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 Second Amendment to 2018 Joint Integrated Resource Plan, including a change to the Demand-Side Action Plan to achieve 1.25% annual energy savings target, additions to the generation portion of the Supply-Side Action Plan including a new cooling pond for Tracy Unit 3 and a new agreement with Idaho Power Company for the orderly retirement of the North Valmy Station, updates to the Transmission Action Plan including several new transmission projects needed to serve growing distribution and transmission load.	Docket No. 18-06___

VOLUME 1 OF 4

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

TRANSMITTAL LETTER

NVEnergy

May 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. 19-05___ - Joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of Second Amendment to 2018 Joint IRP.

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 Second Amendment to the 2018 Joint Integrated Resource Plan (approved by the Commission on February 15, 2019 in Docket No. 18-06003. This Second Amendment addresses requests to update and modify the load forecast, the demand-side management ("DSM") Action Plan, the generation portion of the supply-side Action Plan, and the Transmission Action Plan.

The Companies have included with this Application and incorporate herein by reference the following Application Exhibits:

- **Application Exhibit A** is a narrative discussion of updates to the load forecast, the DSM Action Plan, the generation portion of the Supply Side Action Plan, and the Transmission Action Plan.

- **Application Exhibit B** is a proposed notice of the Application as required by NAC § 703.162.
- **Application Exhibit C** is an updated loads and resources table.

In addition, the Application is supported by Technical Appendices and prepared direct testimony.

- **Mr. Jack McGinley** is the executive sponsor of the Second Amendment.

- The updated load forecast is addressed in Section 3 of the narrative, in Technical Appendices LF-1(portions of which are confidential) through LF-8, and supported by the prepared direct testimony of **Mr. Terry Baxter**.

- The updated DSM Action Plan is addressed in Section 4 of the narrative and supported by the prepared direct testimony **Ms. Anita Hart**.

- The updated portion of the Supply-Side Action Plan addressing the replacement of the Tracy Unit 3 unlined cooling pond is discussed in Section 5 of the narrative, in Technical Appendices GEN-1 and GEN-2 (which is confidential), and in the prepared direct testimony of **Mr. Dariusz Rekowski.**

- The updated portion of the Supply-Side Action Plan seeking approval of the new North Valmy Project Framework Agreement with IPCo is discussed in Section 5 of the Narrative, Technical Appendix GEN-3 (confidential), and prepared direct testimony of **Mr. Matthew Johns**.

- Updates to the budgets of three previously-approved Transmission Action Plan items, requests for approval of scope changes and budget revisions of three other previously-approved Transmission Action Plan items, Transmission Action Plan additions of six new transmission projects required to meet growth and reliability needs, as well as Transmission Action Plan additions for network upgrades needed to satisfy four new generator interconnection requests are discussed in Section 6 of the Narrative, Technical Appendix TRAN-1 through TRAN-11 (portions of TRAN-1, TRAN-3 and TRAN-4 contain customer-specific confidential information), and the prepared direct testimony of **Mr. Sachin Verma**.

Regarding confidentiality, some of the information set forth in the Narrative and in Technical Appendices LF-1, TRAN-1, TRAN-2, TRAN 3 and TRAN-4 contain customer-specific load information and are thus confidential. Portions of TRAN-1 also include Critical Infrastructure Information, which cannot be made public under Federal Energy Regulatory Commission and North American Electric Reliability Corporation regulations and standards.

In addition, limited portions of GEN-2 contain cost estimates for elements of the replacement for the Tracy Unit 3 cooling pond that have not yet been procured. If this commercially confidential information were to be made public, prospective bidders in the competitive solicitations that would be used to procure equipment and services would know Sierra's expectations of prices, which would impact the results of the competitive solicitation. Additionally, the business case writeup shows the operating and maintenance costs utilized for economically dispatching the generating fleet. This information is commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information to any market participant would disadvantage the Companies' customers by limiting the Companies' ability to foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing its bargaining leverage. Publication of this information would also unfairly advantage competing suppliers and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of their customers.

