349	353	223
NW	El Capitan	ELC BK 2		41.2	39.5	42.5	40.1	37.9	ELC1220		1	1	1	1	1
NW	El Capitan	ELC BK 2		41.2	39.5	42.5	40.1	37.9	ELC1221		242	237	254	237	238
STRIP	El Rancho	ER BK 1		11.0	10.6	11.5	12.0	7.0	ER1201		259	258	303	311	308
STRIP	El Rancho	ER BK 1		11.0	10.6	11.5	12.0	7.0	ER1203		278	279	237	248	227
STRIP	El Rancho	ER BK 2		9.2	8.3	8.6	8.9	6.8	ER1205		58	56	55	52	52
STRIP	El Rancho	ER BK 2		9.2	8.3	8.6	8.9	6.8	ER1207		104	107	112	113	118
STRIP	El Rancho	ER BK 3		8.5	8.4	8.6	8.9	12.1	ER1209		234	239	248	260	236
STRIP	El Rancho	ER BK 3		8.5	8.4	8.6	8.9	12.1	ER1211		166	154	160	169	195
STRIP	El Rancho	ER BK 3		8.5	8.4	8.6	8.9	12.1	ER1212		232	222	227	235	236
NW	Elkhorn	ELK BK 1		30.2	29.0	27.3	24.6	21.4	ELK1201		189	180	173	169	163
NW	Elkhorn	ELK BK 1		30.2	29.0	27.3	24.6	21.4	ELK1202		515	371	371	355	294
NW	Elkhorn	ELK BK 1		30.2	29.0	27.3	24.6	21.4	ELK1206		342	363	359	337	332
NW	Elkhorn	ELK BK 1		30.2	29.0	27.3	24.6	21.4	ELK1208		491	496	487	434	0
NW	Elkhorn	ELK BK 2		30.8	29.3	27.5	25.4	21.7	ELK1209		399	446	387	359	475
NW	Elkhorn	ELK BK 2		30.8	29.3	27.5	25.4	21.7	ELK1211		452	424	401	343	423
NW	Elkhorn	ELK BK 2		30.8	29.3	27.5	25.4	21.7	ELK1212		475	472	451	454	359
NW	Elkhorn	ELK BK 3		21.5	14.2	15.5	14.5	13.2	ELK1213		323	1			
NW	Elkhorn	ELK BK 3		21.5	14.2	15.5	14.5	13.2	ELK1214		377	371	273	268	250
NW	Elkhorn	ELK BK 3		21.5	14.2	15.5	14.5	13.2	ELK1216		309	288	457	416	382
STRIP	Excalibur	EX BK 1		11.3	11.9	12.5	13.0	12.8	EX1201		362	374	397	433	418
STRIP	Excalibur	EX BK 1		11.3	11.9	12.5	13.0	12.8	EX1203		218	223	216	220	240

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
STRIP	Excalibur	EX BK 1		11.3	11.9	12.5	13.0	12.8	EX1204		190	198	184	201	234
STRIP	Excalibur	EX BK 2		11.4	12.0	12.6	13.2	13.1	EX1205		229	209	224	238	265
STRIP	Excalibur	EX BK 2		11.4	12.0	12.6	13.2	13.1	EX1206		149	169	162	158	172
STRIP	Excalibur	EX BK 3		10.7	10.5	11.7	10.9	9.8	EX1209		5	5	5	4	4
STRIP	Excalibur	EX BK 3		10.7	10.5	11.7	10.9	9.8	EX1211		246	251	264	187	165
STRIP	Excalibur	EX BK 3		10.7	10.5	11.7	10.9	9.8	EX1212		5	4	4	1	1
STRIP	Excalibur	EX BK 4		10.7	10.6	11.7	10.9	9.8	EX1213		360	368	375	415	401
STRIP	Excalibur	EX BK 4		10.7	10.6	11.7	10.9	9.8	EX1214		164	186	180	201	198
STRIP	Excalibur	EX BK 4		10.7	10.6	11.7	10.9	9.8	EX1215		288	275	264	279	275
SE	Faulkner	FLK BK 3		33.1	32.5	27.8	26.3	24.6	FLK1215		452	450	464	432	422
SE	Faulkner	FLK BK 3		33.1	32.5	27.8	26.3	24.6	FLK1216		148	101	72	65	60
SE	Faulkner	FLK BK 3		33.1	32.5	27.8	26.3	24.6	FLK1217		151	158	139	157	160
SE	Faulkner	FLK BK 3		33.1	32.5	27.8	26.3	24.6	FLK1218		319	296	213	230	213
SE	Faulkner	FLK BK 3		33.1	32.5	27.8	26.3	24.6	FLK1220		153	165	149	111	104
SE	Faulkner	FLK BK 3		33.1	32.5	27.8	26.3	24.6	FLK1221		438	406	383	356	346
SE	Faulkner	FLK BK 4		41.7	39.9	39.5	40.0	37.9	FLK1204		441	423	500	459	431
SE	Faulkner	FLK BK 4		41.7	39.9	39.5	40.0	37.9	FLK1205		485	521	523	502	504
SE	Faulkner	FLK BK 4		41.7	39.9	39.5	40.0	37.9	FLK1206		1	1	1	1	1
SE	Faulkner	FLK BK 4		41.7	39.9	39.5	40.0	37.9	FLK1208		402	366	333	323	276
SE	Faulkner	FLK BK 4		41.7	39.9	39.5	40.0	37.9	FLK1209		363	376	373	370	331
SE	Faulkner	FLK BK 4		41.7	39.9	39.5	40.0	37.9	FLK1210		323	350	437	457	430
SE	Faulkner	FLK BK 5		21.7	20.3	18.7	18.1	20.7	FLK1224		181	184	175	185	178
SE	Faulkner	FLK BK 5		21.7	20.3	18.7	18.1	20.7	FLK1225		1	1	1	1	1
SE	Faulkner	FLK BK 5		21.7	20.3	18.7	18.1	20.7	FLK1226		316	280	251	265	448
SE	Faulkner	FLK BK 5		21.7	20.3	18.7	18.1	20.7	FLK1227		527	522	519	457	431
STRIP	Flamingo	FL BK 1		6.7	6.2	6.4	7.2	8.0	FL1202		166	164	156	161	175
STRIP	Flamingo	FL BK 1		6.7	6.2	6.4	7.2	8.0	FL1203		145	134	177	186	205
STRIP	Flamingo	FL BK 2		13.8	14.7	15.1	14.4	13.0	FL1206		159	180	175	179	138
STRIP	Flamingo	FL BK 2		13.8	14.7	15.1	14.4	13.0	FL1207		158	187	181	191	197
STRIP	Flamingo	FL BK 2		13.8	14.7	15.1	14.4	13.0	FL1208		218	222	218	234	233
STRIP	Flamingo	FL BK 3		13.8	14.7	14.5	14.7	13.3	FL1209		108	113	106	126	120
STRIP	Flamingo	FL BK 3		13.8	14.7	14.5	14.7	13.3	FL1211		315	329	386	375	368
STRIP	Flamingo	FL BK 3		13.8	14.7	14.5	14.7	13.3	FL1212		322	346	323	305	300
SE	Ford	FRD BK 1		26.7	27.4	25.3	25.8	24.8	FRD1204		400	422	404	416	392
SE	Ford	FRD BK 1		26.7	27.4	25.3	25.8	24.8	FRD1208		403	409	367	388	368
SE	Ford	FRD BK 1		26.7	27.4	25.3	25.8	24.8	FRD1209		63	65	43	48	51
SE	Ford	FRD BK 1		26.7	27.4	25.3	25.8	24.8	FRD1210		407	427	396	416	403
SE	Ford	FRD BK 2		38.3	40.1	36.3	38.8	37.1	FRD1216		284	292	287	318	288
SE	Ford	FRD BK 2		38.3	40.1	36.3	38.8	37.1	FRD1217		288	291	281	282	258
SE	Ford	FRD BK 2		38.3	40.1	36.3	38.8	37.1	FRD1218		454	496	472	480	460
SE	Ford	FRD BK 2		38.3	40.1	36.3	38.8	37.1	FRD1220		363	382	378	373	343
SE	Ford	FRD BK 2		38.3	40.1	36.3	38.8	37.1	FRD1221		436	497	463	450	419
SW	Frias	FRS BK 2		31.1	31.4	29.7	29.1	28.3	FRS1206		349	321	439	427	431
SW	Frias	FRS BK 2		31.1	31.4	29.7	29.1	28.3	FRS1210		352	377	371	372	367
SW	Frias	FRS BK 2		31.1	31.4	29.7	29.1	28.3	FRS1211		465	505	481	427	419
SW	Frias	FRS BK 2		31.1	31.4	29.7	29.1	28.3	FRS1212		492	530	538	514	492
SW	Frias	FRS BK 3		30.9	30.8	29.9	29.3	28.1	FRS1214		442	450	301	296	282
SW	Frias	FRS BK 3		30.9	30.8	29.9	29.3	28.1	FRS1215		419	434	429	424	383
SW	Frias	FRS BK 3		30.9	30.8	29.9	29.3	28.1	FRS1217		398	425	401	404	386
STRIP	Garces	GA BK 2		14.6	14.7	15.3	14.2	13.8	GA1201		477	543	503	515	472
STRIP	Garces	GA BK 2		14.6	14.7	15.3	14.2	13.8	GA1202		225	215	217	236	224
STRIP	Garces	GA BK 2		14.6	14.7	15.3	14.2	13.8	GA1204		132	130	140	140	133
STRIP	Garces	GA BK 3		14.9	14.9	15.5	14.4	14.1	GA1205		137	141	117	158	161
STRIP	Garces	GA BK 3		14.9	14.9	15.5	14.4	14.1	GA1206		444	452	479	478	489
STRIP	Garces	GA BK 4		5.5	7.4	7.8	7.6	6.1	GA1209		135	282	284	282	210
STRIP	Garces	GA BK 4		5.5	7.4	7.8	7.6	6.1	GA1210		94	92	92	116	91
STRIP	Garces	GA BK 4		5.5	7.4	7.8	7.6	6.1	GA1211		1	1	1	1	1
NE	Gilmore	GLM BK 1		17.0	17.3	16.7	15.8	15.7	GLM1204		486	440	445	402	425
NE	Gilmore	GLM BK 2		17.3	17.6	17.1	15.8	15.8	GLM1205		384	410	403	381	371
NE	Gilmore	GLM BK 2		17.3	17.6	17.1	15.8	15.8	GLM1206		309	305	306	301	293
NE	Gilmore	GLM BK 2		17.3	17.6	17.1	15.8	15.8	GLM1211		459	472	453	447	425
SW	Goodsprings	GS BK 1		0.7	0.8	0.9	0.1	0.1	GS1201		17	18	27	29	1
SW	Goodsprings	GS BK 1		0.7	0.8	0.9	0.1	0.1	GS1202		22	30	22	6	5
NE	Grand Teton	GTT BK 2		13.4	14.4	10.6	10.1	10.0	GTT1207		147	163	160	167	155
NE	Grand Teton	GTT BK 2		13.4	14.4	10.6	10.1	10.0	GTT1208		88	98	100	108	97

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
NE	Grand Teton	GTT BK 2		13.4	14.4	10.6	10.1	10.0	GTT1212		388	418	247	234	237
SE	Green Valley	GV BK 1		24.4	24.9	24.5	23.9	23.5	GV1201		377	370	344	340	326
SE	Green Valley	GV BK 1		24.4	24.9	24.5	23.9	23.5	GV1203		340	353	341	353	354
SE	Green Valley	GV BK 1		24.4	24.9	24.5	23.9	23.5	GV1204		426	437	455	423	414
SE	Green Valley	GV BK 2		27.4	28.3	27.5	27.5	26.8	GV1207		328	335	315	299	310
SE	Green Valley	GV BK 2		27.4	28.3	27.5	27.5	26.8	GV1208		245	266	262	254	244
SE	Green Valley	GV BK 2		27.4	28.3	27.5	27.5	26.8	GV1209		399	484	471	454	436
SE	Green Valley	GV BK 2		27.4	28.3	27.5	27.5	26.8	GV1210		451	469	477	461	437
SE	Green Valley	GV BK 3		27.3	28.5	27.5	27.5	26.8	GV1211		400	424	423	438	411
SE	Green Valley	GV BK 3		27.3	28.5	27.5	27.5	26.8	GV1212		258	275	265	342	349
SE	Green Valley	GV BK 3		27.3	28.5	27.5	27.5	26.8	GV1214		460	473	460	457	451
SE	Greenway	GNW BK 1		16.9	18.0	15.3	15.9	15.0	GNW1201		1	1	1	1	1
SE	Greenway	GNW BK 2		16.9	17.8	15.4	15.7	14.5	GNW1205		354	367	342	377	357
SE	Greenway	GNW BK 2		16.9	17.8	15.4	15.7	14.5	GNW1206		406	427	409	374	369
SE	Greenway	GNW BK 2		16.9	17.8	15.4	15.7	14.5	GNW1207		344	371	359	326	319
SE	Greenway	GNW BK 2		16.9	17.8	15.4	15.7	14.5	GNW1209		485	495	373	402	353
NE	Gypsum	GYP BK 2		10.7	10.4	10.5	10.3	8.9	GYP1208		292	292	292	264	239
NE	Gypsum	GYP BK 2		10.7	10.4	10.5	10.3	8.9	GYP1210		205	212	263	212	202
SE	Haven	HV BK 1		29.4	30.8	28.0	30.4	27.2	HV1202		416	447	444	423	385
SE	Haven	HV BK 1		29.4	30.8	28.0	30.4	27.2	HV1203		538	477	487	484	473
SE	Haven	HV BK 1		29.4	30.8	28.0	30.4	27.2	HV1204		497	516	521	507	432
SE	Haven	HV BK 2		22.6	23.5	21.0	20.7	19.2	HV1205		288	393	334	344	331
SE	Haven	HV BK 2		22.6	23.5	21.0	20.7	19.2	HV1206		282	304	293	279	274
SE	Haven	HV BK 2		22.6	23.5	21.0	20.7	19.2	HV1209		484	512	426	491	505
SE	Haven	HV BK 2		22.6	23.5	21.0	20.7	19.2	HV1210		221	197	191	196	189
SE	Haven	HV BK 3		22.7	23.5	21.1	20.6	19.2	HV1211		401	397	410	379	245
SE	Haven	HV BK 3		22.7	23.5	21.1	20.6	19.2	HV1212		274	270	108	117	120
SE	Haven	HV BK 3		22.7	23.5	21.1	20.6	19.2	HV1213		250	279	278	255	256
STRIP	Highland	HI BK 1		12.2	11.6	9.9	9.6	12.6	HI1201		148	172	196	185	197
STRIP	Highland	HI BK 1		12.2	11.6	9.9	9.6	12.6	HI1202		277	283	294	263	358
STRIP	Highland	HI BK 1		12.2	11.6	9.9	9.6	12.6	HI1203		194	194	204	212	210
STRIP	Highland	HI BK 2		11.9	11.7	9.9	9.8	10.8	HI1205		250	241	1	1	1
STRIP	Highland	HI BK 2		11.9	11.7	9.9	9.8	10.8	HI1206		301	311	317	343	357
STRIP	Highland	HI BK 3		9.5	9.0	9.0	9.2	9.0	HI1209		5	5	5	6	6
STRIP	Highland	HI BK 3		9.5	9.0	9.0	9.2	9.0	HI1210		103	98	95	106	106
STRIP	Highland	HI BK 3		9.5	9.0	9.0	9.2	9.0	HI1211		367	323	314	328	335
STRIP	Highland	HI BK 4		10.0	10.1	12.6	13.6	13.2	HI1214		175	185	166	183	182
STRIP	Highland	HI BK 4		10.0	10.1	12.6	13.6	13.2	HI1215		109	122	114	133	127
STRIP	Highland	HI BK 4		10.0	10.1	12.6	13.6	13.2	HI1216		1	0	232	256	259
STRIP	Highland	HI BK 5		10.5	10.6	12.9	14.2	13.6	HI1217		165	174	166	187	184
STRIP	Highland	HI BK 5		10.5	10.6	12.9	14.2	13.6	HI1219		9	11	9	10	10
STRIP	Highland	HI BK 5		10.5	10.6	12.9	14.2	13.6	HI1220		293	262	267	311	331
STRIP	Highland	HI BK 5		10.5	10.6	12.9	14.2	13.6	HI1222		88	149	137	175	172
STRIP	Highland	HI BK 5		10.5	10.6	12.9	14.2	13.6	HI1224		115	142	112	135	146
STRIP	Highland	HI BK 6		0.6	0.3	0.4	0.3	0.3	HI1225		6	6	6	6	6
STRIP	Highland	HI BK 6		0.6	0.3	0.4	0.3	0.3	HI1226		28	21	11	9	9
STRIP	Highland	HI BK 6		0.6	0.3	0.4	0.3	0.3	HI1228		1	2	1	1	1
STRIP	Highland	HI BK 8	New	0.0	0.0	0.0	0.0	0.0	HI1229	New					
STRIP	Highland	HI BK 8	New	0.0	0.0	0.0	0.0	0.0	HI1230	New					
STRIP	Highland	HI BK 8	New	0.0	0.0	0.0	0.0	0.0	HI1231	New					
STRIP	Highland	HI BK 8	New	0.0	0.0	0.0	0.0	0.0	HI1232	New					
NW	Hualapai	HU BK 1		26.7	29.1	26.6	26.6	24.7	HU1201		440	458	450	448	444
NW	Hualapai	HU BK 1		26.7	29.1	26.6	26.6	24.7	HU1202		414	453	468	468	512
NW	Hualapai	HU BK 1		26.7	29.1	26.6	26.6	24.7	HU1204		375	394	437	382	296
NW	Hualapai	HU BK 2		28.2	28.0	27.1	27.1	26.8	HU1205		305	327	310	310	310
NW	Hualapai	HU BK 2		28.2	28.0	27.1	27.1	26.8	HU1206		397	382	381	381	403
NW	Hualapai	HU BK 2		28.2	28.0	27.1	27.1	26.8	HU1209		331	343	326	327	318
NW	Hualapai	HU BK 2		28.2	28.0	27.1	27.1	26.8	HU1210		275	301	314	314	371
NW	Hualapai	HU BK 3		21.4	20.0	18.2	18.2	19.4	HU1211		229	234	240	240	169
NW	Hualapai	HU BK 3		21.4	20.0	18.2	18.2	19.4	HU1212		402	421	444	293	288
NW	Hualapai	HU BK 3		21.4	20.0	18.2	18.2	19.4	HU1214		398	321	320	320	445
NW	Indian Springs	IS BK 1		0.0	0.0	0.0	0.0	0.0	IS401		3	3	3	251	251
NW	Indian Springs	IS BK 1		0.0	0.0	0.0	0.0	0.0	IS402		210	209	195	419	215
NW	Indian Springs	IS BK 1		0.0	0.0	0.0	0.0	0.0	IS403		50	54	56	91	32
NW	Indian Springs	IS BK 2		5.7	5.8	5.9	6.1	5.7	IS1204		263	268	276	282	263

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
NW	Iron Mountain	IMT BK 1		27.4	27.8	26.9	27.3	26.6	IMT1201		483	480	466	476	441
NW	Iron Mountain	IMT BK 1		27.4	27.8	26.9	27.3	26.6	IMT1203		340	368	353	380	353
NW	Iron Mountain	IMT BK 1		27.4	27.8	26.9	27.3	26.6	IMT1204		245	261	261	446	423
NW	Iron Mountain	IMT BK 2		26.4	27.2	26.0	26.4	24.9	IMT1205		362	347	334	158	146
NW	Iron Mountain	IMT BK 2		26.4	27.2	26.0	26.4	24.9	IMT1206		166	155	144	167	175
NW	Iron Mountain	IMT BK 2		26.4	27.2	26.0	26.4	24.9	IMT1209		2	2	2	1	2
NW	Iron Mountain	IMT BK 2		26.4	27.2	26.0	26.4	24.9	IMT1211		494	521	513	545	494
NW	Iron Mountain	IMT BK 2		26.4	27.2	26.0	26.4	24.9	IMT1212		511	516	493	504	473
SW	Jean	JN BK 2		4.7	4.9	4.5	4.6	4.5	JN1207		192	215	186	187	170
SW	Jean	JN BK 2		4.7	4.9	4.5	4.6	4.5	JN1208		252	249	66	66	250
SE	Keehn	KHN BK 1		11.0	9.6	8.7	8.4	7.0	KHN1201		127	70	58	66	50
SE	Keehn	KHN BK 1		11.0	9.6	8.7	8.4	7.0	KHN1203		1	1	1	1	1
SE	Keehn	KHN BK 1		11.0	9.6	8.7	8.4	7.0	KHN1204		44	62	56	59	58
SE	Keehn	KHN BK 2		10.9	9.6	8.6	8.2	7.0	KHN1205		2	2	2	2	2
SE	Keehn	KHN BK 2		10.9	9.6	8.6	8.2	7.0	KHN1206		190	185	152	162	154
SE	Keehn	KHN BK 2		10.9	9.6	8.6	8.2	7.0	KHN1210		286	294	283	276	263
SE	Keehn	KHN BK 2		10.9	9.6	8.6	8.2	7.0	KHN1211	New					
SE	Keehn	KHN BK 2		10.9	9.6	8.6	8.2	7.0	KHN1212		148	185	139	99	1
SE	Keehn	KHN BK 2		10.9	9.6	8.6	8.2	7.0	KHN1214		76	7			
SE	Keehn	KHN BK 2		10.9	9.6	8.6	8.2	7.0	KHN1215		234	234	228	133	147
SE	Keehn	KHN BK 2		10.9	9.6	8.6	8.2	7.0	KHN1217		130	135	138	123	138
SE	Kidwell	KI BK 1		0.0	0.0	0.0	0.0	0.0	KI1201		57	58	59	56	56
SE	Kidwell	KI BK 1		0.0	0.0	0.0	0.0	0.0	KI1202		41	46	59	56	56
NW	Kyle Canyon	KC BK 1		0.0	0.0	0.0	0.0	0.0	KC1201		48	27	27	117	85
SE	Lake Las Vegas	LLV BK 1		8.7	8.5	7.9	7.8	7.4	LLV1201		187	181	170	20	160
SE	Lake Las Vegas	LLV BK 1		8.7	8.5	7.9	7.8	7.4	LLV1203		417	421	87	85	89
SE	Lake Las Vegas	LLV BK 2		8.3	8.5	7.5	7.5	7.1	LLV1205		185	83	387	395	366
SE	Lake Las Vegas	LLV BK 2		8.3	8.5	7.5	7.5	7.1	LLV1206		96	101	96	253	90
SE	Lamb	LA BK 1		0.0	0.0	0.0	0.0	0.0	LA401		1	1	1	1	1
NE	Leavitt	LVT BK 1		24.8	24.3	25.4	25.0	20.9	LVT1201		478	476	469	453	417
NE	Leavitt	LVT BK 1		24.8	24.3	25.4	25.0	20.9	LVT1203		241	234	245	264	178
NE	Leavitt	LVT BK 1		24.8	24.3	25.4	25.0	20.9	LVT1204		447	432	481	456	393
NE	Leavitt	LVT BK 2		28.6	28.0	27.5	26.6	26.7	LVT1205		427	455	435	431	370
NE	Leavitt	LVT BK 2		28.6	28.0	27.5	26.6	26.7	LVT1206		474	505	503	449	384
NE	Leavitt	LVT BK 2		28.6	28.0	27.5	26.6	26.7	LVT1209		278	255	237	223	224
NE	Leavitt	LVT BK 2		28.6	28.0	27.5	26.6	26.7	LVT1212		464	481	465	508	502
NE	Leavitt	LVT BK 2		28.6	28.0	27.5	26.6	26.7	LVT1213		321	329	319	302	304
NE	Leavitt	LVT BK 3		28.5	27.6	27.0	25.9	26.3	LVT1214		478	459	518	463	450
NE	Leavitt	LVT BK 3		28.5	27.6	27.0	25.9	26.3	LVT1215		364	393	359	338	326
STRIP	Lewis	LE BK 2		1.1	1.1	1.0	1.0	1.1	LE402		105	104	95	96	101
STRIP	Lewis	LE BK 2		1.1	1.1	1.0	1.0	1.1	LE404		64	53	65	48	61
NE	Lincoln	LCN BK 1		21.8	19.2	19.5	19.7	18.3	LCN1203		421	243	238	242	225
NE	Lincoln	LCN BK 1		21.8	19.2	19.5	19.7	18.3	LCN1204		290	259	234	195	169
NE	Lincoln	LCN BK 2		21.8	19.3	19.2	19.6	18.5	LCN1205		102	91	96	113	89
NE	Lincoln	LCN BK 2		21.8	19.3	19.2	19.6	18.5	LCN1206		261	254	246	252	250
NE	Lincoln	LCN BK 2		21.8	19.3	19.2	19.6	18.5	LCN1210		374	241	269	234	230
NE	Lincoln	LCN BK 2		21.8	19.3	19.2	19.6	18.5	LCN1212		12	12	12	1	12
NE	Lincoln	LCN BK 2		21.8	19.3	19.2	19.6	18.5	LCN1213		226	439	453	425	388
NE	Lincoln	LCN BK 2		21.8	19.3	19.2	19.6	18.5	LCN1214		339	337	331	446	408
SW	Lindell	LI BK 1		14.1	14.9	13.2	13.2	14.6	LI1202		386	394	376	353	400
SW	Lindell	LI BK 1		14.1	14.9	13.2	13.2	14.6	LI1204		327	394	344	347	334
SW	Lindell	LI BK 2		14.1	15.2	14.9	14.3	14.6	LI1207		330	341	325	347	330
SW	Lindell	LI BK 2		14.1	15.2	14.9	14.3	14.6	LI1208		71	72	73	85	90
SW	Lindell	LI BK 2		14.1	15.2	14.9	14.3	14.6	LI1220		243	266	265	238	256
SW	Lindell	LI BK 3		12.3	13.1	13.1	13.5	13.6	LI1211		382	422	419	423	426
SW	Lindell	LI BK 3		12.3	13.1	13.1	13.5	13.6	LI1212		3	3	4	4	3
SW	Lindell	LI BK 3		12.3	13.1	13.1	13.5	13.6	LI1213		201	206	205	206	207
SE	Lindquist	LDQ BK 1		17.7	15.6	13.1	13.1	11.9	LDQ1203		334	322	405	386	362
SE	Lindquist	LDQ BK 1		17.7	15.6	13.1	13.1	11.9	LDQ1204		274	272	281	208	189
SE	Lindquist	LDQ BK 1		17.7	15.6	13.1	13.1	11.9	LDQ1205		268	201	110	52	12
SE	Lindquist	LDQ BK 2		17.4	15.3	12.9	12.8	11.8	LDQ1208		251	239	70	118	118
SE	Lindquist	LDQ BK 2		17.4	15.3	12.9	12.8	11.8	LDQ1210		302	310	321	359	368
SE	Lindquist	LDQ BK 2		17.4	15.3	12.9	12.8	11.8	LDQ1215		258	243	226	244	235
NW	Lone Mountain	LMT BK 1		15.7	15.2	14.9	14.7	13.8	LMT1203		499	495	492	475	440
NW	Lone Mountain	LMT BK 1		15.7	15.2	14.9	14.7	13.8	LMT1204		472	481	483	487	453

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
NW	Lone Mountain	LMT BK 2		15.5	15.3	15.4	14.7	13.9	LMT1211		1	1	1	1	1
NW	Lone Mountain	LMT BK 2		15.5	15.3	15.4	14.7	13.9	LMT1213		51	20	10	6	6
NW	Lone Mountain	LMT BK 2		15.5	15.3	15.4	14.7	13.9	LMT1215		429	427	423	409	397
NW	Lorenzi	LO BK 1		32.5	31.8	31.7	30.5	29.5	LO1201		456	445	465	473	457
NW	Lorenzi	LO BK 1		32.5	31.8	31.7	30.5	29.5	LO1203		385	384	397	364	362
NW	Lorenzi	LO BK 1		32.5	31.8	31.7	30.5	29.5	LO1204		409	396	406	388	371
NW	Lorenzi	LO BK 2		32.8	32.0	31.9	30.5	29.7	LO1207		438	432	426	408	425
NW	Lorenzi	LO BK 2		32.8	32.0	31.9	30.5	29.7	LO1208		502	499	510	482	478
NW	Lorenzi	LO BK 2		32.8	32.0	31.9	30.5	29.7	LO1209		486	564	488	484	475
NW	Lorenzi	LO BK 2		32.8	32.0	31.9	30.5	29.7	LO1210		354	352	343	349	313
NW	Lorenzi	LO BK 3		25.2	24.3	25.5	25.8	24.4	LO1211		502	452	532	532	492
NW	Lorenzi	LO BK 3		25.2	24.3	25.5	25.8	24.4	LO1212		292	289	279	270	264
NW	Lorenzi	LO BK 3		25.2	24.3	25.5	25.8	24.4	LO1214		396	410	397	411	376
STRIP	Lynnwood	LY BK 1		13.3	13.9	15.9	14.2	16.4	LY1202		251	230	297	309	428
STRIP	Lynnwood	LY BK 1		13.3	13.9	15.9	14.2	16.4	LY1204		368	363	372	393	423
STRIP	Lynnwood	LY BK 1		13.3	13.9	15.9	14.2	16.4	LY1205		233	243	283	242	232
STRIP	Lynnwood	LY BK 2		15.1	14.0	15.6	14.3	16.2	LY1208		366	364	362	402	195
STRIP	Lynnwood	LY BK 2		15.1	14.0	15.6	14.3	16.2	LY1209		190	256	259	282	202
SE	Magic Way	MAG BK 1		11.6	15.5	15.8	15.7	13.8	MAG1209		324	434	441	441	402
SE	Magic Way	MAG BK 1		11.6	15.5	15.8	15.7	13.8	MAG1210		219	353	358	356	305
STRIP	Mayfair	MA BK 1		0.0	0.0	0.0	0.0	0.0	MA401		219	224	212	223	249
STRIP	Mayfair	MA BK 1		0.0	0.0	0.0	0.0	0.0	MA402		260	284	301	311	300
STRIP	Mayfair	MA BK 2		15.1	15.8	14.6	15.8	15.7	MA1211		348	327	308	302	296
STRIP	Mayfair	MA BK 2		15.1	15.8	14.6	15.8	15.7	MA1212		370	420	406	444	442
STRIP	Mayfair	MA BK 3		14.7	15.0	14.4	15.3	13.7	MA1213		434	441	427	450	426
STRIP	Mayfair	MA BK 3		14.7	15.0	14.4	15.3	13.7	MA1215		342	368	350	361	332
STRIP	Mayfair	MA BK 4		14.5	14.9	14.3	15.2	13.6	MA1216		278	300	277	278	261
STRIP	Mayfair	MA BK 4		14.5	14.9	14.3	15.2	13.6	MA1218		344	331	322	329	286
SW	McDonald	MCD BK 3		27.5	24.8	25.6	24.5	22.4	MCD1205		214	212	229	218	228
SW	McDonald	MCD BK 3		27.5	24.8	25.6	24.5	22.4	MCD1207		320	201	199	188	154
SW	McDonald	MCD BK 3		27.5	24.8	25.6	24.5	22.4	MCD1208		348	354	348	359	336
SW	McDonald	MCD BK 3		27.5	24.8	25.6	24.5	22.4	MCD1210		486	512	494	474	451
SW	McDonald	MCD BK 4		35.1	35.6	34.2	35.0	33.4	MCD1216		394	407	391	391	356
SW	McDonald	MCD BK 4		35.1	35.6	34.2	35.0	33.4	MCD1217		412	430	418	424	394
SW	McDonald	MCD BK 4		35.1	35.6	34.2	35.0	33.4	MCD1218		302	302	301	267	266
SW	McDonald	MCD BK 4		35.1	35.6	34.2	35.0	33.4	MCD1219		246	247	230	285	293
SW	McDonald	MCD BK 4		35.1	35.6	34.2	35.0	33.4	MCD1220		376	398	367	373	355
STRIP	MGM	MGM BK 4		9.6	10.3	10.4	10.7	10.1	MGM1216		1	1	1	1	1
STRIP	MGM	MGM BK 4		9.6	10.3	10.4	10.7	10.1	MGM1217		141	138	159	158	143
STRIP	MGM	MGM BK 4		9.6	10.3	10.4	10.7	10.1	MGM1218		315	341	337	359	348
NW	Michael Way	MW BK 1		19.4	18.4	18.5	17.9	17.6	MW1201		245	246	247	244	238
NW	Michael Way	MW BK 1		19.4	18.4	18.5	17.9	17.6	MW1202		360	373	380	365	347
NW	Michael Way	MW BK 1		19.4	18.4	18.5	17.9	17.6	MW1204		436	309	322	305	296
NW	Michael Way	MW BK 2		19.7	18.3	18.6	18.0	17.8	MW1207		423	433	438	445	421
NW	Michael Way	MW BK 2		19.7	18.3	18.6	18.0	17.8	MW1209		398	412	407	405	389
NW	Michael Way	MW BK 3		16.8	17.2	17.5	16.5	15.8	MW1211		485	502	509	490	461
NW	Michael Way	MW BK 3		16.8	17.2	17.5	16.5	15.8	MW1213		294	304	303	284	276
NE	Miller	MI BK 3		14.1	14.6	14.0	10.5	13.9	MI1202		254	263	255	277	266
NE	Miller	MI BK 3		14.1	14.6	14.0	10.5	13.9	MI1203		230	230	216	260	192
NE	Miller	MI BK 4		14.1	14.3	14.0	14.4	14.0	MI1206		284	292	274	287	250
NE	Miller	MI BK 4		14.1	14.3	14.0	14.4	14.0	MI1207		344	345	315	317	295
NE	Miller	MI BK 4		14.1	14.3	14.0	14.4	14.0	MI1208		353	374	360	367	342
SE	Mission	MS BK 1		10.5	11.2	10.5	10.7	10.5	MS1201		60	77	72	73	71
SE	Mission	MS BK 1		10.5	11.2	10.5	10.7	10.5	MS1203		377	446	385	388	389
SE	Mission	MS BK 1		10.5	11.2	10.5	10.7	10.5	MS1204		281	308	271	271	273
SE	Mission	MS BK 2		17.2	18.2	17.2	17.2	16.1	MS1205		400	427	400	452	446
SE	Mission	MS BK 2		17.2	18.2	17.2	17.2	16.1	MS1206		213	191	190	183	186
SE	Mission	MS BK 3		16.8	17.2	16.3	16.4	15.2	MS1209		373	387	369	378	383
SE	Mission	MS BK 3		16.8	17.2	16.3	16.4	15.2	MS1210		446	453	411	348	317
SE	Mission	MS BK 3		16.8	17.2	16.3	16.4	15.2	MS1212		213	234	227	240	202
SE	Mission	MS BK 4		10.8	10.9	9.8	10.4	9.7	MS1213		200	186	188	189	192
SE	Mission	MS BK 4		10.8	10.9	9.8	10.4	9.7	MS1214		154	156	144	163	138
SW	Mountains Edge	MTE BK 2		30.8	31.8	28.8	27.9	25.5	MTE1206		412	435	395	349	375
SW	Mountains Edge	MTE BK 2		30.8	31.8	28.8	27.9	25.5	MTE1211		415	448	392	356	356
SW	Mountains Edge	MTE BK 2		30.8	31.8	28.8	27.9	25.5	MTE1212		404	421	352	367	329

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
SW	Mountains Edge	MTE BK 2		30.8	31.8	28.8	27.9	25.5	MTE1213		486	452	494	462	452
SW	Mountains Edge	MTE BK 3		31.5	32.5	29.5	28.7	26.3	MTE1214		328	344	306	295	262
SW	Mountains Edge	MTE BK 3		31.5	32.5	29.5	28.7	26.3	MTE1215		371	448	319	452	444
SW	Mountains Edge	MTE BK 3		31.5	32.5	29.5	28.7	26.3	MTE1217		475	522	590	409	387
SW	MYS	MYS BK 2	New	0.0	0.0	0.0	0.0	0.0	MYS1206	New					
SW	MYS	MYS BK 2	New	0.0	0.0	0.0	0.0	0.0	MYS1207		271	1			
SW	MYS	MYS BK 2	New	0.0	0.0	0.0	0.0	0.0	MYS1208		242				
SW	MYS	MYS BK 2	New	0.0	0.0	0.0	0.0	0.0	MYS1209		1				
SW	MYS	MYS BK 2	New	0.0	0.0	0.0	0.0	0.0	MYS1212		148				
SW	MYS	MYS BK 3		33.8	27.4	6.2	0.0	0.0	MYS1214		181	369			
SW	MYS	MYS BK 3		33.8	27.4	6.2	0.0	0.0	MYS1215		1	249			
SW	MYS	MYS BK 3		33.8	27.4	6.2	0.0	0.0	MYS1216		242	206	286		
SW	MYS	MYS BK 3		33.8	27.4	6.2	0.0	0.0	MYS1218		490	525			
SE	National Park Service	NPS BK 1		0.0	0.0	0.0	0.0	0.0	NPS401		22	21	10	10	10
NE	Nellis	NS BK 1		9.6	8.1	7.8	7.8	9.7	NS1203		159	164	172	143	111
NE	Nellis	NS BK 1		9.6	8.1	7.8	7.8	9.7	NS1204		160	157	153	163	358
NE	Nellis	NS BK 2		9.4	8.1	7.9	7.9	9.8	NS1205		363	338	329	340	317
NE	Nellis	NS BK 2		9.4	8.1	7.9	7.9	9.8	NS1206		252	177	156	180	143
NE	Nellis	NS BK 3		6.2	5.9	5.7	4.9	5.1	NS1210		1				
NE	Nellis	NS BK 3		6.2	5.9	5.7	4.9	5.1	NS1211		286	270	265	224	236
SE	Nelson	NL BK 1		0.0	0.0	0.0	0.0	0.0	NL1201		11	11	10	33	22
NE	North Las Vegas	NLV BK 1		17.3	13.7	13.7	13.8	14.0	NLV1202		414	267	282	275	274
NE	North Las Vegas	NLV BK 1		17.3	13.7	13.7	13.8	14.0	NLV1203		393	375	366	374	379
NE	North Las Vegas	NLV BK 3		13.3	13.7	13.6	13.1	12.5	NLV1204		190	195	176	169	152
NE	North Las Vegas	NLV BK 3		13.3	13.7	13.6	13.1	12.5	NLV1209		308	312	318	320	301
NE	North Las Vegas	NLV BK 4		13.1	13.1	13.4	13.3	12.8	NLV1210		387	415	401	402	390
NE	North Las Vegas	NLV BK 4		13.1	13.1	13.4	13.3	12.8	NLV1211		374	342	359	341	333
NE	North Las Vegas	NLV BK 4		13.1	13.1	13.4	13.3	12.8	NLV1212		53	52	54	58	55
NW	Northwest	NW BK 4		32.3	37.1	34.5	32.7	30.3	NW1204		257	439	369	289	254
NW	Northwest	NW BK 4		32.3	37.1	34.5	32.7	30.3	NW1205		497	490	479	472	427
NW	Northwest	NW BK 4		32.3	37.1	34.5	32.7	30.3	NW1206		296	311	295	300	292
NW	Northwest	NW BK 4		32.3	37.1	34.5	32.7	30.3	NW1208		480	507	491	492	472
NW	Northwest	NW BK 4		32.3	37.1	34.5	32.7	30.3	NW1209		1	1	1	1	1
NW	Northwest	NW BK 5		30.6	30.8	25.6	28.2	35.7	NW1215		217	244	88	85	433
NW	Northwest	NW BK 5		30.6	30.8	25.6	28.2	35.7	NW1216		376	318	305	306	377
NW	Northwest	NW BK 5		30.6	30.8	25.6	28.2	35.7	NW1217		413	409	397	393	363
NW	Northwest	NW BK 5		30.6	30.8	25.6	28.2	35.7	NW1220		281	337	323	318	307
NW	Northwest	NW BK 5		30.6	30.8	25.6	28.2	35.7	NW1221		155	167	160	203	204
SW	Oasis	OA BK 1		5.7	6.7	6.6	7.1	7.2	OA1203		87	94	98	103	108
SW	Oasis	OA BK 1		5.7	6.7	6.6	7.1	7.2	OA1204		203	234	222	239	259
SW	Oasis	OA BK 2		3.6	3.6	4.0	3.8	4.4	OA1205		80	79	78	71	96
SW	Oasis	OA BK 2		3.6	3.6	4.0	3.8	4.4	OA1206		261	271	288	309	340
NE	Olive	OL BK 1		0.0	0.0	0.0	0.0	0.0	OL1202		462	476	420	423	437
NE	Olive	OL BK 1		0.0	0.0	0.0	0.0	0.0	OL1203		393	364	344	327	367
STRIP	Oquendo	OQ BK 1		17.1	16.7	15.0	14.6	14.0	OQ1203		306	297	247	257	267
STRIP	Oquendo	OQ BK 1		17.1	16.7	15.0	14.6	14.0	OQ1204		256	201	164	191	141
STRIP	Oquendo	OQ BK 1		17.1	16.7	15.0	14.6	14.0	OQ1206		269	321	308	315	301
STRIP	Oquendo	OQ BK 2		15.1	14.5	14.8	13.2	12.1	OQ1209		378	401	403	339	313
STRIP	Oquendo	OQ BK 2		15.1	14.5	14.8	13.2	12.1	OQ1210		127	129	120	120	117
STRIP	Oquendo	OQ BK 3		13.7	13.9	13.3	13.1	11.7	OQ1211		141	164	112	112	122
STRIP	Oquendo	OQ BK 3		13.7	13.9	13.3	13.1	11.7	OQ1213		297	298	265	268	254
STRIP	Oquendo	OQ BK 3		13.7	13.9	13.3	13.1	11.7	OQ1214		455	397	402	437	373
NE	Pabco	PBC BK 2		9.8	10.0	9.7	10.1	9.8	PBC1206		406	390	377	383	370
NE	Pabco	PBC BK 2		9.8	10.0	9.7	10.1	9.8	PBC1208		80	91	84	103	88
STRIP	Pawnee	PA BK 1		13.9	13.8	14.4	13.6	13.8	PA1202		365	372	337	335	342
STRIP	Pawnee	PA BK 1		13.9	13.8	14.4	13.6	13.8	PA1203		32	20	21	20	30
STRIP	Pawnee	PA BK 1		13.9	13.8	14.4	13.6	13.8	PA1204		344	346	407	360	342
STRIP	Pawnee	PA BK 2		13.8	14.1	14.3	14.0	13.8	PA1206		254	261	268	267	296
STRIP	Pawnee	PA BK 2		13.8	14.1	14.3	14.0	13.8	PA1207		193	190	180	203	195
STRIP	Pawnee	PA BK 2		13.8	14.1	14.3	14.0	13.8	PA1208		228	223	221	237	237
SW	Peace	PCE BK 1		19.6	19.6	18.0	18.4	18.7	PCE1201		1	1	1	1	1
SW	Peace	PCE BK 1		19.6	19.6	18.0	18.4	18.7	PCE1204		441	455	425	451	471
SW	Peace	PCE BK 2		19.8	19.8	18.5	18.7	18.9	PCE1206		334	336	315	325	335
SW	Peace	PCE BK 2		19.8	19.8	18.5	18.7	18.9	PCE1209		448	464	497	479	487
SW	Peace	PCE BK 2		19.8	19.8	18.5	18.7	18.9	PCE1211		373	355	338	328	300

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
SW	Peace	PCE BK 2		19.8	19.8	18.5	18.7	18.9	PCE1213		236	255	210	241	233
SW	Peace	PCE BK 3		24.9	24.5	21.0	20.8	19.2	PCE1214		501	513	504	465	449
SW	Peace	PCE BK 3		24.9	24.5	21.0	20.8	19.2	PCE1215		380	385	343	349	320
SW	Peace	PCE BK 3		24.9	24.5	21.0	20.8	19.2	PCE1217		295	269	169	232	195
SE	Pearl	PL BK 1		16.0	17.4	15.9	15.0	16.4	PL1201		225	243	216	233	228
SE	Pearl	PL BK 1		16.0	17.4	15.9	15.0	16.4	PL1202		433	433	414	427	428
SE	Pearl	PL BK 1		16.0	17.4	15.9	15.0	16.4	PL1204		142	158	143	155	105
SE	Pearl	PL BK 2		16.7	18.2	17.9	18.0	17.0	PL1206		330	384	385	391	373
SE	Pearl	PL BK 2		16.7	18.2	17.9	18.0	17.0	PL1209		347	378	382	393	415
SE	Pearl	PL BK 3		16.3	17.7	17.7	17.7	17.0	PL1211		228	230	223	245	233
SE	Pearl	PL BK 3		16.3	17.7	17.7	17.7	17.0	PL1213		400	424	398	340	312
SE	Pearl	PL BK 3		16.3	17.7	17.7	17.7	17.0	PL1214		264	282	267	307	285
SE	Pebble	PB BK 1		21.1	22.1	21.1	22.0	21.6	PB1201		469	502	453	488	478
SE	Pebble	PB BK 1		21.1	22.1	21.1	22.0	21.6	PB1203		315	365	346	356	353
SE	Pebble	PB BK 1		21.1	22.1	21.1	22.0	21.6	PB1204		198	202	193	208	198
SE	Pebble	PB BK 2		28.2	29.6	28.3	29.4	28.2	PB1205		475	486	521	526	510
SE	Pebble	PB BK 2		28.2	29.6	28.3	29.4	28.2	PB1209		382	399	424	362	334
SE	Pebble	PB BK 2		28.2	29.6	28.3	29.4	28.2	PB1210		427	437	418	427	412
SE	Pebble	PB BK 3		27.6	28.8	27.9	29.2	27.9	PB1211		387	420	393	406	390
SE	Pebble	PB BK 3		27.6	28.8	27.9	29.2	27.9	PB1212		520	522	508	545	535
SE	Pebble	PB BK 3		27.6	28.8	27.9	29.2	27.9	PB1213		505	528	499	507	496
NE	Pecos	PE BK 6		33.5	34.1	33.7	32.2	28.7	PE1201		89	105	1		
NE	Pecos	PE BK 6		33.5	34.1	33.7	32.2	28.7	PE1202		38	1			
NE	Pecos	PE BK 6		33.5	34.1	33.7	32.2	28.7	PE1207		414	434	449	415	399
NE	Pecos	PE BK 6		33.5	34.1	33.7	32.2	28.7	PE1208		347	462	433	409	361
NE	Pecos	PE BK 7	New	0.0	0.0	0.0			PE1209		484	473	474	470	435
NE	Pecos	PE BK 7	New	0.0	0.0	0.0			PE1212		217	224	239	236	231
STRIP	Polaris	POL BK 1		17.6	17.5	18.0	20.3	17.1	POL1201		191	188	193	206	167
STRIP	Polaris	POL BK 1		17.6	17.5	18.0	20.3	17.1	POL1203		413	439	399	424	443
STRIP	Polaris	POL BK 1		17.6	17.5	18.0	20.3	17.1	POL1204		285	338	345	367	299
STRIP	Polaris	POL BK 2		17.7	17.5	18.0	20.3	17.1	POL1205		115	118	114	176	175
STRIP	Polaris	POL BK 2		17.7	17.5	18.0	20.3	17.1	POL1208		1	1	1	1	1
STRIP	Polaris	POL BK 2		17.7	17.5	18.0	20.3	17.1	POL1209		2	2	2	4	4
STRIP	Polaris	POL BK 2		17.7	17.5	18.0	20.3	17.1	POL1210		91	100	109	119	113
STRIP	Polaris	POL BK 2		17.7	17.5	18.0	20.3	17.1	POL1211		367	358	366	314	325
STRIP	Polaris	POL BK 2		17.7	17.5	18.0	20.3	17.1	POL1212		393	275	267	277	281
STRIP	Polaris	POL BK 3		20.0	20.9	21.1	20.5	19.8	POL1213		399	395	373	401	407
STRIP	Polaris	POL BK 3		20.0	20.9	21.1	20.5	19.8	POL1215		466	505	497	512	540
STRIP	Polaris	POL BK 3		20.0	20.9	21.1	20.5	19.8	POL1216		182	155	151	97	132
NE	Prince	PR BK 1		18.6	16.8	16.1	15.9	15.6	PR1202		427	443	398	392	422
NE	Prince	PR BK 1		18.6	16.8	16.1	15.9	15.6	PR1203		287	201	161	145	162
NE	Prince	PR BK 2		19.2	18.7	16.8	17.9	17.6	PR1206		532	522	525	500	462
NE	Prince	PR BK 2		19.2	18.7	16.8	17.9	17.6	PR1207		258	282	275	270	262
NE	Prince	PR BK 2		19.2	18.7	16.8	17.9	17.6	PR1208		380	397	376	383	353
STRIP	Procyon	PRO BK 2		21.8	23.4	24.6	23.0	19.0	PRO1202		375	383	410	455	447
STRIP	Procyon	PRO BK 2		21.8	23.4	24.6	23.0	19.0	PRO1206		5	4	4	6	6
STRIP	Procyon	PRO BK 2		21.8	23.4	24.6	23.0	19.0	PRO1207		160	172	161	199	224
STRIP	Procyon	PRO BK 2		21.8	23.4	24.6	23.0	19.0	PRO1209		1	1	1	1	1
STRIP	Procyon	PRO BK 2		21.8	23.4	24.6	23.0	19.0	PRO1211		314	314	327	310	305
STRIP	Procyon	PRO BK 2		21.8	23.4	24.6	23.0	19.0	PRO1212		243	273	226	194	197
STRIP	Procyon	PRO BK 3	New	0.0					PRO1213		16	8	7	153	9
STRIP	Procyon	PRO BK 3	New	0.0					PRO1214		1	1	1	1	1
STRIP	Procyon	PRO BK 3	New	0.0					PRO1216	New					
SW	Quail	QUL BK 1		19.4	18.5	19.3	19.0	18.0	QUL1201		336	348	483	430	416
SW	Quail	QUL BK 1		19.4	18.5	19.3	19.0	18.0	QUL1203		295	294	267	294	292
SW	Quail	QUL BK 1		19.4	18.5	19.3	19.0	18.0	QUL1204		296	249	189	218	209
SW	Quail	QUL BK 2		22.6	20.7	22.6	21.7	19.3	QUL1205		477	487	486	467	475
SW	Quail	QUL BK 2		22.6	20.7	22.6	21.7	19.3	QUL1208		451	450	519	425	423
SW	Quail	QUL BK 2		22.6	20.7	22.6	21.7	19.3	QUL1209		120	115	113	115	106
SW	Quail	QUL BK 2		22.6	20.7	22.6	21.7	19.3	QUL1210		472	469	438	356	361
SW	Quail	QUL BK 3		21.8	21.5	23.4	21.4	17.9	QUL1211		248	240	434	438	169
SW	Quail	QUL BK 3		21.8	21.5	23.4	21.4	17.9	QUL1212		232	226	207	221	202
SW	Quail	QUL BK 3		21.8	21.5	23.4	21.4	17.9	QUL1213		100	95	89	158	110
NW	Radar	RA BK 1		0.0	0.0	0.0	0.0	0.0	RA1201		7	19	10	28	18
SW	Railroad	RLR BK 1		22.5	19.2	19.4	20.6	20.3	RLR1201		30	95			

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
SW	Railroad	RLR BK 1		22.5	19.2	19.4	20.6	20.3	RLR1203		221	234	240	265	285
SW	Railroad	RLR BK 1		22.5	19.2	19.4	20.6	20.3	RLR1204		80	99	99	232	208
SW	Railroad	RLR BK 1		22.5	19.2	19.4	20.6	20.3	RLR1218		436	145	105	254	
SW	Railroad	RLR BK 1		22.5	19.2	19.4	20.6	20.3	RLR1219		246	223	218		
SW	Railroad	RLR BK 2		22.3	19.1	19.3	20.5	20.4	RLR1205		221	220	239	238	
SW	Railroad	RLR BK 2		22.3	19.1	19.3	20.5	20.4	RLR1206		203	208	213	330	343
SW	Railroad	RLR BK 2		22.3	19.1	19.3	20.5	20.4	RLR1210		269	259	252	258	252
SW	Railroad	RLR BK 2		22.3	19.1	19.3	20.5	20.4	RLR1211		40	43	40	43	43
SW	Railroad	RLR BK 2		22.3	19.1	19.3	20.5	20.4	RLR1212		427	456	462	397	449
SW	Railroad	RLR BK 3		15.0	15.3	14.4	13.5	0.0	RLR1214		210	215	219	220	223
SW	Railroad	RLR BK 3		15.0	15.3	14.4	13.5	0.0	RLR1215		249	254	234	203	1
SW	Railroad	RLR BK 3		15.0	15.3	14.4	13.5	0.0	RLR1217		250	249	213	207	305
NW	Rainbow	RB BK 1		16.6	17.4	16.7	16.7	17.2	RB1202		277	282	273	273	280
NW	Rainbow	RB BK 1		16.6	17.4	16.7	16.7	17.2	RB1203		456	430	457	457	447
NW	Rainbow	RB BK 1		16.6	17.4	16.7	16.7	17.2	RB1204		317	335	337	333	350
NW	Rainbow	RB BK 2		17.5	17.4	16.7	16.6	16.4	RB1207		218	217	235	235	210
NW	Rainbow	RB BK 2		17.5	17.4	16.7	16.6	16.4	RB1208		347	351	296	283	290
NW	Rainbow	RB BK 3		16.4	17.4	18.7	18.5	18.6	RB1214		104	108	107	108	114
NW	Rainbow	RB BK 3		16.4	17.4	18.7	18.5	18.6	RB1215		431	454	453	440	438
NW	Rainbow	RB BK 3		16.4	17.4	18.7	18.5	18.6	RB1219		242	264	334	334	334
SE	Ranger	RN BK 1		0.0	0.0	0.0	0.0	0.0	RN1201		49	49	50	50	50
SE	Ranger	RN BK 1		0.0	0.0	0.0	0.0	0.0	RN1202		55	55	56	56	56
SW	Red Rock	RRK BK 1		26.1	25.0	23.4	22.8	23.6	RRK1201		428	449	426	419	443
SW	Red Rock	RRK BK 1		26.1	25.0	23.4	22.8	23.6	RRK1203		305	325	322	296	313
SW	Red Rock	RRK BK 1		26.1	25.0	23.4	22.8	23.6	RRK1204		459	511	508	484	473
SW	Red Rock	RRK BK 2		23.7	24.4	22.7	21.9	22.6	RRK1211		468	482	390	385	438
SW	Red Rock	RRK BK 2		23.7	24.4	22.7	21.9	22.6	RRK1212		376	359	346	337	509
SW	Red Rock	RRK BK 2		23.7	24.4	22.7	21.9	22.6	RRK1213		316	251	324	374	
NW	Regena	RGN BK 2		32.0	33.3	31.4	32.5	25.6	RGN1201		1	1	0	1	0
NW	Regena	RGN BK 2		32.0	33.3	31.4	32.5	25.6	RGN1204		498	487	465	449	314
NW	Regena	RGN BK 2		32.0	33.3	31.4	32.5	25.6	RGN1206		82	78	81	81	73
NW	Regena	RGN BK 2		32.0	33.3	31.4	32.5	25.6	RGN1210		428	537	533	533	451
NW	Regena	RGN BK 2		32.0	33.3	31.4	32.5	25.6	RGN1211		372	359	364	368	231
NW	Regena	RGN BK 2		32.0	33.3	31.4	32.5	25.6	RGN1212		121	123	124	123	119
SW	Riley	RLY BK 2		28.6	28.1	28.0	27.2	24.2	RLY1205		430	428	523	494	434
SW	Riley	RLY BK 2		28.6	28.1	28.0	27.2	24.2	RLY1206		530	548	531	504	473
SW	Riley	RLY BK 2		28.6	28.1	28.0	27.2	24.2	RLY1210	New					
SW	Riley	RLY BK 2		28.6	28.1	28.0	27.2	24.2	RLY1211		367	344	294	261	240
SE	River Road	RI BK 1		0.0	0.0	0.0	0.0	0.0	RI2501		319	312	290	285	277
SE	River Road	RI BK 2		4.4	5.1	5.0	5.8	6.5	RI2508		106	102	116	117	150
SE	River Road	RI BK 2		4.4	5.1	5.0	5.8	6.5	RI2509		1	18	18	18	150
SW	Robindale	ROB BK 1		16.4	16.1	15.8	15.2	13.6	ROB1201		381	392	367	344	352
SW	Robindale	ROB BK 1		16.4	16.1	15.8	15.2	13.6	ROB1203		153	155	151	163	153
SW	Robindale	ROB BK 1		16.4	16.1	15.8	15.2	13.6	ROB1204		267	267	264	253	244
SW	Robindale	ROB BK 2		28.1	27.5	27.0	25.1	18.5	ROB1206		304	323	289	262	388
SW	Robindale	ROB BK 2		28.1	27.5	27.0	25.1	18.5	ROB1210		502	515	477	479	451
SW	Robindale	ROB BK 2		28.1	27.5	27.0	25.1	18.5	ROB1212		320	323	298	289	260
SW	Robindale	ROB BK 2		28.1	27.5	27.0	25.1	18.5	ROB1213		495	535	502	383	380
SW	Robindale	ROB BK 3		28.0	27.0	27.3	23.4	18.2	ROB1214		301	255	204	155	
SW	Robindale	ROB BK 3		28.0	27.0	27.3	23.4	18.2	ROB1215		396	379	574	440	
SW	Robindale	ROB BK 3		28.0	27.0	27.3	23.4	18.2	ROB1217		380	403	343	420	395
SW	Rosanna	RO BK 1		15.0	15.1	15.0	15.0	15.9	RO1201		150	156	154	165	175
SW	Rosanna	RO BK 1		15.0	15.1	15.0	15.0	15.9	RO1203		300	327	336	334	351
SW	Rosanna	RO BK 1		15.0	15.1	15.0	15.0	15.9	RO1204		249	263	256	257	258
SW	Rosanna	RO BK 2		15.3	15.5	15.4	15.5	15.4	RO1207		333	332	326	332	355
SW	Rosanna	RO BK 2		15.3	15.5	15.4	15.5	15.4	RO1208		369	404	375	385	370
SW	Rosanna	RO BK 3		13.8	15.0	14.4	13.7	13.9	RO1210		338	370	343	355	360
SW	Rosanna	RO BK 3		13.8	15.0	14.4	13.7	13.9	RO1212		307	332	330	369	309
SE	Russell	RS BK 1		24.1	25.4	24.9	25.7	25.1	RS1201		208	209	230	232	194
SE	Russell	RS BK 1		24.1	25.4	24.9	25.7	25.1	RS1202		183	133	151	169	179
SE	Russell	RS BK 1		24.1	25.4	24.9	25.7	25.1	RS1204		356	384	395	369	359
SE	Russell	RS BK 2		24.7	26.4	24.9	26.3	25.1	RS1205		383	425	380	394	354
SE	Russell	RS BK 2		24.7	26.4	24.9	26.3	25.1	RS1206		386	430	369	480	477
SE	Russell	RS BK 2		24.7	26.4	24.9	26.3	25.1	RS1209		440	479	452	469	425
SE	Russell	RS BK 2		24.7	26.4	24.9	26.3	25.1	RS1210		456	493	465	473	478

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
SE	Russell	RS BK 3		22.7	23.6	22.9	23.8	22.9	RS1211		416	424	411	417	435
SE	Russell	RS BK 3		22.7	23.6	22.9	23.8	22.9	RS1212		474	507	500	513	468
SE	Russell	RS BK 3		22.7	23.6	22.9	23.8	22.9	RS1214		168	171	156	203	178
SE	Sahara	SA BK 1		14.4	13.7	13.2	13.8	14.6	SA1201		407	353	326	391	385
SE	Sahara	SA BK 1		14.4	13.7	13.2	13.8	14.6	SA1203		483	483	487	409	489
SE	Sahara	SA BK 2		17.5	17.7	16.5	17.3	16.7	SA1205		397	388	371	406	441
SE	Sahara	SA BK 2		17.5	17.7	16.5	17.3	16.7	SA1206		378	378	343	399	426
SE	Sahara	SA BK 3		17.6	17.2	16.6	17.3	16.8	SA1209		536	528	508	498	457
SE	Sahara	SA BK 3		17.6	17.2	16.6	17.3	16.8	SA1212		359	357	346	366	338
SE	Sahara	SA BK 4		14.9	14.0	13.2	13.6	14.2	SA1216		408	415	407	434	434
SE	Sahara	SA BK 4		14.9	14.0	13.2	13.6	14.2	SA1217		76	71	76	85	85
STRIP	San Francisco	SF BK 1		12.3	12.9	13.0	13.2	12.7	SF1203		206	201	199	201	193
STRIP	San Francisco	SF BK 1		12.3	12.9	13.0	13.2	12.7	SF1204		205	199	190	203	217
STRIP	San Francisco	SF BK 2		11.7	12.2	12.4	12.6	11.7	SF1206		301	319	293	295	298
STRIP	San Francisco	SF BK 2		11.7	12.2	12.4	12.6	11.7	SF1207		465	477	497	496	480
STRIP	San Francisco	SF BK 3		12.1	12.3	12.3	11.5	11.9	SF1213		346	359	341	339	327
STRIP	San Francisco	SF BK 4		12.1	12.3	12.7	12.0	11.7	SF1215		197	197	149	109	139
STRIP	San Francisco	SF BK 4		12.1	12.3	12.7	12.0	11.7	SF1216		68	116	117	120	130
STRIP	San Francisco	SF BK 4		12.1	12.3	12.7	12.0	11.7	SF1217		283	286	287	281	299
STRIP	San Francisco	SF BK 4		12.1	12.3	12.7	12.0	11.7	SF1218		254	227	268	278	293
SE	Searchlight	SE BK 1		0.0	0.0	0.0	0.0	0.0	SE1201		123	120	114	273	129
SE	Searchlight	SE BK 1		0.0	0.0	0.0	0.0	0.0	SE1202		6	10	12	26	13
NE	Shadow	SH BK 3		0.0	0.0	0.0	0.0	0.0	SH401		75	72	71	109	119
NE	Shadow	SH BK 3		0.0	0.0	0.0	0.0	0.0	SH404		218	222	276	258	325
NE	Shadow	SH BK 4		15.4	15.6	15.3	14.8	14.9	SH1206		254	255	300	265	276
NE	Shadow	SH BK 4		15.4	15.6	15.3	14.8	14.9	SH1207		218	227	223	222	213
NE	Shadow	SH BK 5		15.3	15.3	15.3	14.7	15.0	SH1209		470	494	495	500	488
NE	Shadow	SH BK 5		15.3	15.3	15.3	14.7	15.0	SH1211		232	231	234	233	222
NE	Shadow	SH BK 5		15.3	15.3	15.3	14.7	15.0	SH1212		319	325	364	369	338
NW	Silver Flag	SLV BK 1		0.2	0.2	0.3	0.2	0.2	SLV1201		10	11	12	13	11
STRIP	Sinatra	SNT BK 1		8.0	8.0	7.3	8.5	7.2	SNT1206		184	183	178	193	203
STRIP	Sinatra	SNT BK 1		8.0	8.0	7.3	8.5	7.2	SNT1207		4	4	4	4	4
STRIP	Sinatra	SNT BK 1		8.0	8.0	7.3	8.5	7.2	SNT1208		187	196	189	208	178
STRIP	Sinatra	SNT BK 2		13.0	13.6	12.3	14.0	14.0	SNT1215		163	172	157	177	192
STRIP	Sinatra	SNT BK 2		13.0	13.6	12.3	14.0	14.0	SNT1216		214	230	224	253	220
STRIP	Sinatra	SNT BK 2		13.0	13.6	12.3	14.0	14.0	SNT1218		211	202	200	209	240
STRIP	Sinatra	SNT BK 2		13.0	13.6	12.3	14.0	14.0	SNT1219		14	14	14	14	14
STRIP	Sinatra	SNT BK 2		13.0	13.6	12.3	14.0	14.0	SNT1220		14	14	14	14	14
NW	Skelton	SKL BK 1		44.5	45.0	44.2	45.9	42.8	SKL1205		405	433	431	418	406
NW	Skelton	SKL BK 1		44.5	45.0	44.2	45.9	42.8	SKL1206		489	483	453	450	462
NW	Skelton	SKL BK 1		44.5	45.0	44.2	45.9	42.8	SKL1208		420	445	455	457	444
NW	Skelton	SKL BK 1		44.5	45.0	44.2	45.9	42.8	SKL1209		421	443	452	445	435
NW	Skelton	SKL BK 1		44.5	45.0	44.2	45.9	42.8	SKL1210		349	374	365	466	349
NW	Skelton	SKL BK 2		32.3	31.8	30.5	27.6	27.9	SKL1215		352	343	289	286	239
NW	Skelton	SKL BK 2		32.3	31.8	30.5	27.6	27.9	SKL1217		214	234	231	238	225
NW	Skelton	SKL BK 2		32.3	31.8	30.5	27.6	27.9	SKL1218		298	308	309	198	288
NW	Skelton	SKL BK 2		32.3	31.8	30.5	27.6	27.9	SKL1220		206	205	198	200	183
NW	Skelton	SKL BK 2		32.3	31.8	30.5	27.6	27.9	SKL1221		434	418	427	431	411
NW	Snow Mountain	SN BK 1		0.0	0.0	0.0	0.0	0.0	SN1201		92	42	102	102	100
SE	Southpoint	SO BK 1		0.0	0.0	0.0	0.0	0.0	SO2502		171	181	178	189	202
SE	Southpoint	SO BK 2		0.0	0.0	0.0	0.0	0.0	SO2507		125	130	121	152	152
SE	Southpoint	SO BK 2		0.0	0.0	0.0	0.0	0.0	SO2508		8	12	14	28	28
SW	Sparta	SPA BK 2		33.9	32.6	29.0	25.0	22.5	SPA1205		459	468	281	240	236
SW	Sparta	SPA BK 2		33.9	32.6	29.0	25.0	22.5	SPA1206		450	474	532	489	469
SW	Sparta	SPA BK 2		33.9	32.6	29.0	25.0	22.5	SPA1210		364	399	407	361	342
SW	Sparta	SPA BK 2		33.9	32.6	29.0	25.0	22.5	SPA1213		3	4	1	1	1
SW	Sparta	SPA BK 3	New	0.0	0.0	0.0	0.0		SPA1214		221	188	150	98	
SW	Sparta	SPA BK 3	New	0.0	0.0	0.0	0.0		SPA1215	New					
SW	Sparta	SPA BK 3	New	0.0	0.0	0.0	0.0		SPA1217		119	130			
NE	Speedway	SPD BK 2		10.2	9.6	11.3	8.7	8.3	SPD1201		148	163	163	158	163
NE	Speedway	SPD BK 2		10.2	9.6	11.3	8.7	8.3	SPD1203		118	100	97	68	62
NE	Speedway	SPD BK 2		10.2	9.6	11.3	8.7	8.3	SPD1204	New					
NE	Speedway	SPD BK 2		10.2	9.6	11.3	8.7	8.3	SPD1211		70	68	146	128	88
NE	Speedway	SPD BK 2		10.2	9.6	11.3	8.7	8.3	SPD1213		209	235	235	200	173
STRIP	Spencer	SP BK 3		12.2	13.1	13.5	13.9	13.2	SP1203		230	245	242	271	252

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
STRIP	Spencer	SP BK 3		12.2	13.1	13.5	13.9	13.2	SP1206		350	377	383	382	373
STRIP	Spencer	SP BK 4		15.5	16.7	16.8	15.6	15.5	SP1207		384	412	407	404	402
STRIP	Spencer	SP BK 4		15.5	16.7	16.8	15.6	15.5	SP1210		301	328	318	298	327
STRIP	Spencer	SP BK 5		15.7	16.6	17.1	15.8	15.8	SP1211		248	266	251	262	270
STRIP	Spencer	SP BK 5		15.7	16.6	17.1	15.8	15.8	SP1213		359	371	414	327	307
STRIP	Spencer	SP BK 5		15.7	16.6	17.1	15.8	15.8	SP1214		155	169	220	160	152
SW	Spring Mountain	SM BK 1		0.0	0.0	0.0	0.0	0.0	SM1201		44	44	44	91	45
SW	Spring Mountain	SM BK 1		0.0	0.0	0.0	0.0	0.0	SM1202		176	198	206	443	228
SW	Spring Valley	SV BK 1		9.4	10.1	10.2	9.8	8.9	SV1201		324	355	354	359	332
SW	Spring Valley	SV BK 1		9.4	10.1	10.2	9.8	8.9	SV1202		271	290	280	282	180
SW	Spring Valley	SV BK 2		17.8	19.4	17.2	18.1	15.8	SV1207		175	208	116	123	73
SW	Spring Valley	SV BK 2		17.8	19.4	17.2	18.1	15.8	SV1209		428	504	419	437	425
SW	Spring Valley	SV BK 3		17.4	19.4	17.5	18.1	17.2	SV1211		373	420	394	390	378
SW	Spring Valley	SV BK 3		17.4	19.4	17.5	18.1	17.2	SV1213		257	298	269	303	285
SW	Spring Valley	SV BK 3		17.4	19.4	17.5	18.1	17.2	SV1214		410	431	417	577	494
SW	Spring Valley	SV BK 4		10.2	10.6	10.4	10.3	9.5	SV1216		348	372	355	357	352
STRIP	Strip	STR BK 1		24.1	23.2	23.9	23.4	23.2	STR1203		438	425	425	422	395
STRIP	Strip	STR BK 1		24.1	23.2	23.9	23.4	23.2	STR1204		290	301	298	300	314
STRIP	Strip	STR BK 1		24.1	23.2	23.9	23.4	23.2	STR1205		232	241	176	186	184
STRIP	Strip	STR BK 1		24.1	23.2	23.9	23.4	23.2	STR1206		165	173	171	183	197
STRIP	Strip	STR BK 1		24.1	23.2	23.9	23.4	23.2	STR1207		128	137	127	120	124
STRIP	Strip	STR BK 1		24.1	23.2	23.9	23.4	23.2	STR1208		4	2	4	4	4
STRIP	Strip	STR BK 2		15.7	15.0	16.0	19.6	16.9	STR1215		260	273	261	293	293
STRIP	Strip	STR BK 2		15.7	15.0	16.0	19.6	16.9	STR1216		127	133	163	139	154
STRIP	Strip	STR BK 2		15.7	15.0	16.0	19.6	16.9	STR1217		176	179	199	147	255
STRIP	Strip	STR BK 2		15.7	15.0	16.0	19.6	16.9	STR1218		226	246	159	158	172
STRIP	Strip	STR BK 2		15.7	15.0	16.0	19.6	16.9	STR1219		213	225	226	173	244
NW	Summerlin	SMR BK 1		40.1	41.7	41.2	41.0	39.1	SMR1205		256	282	285	268	265
NW	Summerlin	SMR BK 1		40.1	41.7	41.2	41.0	39.1	SMR1207		375	403	395	478	462
NW	Summerlin	SMR BK 1		40.1	41.7	41.2	41.0	39.1	SMR1208		462	501	513	476	461
NW	Summerlin	SMR BK 1		40.1	41.7	41.2	41.0	39.1	SMR1209		419	448	423	400	384
NW	Summerlin	SMR BK 1		40.1	41.7	41.2	41.0	39.1	SMR1210		343	373	381	385	418
NW	Summerlin	SMR BK 2		37.2	37.7	36.6	34.2	33.9	SMR1217		412	419	421	421	410
NW	Summerlin	SMR BK 2		37.2	37.7	36.6	34.2	33.9	SMR1218		424	424	419	358	357
NW	Summerlin	SMR BK 2		37.2	37.7	36.6	34.2	33.9	SMR1219		454	457	490	470	439
NW	Summerlin	SMR BK 2		37.2	37.7	36.6	34.2	33.9	SMR1220		430	465	447	443	417
SE	Sunset	SUS BK 1		8.6	7.1	5.4	0.0	11.2	SUS1201	New					
SE	Sunset	SUS BK 2		8.6	7.2	5.4	10.8	0.0	SUS1205		428	321	227		
SE	Sunset	SUS BK 2		8.6	7.2	5.4	10.8	0.0	SUS1206		403	373	395		
SE	Sunset	SUS BK 2		8.6	7.2	5.4	10.8	0.0	SUS1212	New					
STRIP	Suzanne	SZ BK 1		19.6	20.7	18.9	19.8	20.9	SZ1201		270	297	312	316	326
STRIP	Suzanne	SZ BK 1		19.6	20.7	18.9	19.8	20.9	SZ1202		431	436	426	454	446
STRIP	Suzanne	SZ BK 1		19.6	20.7	18.9	19.8	20.9	SZ1203		297	296	371	383	413
STRIP	Suzanne	SZ BK 2		19.6	20.6	18.9	19.7	20.8	SZ1205		386	323	340	351	341
STRIP	Suzanne	SZ BK 2		19.6	20.6	18.9	19.7	20.8	SZ1206		279	302	299	286	316
STRIP	Suzanne	SZ BK 2		19.6	20.6	18.9	19.7	20.8	SZ1208		204	220	200	218	232
STRIP	Suzanne	SZ BK 2		19.6	20.6	18.9	19.7	20.8	SZ1209		185	223	194	231	255
STRIP	Suzanne	SZ BK 3		12.6	12.6	12.2	12.6	12.1	SZ1211		170	179	185	194	188
STRIP	Suzanne	SZ BK 3		12.6	12.6	12.2	12.6	12.1	SZ1213		55	55	94	158	168
STRIP	Suzanne	SZ BK 3		12.6	12.6	12.2	12.6	12.1	SZ1214		406	439	414	441	421
STRIP	Swenson	SWN BK 1		11.6	11.8	6.2	6.5	6.5	SWN1201		283	282	289	304	302
STRIP	Swenson	SWN BK 1		11.6	11.8	6.2	6.5	6.5	SWN1207		4	3	2	1	1
STRIP	Swenson	SWN BK 1		11.6	11.8	6.2	6.5	6.5	SWN1208		273	294	1	1	1
STRIP	Swenson	SWN BK 2		10.4	11.9	9.5	8.6	10.4	SWN1209		221	270	218	236	270
STRIP	Swenson	SWN BK 2		10.4	11.9	9.5	8.6	10.4	SWN1213		74	76	75	92	113
STRIP	Swenson	SWN BK 2		10.4	11.9	9.5	8.6	10.4	SWN1216		16	15	13	8	8
STRIP	Swenson	SWN BK 2		10.4	11.9	9.5	8.6	10.4	SWN1219		202	206	179	148	161
SW	Tam	TA BK 1		15.3	15.7	15.7	16.1	16.4	TA1201		362	394	356	373	356
SW	Tam	TA BK 1		15.3	15.7	15.7	16.1	16.4	TA1202		122	142	141	155	190
SW	Tam	TA BK 1		15.3	15.7	15.7	16.1	16.4	TA1204		238	258	263	240	242
SW	Tam	TA BK 2		16.4	17.2	16.4	16.0	15.1	TA1205		344	376	353	365	293
SW	Tam	TA BK 3		16.6	17.1	16.4	15.9	15.1	TA1209		466	474	475	393	373
SW	Tam	TA BK 3		16.6	17.1	16.4	15.9	15.1	TA1210		383	417	393	395	394
SW	Tam	TA BK 3		16.6	17.1	16.4	15.9	15.1	TA1212		390	404	353	377	352
NW	Tenaya	TE BK 1		17.6	17.6	17.5	17.8	17.3	TE1201		389	409	400	395	402

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
NW	Tenaya	TE BK 1		17.6	17.6	17.5	17.8	17.3	TE1203		190	184	170	175	173
NW	Tenaya	TE BK 1		17.6	17.6	17.5	17.8	17.3	TE1204		281	293	278	300	314
NW	Tenaya	TE BK 2		25.9	25.1	26.3	25.0	24.6	TE1205		264	247	248	270	253
NW	Tenaya	TE BK 2		25.9	25.1	26.3	25.0	24.6	TE1206		469	526	525	489	506
NW	Tenaya	TE BK 2		25.9	25.1	26.3	25.0	24.6	TE1208		152	139	116	135	134
NW	Tenaya	TE BK 2		25.9	25.1	26.3	25.0	24.6	TE1209		519	533	541	526	526
NW	Tenaya	TE BK 3		27.1	27.9	27.2	27.6	27.1	TE1211		425	461	446	420	411
NW	Tenaya	TE BK 3		27.1	27.9	27.2	27.6	27.1	TE1212		386	388	393	376	372
NW	Tenaya	TE BK 3		27.1	27.9	27.2	27.6	27.1	TE1213		384	415	423	413	388
SE	Tolson	TOL BK 3		41.6	40.0	37.7	35.4	34.6	TOL1215		433	462	467	477	475
SE	Tolson	TOL BK 3		41.6	40.0	37.7	35.4	34.6	TOL1216		384	338	323	328	304
SE	Tolson	TOL BK 3		41.6	40.0	37.7	35.4	34.6	TOL1218		353	333	312	375	376
SE	Tolson	TOL BK 3		41.6	40.0	37.7	35.4	34.6	TOL1220		479	445	529	406	390
SE	Tolson	TOL BK 3		41.6	40.0	37.7	35.4	34.6	TOL1221		465	494	488	436	423
SE	Tolson	TOL BK 4		44.7	44.5	41.8	43.6	41.0	TOL1204		436	433	381	388	405
SE	Tolson	TOL BK 4		44.7	44.5	41.8	43.6	41.0	TOL1205		446	458	416	439	415
SE	Tolson	TOL BK 4		44.7	44.5	41.8	43.6	41.0	TOL1206		461	512	518	485	456
SE	Tolson	TOL BK 4		44.7	44.5	41.8	43.6	41.0	TOL1208		463	410	454	436	426
SE	Tolson	TOL BK 4		44.7	44.5	41.8	43.6	41.0	TOL1209		325	345	336	326	329
SW	Tomsik	TOM BK 2		26.4	26.3	22.5	19.9	18.7	TOM1201		189	129	51	70	35
SW	Tomsik	TOM BK 2		26.4	26.3	22.5	19.9	18.7	TOM1203		1	1	1	1	1
SW	Tomsik	TOM BK 2		26.4	26.3	22.5	19.9	18.7	TOM1204		371	372	356	312	293
SW	Tomsik	TOM BK 2		26.4	26.3	22.5	19.9	18.7	TOM1210		218	178	130	67	65
SW	Tomsik	TOM BK 2		26.4	26.3	22.5	19.9	18.7	TOM1211		342	343	208	218	206
SW	Tomsik	TOM BK 2		26.4	26.3	22.5	19.9	18.7	TOM1212		419	452	454	383	364
SW	Tomsik	TOM BK 2		26.4	26.3	22.5	19.9	18.7	TOM1213		462	490	489	480	461
SW	Tomsik	TOM BK 3		26.1	25.7	21.9	19.5	18.3	TOM1214		456	487	438	424	393
SW	Tomsik	TOM BK 3		26.1	25.7	21.9	19.5	18.3	TOM1215		1	1	1	1	2
SW	Tomsik	TOM BK 3		26.1	25.7	21.9	19.5	18.3	TOM1217		1	1	1	1	2
NE	Tonopah	TO BK 1		16.4	17.4	17.5	17.4	17.0	TO1201		407	423	397	397	381
NE	Tonopah	TO BK 1		16.4	17.4	17.5	17.4	17.0	TO1203		73	78	76	74	80
NE	Tonopah	TO BK 2		16.6	17.7	17.6	17.6	17.3	TO1204		368	530	506	499	501
NE	Tonopah	TO BK 2		16.6	17.7	17.6	17.6	17.3	TO1206		511	466	481	481	440
NE	Tonopah	TO BK 2		16.6	17.7	17.6	17.6	17.3	TO1207		254	266	283	283	290
NE	Tonopah	TO BK 3		12.5	10.0	9.5	9.3	8.9	TO1209		357	308	252	257	259
NE	Tonopah	TO BK 3		12.5	10.0	9.5	9.3	8.9	TO1211		286	267	226	224	238
NE	Tropical	TRO BK 1		23.7	21.9	20.8	19.4	19.1	TRO1201		455	456	372	373	336
NE	Tropical	TRO BK 1		23.7	21.9	20.8	19.4	19.1	TRO1203		238	245	242	222	190
NE	Tropical	TRO BK 1		23.7	21.9	20.8	19.4	19.1	TRO1204		252	242	225	232	214
NE	Tropical	TRO BK 2		23.4	21.2	20.3	19.2	19.2	TRO1205		459	467	458	447	437
NE	Tropical	TRO BK 2		23.4	21.2	20.3	19.2	19.2	TRO1206		439	282	287	263	283
NE	Tropical	TRO BK 2		23.4	21.2	20.3	19.2	19.2	TRO1209		1	1	1	1	1
NE	Tropical	TRO BK 2		23.4	21.2	20.3	19.2	19.2	TRO1211		339	372	362	359	345
NE	Tropical	TRO BK 2		23.4	21.2	20.3	19.2	19.2	TRO1212		50	55	56	52	50
NE	Tropical	TRO BK 3		25.9	25.5	22.4	21.1	19.7	TRO1214		474	494	501	472	433
NE	Tropical	TRO BK 3		25.9	25.5	22.4	21.1	19.7	TRO1215		441	425	428	496	447
NE	Tropical	TRO BK 3		25.9	25.5	22.4	21.1	19.7	TRO1217		306	267	141	71	72
STRIP	Truman	TR BK 1		6.5	5.8	5.6	5.6	5.6	TR1202		284	289	239	248	220
STRIP	Truman	TR BK 2		6.5	5.8	5.6	5.9	6.0	TR1209		1	1	2	2	2
STRIP	Truman	TR BK 2		6.5	5.8	5.6	5.9	6.0	TR1210		332	251	276	283	294
STRIP	Valley View	VV BK 1		15.5	16.1	18.5	18.0	18.9	VV1201		303	301	343	348	364
STRIP	Valley View	VV BK 1		15.5	16.1	18.5	18.0	18.9	VV1203		185	168	182	198	200
STRIP	Valley View	VV BK 1		15.5	16.1	18.5	18.0	18.9	VV1204		326	329	346	346	357
STRIP	Valley View	VV BK 2		16.5	17.0	17.6	16.7	16.7	VV1206		361	382	382	370	382
STRIP	Valley View	VV BK 2		16.5	17.0	17.6	16.7	16.7	VV1207		408	436	434	455	420
STRIP	Valley View	VV BK 3		16.3	16.7	17.4	16.5	16.5	VV1209		269	271	292	287	311
STRIP	Valley View	VV BK 3		16.3	16.7	17.4	16.5	16.5	VV1210		523	483	465	484	509
STRIP	Valley View	VV BK 3		16.3	16.7	17.4	16.5	16.5	VV1212		1	64	58	63	63
NW	Vegas	VGS BK 1		26.7	27.2	26.1	25.7	26.9	VGS1201		384	403	403	402	406
NW	Vegas	VGS BK 1		26.7	27.2	26.1	25.7	26.9	VGS1203		412	448	414	411	440
NW	Vegas	VGS BK 1		26.7	27.2	26.1	25.7	26.9	VGS1204		209	221	226	225	218
NW	Vegas	VGS BK 2		27.0	27.4	26.4	25.8	26.7	VGS1205		387	419	417	422	447
NW	Vegas	VGS BK 2		27.0	27.4	26.4	25.8	26.7	VGS1206		412	436	411	392	430
NW	Vegas	VGS BK 2		27.0	27.4	26.4	25.8	26.7	VGS1207		404	411	405	380	400
NW	Vegas	VGS BK 2		27.0	27.4	26.4	25.8	26.7	VGS1208		305	301	303	297	320

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
NW	Vegas	VGS BK 3		24.1	24.1	24.8	24.8	25.0	VGS1211		361	377	415	415	418
NW	Vegas	VGS BK 3		24.1	24.1	24.8	24.8	25.0	VGS1212		331	365	350	350	408
NW	Vegas	VGS BK 3		24.1	24.1	24.8	24.8	25.0	VGS1213		432	405	411	412	417
NW	Village	VLG BK 1		23.7	25.3	25.1	25.2	17.9	VLG1201		406	438	421	500	479
NW	Village	VLG BK 1		23.7	25.3	25.1	25.2	17.9	VLG1203		217	220	229	223	205
NW	Village	VLG BK 1		23.7	25.3	25.1	25.2	17.9	VLG1205	New					
NW	Village	VLG BK 1		23.7	25.3	25.1	25.2	17.9	VLG1206		155	152	144	137	64
NW	Village	VLG BK 1		23.7	25.3	25.1	25.2	17.9	VLG1210		132	248	256	211	106
NW	Village	VLG BK 1		23.7	25.3	25.1	25.2	17.9	VLG1212		69	63	76	75	106
NW	Village	VLG BK 1		23.7	25.3	25.1	25.2	17.9	VLG1213		176	159	160	138	138
NW	Village	VLG BK 1		23.7	25.3	25.1	25.2	17.9	VLG1215	New					
NW	Village	VLG BK 1		23.7	25.3	25.1	25.2	17.9	VLG1217		1				
SE	Warmsprings	WSP BK 1		20.2	21.5	22.0	23.2	22.2	WSP1201		439	428	440	415	505
SE	Warmsprings	WSP BK 1		20.2	21.5	22.0	23.2	22.2	WSP1203		224	247	273	271	197
SE	Warmsprings	WSP BK 1		20.2	21.5	22.0	23.2	22.2	WSP1204		428	459	477	462	416
SE	Warmsprings	WSP BK 2		20.2	21.4	21.9	23.1	22.3	WSP1205		150	155	147	171	193
SE	Warmsprings	WSP BK 2		20.2	21.4	21.9	23.1	22.3	WSP1208		155	144	140	178	221
SE	Warmsprings	WSP BK 2		20.2	21.4	21.9	23.1	22.3	WSP1209		306	322	506	474	452
SE	Warmsprings	WSP BK 2		20.2	21.4	21.9	23.1	22.3	WSP1210		427	453	454	425	390
SE	Warmsprings	WSP BK 3		28.9	26.0	26.6	26.2	25.3	WSP1211		561	479	514	490	465
SE	Warmsprings	WSP BK 3		28.9	26.0	26.6	26.2	25.3	WSP1212		326	398	396	374	382
SE	Warmsprings	WSP BK 3		28.9	26.0	26.6	26.2	25.3	WSP1213		464	394	441	376	366
NE	Washburn	WSH BK 1		31.1	31.5	31.0	29.9	28.6	WSH1201		193	211	207	209	201
NE	Washburn	WSH BK 1		31.1	31.5	31.0	29.9	28.6	WSH1203		489	551	551	522	483
NE	Washburn	WSH BK 1		31.1	31.5	31.0	29.9	28.6	WSH1204		510	532	494	492	439
NE	Washburn	WSH BK 2		30.5	30.9	30.4	29.3	27.9	WSH1205		497	500	507	492	471
NE	Washburn	WSH BK 2		30.5	30.9	30.4	29.3	27.9	WSH1208		315	321	318	319	300
NE	Washburn	WSH BK 2		30.5	30.9	30.4	29.3	27.9	WSH1209		369	388	384	343	370
NE	Washburn	WSH BK 2		30.5	30.9	30.4	29.3	27.9	WSH1210		503	510	506	475	472
NE	Washburn	WSH BK 3		27.1	27.3	27.4	25.8	26.5	WSH1211		419	419	424	440	413
NE	Washburn	WSH BK 3		27.1	27.3	27.4	25.8	26.5	WSH1212		400	400	418	410	469
NE	Washburn	WSH BK 3		27.1	27.3	27.4	25.8	26.5	WSH1213		453	470	455	431	393
NE	Washington	WN BK 1		17.3	16.7	16.0	16.0	16.2	WN1201		266	285	269	268	256
NE	Washington	WN BK 1		17.3	16.7	16.0	16.0	16.2	WN1203		434	438	427	427	421
NE	Washington	WN BK 1		17.3	16.7	16.0	16.0	16.2	WN1204		445	457	477	477	473
NE	Washington	WN BK 2		17.4	16.9	16.2	16.3	16.0	WN1206		214	231	206	206	226
NE	Washington	WN BK 2		17.4	16.9	16.2	16.3	16.0	WN1208		277	269	268	267	255
NE	Washington	WN BK 3		16.9	16.6	16.7	16.4	15.8	WN1209		386	383	378	354	352
NE	Washington	WN BK 3		16.9	16.6	16.7	16.4	15.8	WN1210		348	330	324	322	314
NE	Washington	WN BK 3		16.9	16.6	16.7	16.4	15.8	WN1211		419	401	402	402	394
NE	Washington	WN BK 4		17.3	17.2	17.0	16.5	15.8	WN1213		470	491	479	445	448
SE	Water Street	WA BK 1		15.5	15.7	14.5	14.3	13.7	WA1201		200	197	224	191	192
SE	Water Street	WA BK 1		15.5	15.7	14.5	14.3	13.7	WA1203		1	6	1	1	1
SE	Water Street	WA BK 1		15.5	15.7	14.5	14.3	13.7	WA1204		362	364	359	341	346
SE	Water Street	WA BK 2		15.5	14.7	14.5	13.7	13.2	WA1206		476	452	408	406	397
SE	Water Street	WA BK 2		15.5	14.7	14.5	13.7	13.2	WA1208		404	396	370	375	380
SE	Water Street	WA BK 3		5.1	5.0	4.8	4.9	4.6	WA409		344	349	315	325	304
SE	Water Street	WA BK 3		5.1	5.0	4.8	4.9	4.6	WA410		371	356	358	357	342
NW	Westside	WE BK 3		9.7	10.2	9.3	9.2	8.8	WE1219		138	137	121	122	118
NW	Westside	WE BK 3		9.7	10.2	9.3	9.2	8.8	WE1220		326	352	350	345	332
NW	Westside	WE BK 5		19.2	20.6	19.9	20.3	19.0	WE1201		417	438	453	453	421
NW	Westside	WE BK 5		19.2	20.6	19.9	20.3	19.0	WE1203		1	1	2	1	1
NW	Westside	WE BK 5		19.2	20.6	19.9	20.3	19.0	WE1204		488	521	511	508	480
NW	Westside	WE BK 6		26.7	27.9	24.6	27.9	27.2	WE1207		483	516	522	525	493
NW	Westside	WE BK 6		26.7	27.9	24.6	27.9	27.2	WE1208		338	331	367	352	308
NW	Westside	WE BK 6		26.7	27.9	24.6	27.9	27.2	WE1209		363	367	389	390	381
NW	Westside	WE BK 6		26.7	27.9	24.6	27.9	27.2	WE1210		436	460	445	453	473
NW	Westside	WE BK 7		26.5	27.7	24.6	27.9	26.9	WE1211		76	81	79	81	126
NW	Westside	WE BK 7		26.5	27.7	24.6	27.9	26.9	WE1212		410	427	425	425	430
NW	Westside	WE BK 7		26.5	27.7	24.6	27.9	26.9	WE1214		471	499	496	497	477
SE	Whitney	WH BK 1		15.1	14.3	13.3	13.2	12.2	WH1201		352	386	388	360	377
SE	Whitney	WH BK 1		15.1	14.3	13.3	13.2	12.2	WH1202		359	348	350	375	340
SE	Whitney	WH BK 1		15.1	14.3	13.3	13.2	12.2	WH1203		6	6	8	11	3
SE	Whitney	WH BK 1		15.1	14.3	13.3	13.2	12.2	WH1204		347	284	257	262	255
SE	Whitney	WH BK 2		14.8	15.3	14.8	13.5	12.9	WH1206		389	412	402	398	283

NEVADA POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New?	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New?	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
SE	Whitney	WH BK 3		15.9	15.8	14.1	13.6	12.7	WH1209		306	309	298	295	295
SE	Whitney	WH BK 3		15.9	15.8	14.1	13.6	12.7	WH1211		377	476	361	325	312
SE	Whitney	WH BK 4		15.3	16.7	14.2	14.0	13.5	WH1213		486	525	490	490	433
SE	Whitney	WH BK 4		15.3	16.7	14.2	14.0	13.5	WH1214		320	254	254	253	241
SE	Wigwam	WI BK 1		29.5	29.3	28.7	28.5	27.3	WI1201		291	303	300	306	294
SE	Wigwam	WI BK 1		29.5	29.3	28.7	28.5	27.3	WI1203		460	480	451	480	462
SE	Wigwam	WI BK 1		29.5	29.3	28.7	28.5	27.3	WI1204		455	476	478	458	442
SE	Wigwam	WI BK 2		28.7	29.0	28.7	28.2	27.3	WI1205		475	496	460	466	438
SE	Wigwam	WI BK 2		28.7	29.0	28.7	28.2	27.3	WI1206		371	393	385	383	387
SE	Wigwam	WI BK 2		28.7	29.0	28.7	28.2	27.3	WI1208		218	215	220	223	230
SE	Wigwam	WI BK 2		28.7	29.0	28.7	28.2	27.3	WI1209		437	473	470	452	408
SE	Wigwam	WI BK 3		25.1	24.6	25.6	26.0	26.8	WI1211		330	344	346	349	328
SE	Wigwam	WI BK 3		25.1	24.6	25.6	26.0	26.8	WI1212		387	400	428	418	442
SE	Wigwam	WI BK 3		25.1	24.6	25.6	26.0	26.8	WI1213		458	413	425	452	494
SE	Wilson	WIL BK 1		33.8	33.3	40.6	38.1	36.1	WIL1204		8	8	8	8	8
SE	Wilson	WIL BK 1		33.8	33.3	40.6	38.1	36.1	WIL1205		97	49	152	98	99
SE	Wilson	WIL BK 1		33.8	33.3	40.6	38.1	36.1	WIL1206		233	207	440	443	420
SE	Wilson	WIL BK 1		33.8	33.3	40.6	38.1	36.1	WIL1208		452	488	506	492	458
SE	Wilson	WIL BK 1		33.8	33.3	40.6	38.1	36.1	WIL1209		435	463	534	466	436
SE	Wilson	WIL BK 1		33.8	33.3	40.6	38.1	36.1	WIL1210		399	426	441	437	411
SE	Wilson	WIL BK 2		39.8	40.1	40.9	40.2	37.9	WIL1215		1	1	1	1	1
SE	Wilson	WIL BK 2		39.8	40.1	40.9	40.2	37.9	WIL1216		274	291	294	281	282
SE	Wilson	WIL BK 2		39.8	40.1	40.9	40.2	37.9	WIL1217		343	347	369	354	330
SE	Wilson	WIL BK 2		39.8	40.1	40.9	40.2	37.9	WIL1218		469	495	507	496	422
SE	Wilson	WIL BK 2		39.8	40.1	40.9	40.2	37.9	WIL1220		460	463	473	529	509
SE	Wilson	WIL BK 2		39.8	40.1	40.9	40.2	37.9	WIL1221		303	313	325	329	310
SE	Winterwood	WW BK 1		17.2	18.7	18.9	17.9	17.0	WW1203		410	437	481	380	373
SE	Winterwood	WW BK 1		17.2	18.7	18.9	17.9	17.0	WW1204		420	463	516	507	487
SE	Winterwood	WW BK 1		17.2	18.7	18.9	17.9	17.0	WW1205		140	150	142	135	140
SE	Winterwood	WW BK 2		17.2	18.6	18.8	17.9	16.8	WW1207		466	507	474	477	435
SE	Winterwood	WW BK 2		17.2	18.6	18.8	17.9	16.8	WW1210		162	184	170	175	169
SE	Winterwood	WW BK 3		7.1	7.1	6.9	7.0	10.2	WW1211		287	289	280	287	270
SE	Winterwood	WW BK 3		7.1	7.1	6.9	7.0	10.2	WW1214		44	44	39	147	248
SE	Winterwood	WW BK 7		17.9	17.3	15.7	16.1	13.2	WW1216		288	277	272	272	260
SE	Winterwood	WW BK 7		17.9	17.3	15.7	16.1	13.2	WW1217		415	429	425	429	444
SE	Winterwood	WW BK 7		17.9	17.3	15.7	16.1	13.2	WW1219		378	377	361	362	331
SE	Winterwood	WW BK 7		17.9	17.3	15.7	16.1	13.2	WW1220		302	296	257	234	237
SE	Winterwood	WW BK 8		16.9	17.3	15.8	16.4	13.2	WW1224		276	250	254	265	1
SE	Winterwood	WW BK 8		16.9	17.3	15.8	16.4	13.2	WW1225		97	101	95	102	100

SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
EAST	Adobe	ADB BK 1		11.5	10.7	10.9	11.5	11.0	ADB202		213	201	203	197	194
EAST	Adobe	ADB BK 1		11.5	10.7	10.9	11.5	11.0	ADB203		60	58	60	72	66
EAST	Adobe	ADB BK 2		11.0	11.4	12.0	11.8	13.0	ADB201		48	47	48	47	56
EAST	Adobe	ADB BK 2		11.0	11.4	12.0	11.8	13.0	ADB208		233	231	229	225	245
TM	Airport	AIR BK 2		3.2	3.0	1.7	0.0	0.0	AIR1		1	1	1	1	1
TM	Airport	AIR BK 2		3.2	3.0	1.7	0.0	0.0	AIR2		1	1	1	1	1
TM	Airport	AIR BK 2		3.2	3.0	1.7	0.0	0.0	AIR3		211	159	1	1	1
TM	Airport	AIR BK 2		3.2	3.0	1.7	0.0	0.0	AIR4		215	236	226	1	1
TM	Airport	AIR BK 3		34.9	32.3	32.7	31.2	30.6	AIR242		120	115	119	102	105
TM	Airport	AIR BK 3		34.9	32.3	32.7	31.2	30.6	AIR265		229	193	199	194	193
TM	Airport	AIR BK 3		34.9	32.3	32.7	31.2	30.6	AIR269		199	214	205	195	200
TM	Airport	AIR BK 3		34.9	32.3	32.7	31.2	30.6	AIR282		267	257	267	241	279
TM	Airport	AIR BK 4		33.1	34.5	31.7	31.5	32.2	AIR2006		69	69			
TM	Airport	AIR BK 4		33.1	34.5	31.7	31.5	32.2	AIR266		199	206	210	200	204
TM	Airport	AIR BK 4		33.1	34.5	31.7	31.5	32.2	AIR267		408	430	436	445	456
TM	Airport	AIR BK 4		33.1	34.5	31.7	31.5	32.2	AIR283		90	93	93	90	90
EAST	Antelope Valley	ANV BK 1		6.8	6.0	8.4	7.8	7.0	ANV210		157	139	194	181	181
EAST	Antelope Valley	ANV BK 2		5.0	5.1	6.4	4.3	3.5	ANV211		115	118	147	100	81
FF	Austin	AST BK 1		3.9	3.8	3.5	3.4	3.6	AST201		68	66	65	55	62
FF	Austin	AST BK 1		3.9	3.8	3.5	3.4	3.6	AST202		25	23	22	24	25
EAST	Battle Mountain	BMT BK 2		4.9	4.7	4.5	2.3	0.3	BMT1401		180	172	162	51	37
EAST	Battle Mountain	BMT BK 2		4.9	4.7	4.5	2.3	0.3	BMT1402		21	21	23	46	40
EAST	Battle Mountain	BMT BK 3		1.3	1.4	1.4	1.7	1.4	BMT2401		30	31	33	39	37
TM	Bella Vista	BLV BK 1		23.0	22.7	21.9	19.4	19.4	BLV271		436	456	407	384	414
TM	Bella Vista	BLV BK 1		23.0	22.7	21.9	19.4	19.4	BLV283		107	104	104	100	98
TM	Bella Vista	BLV BK 2		36.1	34.9	41.6	34.1	35.0	BLV282		206	207	204	220	223
TM	Bella Vista	BLV BK 2		36.1	34.9	41.6	34.1	35.0	BLV284		632	600	761	580	593
EAST	Big Springs	BSP BK 1		0.0	0.0	1.3	0.4	0.4	BSP213		1	2	31	10	10
FF	Brady's	BDY BK 1		0.7	0.7	0.7	1.3		BDY201		17	17	17	30	
CAR	Brunswick	BWK BK 3		8.0	17.0	15.5	15.8	17.9	BWK2508		186	187			
CAR	Brunswick	BWK BK 4		17.8					BWK1220		217	188			
CAR	Brunswick	BWK BK 4		17.8					BWK1223		213	182			
CAR	Brunswick	BWK BK 4		17.8					BWK1224		424	420			
CAR	Buckeye	BUC BK 2		21.1	21.2	22.0	18.8	18.3	BUC1275		113	210	145	147	151
CAR	Buckeye	BUC BK 2		21.1	21.2	22.0	18.8	18.3	BUC1276		404	382	500	434	346
CAR	Buckeye	BUC BK 2		21.1	21.2	22.0	18.8	18.3	BUC1277		192	174	184	159	179
CAR	Buckeye	BUC BK 2		21.1	21.2	22.0	18.8	18.3	BUC1278		281	254	297	226	255
EAST	Buena Vista	BVV BK 1		1.7	1.7	1.2	1.0	0.2	BVV201		38	38	44	38	10
EAST	Buena Vista	BVV BK 1		1.7	1.7	1.2	1.0	0.2	BVV202		1	1	10	10	10
TM	California	CAL BK 4		12.9	5.2	7.9	7.2		CAL204		298	121	183	167	148
CAR	Carson	CAR BK 1		15.6	16.4	17.5	15.4	16.6	CAR1230		122	128	136	123	134
CAR	Carson	CAR BK 1		15.6	16.4	17.5	15.4	16.6	CAR1231		347	357	420	349	345
CAR	Carson	CAR BK 1		15.6	16.4	17.5	15.4	16.6	CAR1232		282	278	274	261	290
CAR	Carson	CAR BK 1		15.6	16.4	17.5	15.4	16.6	CAR1233		1	1	1	1	1
CAR	Carson	CAR BK 2		17.7	19.0	18.6	17.4	18.3	CAR1240		148	154	155	145	153
CAR	Carson	CAR BK 2		17.7	19.0	18.6	17.4	18.3	CAR1241		182	198	196	203	188
CAR	Carson	CAR BK 2		17.7	19.0	18.6	17.4	18.3	CAR1242		260	266	264	245	253
CAR	Carson	CAR BK 2		17.7	19.0	18.6	17.4	18.3	CAR1243		252	264	256	242	261
TM	Chukar	CHK BK 1		13.3	0.0	0.0			CHK2506		309				
EAST	Coal Canyon	CCN BK 1		1.9	1.8	2.1	2.4	2.6	CCN1201		68	66	73	72	75
EAST	Coal Canyon	CCN BK 1		1.9	1.8	2.1	2.4	2.6	CCN1202		21	19	23	37	44
CAR	Coaldale	CLD BK 1		0.1	0.1	0.0	0.0	0.0	CLD1201		6	5			
EAST	Crescent Valley	CVL BK 1		1.2	1.0	1.0	1.0	1.0	CVL220		27	23	22	22	22
CAR	Curry Street	CUR BK 1		10.0	10.5	9.8	9.8	10.4	CUR1281		297	303	292	277	307
CAR	Curry Street	CUR BK 1		10.0	10.5	9.8	9.8	10.4	CUR1282		172	183	182	182	197
CAR	Curry Street	CUR BK 2		8.1	7.1	8.4	8.2	8.8	CUR1280		373	332	391	380	408
CAR	Dayton	DTN BK 1		9.0	8.5	9.4	12.7	11.2	DTN219		208	198	218	294	280
CAR	Downs	DWN BK 1		8.0	7.7	8.2	9.4	8.2	DWN1285		287	245	282	290	285
CAR	Downs	DWN BK 1		8.0	7.7	8.2	9.4	8.2	DWN1286		111	112	115	147	96
CAR	Downs	DWN BK 1		8.0	7.7	8.2	9.4	8.2	DWN1287		1	1	1	1	1
EAST	Dutch Flat	DHF BK 1		11.4	10.1	9.8	12.2	12.1	DHF208		263	234	226	288	290

SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
EAST	Dutch Flat	DHF BK 2		5.7	5.8	5.9	6.3	6.3	DHF209		87	87	83	96	95
EAST	Dutch Flat	DHF BK 2		5.7	5.8	5.9	6.3	6.3	DHF210		49	50	54	48	51
FF	Eagle	EGL BK 2		5.6	5.7	5.0	4.9	0.2	EGL1218		258	262	262	239	244
FF	Eagle	EGL BK 3		18.6	16.9	14.3	15.9	16.5	EGL201		185	104	156	178	178
FF	Eagle	EGL BK 3		18.6	16.9	14.3	15.9	16.5	EGL202		246	287	215	191	206
TM	El Rancho^	ELR BK 1		4.0	5.0	5.9	1.4	0.0	ELR1		130	158	301	204	1
TM	El Rancho^	ELR BK 1		4.0	5.0	5.9	1.4	0.0	ELR2		412	512	493	1	1
EAST	Elko	EKO BK 1		0.4	0.4	0.5	0.5	0.0	EKO22		41	42	42	43	1
EAST	Elko	EKO BK 1		0.4	0.4	0.5	0.5	0.0	EKO23		64	64	86	89	1
EAST	Elko	EKO BK 2		2.0	2.2	2.2	2.2	0.0	EKO24		294	341	335	341	2
EAST	Elko	EKO BK 2		2.0	2.2	2.2	2.2	0.0	EKO27		197	197	197	198	2
CAR	Emerson	EMN BK 1		22.4	24.1	22.2	25.7	22.5	EMN1221		272	284	272	274	277
CAR	Emerson	EMN BK 1		22.4	24.1	22.2	25.7	22.5	EMN1222		259	256	278	272	267
CAR	Emerson	EMN BK 1		22.4	24.1	22.2	25.7	22.5	EMN1223		322	336	347	404	367
CAR	Emerson	EMN BK 1		22.4	24.1	22.2	25.7	22.5	EMN1224		220	242	241	240	239
FF	Empire	EMP BK 1		0.4	0.5	0.5	0.5	0.4	EMP7001		58	69	67	63	62
CAR	Fairview	FVW BK 1		17.3	18.1	17.4	17.4	17.7	FVW1210		327	325	305	312	320
CAR	Fairview	FVW BK 1		17.3	18.1	17.4	17.4	17.7	FVW1211		136	146	131	134	133
CAR	Fairview	FVW BK 1		17.3	18.1	17.4	17.4	17.7	FVW1212		378	395	373	362	382
FF	Fallon	FLN BK 1		2.7	2.9	2.6	2.6	2.7	FLN1202		125	132	121	120	123
FF	Fallon	FLN BK 2		1.1	1.1	0.1	0.1	0.1	FLN309		1	1	1	1	1
FF	Fallon	FLN BK 2		1.1	1.1	0.1	0.1	0.1	FLN310		18	18	1	1	1
FF	Fallon	FLN BK 3		11.0	11.0	10.6	10.0	7.6	FLN1201		261	263	247	233	247
FF	Fallon	FLN BK 3		11.0	11.0	10.6	10.0	7.6	FLN1203		247	246	244	230	128
FF	Fernley	FLY BK 1		13.6	9.5	9.5	9.0	10.0	FLY1214		161	86	89	78	76
FF	Fernley	FLY BK 1		13.6	9.5	9.5	9.0	10.0	FLY1215		254	173	166	159	168
FF	Fernley	FLY BK 1		13.6	9.5	9.5	9.0	10.0	FLY1216		101	60	60	60	60
FF	Fernley	FLY BK 1		13.6	9.5	9.5	9.0	10.0	FLY1217		202	122	125	119	158
CAR	Fort Churchill	FTC BK 1		3.5	2.7	4.1	3.8	3.7	FTC210		80	64	95	89	90
TM	Fort Sage	FTS BK 1		0.1	0.1	1.4	1.4	2.3	FTS299		3	33	33	33	54
CAR	Gabbs	GBS BK 1		3.6	3.4	2.8	3.1	3.1	GBS47		120	140	117	126	122
CAR	Gabbs	GBS BK 1		3.6	3.4	2.8	3.1	3.1	GBS48		781	670	567	629	624
STAH	Glenbrook	GLN BK 1		3.3	3.2	2.9	3.4	3.7	GLN2302		112	97	92	93	122
STAH	Glenbrook	GLN BK 1		3.3	3.2	2.9	3.4	3.7	GLN2505		16	25	19	17	37
STAH	Glenbrook	GLN BK 1		3.3	3.2	2.9	3.4	3.7	GLN2600		13	15	9	9	9
TM	Glendale	GLD BK 1		28.8	20.3	22.3	20.0	16.8	GLD237		108	115	112	118	2
TM	Glendale	GLD BK 1		28.8	20.3	22.3	20.0	16.8	GLD265		134	131	131	131	134
TM	Glendale	GLD BK 1		28.8	20.3	22.3	20.0	16.8	GLD274		425	311	278	221	262
TM	Glendale	GLD BK 2		36.9	37.1	30.8	29.0	29.0	GLD211		369	366	302	369	322
TM	Glendale	GLD BK 2		36.9	37.1	30.8	29.0	29.0	GLD238		86	94	93	90	94
TM	Glendale	GLD BK 2		36.9	37.1	30.8	29.0	29.0	GLD245		147	158	161	153	151
TM	Glendale	GLD BK 2		36.9	37.1	30.8	29.0	29.0	GLD271		251	257	189	193	189
EAST	Golconda	GOL BK 1		3.3	3.3	3.0	3.5	3.1	GOL1201		54	49	46	41	60
EAST	Golconda	GOL BK 1		3.3	3.3	3.0	3.5	3.1	GOL1202		100	102	94	116	60
EAST	Golconda	GOL BK 1		3.3	3.3	3.0	3.5	3.1	GOL1203		1	1	1	5	30
CAR	Goldfield	GFD BK 1		0.5	0.5	0.7	0.5	0.4	GFD1264		24	25	32	24	18
EAST	Grass Valley	GRS BK 1		15.4	16.3	15.1	15.7	14.6	GRS2517		202	211	214	206	193
EAST	Grass Valley	GRS BK 1		15.4	16.3	15.1	15.7	14.6	GRS2518		166	166	149	158	147
TM	Greg Street	GRG BK 1		28.7	23.1	22.4	19.8	21.1	GRG286		335	207	236	227	241
TM	Greg Street	GRG BK 1		28.7	23.1	22.4	19.8	21.1	GRG287		163	203	161	152	182
TM	Greg Street	GRG BK 1		28.7	23.1	22.4	19.8	21.1	GRG288		296	148	127	112	109
TM	Greg Street	GRG BK 2		38.5	35.9	40.0	40.7	32.2	GRG231		188	208	163	183	179
TM	Greg Street	GRG BK 2		38.5	35.9	40.0	40.7	32.2	GRG232		310	201	313	352	304
TM	Greg Street	GRG BK 2		38.5	35.9	40.0	40.7	32.2	GRG233		396	426	477	508	288
TM	Greg Street	GRG BK 3		27.2	29.7	26.7	24.3	26.5	GRG227		63	66	61	66	144
TM	Greg Street	GRG BK 3		27.2	29.7	26.7	24.3	26.5	GRG228		377	424	383	335	340
TM	Greg Street	GRG BK 3		27.2	29.7	26.7	24.3	26.5	GRG229		246	237	190	216	184
CAR	Hawthorne	HAW BK 1		5.1	4.9	6.3	5.6	5.5	HAW1201		107	104	161	133	126
CAR	Hawthorne	HAW BK 1		5.1	4.9	6.3	5.6	5.5	HAW1202		130	124	131	128	128
FF	Hazen	HAZ BK 1		0.3	0.2	0.3	0.1	0.0	HAZ1210		12	11	14	14	1
CAR	Heybourne	HEY BK 1		13.0	13.5	13.4	12.3	12.5	HEY1287		245	248	266	232	250

SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
CAR	Heybourne	HEY BK 1		13.0	13.5	13.4	12.3	12.5	HEY1288		314	305	300	277	280
CAR	Heybourne	HEY BK 1		13.0	13.5	13.4	12.3	12.5	HEY1289		1	1	1	1	1
CAR	Heybourne	HEY BK 1		13.0	13.5	13.4	12.3	12.5	HEY1290		67	72	60	60	55
TM	Highland^	HLD BK 1		1.7	0.0	0.0	0.0	0.0	HLD1		146	117	1	1	1
TM	Highland^	HLD BK 1		1.7	0.0	0.0	0.0	0.0	HLD2		94	53	1	1	1
TM	Highland^	HLD BK 2		0.9	0.0	0.0	0.0	0.0	HLD3		75	37	1	1	1
TM	Highland^	HLD BK 2		0.9	0.0	0.0	0.0	0.0	HLD4		61	46	1	1	1
TM	Holcomb	HOL BK 1		0.0	0.0	0.0	0.0	0.0	HOL1		1	65	1	1	1
TM	Holcomb	HOL BK 1		0.0	0.0	0.0	0.0	0.0	HOL2		229	263	266	1	1
TM	Holcomb	HOL BK 2		0.0	0.0	0.0	0.0	0.0	HOL3		1	1	1	1	1
TM	Holcomb	HOL BK 2		0.0	0.0	0.0	0.0	0.0	HOL4		212	196	344	1	1
TM	Holcomb	HOL BK 3		0.0	0.0	0.0	0.0	0.0	HOL5		174	222	218	1	1
TM	Holcomb	HOL BK 3		0.0	0.0	0.0	0.0	0.0	HOL6		194	174	1	1	1
EAST	Humboldt House	HBH BK 1		0.0	0.0	0.0	0.0	0.0	HBH701		6	6	1	1	1
TM	Hunter Lake	HLS BK 1		2.2	2.5	1.6	0.0	0.0	HLS1		205	192	227	1	1
TM	Hunter Lake	HLS BK 1		2.2	2.5	1.6	0.0	0.0	HLS2		153	151	1	1	1
TM	Hunter Lake	HLS BK 2		2.0	2.4	2.7	0.0	0.0	HLS3		277	333	373	1	1
TM	Hunter Lake	HLS BK 2		2.0	2.4	2.7	0.0	0.0	HLS4		1	1	1	1	3
TM	Hunter Lake	HLS BK 3		0.7	0.7	0.7	0.0	0.0	HLS6		91	91	101	1	1
EAST	Imlay	ILY BK 1		2.2	2.2	2.2	2.3	2.2	ILY1201		102	104	101	105	103
NTAH	Incline	INC BK 1		27.9	26.2	23.9	24.8	0.6	INC4100		397	407	455	455	15
NTAH	Incline	INC BK 1		27.9	26.2	23.9	24.8	0.6	INC4200		413	441	507	507	8
NTAH	Incline	INC BK 1		27.9	26.2	23.9	24.8	0.6	INC4300		317	317	295	299	1
STAH	Kingsbury	KNG BK 1		0.0	0.0	2.0	1.3	1.5	KNG2800		410	410	58	51	58
EAST	Last Chance	LCH BK 1		43.3	46.8	43.2	39.4	41.2	LCH178		1	1	1	5	5
EAST	Last Chance	LCH BK 1		43.3	46.8	43.2	39.4	41.2	LCH211		374	426	409	362	368
EAST	Last Chance	LCH BK 1		43.3	46.8	43.2	39.4	41.2	LCH212		140	162	158	120	133
EAST	Last Chance	LCH BK 1		43.3	46.8	43.2	39.4	41.2	LCH218		284	278	232	238	239
EAST	Last Chance	LCH BK 1		43.3	46.8	43.2	39.4	41.2	LCH221		204	216	199	192	209
EAST	Limerick	LIM BK 1		0.5	0.5	0.5	0.5	0.5	LIM1201		21	25	23	21	21
EAST	Lone Mountain^	LNM BK 1		0.7	0.7	1.3	0.8	2.4	LNM1201		32	34	60	39	109
FF	Lonely	LNY BK 1		22.8	23.7	22.5	22.0	22.6	LNY1230		411	472	407	376	397
FF	Lonely	LNY BK 1		22.8	23.7	22.5	22.0	22.6	LNY1231		223	214	213	205	232
FF	Lonely	LNY BK 1		22.8	23.7	22.5	22.0	22.6	LNY1232		206	212	202	201	220
FF	Lonely	LNY BK 1		22.8	23.7	22.5	22.0	22.6	LNY1233		244	245	237	238	264
EAST	Lovelock	LOV BK 1		1.9	2.2	2.2	2.0	1.4	LOV701		153	177	176	159	125
EAST	Lovelock	LOV BK 2		1.8	1.9	2.2	1.8	2.2	LOV702		35	31	29	27	49
EAST	Lovelock	LOV BK 2		1.8	1.9	2.2	1.8	2.2	LOV703		106	124	147	118	131
EAST	Lovelock	LOV BK 3		1.0	2.5	2.5	2.7	0.0	LOV1203		46	117	117	123	
CAR	Lower Smoky Valley	LSV BK 1		0.7	0.6	0.6	0.6	0.7	LSV1260		33	31	31		
CAR	Luning	LUN BK 1		0.0	0.0	0.0	0.0	0.0	LUN7005		6	6	1	1	1
CAR	Manhattan	MAN BK 1		0.4	0.0	0.6	0.6	0.6	MAN1201		20	48	30	30	
CAR	Mark Twain	MTW BK 1		21.6	21.0	21.8	21.8	18.4	MTW218		232	233	230	230	230
CAR	Mark Twain	MTW BK 1		21.6	21.0	21.8	21.8	18.4	MTW220		269	256	276	280	196
CAR	Mason Valley	MNV BK 1		12.4	0.0				MNV2501		239				
CAR	Mason Valley	MNV BK 1		12.4	0.0				MNV2506		103				
CAR	Mason Valley	MNV BK 2		7.9	0.0				MNV2507		183				
CAR	Mason Valley	MNV BK 2		7.9	0.0				MNV2508		1				
TM	McCarran	MCN BK 1		4.2	1.5	1.5	0.0	0.0	MCN1		383	450	1	1	1
TM	McCarran	MCN BK 1		4.2	1.5	1.5	0.0	0.0	MCN2		214	212	202	1	1
EAST	McCoy Mine	MCY BK 1		1.2	1.2	1.1	1.7	0.0	MCY201		27	27	25	40	1
TM	Mill Street	MIL BK 1		2.8	3.0	1.8	0.0	0.2	MIL1		345	363	255	1	2
TM	Mill Street	MIL BK 1		2.8	3.0	1.8	0.0	0.2	MIL2		48	48	1	1	23
TM	Mill Street	MIL BK 2		1.7	1.8	1.8	0.0	0.0	MIL3		240	250	254	1	1
CAR	Mina	MNA BK 1		0.3	0.5	0.5	0.2	0.2	MNA1202		6	11	11	9	9
CAR	Mina	MNA BK 1		0.3	0.5	0.5	0.2	0.2	MNA1203		5	12	12	12	12
CAR	Mina	MNA BK 1		0.3	0.5	0.5	0.2	0.2	MNA1204		2	7	7	7	7
CAR	Minden	MIN BK 1		4.5	5.4	4.8	5.2	4.3	MIN1271		1	1	1	1	1
CAR	Minden	MIN BK 1		4.5	5.4	4.8	5.2	4.3	MIN1272		115	150	126	122	124
CAR	Minden	MIN BK 1		4.5	5.4	4.8	5.2	4.3	MIN1273		92	100	99	120	83
CAR	Minden	MIN BK 1		4.5	5.4	4.8	5.2	4.3	MIN1275		1	1	1	1	1

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TM	Mira Loma	MIR BK 3		54.2	52.9	55.1	50.3	54.7	MIR290		422	395	440	458	375
TM	Mira Loma	MIR BK 3		54.2	52.9	55.1	50.3	54.7	MIR291		399	496	446	386	388
TM	Mira Loma	MIR BK 3		54.2	52.9	55.1	50.3	54.7	MIR292		434	397	392	337	514
TM	Moana	MOA BK 1		1.2	1.6	1.2		0.0	MOA2		168	217	171		1
TM	Moana	MOA BK 2		2.2	2.6	2.3	3.1	0.0	MOA3		302	353	321	438	1
TM	Moana	MOA BK 2		2.2	2.6	2.3	3.1	0.0	MOA4		1	1	1		1
TM	Mount Rose	MTR BK 1		32.9	33.4	34.7	32.0	34.1	MTR203		219	212	214	202	216
TM	Mount Rose	MTR BK 1		32.9	33.4	34.7	32.0	34.1	MTR243		232	234	245	227	236
TM	Mount Rose	MTR BK 1		32.9	33.4	34.7	32.0	34.1	MTR282		315	333	349	314	343
TM	Mount Rose	MTR BK 2		18.3	17.9	15.7	15.1	15.1	MTR210		134	132	77	76	76
TM	Mount Rose	MTR BK 2		18.3	17.9	15.7	15.1	15.1	MTR242		290	283	291	278	292
CAR	Muller	MUR BK 1		16.9	16.4	14.3	15.6	15.2	MUR1295		287	278	277	278	310
CAR	Muller	MUR BK 1		16.9	16.4	14.3	15.6	15.2	MUR1296		512	484	384	489	396
TM	North Red Rock	NRR BK 1	New	0.0					NRR280	New					
TM	North Red Rock	NRR BK 1	New	0.0					NRR281	New					
EAST	North Valmy	NVY BK 1		0.0	0.1	0.0	0.0		NVY2404		1	2	1	1	1
EAST	North Valmy	NVY BK 2		2.2	3.5	3.1	2.4	2.9	NVY2401		2	14	14	1	1
EAST	North Valmy	NVY BK 2		2.2	3.5	3.1	2.4	2.9	NVY2402		3	19	17	3	1
EAST	North Valmy	NVY BK 2		2.2	3.5	3.1	2.4	2.9	NVY2403		48	48	46	50	68
TM	Northwest^	NOW BK 1		31.9	29.8	28.8	26.7	29.0	NOW206		148	150	147	130	141
TM	Northwest^	NOW BK 1		31.9	29.8	28.8	26.7	29.0	NOW216		425	398	411	359	386
TM	Northwest^	NOW BK 1		31.9	29.8	28.8	26.7	29.0	NOW218		176	163	146	135	146
TM	Northwest^	NOW BK 2		43.2	42.4	43.3	35.9	41.9	NOW207		329	402	411	344	378
TM	Northwest^	NOW BK 2		43.2	42.4	43.3	35.9	41.9	NOW208		319	310	329	276	316
TM	Northwest^	NOW BK 2		43.2	42.4	43.3	35.9	41.9	NOW244		358	278	268	238	309
EAST	Osgood Valley	OSG BK 1		8.3	9.9	10.3	10.0	9.3	OSG201		155	190	195	184	176
EAST	Osgood Valley	OSG BK 1		8.3	9.9	10.3	10.0	9.3	OSG202		42	42	43	48	43
CAR	Overland	OVL BK 1		10.9	11.7	11.1	11.7	12.3	OVL1250		66	69	66	60	52
CAR	Overland	OVL BK 1		10.9	11.7	11.1	11.7	12.3	OVL1260		1	1	1	1	1
CAR	Overland	OVL BK 1		10.9	11.7	11.1	11.7	12.3	OVL1265		323	354	338	382	337
CAR	Overland	OVL BK 1		10.9	11.7	11.1	11.7	12.3	OVL1270		116	121	106	122	298
EAST	Parran	PAR BK 1		0.0	0.0	0.0	0.0		PAR724		3	3	3	3	
TM	Patrick	PAT BK 1		28.2	34.0	33.2	25.9	19.9	PAT224		87	83			
TM	Patrick	PAT BK 1		28.2	34.0	33.2	25.9	19.9	PAT225		89	287	344	295	268
TM	Patrick	PAT BK 1		28.2	34.0	33.2	25.9	19.9	PAT226		481	456	446	345	225
CAR	Pinenut	PNT BK 1		22.5	23.3	22.2	20.0	17.7	PNT1251		348	351	328	315	230
CAR	Pinenut	PNT BK 1		22.5	23.3	22.2	20.0	17.7	PNT1252		1	1	1	1	1
CAR	Pinenut	PNT BK 1		22.5	23.3	22.2	20.0	17.7	PNT1253		380	337	357	300	355
CAR	Pinenut	PNT BK 1		22.5	23.3	22.2	20.0	17.7	PNT1254		340	392	364	347	235
TM	Pyramid	PYD BK 1		3.0	2.1	2.0	0.0	0.1	PYD1		280	286	281	1	9
TM	Pyramid	PYD BK 1		3.0	2.1	2.0	0.0	0.1	PYD2		136	130	1	1	1
TM	Pyramid	PYD BK 2		0.7	0.9	0.7	0.0	0.0	PYD3		89	118	102	1	1
TM	Pyramid	PYD BK 2		0.7	0.9	0.7	0.0	0.0	PYD4		6	1	1	1	1
FF	Ray Couch	RYC BK 1		5.9	5.9	5.6	4.6	5.4	RYC1206		115	115	111	112	113
FF	Ray Couch	RYC BK 1		5.9	5.9	5.6	4.6	5.4	RYC1208		160	157	158	152	150
FF	Ray Couch	RYC BK 2		3.7	3.7	3.5	4.9	6.1	RYC1207		171	170	162	229	283
EAST	Red House	RED BK 1		0.1	0.1	0.1	0.1	0.0	RED1401		4	4	4	4	1
EAST	Reese River	RRV BK 1		4.9	4.5	5.1	6.4	3.4	RRV230		66	57	69	89	77
EAST	Reese River	RRV BK 1		4.9	4.5	5.1	6.4	3.4	RRV231		47	47	48	60	1
TM	Reno	RNO BK 1		0.7	0.8	0.9	0.0	0.0	RNO1		104	111	119	1	1
TM	Reno	RNO BK 2		3.0	3.1	2.5	0.0	0.0	RNO4		101	90	1	1	1
TM	Reno	RNO BK 2		3.0	3.1	2.5	0.0	0.0	RNO6		312	345	349	1	1
TM	Reno	RNO BK 3		30.1	30.9	30.1	26.4	27.8	RNO204		99	95	100	95	112
TM	Reno	RNO BK 3		30.1	30.9	30.1	26.4	27.8	RNO216		154	147	142	127	147
TM	Reno	RNO BK 3		30.1	30.9	30.1	26.4	27.8	RNO217		5	11	10	12	13
TM	Reno	RNO BK 3		30.1	30.9	30.1	26.4	27.8	RNO243		236	239	230	194	190
TM	Reno	RNO BK 3		30.1	30.9	30.1	26.4	27.8	RNO247		205	224	221	192	180
TM	Reno	RNO BK 4		31.8	31.8	28.7	22.2	29.8	RNO240		300	299	361	249	336
TM	Reno	RNO BK 4		31.8	31.8	28.7	22.2	29.8	RNO263		250	241	143	119	170
TM	Reno	RNO BK 4		31.8	31.8	28.7	22.2	29.8	RNO285		189	195	203	153	292
EAST	Rose Creek	RCR BK 1		2.8	2.5	2.8	2.3	0.0	RCR201		65	59	64	54	1

SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
STAH	Round Hill	RDH BK 1		17.1	16.2	15.2	15.8	15.8	RDH1502		257	229			
STAH	Round Hill	RDH BK 1		17.1	16.2	15.2	15.8	15.8	RDH1503		327	229			
STAH	Round Hill	RDH BK 1		17.1	16.2	15.2	15.8	15.8	RDH1504		193	191			
CAR	Round Mountain	RDM BK 1		15.5	15.5	14.8	14.8	13.1	RDM2221		360	360	368	368	368
CAR	Round Mountain	RDM BK 2		14.9	15.0	15.2	15.2	16.4	RDM2220		65	70	70	70	64
CAR	Round Mountain	RDM BK 2		14.9	15.0	15.2	15.2	16.4	RDM2222		280	280	284	284	482
TM	Rusty Spike	RSK BK 1		29.1	32.7	34.8	38.1	37.1	RSK221		60	115	159	186	214
TM	Rusty Spike	RSK BK 1		29.1	32.7	34.8	38.1	37.1	RSK254		408	399	428	429	436
TM	Rusty Spike	RSK BK 1		29.1	32.7	34.8	38.1	37.1	RSK260		206	243	240	266	214
EAST	Rye Patch	RPH BK 1		0.4	0.3	0.3	0.4	0.0	RPH21		87	79	81	102	1
CAR	Sandia	SND BK 1		0.8	0.0	0.0	0.0	0.0	SND1201		36	37	1	1	1
EAST	Setty	STY BK 1		2.9	4.0	3.0	3.3	3.1	STY2402		55	54	54	49	57
EAST	Setty	STY BK 1		2.9	4.0	3.0	3.3	3.1	STY251		17	39	39	28	18
TM	Silver Lake	SLK BK 1		11.2	10.1	9.5	8.8	8.6	SLK257		262	233	221	201	205
TM	Silver Lake	SLK BK 1		11.2	10.1	9.5	8.8	8.6	SLK259		1	1	0	1	1
TM	Silver Lake	SLK BK 2		40.9	37.8	38.8	36.4	36.5	SLK255		585	514	525	466	480
TM	Silver Lake	SLK BK 2		40.9	37.8	38.8	36.4	36.5	SLK256		194	230	227	216	237
TM	Silver Lake	SLK BK 2		40.9	37.8	38.8	36.4	36.5	SLK258		167	130	150	159	128
CAR	Silver Peak	SVR BK 1		2.2	2.1	2.4	2.9	2.2	SVR203		50	50	55	68	60
CAR	Silver Springs	SIL BK 1		6.8	6.7	7.6	6.8	6.2	SIL1211		275	252	275	254	244
CAR	Silver Springs	SIL BK 1		6.8	6.7	7.6	6.8	6.2	SIL1212		60	60	79	62	41
CAR	Smith Valley	SVL BK 1		13.1	0.0				SVL2501		101				
CAR	Smith Valley	SVL BK 1		13.1	0.0				SVL2502		51				
CAR	Smith Valley	SVL BK 1		13.1	0.0				SVL2504		51				
CAR	Smith Valley	SVL BK 1		13.1	0.0				SVL2506		126				
EAST	Sonoma Heights	SHT BK 1		1.3	1.3	1.2	0.0	0.0	SHT21		175	178	164	1	1
EAST	Sonoma Heights	SHT BK 1		1.3	1.3	1.2	0.0	0.0	SHT23		132	136	131	1	1
EAST	Sonoma Heights	SHT BK 2		0.4	0.4	0.4	0.4	0.1	SHT704		33	37	32	34	9
EAST	Sonoma Heights	SHT BK 3		0.0	0.0	0.0	0.0	0.0	SHT206		1	1	1	1	1
TM	South Meadows	SMD BK 1	New	0.0	0.0				SMD2503	New					
TM	Spanish Springs	SSP BK 1		55.0	49.7	57.0	57.4	51.6	SSP270		405	408	416	483	464
TM	Spanish Springs	SSP BK 1		55.0	49.7	57.0	57.4	51.6	SSP271		309	289	410	407	410
TM	Spanish Springs	SSP BK 1		55.0	49.7	57.0	57.4	51.6	SSP273		560	511	514	475	499
TM	Spanish Springs	SSP BK 2		51.8	52.5	52.1	53.2	54.2	SSP272		328	393	393	467	403
TM	Spanish Springs	SSP BK 2		51.8	52.5	52.1	53.2	54.2	SSP274		130	265	297	294	296
TM	Spanish Springs	SSP BK 2		51.8	52.5	52.1	53.2	54.2	SSP275		741	696	563	502	618
TM	Sparks Industrial	SID BK 1		9.4	6.9	0.2	0.3	0.3	SID211		1	1	1	1	1
TM	Sparks Industrial	SID BK 1		9.4	6.9	0.2	0.3	0.3	SID229		1	1	1		
TM	Sparks Industrial	SID BK 1		9.4	6.9	0.2	0.3	0.3	SID261		215	157	1	1	1
TM	Sparks Industrial	SID BK 1		9.4	6.9	0.2	0.3	0.3	SID274		1	1	1	1	1
CAR	Stagecoach	STA BK 1		2.2	2.3	2.3	2.2	3.0	STA217		52	54	53	52	75
STAH	Stateline	STL BK 1		16.2	17.0	16.0	15.9	15.9	STL2001		1	1	1	1	1
STAH	Stateline	STL BK 1		16.2	17.0	16.0	15.9	15.9	STL2200		239	270	229	226	226
STAH	Stateline	STL BK 1		16.2	17.0	16.0	15.9	15.9	STL2300		232	230	210	228	228
STAH	Stateline	STL BK 1		16.2	17.0	16.0	15.9	15.9	STL3501		222	200	192	194	194
STAH	Stateline	STL BK 4		9.4	5.0	4.4	5.1	5.1	STL3101		375	202	179	185	185
TM	Stead	STD BK 1		12.2	12.3	12.9	11.9	12.4	STD255		1	1	0	1	1
TM	Stead	STD BK 1		12.2	12.3	12.9	11.9	12.4	STD257		286	285	300	300	300
TM	Stead	STD BK 2		4.3	5.2	5.4	5.2	7.8	STD259		100	119	126	126	180
TM	Steamboat	STM BK 1		41.3	39.7	35.6	42.9	41.9	STM212		355	356	352	337	334
TM	Steamboat	STM BK 1		41.3	39.7	35.6	42.9	41.9	STM213		272	269	261	246	250
TM	Steamboat	STM BK 1		41.3	39.7	35.6	42.9	41.9	STM219		1	1	1	1	8
TM	Steamboat	STM BK 1		41.3	39.7	35.6	42.9	41.9	STM268		329	321	285	416	390
TM	Steamboat	STM BK 2		39.2	36.0	30.9	27.8	29.2	STM210		298	294	308	294	298
TM	Steamboat	STM BK 2		39.2	36.0	30.9	27.8	29.2	STM214		235	172	413	355	391
TM	Steamboat	STM BK 2		39.2	36.0	30.9	27.8	29.2	STM215		411	401			
CAR	Stickleman	STK BK 1		0.7	0.7	0.7	0.7	0.7	STK1201		32	32	32	32	32
TM	Sugarloaf	SLF BK 1		50.3	50.9	49.2	44.7	52.7	SLF301		107	113	109	297	476
TM	Sugarloaf	SLF BK 1		50.3	50.9	49.2	44.7	52.7	SLF302		610	639	607	536	533
TM	Sugarloaf	SLF BK 1		50.3	50.9	49.2	44.7	52.7	SLF303		410	456	440	206	234
TM	Sugarloaf	SLF BK 1		50.3	50.9	49.2	44.7	52.7	SLF304		38	14			

SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Area	Substation	Transformer	New	2018 Transformer Past Peak MVA	2017 Transformer Past Peak MVA	2016 Transformer Past Peak MVA	2015 Transformer Past Peak MVA	2014 Transformer Past Peak MVA	Feeder	New	2018 Feeder Past Peak Amps	2017 Feeder Past Peak Amps	2016 Feeder Past Peak Amps	2015 Feeder Past Peak Amps	2014 Feeder Past Peak Amps
TM	Sutro	SUT BK 1		8.3	7.7	8.4	1.3	1.7	SUT211		1	1	1	1	1
TM	Sutro	SUT BK 1		8.3	7.7	8.4	1.3	1.7	SUT241		107	94	101	91	114
TM	Sutro	SUT BK 1		8.3	7.7	8.4	1.3	1.7	SUT246		84	84	94	106	116
EAST	T Lazy S	TLS BK 1		0.6	0.8	2.9	3.2	3.2	TLS240		13	18	68	75	75
CAR	Topaz	TPZ BK 1		3.3	2.7	3.7	3.7	3.0	TPZ1261		154	126	170	170	143
EAST	Toulon	TLN BK 1		0.1	0.1	0.2	0.2		TLN701		8	12	17	15	
TM	Tracy	TCY BK 1		6.4	6.0	5.8	5.2	1.9	TCY277		76	71	65	65	30
TM	Tracy	TCY BK 1		6.4	6.0	5.8	5.2	1.9	TCY278		72	69	75	75	18
NTAH	Truckee	TRK BK 1		6.8	7.9	4.0	4.7	0.0	TRK7202		22	28	19	19	
NTAH	Truckee	TRK BK 1		6.8	7.9	4.0	4.7	0.0	TRK7203		238	295	145	145	
NTAH	Truckee	TRK BK 1		6.8	7.9	4.0	4.7	0.0	TRK7204		101	1	1		
TM	University	UNV BK 1		1.2	1.0	1.0	0.0	0.9	UNV1		33	94	1	1	135
TM	University	UNV BK 1		1.2	1.0	1.0	0.0	0.9	UNV2		134	142	133	1	1
TM	Valley Road	VAL BK 2		40.8	41.5	42.2	39.6	38.4	VAL246		212	175	239	246	260
TM	Valley Road	VAL BK 2		40.8	41.5	42.2	39.6	38.4	VAL249		376	471	394	370	359
TM	Valley Road	VAL BK 2		40.8	41.5	42.2	39.6	38.4	VAL254		41	38	33	33	31
TM	Valley Road	VAL BK 2		40.8	41.5	42.2	39.6	38.4	VAL262		397	369	342	317	331
TM	Valley Road	VAL BK 3		18.6	20.7	19.2	17.6	20.3	VAL244		7	101	97	191	139
TM	Valley Road	VAL BK 3		18.6	20.7	19.2	17.6	20.3	VAL248		246	260	241	149	205
TM	Valley Road	VAL BK 3		18.6	20.7	19.2	17.6	20.3	VAL251		179	153	141	101	161
TM	Verdi PH	VRD BK 1		0.0	0.1	0.0	0.0	0.0	VRD204		1	2	1	1	1
CAR	Virginia City	VCY BK 1		2.8	2.8	3.0	3.8	4.8	VCY213		10	6	5	5	26
CAR	Virginia City	VCY BK 1		2.8	2.8	3.0	3.8	4.8	VCY214		26	28	31	33	32
CAR	Virginia City	VCY BK 1		2.8	2.8	3.0	3.8	4.8	VCY215		29	32	35	51	57
FF	Wadsworth	WAD BK 1		2.4	2.4	2.7	2.6	2.6	WAD1221		110	113	125	120	120
TM	Washoe PH	WSO BK 1		2.5	0.1	0.1	0.1	0.1	WSO201		56	12	1	1	1
TM	Washoe PH	WSO BK 1		2.5	0.1	0.1	0.1	0.1	WSO203		1	1	1	1	1
TM	Washoe PH	WSO BK 1		2.5	0.1	0.1	0.1	0.1	WSO204		1	1	1	1	1
TM	West 7th Street	WST BK 1		3.8	2.4	2.4	0.0	0.0	WST1		305	323	319	1	5
TM	West 7th Street	WST BK 1		3.8	2.4	2.4	0.0	0.0	WST2		194	197	1	1	1
CAR	West Tonopah	WTP BK 1		4.5	4.5	4.5	4.2	3.7	WTP1201		84	77	75	82	59
CAR	West Tonopah	WTP BK 1		4.5	4.5	4.5	4.2	3.7	WTP1202		47	40	40	42	56
CAR	West Tonopah	WTP BK 1		4.5	4.5	4.5	4.2	3.7	WTP1203		78	93	92	100	83
FF	Westside^	WES BK 1		7.6	7.7	8.0	8.0	7.8	WES1211		195	182	1	1	1
FF	Westside^	WES BK 1		7.6	7.7	8.0	8.0	7.8	WES1212		104	106	106	102	104
FF	Westside^	WES BK 1		7.6	7.7	8.0	8.0	7.8	WES1213		63	72	264	270	260
TM	Wheeler	WLR BK 2		1.5	1.5	1.5	0.0	0.1	WLR2		204	213	206	1	4
EAST	Winnemucca	WIN BK 2		19.5	19.8	19.2	21.9	20.9	WIN201		189	199	199	217	213
EAST	Winnemucca	WIN BK 2		19.5	19.8	19.2	21.9	20.9	WIN202		1	1	1	1	1
EAST	Winnemucca	WIN BK 2		19.5	19.8	19.2	21.9	20.9	WIN205		142	138	128	161	141
EAST	Winnemucca	WIN BK 2		19.5	19.8	19.2	21.9	20.9	WIN206		118	119	116	131	129
EAST	Winnemucca	WIN BK 2		19.5	19.8	19.2	21.9	20.9	WIN701		1	1	1	1	1

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NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER FORECAST

Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NE	Allen	ALN BK 1	37.33	18.0	18.6	19.2	19.6	20.1	20.7	21.2
Nevada Power	NE	Allen	ALN BK 2//3	74.66	60.0	60.1	60.4	60.8	61.4	61.8	62.1
Nevada Power	NE	Alta	AL BK 3	37.33	22.2	22.9	23.0	23.1	23.4	23.6	23.9
Nevada Power	NE	Alta	AL BK 4	22.4	12.4	12.5	12.6	12.7	12.8	12.9	13.0
Nevada Power	NE	Alta	AL BK 5	37.33	28.0	28.3	28.5	28.7	28.9	29.2	29.4
Nevada Power	NE	Alta	AL BK 6	22.4	4.7	4.7	4.7	4.8	4.8	4.8	4.9
Nevada Power	NE	Andrews	AND BK 1//2	74.66	50.6	54.1	54.4	54.8	55.3	56.5	57.6
Nevada Power	NE	Artesian	AR BK 2	37.33	25.3	26.1	26.3	26.5	26.7	27.1	27.5
Nevada Power	NE	Artesian	AR BK 3//4	74.66	49.4	49.8	50.3	50.8	51.3	51.8	52.3
Nevada Power	NE	Blade Runner	BLR BK 1	28	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Nevada Power	NE	Carey	CA BK 5	22.4	8.0	9.0	9.0	9.1	9.2	9.5	9.8
Nevada Power	NE	Carey	CA BK 6//7	44.8	29.6	29.9	30.3	30.7	31.1	31.5	31.9
Nevada Power	NE	Carey	CA BK 8//9	44.8	15.4	15.4	15.5	15.6	15.7	15.8	15.9
Nevada Power	NE	Craig	CR BK 1//2	74.66	46.8	52.1	53.1	53.8	54.6	56.6	58.5
Nevada Power	NE	Craig	CR BK 3	37.33	25.7	28.1	28.3	28.5	28.8	29.5	30.3
Nevada Power	NE	DeBuono	DEB BK 1	22.4	14.2	14.2	14.2	14.3	14.5	14.5	14.6
Nevada Power	NE	DeBuono	DEB BK 2//3	44.8	32.3	32.3	32.5	32.7	33.1	33.3	33.4
Nevada Power	NE	Gilmore	GLM BK 1//2	74.66	36.0	40.2	40.4	40.7	41.1	42.4	43.7
Nevada Power	NE	Grand Teton	GTT BK 2	37.33	14.1	16.0	18.0	19.7	21.1	22.9	24.7
Nevada Power	NE	Gypsum	GYP BK 2	22.4	11.9	18.3	23.1	25.2	27.4	31.3	35.2
Nevada Power	NE	Leavitt	LVT BK 1	37.33	25.5	26.4	26.7	26.9	27.1	27.5	28.0
Nevada Power	NE	Leavitt	LVT BK 2//3	74.66	57.8	64.1	65.3	65.8	66.5	68.7	70.8
Nevada Power	NE	Lincoln	LCN BK 1//2	74.66	48.8	56.0	56.7	57.3	58.0	60.3	62.6
Nevada Power	NE	Miller	MI BK 3//4	44.8	29.9	31.7	33.8	34.2	34.6	35.8	37.0
Nevada Power	NE	Nellis	NS BK 1//2	26	19.2	25.1	25.5	26.0	26.5	28.4	30.2
Nevada Power	NE	Nellis	NS BK 3	22.4	6.2	7.9	12.6	12.7	12.8	14.5	16.2
Nevada Power	NE	North Las Vegas	NLV BK 1	22.4	18.1	18.4	18.5	18.7	18.9	19.1	19.3
Nevada Power	NE	North Las Vegas	NLV BK 3//4	44	27.2	27.4	27.5	27.7	28.0	28.1	28.3
Nevada Power	NE	Olive	OL BK 1	22.4	20.2	20.4	20.5	20.6	20.8	21.0	21.2

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER FORECAST

Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NE	Pabco	PBC BK 2	12.5	9.8	9.8	9.9	9.9	10.0	10.1	10.1
Nevada Power	NE	Pecos	PE BK 6//7	74.66	38.9	44.1	45.6	46.3	47.3	49.3	51.4
Nevada Power	NE	Pecos	PE BK 6//7	74.66	38.9	44.1	45.6	46.3	47.3	49.3	51.4
Nevada Power	NE	Prince	PR BK 1//2	40	38.2	38.3	38.7	39.2	39.6	39.9	40.3
Nevada Power	NE	Shadow	SH BK 3	6.7	2.5	2.7	2.7	2.8	2.8	2.9	2.9
Nevada Power	NE	Shadow	SH BK 4//5	44.8	31.1	31.1	31.3	31.5	31.8	32.0	32.1
Nevada Power	NE	Speedway	SPD BK 2	37.33	23.7	43.8	46.2	47.1	47.6	53.6	59.6
Nevada Power	NE	Tonopah	TO BK 1//2	44.8	30.1	30.1	30.2	30.4	30.7	30.9	31.1
Nevada Power	NE	Tonopah	TO BK 3	22.4	16.9	16.9	17.0	17.1	17.3	17.4	17.5
Nevada Power	NE	Tropical	TRO BK 1//2	74.66	50.4	52.0	52.6	53.3	54.2	55.1	56.0
Nevada Power	NE	Tropical	TRO BK 3	37.33	28.9	30.1	31.3	31.9	32.3	33.1	33.9
Nevada Power	NE	Washburn	WSH BK 1//2	74.66	62.3	63.5	64.2	65.0	65.8	66.7	67.6
Nevada Power	NE	Washburn	WSH BK 3	37.33	28.3	28.6	28.9	29.1	29.4	29.7	30.0
Nevada Power	NE	Washington	WN BK 1//2	44.8	34.7	34.9	35.0	35.3	35.6	35.9	36.1
Nevada Power	NE	Washington	WN BK 3//4	44.8	34.3	34.5	34.7	34.9	35.3	35.5	35.8
Nevada Power	NW	Angel Peak	AP BK 1	4.83	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Nevada Power	NW	Angel Peak	AP BK 2	5	0.9	0.9	1.0	1.0	1.0	1.0	1.0
Nevada Power	NW	Beltway	BLT BK 4	37.33	28.8	33.2	36.8	39.6	40.5	43.4	46.4
Nevada Power	NW	Canyon	CN BK 1	5	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Nevada Power	NW	Charleston	CHR BK 1	25	12.5	12.8	12.9	13.0	13.1	13.2	13.4
Nevada Power	NW	Cheyenne	CHN BK 1//2	74.66	52.3	52.4	52.6	53.0	53.5	53.8	54.1
Nevada Power	NW	Cheyenne	CHN BK 3	37.33	19.1	19.1	19.2	19.3	19.5	19.6	19.7
Nevada Power	NW	Cold Creek	CC BK 2	22.4	5.4	5.4	5.5	5.5	5.6	5.6	5.6
Nevada Power	NW	El Capitan	ELC BK 1	56	40.0	44.7	45.4	45.9	46.5	48.1	49.7
Nevada Power	NW	El Capitan	ELC BK 2	56	42.8	46.9	48.2	49.3	50.1	52.0	53.8
Nevada Power	NW	Elkhorn	ELK BK 1//2	74.66	63.4	64.6	64.9	65.4	66.1	66.7	67.4
Nevada Power	NW	Elkhorn	ELK BK 3	37.33	22.1	22.6	22.7	22.9	23.1	23.3	23.6
Nevada Power	NW	Hualapai	HU BK 1//2	74.66	54.8	56.2	56.9	57.6	58.5	59.4	60.4
Nevada Power	NW	Hualapai	HU BK 3	37.33	20.3	20.4	20.6	20.9	21.1	21.3	21.5

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER FORECAST

Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NW	Indian Springs	IS BK 1	6.25	2.0	2.6	2.6	2.6	2.7	2.8	3.0
Nevada Power	NW	Indian Springs	IS BK 2	10	5.7	5.7	5.7	5.7	5.8	5.8	5.9
Nevada Power	NW	Iron Mountain	IMT BK 1//2	74.66	54.6	56.5	58.3	60.3	62.4	64.4	66.3
Nevada Power	NW	Kyle Canyon	KC BK 1	5.25	1.0	1.0	1.1	1.1	1.1	1.1	1.1
Nevada Power	NW	Lone Mountain	LMT BK 1//2	74.66	32.4	33.6	34.6	35.0	35.5	36.3	37.1
Nevada Power	NW	Lorenzi	LO BK 1//2	74.66	66.4	67.1	67.6	68.1	68.8	69.4	69.9
Nevada Power	NW	Lorenzi	LO BK 3	37.33	25.2	25.4	25.6	25.9	26.3	26.6	26.9
Nevada Power	NW	Michael Way	MW BK 1//2	44.8	39.1	39.1	39.6	39.9	40.3	40.6	40.9
Nevada Power	NW	Michael Way	MW BK 3	22.4	17.4	17.4	17.5	17.6	17.8	17.9	18.0
Nevada Power	NW	Northwest	NW BK 4	56	34.2	36.3	38.2	39.9	41.2	42.9	44.7
Nevada Power	NW	Northwest	NW BK 5	56	31.8	33.4	33.7	34.0	34.3	35.0	35.6
Nevada Power	NW	Radar	RA BK 1	2.8	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Nevada Power	NW	Rainbow	RB BK 1//2	44.8	34.1	34.1	34.3	34.5	34.9	35.0	35.2
Nevada Power	NW	Rainbow	RB BK 3	25	16.7	16.9	17.0	17.1	17.3	17.4	17.6
Nevada Power	NW	Regena	RGN BK 2	37.33	32.7	33.2	33.6	34.0	34.5	35.0	35.4
Nevada Power	NW	Silver Flag	SLV BK 1	10	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Nevada Power	NW	Skelton	SKL BK 1	56	44.6	44.9	45.3	45.7	46.2	46.6	47.0
Nevada Power	NW	Skelton	SKL BK 2	56	32.7	33.0	33.4	33.6	34.0	34.3	34.6
Nevada Power	NW	Snow Mountain	SN BK 1	18.6	2.0	2.0	2.0	2.0	2.0	2.0	2.1
Nevada Power	NW	Summerlin	SMR BK 1	56	40.8	42.3	42.5	42.8	43.3	43.9	44.5
Nevada Power	NW	Summerlin	SMR BK 2	56	37.4	37.4	37.6	37.9	38.2	38.4	38.7
Nevada Power	NW	Tenaya	TE BK 1	35.6	18.6	19.9	20.0	20.2	20.4	20.8	21.3
Nevada Power	NW	Tenaya	TE BK 2//3	71.2	55.2	56.3	56.9	57.3	57.9	58.5	59.2
Nevada Power	NW	Vegas	VGS BK 1//2	75	53.8	53.9	54.2	54.6	55.1	55.5	55.8
Nevada Power	NW	Vegas	VGS BK 3	37.5	24.1	24.3	24.6	25.0	25.4	25.7	26.1
Nevada Power	NW	Village	VLG BK 1	37.33	36.3	37.2	37.8	38.1	38.5	39.0	39.5
Nevada Power	NW	Westside	WE BK 3	37.33	10.5	11.4	12.4	13.1	13.4	14.2	14.9
Nevada Power	NW	Westside	WE BK 5	37.33	19.2	19.2	19.3	19.4	19.6	19.7	19.8
Nevada Power	NW	Westside	WE BK 6//7	74.66	53.3	53.4	53.7	54.1	54.6	54.9	55.3

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER FORECAST

Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SE	Anthem	ANT BK 1//2	74.66	61.1	62.2	63.0	63.8	64.8	65.7	66.6
Nevada Power	SE	Anthem	ANT BK 3	37.33	8.9	8.9	9.0	9.0	9.1	9.2	9.2
Nevada Power	SE	Balboa	BL BK 1	22.4	18.2	18.3	18.4	18.5	18.7	18.8	18.9
Nevada Power	SE	Balboa	BL BK 2//3	44.8	32.9	33.1	33.2	33.5	33.8	34.0	34.3
Nevada Power	SE	Bicentennial	BCT BK 1//2	74.66	55.2	56.9	58.4	59.9	60.6	62.0	63.3
Nevada Power	SE	Big Bend	BGB BK 1	22.4	6.7	6.7	6.7	6.8	6.8	6.9	6.9
Nevada Power	SE	Big Bend	BGB BK 2	22.4	13.1	13.1	13.1	13.2	13.4	13.4	13.5
Nevada Power	SE	Boulder Beach	BB BK 1	6.25	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Nevada Power	SE	Burnham	BRN BK 1//2	74.66	52.8	53.2	53.5	53.9	54.4	54.8	55.2
Nevada Power	SE	Burnham	BRN BK 3	37.33	23.6	23.7	23.8	23.9	24.2	24.3	24.4
Nevada Power	SE	Cabana	CB BK 1//2	74.66	54.6	54.8	55.3	55.8	56.4	56.9	57.3
Nevada Power	SE	Cabana	CB BK 3	37.33	23.7	24.0	24.3	24.7	24.9	25.2	25.6
Nevada Power	SE	Cactus	CCT BK 1//2	74.66	35.9	38.0	39.5	41.1	42.0	43.6	45.1
Nevada Power	SE	Faulkner	FLK BK 3	56	36.2	49.2	49.6	49.9	50.4	54.0	57.5
Nevada Power	SE	Faulkner	FLK BK 4	56	44.9	45.4	45.8	46.3	46.9	47.5	48.0
Nevada Power	SE	Faulkner	FLK BK 5	56	22.8	25.5	27.2	28.5	29.8	31.5	33.3
Nevada Power	SE	Ford	FRD BK 1	56	26.8	27.8	28.1	28.4	28.7	29.2	29.7
Nevada Power	SE	Ford	FRD BK 2	56	39.5	39.7	39.9	40.2	40.7	41.0	41.3
Nevada Power	SE	Green Valley	GV BK 1	37.33	24.8	24.9	25.0	25.2	25.5	25.7	25.8
Nevada Power	SE	Green Valley	GV BK 2//3	74.66	55.3	56.0	56.3	56.7	57.2	57.7	58.2
Nevada Power	SE	Greenway	GNW BK 1//2	74.66	34.1	34.6	34.8	35.1	35.5	35.9	36.3
Nevada Power	SE	Haven	HV BK 1	37.33	30.1	30.5	30.6	30.8	31.1	31.4	31.6
Nevada Power	SE	Haven	HV BK 2//3	74.66	46.2	47.4	47.9	48.5	49.2	50.0	50.7
Nevada Power	SE	Keehn	KHN BK 1//2	74.66	40.8	53.2	61.5	63.5	65.3	71.5	77.6
Nevada Power	SE	Kidwell	KI BK 1	3.5	2.1	2.2	2.2	2.2	2.2	2.3	2.3
Nevada Power	SE	Lake Las Vegas	LLV BK 1//2	44.8	18.0	19.5	21.1	22.2	23.0	24.2	25.5
Nevada Power	SE	Lamb	LA BK 1	5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nevada Power	SE	Lindquist	LDQ BK 1//2	44.8	37.7	39.3	40.1	40.9	41.7	42.7	43.7
Nevada Power	SE	Magic Way	MAG BK 1	25	11.7	12.2	12.7	13.1	13.3	13.6	14.0

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER FORECAST

Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SE	Mission	MS BK 1//4	44.8	21.5	23.6	24.0	24.5	25.0	25.8	26.7
Nevada Power	SE	Mission	MS BK 2//3	44.8	34.8	37.1	38.8	39.5	40.2	41.5	42.9
Nevada Power	SE	National Park Service	NPS BK 1	0.5	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nevada Power	SE	Nelson	NL BK 1	1.5	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Nevada Power	SE	Pearl	PL BK 1	22.4	16.0	16.2	16.3	16.4	16.5	16.7	16.8
Nevada Power	SE	Pearl	PL BK 2//3	44.8	33.2	33.2	33.4	33.6	34.0	34.2	34.4
Nevada Power	SE	Pebble	PB BK 1	37.33	21.2	21.8	22.1	22.3	22.5	22.9	23.2
Nevada Power	SE	Pebble	PB BK 2//3	74.66	57.1	57.6	58.0	58.5	59.2	59.7	60.2
Nevada Power	SE	Ranger	RN BK 1	9.4	2.2	2.2	2.2	2.3	2.3	2.3	2.3
Nevada Power	SE	River Road	RI BK 1	22.4	14.1	14.2	14.4	14.6	14.8	14.9	15.1
Nevada Power	SE	River Road	RI BK 2	10.5	4.4	4.4	4.4	4.4	4.5	4.5	4.5
Nevada Power	SE	Russell	RS BK 1//2	74.66	50.4	50.4	50.7	51.0	51.5	51.8	52.1
Nevada Power	SE	Russell	RS BK 3	37.33	22.7	22.7	22.8	23.0	23.2	23.4	23.5
Nevada Power	SE	Sahara	SA BK 1//4	44.8	29.7	31.0	31.2	31.4	31.7	32.2	32.8
Nevada Power	SE	Sahara	SA BK 2//3	44.8	32.0	33.8	34.0	34.2	34.6	35.2	35.8
Nevada Power	SE	Searchlight	SE BK 1	9.4	2.8	2.8	2.9	2.9	3.0	3.0	3.0
Nevada Power	SE	Southpoint	SO BK 1	22.4	7.4	7.4	7.4	7.5	7.6	7.6	7.6
Nevada Power	SE	Southpoint	SO BK 2	22.4	5.7	5.7	5.8	5.8	5.9	5.9	5.9
Nevada Power	SE	Sunset	SUS BK 1//2	44.8	22.6	25.3	26.4	27.0	27.7	28.9	30.2
Nevada Power	SE	Tolson	TOL BK 3	56	39.7	45.9	46.7	47.5	48.2	50.4	52.5
Nevada Power	SE	Tolson	TOL BK 4	56	47.0	48.1	48.9	49.5	50.2	51.0	51.8
Nevada Power	SE	Warmsprings	WSP BK 1//2	74.66	40.7	42.5	42.8	43.1	43.5	44.2	44.9
Nevada Power	SE	Warmsprings	WSP BK 3	37.33	29.8	29.9	30.1	30.3	30.6	30.8	31.0
Nevada Power	SE	Water Street	WA BK 1//2	44.8	31.7	33.1	33.2	33.5	33.8	34.3	34.9
Nevada Power	SE	Water Street	WA BK 3	22.4	5.1	5.1	5.1	5.2	5.2	5.2	5.3
Nevada Power	SE	Whitney	WH BK 1//2	35	31.5	32.1	32.7	33.0	33.3	33.8	34.2
Nevada Power	SE	Whitney	WH BK 3//4	35	31.3	31.8	31.9	32.2	32.5	32.8	33.0
Nevada Power	SE	Wigwam	WI BK 1//2	74.66	58.5	59.0	59.6	60.0	60.6	61.1	61.7
Nevada Power	SE	Wigwam	WI BK 3	37.33	25.2	26.6	26.7	26.9	27.2	27.7	28.1