Finally, GEN-3, the new North Valmy Project Framework Agreement, is being designated as confidential. IPCo has filed the entire Framework Agreement as confidential at the Idaho Public Utilities Commission. The assertion of IPCo, the counterparty to the agreement, that the entire agreement is confidential qualifies the agreement for protection as a trade secret or confidential commercial information pursuant to NRS § 703.190. If IPCo and/or the Idaho Commission determine that all or portions of the Framework Agreement can be made available publicly, the Companies will make a filing with the Commission amending its request for confidential treatment.

The Companies request that designated information remain confidential for a period of at least 5 years, after which it may be destroyed or returned to the Companies, whichever is more convenient for the Commission.

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
Deputy General Counsel

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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 APPLICATION** upon the persons listed below by electronic mail:

Tammy Cordova
Public Utilities Comm. of Nevada
1150 E. William Street
Carson City, NV 89701-3109
tcordova@puc.nv.gov

Staff Counsel Division
Public Utilities Comm. of Nevada
9075 West Diablo, Suite 250
Las Vegas, NV 89148
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DATED this 1st day of May, 2019.

/s/Connie Silveira
Connie Silveira
Senior Legal Administrative Assistant
Nevada Power Company
Sierra Pacific Power Company

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

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 Second Amendment to 2018 Joint Integrated Resource Plan, including a change to the Demand-Side Action Plan to achieve 1.25% annual energy savings target, additions to the generation portion of the Supply-Side Action Plan including a new cooling pond for Tracy Unit 3 and a new agreement with Idaho Power Company for the orderly retirement of the North Valmy Station, updates to the Transmission Action Plan including several new transmission projects needed to serve growing distribution and transmission load.	)))))))))))))) /	Docket No. 19-05_____

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

APPLICATION TO APPROVE SECOND 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"), 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' Second Amendment to their 2018 joint triennial integrated resource plan ("2018 Joint IRP"). As an amendment to the Companies' 2018 Joint IRP, NRS § 704.751(2)(a) requires that that Commission issue an order accepting or modifying the Second Amendment, 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 Sunday, October 13, 2019.

I.
SUMMARY AND INTRODUCTION

In the 16 months since preparation on the 2018 Joint IRP began, regulations implementing the numerous energy-related bills from the 2017 Nevada Legislature have been finalized, conditions impacting the operations of two of its generating units have changed, and loads on the Companies' distribution and transmission systems have continued to grow. These and related events have raised the need to amend some aspects the Action Plan approved by the Commission in Docket No. 18-06003. Included in this Second Amendment are requests to amend the Demand-Side Management ("DSM") Plan to add a program that will increase the net benefits of the DSM portfolio to 1.25 percent of retail sales, to amend the generation section of the Supply-Side Plan to obtain approval to construct a replacement for the unlined cooling pond serving the existing Tracy 3 unit and to approve a new agreement with Idaho Power Company ("IPCo.") addressing the North Valmy Station, and to make several updates and additions to the Companies' Transmission Plan.

The projects for which approvals are sought in this Second Amendment do not result in material changes to either loads or resources (capacity or energy) and have not been analyzed utilizing production cost modeling. Nevertheless, consistent with NAC § 704.9516(1), which sets forth the requirements of an amendment to an approved Action Plan, an updated current peak demand forecast and a current loads and resources table are provided. The projects addressed in this Second Amendment have not had an incremental impact on the Companies' ability to finance their operations or on imputed debt.

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 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:

Michael Greene
Deputy General Counsel
6100 Neil Road
Reno, NV 89511
775-834-5692
mgreene@nvenergy.com

LoreLei Reid
Manager, Regulatory Services
6100 Neil Road
Reno, NV 89511
775-834-5823
regulatory@nvenergy.com

III.
APPLICATION EXHIBITS

To aid the Commission in considering the Second Amendment, the Companies have included with this Application and incorporated herein by reference are the following exhibits:

- **Application Exhibit A** is a narrative discussion of updates to the load forecast, the DSM Action Plan, the generation portion of the Supply Side Action Plan, and the Transmission Action Plan.
- **Application Exhibit B** is a proposed notice of the Application as required by NAC § 703.162.
- **Application Exhibit C** is an updated loads and resources table.

The form of Exhibit A, the 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.

IV.
ADDITIONAL 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, the Second Amendment includes all such additional 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, is set forth by general topic below.