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER FORECAST

Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SE	Wilson	WIL BK 1	56	35.4	36.9	38.1	39.0	40.0	41.1	42.3
Nevada Power	SE	Wilson	WIL BK 2	56	40.7	41.9	42.2	42.6	43.2	43.8	44.4
Nevada Power	SE	Winterwood	WW BK 1//2	44.8	34.4	34.7	34.9	35.1	35.5	35.7	36.0
Nevada Power	SE	Winterwood	WW BK 3	22.4	7.1	7.2	7.4	7.6	7.8	7.9	8.1
Nevada Power	SE	Winterwood	WW BK 7//8	44.8	34.9	35.9	36.1	36.4	36.7	37.2	37.7
Nevada Power	STRIP	Claymont	CM BK 1	37.33	19.4	19.4	19.5	19.7	19.8	20.0	20.1
Nevada Power	STRIP	Claymont	CM BK 2	37.33	24.5	24.7	24.8	25.0	25.2	25.4	25.6
Nevada Power	STRIP	Claymont	CM BK 3	37.33	21.5	22.3	22.4	22.6	22.8	23.1	23.4
Nevada Power	STRIP	Claymont	CM BK 4	37.33	17.8	26.2	26.4	26.5	26.8	29.1	31.3
Nevada Power	STRIP	Commerce	COM BK 1	56	13.2	15.4	15.5	15.6	15.8	16.4	17.1
Nevada Power	STRIP	Commerce	COM BK 2	56	19.2	19.9	21.3	22.0	22.2	23.0	23.7
Nevada Power	STRIP	Concourse	CON BK 1	37.33	23.3	23.6	23.7	23.9	24.1	24.4	24.6
Nevada Power	STRIP	Concourse	CON BK 2//3	74.66	39.7	39.7	39.9	40.2	40.6	40.8	41.1
Nevada Power	STRIP	El Rancho	ER BK 1	17.5	12.0	12.0	12.0	12.1	12.3	12.3	12.4
Nevada Power	STRIP	El Rancho	ER BK 2//3	35	27.1	27.1	27.3	27.5	27.7	27.9	28.0
Nevada Power	STRIP	Excalibur	EX BK 1//2	44.8	23.3	23.3	23.4	23.5	23.8	23.9	24.0
Nevada Power	STRIP	Excalibur	EX BK 3//4	44.8	21.4	21.4	21.5	21.7	21.9	22.0	22.1
Nevada Power	STRIP	Flamingo	FL BK 1	22.4	6.7	6.7	6.7	6.7	6.8	6.9	6.9
Nevada Power	STRIP	Flamingo	FL BK 2//3	43.2	28.8	29.9	30.0	30.2	30.5	31.0	31.4
Nevada Power	STRIP	Garces	GA BK 2//3	44.8	29.7	31.1	31.9	32.2	32.5	33.2	33.9
Nevada Power	STRIP	Garces	GA BK 4	22.4	14.6	14.6	14.7	14.8	14.9	15.0	15.1
Nevada Power	STRIP	Highland	HI BK 1//2	40	25.7	26.1	26.5	26.7	26.9	27.2	27.5
Nevada Power	STRIP	Highland	HI BK 3	22.4	9.8	9.9	10.0	10.1	10.2	10.2	10.3
Nevada Power	STRIP	Highland	HI BK 4//5	74.66	31.3	49.5	49.7	50.1	50.6	55.4	60.2
Nevada Power	STRIP	Highland	HI BK 6	37.33	19.4	29.4	29.5	29.7	30.0	32.7	35.3
Nevada Power	STRIP	Highland	HI BK 8	56	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nevada Power	STRIP	Lewis	LE BK 1	10	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nevada Power	STRIP	Lewis	LE BK 2	22.4	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Nevada Power	STRIP	Lynnwood	LY BK 1//2	44.8	31.2	36.3	36.5	36.7	37.1	38.5	40.0

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER FORECAST

Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	STRIP	Mayfair	MA BK 1	6.25	2.7	2.7	2.7	2.8	2.8	2.8	2.8
Nevada Power	STRIP	Mayfair	MA BK 2	22.4	16.4	16.5	16.6	16.7	16.8	16.9	17.0
Nevada Power	STRIP	Mayfair	MA BK 3//4	44.8	29.8	33.3	33.4	33.7	34.0	35.0	36.1
Nevada Power	STRIP	MGM	MGM BK 4	22.4	9.6	9.6	9.6	9.7	9.8	9.8	9.9
Nevada Power	STRIP	Oquendo	OQ BK 1	22.4	18.2	18.9	19.0	19.1	19.3	19.6	19.9
Nevada Power	STRIP	Oquendo	OQ BK 2//3	44.8	31.7	36.5	36.7	37.0	37.3	38.8	40.2
Nevada Power	STRIP	Pawnee	PA BK 1//2	44.8	29.2	29.5	29.6	29.8	30.1	30.4	30.6
Nevada Power	STRIP	Polaris	POL BK 1//2	74.66	36.2	36.3	36.5	36.7	37.1	37.3	37.5
Nevada Power	STRIP	Polaris	POL BK 3	37.33	20.2	20.2	20.3	20.4	20.6	20.8	20.9
Nevada Power	STRIP	Procyon	PRO BK 2	37.33	23.0	27.7	27.8	28.0	28.3	29.6	30.9
Nevada Power	STRIP	Procyon	PRO BK 3	37.33	4.2	18.2	18.3	18.4	18.6	22.2	25.8
Nevada Power	STRIP	San Francisco	SF BK 1//2	35	24.3	24.3	24.5	24.6	24.9	25.0	25.1
Nevada Power	STRIP	San Francisco	SF BK 3//4	35	25.6	25.8	25.9	26.1	26.4	26.6	26.8
Nevada Power	STRIP	Sinatra	SNT BK 1	56	8.0	8.0	8.0	8.1	8.2	8.2	8.3
Nevada Power	STRIP	Sinatra	SNT BK 2	56	13.0	13.0	13.1	13.2	13.3	13.4	13.4
Nevada Power	STRIP	Spencer	SP BK 3	22.4	12.2	12.2	12.3	12.4	12.5	12.6	12.7
Nevada Power	STRIP	Spencer	SP BK 4//5	44.8	32.1	33.8	34.0	34.2	34.6	35.2	35.8
Nevada Power	STRIP	Strip	STR BK 1	56	24.1	24.2	24.3	24.5	24.7	24.9	25.0
Nevada Power	STRIP	Strip	STR BK 2	56	15.7	15.7	15.8	15.9	16.1	16.2	16.3
Nevada Power	STRIP	Suzanne	SZ BK 1//2	74.66	41.5	42.4	47.4	47.7	48.2	49.9	51.5
Nevada Power	STRIP	Suzanne	SZ BK 3	37.33	12.6	22.6	22.7	22.8	23.1	25.7	28.3
Nevada Power	STRIP	Swenson	SWN BK 1	37.33	11.6	21.6	21.7	21.8	22.0	24.6	27.3
Nevada Power	STRIP	Swenson	SWN BK 2	37.33	11.6	30.4	40.8	41.0	41.5	48.9	56.4
Nevada Power	STRIP	Truman	TR BK 1//2	28	13.8	14.2	14.3	14.4	14.5	14.7	14.9
Nevada Power	STRIP	Valley View	VV BK 1	22.4	16.0	16.8	17.3	17.5	17.7	18.1	18.5
Nevada Power	STRIP	Valley View	VV BK 2//3	44.8	35.4	36.8	37.0	37.3	37.7	38.2	38.8
Nevada Power	SW	Arden	AD BK 4//5	74.66	42.7	47.3	49.9	52.0	53.5	56.3	59.0
Nevada Power	SW	Avera	AVR BK 1	56	38.8	44.9	45.6	46.2	46.8	48.8	50.8
Nevada Power	SW	Avera	AVR BK 2	56	32.8	35.7	35.9	36.2	36.5	37.5	38.4

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Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SW	Blue Diamond	BD BK 2//3	5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nevada Power	SW	Camero	CMO BK 2	37.33	18.3	20.8	21.1	21.5	21.8	22.7	23.6
Nevada Power	SW	Decatur	DE BK 3//7	44.8	33.2	34.5	34.8	35.0	35.4	35.9	36.5
Nevada Power	SW	Decatur	DE BK 4//5	44.8	24.2	24.3	24.4	24.5	24.8	24.9	25.1
Nevada Power	SW	Durango	DU BK 1//2	74.66	52.4	52.7	52.9	53.5	54.0	54.4	54.8
Nevada Power	SW	Durango	DU BK 3	37.33	18.9	18.9	19.0	19.1	19.3	19.4	19.5
Nevada Power	SW	Frias	FRS BK 2//3	74.66	64.6	68.3	69.5	70.3	71.4	73.1	74.8
Nevada Power	SW	Goodsprings	GS BK 1	9.375	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Nevada Power	SW	Jean	JN BK 2	15.6	4.7	4.7	4.7	4.7	4.8	4.8	4.8
Nevada Power	SW	Lindell	LI BK 1//2	44.8	28.4	28.9	29.1	29.3	29.6	29.9	30.2
Nevada Power	SW	Lindell	LI BK 3	22.4	12.3	12.3	12.3	12.4	12.6	12.6	12.7
Nevada Power	SW	McDonald	MCD BK 3	56	30.0	32.4	33.4	33.8	34.2	35.3	36.3
Nevada Power	SW	McDonald	MCD BK 4	56	36.5	38.7	39.2	39.4	39.8	40.7	41.5
Nevada Power	SW	Mountains Edge	MTE BK 2//3	74.66	64.9	67.4	68.5	69.4	70.4	71.8	73.2
Nevada Power	SW	MYS	MYS BK 2//3	74.66	46.1	60.2	68.6	73.5	76.9	84.7	92.4
Nevada Power	SW	MYS	MYS BK 2//3	74.66	46.1	60.2	68.6	73.5	76.9	84.7	92.4
Nevada Power	SW	Oasis	OA BK 1	14.4	5.7	5.7	5.7	5.8	5.8	5.9	5.9
Nevada Power	SW	Oasis	OA BK 2//3	28.8	7.3	7.3	7.3	7.3	7.4	7.5	7.5
Nevada Power	SW	Peace	PCE BK 1//2	74.66	42.6	45.5	47.0	48.5	49.7	51.5	53.2
Nevada Power	SW	Peace	PCE BK 3	37.33	26.1	26.8	26.9	27.1	27.3	27.7	28.0
Nevada Power	SW	Quail	QUL BK 1	37.33	20.7	22.1	22.5	22.9	23.4	24.1	24.7
Nevada Power	SW	Quail	QUL BK 2//3	74.66	45.6	53.4	58.5	60.4	61.1	65.0	68.9
Nevada Power	SW	Railroad	RLR BK 1//2	74.66	46.1	47.3	48.8	50.3	51.3	52.6	53.9
Nevada Power	SW	Railroad	RLR BK 3	37.33	16.4	17.5	18.1	18.2	18.4	18.9	19.4
Nevada Power	SW	Red Rock	RRK BK 1//2	74.66	44.4	46.2	47.6	48.6	49.7	51.0	52.4
Nevada Power	SW	Riley	RLY BK 2	37.33	30.9	32.6	33.5	34.3	35.1	36.2	37.2
Nevada Power	SW	Robindale	ROB BK 1	37.33	17.3	18.1	18.3	18.5	18.7	19.0	19.3
Nevada Power	SW	Robindale	ROB BK 2//3	74.66	58.1	64.3	67.0	69.5	71.6	74.9	78.3
Nevada Power	SW	Rosanna	RO BK 1//2	44.8	30.4	31.5	31.7	32.0	32.4	32.9	33.4

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Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SW	Rosanna	RO BK 3	22.4	13.8	13.8	13.9	14.0	14.2	14.2	14.3
Nevada Power	SW	Sparta	SPA BK 2//3	74.66	37.3	41.0	43.2	44.8	46.5	48.8	51.1
Nevada Power	SW	Sparta	SPA BK 2//3	74.66	37.3	41.0	43.2	44.8	46.5	48.8	51.1
Nevada Power	SW	Spring Mountain	SM BK 1	9.375	4.8	4.8	4.8	4.8	4.9	4.9	4.9
Nevada Power	SW	Spring Valley	SV BK 1//4	44.8	19.6	20.2	20.3	20.4	20.6	20.9	21.1
Nevada Power	SW	Spring Valley	SV BK 2//3	44.8	35.3	35.7	35.9	36.1	36.5	36.8	37.1
Nevada Power	SW	Tam	TA BK 1	22.4	15.3	15.3	15.4	15.5	15.6	15.7	15.8
Nevada Power	SW	Tam	TA BK 2//3	44.8	33.5	34.0	34.1	34.4	34.7	35.0	35.4
Nevada Power	SW	Tomsik	TOM BK 2//3	74.66	65.6	72.5	76.3	78.3	79.7	83.2	86.7
Sierra	CAR	Brunswick	BWK BK 3	28	13.4	13.4	13.5	13.6	13.7	13.8	13.9
Sierra	CAR	Brunswick	BWK BK 4	28	18.4	18.4	18.5	18.7	18.8	18.9	19.1
Sierra	CAR	Buckeye	BUC BK 2	25	21.7	21.8	22.1	22.4	22.7	23.0	23.2
Sierra	CAR	Carson	CAR BK 1	25	16.3	16.5	16.6	16.7	16.9	17.0	17.2
Sierra	CAR	Carson	CAR BK 2	25	17.8	17.8	17.9	18.0	18.2	18.3	18.4
Sierra	CAR	Coaldale	CLD BK 1	1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	CAR	Curry Street	CUR BK 1	14	10.1	10.2	10.2	10.3	10.4	10.5	10.6
Sierra	CAR	Curry Street	CUR BK 2	14	9.4	9.7	9.8	9.9	10.0	10.1	10.2
Sierra	CAR	Dayton	DTN BK 1	14	10.3	10.5	10.6	10.8	10.9	11.1	11.2
Sierra	CAR	Downs	DWN BK 1	28	10.6	11.0	11.2	11.4	11.6	11.9	12.1
Sierra	CAR	Emerson	EMN BK 1	28	22.6	22.6	22.7	22.8	23.1	23.2	23.3
Sierra	CAR	Fairview	FVW BK 1	28	18.0	18.0	18.1	18.3	18.5	18.6	18.7
Sierra	CAR	Fort Churchill	FTC BK 1	4.7	3.9	3.9	3.9	3.9	4.0	4.0	4.0
Sierra	CAR	Gabbs	GBS BK 1	4.7	3.6	3.6	3.6	3.6	3.6	3.7	3.7
Sierra	CAR	Goldfield	GFD BK 1	1	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Sierra	CAR	Hawthorne	HAW BK 1	7	5.3	5.3	5.4	5.4	5.5	5.5	5.5
Sierra	CAR	Heybourne	HEY BK 1	40	13.7	13.9	14.0	14.1	14.2	14.4	14.5
Sierra	CAR	Lower Smoky Valley	LSV BK 1	1.5	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Sierra	CAR	Luning	LUN BK 1	1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	CAR	Manhattan	MAN BK 1	5.25	0.4	0.4	0.4	0.4	0.4	0.4	0.4

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Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Sierra	CAR	Mark Twain	MTW BK 1	46.7	23.8	23.9	24.1	24.4	24.6	24.8	25.0
Sierra	CAR	Mason Valley	MNV BK 1	47	13.3	13.4	13.4	13.5	13.7	13.8	13.9
Sierra	CAR	Mason Valley	MNV BK 2	47	12.8	12.9	13.0	13.1	13.2	13.3	13.4
Sierra	CAR	Mina	MNA BK 1	1.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Sierra	CAR	Minden	MIN BK 1	9.4	5.1	5.1	5.1	5.1	5.2	5.2	5.2
Sierra	CAR	Muller	MUR BK 1	28	17.3	17.6	17.7	17.8	18.0	18.2	18.3
Sierra	CAR	Overland	OVL BK 1	28	12.0	12.5	12.6	12.7	12.8	13.0	13.3
Sierra	CAR	Pinenut	PNT BK 1	28	24.6	24.7	24.9	25.2	25.4	25.7	25.9
Sierra	CAR	Round Mountain	RDM BK 1	20	17.5	17.5	17.6	17.7	17.9	18.0	18.1
Sierra	CAR	Round Mountain	RDM BK 2	20	14.8	17.3	17.3	17.5	17.6	18.4	19.1
Sierra	CAR	Sandia	SND BK 1	1.78	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Sierra	CAR	Silver Peak	SVR BK 1	7	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Sierra	CAR	Silver Springs	SIL BK 1	9.4	7.0	7.0	7.0	7.1	7.2	7.2	7.3
Sierra	CAR	Smith Valley	SVL BK 1	47	13.0	13.1	13.2	13.3	13.5	13.6	13.7
Sierra	CAR	Stagecoach	STA BK 1	4.2	2.3	2.3	2.4	2.4	2.4	2.4	2.5
Sierra	CAR	Stickleman	STK BK 1	1	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Sierra	CAR	Topaz	TPZ BK 1	3.75	3.3	3.3	3.3	3.4	3.4	3.4	3.4
Sierra	CAR	Virginia City	VCY BK 1	6.3	2.9	2.9	2.9	2.9	2.9	2.9	3.0
Sierra	CAR	West Tonopah	WTP BK 1	7	5.0	5.1	5.1	5.2	5.2	5.3	5.3
Sierra	EAST	Adobe	ADB BK 1	33.6	11.6	11.6	11.7	11.8	11.9	12.0	12.0
Sierra	EAST	Adobe	ADB BK 2	33.6	12.2	12.3	12.4	12.5	12.6	12.7	12.8
Sierra	EAST	Antelope Valley	ANV BK 1	14	6.8	6.8	6.8	6.9	6.9	7.0	7.0
Sierra	EAST	Antelope Valley	ANV BK 2	10.5	5.0	5.0	5.0	5.1	5.1	5.1	5.2
Sierra	EAST	Battle Mountain	BMT BK 2	7	5.9	5.9	5.9	6.0	6.0	6.0	6.1
Sierra	EAST	Battle Mountain	BMT BK 3	4.68	1.3	1.3	1.3	1.3	1.3	1.3	1.4
Sierra	EAST	Big Springs	BSP BK 1	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	EAST	Buena Vista	BVV BK 1	2.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Sierra	EAST	Coal Canyon	CCN BK 1	7	1.9	1.9	1.9	1.9	2.0	2.0	2.0
Sierra	EAST	Crescent Valley	CVL BK 1	1.5	1.2	1.2	1.2	1.2	1.2	1.2	1.3

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Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Sierra	EAST	Dutch Flat	DHF BK 1	14	11.4	11.4	11.5	11.6	11.7	11.7	11.8
Sierra	EAST	Dutch Flat	DHF BK 2	11.2	5.7	5.8	5.8	5.8	5.9	5.9	5.9
Sierra	EAST	Elko	EKO BK 1	2.5	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Sierra	EAST	Elko	EKO BK 2	2.5	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Sierra	EAST	Golconda	GOL BK 1	4.7	3.3	3.3	3.4	3.4	3.4	3.4	3.5
Sierra	EAST	Grass Valley	GRS BK 1	28	17.3	21.0	21.1	21.3	21.5	22.5	23.6
Sierra	EAST	Humboldt House	HBH BK 1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	EAST	Imlay	ILY BK 1	2.31	2.2	2.2	2.3	2.3	2.3	2.3	2.3
Sierra	EAST	Last Chance	LCH BK 1	60	45.9	46.0	46.2	46.5	47.0	47.3	47.6
Sierra	EAST	Limerick	LIM BK 1	1.5	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Sierra	EAST	Lone Mountain^	LNM BK 1	6.25	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Sierra	EAST	Lovelock	LOV BK 1	2.5	1.9	1.9	1.9	2.0	2.0	2.0	2.0
Sierra	EAST	Lovelock	LOV BK 2	3.5	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Sierra	EAST	Lovelock	LOV BK 3	7	1.0	1.0	1.1	1.1	1.1	1.1	1.1
Sierra	EAST	McCoy Mine	MCY BK 1	4.7	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Sierra	EAST	North Valmy	NVY BK 1	25	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	EAST	North Valmy	NVY BK 2	25	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Sierra	EAST	Osgood Valley	OSG BK 1	20	8.3	8.3	8.4	8.4	8.5	8.6	8.6
Sierra	EAST	Parran	PAR BK 1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	EAST	Red House	RED BK 1	0.28	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	EAST	Reese River	RRV BK 1	7	5.4	5.4	5.4	5.4	5.5	5.5	5.5
Sierra	EAST	Rose Creek	RCR BK 1	7	2.9	2.9	2.9	2.9	2.9	2.9	3.0
Sierra	EAST	Rye Patch	RPH BK 1	1	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Sierra	EAST	Setty	STY BK 1	14	2.9	2.9	2.9	2.9	3.0	3.0	3.0
Sierra	EAST	Sonoma Heights	SHT BK 1	1.5	1.3	1.3	1.3	1.3	1.3	1.4	1.4
Sierra	EAST	Sonoma Heights	SHT BK 2	0.75	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Sierra	EAST	Sonoma Heights	SHT BK 3	8.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	EAST	T Lazy S	TLS BK 1	4.687	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Sierra	EAST	Toulon	TLN BK 1	0.29	0.1	0.1	0.1	0.1	0.1	0.1	0.1

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Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Sierra	EAST	Winnemucca	WIN BK 2	28	19.7	19.8	19.9	20.0	20.2	20.3	20.4
Sierra	FF	Austin	AST BK 1	22.4	4.0	4.0	4.0	4.0	4.1	4.1	4.1
Sierra	FF	Brady's	BDY BK 1	5	0.7	0.7	0.7	0.7	0.8	0.8	0.8
Sierra	FF	Eagle	EGL BK 2	14	5.8	5.8	5.9	5.9	6.0	6.0	6.0
Sierra	FF	Eagle	EGL BK 3	28	20.7	20.9	21.2	21.3	21.6	21.8	22.0
Sierra	FF	Empire	EMP BK 1	1	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Sierra	FF	Fallon	FLN BK 1	7	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Sierra	FF	Fallon	FLN BK 2	12.48	1.1	1.1	1.1	1.1	1.2	1.2	1.2
Sierra	FF	Fallon	FLN BK 3	14	11.1	11.1	11.1	11.2	11.3	11.4	11.5
Sierra	FF	Fernley	FLY BK 1	28	14.0	14.2	14.3	14.4	14.5	14.7	14.8
Sierra	FF	Hazen	HAZ BK 1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Sierra	FF	Lonely	LNY BK 1	28	24.1	24.5	25.1	25.6	26.2	26.7	27.2
Sierra	FF	Ray Couch	RYC BK 1	14	6.0	6.0	6.1	6.1	6.2	6.2	6.2
Sierra	FF	Ray Couch	RYC BK 2	7	3.7	3.7	3.7	3.7	3.8	3.8	3.8
Sierra	FF	Wadsworth	WAD BK 1	5.25	2.4	2.4	2.4	2.5	2.5	2.5	2.5
Sierra	FF	Westside^	WES BK 1	10.5	9.0	10.5	12.0	12.7	12.9	13.8	14.8
Sierra	NTAH	Incline	INC BK 1	33.6	28.7	28.7	28.9	29.1	29.4	29.5	29.7
Sierra	NTAH	Truckee	TRK BK 1	14	6.8	6.8	6.8	6.9	6.9	7.0	7.0
Sierra	STAH	Glenbrook	GLN BK 1	5	3.4	3.4	3.5	3.5	3.5	3.5	3.6
Sierra	STAH	Kingsbury	KNG BK 1	12.5	10.2	10.2	10.3	10.3	10.5	10.5	10.6
Sierra	STAH	Round Hill	RDH BK 1	25	18.4	18.6	18.8	18.9	19.1	19.3	19.4
Sierra	STAH	Stateline	STL BK 1	28	16.2	16.2	16.3	16.4	16.5	16.6	16.7
Sierra	STAH	Stateline	STL BK 4	14	9.4	9.4	9.4	9.5	9.6	9.6	9.7
Sierra	TM	Airport	AIR BK 2	5.25	3.2	3.2	3.2	3.3	3.3	3.3	3.3
Sierra	TM	Airport	AIR BK 3	46.7	36.4	37.2	38.0	38.4	38.8	39.4	40.0
Sierra	TM	Airport	AIR BK 4	60	33.8	34.5	35.1	35.7	36.5	37.2	37.9
Sierra	TM	Bella Vista	BLV BK 1	42	23.1	23.1	23.2	23.4	23.6	23.7	23.9
Sierra	TM	Bella Vista	BLV BK 2	60	38.4	38.5	38.7	38.9	39.3	39.6	39.8
Sierra	TM	California	CAL BK 4	28	16.7	17.6	18.6	19.2	19.8	20.6	21.4

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER FORECAST

Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Sierra	TM	Chukar	CHK BK 1	60	4.8	4.8	4.9	4.9	4.9	5.0	5.0
Sierra	TM	El Rancho^	ELR BK 1	5.25	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Sierra	TM	Fort Sage	FTS BK 1	10	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	TM	Glendale	GLD BK 1	40	29.6	30.0	30.3	30.5	30.8	31.1	31.4
Sierra	TM	Glendale	GLD BK 2	60	37.2	37.4	37.5	37.8	38.2	38.4	38.7
Sierra	TM	Greg Street	GRG BK 1	46.7	31.4	31.8	32.0	32.4	32.8	33.1	33.5
Sierra	TM	Greg Street	GRG BK 2	46.7	39.6	40.2	40.6	41.0	41.5	42.0	42.4
Sierra	TM	Greg Street	GRG BK 3	60	31.9	33.1	33.3	33.5	33.8	34.3	34.8
Sierra	TM	Highland^	HLD BK 1	2.5	1.7	1.7	1.7	1.8	1.8	1.8	1.8
Sierra	TM	Highland^	HLD BK 2	3.1	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Sierra	TM	Holcomb	HOL BK 1	2.4	1.7	1.7	1.7	1.8	1.8	1.8	1.8
Sierra	TM	Holcomb	HOL BK 2	2.4	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Sierra	TM	Holcomb	HOL BK 3	5.28	2.8	2.8	2.8	2.8	2.9	2.9	2.9
Sierra	TM	Hunter Lake	HLS BK 1	3.13	2.2	2.2	2.2	2.3	2.3	2.3	2.3
Sierra	TM	Hunter Lake	HLS BK 2	3.13	2.0	2.0	2.0	2.1	2.1	2.1	2.1
Sierra	TM	Hunter Lake	HLS BK 3	5.25	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Sierra	TM	McCarran	MCN BK 1	4.7	4.2	4.2	4.2	4.2	4.3	4.3	4.3
Sierra	TM	Mill Street	MIL BK 1	3.75	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Sierra	TM	Mill Street	MIL BK 2	3.125	1.7	1.7	1.7	1.8	1.8	1.8	1.8
Sierra	TM	Mira Loma	MIR BK 3	60	49.6	51.5	53.3	54.9	56.3	58.0	59.7
Sierra	TM	Moana	MOA BK 1	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	TM	Moana	MOA BK 2	3.13	2.2	2.2	2.2	2.2	2.2	2.2	2.3
Sierra	TM	Mount Rose	MTR BK 1	40	33.4	33.8	34.2	34.6	35.2	35.6	36.0
Sierra	TM	Mount Rose	MTR BK 2	33.6	18.5	18.6	18.9	19.0	19.2	19.4	19.5
Sierra	TM	North Red Rock	NRR BK 1	60	18.8	20.3	21.8	23.1	23.8	25.0	26.3
Sierra	TM	Northwest^	NOW BK 1	46.7	33.2	34.1	34.4	34.8	35.3	35.8	36.3
Sierra	TM	Northwest^	NOW BK 2	46.7	45.0	46.9	47.7	48.4	49.3	50.4	51.5
Sierra	TM	Patrick	PAT BK 1	60	58.7	70.1	70.4	70.9	71.6	74.9	78.1
Sierra	TM	Pyramid	PYD BK 1	3	3.0	3.0	3.0	3.0	3.1	3.1	3.1

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY SUBSTATION TRANSFORMER FORECAST

Company	Area	Substation	Transformer	Rating (MVA)	2019	2020	2021	2022	2023	2024	2025
Sierra	TM	Pyramid	PYD BK 2	2.5	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Sierra	TM	Reno	RNO BK 1	6	0.7	0.7	0.8	0.8	0.8	0.8	0.8
Sierra	TM	Reno	RNO BK 2	7	0.7	0.7	0.7	0.7	0.7	0.7	0.8
Sierra	TM	Reno	RNO BK 3	46.7	30.8	31.0	31.3	31.5	31.9	32.2	32.5
Sierra	TM	Reno	RNO BK 4	46.7	35.7	35.8	36.1	36.4	36.7	37.0	37.3
Sierra	TM	Rusty Spike	RSK BK 1	46.7	31.4	31.5	31.7	31.9	32.3	32.5	32.7
Sierra	TM	Silver Lake	SLK BK 1	13.3	11.2	11.2	11.2	11.3	11.4	11.5	11.5
Sierra	TM	Silver Lake	SLK BK 2	46.7	44.1	47.8	50.1	51.6	52.4	54.5	56.6
Sierra	TM	South Meadows	SMD BK 1	60	13.4	15.4	17.2	19.1	19.4	20.9	22.4
Sierra	TM	Spanish Springs	SSP BK 1	60	57.9	60.2	61.8	62.5	63.5	64.9	66.3
Sierra	TM	Spanish Springs	SSP BK 2	60	56.1	58.0	58.7	59.1	59.7	60.6	61.5
Sierra	TM	Sparks Industrial	SID BK 1	13.75	9.6	10.3	10.6	10.8	10.9	11.2	11.5
Sierra	TM	Stead	STD BK 1	13.3	0.2	0.4	0.5	0.5	0.5	0.6	0.7
Sierra	TM	Stead	STD BK 2	14	4.3	4.3	4.3	4.3	4.4	4.4	4.4
Sierra	TM	Steamboat	STM BK 1	46.7	44.9	46.1	47.1	48.2	48.9	49.9	50.9
Sierra	TM	Steamboat	STM BK 2	46.7	40.3	44.2	46.2	46.8	47.4	49.2	50.9
Sierra	TM	Sugarloaf	SLF BK 1	60	57.5	60.7	63.2	64.7	65.8	67.9	70.0
Sierra	TM	Sutro	SUT BK 1	13.75	8.3	8.4	8.5	8.5	8.6	8.7	8.8
Sierra	TM	Tracy	TCY BK 1	13.3	6.5	6.5	6.6	6.6	6.7	6.7	6.8
Sierra	TM	University	UNV BK 1	4.687	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Sierra	TM	Valley Road	VAL BK 2	46.7	44.6	45.9	47.0	47.5	48.1	49.0	49.9
Sierra	TM	Valley Road	VAL BK 3	46.7	20.2	20.4	20.5	20.7	20.9	21.0	21.2
Sierra	TM	Verdi PH	VRD BK 1	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	TM	Washoe PH	WSO BK 1	3	2.5	2.5	2.6	2.6	2.6	2.6	2.6
Sierra	TM	West 7th Street	WST BK 1	4.687	3.8	3.8	3.8	3.8	3.9	3.9	3.9
Sierra	TM	Wheeler	WLR BK 2	4.7	3.0	3.0	3.1	3.1	3.1	3.1	3.1

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NE	Allen	ALN1201	600	353	361	364	367	372	377	382
Nevada Power	NE	Allen	ALN1203	600	487	488	491	496	501	505	508
Nevada Power	NE	Allen	ALN1204	600	24	42	60	74	88	104	120
Nevada Power	NE	Allen	ALN1205	600	408	408	410	413	417	419	421
Nevada Power	NE	Allen	ALN1206	600	438	439	441	444	448	451	453
Nevada Power	NE	Allen	ALN1210	600	2	2	2	2	2	2	2
Nevada Power	NE	Allen	ALN1212	600	402	402	404	407	411	413	415
Nevada Power	NE	Allen	ALN1213	600	464	464	466	470	474	477	479
Nevada Power	NE	Allen	ALN1214	600	491	491	494	497	502	505	508
Nevada Power	NE	Allen	ALN1215	600	420	422	424	428	432	435	439
Nevada Power	NE	Allen	ALN1217	600	201	201	202	204	206	207	208
Nevada Power	NE	Alta	AL1202	600	466	495	497	501	506	516	526
Nevada Power	NE	Alta	AL1203	585	304	304	306	308	311	313	314
Nevada Power	NE	Alta	AL1205	585	266	266	267	269	271	273	274
Nevada Power	NE	Alta	AL1208	585	95	95	95	96	97	97	98
Nevada Power	NE	Alta	AL1209	585	505	510	513	516	521	526	530
Nevada Power	NE	Alta	AL1210	585	374	374	376	379	383	385	387
Nevada Power	NE	Alta	AL1212	585	314	314	316	318	321	323	325
Nevada Power	NE	Alta	AL1213	530	334	348	350	352	356	361	366
Nevada Power	NE	Alta	AL1214	585	356	356	358	360	364	366	368
Nevada Power	NE	Alta	AL1217	530	45	45	45	46	46	46	47
Nevada Power	NE	Alta	AL1218	530	188	188	189	191	193	194	195
Nevada Power	NE	Andrews	AND1203	600	1	1	1	1	1	1	1
Nevada Power	NE	Andrews	AND1204	600	431	439	441	444	449	453	458
Nevada Power	NE	Andrews	AND1207	600	342	342	344	346	349	351	353
Nevada Power	NE	Andrews	AND1209	600	379	379	381	384	387	389	392
Nevada Power	NE	Andrews	AND1212	600	462	578	581	585	591	623	655
Nevada Power	NE	Andrews	AND1213	600	404	404	406	408	412	415	417
Nevada Power	NE	Andrews	AND1214	600	1	1	1	1	1	1	1
Nevada Power	NE	Andrews	AND1215	600	1	1	1	1	1	1	1
Nevada Power	NE	Andrews	AND1217	600	436	473	475	478	483	495	507
Nevada Power	NE	Artesian	AR1202	600	213	213	214	216	218	219	220
Nevada Power	NE	Artesian	AR1203	585	147	147	147	148	150	151	151
Nevada Power	NE	Artesian	AR1204	585	431	471	474	477	482	495	508
Nevada Power	NE	Artesian	AR1206	585	440	440	442	446	450	452	455
Nevada Power	NE	Artesian	AR1208	600	370	370	372	374	378	380	382
Nevada Power	NE	Artesian	AR1210	585	229	242	243	245	247	252	256
Nevada Power	NE	Artesian	AR1211	585	479	479	482	485	490	493	495
Nevada Power	NE	Artesian	AR1213	585	496	497	500	503	508	511	514
Nevada Power	NE	Artesian	AR1214	585	431	431	433	437	441	443	446
Nevada Power	NE	Artesian	AR1215	585	417	424	434	445	451	460	468
Nevada Power	NE	Blade Runner	BLR1202	600	24	24	24	24	24	24	25
Nevada Power	NE	Carey	CA1201	585	134	134	135	136	137	138	139
Nevada Power	NE	Carey	CA1203	600	248	295	297	299	302	315	328
Nevada Power	NE	Carey	CA1204	600	1	1	1	1	1	1	1
Nevada Power	NE	Carey	CA1207	600	323	331	343	357	365	375	386
Nevada Power	NE	Carey	CA1208	585	210	210	211	213	215	216	217
Nevada Power	NE	Carey	CA1209	600	202	202	203	204	206	207	208
Nevada Power	NE	Carey	CA1211	600	396	396	398	401	405	407	409
Nevada Power	NE	Carey	CA1212	600	248	252	254	255	258	261	263
Nevada Power	NE	Carey	CA1213	600	261	261	263	264	267	269	270
Nevada Power	NE	Carey	CA1215	600	328	328	330	332	336	337	339
Nevada Power	NE	Carey	CA1220	600	148	148	149	150	152	152	153

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NE	Carey	CA1221	600	3	3	3	3	3	3	3
Nevada Power	NE	Craig	CR1201	600	319	319	320	322	326	327	329
Nevada Power	NE	Craig	CR1203	600	521	521	524	528	533	536	539
Nevada Power	NE	Craig	CR1204	600	337	357	376	394	412	430	449
Nevada Power	NE	Craig	CR1205	600	398	437	457	460	464	481	497
Nevada Power	NE	Craig	CR1206	600	217	217	218	219	221	223	224
Nevada Power	NE	Craig	CR1208	600	346	531	534	537	543	592	641
Nevada Power	NE	Craig	CR1209	585	220	220	221	223	225	226	227
Nevada Power	NE	Craig	CR1211	600	386	449	452	455	459	478	496
Nevada Power	NE	Craig	CR1212	600	436	483	489	493	498	513	529
Nevada Power	NE	Craig	CR1213	600	423	423	426	428	433	435	437
Nevada Power	NE	DeBuono	DEB1203	530	284	284	286	288	291	292	294
Nevada Power	NE	DeBuono	DEB1204	530	371	371	373	376	380	382	384
Nevada Power	NE	DeBuono	DEB1210	530	306	306	308	310	313	315	317
Nevada Power	NE	DeBuono	DEB1214	530	388	388	390	393	397	399	401
Nevada Power	NE	DeBuono	DEB1215	530	433	435	437	440	445	448	451
Nevada Power	NE	DeBuono	DEB1216	530	387	387	389	392	396	398	400
Nevada Power	NE	Gilmore	GLM1204	600	402	564	567	570	576	620	664
Nevada Power	NE	Gilmore	GLM1205	600	529	529	532	536	541	544	547
Nevada Power	NE	Gilmore	GLM1206	600	330	362	364	366	370	380	390
Nevada Power	NE	Gilmore	GLM1211	600	461	461	464	468	473	476	479
Nevada Power	NE	Grand Teton	GTT1207	600	167	239	312	369	414	475	537
Nevada Power	NE	Grand Teton	GTT1208	600	88	88	88	89	90	90	91
Nevada Power	NE	Grand Teton	GTT1212	600	403	419	438	459	480	500	519
Nevada Power	NE	Gypsum	GYP1208	600	320	458	461	464	469	506	543
Nevada Power	NE	Gypsum	GYP1210	600	236	397	464	468	472	531	591
Nevada Power	NE	Leavitt	LVT1201	600	478	478	481	484	489	492	494
Nevada Power	NE	Leavitt	LVT1203	600	253	264	271	273	275	281	286
Nevada Power	NE	Leavitt	LVT1204	600	468	500	503	507	512	523	534
Nevada Power	NE	Leavitt	LVT1205	600	453	453	455	458	463	466	468
Nevada Power	NE	Leavitt	LVT1206	600	450	529	532	536	542	565	588
Nevada Power	NE	Leavitt	LVT1209	600	289	393	395	397	401	429	457
Nevada Power	NE	Leavitt	LVT1212	600	464	464	467	470	475	477	480
Nevada Power	NE	Leavitt	LVT1213	600	322	323	325	328	331	334	336
Nevada Power	NE	Leavitt	LVT1214	600	483	483	486	489	494	497	499
Nevada Power	NE	Leavitt	LVT1215	600	380	487	532	535	541	581	621
Nevada Power	NE	Lincoln	LCN1203	600	437	474	477	480	485	497	509
Nevada Power	NE	Lincoln	LCN1204	600	314	429	431	434	438	469	501
Nevada Power	NE	Lincoln	LCN1205	600	122	142	157	163	169	181	192
Nevada Power	NE	Lincoln	LCN1206	600	261	267	274	281	284	290	296
Nevada Power	NE	Lincoln	LCN1210	600	415	527	530	534	539	570	601
Nevada Power	NE	Lincoln	LCN1212	600	12	12	12	12	12	13	13
Nevada Power	NE	Lincoln	LCN1213	600	226	226	227	229	231	233	234
Nevada Power	NE	Lincoln	LCN1214	600	485	529	531	535	540	554	568
Nevada Power	NE	Miller	MI1202	585	254	254	256	257	260	261	263
Nevada Power	NE	Miller	MI1203	585	285	353	440	443	448	488	529
Nevada Power	NE	Miller	MI1206	585	294	303	304	306	309	313	317
Nevada Power	NE	Miller	MI1207	585	350	356	364	372	382	390	398
Nevada Power	NE	Miller	MI1208	585	363	363	365	368	372	374	376
Nevada Power	NE	Nellis	NS1203	585	0	136	137	138	139	174	209
Nevada Power	NE	Nellis	NS1204	585	173	186	199	214	229	243	257
Nevada Power	NE	Nellis	NS1205	585	376	376	379	382	387	390	392
Nevada Power	NE	Nellis	NS1206	585	406	528	530	534	539	573	606

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NE	Nellis	NS1210	530	1	1	1	1	1	1	1
Nevada Power	NE	Nellis	NS1211	530	285	366	583	588	594	671	748
Nevada Power	NE	North Las Vegas	NLV1202	530	451	469	471	475	480	487	494
Nevada Power	NE	North Las Vegas	NLV1203	530	393	393	395	397	401	404	406
Nevada Power	NE	North Las Vegas	NLV1204	530	190	190	191	192	194	195	196
Nevada Power	NE	North Las Vegas	NLV1209	530	309	309	311	313	316	318	319
Nevada Power	NE	North Las Vegas	NLV1210	530	422	422	424	427	431	434	436
Nevada Power	NE	North Las Vegas	NLV1211	530	380	386	388	390	394	398	401
Nevada Power	NE	North Las Vegas	NLV1212	530	53	53	53	54	54	54	55
Nevada Power	NE	Olive	OL1202	585	462	462	465	468	473	475	478
Nevada Power	NE	Olive	OL1203	585	474	482	484	488	492	497	502
Nevada Power	NE	Pabco	PBC1206	585	406	406	408	411	415	418	420
Nevada Power	NE	Pabco	PBC1208	530	80	80	81	81	82	82	83
Nevada Power	NE	Pecos	PE1201	600	235	333	339	342	345	372	400
Nevada Power	NE	Pecos	PE1202	600	111	213	244	245	248	282	316
Nevada Power	NE	Pecos	PE1207	600	443	460	479	499	521	541	560
Nevada Power	NE	Pecos	PE1208	600	356	356	358	360	364	366	368
Nevada Power	NE	Pecos	PE1209	600	495	518	525	533	543	555	567
Nevada Power	NE	Pecos	PE1212	600	217	217	218	219	222	223	224
Nevada Power	NE	Prince	PR1202	585	444	450	464	476	480	489	498
Nevada Power	NE	Prince	PR1203	585	287	287	289	291	294	295	297
Nevada Power	NE	Prince	PR1206	600	534	535	537	541	546	549	552
Nevada Power	NE	Prince	PR1207	585	258	258	259	261	263	265	266
Nevada Power	NE	Prince	PR1208	585	380	380	382	384	388	390	393
Nevada Power	NE	Shadow	SH1206	585	254	254	255	257	260	261	262
Nevada Power	NE	Shadow	SH1207	585	220	220	221	223	225	226	227
Nevada Power	NE	Shadow	SH1209	585	471	471	473	476	481	484	486
Nevada Power	NE	Shadow	SH1211	585	232	232	233	235	237	239	240
Nevada Power	NE	Shadow	SH1212	585	333	333	335	337	340	342	344
Nevada Power	NE	Shadow	SH401	585	106	137	137	138	140	148	157
Nevada Power	NE	Shadow	SH404	585	241	241	242	244	246	248	249
Nevada Power	NE	Speedway	SPD1201	600	202	311	414	444	448	510	571
Nevada Power	NE	Speedway	SPD1203	600	118	480	482	486	491	584	677
Nevada Power	NE	Speedway	SPD1204	600	280	280	282	284	287	288	290
Nevada Power	NE	Speedway	SPD1211	600	220	490	493	496	501	572	642
Nevada Power	NE	Speedway	SPD1213	600	388	508	510	514	519	552	584
Nevada Power	NE	Tonopah	TO1201	585	419	419	421	424	428	430	433
Nevada Power	NE	Tonopah	TO1203	585	73	73	74	74	75	75	76
Nevada Power	NE	Tonopah	TO1204	585	368	368	369	372	376	378	380
Nevada Power	NE	Tonopah	TO1206	585	367	367	369	372	375	377	380
Nevada Power	NE	Tonopah	TO1207	585	254	254	256	257	260	261	263
Nevada Power	NE	Tonopah	TO1209	585	392	393	395	398	402	405	407
Nevada Power	NE	Tonopah	TO1211	585	457	457	460	463	468	470	473
Nevada Power	NE	Tropical	TRO1201	600	500	500	503	507	512	515	518
Nevada Power	NE	Tropical	TRO1203	600	238	249	250	252	254	259	263
Nevada Power	NE	Tropical	TRO1204	600	289	318	333	349	367	386	405
Nevada Power	NE	Tropical	TRO1205	600	473	481	486	491	497	504	510
Nevada Power	NE	Tropical	TRO1206	600	508	531	533	537	542	551	560
Nevada Power	NE	Tropical	TRO1209	600	1	1	1	1	1	1	1
Nevada Power	NE	Tropical	TRO1211	600	339	339	341	343	346	348	350
Nevada Power	NE	Tropical	TRO1212	600	50	50	50	51	51	51	52
Nevada Power	NE	Tropical	TRO1214	600	474	474	477	480	485	487	490
Nevada Power	NE	Tropical	TRO1215	600	508	530	551	564	570	585	600

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NE	Tropical	TRO1217	600	384	419	449	462	467	488	509
Nevada Power	NE	Washburn	WSH1201	600	193	193	194	195	197	198	199
Nevada Power	NE	Washburn	WSH1203	600	493	499	509	520	531	540	549
Nevada Power	NE	Washburn	WSH1204	600	510	511	513	517	522	525	528
Nevada Power	NE	Washburn	WSH1205	600	497	497	500	503	508	511	514
Nevada Power	NE	Washburn	WSH1208	600	330	367	374	381	385	399	413
Nevada Power	NE	Washburn	WSH1209	600	382	394	396	398	402	407	412
Nevada Power	NE	Washburn	WSH1210	600	507	511	517	524	532	539	545
Nevada Power	NE	Washburn	WSH1211	600	419	419	421	424	428	430	433
Nevada Power	NE	Washburn	WSH1212	600	414	432	440	443	447	456	464
Nevada Power	NE	Washburn	WSH1213	600	497	497	500	503	508	511	514
Nevada Power	NE	Washington	WN1201	585	266	266	267	269	272	273	275
Nevada Power	NE	Washington	WN1203	585	434	434	437	440	444	446	449
Nevada Power	NE	Washington	WN1204	600	450	456	459	462	466	470	474
Nevada Power	NE	Washington	WN1206	585	214	214	215	217	219	220	222
Nevada Power	NE	Washington	WN1208	585	278	278	279	281	284	286	287
Nevada Power	NE	Washington	WN1209	585	387	389	391	394	399	401	404
Nevada Power	NE	Washington	WN1210	530	348	351	353	356	359	362	365
Nevada Power	NE	Washington	WN1211	585	422	422	424	427	431	434	436
Nevada Power	NE	Washington	WN1213	530	470	473	475	479	483	487	490
Nevada Power	NW	Angel Peak	AP3402	200	16	16	16	16	16	16	16
Nevada Power	NW	Angel Peak	AP401	150	22	22	23	23	23	23	23
Nevada Power	NW	Angel Peak	AP402	150	16	16	16	16	16	16	16
Nevada Power	NW	Angel Peak	AP403	150	34	42	42	43	43	45	47
Nevada Power	NW	Beltway	BLT1213	600	234	243	244	246	249	252	256
Nevada Power	NW	Beltway	BLT1214	600	155	172	174	177	181	187	194
Nevada Power	NW	Beltway	BLT1216	600	0	34	99	154	156	195	234
Nevada Power	NW	Beltway	BLT1217	600	27	38	38	39	39	42	45
Nevada Power	NW	Beltway	BLT1218	600	253	386	483	544	573	653	733
Nevada Power	NW	Beltway	BLT1219	600	428	428	430	433	437	439	442
Nevada Power	NW	Beltway	BLT1223	600	255	255	256	258	260	262	263
Nevada Power	NW	Canyon	CN3401	200	19	19	19	20	20	20	20
Nevada Power	NW	Charleston	CHR1201	600	316	316	318	320	323	325	327
Nevada Power	NW	Charleston	CHR1202	600	265	277	278	280	283	288	292
Nevada Power	NW	Cheyenne	CHN1202	600	409	409	411	414	418	421	423
Nevada Power	NW	Cheyenne	CHN1204	600	401	401	403	406	410	413	415
Nevada Power	NW	Cheyenne	CHN1205	600	411	411	414	416	421	423	425
Nevada Power	NW	Cheyenne	CHN1207	600	468	468	470	473	478	481	483
Nevada Power	NW	Cheyenne	CHN1208	600	481	481	483	486	491	494	497
Nevada Power	NW	Cheyenne	CHN1210	600	288	288	289	291	294	296	298
Nevada Power	NW	Cheyenne	CHN1211	600	381	381	382	385	389	391	393
Nevada Power	NW	Cheyenne	CHN1212	600	421	421	423	426	430	432	435
Nevada Power	NW	Cheyenne	CHN1214	600	136	136	136	137	139	139	140
Nevada Power	NW	Cold Creek	CC1202	530	121	121	122	122	124	124	125
Nevada Power	NW	Cold Creek	CC1206	530	135	135	136	137	138	139	139
Nevada Power	NW	El Capitan	ELC1204	600	267	290	297	301	305	315	324
Nevada Power	NW	El Capitan	ELC1205	600	280	420	431	436	442	483	523
Nevada Power	NW	El Capitan	ELC1208	600	460	492	498	505	514	527	541
Nevada Power	NW	El Capitan	ELC1209	600	436	450	458	461	466	473	481
Nevada Power	NW	El Capitan	ELC1210	600	439	445	447	450	455	458	462
Nevada Power	NW	El Capitan	ELC1215	600	497	501	503	507	512	516	519
Nevada Power	NW	El Capitan	ELC1216	600	465	469	472	475	481	485	489
Nevada Power	NW	El Capitan	ELC1217	600	508	550	558	565	575	592	609

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NW	El Capitan	ELC1218	600	277	415	458	491	509	567	625
Nevada Power	NW	El Capitan	ELC1220	600	1	1	1	1	1	1	1
Nevada Power	NW	El Capitan	ELC1221	600	243	247	249	251	255	258	261
Nevada Power	NW	Elkhorn	ELK1201	600	190	190	191	192	194	195	196
Nevada Power	NW	Elkhorn	ELK1202	600	515	515	517	521	526	529	532
Nevada Power	NW	Elkhorn	ELK1206	600	342	342	343	346	349	351	353
Nevada Power	NW	Elkhorn	ELK1208	600	519	527	530	534	539	544	549
Nevada Power	NW	Elkhorn	ELK1209	600	411	413	415	418	422	425	428
Nevada Power	NW	Elkhorn	ELK1211	600	487	491	494	498	503	507	511
Nevada Power	NW	Elkhorn	ELK1212	600	515	555	559	563	569	582	596
Nevada Power	NW	Elkhorn	ELK1213	600	323	323	325	327	330	332	334
Nevada Power	NW	Elkhorn	ELK1214	600	377	398	400	402	406	414	421
Nevada Power	NW	Elkhorn	ELK1216	600	342	342	345	347	350	352	354
Nevada Power	NW	Hualapai	HU1201	600	440	440	442	445	449	452	454
Nevada Power	NW	Hualapai	HU1202	600	414	414	416	419	423	426	428
Nevada Power	NW	Hualapai	HU1204	600	376	379	381	384	388	391	393
Nevada Power	NW	Hualapai	HU1205	600	305	361	379	397	417	445	473
Nevada Power	NW	Hualapai	HU1206	600	396	396	398	401	405	407	409
Nevada Power	NW	Hualapai	HU1209	600	331	331	333	335	339	340	342
Nevada Power	NW	Hualapai	HU1210	600	275	282	283	285	288	291	294
Nevada Power	NW	Hualapai	HU1211	600	146	151	157	162	164	169	173
Nevada Power	NW	Hualapai	HU1212	600	439	439	442	445	449	452	454
Nevada Power	NW	Hualapai	HU1214	600	395	395	397	400	404	406	409
Nevada Power	NW	Indian Springs	IS1204	600	263	263	264	266	269	270	272
Nevada Power	NW	Indian Springs	IS401	530	3	3	3	3	3	3	3
Nevada Power	NW	Indian Springs	IS402	530	210	210	211	212	214	216	217
Nevada Power	NW	Indian Springs	IS403	530	61	149	150	151	152	175	198
Nevada Power	NW	Iron Mountain	IMT1201	600	486	493	497	502	508	514	520
Nevada Power	NW	Iron Mountain	IMT1203	600	340	340	342	345	348	350	352
Nevada Power	NW	Iron Mountain	IMT1204	600	256	256	257	259	261	263	264
Nevada Power	NW	Iron Mountain	IMT1205	600	382	403	410	414	418	427	436
Nevada Power	NW	Iron Mountain	IMT1206	600	166	175	176	177	179	182	185
Nevada Power	NW	Iron Mountain	IMT1209	600	2	55	120	190	262	327	392
Nevada Power	NW	Iron Mountain	IMT1211	600	496	496	498	501	507	509	512
Nevada Power	NW	Iron Mountain	IMT1212	600	513	513	516	519	524	527	530
Nevada Power	NW	Kyle Canyon	KC1201	300	48	48	49	49	50	50	50
Nevada Power	NW	Lone Mountain	LMT1203	600	499	499	502	505	510	513	516
Nevada Power	NW	Lone Mountain	LMT1204	600	472	472	474	477	482	485	487
Nevada Power	NW	Lone Mountain	LMT1211	600	1	1	1	1	1	1	1
Nevada Power	NW	Lone Mountain	LMT1213	600	109	165	202	213	224	252	281
Nevada Power	NW	Lone Mountain	LMT1215	600	429	429	431	434	438	441	443
Nevada Power	NW	Lorenzi	LO1201	585	475	475	477	480	485	488	490
Nevada Power	NW	Lorenzi	LO1203	585	405	405	407	410	414	416	419
Nevada Power	NW	Lorenzi	LO1204	600	423	456	466	469	474	487	500
Nevada Power	NW	Lorenzi	LO1207	585	438	438	440	443	448	450	453
Nevada Power	NW	Lorenzi	LO1208	585	502	502	504	508	513	516	518
Nevada Power	NW	Lorenzi	LO1209	600	488	488	490	494	499	502	504
Nevada Power	NW	Lorenzi	LO1210	585	354	354	356	359	362	364	366
Nevada Power	NW	Lorenzi	LO1211	600	502	502	505	508	513	516	519
Nevada Power	NW	Lorenzi	LO1212	600	295	301	308	316	325	333	341
Nevada Power	NW	Lorenzi	LO1214	600	396	396	398	400	404	407	409
Nevada Power	NW	Michael Way	MW1201	600	245	245	246	248	251	252	253
Nevada Power	NW	Michael Way	MW1202	600	361	361	363	366	370	372	375

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NW	Michael Way	MW1204	600	436	436	438	441	445	448	450
Nevada Power	NW	Michael Way	MW1207	600	425	427	429	432	437	440	442
Nevada Power	NW	Michael Way	MW1209	600	398	398	413	416	420	425	431
Nevada Power	NW	Michael Way	MW1211	600	486	486	488	491	496	499	502
Nevada Power	NW	Michael Way	MW1213	600	322	322	324	326	329	331	333
Nevada Power	NW	Northwest	NW1204	600	329	365	399	422	436	463	490
Nevada Power	NW	Northwest	NW1205	600	514	569	617	668	707	756	804
Nevada Power	NW	Northwest	NW1206	600	303	307	309	311	314	317	320
Nevada Power	NW	Northwest	NW1208	600	480	480	482	485	490	493	496
Nevada Power	NW	Northwest	NW1209	600	1	1	1	1	1	1	1
Nevada Power	NW	Northwest	NW1215	600	231	244	245	247	249	254	259
Nevada Power	NW	Northwest	NW1216	600	378	403	405	408	412	421	429
Nevada Power	NW	Northwest	NW1217	600	440	458	460	463	468	475	482
Nevada Power	NW	Northwest	NW1220	600	282	301	311	313	316	325	334
Nevada Power	NW	Northwest	NW1221	600	170	170	171	172	174	175	176
Nevada Power	NW	Radar	RA1201	530	7	7	7	7	7	7	7
Nevada Power	NW	Rainbow	RB1202	585	277	277	279	281	284	285	287
Nevada Power	NW	Rainbow	RB1203	585	456	456	459	462	466	469	471
Nevada Power	NW	Rainbow	RB1204	585	317	317	319	321	324	326	328
Nevada Power	NW	Rainbow	RB1207	585	218	218	219	221	223	224	225
Nevada Power	NW	Rainbow	RB1208	585	347	347	349	351	355	357	359
Nevada Power	NW	Rainbow	RB1214	530	104	104	105	106	107	107	108
Nevada Power	NW	Rainbow	RB1215	530	432	432	434	437	441	444	446
Nevada Power	NW	Rainbow	RB1219	585	257	267	268	270	273	276	280
Nevada Power	NW	Regena	RGN1201	600	1	1	1	1	1	1	1
Nevada Power	NW	Regena	RGN1204	600	513	528	536	539	545	553	561
Nevada Power	NW	Regena	RGN1206	600	84	84	84	85	85	86	86
Nevada Power	NW	Regena	RGN1210	600	428	429	431	434	439	441	444
Nevada Power	NW	Regena	RGN1211	600	383	391	401	411	423	433	443
Nevada Power	NW	Regena	RGN1212	600	125	125	125	126	127	128	129
Nevada Power	NW	Silver Flag	SLV1201	200	10	10	10	10	10	10	10
Nevada Power	NW	Skelton	SKL1205	600	405	414	423	428	432	439	446
Nevada Power	NW	Skelton	SKL1206	600	436	436	439	442	446	448	451
Nevada Power	NW	Skelton	SKL1208	600	473	473	476	479	484	486	489
Nevada Power	NW	Skelton	SKL1209	600	421	421	424	427	431	433	435
Nevada Power	NW	Skelton	SKL1210	600	357	361	364	368	374	378	382
Nevada Power	NW	Skelton	SKL1215	600	364	364	365	368	372	374	376
Nevada Power	NW	Skelton	SKL1217	600	214	215	216	217	219	220	222
Nevada Power	NW	Skelton	SKL1218	600	302	311	320	322	326	332	337
Nevada Power	NW	Skelton	SKL1220	600	206	209	210	211	214	216	217
Nevada Power	NW	Skelton	SKL1221	600	435	439	442	446	451	456	460
Nevada Power	NW	Snow Mountain	SN1201	530	92	92	93	93	94	95	95
Nevada Power	NW	Summerlin	SMR1205	600	256	256	257	259	262	263	264
Nevada Power	NW	Summerlin	SMR1207	600	375	375	377	380	384	386	388
Nevada Power	NW	Summerlin	SMR1208	600	464	464	466	470	474	477	480
Nevada Power	NW	Summerlin	SMR1209	600	427	435	439	442	446	451	456
Nevada Power	NW	Summerlin	SMR1210	600	370	429	431	434	439	456	473
Nevada Power	NW	Summerlin	SMR1217	600	412	412	414	417	421	424	426
Nevada Power	NW	Summerlin	SMR1218	600	436	436	438	442	446	448	451
Nevada Power	NW	Summerlin	SMR1219	600	454	454	457	460	464	467	469
Nevada Power	NW	Summerlin	SMR1220	600	430	430	432	435	439	442	444
Nevada Power	NW	Tenaya	TE1201	585	435	498	501	504	509	528	546
Nevada Power	NW	Tenaya	TE1203	600	190	190	191	192	194	195	196

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	NW	Tenaya	TE1204	600	282	282	283	285	288	290	291
Nevada Power	NW	Tenaya	TE1205	600	303	303	304	306	309	311	313
Nevada Power	NW	Tenaya	TE1206	600	481	481	483	487	492	494	497
Nevada Power	NW	Tenaya	TE1208	600	171	171	172	173	174	175	176
Nevada Power	NW	Tenaya	TE1209	600	519	519	522	525	531	533	536
Nevada Power	NW	Tenaya	TE1211	600	439	451	453	456	461	466	472
Nevada Power	NW	Tenaya	TE1212	600	412	448	466	470	474	490	506
Nevada Power	NW	Tenaya	TE1213	600	384	384	385	388	392	394	396
Nevada Power	NW	Vegas	VGS1201	600	385	387	390	394	400	403	407
Nevada Power	NW	Vegas	VGS1203	600	417	417	419	422	427	429	431
Nevada Power	NW	Vegas	VGS1204	600	209	209	210	211	213	215	216
Nevada Power	NW	Vegas	VGS1205	600	387	387	389	391	395	398	400
Nevada Power	NW	Vegas	VGS1206	600	412	412	414	417	421	423	425
Nevada Power	NW	Vegas	VGS1207	600	404	404	406	409	413	415	417
Nevada Power	NW	Vegas	VGS1208	600	305	305	306	308	311	313	315
Nevada Power	NW	Vegas	VGS1211	600	361	361	363	365	369	371	373
Nevada Power	NW	Vegas	VGS1212	600	331	340	351	362	374	385	396
Nevada Power	NW	Vegas	VGS1213	600	432	432	434	437	441	444	446
Nevada Power	NW	Village	VLG1201	600	406	406	408	411	415	417	420
Nevada Power	NW	Village	VLG1203	600	223	231	232	234	237	240	244
Nevada Power	NW	Village	VLG1205	600	52	52	52	53	53	53	54
Nevada Power	NW	Village	VLG1206	600	155	155	155	157	158	159	160
Nevada Power	NW	Village	VLG1210	600	132	132	133	134	135	136	137
Nevada Power	NW	Village	VLG1212	600	69	69	69	70	71	71	71
Nevada Power	NW	Village	VLG1213	600	220	254	274	276	279	294	308
Nevada Power	NW	Village	VLG1215	600	134	134	135	136	137	138	139
Nevada Power	NW	Village	VLG1217	600	357	357	359	362	365	367	369
Nevada Power	NW	Westside	WE1201	585	417	417	419	422	426	428	431
Nevada Power	NW	Westside	WE1203	585	1	1	1	1	1	1	1
Nevada Power	NW	Westside	WE1204	600	488	488	490	494	499	502	504
Nevada Power	NW	Westside	WE1207	600	483	488	491	494	499	503	507
Nevada Power	NW	Westside	WE1208	585	338	338	340	342	345	347	349
Nevada Power	NW	Westside	WE1209	585	363	363	365	368	371	374	376
Nevada Power	NW	Westside	WE1210	585	436	436	438	441	446	448	450
Nevada Power	NW	Westside	WE1211	585	76	76	77	77	78	78	79
Nevada Power	NW	Westside	WE1212	585	413	413	415	418	422	425	427
Nevada Power	NW	Westside	WE1214	585	471	471	473	477	482	484	487
Nevada Power	NW	Westside	WE1219	600	181	223	266	298	309	341	373
Nevada Power	NW	Westside	WE1220	600	326	326	328	330	333	335	337
Nevada Power	SE	Anthem	ANT1201	600	375	386	388	390	394	399	404
Nevada Power	SE	Anthem	ANT1203	600	144	144	145	146	147	148	149
Nevada Power	SE	Anthem	ANT1204	600	493	501	510	518	527	535	544
Nevada Power	SE	Anthem	ANT1205	600	406	407	410	414	418	421	424
Nevada Power	SE	Anthem	ANT1207	600	463	484	487	490	495	503	511
Nevada Power	SE	Anthem	ANT1209	600	189	189	190	191	193	194	195
Nevada Power	SE	Anthem	ANT1212	600	432	440	455	472	489	504	518
Nevada Power	SE	Anthem	ANT1213	600	370	370	372	374	378	380	382
Nevada Power	SE	Anthem	ANT1214	600	413	413	415	418	422	424	427
Nevada Power	SE	Balboa	BL1201	530	194	194	195	196	198	199	200
Nevada Power	SE	Balboa	BL1203	585	459	462	465	468	473	476	480
Nevada Power	SE	Balboa	BL1204	585	210	210	211	212	214	216	217
Nevada Power	SE	Balboa	BL1207	585	353	353	355	357	361	363	365
Nevada Power	SE	Balboa	BL1208	530	386	388	390	393	397	400	403

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SE	Balboa	BL1209	585	199	199	200	202	204	205	206
Nevada Power	SE	Balboa	BL1210	530	190	191	192	193	195	197	198
Nevada Power	SE	Balboa	BL1211	600	409	415	417	420	424	427	431
Nevada Power	SE	Bicentennial	BCT1201	600	81	86	86	87	88	89	91
Nevada Power	SE	Bicentennial	BCT1203	600	393	393	395	397	401	404	406
Nevada Power	SE	Bicentennial	BCT1204	600	361	361	363	366	369	371	373
Nevada Power	SE	Bicentennial	BCT1205	600	454	454	456	459	464	466	469
Nevada Power	SE	Bicentennial	BCT1210	600	221	221	223	224	226	228	229
Nevada Power	SE	Bicentennial	BCT1211	600	261	261	262	264	267	268	270
Nevada Power	SE	Bicentennial	BCT1213	600	9	9	9	10	10	10	11
Nevada Power	SE	Bicentennial	BCT1214	600	293	293	294	296	299	301	303
Nevada Power	SE	Bicentennial	BCT1215	600	194	194	195	196	198	199	200
Nevada Power	SE	Bicentennial	BCT1217	600	311	386	444	494	506	555	604
Nevada Power	SE	Big Bend	BGB2501	400	156	156	156	157	159	160	161
Nevada Power	SE	Big Bend	BGB2507	400	305	305	306	308	311	313	315
Nevada Power	SE	Boulder Beach	BB1201	530	101	101	101	102	103	103	104
Nevada Power	SE	Burnham	BRN1201	600	340	340	342	344	348	350	351
Nevada Power	SE	Burnham	BRN1202	600	448	448	450	453	458	460	463
Nevada Power	SE	Burnham	BRN1204	600	427	428	430	434	438	441	444
Nevada Power	SE	Burnham	BRN1205	600	338	338	340	342	346	348	350
Nevada Power	SE	Burnham	BRN1206	600	309	323	324	327	330	335	340
Nevada Power	SE	Burnham	BRN1209	600	387	391	393	396	400	403	407
Nevada Power	SE	Burnham	BRN1210	600	207	208	209	211	213	214	215
Nevada Power	SE	Burnham	BRN1211	600	386	386	388	391	395	397	399
Nevada Power	SE	Burnham	BRN1212	600	393	393	395	398	401	404	406
Nevada Power	SE	Burnham	BRN1214	600	386	386	388	390	394	396	398
Nevada Power	SE	Cabana	CB1201	600	342	342	343	346	349	351	353
Nevada Power	SE	Cabana	CB1202	600	410	410	412	415	419	422	424
Nevada Power	SE	Cabana	CB1204	600	488	499	511	520	528	538	548
Nevada Power	SE	Cabana	CB1205	600	411	411	413	416	420	423	425
Nevada Power	SE	Cabana	CB1206	600	145	145	146	147	149	149	150
Nevada Power	SE	Cabana	CB1209	600	486	486	488	491	496	499	502
Nevada Power	SE	Cabana	CB1210	600	413	413	415	418	422	424	427
Nevada Power	SE	Cabana	CB1211	600	469	469	472	475	480	482	485
Nevada Power	SE	Cabana	CB1212	600	295	295	297	299	302	303	305
Nevada Power	SE	Cabana	CB1214	600	409	419	431	445	450	460	470
Nevada Power	SE	Cactus	CCT1201	600	1	1	1	1	1	1	1
Nevada Power	SE	Cactus	CCT1202	600	334	367	379	391	403	420	437
Nevada Power	SE	Cactus	CCT1207	600	432	432	435	438	442	444	447
Nevada Power	SE	Cactus	CCT1209	600	1	1	1	1	1	1	1
Nevada Power	SE	Cactus	CCT1211	600	427	433	441	450	461	469	477
Nevada Power	SE	Cactus	CCT1212	600	289	324	371	418	433	469	505
Nevada Power	SE	Cactus	CCT1214	600	278	300	302	304	307	314	321
Nevada Power	SE	Cactus	CCT1216	600	1	1	1	1	1	1	1
Nevada Power	SE	Cactus	CCT1217	600	1	1	1	1	1	1	1
Nevada Power	SE	Cactus	CCT1218	600	1	1	1	1	1	1	1
Nevada Power	SE	Faulkner	FLK1204	600	454	462	471	481	493	503	512
Nevada Power	SE	Faulkner	FLK1205	600	485	490	497	503	508	513	519
Nevada Power	SE	Faulkner	FLK1206	600	1	1	1	1	1	1	1
Nevada Power	SE	Faulkner	FLK1208	600	463	468	470	474	478	482	486
Nevada Power	SE	Faulkner	FLK1209	600	406	406	408	411	415	417	419
Nevada Power	SE	Faulkner	FLK1210	600	362	365	367	370	373	376	379
Nevada Power	SE	Faulkner	FLK1215	600	459	459	461	464	469	471	474

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SE	Faulkner	FLK1216	600	166	169	170	171	173	175	177
Nevada Power	SE	Faulkner	FLK1217	600	167	419	421	424	428	494	559
Nevada Power	SE	Faulkner	FLK1218	600	397	557	567	571	577	621	666
Nevada Power	SE	Faulkner	FLK1220	600	184	307	309	311	314	347	379
Nevada Power	SE	Faulkner	FLK1221	600	441	504	506	510	515	534	552
Nevada Power	SE	Faulkner	FLK1224	600	181	214	215	216	218	228	237
Nevada Power	SE	Faulkner	FLK1225	600	2	29	57	85	113	141	169
Nevada Power	SE	Faulkner	FLK1226	600	357	421	461	486	511	550	589
Nevada Power	SE	Faulkner	FLK1227	600	539	542	547	553	560	565	570
Nevada Power	SE	Ford	FRD1204	600	407	441	448	455	462	476	490
Nevada Power	SE	Ford	FRD1208	600	403	414	419	422	426	432	438
Nevada Power	SE	Ford	FRD1209	600	63	63	64	64	65	65	65
Nevada Power	SE	Ford	FRD1210	600	407	407	409	412	416	419	421
Nevada Power	SE	Ford	FRD1216	600	329	329	330	333	336	338	340
Nevada Power	SE	Ford	FRD1217	600	294	304	307	311	314	319	325
Nevada Power	SE	Ford	FRD1218	600	461	461	463	466	471	474	476
Nevada Power	SE	Ford	FRD1220	600	364	366	368	371	374	377	379
Nevada Power	SE	Ford	FRD1221	600	436	436	438	441	446	448	451
Nevada Power	SE	Green Valley	GV1201	585	378	380	383	387	391	394	398
Nevada Power	SE	Green Valley	GV1203	585	340	340	342	344	347	349	351
Nevada Power	SE	Green Valley	GV1204	600	449	449	451	454	459	461	464
Nevada Power	SE	Green Valley	GV1207	585	328	328	329	332	335	337	339
Nevada Power	SE	Green Valley	GV1208	600	245	245	247	248	251	252	254
Nevada Power	SE	Green Valley	GV1209	600	425	457	459	462	467	478	488
Nevada Power	SE	Green Valley	GV1210	600	452	452	455	458	462	465	467
Nevada Power	SE	Green Valley	GV1211	585	400	400	402	405	409	411	413
Nevada Power	SE	Green Valley	GV1212	585	258	259	260	262	265	266	268
Nevada Power	SE	Green Valley	GV1214	585	460	460	462	466	470	473	475
Nevada Power	SE	Greenway	GNW1201	600	1	1	1	1	1	1	1
Nevada Power	SE	Greenway	GNW1205	600	359	360	363	366	369	372	374
Nevada Power	SE	Greenway	GNW1206	600	406	413	415	418	422	427	431
Nevada Power	SE	Greenway	GNW1207	600	344	344	346	349	352	354	356
Nevada Power	SE	Greenway	GNW1209	600	492	507	512	517	525	533	541
Nevada Power	SE	Haven	HV1202	600	442	452	454	457	462	467	472
Nevada Power	SE	Haven	HV1203	600	545	545	548	552	558	561	564
Nevada Power	SE	Haven	HV1204	600	500	505	508	511	517	521	525
Nevada Power	SE	Haven	HV1205	585	288	289	290	292	295	297	298
Nevada Power	SE	Haven	HV1206	585	293	303	317	331	346	360	373
Nevada Power	SE	Haven	HV1209	600	484	499	501	505	510	516	523
Nevada Power	SE	Haven	HV1210	585	221	221	222	224	226	227	229
Nevada Power	SE	Haven	HV1211	585	436	438	440	443	448	451	454
Nevada Power	SE	Haven	HV1212	600	274	274	275	277	280	281	283
Nevada Power	SE	Haven	HV1213	600	250	278	279	281	284	293	302
Nevada Power	SE	Keehn	KHN1201	600	430	585	588	592	598	639	681
Nevada Power	SE	Keehn	KHN1203	600	1	35	94	94	95	119	142
Nevada Power	SE	Keehn	KHN1204	600	168	208	247	252	259	281	304
Nevada Power	SE	Keehn	KHN1205	600	2	2	2	2	2	2	2
Nevada Power	SE	Keehn	KHN1206	600	197	218	243	268	294	319	343
Nevada Power	SE	Keehn	KHN1210	600	302	375	412	429	441	476	511
Nevada Power	SE	Keehn	KHN1211	600	354	404	406	409	413	428	442
Nevada Power	SE	Keehn	KHN1212	600	172	199	222	233	243	261	279
Nevada Power	SE	Keehn	KHN1214	600	158	235	282	302	319	360	400
Nevada Power	SE	Keehn	KHN1215	600	234	234	235	237	239	241	242

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SE	Keehn	KHN1217	600	130	130	130	131	133	133	134
Nevada Power	SE	Kidwell	KI1201	200	57	57	58	58	59	59	59
Nevada Power	SE	Kidwell	KI1202	200	42	44	44	44	45	45	46
Nevada Power	SE	Lake Las Vegas	LLV1201	600	205	241	277	299	313	340	367
Nevada Power	SE	Lake Las Vegas	LLV1203	600	431	445	462	477	493	509	525
Nevada Power	SE	Lake Las Vegas	LLV1205	600	205	225	244	256	264	278	293
Nevada Power	SE	Lake Las Vegas	LLV1206	600	96	97	97	98	99	100	100
Nevada Power	SE	Lamb	LA401	600	1	1	1	1	1	1	1
Nevada Power	SE	Lindquist	LDQ1203	600	359	371	376	379	384	390	396
Nevada Power	SE	Lindquist	LDQ1204	600	278	279	282	286	290	293	296
Nevada Power	SE	Lindquist	LDQ1205	600	332	384	409	432	452	482	512
Nevada Power	SE	Lindquist	LDQ1208	600	275	278	281	283	286	289	292
Nevada Power	SE	Lindquist	LDQ1210	600	302	302	304	306	309	311	312
Nevada Power	SE	Lindquist	LDQ1215	600	274	278	280	282	285	288	291
Nevada Power	SE	Magic Way	MAG1209	600	329	334	339	341	345	349	353
Nevada Power	SE	Magic Way	MAG1210	600	220	238	254	271	274	288	301
Nevada Power	SE	Mission	MS1201	530	69	77	78	79	81	84	86
Nevada Power	SE	Mission	MS1203	530	378	460	463	466	470	494	517
Nevada Power	SE	Mission	MS1204	530	281	290	302	316	331	343	355
Nevada Power	SE	Mission	MS1205	530	400	400	402	405	409	411	414
Nevada Power	SE	Mission	MS1206	530	213	227	234	242	251	260	269
Nevada Power	SE	Mission	MS1209	600	398	490	557	571	586	633	681
Nevada Power	SE	Mission	MS1210	600	463	463	466	469	474	476	479
Nevada Power	SE	Mission	MS1212	585	215	215	216	217	219	221	222
Nevada Power	SE	Mission	MS1213	530	200	200	201	202	204	205	206
Nevada Power	SE	Mission	MS1214	530	154	154	155	156	158	159	159
Nevada Power	SE	National Park Service	NPS401	150	22	22	22	22	22	22	23
Nevada Power	SE	Nelson	NL1201	100	11	11	11	11	11	11	11
Nevada Power	SE	Pearl	PL1201	585	225	225	226	227	230	231	232
Nevada Power	SE	Pearl	PL1202	600	433	441	444	447	451	456	461
Nevada Power	SE	Pearl	PL1204	585	142	142	143	144	145	146	147
Nevada Power	SE	Pearl	PL1206	585	330	331	333	335	339	341	343
Nevada Power	SE	Pearl	PL1209	585	347	349	350	353	356	359	361
Nevada Power	SE	Pearl	PL1211	585	228	228	229	231	233	234	236
Nevada Power	SE	Pearl	PL1213	600	405	405	408	411	415	417	419
Nevada Power	SE	Pearl	PL1214	585	264	264	266	268	270	272	273
Nevada Power	SE	Pebble	PB1201	600	472	493	495	499	504	512	520
Nevada Power	SE	Pebble	PB1203	600	316	324	334	338	342	348	354
Nevada Power	SE	Pebble	PB1204	600	198	198	199	201	203	204	205
Nevada Power	SE	Pebble	PB1205	600	520	533	535	539	544	550	557
Nevada Power	SE	Pebble	PB1209	600	382	385	387	390	393	396	399
Nevada Power	SE	Pebble	PB1210	600	433	437	443	450	458	465	471
Nevada Power	SE	Pebble	PB1211	600	400	401	404	408	414	417	421
Nevada Power	SE	Pebble	PB1212	600	520	520	523	527	532	535	538
Nevada Power	SE	Pebble	PB1213	600	505	505	508	511	517	519	522
Nevada Power	SE	Ranger	RN1201	150	49	49	49	49	50	50	50
Nevada Power	SE	Ranger	RN1202	150	55	55	55	55	56	56	57
Nevada Power	SE	River Road	RI2501	400	326	329	333	337	342	346	350
Nevada Power	SE	River Road	RI2508	400	106	106	106	107	108	109	109
Nevada Power	SE	River Road	RI2509	400	1	1	1	1	1	1	1
Nevada Power	SE	Russell	RS1201	585	208	208	209	211	213	214	215
Nevada Power	SE	Russell	RS1202	585	183	183	184	185	187	188	189
Nevada Power	SE	Russell	RS1204	585	356	356	358	361	364	366	368

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SE	Russell	RS1205	585	383	383	385	387	391	393	396
Nevada Power	SE	Russell	RS1206	600	390	390	392	395	399	401	403
Nevada Power	SE	Russell	RS1209	600	514	514	516	520	525	528	531
Nevada Power	SE	Russell	RS1210	600	456	457	459	462	467	470	472
Nevada Power	SE	Russell	RS1211	600	416	416	418	421	425	428	430
Nevada Power	SE	Russell	RS1212	600	475	475	478	481	487	490	493
Nevada Power	SE	Russell	RS1214	600	168	168	169	170	172	172	173
Nevada Power	SE	Sahara	SA1201	600	407	470	472	476	480	499	517
Nevada Power	SE	Sahara	SA1203	600	496	496	498	502	507	509	512
Nevada Power	SE	Sahara	SA1205	600	397	397	399	402	406	408	410
Nevada Power	SE	Sahara	SA1206	600	378	378	380	382	386	388	390
Nevada Power	SE	Sahara	SA1209	600	329	332	334	336	339	342	345
Nevada Power	SE	Sahara	SA1212	600	421	502	504	508	513	536	559
Nevada Power	SE	Sahara	SA1216	600	413	413	415	418	422	424	427
Nevada Power	SE	Sahara	SA1217	600	76	76	77	77	78	78	79
Nevada Power	SE	Searchlight	SE1201	199	124	125	127	129	131	133	134
Nevada Power	SE	Searchlight	SE1202	300	6	6	6	6	6	6	6
Nevada Power	SE	Southpoint	SO2502	400	171	171	172	173	175	176	177
Nevada Power	SE	Southpoint	SO2507	400	125	125	125	126	128	128	129
Nevada Power	SE	Southpoint	SO2508	400	8	8	8	8	8	8	8
Nevada Power	SE	Sunset	SUS1201	600	78	109	131	151	167	190	212
Nevada Power	SE	Sunset	SUS1205	600	466	527	530	535	541	559	578
Nevada Power	SE	Sunset	SUS1206	600	545	547	550	554	559	563	566
Nevada Power	SE	Sunset	SUS1212	600	2	29	56	57	57	71	85
Nevada Power	SE	Tolson	TOL1204	600	482	501	511	515	520	529	539
Nevada Power	SE	Tolson	TOL1205	600	466	476	488	501	516	529	541
Nevada Power	SE	Tolson	TOL1206	600	505	528	532	537	542	552	561
Nevada Power	SE	Tolson	TOL1208	600	465	465	467	471	475	478	480
Nevada Power	SE	Tolson	TOL1209	600	325	325	335	338	341	345	349
Nevada Power	SE	Tolson	TOL1215	600	468	468	470	473	478	481	483
Nevada Power	SE	Tolson	TOL1216	600	424	464	484	499	514	537	560
Nevada Power	SE	Tolson	TOL1218	600	189	435	446	457	463	532	601
Nevada Power	SE	Tolson	TOL1220	600	493	493	496	499	504	507	510
Nevada Power	SE	Tolson	TOL1221	600	465	469	471	475	479	483	487
Nevada Power	SE	Warmsprings	WSP1201	600	439	439	441	444	448	451	453
Nevada Power	SE	Warmsprings	WSP1203	600	224	224	225	227	229	230	231
Nevada Power	SE	Warmsprings	WSP1204	600	428	428	430	433	438	440	442
Nevada Power	SE	Warmsprings	WSP1205	600	150	150	151	152	154	154	155
Nevada Power	SE	Warmsprings	WSP1208	600	155	155	156	157	159	160	160
Nevada Power	SE	Warmsprings	WSP1209	600	320	403	405	408	413	436	459
Nevada Power	SE	Warmsprings	WSP1210	600	427	427	429	432	437	439	441
Nevada Power	SE	Warmsprings	WSP1211	600	561	562	565	569	575	578	581
Nevada Power	SE	Warmsprings	WSP1212	530	332	332	333	335	339	341	343
Nevada Power	SE	Warmsprings	WSP1213	600	500	506	509	513	518	522	527
Nevada Power	SE	Water Street	WA1201	585	200	225	226	227	230	237	245
Nevada Power	SE	Water Street	WA1203	530	1	1	1	1	1	1	1
Nevada Power	SE	Water Street	WA1204	585	362	381	383	386	390	397	404
Nevada Power	SE	Water Street	WA1206	585	484	484	487	490	495	498	501
Nevada Power	SE	Water Street	WA1208	585	429	450	452	456	460	468	476
Nevada Power	SE	Water Street	WA409	600	344	345	347	349	353	355	357
Nevada Power	SE	Water Street	WA410	600	373	373	375	377	381	383	385
Nevada Power	SE	Whitney	WH1201	585	353	353	355	358	362	364	366
Nevada Power	SE	Whitney	WH1202	585	373	377	383	385	389	393	397

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SE	Whitney	WH1203	530	6	6	6	6	6	6	6
Nevada Power	SE	Whitney	WH1204	585	409	430	451	454	459	471	484
Nevada Power	SE	Whitney	WH1206	585	394	394	396	398	402	405	407
Nevada Power	SE	Whitney	WH1209	585	306	326	328	330	333	340	347
Nevada Power	SE	Whitney	WH1211	585	384	384	386	388	392	394	396
Nevada Power	SE	Whitney	WH1213	585	489	489	492	495	500	503	506
Nevada Power	SE	Whitney	WH1214	585	320	320	321	324	327	329	330
Nevada Power	SE	Wigwam	WI1201	600	291	291	292	294	297	299	300
Nevada Power	SE	Wigwam	WI1203	600	460	460	463	466	470	473	476
Nevada Power	SE	Wigwam	WI1204	600	455	455	457	460	465	467	470
Nevada Power	SE	Wigwam	WI1205	600	475	475	477	481	485	488	491
Nevada Power	SE	Wigwam	WI1206	600	371	371	373	376	379	382	384
Nevada Power	SE	Wigwam	WI1208	600	233	259	272	274	277	288	299
Nevada Power	SE	Wigwam	WI1209	600	437	437	439	442	446	449	451
Nevada Power	SE	Wigwam	WI1211	600	330	330	332	334	337	339	341
Nevada Power	SE	Wigwam	WI1212	600	387	387	389	392	396	398	400
Nevada Power	SE	Wigwam	WI1213	600	465	526	529	533	538	557	575
Nevada Power	SE	Wilson	WIL1204	600	8	8	8	8	8	8	9
Nevada Power	SE	Wilson	WIL1205	600	114	131	148	166	184	202	219
Nevada Power	SE	Wilson	WIL1206	600	283	331	362	378	391	418	445
Nevada Power	SE	Wilson	WIL1208	600	467	467	470	474	479	482	485
Nevada Power	SE	Wilson	WIL1209	600	435	436	439	442	447	450	454
Nevada Power	SE	Wilson	WIL1210	600	399	400	402	405	409	412	414
Nevada Power	SE	Wilson	WIL1215	600	1	1	1	1	1	1	1
Nevada Power	SE	Wilson	WIL1216	600	284	297	305	312	321	330	339
Nevada Power	SE	Wilson	WIL1217	600	345	355	356	359	363	367	371
Nevada Power	SE	Wilson	WIL1218	600	469	469	472	475	480	482	485
Nevada Power	SE	Wilson	WIL1220	600	495	504	507	510	516	521	526
Nevada Power	SE	Wilson	WIL1221	600	303	325	327	329	332	339	347
Nevada Power	SE	Winterwood	WW1203	585	410	422	424	427	431	436	441
Nevada Power	SE	Winterwood	WW1204	585	420	421	424	427	431	434	436
Nevada Power	SE	Winterwood	WW1205	600	143	143	143	144	146	147	147
Nevada Power	SE	Winterwood	WW1207	585	466	466	468	471	476	479	481
Nevada Power	SE	Winterwood	WW1210	600	162	162	162	163	165	166	167
Nevada Power	SE	Winterwood	WW1211	585	287	293	301	309	318	326	334
Nevada Power	SE	Winterwood	WW1214	600	44	44	44	44	45	45	45
Nevada Power	SE	Winterwood	WW1216	600	290	290	291	293	296	298	299
Nevada Power	SE	Winterwood	WW1217	600	415	426	429	432	436	441	447
Nevada Power	SE	Winterwood	WW1219	600	378	378	380	382	386	388	390
Nevada Power	SE	Winterwood	WW1220	600	305	340	342	346	350	361	373
Nevada Power	SE	Winterwood	WW1224	600	276	276	278	280	282	284	285
Nevada Power	SE	Winterwood	WW1225	600	97	97	98	98	99	100	100
Nevada Power	STRIP	Claymont	CM1202	585	115	115	115	116	117	118	119
Nevada Power	STRIP	Claymont	CM1204	585	393	393	395	397	401	404	406
Nevada Power	STRIP	Claymont	CM1205	585	405	405	407	410	414	416	418
Nevada Power	STRIP	Claymont	CM1209	585	432	438	441	444	448	452	456
Nevada Power	STRIP	Claymont	CM1211	585	359	359	361	363	367	369	371
Nevada Power	STRIP	Claymont	CM1212	585	372	372	374	376	380	382	384
Nevada Power	STRIP	Claymont	CM1223	585	304	304	306	308	311	312	314
Nevada Power	STRIP	Claymont	CM1224	585	399	399	401	404	408	410	413
Nevada Power	STRIP	Claymont	CM1225	585	290	328	330	332	335	347	358
Nevada Power	STRIP	Claymont	CM1228	585	341	341	342	345	348	350	352
Nevada Power	STRIP	Claymont	CM1229	585	231	620	623	628	634	735	836

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Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	STRIP	Claymont	CM1230	585	92	92	92	93	94	94	95
Nevada Power	STRIP	Claymont	CM1231	600	249	249	251	252	255	256	258
Nevada Power	STRIP	Commerce	COM1203	600	1	1	1	1	1	1	1
Nevada Power	STRIP	Commerce	COM1204	600	1	1	1	1	1	1	1
Nevada Power	STRIP	Commerce	COM1205	600	337	425	427	430	435	459	483
Nevada Power	STRIP	Commerce	COM1207	600	311	327	329	331	335	341	347
Nevada Power	STRIP	Commerce	COM1216	600	412	412	414	417	422	424	426
Nevada Power	STRIP	Commerce	COM1218	600	109	121	167	184	185	205	224
Nevada Power	STRIP	Commerce	COM1219	600	434	458	476	486	491	505	520
Nevada Power	STRIP	Concourse	CON1201	600	387	395	397	400	404	408	413
Nevada Power	STRIP	Concourse	CON1203	600	450	457	459	462	467	471	475
Nevada Power	STRIP	Concourse	CON1204	600	255	255	256	258	261	262	263
Nevada Power	STRIP	Concourse	CON1205	600	345	345	347	349	353	355	357
Nevada Power	STRIP	Concourse	CON1206	600	431	431	433	437	441	443	446
Nevada Power	STRIP	Concourse	CON1209	600	161	161	161	163	164	165	166
Nevada Power	STRIP	Concourse	CON1211	600	305	305	306	308	311	313	315
Nevada Power	STRIP	Concourse	CON1212	600	4	4	4	4	4	4	4
Nevada Power	STRIP	Concourse	CON1213	600	231	231	232	233	236	237	238
Nevada Power	STRIP	Concourse	CON1214	600	2	2	2	2	2	2	2
Nevada Power	STRIP	Concourse	CON1215	600	142	142	143	144	145	146	147
Nevada Power	STRIP	Concourse	CON1217	600	369	369	371	373	377	379	381
Nevada Power	STRIP	El Rancho	ER1201	585	284	284	285	287	290	292	293
Nevada Power	STRIP	El Rancho	ER1203	585	301	302	303	306	309	310	312
Nevada Power	STRIP	El Rancho	ER1205	585	521	521	524	527	533	535	538
Nevada Power	STRIP	El Rancho	ER1207	585	104	104	105	106	107	107	108
Nevada Power	STRIP	El Rancho	ER1209	585	235	235	236	237	240	241	242
Nevada Power	STRIP	El Rancho	ER1211	585	166	166	167	168	169	170	171
Nevada Power	STRIP	El Rancho	ER1212	530	232	232	233	235	237	238	239
Nevada Power	STRIP	Excalibur	EX1201	600	362	362	364	367	370	372	374
Nevada Power	STRIP	Excalibur	EX1203	600	218	218	219	221	223	224	225
Nevada Power	STRIP	Excalibur	EX1204	600	190	190	191	192	194	195	197
Nevada Power	STRIP	Excalibur	EX1205	600	229	229	230	232	234	236	237
Nevada Power	STRIP	Excalibur	EX1206	600	178	178	179	180	182	183	184
Nevada Power	STRIP	Excalibur	EX1209	600	5	5	5	5	5	5	5
Nevada Power	STRIP	Excalibur	EX1211	600	246	246	248	249	252	253	255
Nevada Power	STRIP	Excalibur	EX1212	585	5	5	5	5	5	5	5
Nevada Power	STRIP	Excalibur	EX1213	585	360	360	361	364	368	370	372
Nevada Power	STRIP	Excalibur	EX1214	585	164	164	165	166	167	168	169
Nevada Power	STRIP	Excalibur	EX1215	585	288	288	290	292	295	296	298
Nevada Power	STRIP	Flamingo	FL1202	585	166	166	167	168	170	171	172
Nevada Power	STRIP	Flamingo	FL1203	600	145	145	145	146	148	149	149
Nevada Power	STRIP	Flamingo	FL1206	585	159	159	160	161	163	164	165
Nevada Power	STRIP	Flamingo	FL1207	585	158	158	158	160	161	162	163
Nevada Power	STRIP	Flamingo	FL1208	585	218	218	219	220	222	224	225
Nevada Power	STRIP	Flamingo	FL1209	585	108	108	108	109	110	111	111
Nevada Power	STRIP	Flamingo	FL1211	585	316	368	370	372	376	391	406
Nevada Power	STRIP	Flamingo	FL1212	585	378	379	380	383	387	389	391
Nevada Power	STRIP	Garces	GA1201	600	487	529	562	566	572	593	614
Nevada Power	STRIP	Garces	GA1202	600	225	225	226	228	230	232	233
Nevada Power	STRIP	Garces	GA1204	600	132	132	133	134	135	136	136
Nevada Power	STRIP	Garces	GA1205	600	137	137	138	139	140	141	142
Nevada Power	STRIP	Garces	GA1206	600	444	467	470	473	478	486	495
Nevada Power	STRIP	Garces	GA1209	600	135	135	136	137	138	139	139

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	STRIP	Garces	GA1210	600	544	544	547	551	556	559	562
Nevada Power	STRIP	Garces	GA1211	600	1	1	1	1	1	1	1
Nevada Power	STRIP	Highland	HI1201	585	148	148	148	149	151	152	153
Nevada Power	STRIP	Highland	HI1202	585	328	335	341	343	346	351	356
Nevada Power	STRIP	Highland	HI1203	585	194	194	195	196	198	199	201
Nevada Power	STRIP	Highland	HI1205	585	250	250	252	254	256	257	259
Nevada Power	STRIP	Highland	HI1206	585	324	336	346	348	351	358	365
Nevada Power	STRIP	Highland	HI1209	585	5	5	5	5	5	5	5
Nevada Power	STRIP	Highland	HI1210	585	115	118	119	119	121	122	123
Nevada Power	STRIP	Highland	HI1211	585	372	374	375	378	382	384	387
Nevada Power	STRIP	Highland	HI1214	600	175	175	175	177	178	179	180
Nevada Power	STRIP	Highland	HI1215	600	109	109	109	110	111	112	112
Nevada Power	STRIP	Highland	HI1216	600	467	467	469	472	477	480	482
Nevada Power	STRIP	Highland	HI1217	600	165	165	166	167	169	170	171
Nevada Power	STRIP	Highland	HI1219	600	9	9	9	9	9	9	9
Nevada Power	STRIP	Highland	HI1220	600	354	355	357	359	363	365	367
Nevada Power	STRIP	Highland	HI1222	600	88	551	554	558	563	682	801
Nevada Power	STRIP	Highland	HI1224	600	115	492	495	498	503	600	697
Nevada Power	STRIP	Highland	HI1225	600	469	469	472	475	480	482	485
Nevada Power	STRIP	Highland	HI1226	600	28	491	494	497	502	621	739
Nevada Power	STRIP	Highland	HI1228	600	464	464	466	470	474	477	479
Nevada Power	STRIP	Highland	HI1229	600	1	1	1	1	1	1	1
Nevada Power	STRIP	Highland	HI1230	600	1	1	1	1	1	1	1
Nevada Power	STRIP	Highland	HI1231	600	1	1	1	1	1	1	1
Nevada Power	STRIP	Highland	HI1232	600	1	1	1	1	1	1	1
Nevada Power	STRIP	Lewis	LE402	600	105	105	106	106	107	108	109
Nevada Power	STRIP	Lewis	LE404	600	64	64	64	65	65	66	66
Nevada Power	STRIP	Lynnwood	LY1202	585	391	626	629	633	640	702	764
Nevada Power	STRIP	Lynnwood	LY1204	585	368	368	370	372	376	378	380
Nevada Power	STRIP	Lynnwood	LY1205	585	233	233	235	236	239	240	241
Nevada Power	STRIP	Lynnwood	LY1208	585	366	366	368	371	374	376	378
Nevada Power	STRIP	Lynnwood	LY1209	585	190	190	191	192	194	195	196
Nevada Power	STRIP	Mayfair	MA1211	585	352	353	355	357	361	363	365
Nevada Power	STRIP	Mayfair	MA1212	585	432	432	434	437	441	444	446
Nevada Power	STRIP	Mayfair	MA1213	585	458	463	465	469	473	477	481
Nevada Power	STRIP	Mayfair	MA1215	585	344	354	356	358	362	366	371
Nevada Power	STRIP	Mayfair	MA1216	585	278	424	426	429	434	472	511
Nevada Power	STRIP	Mayfair	MA1218	585	344	344	346	349	352	354	356
Nevada Power	STRIP	Mayfair	MA401	585	221	221	222	223	226	227	228
Nevada Power	STRIP	Mayfair	MA402	585	264	264	265	267	270	271	273
Nevada Power	STRIP	MGM	MGM1216	600	1	1	1	1	1	1	1
Nevada Power	STRIP	MGM	MGM1217	600	141	141	142	143	144	145	146
Nevada Power	STRIP	MGM	MGM1218	600	315	315	316	318	321	323	325
Nevada Power	STRIP	Oquendo	OQ1203	585	306	309	310	312	315	318	320
Nevada Power	STRIP	Oquendo	OQ1204	585	309	336	337	340	343	352	360
Nevada Power	STRIP	Oquendo	OQ1206	585	270	272	273	275	278	279	281
Nevada Power	STRIP	Oquendo	OQ1209	585	381	389	391	393	397	401	405
Nevada Power	STRIP	Oquendo	OQ1210	585	199	346	348	350	354	392	431
Nevada Power	STRIP	Oquendo	OQ1211	585	179	181	182	183	185	187	188
Nevada Power	STRIP	Oquendo	OQ1213	585	297	327	329	331	334	344	353
Nevada Power	STRIP	Oquendo	OQ1214	585	482	521	523	527	532	545	558
Nevada Power	STRIP	Pawnee	PA1202	600	380	390	392	394	398	403	407
Nevada Power	STRIP	Pawnee	PA1203	585	32	32	32	32	33	33	33

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	STRIP	Pawnee	PA1204	585	344	346	348	350	354	356	359
Nevada Power	STRIP	Pawnee	PA1206	585	314	314	316	318	321	323	325
Nevada Power	STRIP	Pawnee	PA1207	585	193	193	194	196	198	199	200
Nevada Power	STRIP	Pawnee	PA1208	585	228	228	229	231	233	234	236
Nevada Power	STRIP	Polaris	POL1201	600	191	191	192	194	196	197	198
Nevada Power	STRIP	Polaris	POL1203	600	413	413	415	417	422	424	426
Nevada Power	STRIP	Polaris	POL1204	600	285	287	289	291	294	296	298
Nevada Power	STRIP	Polaris	POL1205	600	115	115	116	117	118	118	119
Nevada Power	STRIP	Polaris	POL1208	600	1	1	1	1	1	1	1
Nevada Power	STRIP	Polaris	POL1209	600	2	2	2	2	2	2	2
Nevada Power	STRIP	Polaris	POL1210	600	91	91	92	92	93	94	94
Nevada Power	STRIP	Polaris	POL1211	600	410	410	412	415	419	422	424
Nevada Power	STRIP	Polaris	POL1212	600	393	395	397	400	404	406	409
Nevada Power	STRIP	Polaris	POL1213	600	400	400	402	405	409	411	413
Nevada Power	STRIP	Polaris	POL1215	600	466	466	468	471	476	479	481
Nevada Power	STRIP	Polaris	POL1216	600	192	193	193	195	197	198	199
Nevada Power	STRIP	Procyon	PRO1202	600	375	375	377	380	384	386	388
Nevada Power	STRIP	Procyon	PRO1206	600	5	5	5	5	5	5	5
Nevada Power	STRIP	Procyon	PRO1207	600	160	160	161	162	164	164	165
Nevada Power	STRIP	Procyon	PRO1209	600	63	274	276	277	280	334	389
Nevada Power	STRIP	Procyon	PRO1211	600	326	332	334	336	340	343	346
Nevada Power	STRIP	Procyon	PRO1212	600	243	243	244	246	248	250	251
Nevada Power	STRIP	Procyon	PRO1213	600	16	16	16	16	16	17	17
Nevada Power	STRIP	Procyon	PRO1214	600	94	408	410	413	417	498	579
Nevada Power	STRIP	Procyon	PRO1216	600	98	430	433	436	440	526	611
Nevada Power	STRIP	San Francisco	SF1203	585	206	206	207	209	211	212	213
Nevada Power	STRIP	San Francisco	SF1204	585	217	218	219	220	222	224	225
Nevada Power	STRIP	San Francisco	SF1206	585	301	301	303	305	308	310	311
Nevada Power	STRIP	San Francisco	SF1207	585	469	469	471	475	479	482	485
Nevada Power	STRIP	San Francisco	SF1213	585	346	346	348	350	354	356	358
Nevada Power	STRIP	San Francisco	SF1215	585	197	197	198	199	201	202	203
Nevada Power	STRIP	San Francisco	SF1216	585	134	134	135	136	137	138	139
Nevada Power	STRIP	San Francisco	SF1217	585	283	291	293	295	298	301	305
Nevada Power	STRIP	San Francisco	SF1218	585	254	254	256	257	260	261	263
Nevada Power	STRIP	Sinatra	SNT1206	600	184	184	185	186	188	189	190
Nevada Power	STRIP	Sinatra	SNT1207	600	4	4	4	4	4	4	4
Nevada Power	STRIP	Sinatra	SNT1208	600	187	187	188	190	192	193	194
Nevada Power	STRIP	Sinatra	SNT1215	600	163	163	164	165	167	168	169
Nevada Power	STRIP	Sinatra	SNT1216	600	214	214	215	217	219	220	221
Nevada Power	STRIP	Sinatra	SNT1218	600	211	211	212	214	216	217	218
Nevada Power	STRIP	Sinatra	SNT1219	600	14	14	14	14	15	15	15
Nevada Power	STRIP	Sinatra	SNT1220	600	14	14	14	14	14	15	15
Nevada Power	STRIP	Spencer	SP1203	530	230	230	231	233	235	236	238
Nevada Power	STRIP	Spencer	SP1206	585	350	350	352	355	358	360	362
Nevada Power	STRIP	Spencer	SP1207	585	384	407	409	412	416	424	431
Nevada Power	STRIP	Spencer	SP1210	585	303	303	305	307	310	312	314
Nevada Power	STRIP	Spencer	SP1211	585	289	345	347	349	353	369	384
Nevada Power	STRIP	Spencer	SP1213	585	360	360	362	364	368	370	372
Nevada Power	STRIP	Spencer	SP1214	530	155	155	156	157	158	159	160
Nevada Power	STRIP	Strip	STR1203	600	443	445	447	451	455	458	461
Nevada Power	STRIP	Strip	STR1204	600	290	290	291	293	296	298	299
Nevada Power	STRIP	Strip	STR1205	600	232	232	234	235	238	239	240
Nevada Power	STRIP	Strip	STR1206	600	165	165	166	167	168	169	170

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	STRIP	Strip	STR1207	600	128	128	129	130	131	132	133
Nevada Power	STRIP	Strip	STR1208	600	4	4	4	4	4	4	4
Nevada Power	STRIP	Strip	STR1215	600	260	260	261	263	266	267	269
Nevada Power	STRIP	Strip	STR1216	600	127	127	127	128	129	130	131
Nevada Power	STRIP	Strip	STR1217	600	176	176	177	178	180	181	182
Nevada Power	STRIP	Strip	STR1218	600	226	226	227	229	231	233	234
Nevada Power	STRIP	Strip	STR1219	600	213	213	214	215	217	218	220
Nevada Power	STRIP	Suzanne	SZ1201	600	270	270	271	273	276	277	279
Nevada Power	STRIP	Suzanne	SZ1202	600	431	431	433	436	440	442	445
Nevada Power	STRIP	Suzanne	SZ1203	600	390	430	451	454	458	475	492
Nevada Power	STRIP	Suzanne	SZ1205	600	386	386	388	390	394	396	398
Nevada Power	STRIP	Suzanne	SZ1206	600	301	301	302	304	307	309	310
Nevada Power	STRIP	Suzanne	SZ1208	600	204	204	205	207	209	210	211
Nevada Power	STRIP	Suzanne	SZ1209	600	185	185	389	392	396	449	502
Nevada Power	STRIP	Suzanne	SZ1211	600	170	170	171	172	174	175	176
Nevada Power	STRIP	Suzanne	SZ1213	600	55	518	520	524	529	648	766
Nevada Power	STRIP	Suzanne	SZ1214	600	406	406	408	411	415	417	420
Nevada Power	STRIP	Swenson	SWN1201	600	283	283	284	286	289	291	292
Nevada Power	STRIP	Swenson	SWN1207	600	4	4	4	4	4	4	4
Nevada Power	STRIP	Swenson	SWN1208	600	273	273	274	276	279	280	282
Nevada Power	STRIP	Swenson	SWN1209	600	221	221	222	223	226	227	228
Nevada Power	STRIP	Swenson	SWN1213	600	74	461	463	466	471	570	669
Nevada Power	STRIP	Swenson	SWN1216	600	16	16	16	16	16	16	16
Nevada Power	STRIP	Swenson	SWN1219	600	260	282	292	294	297	306	316
Nevada Power	STRIP	Truman	TR1202	585	298	311	312	314	318	322	327
Nevada Power	STRIP	Truman	TR1209	585	1	1	1	1	1	1	1
Nevada Power	STRIP	Truman	TR1210	585	359	364	366	369	372	376	379
Nevada Power	STRIP	Valley View	VV1201	585	303	303	304	306	309	311	313
Nevada Power	STRIP	Valley View	VV1203	585	213	251	268	276	278	295	311
Nevada Power	STRIP	Valley View	VV1204	585	326	326	328	330	333	335	337
Nevada Power	STRIP	Valley View	VV1206	585	460	517	520	523	529	546	563
Nevada Power	STRIP	Valley View	VV1207	600	408	408	410	413	417	419	422
Nevada Power	STRIP	Valley View	VV1209	585	297	308	309	312	315	319	324
Nevada Power	STRIP	Valley View	VV1210	585	523	523	526	529	535	538	540
Nevada Power	STRIP	Valley View	VV1212	585	1	1	1	1	1	1	1
Nevada Power	SW	Arden	AD1202	600	180	189	199	210	216	225	234
Nevada Power	SW	Arden	AD1203	600	431	437	439	442	447	451	455
Nevada Power	SW	Arden	AD1204	600	486	522	527	533	538	552	565
Nevada Power	SW	Arden	AD1205	600	352	425	474	506	539	586	633
Nevada Power	SW	Arden	AD1206	600	136	147	149	150	151	155	159
Nevada Power	SW	Arden	AD1207	600	410	462	485	508	526	555	584
Nevada Power	SW	Arden	AD1208	600	59	87	116	140	141	162	183
Nevada Power	SW	Avera	AVR1205	600	461	505	513	517	523	538	553
Nevada Power	SW	Avera	AVR1206	600	324	377	390	394	399	418	437
Nevada Power	SW	Avera	AVR1208	600	454	514	520	526	531	550	570
Nevada Power	SW	Avera	AVR1209	600	468	520	528	538	548	568	588
Nevada Power	SW	Avera	AVR1210	600	115	186	188	189	192	211	230
Nevada Power	SW	Avera	AVR1215	600	434	442	445	448	452	457	461
Nevada Power	SW	Avera	AVR1216	600	347	359	364	366	370	376	381
Nevada Power	SW	Avera	AVR1217	600	407	487	490	493	498	521	544
Nevada Power	SW	Avera	AVR1221	600	358	392	394	396	400	411	421
Nevada Power	SW	Blue Diamond	BD401	600	1	1	1	1	1	1	1
Nevada Power	SW	Blue Diamond	BD402	600	1	1	1	1	1	1	1