Mr. Jack McGinley is the executive sponsor of the Second Amendment.

The updated load forecast is addressed in Section 3 of the narrative, in Technical Appendices LF-1 (portions of which are confidential) through LF-8, and supported by the prepared direct testimony of Mr. Terry Baxter.

The updated DSM Action Plan is addressed in Section 4 of the narrative and supported by the prepared direct testimony Ms. Anita Hart.

The updated portion of the Supply-Side Action Plan addressing the replacement of the Tracy Unit 3 unlined cooling pond is discussed in Section 5 of the narrative, in Technical Appendices GEN-1 and GEN-2 (confidential), and in the prepared direct testimony of Mr. Dariusz Rekowski.

The updated portion of the Supply-Side Action Plan seeking approval of the new North Valmy Project Framework Agreement with IPCo is discussed in Section 5 of the narrative, Technical Appendix GEN-3 (confidential), and prepared direct testimony of Mr. Matthew Johns.

Updates to the budgets of three previously-approved Transmission Action Plan items, requests for approval of scope changes and budget revisions of three other previously-approved

Transmission Action Plan items, Transmission Action Plan additions of six new transmission projects required to meet growth and reliability needs, as well as Transmission Action Plan additions for network upgrades needed to satisfy four new generator interconnection requests are discussed in Section 6 of the narrative, Technical Appendix TRAN-1 through TRAN-11 (portions of TRAN-1, TRAN-2, TRAN-3 and TRAN-4 contain confidential information), and the prepared direct testimony of Mr. Sachin Verma.

V.
CONFIDENTIALITY

None of the information set forth in the Prepared Direct Testimony is commercially confidential and/or trade secret information subject to protection pursuant to NRS § 703.190. However, some of the information set forth in some of the Narrative and in Technical Appendices LF-1, TRAN-1, TRAN-2, TRAN 3, and TRAN-4 contain customer-specific load information and are thus confidential. Portions of TRAN-1 and TRAN-2 also include Critical Infrastructure Information, which cannot be made public under Federal Energy Regulatory Commission and North American Electric Reliability Corporation regulations and standards.

In addition, GEN-2 contains cost estimates for elements of the replacement for the Tracy Unit 3 cooling pond that have not yet been procured. If this commercially confidential information were to be made public, prospective bidders in the competitive solicitations that would be used to procure equipment and services would know Sierra's expectations of prices, which would impact the results of the competitive solicitation. Additionally, the business case write-up shows the operating and maintenance costs utilized for economically dispatching the generating fleet. This information is commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information to any market participant would disadvantage the Companies' customers by limiting the Companies' ability to foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing its bargaining leverage.

Publication of this information would also unfairly advantage competing suppliers and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of their customers.

Finally, GEN-03, the new North Valmy Project Framework Agreement, is being designated as confidential. IPCo has filed the entire Framework Agreement as confidential at the Idaho Public Utilities Commission ("IPUC"). The assertion of IPCo, the counterparty to the agreement, that the entire agreement is confidential qualifies the agreement for protection as a trade secret or confidential commercial information pursuant to NRS § 703.190. If IPCo and/or the IPUC determine that all or portions of the Framework Agreement can be made available publicly, the Companies will make a filing with the Commission amending its request for confidential treatment.

The Companies request that designated information remain confidential for a period of at least five years, after which it may be destroyed or returned to the Companies, whichever is more convenient for the Commission.

VI.
PRAYER

NAC § 704.9516(1)(a) requires that an amendment to an Action Plan include a section that identifies the items for which the applicant is requesting specific approval. In compliance with this provision of the IRP regulations, Sierra and Nevada Power are making the following specific requests.

1. Approval of the 2019 IRPA 2nd Forecast, a long-term base load forecast, as being the most accurate information upon which to base the planning decisions set forth in the filing.

2. Approval the Companies' request to amend their 2019-2021 DSM Action Plan to incorporate the FlexPay program, including the current FlexPay budget, into their DSM portfolio for program years 2020 and 2021.

3. Approval of the Companies' request to amend their 2019-2020 Supply-Side Action Plan to expend an estimated $12.9 million to construct a new cooling pond and upgrade

associated fresh and waste water treatment systems for Tracy Unit 3. The new cooling pond will be completed and in service prior to December 31, 2020, at which time the current discharge permit prohibits any further discharge into the existing unlined cooling pond from Tracy Unit 3.