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SW	Blue Diamond	BD403	600	1	1	1	1	1	1	1
Nevada Power	SW	Blue Diamond	BD404	600	1	1	1	1	1	1	1
Nevada Power	SW	Camero	CMO1201	600	1	1	1	1	1	1	1
Nevada Power	SW	Camero	CMO1205	600	366	454	458	461	466	491	516
Nevada Power	SW	Camero	CMO1206	600	377	406	416	426	437	452	467
Nevada Power	SW	Camero	CMO1212	600	140	140	141	142	143	144	145
Nevada Power	SW	Camero	CMO1213	600	1	1	1	1	1	1	1
Nevada Power	SW	Decatur	DE1201	600	296	296	297	299	302	304	306
Nevada Power	SW	Decatur	DE1203	600	392	451	458	461	466	484	503
Nevada Power	SW	Decatur	DE1204	600	413	415	417	420	425	428	431
Nevada Power	SW	Decatur	DE1205	600	18	18	18	18	19	19	19
Nevada Power	SW	Decatur	DE1206	600	258	258	259	261	264	265	267
Nevada Power	SW	Decatur	DE1209	600	423	423	425	428	433	435	437
Nevada Power	SW	Decatur	DE1212	600	457	457	460	463	468	470	473
Nevada Power	SW	Decatur	DE1214	600	452	452	454	457	462	464	467
Nevada Power	SW	Durango	DU1201	585	474	474	477	488	493	497	502
Nevada Power	SW	Durango	DU1203	600	496	497	500	503	508	511	514
Nevada Power	SW	Durango	DU1204	600	362	362	364	367	370	372	374
Nevada Power	SW	Durango	DU1205	600	37	37	37	37	37	38	38
Nevada Power	SW	Durango	DU1208	585	486	486	489	492	497	500	502
Nevada Power	SW	Durango	DU1209	585	508	508	510	514	519	522	525
Nevada Power	SW	Durango	DU1210	600	475	488	490	493	498	504	510
Nevada Power	SW	Durango	DU1211	600	402	402	404	407	411	414	416
Nevada Power	SW	Durango	DU1212	600	476	476	478	482	486	489	492
Nevada Power	SW	Durango	DU1215	600	5	5	5	5	5	5	5
Nevada Power	SW	Frias	FRS1206	600	413	515	528	532	538	569	600
Nevada Power	SW	Frias	FRS1210	600	352	352	354	357	360	362	364
Nevada Power	SW	Frias	FRS1211	600	465	467	471	476	482	486	490
Nevada Power	SW	Frias	FRS1212	600	496	496	499	502	507	510	513
Nevada Power	SW	Frias	FRS1214	600	452	459	467	470	475	481	486
Nevada Power	SW	Frias	FRS1215	600	454	487	509	527	547	570	593
Nevada Power	SW	Frias	FRS1217	600	414	444	446	450	454	464	475
Nevada Power	SW	Goodsprings	GS1201	530	17	17	17	17	17	17	17
Nevada Power	SW	Goodsprings	GS1202	530	22	22	22	22	22	22	23
Nevada Power	SW	Jean	JN1207	530	193	193	194	195	197	198	199
Nevada Power	SW	Jean	JN1208	530	252	252	253	255	258	259	260
Nevada Power	SW	Lindell	LI1202	585	386	386	388	391	395	397	399
Nevada Power	SW	Lindell	LI1204	585	328	328	330	333	336	339	341
Nevada Power	SW	Lindell	LI1207	585	334	345	347	349	353	357	362
Nevada Power	SW	Lindell	LI1208	585	72	76	80	81	81	84	86
Nevada Power	SW	Lindell	LI1211	530	382	383	385	387	391	394	396
Nevada Power	SW	Lindell	LI1212	530	3	3	3	3	3	3	3
Nevada Power	SW	Lindell	LI1213	530	201	201	202	203	205	206	208
Nevada Power	SW	Lindell	LI1220	585	243	251	252	254	256	260	263
Nevada Power	SW	McDonald	MCD1205	600	214	214	216	217	219	220	222
Nevada Power	SW	McDonald	MCD1207	600	400	431	445	450	455	468	482
Nevada Power	SW	McDonald	MCD1208	600	384	426	449	452	457	475	493
Nevada Power	SW	McDonald	MCD1210	600	495	532	541	552	560	576	593
Nevada Power	SW	McDonald	MCD1216	600	394	394	396	399	403	405	407
Nevada Power	SW	McDonald	MCD1217	600	419	433	435	438	443	449	455
Nevada Power	SW	McDonald	MCD1218	600	313	313	314	317	320	322	323
Nevada Power	SW	McDonald	MCD1219	600	296	341	348	351	354	369	383
Nevada Power	SW	McDonald	MCD1220	600	379	421	429	432	437	451	465

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SW	Mountains Edge	MTE1206	600	417	422	429	437	446	454	461
Nevada Power	SW	Mountains Edge	MTE1211	600	425	435	448	461	474	487	499
Nevada Power	SW	Mountains Edge	MTE1212	600	416	461	485	492	500	521	542
Nevada Power	SW	Mountains Edge	MTE1213	600	492	492	494	497	502	505	508
Nevada Power	SW	Mountains Edge	MTE1214	600	332	362	364	366	370	380	389
Nevada Power	SW	Mountains Edge	MTE1215	600	464	487	489	493	498	506	515
Nevada Power	SW	Mountains Edge	MTE1217	600	475	475	477	481	486	488	491
Nevada Power	SW	MYS	MYS1206	600	60	118	176	236	297	356	415
Nevada Power	SW	MYS	MYS1207	600	475	744	781	787	795	875	955
Nevada Power	SW	MYS	MYS1208	600	301	359	399	402	406	433	459
Nevada Power	SW	MYS	MYS1209	600	107	213	321	376	380	448	516
Nevada Power	SW	MYS	MYS1212	600	207	265	324	385	428	483	538
Nevada Power	SW	MYS	MYS1214	600	256	330	381	384	388	421	453
Nevada Power	SW	MYS	MYS1215	600	1	1	1	1	1	1	1
Nevada Power	SW	MYS	MYS1216	600	274	306	340	374	407	440	473
Nevada Power	SW	MYS	MYS1218	600	499	499	502	505	510	513	516
Nevada Power	SW	Oasis	OA1203	585	87	87	88	88	89	90	90
Nevada Power	SW	Oasis	OA1204	585	203	203	204	206	208	209	210
Nevada Power	SW	Oasis	OA1205	530	80	80	80	81	81	82	82
Nevada Power	SW	Oasis	OA1206	585	261	261	263	264	267	269	270
Nevada Power	SW	Peace	PCE1201	600	1	1	1	1	1	1	1
Nevada Power	SW	Peace	PCE1204	600	449	500	554	608	644	693	742
Nevada Power	SW	Peace	PCE1206	600	388	394	396	399	403	406	410
Nevada Power	SW	Peace	PCE1209	600	448	448	450	453	458	460	463
Nevada Power	SW	Peace	PCE1211	600	468	547	557	568	574	601	627
Nevada Power	SW	Peace	PCE1213	600	236	236	237	238	241	242	243
Nevada Power	SW	Peace	PCE1214	600	501	501	503	507	512	515	518
Nevada Power	SW	Peace	PCE1215	600	392	392	394	397	401	403	405
Nevada Power	SW	Peace	PCE1217	600	338	371	373	375	379	389	399
Nevada Power	SW	Quail	QUL1201	600	336	336	338	340	344	346	347
Nevada Power	SW	Quail	QUL1203	600	310	322	324	326	329	334	339
Nevada Power	SW	Quail	QUL1204	600	347	400	416	430	445	470	495
Nevada Power	SW	Quail	QUL1205	600	485	492	500	508	514	522	529
Nevada Power	SW	Quail	QUL1208	600	451	451	453	456	461	463	466
Nevada Power	SW	Quail	QUL1209	600	120	143	144	145	147	153	160
Nevada Power	SW	Quail	QUL1210	600	472	472	474	477	482	485	487
Nevada Power	SW	Quail	QUL1211	600	278	326	333	340	348	366	383
Nevada Power	SW	Quail	QUL1212	600	234	304	519	580	586	674	762
Nevada Power	SW	Quail	QUL1213	600	117	332	333	336	339	395	450
Nevada Power	SW	Railroad	RLR1201	600	30	30	30	30	30	30	31
Nevada Power	SW	Railroad	RLR1203	600	221	221	222	223	225	227	228
Nevada Power	SW	Railroad	RLR1204	600	80	80	80	81	82	82	83
Nevada Power	SW	Railroad	RLR1205	600	221	221	222	224	226	227	228
Nevada Power	SW	Railroad	RLR1206	600	203	203	204	205	207	208	209
Nevada Power	SW	Railroad	RLR1210	600	269	269	270	272	275	276	278
Nevada Power	SW	Railroad	RLR1211	600	40	40	40	41	41	41	42
Nevada Power	SW	Railroad	RLR1212	600	432	432	434	437	442	444	447
Nevada Power	SW	Railroad	RLR1214	600	210	210	211	213	215	216	217
Nevada Power	SW	Railroad	RLR1215	600	273	297	321	323	326	339	353
Nevada Power	SW	Railroad	RLR1217	600	294	322	324	326	330	339	348
Nevada Power	SW	Railroad	RLR1218	600	436	436	438	442	446	448	451
Nevada Power	SW	Railroad	RLR1219	600	305	362	422	480	506	556	606
Nevada Power	SW	Red Rock	RRK1201	600	428	428	430	433	437	440	442

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SW	Red Rock	RRK1203	600	305	305	307	309	312	314	315
Nevada Power	SW	Red Rock	RRK1204	600	10	41	64	64	65	78	92
Nevada Power	SW	Red Rock	RRK1211	600	580	586	592	598	606	612	619
Nevada Power	SW	Red Rock	RRK1212	600	402	402	404	407	411	413	415
Nevada Power	SW	Red Rock	RRK1213	600	383	431	462	494	525	561	596
Nevada Power	SW	Riley	RLY1205	600	460	492	499	505	512	525	538
Nevada Power	SW	Riley	RLY1206	600	550	565	579	593	608	622	637
Nevada Power	SW	Riley	RLY1210	600	0	21	39	52	65	82	98
Nevada Power	SW	Riley	RLY1211	600	429	439	442	445	450	456	461
Nevada Power	SW	Robindale	ROB1201	600	424	453	458	463	469	480	491
Nevada Power	SW	Robindale	ROB1203	600	155	163	164	165	167	170	173
Nevada Power	SW	Robindale	ROB1204	600	267	267	268	270	273	274	276
Nevada Power	SW	Robindale	ROB1206	600	336	351	368	386	392	406	420
Nevada Power	SW	Robindale	ROB1210	600	502	503	518	522	527	533	540
Nevada Power	SW	Robindale	ROB1212	600	334	373	382	392	399	415	431
Nevada Power	SW	Robindale	ROB1213	600	496	496	499	502	507	510	513
Nevada Power	SW	Robindale	ROB1214	600	320	531	599	665	726	828	930
Nevada Power	SW	Robindale	ROB1215	600	423	424	427	430	435	438	441
Nevada Power	SW	Robindale	ROB1217	600	389	408	418	429	439	452	464
Nevada Power	SW	Rosanna	RO1201	585	150	178	179	180	182	190	198
Nevada Power	SW	Rosanna	RO1203	585	300	315	316	318	322	327	332
Nevada Power	SW	Rosanna	RO1204	585	255	263	268	274	280	286	292
Nevada Power	SW	Rosanna	RO1207	600	333	334	336	338	341	343	345
Nevada Power	SW	Rosanna	RO1208	585	369	369	371	373	377	379	381
Nevada Power	SW	Rosanna	RO1210	530	339	340	342	344	348	350	352
Nevada Power	SW	Rosanna	RO1212	530	307	307	309	311	314	316	317
Nevada Power	SW	Sparta	SPA1205	600	477	522	524	528	533	548	562
Nevada Power	SW	Sparta	SPA1206	600	470	486	495	498	503	511	519
Nevada Power	SW	Sparta	SPA1210	600	379	379	381	384	388	390	392
Nevada Power	SW	Sparta	SPA1213	600	3	3	3	3	4	4	4
Nevada Power	SW	Sparta	SPA1214	600	292	341	361	364	368	387	406
Nevada Power	SW	Sparta	SPA1215	600	1	21	42	63	84	105	126
Nevada Power	SW	Sparta	SPA1217	600	162	205	249	291	332	374	416
Nevada Power	SW	Spring Mountain	SM1201	530	45	45	46	46	46	47	47
Nevada Power	SW	Spring Mountain	SM1202	530	176	176	177	178	180	181	182
Nevada Power	SW	Spring Valley	SV1201	585	324	336	338	340	343	348	353
Nevada Power	SW	Spring Valley	SV1202	585	271	285	287	289	292	297	302
Nevada Power	SW	Spring Valley	SV1207	585	175	175	176	177	179	180	181
Nevada Power	SW	Spring Valley	SV1209	585	428	446	448	451	455	462	469
Nevada Power	SW	Spring Valley	SV1211	585	377	377	379	382	385	388	390
Nevada Power	SW	Spring Valley	SV1213	585	257	257	258	260	263	264	266
Nevada Power	SW	Spring Valley	SV1214	585	410	410	412	415	419	422	424
Nevada Power	SW	Spring Valley	SV1216	530	348	348	350	353	356	358	360
Nevada Power	SW	Tam	TA1201	585	362	362	364	366	370	372	374
Nevada Power	SW	Tam	TA1202	530	122	122	123	124	125	126	126
Nevada Power	SW	Tam	TA1204	585	238	238	239	241	243	244	246
Nevada Power	SW	Tam	TA1205	585	344	344	345	348	351	353	355
Nevada Power	SW	Tam	TA1209	585	481	498	501	504	510	517	524
Nevada Power	SW	Tam	TA1210	585	383	386	388	391	395	398	401
Nevada Power	SW	Tam	TA1212	585	400	402	404	407	411	414	417
Nevada Power	SW	Tomsik	TOM1201	600	259	435	513	552	564	640	716
Nevada Power	SW	Tomsik	TOM1203	600	1	1	1	1	1	1	1
Nevada Power	SW	Tomsik	TOM1204	600	388	460	488	492	497	525	552

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Nevada Power	SW	Tomsik	TOM1210	600	262	300	323	327	331	348	365
Nevada Power	SW	Tomsik	TOM1211	600	363	390	413	437	458	481	505
Nevada Power	SW	Tomsik	TOM1212	600	425	426	429	433	437	441	444
Nevada Power	SW	Tomsik	TOM1213	600	469	471	475	480	487	491	495
Nevada Power	SW	Tomsik	TOM1214	600	462	469	480	490	497	506	515
Nevada Power	SW	Tomsik	TOM1215	600	1	1	1	1	1	1	1
Nevada Power	SW	Tomsik	TOM1217	600	445	445	447	450	455	457	460
Sierra	CAR	Brunswick	BWK1220	855	218	218	219	221	223	224	225
Sierra	CAR	Brunswick	BWK1223	855	232	232	233	234	237	238	239
Sierra	CAR	Brunswick	BWK1224	855	437	438	440	443	448	451	453
Sierra	CAR	Brunswick	BWK2508	550	319	319	320	323	326	328	329
Sierra	CAR	Buckeye	BUC1275	550	113	113	121	131	134	139	144
Sierra	CAR	Buckeye	BUC1276	550	507	510	513	516	522	526	530
Sierra	CAR	Buckeye	BUC1277	550	103	103	105	106	108	109	110
Sierra	CAR	Buckeye	BUC1278	550	299	300	302	304	307	309	311
Sierra	CAR	Carson	CAR1230	550	122	122	123	124	125	126	126
Sierra	CAR	Carson	CAR1231	550	353	359	360	363	367	370	373
Sierra	CAR	Carson	CAR1232	550	311	315	317	320	323	326	329
Sierra	CAR	Carson	CAR1233	550	1	1	1	1	1	1	1
Sierra	CAR	Carson	CAR1240	550	151	151	152	153	154	155	156
Sierra	CAR	Carson	CAR1241	550	182	182	183	184	186	187	188
Sierra	CAR	Carson	CAR1242	550	261	261	262	264	267	268	270
Sierra	CAR	Carson	CAR1243	550	255	256	257	260	263	265	267
Sierra	CAR	Coaldale	CLD1201	175	6	6	6	6	6	6	6
Sierra	CAR	Curry Street	CUR1280	550	439	455	457	460	465	471	478
Sierra	CAR	Curry Street	CUR1281	550	297	301	302	304	307	310	313
Sierra	CAR	Curry Street	CUR1282	550	177	177	177	179	180	181	182
Sierra	CAR	Dayton	DTN219	550	242	245	248	252	256	259	263
Sierra	CAR	Downs	DWN1285	550	307	326	333	341	350	361	372
Sierra	CAR	Downs	DWN1286	550	209	209	210	212	214	216	217
Sierra	CAR	Downs	DWN1287	550	1	1	1	1	1	1	1
Sierra	CAR	Emerson	EMN1221	550	272	272	273	275	278	280	281
Sierra	CAR	Emerson	EMN1222	550	259	259	260	262	265	266	268
Sierra	CAR	Emerson	EMN1223	550	328	328	330	332	335	337	339
Sierra	CAR	Emerson	EMN1224	550	222	222	223	224	227	228	229
Sierra	CAR	Fairview	FVW1210	550	343	343	345	347	351	353	355
Sierra	CAR	Fairview	FVW1211	550	144	144	144	145	147	148	148
Sierra	CAR	Fairview	FVW1212	940	389	389	392	395	399	402	404
Sierra	CAR	Fort Churchill	FTC210	550	90	90	91	91	92	93	93
Sierra	CAR	Gabbs	GBS47	550	120	120	121	121	123	123	124
Sierra	CAR	Gabbs	GBS48	1155	781	781	785	791	799	803	807
Sierra	CAR	Goldfield	GFD1264	350	25	25	25	25	25	26	26
Sierra	CAR	Hawthorne	HAW1201	350	107	107	107	108	109	110	110
Sierra	CAR	Hawthorne	HAW1202	350	140	140	141	142	143	144	145
Sierra	CAR	Heybourne	HEY1287	550	247	248	249	251	253	255	256
Sierra	CAR	Heybourne	HEY1288	855	321	321	323	325	328	330	332
Sierra	CAR	Heybourne	HEY1289	855	1	1	1	1	1	1	1
Sierra	CAR	Heybourne	HEY1290	550	91	103	103	104	105	109	112
Sierra	CAR	Lower Smoky Valley	LSV1260	175	33	33	33	33	34	34	34
Sierra	CAR	Luning	LUN7005	600	6	6	6	6	6	6	6
Sierra	CAR	Manhattan	MAN1201	350	20	20	20	20	20	21	21
Sierra	CAR	Mark Twain	MTW218	550	271	273	277	280	283	286	290
Sierra	CAR	Mark Twain	MTW220	550	283	283	285	287	290	292	293

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Sierra	CAR	Mason Valley	MNV2501	550	245	246	247	249	252	254	255
Sierra	CAR	Mason Valley	MNV2506	550	119	119	119	120	121	122	122
Sierra	CAR	Mason Valley	MNV2507	550	305	305	307	310	314	316	318
Sierra	CAR	Mason Valley	MNV2508	550	1	1	1	1	1	1	1
Sierra	CAR	Mina	MNA1202	350	6	6	6	6	6	6	6
Sierra	CAR	Mina	MNA1203	350	5	5	5	5	5	5	5
Sierra	CAR	Mina	MNA1204	170	2	2	2	2	2	2	2
Sierra	CAR	Minden	MIN1271	350	1	1	1	1	1	1	1
Sierra	CAR	Minden	MIN1272	550	121	121	122	123	124	124	125
Sierra	CAR	Minden	MIN1273	550	114	114	115	115	117	117	118
Sierra	CAR	Minden	MIN1275	550	1	1	1	1	1	1	1
Sierra	CAR	Muller	MUR1295	550	292	293	295	298	301	303	305
Sierra	CAR	Muller	MUR1296	855	528	540	542	546	552	557	563
Sierra	CAR	Overland	OVL1250	550	66	67	68	68	70	70	71
Sierra	CAR	Overland	OVL1260	550	1	1	1	1	1	1	1
Sierra	CAR	Overland	OVL1265	550	330	330	331	334	337	339	341
Sierra	CAR	Overland	OVL1270	855	160	185	186	188	190	198	205
Sierra	CAR	Pinenut	PNT1251	550	350	352	355	359	364	367	371
Sierra	CAR	Pinenut	PNT1252	600	1	1	1	1	1	1	1
Sierra	CAR	Pinenut	PNT1253	550	444	444	447	450	454	457	459
Sierra	CAR	Pinenut	PNT1254	550	382	388	393	396	400	405	409
Sierra	CAR	Round Mountain	RDM2220	350	112	169	170	171	173	188	204
Sierra	CAR	Round Mountain	RDM2221	1155	407	407	409	412	416	418	421
Sierra	CAR	Round Mountain	RDM2222	1155	233	233	234	236	238	239	241
Sierra	CAR	Sandia	SND1201	350	36	36	36	37	37	37	37
Sierra	CAR	Silver Peak	SVR203	350	50	50	50	50	51	51	51
Sierra	CAR	Silver Springs	SIL1211	550	279	279	281	283	285	287	289
Sierra	CAR	Silver Springs	SIL1212	550	63	64	64	65	66	67	67
Sierra	CAR	Smith Valley	SVL2501	550	112	112	113	114	116	117	118
Sierra	CAR	Smith Valley	SVL2502	550	37	38	39	39	40	41	42
Sierra	CAR	Smith Valley	SVL2504	550	52	52	53	53	53	54	54
Sierra	CAR	Smith Valley	SVL2506	550	127	127	128	128	130	130	131
Sierra	CAR	Stagecoach	STA217	265	54	54	55	55	56	56	57
Sierra	CAR	Stickleman	STK1201	350	42	42	42	42	43	43	43
Sierra	CAR	Topaz	TPZ1261	265	154	154	154	156	157	158	159
Sierra	CAR	Virginia City	VCY213	265	10	10	10	10	11	11	11
Sierra	CAR	Virginia City	VCY214	265	26	26	26	26	27	27	27
Sierra	CAR	Virginia City	VCY215	350	30	30	30	30	31	31	31
Sierra	CAR	West Tonopah	WTP1201	550	109	113	113	114	115	117	118
Sierra	CAR	West Tonopah	WTP1202	175	47	47	47	47	48	48	48
Sierra	CAR	West Tonopah	WTP1203	550	79	79	79	80	80	81	81
Sierra	EAST	Adobe	ADB201	550	48	48	48	49	49	49	50
Sierra	EAST	Adobe	ADB202	550	214	215	216	217	219	221	222
Sierra	EAST	Adobe	ADB203	570	63	63	64	64	65	65	66
Sierra	EAST	Adobe	ADB208	570	262	266	268	270	272	275	277
Sierra	EAST	Antelope Valley	ANV210	550	157	157	158	159	161	162	162
Sierra	EAST	Antelope Valley	ANV211	570	115	115	116	117	118	119	119
Sierra	EAST	Battle Mountain	BMT1401	265	224	224	225	226	229	230	231
Sierra	EAST	Battle Mountain	BMT1402	265	21	21	21	22	22	22	22
Sierra	EAST	Battle Mountain	BMT2401	550	30	30	30	30	31	31	31
Sierra	EAST	Big Springs	BSP213	550	1	1	1	1	1	1	1
Sierra	EAST	Buena Vista	BVV201	265	38	38	38	38	39	39	39
Sierra	EAST	Buena Vista	BVV202	600	1	1	1	1	1	1	1

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Sierra	EAST	Coal Canyon	CCN1201	365	68	68	69	69	70	70	71
Sierra	EAST	Coal Canyon	CCN1202	265	21	21	21	21	21	21	21
Sierra	EAST	Crescent Valley	CVL220	265	28	28	28	28	29	29	29
Sierra	EAST	Dutch Flat	DHF208	640	264	264	265	267	270	271	273
Sierra	EAST	Dutch Flat	DHF209	265	87	87	88	88	89	90	90
Sierra	EAST	Dutch Flat	DHF210	175	49	49	49	50	50	50	51
Sierra	EAST	Elko	EKO22	570	41	41	41	41	42	42	42
Sierra	EAST	Elko	EKO23	600	64	64	64	65	65	66	66
Sierra	EAST	Elko	EKO24	600	300	300	302	304	307	309	310
Sierra	EAST	Elko	EKO27	570	197	197	198	199	201	202	204
Sierra	EAST	Golconda	GOL1201	265	54	54	54	55	55	55	56
Sierra	EAST	Golconda	GOL1202	265	100	100	101	102	103	103	104
Sierra	EAST	Golconda	GOL1203	365	1	1	1	1	1	1	1
Sierra	EAST	Grass Valley	GRS2517	350	204	212	213	215	217	220	223
Sierra	EAST	Grass Valley	GRS2518	570	211	288	289	291	294	315	336
Sierra	EAST	Humboldt House	HBH701	600	6	6	6	6	7	7	7
Sierra	EAST	Imlay	ILY1201	365	104	104	104	105	106	107	107
Sierra	EAST	Last Chance	LCH178	550	1	1	1	1	1	1	1
Sierra	EAST	Last Chance	LCH211	550	361	361	363	366	369	371	373
Sierra	EAST	Last Chance	LCH212	550	181	181	182	184	185	186	187
Sierra	EAST	Last Chance	LCH218	550	310	312	314	316	319	322	324
Sierra	EAST	Last Chance	LCH221	550	212	212	213	214	216	217	219
Sierra	EAST	Limerick	LIM1201	175	54	54	54	55	55	56	56
Sierra	EAST	Lone Mountain^	LNM1201	315	37	37	38	38	38	38	39
Sierra	EAST	Lovelock	LOV1203	550	47	49	49	49	50	51	51
Sierra	EAST	Lovelock	LOV701	315	155	155	156	157	158	159	160
Sierra	EAST	Lovelock	LOV702	315	35	35	35	35	36	36	36
Sierra	EAST	Lovelock	LOV703	315	107	107	107	108	109	110	110
Sierra	EAST	McCoy Mine	MCY201	175	27	27	27	27	28	28	28
Sierra	EAST	North Valmy	NVY2401	175	2	2	2	2	2	2	2
Sierra	EAST	North Valmy	NVY2402	550	3	3	3	3	3	3	3
Sierra	EAST	North Valmy	NVY2403	600	48	48	48	49	49	49	50
Sierra	EAST	North Valmy	NVY2404	230	1	1	1	1	1	1	1
Sierra	EAST	Osgood Valley	OSG201	570	156	156	156	157	159	160	161
Sierra	EAST	Osgood Valley	OSG202	550	42	42	42	43	43	43	44
Sierra	EAST	Parran	PAR724	50	3	3	3	3	3	3	3
Sierra	EAST	Red House	RED1401	600	4	4	4	4	4	4	5
Sierra	EAST	Reese River	RRV230	265	78	78	78	79	80	80	81
Sierra	EAST	Reese River	RRV231	265	48	48	48	48	49	49	49
Sierra	EAST	Rose Creek	RCR201	175	66	66	66	67	67	68	68
Sierra	EAST	Rye Patch	RPH21	350	96	96	96	97	98	98	99
Sierra	EAST	Setty	STY2402	365	55	55	55	56	56	56	57
Sierra	EAST	Setty	STY251	550	17	17	17	17	17	17	17
Sierra	EAST	Sonoma Heights	SHT206	350	1	1	1	1	1	1	1
Sierra	EAST	Sonoma Heights	SHT21	570	185	185	186	187	189	190	191
Sierra	EAST	Sonoma Heights	SHT23	350	132	132	132	133	135	135	136
Sierra	EAST	Sonoma Heights	SHT704	570	33	33	33	33	33	34	34
Sierra	EAST	T Lazy S	TLS240	265	22	22	22	23	23	23	23
Sierra	EAST	Toulon	TLN701	170	8	8	8	8	8	8	8
Sierra	EAST	Winnemucca	WIN201	550	191	191	192	194	195	197	198
Sierra	EAST	Winnemucca	WIN202	550	1	1	1	1	1	1	1
Sierra	EAST	Winnemucca	WIN205	550	145	145	145	146	148	149	149
Sierra	EAST	Winnemucca	WIN206	550	118	118	119	119	121	121	122

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Sierra	EAST	Winnemucca	WIN701	600	3	3	3	3	3	3	3
Sierra	FF	Austin	AST201	570	70	70	70	71	71	72	72
Sierra	FF	Austin	AST202	570	25	25	25	26	26	26	26
Sierra	FF	Brady's	BDY201	175	17	17	17	17	17	17	18
Sierra	FF	Eagle	EGL1218	940	270	270	272	274	276	278	279
Sierra	FF	Eagle	EGL201	550	214	219	224	226	228	232	236
Sierra	FF	Eagle	EGL202	550	268	268	270	271	274	276	277
Sierra	FF	Empire	EMP7001	140	58	58	58	59	59	60	60
Sierra	FF	Fallon	FLN1201	570	264	265	266	268	271	272	274
Sierra	FF	Fallon	FLN1202	550	125	125	126	127	128	129	129
Sierra	FF	Fallon	FLN1203	570	249	249	250	252	254	256	257
Sierra	FF	Fallon	FLN309	600	1	1	1	1	1	1	1
Sierra	FF	Fallon	FLN310	600	18	18	18	18	18	18	19
Sierra	FF	Fernley	FLY1214	550	173	178	179	180	182	185	187
Sierra	FF	Fernley	FLY1215	940	261	265	267	269	271	274	276
Sierra	FF	Fernley	FLY1216	550	101	101	101	102	103	104	104
Sierra	FF	Fernley	FLY1217	940	202	203	204	206	208	209	211
Sierra	FF	Hazen	HAZ1210	265	13	13	13	13	14	14	14
Sierra	FF	Lonely	LNY1230	550	419	424	431	437	442	447	453
Sierra	FF	Lonely	LNY1231	550	239	241	245	249	253	257	260
Sierra	FF	Lonely	LNY1232	550	241	251	263	275	288	300	312
Sierra	FF	Lonely	LNY1233	550	247	249	252	256	261	264	268
Sierra	FF	Ray Couch	RYC1206	550	116	116	117	118	119	120	120
Sierra	FF	Ray Couch	RYC1207	550	172	172	173	174	176	176	177
Sierra	FF	Ray Couch	RYC1208	550	163	163	164	165	167	168	169
Sierra	FF	Wadsworth	WAD1221	365	113	113	113	114	115	116	116
Sierra	FF	Westside^	WES1211	550	258	328	399	431	436	480	524
Sierra	FF	Westside^	WES1212	550	107	107	108	109	110	110	111
Sierra	FF	Westside^	WES1213	550	63	63	63	63	64	64	65
Sierra	NTAH	Incline	INC4100	550	420	421	423	426	431	433	436
Sierra	NTAH	Incline	INC4200	550	420	420	422	425	430	432	434
Sierra	NTAH	Incline	INC4300	550	319	319	321	323	326	328	330
Sierra	NTAH	Truckee	TRK7202	315	22	22	22	23	23	23	23
Sierra	NTAH	Truckee	TRK7203	570	238	238	239	241	243	245	246
Sierra	NTAH	Truckee	TRK7204	570	101	101	102	102	103	104	105
Sierra	STAH	Glenbrook	GLN2302	570	118	118	119	119	121	121	122
Sierra	STAH	Glenbrook	GLN2505	175	16	16	16	16	17	17	17
Sierra	STAH	Glenbrook	GLN2600	175	13	13	13	14	14	14	14
Sierra	STAH	Kingsbury	KNG2800	570	410	410	412	415	419	421	424
Sierra	STAH	Round Hill	RDH1502	550	261	262	263	265	268	269	271
Sierra	STAH	Round Hill	RDH1503	550	331	336	341	343	347	351	354
Sierra	STAH	Round Hill	RDH1504	550	239	243	244	246	248	250	253
Sierra	STAH	Stateline	STL2001	600	1	1	1	1	1	1	1
Sierra	STAH	Stateline	STL2200	600	239	239	240	242	245	246	247
Sierra	STAH	Stateline	STL2300	600	232	232	234	235	238	239	240
Sierra	STAH	Stateline	STL3101	600	375	375	377	380	384	386	388
Sierra	STAH	Stateline	STL3501	600	222	222	224	225	227	229	230
Sierra	TM	Airport	AIR1	550	1	1	1	1	1	1	1
Sierra	TM	Airport	AIR2	600	1	1	1	1	1	1	1
Sierra	TM	Airport	AIR2006	550	69	69	69	70	71	71	71
Sierra	TM	Airport	AIR242	550	120	120	120	121	122	123	124
Sierra	TM	Airport	AIR265	550	253	253	255	256	259	260	262
Sierra	TM	Airport	AIR266	550	200	200	201	203	205	206	207

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Sierra	TM	Airport	AIR267	550	423	440	451	464	479	492	506
Sierra	TM	Airport	AIR269	550	212	229	244	250	253	263	273
Sierra	TM	Airport	AIR282	550	267	268	269	271	274	275	277
Sierra	TM	Airport	AIR283	550	90	90	90	91	92	92	93
Sierra	TM	Airport	AIR3	550	211	211	212	214	216	217	218
Sierra	TM	Airport	AIR4	550	215	215	216	217	219	221	222
Sierra	TM	Bella Vista	BLV271	550	437	437	439	442	447	449	452
Sierra	TM	Bella Vista	BLV282	550	225	225	226	227	230	231	232
Sierra	TM	Bella Vista	BLV283	550	107	107	107	108	109	110	110
Sierra	TM	Bella Vista	BLV284	855	671	671	675	680	687	691	695
Sierra	TM	California	CAL204	550	392	414	436	450	465	483	501
Sierra	TM	Chukar	CHK2506	855	112	112	112	113	114	115	115
Sierra	TM	El Rancho^	ELR1	384	130	130	131	132	133	134	134
Sierra	TM	El Rancho^	ELR2	550	0	0	0	0	0	0	0
Sierra	TM	Fort Sage	FTS299	570	3	3	3	3	3	3	3
Sierra	TM	Glendale	GLD211	550	374	377	379	381	385	388	391
Sierra	TM	Glendale	GLD237	550	108	108	109	110	111	111	112
Sierra	TM	Glendale	GLD238	315	86	86	86	87	88	88	89
Sierra	TM	Glendale	GLD245	550	151	151	151	153	154	155	156
Sierra	TM	Glendale	GLD265	550	145	145	145	147	148	149	150
Sierra	TM	Glendale	GLD271	550	251	251	252	254	256	258	259
Sierra	TM	Glendale	GLD274	550	433	441	447	450	455	460	465
Sierra	TM	Greg Street	GRG227	470	63	63	63	64	64	64	65
Sierra	TM	Greg Street	GRG228	470	430	458	460	463	468	478	487
Sierra	TM	Greg Street	GRG229	550	308	308	309	311	315	316	318
Sierra	TM	Greg Street	GRG231	550	206	209	210	211	214	215	217
Sierra	TM	Greg Street	GRG232	550	310	310	312	314	317	319	320
Sierra	TM	Greg Street	GRG233	550	407	418	423	428	435	443	450
Sierra	TM	Greg Street	GRG286	550	335	335	337	339	342	344	346
Sierra	TM	Greg Street	GRG287	550	197	200	201	202	204	206	208
Sierra	TM	Greg Street	GRG288	550	328	334	339	344	349	355	360
Sierra	TM	Highland^	HLD1	355	146	146	146	147	149	150	151
Sierra	TM	Highland^	HLD2	355	94	94	94	95	96	97	97
Sierra	TM	Highland^	HLD3	384	75	75	76	76	77	77	78
Sierra	TM	Highland^	HLD4	550	61	61	61	62	62	63	63
Sierra	TM	Holcomb	HOL1	310	1	1	1	1	1	1	1
Sierra	TM	Holcomb	HOL2	310	231	231	232	233	236	237	238
Sierra	TM	Holcomb	HOL3	350	1	1	1	1	1	1	1
Sierra	TM	Holcomb	HOL4	350	212	212	213	214	216	218	219
Sierra	TM	Holcomb	HOL5	384	179	179	180	181	183	184	185
Sierra	TM	Holcomb	HOL6	384	194	194	195	196	198	199	200
Sierra	TM	Hunter Lake	HLS1	475	205	205	206	208	210	211	212
Sierra	TM	Hunter Lake	HLS2	475	153	153	154	155	157	157	158
Sierra	TM	Hunter Lake	HLS3	475	282	282	283	285	288	290	291
Sierra	TM	Hunter Lake	HLS4	475	1	1	1	1	1	1	1
Sierra	TM	Hunter Lake	HLS6	384	91	91	91	92	93	94	94
Sierra	TM	McCarran	MCN1	550	383	383	385	387	391	393	396
Sierra	TM	McCarran	MCN2	550	214	214	215	217	219	220	221
Sierra	TM	Mill Street	MIL1	475	129	129	130	131	132	133	134
Sierra	TM	Mill Street	MIL2	384	48	48	48	49	49	49	50
Sierra	TM	Mill Street	MIL3	475	240	240	241	242	245	246	247
Sierra	TM	Mira Loma	MIR290	550	425	427	431	436	443	447	451
Sierra	TM	Mira Loma	MIR291	550	270	294	316	334	347	366	385

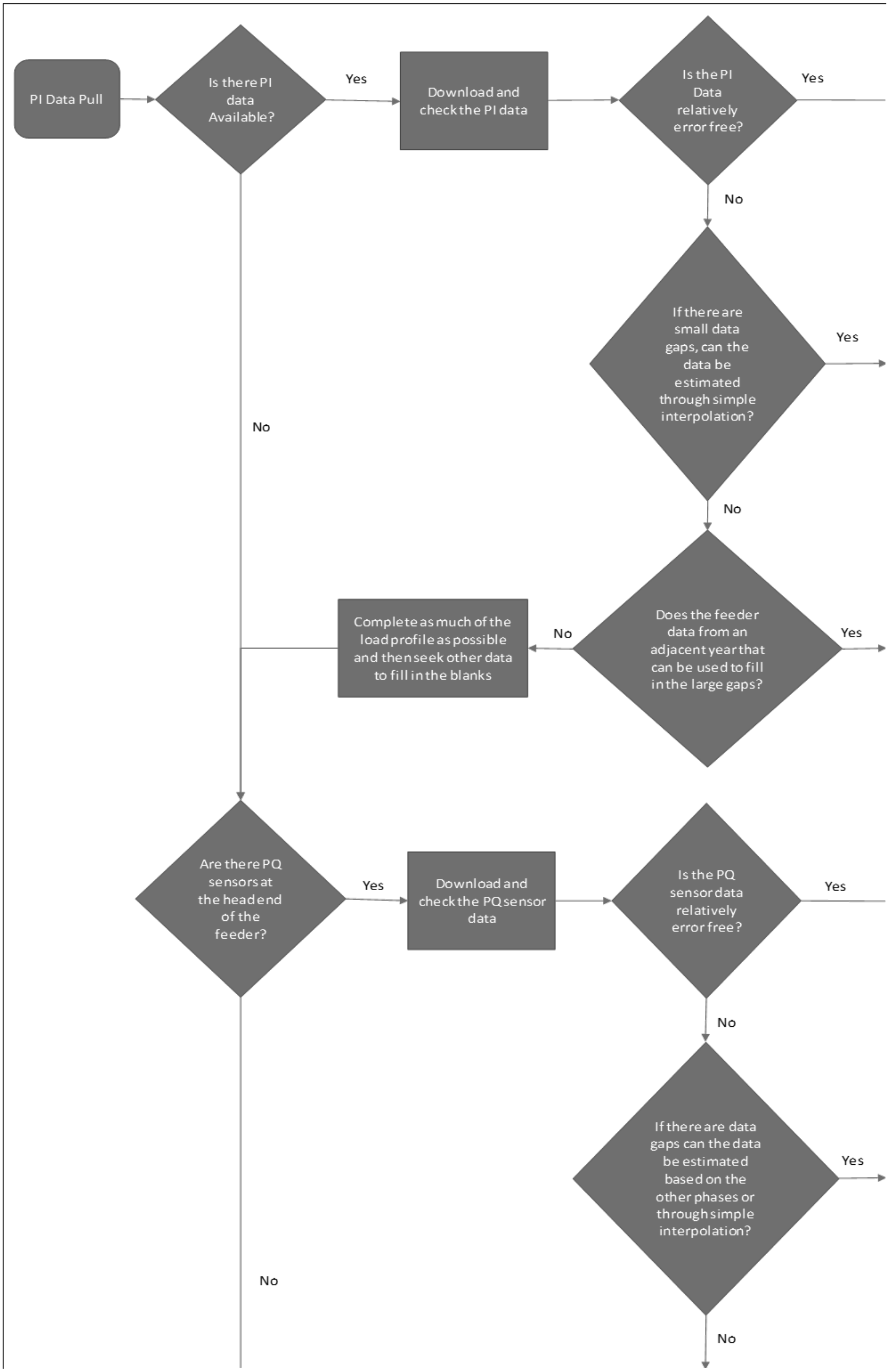
NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

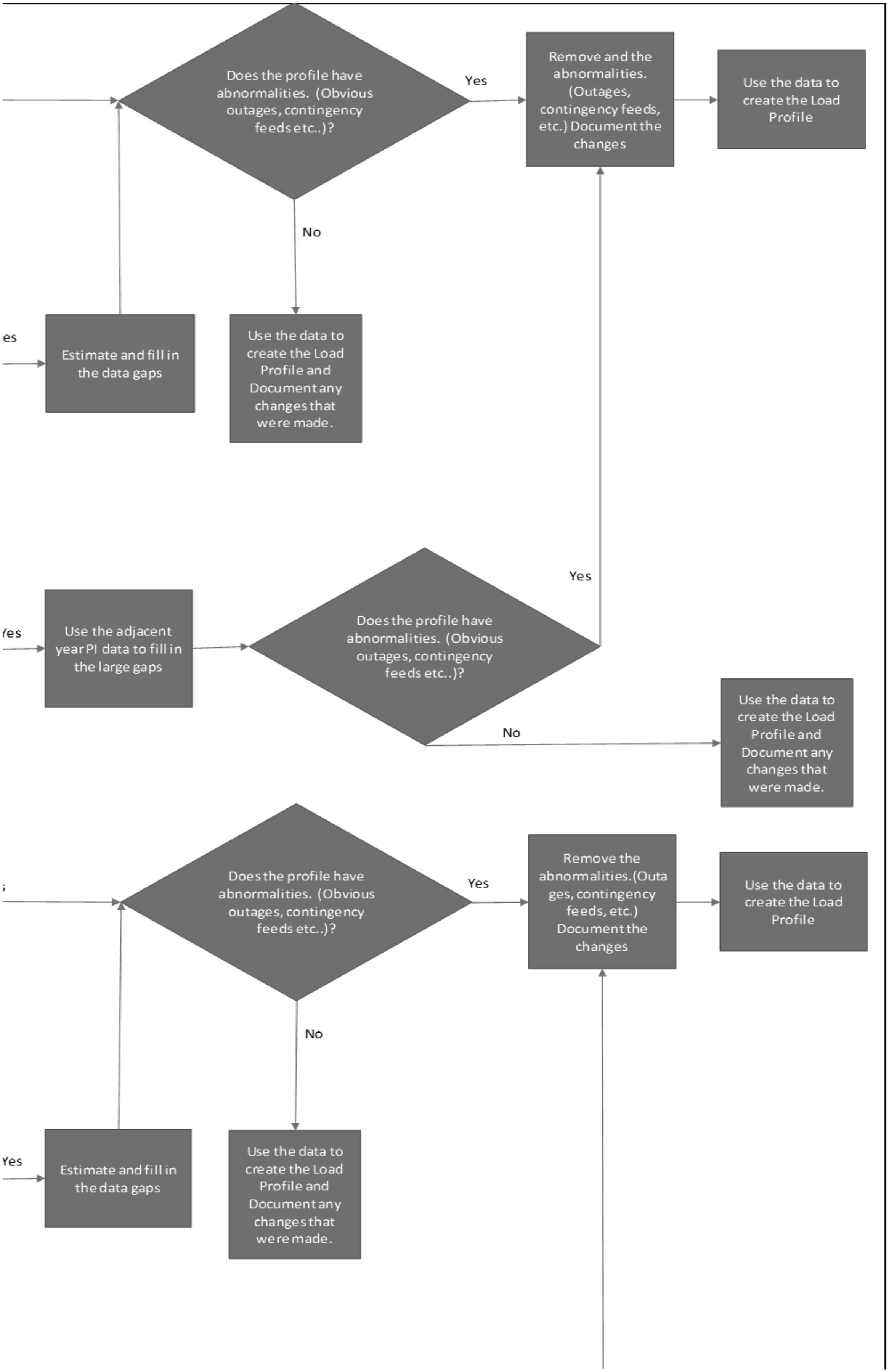
Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Sierra	TM	Mira Loma	MIR292	550	459	479	494	507	521	536	552
Sierra	TM	Moana	MOA2	384	1	1	1	1	1	1	1
Sierra	TM	Moana	MOA3	475	305	305	307	309	312	314	315
Sierra	TM	Moana	MOA4	480	1	1	1	1	1	1	1
Sierra	TM	Mount Rose	MTR203	570	226	230	234	235	238	241	243
Sierra	TM	Mount Rose	MTR210	550	134	135	136	137	138	140	141
Sierra	TM	Mount Rose	MTR242	855	294	297	301	303	306	309	313
Sierra	TM	Mount Rose	MTR243	855	233	233	234	236	239	241	242
Sierra	TM	Mount Rose	MTR282	550	322	326	331	337	344	349	355
Sierra	TM	North Red Rock	NRR280	550	147	167	188	207	220	238	256
Sierra	TM	North Red Rock	NRR281	550	291	306	317	330	333	343	354
Sierra	TM	Northwest^	NOW206	550	165	176	177	178	180	184	188
Sierra	TM	Northwest^	NOW207	550	337	344	350	357	365	373	380
Sierra	TM	Northwest^	NOW208	550	326	334	343	351	359	367	375
Sierra	TM	Northwest^	NOW216	550	425	425	428	431	435	437	440
Sierra	TM	Northwest^	NOW218	550	191	200	204	209	214	220	226
Sierra	TM	Northwest^	NOW244	550	389	418	420	423	428	437	447
Sierra	TM	Patrick	PAT224	855	87	87	87	88	89	89	90
Sierra	TM	Patrick	PAT225	855	775	991	996	1003	1013	1073	1132
Sierra	TM	Patrick	PAT226	550	533	581	584	588	594	609	624
Sierra	TM	Pyramid	PYD1	550	280	280	281	283	286	288	289
Sierra	TM	Pyramid	PYD2	550	136	136	136	137	139	139	140
Sierra	TM	Pyramid	PYD3	384	89	89	89	90	91	91	92
Sierra	TM	Pyramid	PYD4	384	6	6	6	6	6	6	6
Sierra	TM	Reno	RNO1	550	104	104	105	105	106	107	107
Sierra	TM	Reno	RNO204	570	103	106	108	109	110	111	113
Sierra	TM	Reno	RNO216	550	157	157	158	159	160	161	162
Sierra	TM	Reno	RNO217	170	5	5	5	5	5	5	5
Sierra	TM	Reno	RNO240	550	382	383	386	389	393	395	398
Sierra	TM	Reno	RNO243	570	238	239	241	244	248	251	253
Sierra	TM	Reno	RNO247	560	214	214	215	216	218	219	221
Sierra	TM	Reno	RNO263	560	253	253	254	256	258	260	261
Sierra	TM	Reno	RNO285	550	196	198	201	203	205	207	209
Sierra	TM	Reno	RNO4	384	101	101	101	102	103	103	104
Sierra	TM	Reno	RNO6	384	0	0	0	0	0	0	0
Sierra	TM	Rusty Spike	RSK221	550	61	63	65	65	66	67	68
Sierra	TM	Rusty Spike	RSK254	550	463	463	466	469	473	476	479
Sierra	TM	Rusty Spike	RSK260	550	207	207	208	209	211	212	213
Sierra	TM	Silver Lake	SLK255	550	469	476	485	495	503	512	520
Sierra	TM	Silver Lake	SLK256	550	237	237	238	240	242	244	245
Sierra	TM	Silver Lake	SLK257	550	263	263	264	266	269	270	271
Sierra	TM	Silver Lake	SLK258	550	327	406	448	472	481	519	558
Sierra	TM	Silver Lake	SLK259	550	1	1	1	1	1	1	1
Sierra	TM	South Meadows	SMD2503	600	313	360	402	445	452	487	522
Sierra	TM	Spanish Springs	SSP270	855	418	420	422	425	430	433	436
Sierra	TM	Spanish Springs	SSP271	550	309	309	311	313	316	318	320
Sierra	TM	Spanish Springs	SSP272	550	328	328	330	332	335	337	339
Sierra	TM	Spanish Springs	SSP273	855	618	667	701	714	728	756	783
Sierra	TM	Spanish Springs	SSP274	550	176	187	187	189	191	194	198
Sierra	TM	Spanish Springs	SSP275	855	800	833	847	853	861	877	892
Sierra	TM	Sparks Industrial	SID211	550	1	1	1	1	1	1	1
Sierra	TM	Sparks Industrial	SID229	550	1	1	1	1	1	1	1
Sierra	TM	Sparks Industrial	SID261	550	220	236	244	246	248	256	263

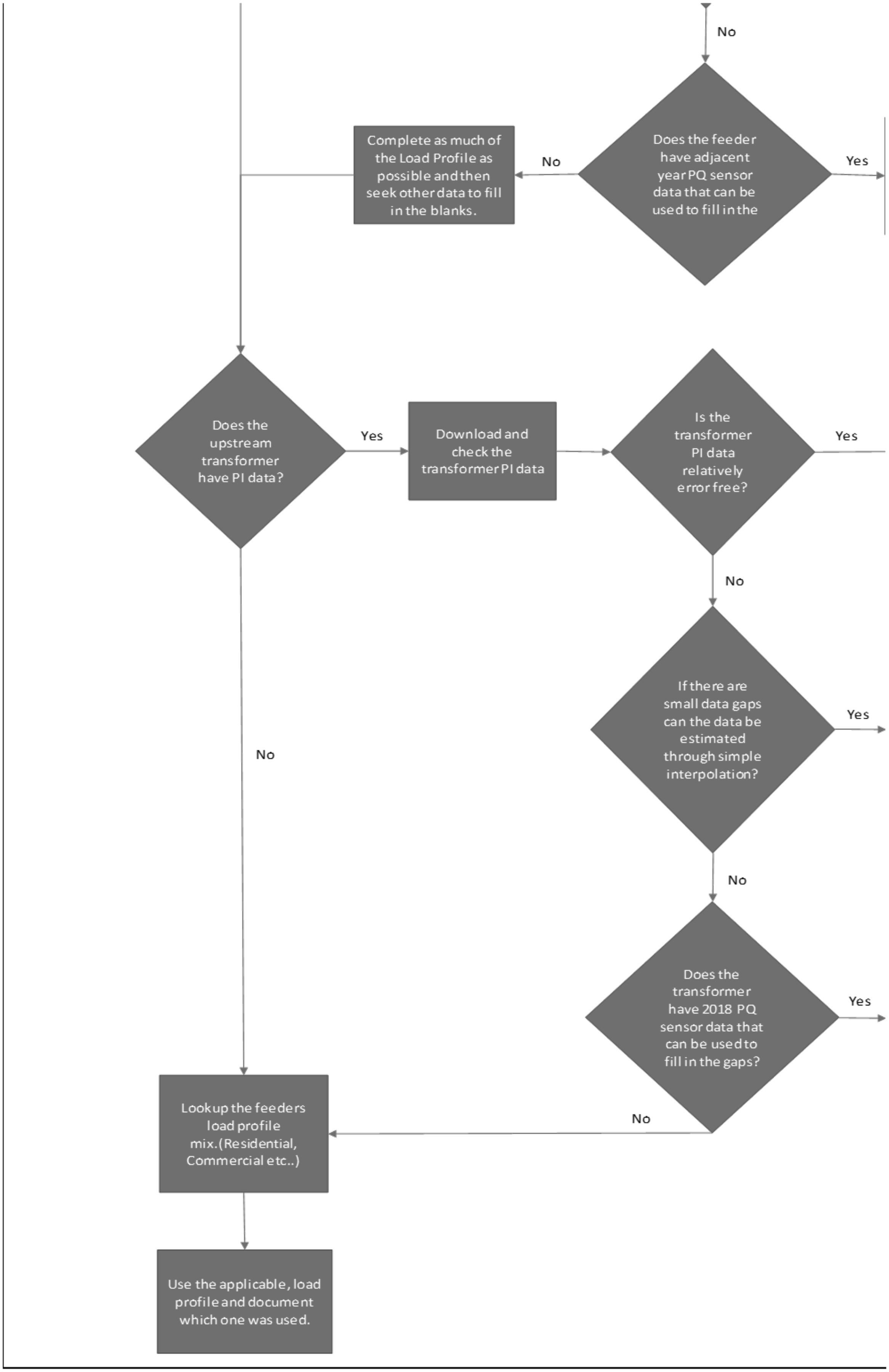
NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY FEEDER FORECAST