4. Approval of the Companies' request to amend their 2019-2020 Supply-Side Action Plan by approving a new North Valmy Project Framework Agreement with IPCo, which provides a mechanism for either owner to cease its participation in one or both units in the event of several end-of-operation scenarios, as well as addresses with more specificity the North Valmy Station's decommissioning requirements.

5. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to cancel the recently approved East Tracy 345/120 kV Transformer Project and to instead expend $14.62 million to construct a new West Tracy 345/120 kV Transformer Project.

6. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to increase the 2018 budget for the Bordertown to California Substation project from $31.371 million to $44.692 million. The revised budget updates all scope revisions and project cost estimates required to comply with the changes in project design features as well as mitigation and monitoring plans identified in the final Environmental Impact Statement the draft Record of Decision governing the project.

7. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $7.5 million to increase the footprint of the previously approved new Olinghouse 345 kV Substation to accommodate an expandable breaker-and-a-half configuration, which will provide for the most cost effective accommodation of anticipated generator interconnection requests. The in-service date for the Olinghouse 345 kV Substation project is April 1, 2021.

8. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $52.684 million to construct the new Comstock Meadows 345 kV/120 kV Substation and associated facilities to provide a second 345 kV injection point into the 120 kV system, consistent with the Tracy Area Master Plan. The in-service date for the

Comstock Meadows 345 kV/120 kV Project is May 1, 2021.

9. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend $6.95 million to conduct routing and constraint studies for a new major northern Nevada transmission interconnection, a transmission hub at Ft. Churchill and three new transmission lines: from Robinson Summit Substation to Ft. Churchill Substation, from Harry Allen Substation to Ft. Churchill, and from Ft. Churchill to the Reno 345 kV system.

10. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $7.21 million to construct a new breaker at the Reid Gardner 230 kV Substation and a new 2.6 mile 230 kV line from Reid Gardner to Tortoise Substation, and associated facilities, thereby extending a second source to the Overton Power District and the Lincoln County Power District. The in-service date for the Reid Gardner to Tortoise 230 kV Project is June 1, 2022.

11. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $24.880 million to construct a new Shaffer 345 kV Substation and line fold on the Hilltop to Ft. Sage 345 kV line and associated facilities, to provide a second point of service to Lassen Municipal Utility District. The in-service date for the Shaffer 345 kV Project is June 30, 2022.

12. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $7.7 million to install a 230/69 kV transformer at the existing Bighorn Substation and construct a new five mile 69 kV line and associated facilities from Bighorn Substation to the Oasis/Jean 69 kV system to increase reliability and mitigate service quality issues for approximately 21 MW of customer load currently being served radially out of Arden 69 kV. The in-service date for the project is December 31, 2020.

13. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $4.170 million to commence routing and siting for an additional transmission source into the West Henderson area.

14. Approval of the Companies' request to amend their 2019-2020 Transmission

Action Plan to expend approximately $15.338 million to construct network upgrades including the new Carson Lake 230 kV Substation in a six-breaker ring, breaker-and-a-half configuration, to satisfy a generation interconnection request. The new Carson Lake project will be in service in time to meet the requirements of the generator, December 1, 2021.

15. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $2.1 million to construct network upgrades needed to support the addition of the Harry Allen Solar project, a 100 MW solar PV generating facility at the existing Harry Allen 230 kV Substation, The new Harry Allen interconnection project will be in service in time to meet the requirements of the generator, September 1, 2020.

16. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $2.650 million to construct network upgrades needed to interconnect the Aiya Solar project, a 100 MW solar PV generating facility, at the existing Reid Gardner 230 kV Substation. The new Reid Gardner 230 kV interconnection project will be in service in time to meet the requirements of the generator, June 30, 3022.

17. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $15.795 million to construct network upgrades needed to support the interconnection of S Power's Pershing Solar project at the new Trinity Peak 345 kV substation. The new Trinity Peak interconnection will be in service in time to meet the requirements of the generator, November 1, 2021.