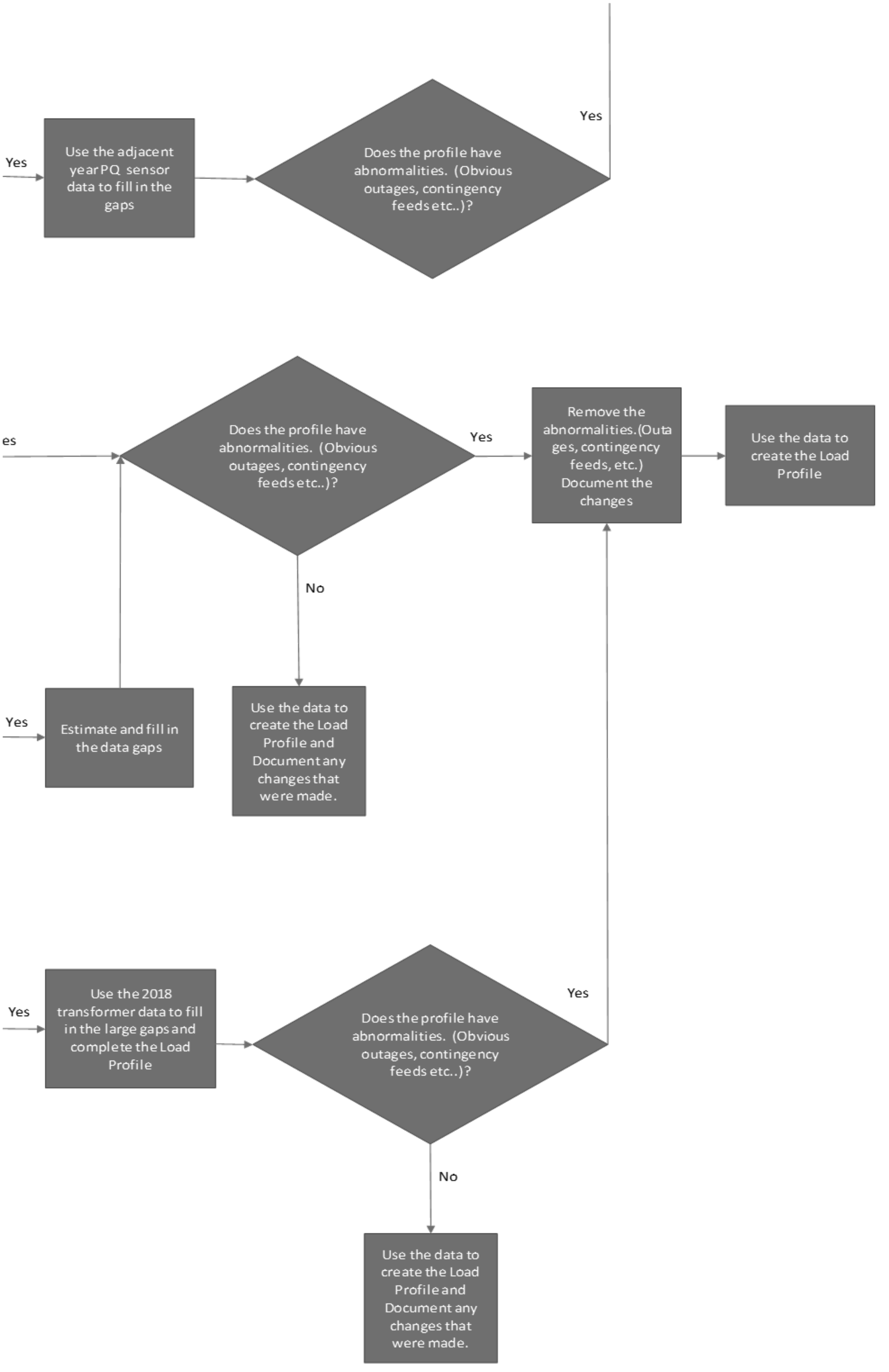
Company	Area	Substation	Feeder	Rating (amps)	2019	2020	2021	2022	2023	2024	2025
Sierra	TM	Sparks Industrial	SID274	274	1	1	1	1	1	1	1
Sierra	TM	Stead	STD255	550	1	1	1	1	1	1	1
Sierra	TM	Stead	STD257	550	9	13	16	17	17	19	20
Sierra	TM	Stead	STD259	550	100	100	101	102	103	103	104
Sierra	TM	Steamboat	STM210	570	313	313	315	317	321	323	325
Sierra	TM	Steamboat	STM212	570	381	387	389	392	396	400	404
Sierra	TM	Steamboat	STM213	550	282	282	283	285	288	290	291
Sierra	TM	Steamboat	STM214	550	186	199	201	204	208	213	218
Sierra	TM	Steamboat	STM215	550	477	556	596	605	613	647	681
Sierra	TM	Steamboat	STM219	315	1	1	1	1	1	1	1
Sierra	TM	Steamboat	STM268	570	379	402	423	442	451	469	487
Sierra	TM	Sugarloaf	SLF301	550	129	156	179	193	202	221	239
Sierra	TM	Sugarloaf	SLF302	940	684	717	744	760	769	790	812
Sierra	TM	Sugarloaf	SLF303	940	432	448	454	459	465	474	482
Sierra	TM	Sugarloaf	SLF304	550	96	96	96	97	98	99	99
Sierra	TM	Sutro	SUT211	550	1	1	1	1	1	1	1
Sierra	TM	Sutro	SUT241	480	107	110	111	112	113	114	116
Sierra	TM	Sutro	SUT246	550	84	84	84	85	86	86	87
Sierra	TM	Tracy	TCY277	150	77	77	78	78	79	79	80
Sierra	TM	Tracy	TCY278	550	75	75	75	75	76	77	77
Sierra	TM	University	UNV1	475	1	1	1	1	1	1	1
Sierra	TM	University	UNV2	475	135	135	136	137	138	139	140
Sierra	TM	Valley Road	VAL244	395	7	7	7	7	7	8	8
Sierra	TM	Valley Road	VAL246	470	281	281	282	284	287	289	290
Sierra	TM	Valley Road	VAL248	395	279	279	280	282	285	287	288
Sierra	TM	Valley Road	VAL249	550	395	420	443	450	458	473	489
Sierra	TM	Valley Road	VAL251	395	184	188	189	191	193	195	197
Sierra	TM	Valley Road	VAL254	395	41	41	41	41	42	42	42
Sierra	TM	Valley Road	VAL262	470	398	402	404	407	411	414	417
Sierra	TM	Verdi PH	VRD204	175	1	1	1	1	1	1	1
Sierra	TM	Washoe PH	WSO201	150	56	56	57	57	58	58	58
Sierra	TM	Washoe PH	WSO203	550	1	1	1	1	1	1	1
Sierra	TM	Washoe PH	WSO204	550	1	1	1	1	1	1	1
Sierra	TM	West 7th Street	WST1	550	306	306	307	309	312	314	316
Sierra	TM	West 7th Street	WST2	550	194	194	195	197	199	200	201
Sierra	TM	Wheeler	WLR2	475	422	422	424	427	431	433	436

DRP-3


PI Data Pull
Is there PI data Available?
Yes
No
Download and check the PI data
Is the PI Data relatively error free?
Yes
No
If there are small data gaps, can the data be estimated through simple interpolation?
Yes
No
Does the feeder data from an adjacent year that can be used to fill in the large gaps?
Yes
No
Complete as much of the load profile as possible and then seek other data to fill in the blanks
Are there PQ sensors at the head end of the feeder?
Yes
No
Download and check the PQ sensor data
Is the PQ sensor data relatively error free?
Yes
No
If there are data gaps can the data be estimated based on the other phases or through simple interpolation?
Yes
No


Does the profile have abnormalities. (Obvious outages, contingency feeds etc..)?
Yes
Remove and the abnormalities. (Outages, contingency feeds, etc.) Document the changes
Use the data to create the Load Profile
No
es
Estimate and fill in the data gaps
Use the data to create the Load Profile and Document any changes that were made.
Yes
/es
Use the adjacent year PI data to fill in the large gaps
Does the profile have abnormalities. (Obvious outages, contingency feeds etc..)?
No
Use the data to create the Load Profile and Document any changes that were made.
Does the profile have abnormalities. (Obvious outages, contingency feeds etc..)?
Yes
Remove the abnormalities.(Outages, contingency feeds, etc.) Document the changes
Use the data to create the Load Profile
No
Yes
Estimate and fill in the data gaps
Use the data to create the Load Profile and Document any changes that were made.


No
Does the feeder have adjacent year PQ sensor data that can be used to fill in the
Yes
No
Complete as much of the Load Profile as possible and then seek other data to fill in the blanks.
Does the upstream transformer have PI data?
Yes
Download and check the transformer PI data
Is the transformer PI data relatively error free?
Yes
No
If there are small data gaps can the data be estimated through simple interpolation?
Yes
No
No
Does the transformer have 2018 PQ sensor data that can be used to fill in the gaps?
Yes
No
Lookup the feeders load profile mix.(Residential, Commercial etc..)
Use the applicable, load profile and document which one was used.


Yes
Use the adjacent year PQ sensor data to fill in the gaps
Does the profile have abnormalities. (Obvious outages, contingency feeds etc..)?
Yes
es
Does the profile have abnormalities. (Obvious outages, contingency feeds etc..)?
Yes
Remove the abnormalities.(Outages, contingency feeds, etc.) Document the changes
Use the data to create the Load Profile
No
Yes
Estimate and fill in the data gaps
Use the data to create the Load Profile and Document any changes that were made.
Yes
Use the 2018 transformer data to fill in the large gaps and complete the Load Profile
Does the profile have abnormalities. (Obvious outages, contingency feeds etc..)?
Yes
No
Use the data to create the Load Profile and Document any changes that were made.

DRP-4

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
North-East	400005Z	Mill Iron				Y	
South-SW	AD1202	AD BK 4	Y				Replaced with 2018 data due to bad PI data
South-SW	AD1203	AD BK 4	Y				Load profile was changed, removed bad/abnormal data
South-SW	AD1204	AD BK 4	Y				Load profile was changed, removed bad/abnormal data
South-SW	AD1205	AD BK 5	Y				Load profile was changed, removed bad/abnormal data
South-SW	AD1206	AD BK 5	Y				Load profile was changed, removed bad/abnormal data
South-SW	AD1207	AD BK 5	Y				Load profile was changed, removed bad/abnormal data
North-East	ADB201	Adobe	Y				Load profile was changed, removed bad/abnormal data
North-East	ADB202	Adobe	Y				Load profile was changed, removed bad/abnormal data
North-East	ADB203	Adobe	Y				Load profile was changed, removed bad/abnormal data
North-East	ADB208	Adobe	Y				Load profile was changed, removed bad/abnormal data
North-TM	AIR1	Airport				Y	
North-TM	AIR242	Airport	Y				Load profile was changed, removed bad/abnormal data
North-TM	AIR265	Airport	Y				Load profile was changed, removed bad/abnormal data
North-TM	AIR266	Airport	Y				
North-TM	AIR267	Airport	Y				Load profile was changed, removed bad/abnormal data
North-TM	AIR269	Airport	Y				
North-TM	AIR282	Airport	Y				
North-TM	AIR283	Airport	Y				
North-TM	AIR3	Airport				Y	
North-TM	AIR4	Airport		Y		Y	Generic profile used for part of year
South-NE	AL1202	AL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1203	AL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1205	AL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1208	AL BK 4	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1209	AL BK 4	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1210	AL BK 5	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1212	AL BK 5	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1213	AL BK 5	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1214	AL BK 5	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1217	AL BK 6	Y				Load profile was changed, removed bad/abnormal data
South-NE	AL1218	AL BK 6	Y				Load profile was changed, removed bad/abnormal data
Carson	ALK701	Alkali				Y	
South-NE	ALN1201	ALN BK 1	Y				
South-NE	ALN1203	ALN BK 1	Y				
South-NE	ALN1205	ALN BK 2	Y				
South-NE	ALN1206	ALN BK 2	Y				
South-NE	ALN1210	ALN BK 2	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-NE	ALN1212	ALN BK 2	Y				
South-NE	ALN1213	ALN BK 2	Y				
South-NE	ALN1214	ALN BK 3	Y				
South-NE	ALN1215	ALN BK 3	Y				
South-NE	ALN1217	ALN BK 3	Y				
Carson	ANC204	Anaconda	Y				Load profile was changed, removed bad/abnormal data
Carson	ANC205	Anaconda	Y				Load profile was changed, removed bad/abnormal data
South-NE	AND1204	AND BK 1	Y				
South-NE	AND1207	AND BK 2	Y				
South-NE	AND1209	AND BK 2	Y				
South-NE	AND1212	AND BK 2	Y				
South-NE	AND1213	AND BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	AND1217	AND BK 2	Y				
South-SE	ANT1201	ANT BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	ANT1203	ANT BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	ANT1204	ANT BK 1	Y				
South-SE	ANT1205	ANT BK 2	Y				
South-SE	ANT1206	ANT BK 2				Y	
South-SE	ANT1207	ANT BK 2	Y				
South-SE	ANT1209	ANT BK 2	Y				
South-SE	ANT1212	ANT BK 2	Y				
South-SE	ANT1213	ANT BK 2	Y				
South-SE	ANT1214	ANT BK 3	Y				
North-East	ANV210	Antelope Valley			Y		
North-East	ANV211	Antelope Valley			Y		
South-NW	AP3402	AP BK 2		Y			Approximated Phase C data based on hourly average of phase A and B
South-NW	AP401	AP BK 1		Y			Approximated current data to fill in gaps
South-NW	AP402	AP BK 1				Y	
South-NW	AP403	AP BK 1		Y			Load profile was changed, removed bad/abnormal data
South-NE	AR1202	AR BK 2	Y				
South-NE	AR1203	AR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	AR1204	AR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	AR1206	AR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	AR1208	AR BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	AR1210	AR BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	AR1211	AR BK 4	Y				Load profile was changed, removed bad/abnormal data
South-NE	AR1213	AR BK 4	Y				
South-NE	AR1214	AR BK 4	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-NE	AR1215	AR BK 4	Y				Load profile was changed, removed bad/abnormal data
North-East	AST201	Austin	Y				
North-East	AST202	Austin	Y				Load profile was changed, removed bad/abnormal data
Carson	ATC41	Atomic				Y	
South-SW	AVR1205	AVR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	AVR1206	AVR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	AVR1208	AVR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	AVR1209	AVR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	AVR1210	AVR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	AVR1215	AVR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	AVR1216	AVR BK 2	Y				
South-SW	AVR1217	AVR BK 2	Y				
South-SW	AVR1228	AVR BK 2	Y				
South-SW	AVR1220	AVR BK 2	Y				
South-SW	AVR1221	AVR BK 2	Y				
South-SE	BB1201	BB BK 1		Y			Replaced missing phase information based on the other phases
South-SE	BCT1201	BCT BK 1	Y				
South-SE	BCT1203	BCT BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	BCT1204	BCT BK 1	Y				
South-SE	BCT1205	BCT BK 2	Y				
South-SE	BCT1210	BCT BK 2	Y				
South-SE	BCT1211	BCT BK 2	Y				
South-SE	BCT1213	BCT BK 2	Y				
South-SE	BCT1214	BCT BK 2	Y				
South-SE	BCT1215	BCT BK 2	Y				
South-SE	BCT1217	BCT BK 2	Y				
South-SE	BGB2501	BGB BK 1			Y		
South-SE	BGB2507	BGB BK 2			Y		
North-East	BHS201	Bradys Hot Springs				Y	
North-TM	BKY4201	Brockway				Y	
North-TM	BKY4202	Brockway				Y	
North-TM	BKY5100	Brockway				Y	
North-TM	BKY5200	Brockway				Y	
South-SE	BL1201	BL BK 1			Y		
South-SE	BL1203	BL BK 1			Y		
South-SE	BL1204	BL BK 1			Y		
South-SE	BL1207	BL BK 2			Y		
South-SE	BL1208	BL BK 2			Y		

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SE	BL1209	BL BK 3			Y		
South-SE	BL1210	BL BK 3			Y		
South-SE	BL1211	BL BK 3			Y		
South-NW	BLT1213	BLT BK 4	Y				Load profile was changed, removed bad/abnormal data
South-NW	BLT1214	BLT BK 4	Y				Load profile was changed, removed bad/abnormal data
South-NW	BLT1218	BLT BK 4	Y				Load profile was changed, removed bad/abnormal data
South-NW	BLT1219	BLT BK 4	Y				Load profile was changed, removed bad/abnormal data
South-NW	BLT1223	BLT BK 4	Y				Load profile was changed, removed bad/abnormal data
North-TM	BLV271	Bella Vista	Y				Load profile was changed, removed bad/abnormal data
North-TM	BLV282	Bella Vista	Y				
North-TM	BLV283	Bella Vista	Y				
North-TM	BLV284	Bella Vista	Y				Load profile was changed, removed bad/abnormal data
North-East	BMT1401	Battle Mountain	Y				Load profile was changed, removed bad/abnormal data
North-East	BMT1402	Battle Mountain	Y				
North-East	BMT2401	Battle Mountain			Y		Load profile was changed, removed bad/abnormal data
Carson	BRG205	Bridge Street				Y	PI tags no longer valid, used generic profile
Carson	BRG206	Bridge Street				Y	PI tags no longer valid, used generic profile
Carson	BRG208	Bridge Street				Y	PI tags no longer valid, used generic profile
South-SE	BRN1201	BRN BK 1	Y				
South-SE	BRN1202	BRN BK 1	Y				
South-SE	BRN1204	BRN BK 1	Y				
South-SE	BRN1205	BRN BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	BRN1206	BRN BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	BRN1209	BRN BK 2	Y				
South-SE	BRN1210	BRN BK 2	Y				
South-SE	BRN1211	BRN BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SE	BRN1212	BRN BK 3	Y				
South-SE	BRN1214	BRN BK 3	Y				Load profile was changed, removed bad/abnormal data
Carson	BUC1275	Buckeye	Y			Y	Load profile was changed, removed bad/abnormal data
Carson	BUC1276	Buckeye	Y			Y	Load profile was changed, removed bad/abnormal data
Carson	BUC1277	Buckeye	Y				
Carson	BUC1278	Buckeye	Y			Y	Load profile was changed, removed bad/abnormal data
North-East	BVV201	Buena Vista Valley		Y			Load profile was changed, removed bad/abnormal data
North-East	BVV202	Buena Vista Valley				Y	
Carson	BWK1291	Brunswick	Y			Y	Load profile was changed, removed bad/abnormal data
Carson	BWK1292	Brunswick	Y			Y	Load profile was changed, removed bad/abnormal data
Carson	BWK1293	Brunswick	Y			Y	Load profile was changed, removed bad/abnormal data
Carson	BWK216	Brunswick	Y			Y	Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-NE	CA1201	CA BK 5	Y				
South-NE	CA1203	CA BK 5	Y				
South-NE	CA1207	CA BK 6	Y				
South-NE	CA1208	CA BK 6	Y				
South-NE	CA1209	CA BK 7	Y				Load profile was changed, removed bad/abnormal data
South-NE	CA1211	CA BK 7	Y				Load profile was changed, removed bad/abnormal data
South-NE	CA1212	CA BK 7	Y				
South-NE	CA1213	CA BK 8	Y				
South-NE	CA1215	CA BK 8	Y				
South-NE	CA1220	CA BK 9	Y				Load profile was changed, removed bad/abnormal data
South-NE	CA1221	CA BK 9	Y				
North-TM	CAL204	California			Y		
Carson	CAN202	Candelaria				Y	
Carson	CAR1230	Carson	Y				Load profile was changed, removed bad/abnormal data
Carson	CAR1231	Carson	Y				Load profile was changed, removed bad/abnormal data
Carson	CAR1232	Carson	Y			Y	Load profile was changed, removed bad/abnormal data
Carson	CAR1240	Carson	Y			Y	Load profile was changed, removed bad/abnormal data
Carson	CAR1241	Carson	Y			Y	Load profile was changed, removed bad/abnormal data
Carson	CAR1242	Carson	Y				
Carson	CAR1243	Carson	Y			Y	Load profile was changed, removed bad/abnormal data
South-SE	CB1201	CB BK 1				Y	
South-SE	CB1202	CB BK 1				Y	
South-SE	CB1204	CB BK 1				Y	
South-SE	CB1205	CB BK 2			Y		Load profile was changed, removed bad/abnormal data
South-SE	CB1206	CB BK 2			Y		Load profile was changed, removed bad/abnormal data
South-SE	CB1209	CB BK 2			Y		Load profile was changed, removed bad/abnormal data
South-SE	CB1210	CB BK 2			Y		Load profile was changed, removed bad/abnormal data
South-SE	CB1211	CB BK 3			Y		Load profile was changed, removed bad/abnormal data
South-SE	CB1212	CB BK 3			Y		Load profile was changed, removed bad/abnormal data
South-SE	CB1214	CB BK 3			Y		Load profile was changed, removed bad/abnormal data
North-East	CBH1401	C-Punch				Y	
South-NW	CC1202	CC BK 2	Y	Y			Load profile was changed, removed bad/abnormal data
South-NW	CC1206	CC BK 2	Y				Load profile was changed, removed bad/abnormal data
North-East	CCN1201	Coal Canyon		Y			Load profile was changed, removed bad/abnormal data
North-East	CCN1202	Coal Canyon		Y			Load profile was changed, removed bad/abnormal data
South-SE	CCT1202	CCT BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	CCT1207	CCT BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	CCT1211	CCT BK 2	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SE	CCT1212	CCT BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	CCT1214	CCT BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	CCT1216	CCT BK 2	Y				
South-SE	CCT1217	CCT BK 2	Y				
North-TM	CEM41	Cemetery				Y	
North-TM	CEM42	Cemetery				Y	
South-NW	CHN1202	CHN BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	CHN1204	CHN BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	CHN1205	CHN BK 2	Y				
South-NW	CHN1207	CHN BK 2	Y				
South-NW	CHN1208	CHN BK 2	Y				
South-NW	CHN1210	CHN BK 2	Y				
South-NW	CHN1211	CHN BK 3	Y				
South-NW	CHN1212	CHN BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	CHN1214	CHN BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	CHR1201	CHR BK 1			Y		
South-NW	CHR1202	CHR BK 1		Y			
South-STRIP	CM1202	CM BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CM1204	CM BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CM1205	CM BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CM1209	CM BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CM1211	CM BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CM1212	CM BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CM1223	CM BK 3	Y				
South-STRIP	CM1224	CM BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CM1225	CM BK 3	Y				
South-STRIP	CM1228	CM BK 4	Y				
South-STRIP	CM1229	CM BK 4	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CM1230	CM BK 4	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CM1231	CM BK 4	Y				Load profile was changed, removed bad/abnormal data
South-SW	CMO1205	CMO BK 2	Y				
South-SW	CMO1206	CMO BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	CMO1212	CMO BK 2	Y				
South-NW	CN3401	CN BK 1		Y			Load profile was changed, removed bad/abnormal data
South-STRIP	COM1205	COM BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	COM1207	COM BK 1	Y				
South-STRIP	COM1216	COM BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	COM1218	COM BK 2	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-STRIP	COM1219	COM BK 2	Y				
South-STRIP	CON1201	CON BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CON1203	CON BK 1	Y				
South-STRIP	CON1204	CON BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CON1205	CON BK 2	Y				
South-STRIP	CON1206	CON BK 2	Y				
South-STRIP	CON1209	CON BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CON1211	CON BK 2	Y				
South-STRIP	CON1212	CON BK 2	Y				
South-STRIP	CON1213	CON BK 2	Y				
South-STRIP	CON1214	CON BK 3	Y				
South-STRIP	CON1215	CON BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	CON1217	CON BK 3	Y				Load profile was changed, removed bad/abnormal data
North-East	COR21	Coeur				Y	
South-NE	CR1201	CR BK 1	Y				
South-NE	CR1203	CR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NE	CR1204	CR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NE	CR1205	CR BK 2	Y				
South-NE	CR1206	CR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	CR1208	CR BK 2	Y				
South-NE	CR1209	CR BK 2	Y				
South-NE	CR1211	CR BK 3	Y				
South-NE	CR1212	CR BK 3	Y				
South-NE	CR1213	CR BK 3	Y				
Carson	CUR1280	Curry Street		Y			Used all 2018 data that was available
Carson	CUR1281	Curry Street	Y				Load profile was changed, removed bad/abnormal data
Carson	CUR1282	Curry Street	Y				
North-East	CVL220	Crescent Valley		Y			Filled in all blanks with available 2018 data
South-SW	DE1201	DE BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	DE1203	DE BK 3	Y				
South-SW	DE1204	DE BK 3	Y				
South-SW	DE1205	DE BK 4	Y				
South-SW	DE1206	DE BK 4	Y				
South-SW	DE1209	DE BK 5	Y				
South-SW	DE1212	DE BK 5	Y				
South-SW	DE1214	DE BK 7	Y				Load profile was changed, removed bad/abnormal data
South-NE	CR1214	CR BK 3				Y	
South-NE	DEB1203	DEB BK 1	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-NE	DEB1204	DEB BK 1	Y				
South-NE	DEB1210	DEB BK 2	Y				
South-NE	DEB1214	DEB BK 3	Y				
South-NE	DEB1215	DEB BK 3	Y				
South-NE	DEB1216	DEB BK 3	Y				Load profile was changed, removed bad/abnormal data
North-East	DHF208	Dutch Flat		Y			Approximated missing phase current data based on the other phases
North-East	DHF209	Dutch Flat			Y		
North-East	DHF210	Dutch Flat			Y		
Carson	DTN219	Dayton		Y		Y	Load profile was changed, removed bad/abnormal data
South-SW	DE1215	DE BK 7				Y	
South-SW	DU1201	DU BK 1	Y				
South-SW	DU1202	DU BK 1				Y	
South-SW	DU1203	DU BK 1	Y				
South-SW	DU1204	DU BK 1	Y				
South-SW	DU1205	DU BK 1	Y				
South-SW	DU1206	DU BK 1				Y	
South-SW	DU1207	DU BK 1				Y	
South-SW	DU1208	DU BK 2	Y				
South-SW	DU1209	DU BK 2	Y				
South-SW	DU1210	DU BK 2	Y				
South-SW	DU1211	DU BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	DU1212	DU BK 3	Y				
South-SW	DU1213	DU BK 3				Y	
South-SW	DU1215	DU BK 3			Y		Bad PI data, used scaled transformer data
Carson	DWN1285	Downs	Y				
Carson	DWN1286	Downs	Y				
North-East	EGL1218	Eagle	Y				
North-East	EGL201	Eagle	Y				Load profile was changed, removed bad/abnormal data
North-East	EGL202	Eagle	Y				Load profile was changed, removed bad/abnormal data
South-NW	ELC1204	ELC BK 1	Y				
South-NW	ELC1205	ELC BK 1	Y				
South-NW	ELC1208	ELC BK 1	Y				
South-NW	ELC1209	ELC BK 1	Y				
South-NW	ELC1210	ELC BK 1	Y				
South-NW	ELC1215	ELC BK 2	Y				
South-NW	ELC1216	ELC BK 2	Y				
South-NW	ELC1217	ELC BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	ELC1218	ELC BK 2	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-NW	ELC1220	ELC BK 2	Y				
South-NW	ELC1221	ELC BK 2	Y				
South-NW	ELK1201	ELK BK 1	Y				
South-NW	ELK1202	ELK BK 1	Y				
South-NW	ELK1206	ELK BK 1	Y				
South-NW	ELK1208	ELK BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	ELK1209	ELK BK 2	Y				
South-NW	ELK1211	ELK BK 2	Y				
South-NW	ELK1212	ELK BK 2	Y				
South-NW	ELK1213	ELK BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	ELK1214	ELK BK 3	Y				
South-NW	ELK1216	ELK BK 3	Y				
North-East	EGL1218	Eagle	Y				Load profile was changed, removed bad/abnormal data
North-East	ELK22	Elko				Y	
North-East	ELK23	Elko				Y	
North-East	ELK24	Elko				Y	
North-East	ELK27	Elko				Y	
North-TM	ELR1	El Rancho^		Y			
North-TM	ELR2	El Rancho^		Y			Load profile was changed, removed bad/abnormal data
North-East	EMP7001	Empire		Y			Load profile was changed, removed bad/abnormal data
Carson	EMR1221	Emerson	Y				Load profile was changed, removed bad/abnormal data
Carson	EMR1222	Emerson	Y				Load profile was changed, removed bad/abnormal data
Carson	EMR1223	Emerson	Y				
Carson	EMR1224	Emerson	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	ER1201	ER BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	ER1203	ER BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	ER1205	ER BK 2	Y				
South-STRIP	ER1207	ER BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	ER1209	ER BK 3	Y				
South-STRIP	ER1211	ER BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	ER1212	ER BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	EX1201	EX BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	EX1203	EX BK 1	Y				
South-STRIP	EX1204	EX BK 1	Y				
South-STRIP	EX1205	EX BK 2	Y				
South-STRIP	EX1206	EX BK 2	Y				
South-STRIP	EX1209	EX BK 3	Y				
South-STRIP	EX1211	EX BK 3	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-STRIP	EX1212	EX BK 3	Y				
South-STRIP	EX1213	EX BK 4	Y				
South-STRIP	EX1214	EX BK 4	Y				
South-STRIP	EX1215	EX BK 4	Y				
South-STRIP	FL1202	FL BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	FL1203	FL BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	FL1206	FL BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	FL1207	FL BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	FL1208	FL BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	FL1209	FL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	FL1211	FL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	FL1212	FL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SE	FLK1204	FLK BK 4	Y				Load profile was changed, removed bad/abnormal data
South-SE	FLK1205	FLK BK 4	Y				Load profile was changed, removed bad/abnormal data
South-SE	FLK1206	FLK BK 4	Y				
South-SE	FLK1208	FLK BK 4	Y				
South-SE	FLK1209	FLK BK 4	Y				
South-SE	FLK1210	FLK BK 4	Y				
South-SE	FLK1215	FLK BK 3	Y				
South-SE	FLK1216	FLK BK 3	Y				
South-SE	FLK1217	FLK BK 3	Y				
South-SE	FLK1218	FLK BK 3	Y				
South-SE	FLK1220	FLK BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SE	FLK1221	FLK BK 3	Y				
South-SE	FLK1224	FLK BK 5	Y				
South-SE	FLK1226	FLK BK 5	Y				
South-SE	FLK1227	FLK BK 5	Y				
North-East	FLN1201	Fallon				Y	
North-East	FLN1202	Fallon			Y		Load profile was changed, removed bad/abnormal data
North-East	FLN1203	Fallon				Y	
North-East	FLN309	Fallon				Y	
North-East	FLN310	Fallon				Y	
Carson	FLT203	Fletcher				Y	
North-East	FLY1214	Fernley	Y				Load profile was changed, removed bad/abnormal data
North-East	FLY1215	Fernley	Y				
North-East	FLY1216	Fernley	Y				
North-East	FLY1217	Fernley	Y				Load profile was changed, removed bad/abnormal data
South-SE	FRD1204	FRD BK 1	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SE	FRD1205	FRD BK 1				Y	
South-SE	FRD1206	FRD BK 1	Y				
South-SE	FRD1208	FRD BK 1	Y				
South-SE	FRD1209	FRD BK 1	Y				
South-SE	FRD1210	FRD BK 1	Y				
South-SE	FRD1215	FRD BK 2				Y	
South-SE	FRD1216	FRD BK 2	Y				
South-SE	FRD1217	FRD BK 2	Y				
South-SE	FRD1218	FRD BK 2	Y				
South-SE	FRD1220	FRD BK 2	Y				
South-SE	FRD1221	FRD BK 2	Y				
South-SW	FRS1201	FRS BK 1				Y	
South-SW	FRS1203	FRS BK 1				Y	
South-SW	FRS1204	FRS BK 1				Y	
South-SW	FRS1205	FRS BK 1				Y	
South-SW	FRS1206	FRS BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	FRS1210	FRS BK 2	Y				
South-SW	FRS1211	FRS BK 2	Y				
South-SW	FRS1212	FRS BK 2	Y				
South-SW	FRS1213	FRS BK 3				Y	
South-SW	FRS1214	FRS BK 3	Y				
South-SW	FRS1215	FRS BK 3	Y				
South-SW	FRS1217	FRS BK 3	Y				
Carson	FTC210	Fort Churchill		Y		Y	Load profile was changed, removed bad/abnormal data
North-TM	FTS299	Fort Sage	Y		Y		Load profile was changed, removed bad/abnormal data
Carson	FVW1210	Fairview	Y				Load profile was changed, removed bad/abnormal data
Carson	FVW1211	Fairview	Y				Load profile was changed, removed bad/abnormal data
Carson	FVW1212	Fairview	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	GA1201	GA BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	GA1202	GA BK 2	Y				
South-STRIP	GA1204	GA BK 2	Y				
South-STRIP	GA1205	GA BK 3	Y				
South-STRIP	GA1206	GA BK 3	Y				
South-STRIP	GA1209	GA BK 4	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	GA1210	GA BK 4	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	GA1211	GA BK 4	Y				
Carson	GBS47	Gabbs	Y				Load profile was changed, removed bad/abnormal data
Carson	GBS48	Gabbs	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
Carson	GFD1264	Goldfield		Y		Y	Load profile was changed, removed bad/abnormal data
North-TM	GLD211	Glendale	Y				Load profile was changed, removed bad/abnormal data
North-TM	GLD237	Glendale	Y				Load profile was changed, removed bad/abnormal data
North-TM	GLD238	Glendale	Y				Load profile was changed, removed bad/abnormal data
North-TM	GLD245	Glendale	Y				Some 2017 data replaced with 2018 data
North-TM	GLD265	Glendale	Y				Load profile was changed, removed bad/abnormal data
North-TM	GLD271	Glendale	Y				Load profile was changed, removed bad/abnormal data
North-TM	GLD274	Glendale	Y				Load profile was changed, removed bad/abnormal data
South-NE	GLM1204	GLM BK 1	Y				
South-NE	GLM1205	GLM BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	GLM1206	GLM BK 2	Y				
South-NE	GLM1211	GLM BK 2	Y				
Carson	GLN2302	Glenbrook	Y				Load profile was changed, removed bad/abnormal data
Carson	GLN2505	Glenbrook	Y				Load profile was changed, removed bad/abnormal data
Carson	GLN2600	Glenbrook		Y		Y	Approximated missing phase data based on the other phases
North-TM	GLS7400	Glenshire				Y	
North-TM	GLS7600	Glenshire				Y	
South-SE	GNW1205	GNW BK 2	Y				
South-SE	GNW1206	GNW BK 2	Y				
South-SE	GNW1207	GNW BK 2	Y				
South-SE	GNW1209	GNW BK 2	Y				
North-East	GOL1201	Golconda		Y			Approximated missing phase current data based on the other phases
North-East	GOL1202	Golconda		Y		Y	Generic profile used for part of year
North-East	GOL1203	Golconda				Y	
North-TM	GRG227	Greg St	Y				Load profile was changed, removed bad/abnormal data
North-TM	GRG228	Greg St	Y				Load profile was changed, removed bad/abnormal data
North-TM	GRG229	Greg St	Y				Load profile was changed, removed bad/abnormal data
North-TM	GRG231	Greg St	Y				Load profile was changed, removed bad/abnormal data
North-TM	GRG232	Greg St	Y				Load profile was changed, removed bad/abnormal data
North-TM	GRG233	Greg St	Y				Load profile was changed, removed bad/abnormal data
North-TM	GRG286	Greg St	Y				Load profile was changed, removed bad/abnormal data
North-TM	GRG287	Greg St	Y				Load profile was changed, removed bad/abnormal data
North-TM	GRG288	Greg St	Y				Load profile was changed, removed bad/abnormal data
North-East	GRS2517	Grass Valley	Y				Load profile was changed, removed bad/abnormal data
North-East	GRS2518	Grass Valley	Y				Load profile was changed, removed bad/abnormal data
South-SW	GS1201	GS BK 1		Y			Approximated missing current data based on A phase data
South-SW	GS1202	GS BK 1		Y			Approximated missing current data based on available data
South-NE	GTT1207	GTT BK 2	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-NE	GTT1208	GTT BK 2	Y				
South-NE	GTT1212	GTT BK 2	Y				
South-SE	GV1201	GV BK 1			Y		
South-SE	GV1203	GV BK 1			Y		
South-SE	GV1204	GV BK 1			Y		
South-SE	GV1207	GV BK 2			Y		
South-SE	GV1208	GV BK 2			Y		
South-SE	GV1209	GV BK 2			Y		
South-SE	GV1210	GV BK 2			Y		
South-SE	GV1211	GV BK 3			Y		
South-SE	GV1212	GV BK 3			Y		
South-SE	GV1214	GV BK 3			Y		
South-NE	GYP1208	GYP BK 2	Y				
South-NE	GYP1210	GYP BK 2			Y		
Carson	HAW1201	Hawthorne			Y		Load profile was changed, removed bad/abnormal data
Carson	HAW1202	Hawthorne			Y		Load profile was changed, removed bad/abnormal data
North-East	HAZ1210	Hazen		Y		Y	Generic profile used for part of year
North-East	HBH701	Humboldt House				Y	
Carson	HEY1287	Heybourne	Y				
Carson	HEY1288	Heybourne	Y				
Carson	HEY1290	Heybourne	Y				
South-STRIP	HI1201	HI BK 1	Y				
South-STRIP	HI1202	HI BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1203	HI BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1205	HI BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1206	HI BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1209	HI BK 3	Y				
South-STRIP	HI1210	HI BK 3	Y				
South-STRIP	HI1211	HI BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1214	HI BK 4	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1215	HI BK 4	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1216	HI BK 4	Y				
South-STRIP	HI1217	HI BK 5	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1219	HI BK 5	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1220	HI BK 5	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1222	HI BK 5	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1224	HI BK 5	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	HI1225	HI BK 6	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-STRIP	HI1226	HI BK 6	Y				Load profile was changed, removed bad/abnormal data
North-TM	HLD1	Highland^		Y		Y	Generic profile used for part of year
North-TM	HLD2	Highland^		Y		Y	Generic profile used for part of year
North-TM	HLD3	Highland^		Y		Y	Generic profile used for part of year
North-TM	HLD4	Highland^		Y		Y	Generic profile used for part of year
North-TM	HLS1	Hunter Lake		Y			Replaced missing 2017 data with 2018 data
North-TM	HLS2	Hunter Lake		Y			Replaced missing 2017 data with 2018 data
North-TM	HLS3	Hunter Lake		Y			Approximated missing phase currrent data based on the other phases
North-TM	HLS6	Hunter Lake				Y	
North-TM	HOB7700	Hobart				Y	
North-TM	HOL1	Holcomb		Y		Y	Generic profile used for part of year
North-TM	HOL2	Holcomb		Y			Replaced missing 2017 data with 2018 data
North-TM	HOL240	Holcomb				Y	
North-TM	HOL241	Holcomb				Y	
North-TM	HOL3	Holcomb				Y	
North-TM	HOL4	Holcomb		Y			Approximated missing phase currrent data based on the other phases
North-TM	HOL5	Holcomb		Y			Approximated missing phase currrent data based on the other phases
North-TM	HOL6	Holcomb		Y			Replaced missing 2017 data with 2018 data
North-East	HSP1401	Hot Springs				Y	
South-NW	HU1201	HU BK 1	Y				
South-NW	HU1202	HU BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	HU1204	HU BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	HU1205	HU BK 2	Y				
South-NW	HU1206	HU BK 2	Y				
South-NW	HU1209	HU BK 2	Y				
South-NW	HU1210	HU BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	HU1211	HU BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	HU1212	HU BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	HU1214	HU BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SE	HV1202	HV BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	HV1203	HV BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	HV1204	HV BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	HV1205	HV BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	HV1206	HV BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	HV1209	HV BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	HV1210	HV BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	HV1211	HV BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SE	HV1212	HV BK 3	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SE	HV1213	HV BK 3	Y				Load profile was changed, removed bad/abnormal data
North-East	ILY1201	Imlay	Y				Load profile was changed, removed bad/abnormal data
South-NW	IMT1201	IMT BK 1	Y				
South-NW	IMT1203	IMT BK 1	Y				
South-NW	IMT1204	IMT BK 1	Y				
South-NW	IMT1205	IMT BK 2	Y				
South-NW	IMT1206	IMT BK 2	Y				
South-NW	IMT1209	IMT BK 2	Y				
South-NW	IMT1211	IMT BK 2	Y				
South-NW	IMT1212	IMT BK 2	Y				
North-TM	INC4100	Incline	Y				Load profile was changed, removed bad/abnormal data
North-TM	INC4200	Incline	Y				Load profile was changed, removed bad/abnormal data
North-TM	INC4300	Incline	Y				Load profile was changed, removed bad/abnormal data
South-NW	IS1204	IS BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	IS401	IS BK 1				Y	
South-NW	IS402	IS BK 1		Y			
South-NW	IS403	IS BK 1		Y			
South-SW	JN1207	JN BK 2			Y		
South-SW	JN1208	JN BK 2			Y		
South-NW	KC1201	KC BK 1		Y			Load profile was changed, removed bad/abnormal data
Carson	KGB2800	Kingsbury				Y	
South-SE	KHN1201	KHN BK 1	Y				
South-SE	KHN1204	KHN BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	KHN1205	KHN BK 2	Y				
South-SE	KHN1206	KHN BK 2	Y				
South-SE	KHN1210	KHN BK 2	Y				
South-SE	KHN1212	KHN BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	KHN1214	KHN BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	KHN1215	KHN BK 2	Y				
South-SE	KHN1217	KHN BK 2	Y				
South-SE	KI1201	KI BK 1				Y	
South-SE	KI1202	KI BK 1		Y			Load profile was changed, removed bad/abnormal data
Carson	KIN1203	Kincaid				Y	
North-East	KRA1204	Kramer		Y			Load profile was changed, removed bad/abnormal data
North-TM	KSR1301	Kaiser				Y	
North-TM	KSR1302	Kaiser				Y	
Carson	LBY7001	Lucky Boy				Y	
North-East	LCH211	Last Chance	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
North-East	LCH212	Last Chance	Y				Load profile was changed, removed bad/abnormal data
North-East	LCH218	Last Chance	Y				Load profile was changed, removed bad/abnormal data
North-East	LCH221	Last Chance	Y				Load profile was changed, removed bad/abnormal data
Carson	LCK701	Lockes				Y	
South-NE	LCN1203	LCN BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NE	LCN1204	LCN BK 1	Y				
South-NE	LCN1205	LCN BK 2	Y				
South-NE	LCN1206	LCN BK 2	Y				
South-NE	LCN1210	LCN BK 2	Y				
South-NE	LCN1212	LCN BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	LCN1213	LCN BK 2	Y				
South-NE	LCN1214	LCN BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	LDQ1203	LDQ BK 1	Y				
South-SE	LDQ1204	LDQ BK 1	Y				
South-SE	LDQ1205	LDQ BK 1	Y				
South-SE	LDQ1208	LDQ BK 2	Y				
South-SE	LDQ1210	LDQ BK 2	Y				
South-SE	LDQ1215	LDQ BK 2	Y				
South-STRIP	LE402	LE BK 2				Y	
South-STRIP	LE404	LE BK 2				Y	
South-SW	LI1202	LI BK 1			Y		
South-SW	LI1204	LI BK 1			Y		
South-SW	LI1207	LI BK 2			Y		
South-SW	LI1208	LI BK 2			Y		
South-SW	LI1211	LI BK 3			Y		
South-SW	LI1212	LI BK 3			Y		
South-SW	LI1213	LI BK 3			Y		
South-SW	LI1220	LI BK 2			Y		
North-East	LIM1201	Limerick		Y			Load profile was changed, removed bad/abnormal data
South-SE	LLV1201	LLV BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	LLV1203	LLV BK 1	Y				
South-SE	LLV1205	LLV BK 2	Y				
South-SE	LLV1206	LLV BK 2	Y				
North-East	LMT1201	Lone Mountain^		Y			Load profile was changed, removed bad/abnormal data
South-NW	LMT1203	LMT BK 1	Y				
South-NW	LMT1204	LMT BK 1	Y				
South-NW	LMT1213	LMT BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	LMT1215	LMT BK 2	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
North-East	LNY1230	Lonely	Y				
North-East	LNY1231	Lonely	Y				
North-East	LNY1232	Lonely	Y				Load profile was changed, removed bad/abnormal data
North-East	LNY1233	Lonely	Y				Load profile was changed, removed bad/abnormal data
South-NW	LO1201	LO BK 1	Y				
South-NW	LO1203	LO BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	LO1204	LO BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	LO1207	LO BK 2	Y				
South-NW	LO1208	LO BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	LO1209	LO BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	LO1210	LO BK 2	Y				
South-NW	LO1211	LO BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	LO1212	LO BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	LO1214	LO BK 3	Y				
North-East	LOV1203	Lovelock		Y			Filled in all 2017 blanks with available 2018 data
North-East	LOV701	Lovelock		Y			Filled in all 2017 blanks with available 2018 data
North-East	LOV702	Lovelock		Y			Load profile was changed, removed bad/abnormal data
North-East	LOV703	Lovelock		Y			Filled in all 2017 blanks with available 2018 data
North-TM	LOY619	Loyalton				Y	
Carson	LUN7005	Luning				Y	
South-NE	LVT1201	LVT BK 1	Y				
South-NE	LVT1203	LVT BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NE	LVT1204	LVT BK 1	Y				
South-NE	LVT1205	LVT BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	LVT1206	LVT BK 2	Y				
South-NE	LVT1209	LVT BK 2	Y				
South-NE	LVT1212	LVT BK 2	Y				
South-NE	LVT1213	LVT BK 2	Y				
South-NE	LVT1214	LVT BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	LVT1215	LVT BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	LY1202	LY BK 1				Y	
South-STRIP	LY1204	LY BK 1				Y	
South-STRIP	LY1205	LY BK 1				Y	
South-STRIP	LY1208	LY BK 2				Y	
South-STRIP	LY1209	LY BK 2				Y	
South-STRIP	MA1211	MA BK 2	Y				
South-STRIP	MA1212	MA BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	MA1213	MA BK 3	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-STRIP	MA1215	MA BK 3	Y				
South-STRIP	MA1216	MA BK 4	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	MA1218	MA BK 4	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	MA401	MA BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	MA402	MA BK 1	Y				
South-SE	MAG1209	MAG BK 1			Y		
South-SE	MAG1210	MAG BK 1			Y		
Carson	MAN1201	Manhattan		Y		Y	Generic profile used in place of some bad sensor data
South-SW	MCD1205	MCD BK 3	Y				
South-SW	MCD1207	MCD BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	MCD1208	MCD BK 3	Y				
South-SW	MCD1210	MCD BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	MCD1216	MCD BK 4	Y				
South-SW	MCD1217	MCD BK 4	Y				
South-SW	MCD1218	MCD BK 4	Y				
South-SW	MCD1219	MCD BK 4	Y				Load profile was changed, removed bad/abnormal data
South-SW	MCD1220	MCD BK 4	Y				
North-TM	MCN1	McCarran		Y		Y	Generic profile used for part of year
North-TM	MCN2	McCarran		Y			Approximated Phase B and C based on A phase
North-East	MCY201	McCoy				Y	
Carson	MEY3100	Meyers	Y				
Carson	MEY3200	Meyers	Y				
Carson	MEY3300	Meyers	Y				
Carson	MEY3400	Meyers	Y				
Carson	MEY3500	Meyers	Y				
South-STRIP	MGM1217	MGM BK 4	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	MGM1218	MGM BK 4	Y				
South-NE	MI1202	MI BK 3			Y		
South-NE	MI1203	MI BK 3			Y		
South-NE	MI1206	MI BK 4			Y		
South-NE	MI1207	MI BK 4			Y		
South-NE	MI1208	MI BK 4			Y		
North-TM	MIL1	Mill St		Y			Load profile was changed, removed bad/abnormal data
North-TM	MIL2	Mill St		Y			Approximated missing phase data based on the other phases
North-TM	MIL3	Mill St		Y			Load profile was changed, removed bad/abnormal data
Carson	MIN1272	Minden		Y			Approximated some phase data based on available data
Carson	MIN1273	Minden		Y		Y	Approximated some phase data based on available data
North-TM	MIR290	Mira Loma	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
North-TM	MIR291	Mira Loma	Y				Load profile was changed, removed bad/abnormal data
North-TM	MIR292	Mira Loma	Y				Load profile was changed, removed bad/abnormal data
Carson	MLR41	Millers^				Y	
Carson	MNA1202	Mina				Y	
Carson	MNA1203	Mina				Y	
Carson	MNA1204	Mina				Y	
North-TM	MOA2	Moana		Y			Load profile was changed, removed bad/abnormal data
North-TM	MOA3	Moana		Y			Approximated missing phase data based on the other phases
North-East	MRB1401	Marble Bluff				Y	
South-SE	MS1201	MS BK 1			Y		Load profile was changed, removed bad/abnormal data
South-SE	MS1203	MS BK 1			Y		
South-SE	MS1204	MS BK 1			Y		
South-SE	MS1205	MS BK 2			Y		
South-SE	MS1206	MS BK 2			Y		
South-SE	MS1209	MS BK 3			Y		
South-SE	MS1210	MS BK 3			Y		
South-SE	MS1212	MS BK 3			Y		
South-SE	MS1213	MS BK 4			Y		Load profile was changed, removed bad/abnormal data
South-SE	MS1214	MS BK 4			Y		
South-SW	MTE1206	MTE BK 2	Y				
South-SW	MTE1211	MTE BK 2	Y				
South-SW	MTE1212	MTE BK 2	Y				
South-SW	MTE1213	MTE BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	MTE1214	MTE BK 3	Y				
South-SW	MTE1215	MTE BK 3	Y				
South-SW	MTE1217	MTE BK 3	Y				
North-TM	MTR203	Mt Rose	Y				Load profile was changed, removed bad/abnormal data
North-TM	MTR210	Mt Rose	Y				Load profile was changed, removed bad/abnormal data
North-TM	MTR242	Mt Rose	Y				
North-TM	MTR243	Mt Rose	Y				Load profile was changed, removed bad/abnormal data
North-TM	MTR282	Mt Rose	Y				Load profile was changed, removed bad/abnormal data
Carson	MTW218	Mark Twain	Y				
Carson	MTW220	Mark Twain	Y				
Carson	MUR1295	Muller	Y				Load profile was changed, removed bad/abnormal data
Carson	MUR1296	Muller	Y				Load profile was changed, removed bad/abnormal data
South-NW	MW1201	MW BK 1	Y				
South-NW	MW1202	MW BK 1	Y				
South-NW	MW1204	MW BK 1	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-NW	MW1207	MW BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	MW1209	MW BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	MW1211	MW BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	MW1213	MW BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	MYS1207	MYS BK 3				Y	
South-SW	MYS1214	MYS BK 3	Y				Replaced with 2018 data due to bad PI data in 2017
South-SW	MYS1215	MYS BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	MYS1216	MYS BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	MYS1218	MYS BK 3	Y				Replaced with 2018 data due to bad PI data
South-SE	NL1201	NL BK 1		Y		Y	Generic profile used in place of bad/no sensor data
South-NE	NLV1202	NLV BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NE	NLV1203	NLV BK 1	Y				
South-NE	NLV1204	NLV BK 3	Y				
South-NE	NLV1209	NLV BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	NLV1210	NLV BK 4	Y				Load profile was changed, removed bad/abnormal data
South-NE	NLV1211	NLV BK 4	Y				
South-NE	NLV1212	NLV BK 4	Y				
Carson	NNH1201	No Name Hill Tap				Y	
North-TM	NOW206	Northwest^	Y				Load profile was changed, removed bad/abnormal data
North-TM	NOW207	Northwest^	Y				Load profile was changed, removed bad/abnormal data
North-TM	NOW208	Northwest^	Y				
North-TM	NOW216	Northwest^	Y				
North-TM	NOW218	Northwest^	Y				
North-TM	NOW244	Northwest^	Y				Load profile was changed, removed bad/abnormal data
South-SE	NPS401	NPS BK 1		Y			Load profile was changed, removed bad/abnormal data
South-NE	NS1203	NS BK 1			Y		
South-NE	NS1204	NS BK 1			Y		
South-NE	NS1205	NS BK 2			Y		
South-NE	NS1206	NS BK 2			Y		
South-NE	NS1211	NS BK 3			Y		
North-TM	NST8400	Northstar	Y				Load profile was changed, removed bad/abnormal data
North-TM	NST8500	Northstar	Y				Load profile was changed, removed bad/abnormal data
North-TM	NST8600	Northstar	Y				Load profile was changed, removed bad/abnormal data
North-TM	NUG1	Nugget				Y	
North-TM	NUG2	Nugget				Y	
North-East	NVY2401	North Valmy	Y				
North-East	NVY2402	North Valmy	Y				Load profile was changed, removed bad/abnormal data
South-NW	NW1204	NW BK 4	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-NW	NW1205	NW BK 4	Y				
South-NW	NW1206	NW BK 4	Y				
South-NW	NW1208	NW BK 4	Y				
South-NW	NW1215	NW BK 5	Y				Load profile was changed, removed bad/abnormal data
South-NW	NW1216	NW BK 5	Y				Load profile was changed, removed bad/abnormal data
South-NW	NW1217	NW BK 5	Y				
South-NW	NW1220	NW BK 5	Y				
South-NW	NW1221	NW BK 5	Y				
South-SW	OA1203	OA BK 1			Y		Load profile was changed, removed bad/abnormal data
South-SW	OA1204	OA BK 1			Y		Load profile was changed, removed bad/abnormal data
South-SW	OA1205	OA BK 2			Y		
South-SW	OA1206	OA BK 2			Y		
South-NE	OL1202	OL BK 1			Y		
South-NE	OL1203	OL BK 1			Y		
South-STRIP	OQ1203	OQ BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	OQ1204	OQ BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	OQ1206	OQ BK 1	Y				
South-STRIP	OQ1209	OQ BK 2	Y				
South-STRIP	OQ1210	OQ BK 2	Y				
South-STRIP	OQ1211	OQ BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	OQ1213	OQ BK 3	Y				
South-STRIP	OQ1214	OQ BK 3	Y				
North-East	OSG201	Osgood	Y				Load profile was changed, removed bad/abnormal data
North-East	OSG202	Osgood	Y				
Carson	OVL1250	Overland			Y		Problem with the PI tags, so used scaled transformer profile
Carson	OVL1265	Overland	Y				
Carson	OVL1270	Overland	Y				
South-STRIP	PA1202	PA BK 1			Y		Some bad data replaced with 2018 data
South-STRIP	PA1203	PA BK 1			Y		
South-STRIP	PA1204	PA BK 1			Y		
South-STRIP	PA1206	PA BK 2			Y		
South-STRIP	PA1207	PA BK 2			Y		Load profile was changed, removed bad/abnormal data
South-STRIP	PA1208	PA BK 2			Y		
North-East	PAR724	Parran				Y	
North-TM	PAT224	Patrick	Y				Load profile was changed, removed bad/abnormal data
North-TM	PAT225	Patrick	Y				
North-TM	PAT226	Patrick	Y				Load profile was changed, removed bad/abnormal data
South-SE	PB1201	PB BK 1			Y		

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SE	PB1203	PB BK 1			Y		Load profile was changed, removed bad/abnormal data
South-SE	PB1204	PB BK 1			Y		Load profile was changed, removed bad/abnormal data
South-SE	PB1205	PB BK 2			Y		
South-SE	PB1209	PB BK 2			Y		
South-SE	PB1210	PB BK 2			Y		
South-SE	PB1211	PB BK 3			Y		
South-SE	PB1212	PB BK 3			Y		
South-SE	PB1213	PB BK 3			Y		
South-NE	PBC1206	PBC BK 2			Y		Load profile was changed, removed bad/abnormal data
South-NE	PBC1208	PBC BK 2			Y		Load profile was changed, removed bad/abnormal data
South-SW	PCE1204	PCE BK 1	Y				
South-SW	PCE1206	PCE BK 2	Y				
South-SW	PCE1209	PCE BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	PCE1211	PCE BK 2	Y				
South-SW	PCE1213	PCE BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	PCE1214	PCE BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	PCE1215	PCE BK 3	Y				
South-SW	PCE1217	PCE BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	PE1201	PE BK 6	Y				Load profile was changed, removed bad/abnormal data
South-NE	PE1207	PE BK 6	Y				
South-NE	PE1208	PE BK 6	Y				
South-NE	PE1209	PE BK 6	Y				
South-NE	PE1212	PE BK 6	Y				
South-SE	PL1201	PL BK 1			Y		
South-SE	PL1202	PL BK 1			Y		
South-SE	PL1204	PL BK 1			Y		
South-SE	PL1206	PL BK 2			Y		
South-SE	PL1209	PL BK 2			Y		
South-SE	PL1211	PL BK 3			Y		
South-SE	PL1213	PL BK 3			Y		
South-SE	PL1214	PL BK 3			Y		
Carson	PNT1251	Pinenut	Y				
Carson	PNT1253	Pinenut	Y				Load profile was changed, removed bad/abnormal data
Carson	PNT1254	Pinenut	Y				
South-STRIP	POL1201	POL BK 1	Y				
South-STRIP	POL1203	POL BK 1	Y				
South-STRIP	POL1204	POL BK 1	Y				
South-STRIP	POL1205	POL BK 2	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-STRIP	POL1208	POL BK 2	Y				
South-STRIP	POL1209	POL BK 2	Y				
South-STRIP	POL1210	POL BK 2	Y				
South-STRIP	POL1211	POL BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	POL1212	POL BK 2	Y				
South-STRIP	POL1213	POL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	POL1215	POL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	POL1216	POL BK 3	Y				Load profile was changed, removed bad/abnormal data
North-TM	POR31	Portola				Y	
North-TM	POR32	Portola				Y	
South-NE	PR1202	PR BK 1			Y		Load profile was changed, removed bad/abnormal data
South-NE	PR1203	PR BK 1			Y		Load profile was changed, removed bad/abnormal data
South-NE	PR1206	PR BK 2			Y		Load profile was changed, removed bad/abnormal data
South-NE	PR1207	PR BK 2			Y		Load profile was changed, removed bad/abnormal data
South-NE	PR1208	PR BK 2			Y		Load profile was changed, removed bad/abnormal data
South-STRIP	PRO1202	PRO BK 2	Y				
South-STRIP	PRO1206	PRO BK 2	Y				
South-STRIP	PRO1207	PRO BK 2	Y				
South-STRIP	PRO1211	PRO BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	PRO1212	PRO BK 2	Y				
South-STRIP	PRO1213	PRO BK 2	Y				
North-TM	PYR1	Pyramid		Y			Replaced missing 2017 data with 2018 data
North-TM	PYR2	Pyramid		Y		Y	Generic profile used for part of year
North-TM	PYR3	Pyramid		Y			Load profile was changed, removed bad/abnormal data
North-TM	PYR4	Pyramid				Y	
North-East	QMW7201	Quarry				Y	
South-SW	QUL1201	QUL BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	QUL1203	QUL BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	QUL1204	QUL BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	QUL1205	QUL BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	QUL1208	QUL BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	QUL1209	QUL BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	QUL1210	QUL BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	QUL1211	QUL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	QUL1212	QUL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	QUL1213	QUL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	RA1201	RA BK 1		Y			Filled in 2017 data with 2018 data
North-East	RAN250	Rain				Y	

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
Carson	RAW71	Rawhide	Y				
South-NW	RB1202	RB BK 1			Y		
South-NW	RB1203	RB BK 1			Y		Generic profile used for part of year
South-NW	RB1204	RB BK 1			Y		
South-NW	RB1207	RB BK 2			Y		
South-NW	RB1208	RB BK 2			Y		Generic profile used for part of year
South-NW	RB1214	RB BK 3			Y		
South-NW	RB1215	RB BK 3			Y	Y	Generic profile used for part of year
South-NW	RB1219	RB BK 3			Y		
North-East	RCR201	Rose Creek		Y			Filled in all 2017 blanks with available 2018 data
Carson	RDH1502	Round Hill	Y				Load profile was changed, removed bad/abnormal data
Carson	RDH1503	Round Hill	Y				Load profile was changed, removed bad/abnormal data
Carson	RDH1504	Round Hill	Y				Load profile was changed, removed bad/abnormal data
Carson	RDM2220	Round Mountain		Y			Approximated some phase data based on available data
Carson	RDM2221	Round Mountain			Y		Load profile was changed, removed bad/abnormal data
Carson	RDM2222	Round Mountain			Y		Load profile was changed, removed bad/abnormal data
North-East	RED1401	Red House				Y	
South-NW	RGN1204	RGN BK 2	Y				
South-NW	RGN1206	RGN BK 2	Y				
South-NW	RGN1210	RGN BK 2	Y				
South-NW	RGN1211	RGN BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	RGN1212	RGN BK 2	Y				
South-SE	RI2501	RI BK 1		Y			Approximated phase information based on available data
South-SE	RI2508	RI BK 2		Y			Load profile was changed, removed bad/abnormal data
South-SE	RI2509	RI BK 2				Y	
South-SW	RLR1201	RLR BK 1	Y				Replaced with 2018 data due to bad PI data
South-SW	RLR1203	RLR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1204	RLR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1205	RLR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1206	RLR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1210	RLR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1211	RLR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1212	RLR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1214	RLR BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1215	RLR BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1217	RLR BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1218	RLR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLR1219	RLR BK 1	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SW	RLY1205	RLY BK 2	Y				
South-SW	RLY1206	RLY BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	RLY1211	RLY BK 2	Y				
South-SE	RN1201	RN BK 1				Y	
South-SE	RN1202	RN BK 1				Y	
North-TM	RNO1	Reno		Y			Approximated missing phase data based on the other phases
North-TM	RNO204	Reno	Y				Load profile was changed, removed bad/abnormal data
North-TM	RNO216	Reno	Y				Load profile was changed, removed bad/abnormal data
North-TM	RNO217	Reno				Y	
North-TM	RNO240	Reno	Y				Load profile was changed, removed bad/abnormal data
North-TM	RNO243	Reno	Y				Load profile was changed, removed bad/abnormal data
North-TM	RNO247	Reno	Y				Load profile was changed, removed bad/abnormal data
North-TM	RNO263	Reno	Y				Load profile was changed, removed bad/abnormal data
North-TM	RNO285	Reno	Y				Load profile was changed, removed bad/abnormal data
North-TM	RNO4	Reno		Y			Approximated missing phase data based on the other phases
North-TM	RNO6	Reno		Y			Load profile was changed, removed bad/abnormal data
South-SW	RO1201	RO BK 1			Y		
South-SW	RO1203	RO BK 1			Y		
South-SW	RO1204	RO BK 1			Y		
South-SW	RO1207	RO BK 2			Y		
South-SW	RO1208	RO BK 2			Y		
South-SW	RO1210	RO BK 3			Y		
South-SW	RO1212	RO BK 3			Y		
South-SW	ROB1201	ROB BK 1	Y				
South-SW	ROB1203	ROB BK 1	Y				
South-SW	ROB1204	ROB BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	ROB1206	ROB BK 2	Y				
South-SW	ROB1210	ROB BK 2	Y				
South-SW	ROB1212	ROB BK 2	Y				
South-SW	ROB1213	ROB BK 2	Y				
South-SW	ROB1214	ROB BK 3	Y				
South-SW	ROB1215	ROB BK 3	Y				
South-SW	ROB1217	ROB BK 3	Y				
North-East	RPH21	Rye Patch		Y			Load profile was changed, removed bad/abnormal data
Carson	RRD7007	Railroad^				Y	
South-SW	RRK1201	RRK BK 1	Y				
South-SW	RRK1203	RRK BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SW	RRK1204	RRK BK 1	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SW	RRK1211	RRK BK 2	Y				
South-SW	RRK1212	RRK BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	RRK1213	RRK BK 2	Y				
North-East	RRV230	Reese River	Y				Load profile was changed, removed bad/abnormal data
North-East	RRV231	Reese River	Y				
South-SE	RS1201	RS BK 1			Y		
South-SE	RS1202	RS BK 1			Y		
South-SE	RS1204	RS BK 1			Y		
South-SE	RS1205	RS BK 2			Y		
South-SE	RS1206	RS BK 2			Y		
South-SE	RS1209	RS BK 2			Y		Load profile was changed, removed bad/abnormal data
South-SE	RS1210	RS BK 2			Y		
South-SE	RS1211	RS BK 3			Y		Load profile was changed, removed bad/abnormal data
South-SE	RS1212	RS BK 3			Y		Load profile was changed, removed bad/abnormal data
South-SE	RS1214	RS BK 3			Y		Load profile was changed, removed bad/abnormal data
North-TM	RSK221	Rusty Spike	Y				Load profile was changed, removed bad/abnormal data
North-TM	RSK254	Rusty Spike	Y				Load profile was changed, removed bad/abnormal data
North-TM	RSK260	Rusty Spike	Y				Load profile was changed, removed bad/abnormal data
North-TM	RUS7900	Russell Valley				Y	
North-East	RYC1206	Ray Couch	Y				
North-East	RYC1207	Ray Couch	Y				
North-East	RYC1208	Ray Couch	Y				
South-SE	SA1201	SA BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	SA1203	SA BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	SA1205	SA BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	SA1206	SA BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	SA1209	SA BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SE	SA1212	SA BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SE	SA1216	SA BK 4	Y				Load profile was changed, removed bad/abnormal data
South-SE	SA1217	SA BK 4	Y				Load profile was changed, removed bad/abnormal data
Carson	SAN1201	Sandia				Y	
Carson	SCH1204	Scheelite				Y	
South-SE	SE1201	SE BK 1	Y				
South-SE	SE1202	SE BK 1	Y				
South-STRIP	SF1203	SF BK 1			Y		
South-STRIP	SF1204	SF BK 1			Y		
South-STRIP	SF1206	SF BK 2			Y		
South-STRIP	SF1207	SF BK 2			Y		

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-STRIP	SF1213	SF BK 3			Y		
South-STRIP	SF1215	SF BK 4				Y	
South-STRIP	SF1216	SF BK 4				Y	
South-STRIP	SF1217	SF BK 4				Y	
South-STRIP	SF1218	SF BK 4				Y	
South-NE	SH1206	SH BK 4	Y				Load profile was changed, removed bad/abnormal data
South-NE	SH1207	SH BK 4	Y				
South-NE	SH1209	SH BK 5	Y				Load profile was changed, removed bad/abnormal data
South-NE	SH1211	SH BK 5	Y				Load profile was changed, removed bad/abnormal data
South-NE	SH1212	SH BK 5	Y				Load profile was changed, removed bad/abnormal data
South-NE	SH401	SH BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	SH404	SH BK 3	Y				Load profile was changed, removed bad/abnormal data
North-East	SHT206	Sonoma Heights				Y	
North-East	SHT21	Sonoma Heights		Y			Approximated missing phase current data based on the other phases
North-East	SHT23	Sonoma Heights		Y			Filled in all 2017 blanks with available 2018 data
North-East	SHT704	Sonoma Heights		Y			Load profile was changed, removed bad/abnormal data
North-TM	SID261	Sparks Ind	Y				Load profile was changed, removed bad/abnormal data
Carson	SIL1211	Silver Springs	Y				
Carson	SIL1212	Silver Springs	Y				
South-NW	SKL1205	SKL BK 1	Y				
South-NW	SKL1206	SKL BK 1	Y				
South-NW	SKL1208	SKL BK 1	Y				
South-NW	SKL1209	SKL BK 1	Y				
South-NW	SKL1210	SKL BK 1	Y				
South-NW	SKL1215	SKL BK 2	Y				
South-NW	SKL1217	SKL BK 2	Y				
South-NW	SKL1218	SKL BK 2	Y				
South-NW	SKL1220	SKL BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	SKL1221	SKL BK 2	Y				Load profile was changed, removed bad/abnormal data
North-TM	SLF301	Sugarloaf	Y				
North-TM	SLF302	Sugarloaf	Y				
North-TM	SLF303	Sugarloaf	Y				
North-TM	SLF304	Sugarloaf	Y				Load profile was changed, removed bad/abnormal data
North-TM	SLK255	Silver Lake	Y				Load profile was changed, removed bad/abnormal data
North-TM	SLK256	Silver Lake	Y				
North-TM	SLK257	Silver Lake	Y				
North-TM	SLK258	Silver Lake	Y				Load profile was changed, removed bad/abnormal data
North-TM	SLK259	Silver Lake	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-NW	SLV1201	SLV BK 1	Y				
South-SW	SM1201	SM BK 1		Y			
South-SW	SM1202	SM BK 1		Y			Corrected some current data based on available data
South-NW	SMR1205	SMR BK 1	Y				
South-NW	SMR1207	SMR BK 1	Y				
South-NW	SMR1208	SMR BK 1	Y				
South-NW	SMR1209	SMR BK 1	Y				
South-NW	SMR1210	SMR BK 1	Y				
South-NW	SMR1217	SMR BK 2	Y				
South-NW	SMR1218	SMR BK 2	Y				
South-NW	SMR1219	SMR BK 2	Y				
South-NW	SMR1220	SMR BK 2	Y				
South-NW	SN1201	SN BK 1			Y		Load profile was changed, removed bad/abnormal data
South-STRIP	SNT1206	SNT BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SNT1207	SNT BK 1	Y				
South-STRIP	SNT1208	SNT BK 1	Y				
South-STRIP	SNT1215	SNT BK 2	Y				
South-STRIP	SNT1216	SNT BK 2	Y				
South-STRIP	SNT1218	SNT BK 2	Y				
South-STRIP	SNT1219	SNT BK 2	Y				
South-STRIP	SNT1220	SNT BK 2	Y				
South-SE	SO2502	SO BK 1		Y			Load profile was changed, removed bad/abnormal data
South-SE	SO2507	SO BK 2		Y			Load profile was changed, removed bad/abnormal data
South-SE	SO2508	SO BK 2		Y			Load profile was changed, removed bad/abnormal data
South-STRIP	SP1203	SP BK 3			Y		
South-STRIP	SP1206	SP BK 3			Y		
South-STRIP	SP1207	SP BK 4			Y		
South-STRIP	SP1210	SP BK 4			Y		
South-STRIP	SP1211	SP BK 5			Y		
South-STRIP	SP1213	SP BK 5			Y		Load profile was changed, removed bad/abnormal data
South-STRIP	SP1214	SP BK 5			Y		
South-SW	SPA1205	SPA BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	SPA1206	SPA BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	SPA1210	SPA BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	SPA1213	SPA BK 2			Y		2017 & 2018 PI data is bad, replaced with scaled transformer data
South-SW	SPA1214	SPA BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	SPA1217	SPA BK 2	Y				Load profile was changed, removed bad/abnormal data
North-TM	SPA270	Spanish Springs	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
North-TM	SPA271	Spanish Springs	Y				Load profile was changed, removed bad/abnormal data
North-TM	SPA272	Spanish Springs	Y				Load profile was changed, removed bad/abnormal data
North-TM	SPA273	Spanish Springs	Y				
North-TM	SPA274	Spanish Springs	Y				
North-TM	SPA275	Spanish Springs	Y				
South-NE	SPD1201	SPD BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	SPD1203	SPD BK 2	Y				
South-NE	SPD1211	SPD BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	SPD1213	SPD BK 2	Y				
North-TM	SQV7201	Squaw Valley	Y				
North-TM	SQV8100	Squaw Valley	Y				
North-TM	SQV8200	Squaw Valley	Y				
North-TM	SQV8300	Squaw Valley	Y				
North-TM	SRB51	Sierra Brooks				Y	
Carson	STA217	Stagecoach		Y			Load profile was changed, removed bad/abnormal data
North-TM	STD1	Stead				Y	
North-TM	STD2	Stead				Y	
North-TM	STD257	Stead	Y				Load profile was changed, removed bad/abnormal data
North-TM	STD259	Stead	Y				Load profile was changed, removed bad/abnormal data
North-TM	STD3	Stead				Y	
North-TM	STD4	Stead				Y	
Carson	STK1201	Stickleman				Y	
Carson	STL2200	Stateline	Y				Load profile was changed, removed bad/abnormal data
Carson	STL2300	Stateline	Y				Load profile was changed, removed bad/abnormal data
Carson	STL3101	Stateline	Y				Load profile was changed, removed bad/abnormal data
Carson	STL3501	Stateline	Y				Load profile was changed, removed bad/abnormal data
North-TM	STM210	Steamboat	Y		Y		Load profile was changed, removed bad/abnormal data
North-TM	STM212	Steamboat	Y				
North-TM	STM213	Steamboat	Y				Load profile was changed, removed bad/abnormal data
North-TM	STM214	Steamboat	Y				Load profile was changed, removed bad/abnormal data
North-TM	STM215	Steamboat	Y				Load profile was changed, removed bad/abnormal data
North-TM	STM219	Steamboat				Y	
North-TM	STM268	Steamboat	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	STR1203	STR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	STR1204	STR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	STR1205	STR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	STR1206	STR BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	STR1207	STR BK 1	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-STRIP	STR1208	STR BK 1	Y				
South-STRIP	STR1215	STR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	STR1216	STR BK 2	Y				
South-STRIP	STR1217	STR BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	STR1218	STR BK 2	Y				
South-STRIP	STR1219	STR BK 2	Y				
North-East	STY2402	Setty	Y				
North-East	STY251	Setty	Y				
South-SE	SUS1205	SUS BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	SUS1206	SUS BK 2	Y				
North-TM	SUT211	Sutro				Y	
North-TM	SUT241	Sutro				Y	
North-TM	SUT246	Sutro				Y	
South-SW	SV1201	SV BK 1			Y		
South-SW	SV1202	SV BK 1			Y		
South-SW	SV1207	SV BK 2			Y		
South-SW	SV1209	SV BK 2			Y		
South-SW	SV1211	SV BK 3			Y		
South-SW	SV1213	SV BK 3			Y		
South-SW	SV1214	SV BK 3			Y		
South-SW	SV1216	SV BK 4	Y				Load profile was changed, removed bad/abnormal data
Carson	SVR203	Silver Peak	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SWN1201	SWN BK 1	Y				
South-STRIP	SWN1207	SWN BK 1	Y				
South-STRIP	SWN1208	SWN BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SWN1209	SWN BK 2	Y				
South-STRIP	SWN1213	SWN BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SWN1216	SWN BK 2	Y				
South-STRIP	SWN1219	SWN BK 2	Y				Load profile was changed, removed bad/abnormal data
Carson	SWW201	Sweetwater				Y	
South-STRIP	SZ1201	SZ BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SZ1202	SZ BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SZ1203	SZ BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SZ1205	SZ BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SZ1206	SZ BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SZ1208	SZ BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SZ1209	SZ BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SZ1211	SZ BK 3	Y				Load profile was changed, removed bad/abnormal data

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-STRIP	SZ1213	SZ BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	SZ1214	SZ BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	TA1201	TA BK 1			Y		Load profile was changed, removed bad/abnormal data
South-SW	TA1202	TA BK 1			Y		Load profile was changed, removed bad/abnormal data
South-SW	TA1204	TA BK 1			Y		Load profile was changed, removed bad/abnormal data
South-SW	TA1205	TA BK 2			Y		Load profile was changed, removed bad/abnormal data
South-SW	TA1209	TA BK 3			Y		Load profile was changed, removed bad/abnormal data
South-SW	TA1210	TA BK 3			Y		Load profile was changed, removed bad/abnormal data
South-SW	TA1212	TA BK 3			Y		Load profile was changed, removed bad/abnormal data
North-TM	TAH5201	Tahoe City	Y				Load profile was changed, removed bad/abnormal data
North-TM	TAH625	Tahoe City				Y	
North-TM	TAH629	Tahoe City				Y	
North-TM	TAH7100	Tahoe City	Y				Load profile was changed, removed bad/abnormal data
North-TM	TAH7200	Tahoe City	Y				Load profile was changed, removed bad/abnormal data
North-TM	TAH7300	Tahoe City	Y				Load profile was changed, removed bad/abnormal data
North-TM	TCY277	Tracy		Y			Load profile was changed, removed bad/abnormal data
North-TM	TCY278	Tracy		Y			Load profile was changed, removed bad/abnormal data
South-NW	TE1201	TE BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	TE1203	TE BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	TE1204	TE BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	TE1205	TE BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	TE1206	TE BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	TE1208	TE BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	TE1209	TE BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NW	TE1211	TE BK 3	Y		Y		Load profile was changed, removed bad/abnormal data
South-NW	TE1212	TE BK 3	Y				
South-NW	TE1213	TE BK 3	Y				
North-East	TLS240	T Lazy S		Y			Load profile was changed, removed bad/abnormal data
South-NE	TO1201	TO BK 1			Y		
South-NE	TO1203	TO BK 1			Y		
South-NE	TO1204	TO BK 2			Y		
South-NE	TO1206	TO BK 2			Y		
South-NE	TO1207	TO BK 2			Y		
South-NE	TO1209	TO BK 3			Y		Load profile was changed, removed bad/abnormal data
South-NE	TO1211	TO BK 3			Y		Load profile was changed, removed bad/abnormal data
South-SE	TOL1204	TOL BK 4	Y				
South-SE	TOL1205	TOL BK 4	Y				
South-SE	TOL1206	TOL BK 4	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SE	TOL1208	TOL BK 4	Y				
South-SE	TOL1209	TOL BK 4	Y				
South-SE	TOL1210	TOL BK 4				Y	
South-SE	TOL1215	TOL BK 3	Y				
South-SE	TOL1216	TOL BK 3	Y				
South-SE	TOL1217	TOL BK 3				Y	
South-SE	TOL1218	TOL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SE	TOL1220	TOL BK 3	Y				
South-SE	TOL1221	TOL BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SW	TOM1201	TOM BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	TOM1204	TOM BK 2	Y				
South-SW	TOM1210	TOM BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SW	TOM1211	TOM BK 2	Y				
South-SW	TOM1212	TOM BK 2	Y				
South-SW	TOM1213	TOM BK 2	Y				
South-SW	TOM1214	TOM BK 3	Y				
North-East	TOU701	Toulon		Y		Y	Generic profile used for part of year
Carson	TPZ1261	Topaz		Y			Load profile was changed, removed bad/abnormal data
South-STRIP	TR1202	TR BK 1			Y		
South-STRIP	TR1209	TR BK 2				Y	
South-STRIP	TR1210	TR BK 2			Y		
North-TM	TRK7202	Truckee	Y				Load profile was changed, removed bad/abnormal data
North-TM	TRK7203	Truckee	Y				Load profile was changed, removed bad/abnormal data
North-TM	TRK7204	Truckee	Y				Open for most of the year
South-NE	TRO1201	TRO BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NE	TRO1203	TRO BK 1	Y				
South-NE	TRO1204	TRO BK 1	Y				
South-NE	TRO1205	TRO BK 2	Y				
South-NE	TRO1206	TRO BK 2	Y				
South-NE	TRO1211	TRO BK 2	Y				
South-NE	TRO1212	TRO BK 2	Y				
South-NE	TRO1214	TRO BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	TRO1215	TRO BK 3	Y				
South-NE	TRO1217	TRO BK 3	Y				
Carson	TVH7008	TV Hill				Y	
North-TM	UNV1	University				Y	
North-TM	UNV2	University		Y			Replaced missing 2017 data with 2018 data
North-TM	UNV3	University				Y	

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
North-TM	UNV4	University				Y	
North-TM	VAL244	Valley Road	Y				
North-TM	VAL246	Valley Road	Y				Load profile was changed, removed bad/abnormal data
North-TM	VAL248	Valley Road	Y				Load profile was changed, removed bad/abnormal data
North-TM	VAL249	Valley Road	Y				Load profile was changed, removed bad/abnormal data
North-TM	VAL251	Valley Road	Y				Load profile was changed, removed bad/abnormal data
North-TM	VAL254	Valley Road	Y				Load profile was changed, removed bad/abnormal data
North-TM	VAL262	Valley Road	Y				Load profile was changed, removed bad/abnormal data
Carson	VCY213	Virginia City				Y	
Carson	VCY214	Virginia City		Y			Replaced with 2018 data due to lack of 2017 data
Carson	VCY215	Virginia City		Y		Y	Used all 2018 data that was available
South-NW	VGS1201	VGS BK 1			Y		
South-NW	VGS1203	VGS BK 1			Y		
South-NW	VGS1204	VGS BK 1			Y		
South-NW	VGS1205	VGS BK 2			Y		
South-NW	VGS1206	VGS BK 2			Y		
South-NW	VGS1207	VGS BK 2			Y		
South-NW	VGS1208	VGS BK 2			Y		
South-NW	VGS1211	VGS BK 3			Y		Load profile was changed, removed bad/abnormal data
South-NW	VGS1212	VGS BK 3			Y		Load profile was changed, removed bad/abnormal data
South-NW	VGS1213	VGS BK 3			Y		
South-NW	VLG1201	VLG BK 1	Y				
South-NW	VLG1203	VLG BK 1	Y				
South-NW	VLG1206	VLG BK 1	Y				
South-NW	VLG1210	VLG BK 1	Y				
South-NW	VLG1212	VLG BK 1	Y				Load profile was changed, removed bad/abnormal data
South-NW	VLG1213	VLG BK 1	Y				
South-STRIP	VV1201	VV BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	VV1203	VV BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	VV1204	VV BK 1	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	VV1206	VV BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	VV1207	VV BK 2	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	VV1209	VV BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	VV1210	VV BK 3	Y				Load profile was changed, removed bad/abnormal data
South-STRIP	VV1212	VV BK 3	Y				Load profile was changed, removed bad/abnormal data
South-SE	WA1201	WA BK 1				Y	
South-SE	WA1203	WA BK 1				Y	
South-SE	WA1204	WA BK 1				Y	

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SE	WA1206	WA BK 2			Y		
South-SE	WA1208	WA BK 2			Y		
South-SE	WA409	WA BK 3				Y	
South-SE	WA410	WA BK 3				Y	
North-East	WAD1221	Wadsworth				Y	
South-NW	WE1201	WE BK 5	Y				
South-NW	WE1204	WE BK 5	Y				
South-NW	WE1207	WE BK 6	Y				
South-NW	WE1208	WE BK 6	Y				
South-NW	WE1209	WE BK 6	Y				Load profile was changed, removed bad/abnormal data
South-NW	WE1210	WE BK 6	Y				Load profile was changed, removed bad/abnormal data
South-NW	WE1211	WE BK 7	Y				Load profile was changed, removed bad/abnormal data
South-NW	WE1212	WE BK 7	Y				Load profile was changed, removed bad/abnormal data
South-NW	WE1214	WE BK 7	Y				Load profile was changed, removed bad/abnormal data
South-NW	WE1219	WE BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NW	WE1220	WE BK 3	Y				Load profile was changed, removed bad/abnormal data
North-East	WES1212	West Side^	Y				
South-SE	WH1201	WH BK 1				Y	
South-SE	WH1202	WH BK 1				Y	
South-SE	WH1203	WH BK 1				Y	
South-SE	WH1204	WH BK 1				Y	
South-SE	WH1206	WH BK 2				Y	
South-SE	WH1209	WH BK 3				Y	
South-SE	WH1211	WH BK 3				Y	
South-SE	WH1213	WH BK 4				Y	
South-SE	WH1214	WH BK 4				Y	
South-SE	WI1201	WI BK 1				Y	
South-SE	WI1203	WI BK 1				Y	
South-SE	WI1204	WI BK 1				Y	
South-SE	WI1205	WI BK 2				Y	
South-SE	WI1206	WI BK 2				Y	
South-SE	WI1208	WI BK 2				Y	
South-SE	WI1209	WI BK 2				Y	
South-SE	WI1211	WI BK 3				Y	
South-SE	WI1212	WI BK 3				Y	
South-SE	WI1213	WI BK 3				Y	
South-SE	WIL1204	WIL BK 1	Y				
South-SE	WIL1205	WIL BK 1	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SE	WIL1206	WIL BK 1	Y				
South-SE	WIL1208	WIL BK 1	Y				
South-SE	WIL1209	WIL BK 1	Y				
South-SE	WIL1210	WIL BK 1	Y				
South-SE	WIL1216	WIL BK 2	Y				
South-SE	WIL1217	WIL BK 2	Y				
South-SE	WIL1218	WIL BK 2	Y				
South-SE	WIL1220	WIL BK 2	Y				
South-SE	WIL1221	WIL BK 2	Y				Load profile was changed, removed bad/abnormal data
North-East	WIN201	Winnemucca	Y				Load profile was changed, removed bad/abnormal data
North-East	WIN205	Winnemucca	Y				Load profile was changed, removed bad/abnormal data
North-East	WIN206	Winnemucca	Y				
North-East	WIN701	Winnemucca				Y	
North-TM	WLR1	Wheeler				Y	
North-TM	WLR264	Wheeler				Y	
North-TM	WLR2	Wheeler		Y			Replaced missing 2017 data with 2018 data
South-NE	WN1201	WN BK 1				Y	
South-NE	WN1203	WN BK 1				Y	
South-NE	WN1204	WN BK 1				Y	
South-NE	WN1206	WN BK 2				Y	
South-NE	WN1208	WN BK 2				Y	
South-NE	WN1209	WN BK 3				Y	
South-NE	WN1210	WN BK 3				Y	
South-NE	WN1211	WN BK 3				Y	
South-NE	WN1213	WN BK 4				Y	
South-NE	WSH1201	WSH BK 1	Y				
South-NE	WSH1203	WSH BK 1	Y				
South-NE	WSH1204	WSH BK 1	Y				
South-NE	WSH1205	WSH BK 2	Y				
South-NE	WSH1208	WSH BK 2	Y				
South-NE	WSH1209	WSH BK 2	Y				
South-NE	WSH1210	WSH BK 2	Y				Load profile was changed, removed bad/abnormal data
South-NE	WSH1211	WSH BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	WSH1212	WSH BK 3	Y				Load profile was changed, removed bad/abnormal data
South-NE	WSH1213	WSH BK 3	Y				Load profile was changed, removed bad/abnormal data
North-TM	WSH201	Washoe				Y	
North-TM	WSH203	Washoe				Y	
South-SE	WSP1201	WSP BK 1	Y				

NEVADA POWER AND SIERRA DISTRIBUTION FEEDER LOADING DATA SOURCES

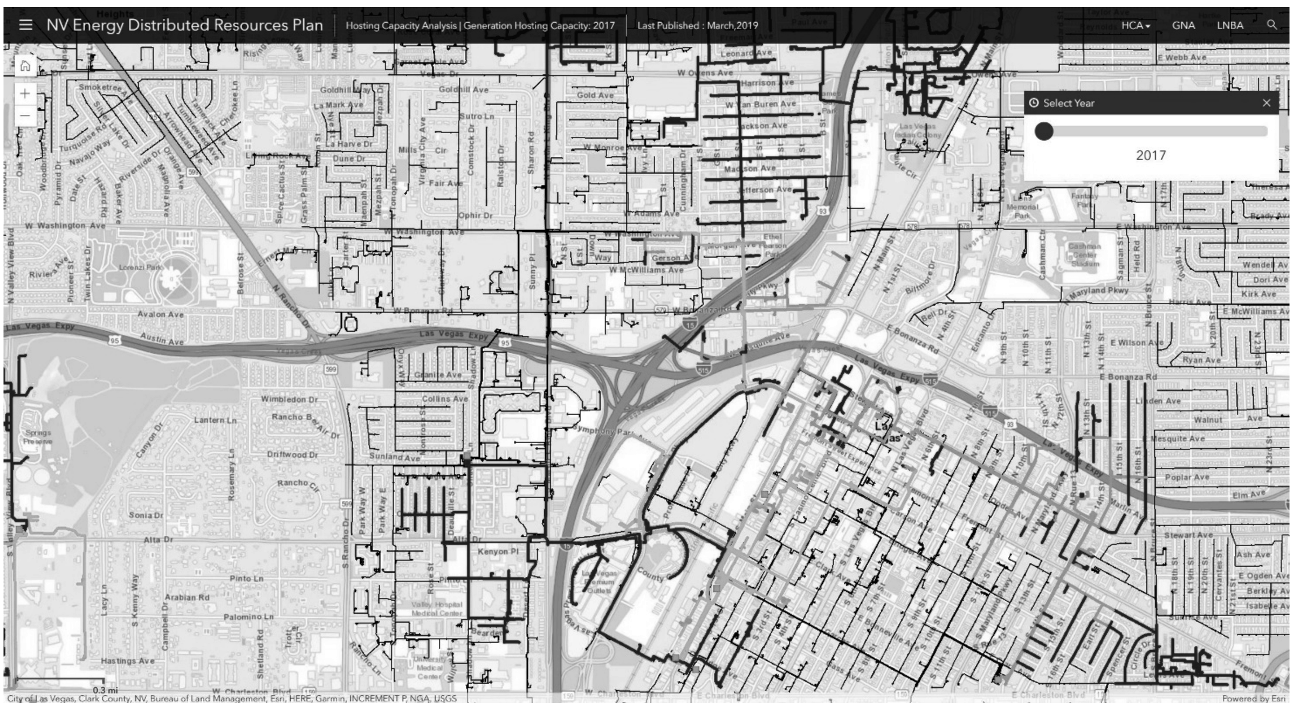
Region	Feeder ID	Substation or Transformer ID	PI data?	PQ Sensors?	Scaled Transformer data?	Generic profile?	Notes
South-SE	WSP1203	WSP BK 1	Y				
South-SE	WSP1204	WSP BK 1	Y				Load profile was changed, removed bad/abnormal data
South-SE	WSP1205	WSP BK 2	Y				
South-SE	WSP1208	WSP BK 2	Y				
South-SE	WSP1209	WSP BK 2	Y				Load profile was changed, removed bad/abnormal data
South-SE	WSP1210	WSP BK 2	Y				
South-SE	WSP1211	WSP BK 3	Y				
South-SE	WSP1212	WSP BK 3	Y				
South-SE	WSP1213	WSP BK 3	Y				
North-TM	WSH204	Washoe				Y	
North-TM	WST1	W 7 th		Y			Load profile was changed, removed bad/abnormal data
North-TM	WST2	W 7 th				Y	
Carson	WTP1201	West Tonopah		Y			Used all 2018 data that was available
Carson	WTP1202	West Tonopah		Y			Used all 2018 data that was available
Carson	WTP1203	West Tonopah		Y			Used all 2018 data that was available
South-SE	WW1203	WW BK 1				Y	
South-SE	WW1204	WW BK 1				Y	
South-SE	WW1205	WW BK 1				Y	
South-SE	WW1207	WW BK 2				Y	
South-SE	WW1210	WW BK 2				Y	
South-SE	WW1211	WW BK 3				Y	
South-SE	WW1214	WW BK 3				Y	
South-SE	WW1216	WW BK 7	Y				Load profile was changed, removed bad/abnormal data
South-SE	WW1217	WW BK 7	Y				
South-SE	WW1219	WW BK 7	Y				
South-SE	WW1220	WW BK 7	Y				
South-SE	WW1224	WW BK 8	Y				
South-SE	WW1225	WW BK 8	Y				

DRP-5

Technical Appendix DRP-5
Publicly-accessible DRP Web Portal

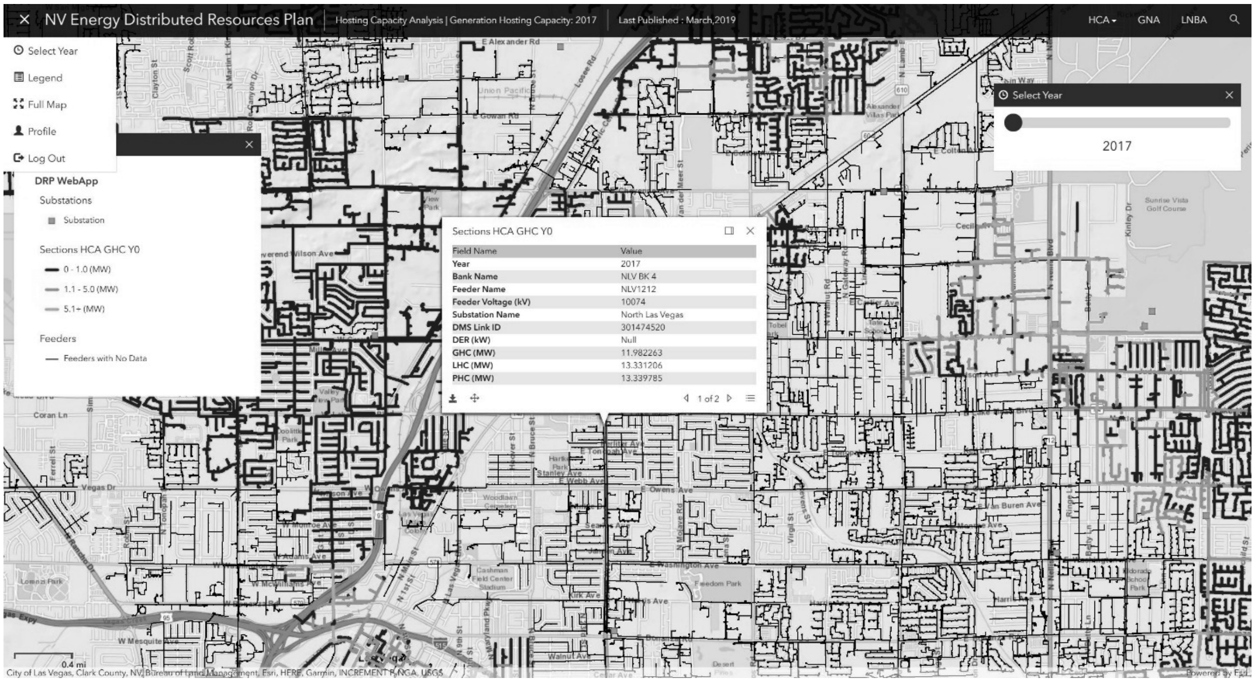
The graphic below provides a screen shot of the landing page of the DRP web portal. As noted by the title, this is the Hosting Capacity Analysis (“HCA”) (uniform) Generation Hosting Capacity screen based upon 2017 data, and is centered on Las Vegas. The black lines represent the distribution feeders from the various substations, which are shown as green boxes, overlaid on an ESRI-based map. This screen shows the result of the integration of NV Energy’s AutoCAD Map 3D GIS data and the DNV-GL Synergi Electric software data.

<u>DRP Portal Landing Page</u>



For HCA results, there are three views that can be accessed via clicking the pulldown menu for “HCA” on the top right of the screen: Generation Hosting Capacity, Photovoltaic Hosting Capacity, and Load Hosting Capacity. The map and the displayed data are the same for each of these views, but the color-coding of the feeders will change depending upon which view is selected. The graphic below shows an example of the HCA – Generation Hosting Capacity results view. The legend is accessed by clicking the icon on top left of the screen with the three parallel lines and shows the color coding for the feeders and the corresponding value ranges.

<u>HCA -- Generation Hosting Capacity Results View</u>



On all of the HCA website portal views:

- The feeders are displayed in Red, Amber, and Green, which represent the incremental Hosting Capacity available on the feeders sections in kW.
- Identifying information, the amount of existing Distributed Resources capacity, and HCA results data for Generation, Photovoltaic, and Load Hosting Capacity for 2017 to 2025 are shown in a popup box for all feeder sections by clicking on any feeder section and by using the “Select Year” slider on the upper right of the screen. This data will be downloadable.[1] Note, however, that data for the redacted feeders discussed in the DRP narrative in Section 6 will not be shown.

The color coding value ranges for the three HCA views is the same for each view, and is provided below:

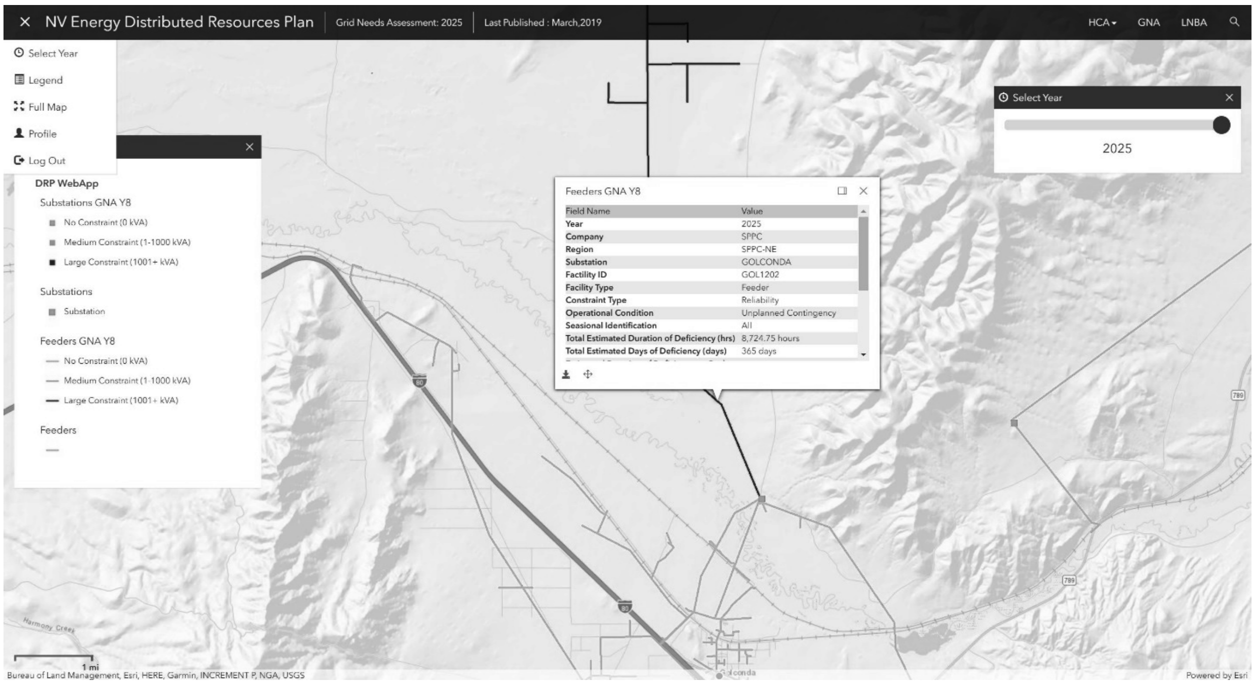
		Feeder Sections		
Incremental HCA Results		Red	Amber	Green
	Generation	0-1.0 MW	1.1-5.0 MW	5.1+ MW
	Photovoltaic	0-1.0 MW	1.1-5.0 MW	5.1+ MW
	Load	0-1.0 MW	1.1-5.0 MW	5.1+ MW

[1] When the web portal is available to the public, which is currently planned by the end of April, only HCA results for 2017 will be available. NV Energy plans to conduct HCA studies for the years 2018 to 2025 and populate the results to the web portal by October 2019. Note that the data download feature is not yet available as of the date of this filing.

At the bottom of the legend, access to historical and forecasted substation transformer and feeder loading data can be gained by clicking the icon on the top left of the screen with the three parallel lines and clicking the download icon indicating this data.[2]

Next, the Grid Needs Assessment ("GNA") website portal screen can be accessed by clicking on "GNA" on the top right of the screen. The graphic below shows an example of the Grid Needs Assessment results view.

<u>Grid Needs Assessment Results View</u>



On the GNA view:

- Any distribution facility (substation or feeder) without an identified constraint is shown as green. Substations or feeder sections are colored amber or red based upon the amount of the deficiency in the first year that it is forecasted to occur (*i.e.,* the Initial Deficiency).
- Identifying information, deficiency information, and information about the traditional wired solution are shown for any facility in a popup box for all substations and feeder sections by clicking on any substation or feeder section with an amber or red color, and by using the "Select Year" slider on the upper right of the screen. This data will be downloadable (note Footnote 2).

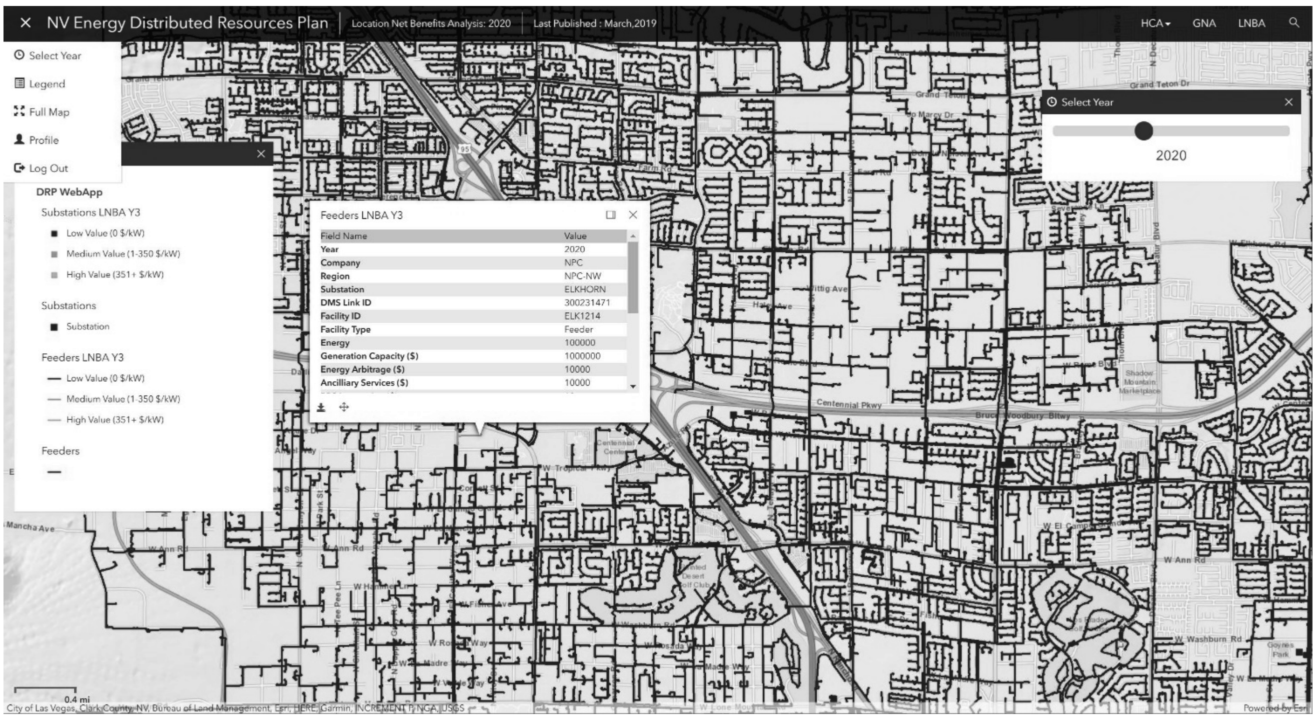
[2] Not shown in the above graphic as this feature was not yet available as of the date of this filing.

The color coding value ranges for the GNA view are provided below:

GNA Initial Deficiency	**Substations**			**Feeder Section**		
	Green	Amber	Red	Green	Amber	Red
	No Constraint (0 kVA)	Medium Constraint (1-1000 kVA)	Large Constraint (1001+ kVA)	No Constraint (0 kVA)	Medium Constraint (1-1000 kVA)	Large Constraint (1001+ kVA)

Finally, the Locational Net Benefits Analysis ("LNBA") can be accessed by clicking on "LNBA" on the top right of the screen. The graphic below shows an example of the Locational Net Benefits Analysis results view.

<u>Locational Net Benefits Analysis Results View</u>



On the LNBA view:

- Any distribution facility (substation or feeder) for which a Non-Wires Alternative analysis was performed will have data reflected on this view and will be colored either amber or green on the basis of the distribution upgrade value in $/kW (*i.e.*, the estimated cost of the traditional distribution wired solution divided by the total kW additive capacity of the potential Non-Wires Alternative portfolio solution). Any facility without a constraint will be red.
- Identifying information, system-level benefits, and locational-level benefits are shown for any facility for which a Non-Wires Alternative analysis was performed in a popup box for all substations and feeder sections by clicking on any substation or feeder section with an

amber or green color, and by using the "Select Year" slider on the upper right of the screen. This data will be downloadable (note Footnote 2).

- It should be noted that even when a facility is red with a low value or 0 $/kW of distribution upgrade deferral value, there will still be some $/kW value from the system benefits. This system value benefit is not shown on the web portal because at this time there isn't a related Non-Wires Alternative kW value that can be used to calculate this system value benefit.

The color coding value ranges for the LNBA view are provided below:

LNBA Distribution Upgrade Deferral Value	**Substations**			**Feeder Sections**		
	Red	Amber	Green	Red	Amber	Green
	Low Value (0 $/kW)	Medium Value (1-350 $/kW)	High Value (351+ $/kW)	Low Value (0 $/kW)	Medium Value (1-350 $/kW)	High Value (351+ $/kW)

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of **NEVADA POWER COMPANY D/B/A NV ENERGY and SIERRA PACIFIC POWER COMPANY D/B/A/ NV ENERGY** Docket No. 19-04**___** upon the persons listed below by the following:

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