18. Grant the Companies' request to maintain the confidentiality of the information as provided above;

19. Grant any other requests as are specifically set forth in the testimony and exhibits filed herewith, both those that are directly addressed and those that are not directly addressed in this Application; and

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

20. Grant such additional other relief as the Commission may deem appropriate and necessary.

Dated this 1st day of May, 2019.

Respectfully submitted,

NEVADA POWER COMPANY
SIERRA PACIFIC POWER COMPANY

/s/Mike Greene
Deputy General Counsel
Nevada Power Company
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/s/Tim Clausen
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EXHIBIT A

SECOND AMENDMENT TO
2018 JOINT INTEGRATED RESOURCE PLAN

APPLICATION EXHIBIT A

NARRATIVE

NEVADA POWER COMPANY D/B/A NV ENERGY
SIERRA PACIFIC POWER COMPANY D/B/A/ NV ENERGY
SECOND AMENDMENT TO 2018 JOINT IRP

Contents

SECTION 1. INTRODUCTION

Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra" and together with Nevada Power the "Companies" or "NV Energy") are filing this Second Amendment to their 2018 joint integrated resource plan ("2018 Joint IRP").

In the 16 months since preparation on the 2018 Joint IRP began, regulations implementing the numerous energy-related bills from the 2017 Nevada Legislature have been finalized, conditions impacting the operations of two of its generating units have changed, and loads on the Companies' distribution and transmission systems have continued to grow. These and related events have raised the need to amend some aspects the Action Plan approved by the Commission in Docket No. 18-06003. Included in this Second Amendment are requests to amend the Demand-Side Management ("DSM") Plan to add a program that will increase the net benefits of the DSM portfolio to 1.25 percent of retail sales, to amend the generation section of the Supply-Side Plan to obtain approval to construct a replacement for the unlined cooling pond serving the existing Tracy 3 unit and to approve a new agreement with Idaho Power Company ("IPCo.") addressing the North Valmy Station, and to make several updates and additions to the Companies' Transmission Plan.

Consistent with NAC § 704.9516(1), which sets forth the requirements of an amendment to an approved Action Plan, an updated current peak demand forecast and a current loads and resources table are provided. The projects for which approvals are sought in this Second Amendment do not result in material changes to either loads or resources (capacity or energy) and have not been analyzed utilizing production cost modeling. Nor have the projects addressed in this Second Amendment had an incremental impact on the Companies' ability to finance their operations or on imputed debt.

SECTION 2. SUMMARY OF SPECIFIC APPROVALS REQUESTED

NAC § 704.9516(1)(a) requires that an amendment to an Action Plan include a section that identifies the items for which the applicant is requesting specific approval. In compliance with this provision of the IRP regulations, Sierra and Nevada Power are making the following specific requests for approval.

1. Approval of the 2019 IRPA 2nd Forecast, a long-term base load forecast, as being the most accurate information upon which to base the planning decisions set forth in the filing.

2. Approval of the Companies' request to amend their 2019-2021 DSM Action Plan to incorporate the FlexPay program, including the current FlexPay budget, into their DSM portfolio for program years 2020 and 2021.

3. Approval of the Companies' request to amend their 2019-2020 Supply-Side Action Plan to expend an estimated $12.9 million (without AFUDC) ($13.6 million with AFUDC) to construct a new cooling pond and upgrade associated fresh and waste water treatment systems for Tracy Unit 3. The new cooling pond will be completed and in service prior to December 31, 2020, at which time the current permit prohibits any discharge into the existing unlined cooling pond from Tracy Unit 3.

4. Approval of the Companies' request to amend their 2019-2020 Supply-Side Action Plan by approving a new North Valmy Project Framework Agreement with IPCo, which provides a mechanism for either owner to cease its participation in one or both units in the event of several end-of-operation scenarios, as well as addresses with more specificity the North Valmy Station's decommissioning requirements.

5. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to cancel the recently approved East Tracy 345/120 kV Transformer Project and to instead expend $14.62 million to construct a new West Tracy 345/120 kV Transformer Project. In addition to moving the previously approved East Tracy 345/120 kV transformer to the West Tracy 345 kV Substation, the updated project includes the addition of a 120 kV switchyard at West Tracy, re-termination of the existing 345 kV line from West Tracy to Mira Loma Substation, and a new 120 kV line from West Tracy to Dove 120 kV Substation. The in-service date for the West Tracy Transformer Project is May 2021.

6. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to increase the 2018 budget for the Bordertown to California Substation project from $31.371 million to $44.692 million. The revised budget updates all scope revisions and project cost estimates required to comply with the changes in project design features as well as mitigation and monitoring plans identified in the final Environmental Impact Statement the draft Record of Decision governing the project.

7. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $7.5 million to increase the footprint of the previously approved new Olinghouse 345 kV Substation to accommodate an expandable breaker-and-a-half configuration, which will provide for the most cost effective accommodation of anticipated generator interconnection requests. The in-service date for the Olinghouse 345 kV Substation project is April 1, 2021.

8. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend

approximately $52.684 million to construct the new Comstock Meadows 345 kV/120 kV Substation and associated facilities to provide a second 345 kV injection point into the 120 kV system, consistent with the Tracy Area Master Plan. The in-service date for the Comstock Meadows 345 kV/120 kV Project is May 1, 2021.

9. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend $6.95 million during the Action Plan period ($21 million over 5 years) to conduct routing and constraint studies for a new major northern Nevada transmission interconnection, a transmission hub at Ft. Churchill and three new transmission lines: from Robinson Summit Substation to Ft. Churchill Substation, from Harry Allen Substation to Ft. Churchill, and from Ft. Churchill to the Reno 345 kV system.

10. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $7.21 million to construct a new breaker at the Reid Gardner 230 kV Substation and a new 2.6 mile 230 kV line from Reid Gardner to Tortoise Substation, and associated facilities, thereby extending a second source to the Overton Power District and the Lincoln County Power District. The in-service date for the Reid Gardner to Tortoise 230 kV Project is June 1, 2022.

11. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $24.880 million to construct a new Shaffer 345 kV Substation and line fold on the Hilltop to Ft. Sage 345 kV line and associated facilities, to provide a second point of service to Lassen Municipal Utility District. The in-service date for the Shaffer 345 kV Project is June 30, 2022.

12. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $7.7 million to install a 230/69 kV transformer at the existing Bighorn Substation and construct a new 5 mile 69 kV line and associated facilities from Bighorn Substation to the Oasis/Jean 69 kV system to increase reliability and mitigate service quality issues for approximately 21 MW of customer load currently being served radially out of Arden 69 kV. The in-service date for the project is December 31, 2020.

13. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $2.9 million during the Action Plan period ($4.170 million over 3 years) to commence routing and siting for an additional transmission source into the West Henderson area.

14. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $15.338 million to construct network upgrades including the new Carson Lake 230 kV Substation in a six-breaker ring, breaker-and-a-half configuration, to satisfy a generation interconnection request. The new Carson Lake project will be in service in time to meet the requirements of the generator, December 1, 2021.

15. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $2.1 million to construct network upgrades needed to support the addition of the Harry Allen Solar project, a 100 MW solar PV generating facility at the existing Harry Allen 230 kV Substation, The new Harry Allen interconnection project will be in service in time to meet the requirements of the generator, September 1, 2020.

16. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend

approximately $2.650 million to construct network upgrades needed to interconnect the Aiya Solar project, a 100 MW solar PV generating facility, at the existing Reid Gardner 230 kV Substation. The new Reid Gardner 230 kV interconnection project will be in service in time to meet the requirements of the generator, June 30, 3022.

17. Approval of the Companies' request to amend their 2019-2020 Transmission Action Plan to expend approximately $15.795 million to construct network upgrades needed to support the interconnection of S Power's Pershing Solar project at the new Trinity Peak 345 kV substation. The new Trinity Peak interconnection will be in service in time to meet the requirements of the generator, November 1, 2021.

SECTION 3. LOAD FORECAST

A. Summary of Results From The Second Amendment Load Forecast

The 2019 IRP Second Amendment Forecast (“2019 IRPA 2nd Forecast”) was completed in February 2019 and covers calendar years 2020 through 2039. The 2019 IRPA 2nd Forecast updates a number of inputs relative to the 2018 Integrated Resource Plan Forecast (“2018 IRP Forecast”) that was filed and approved by the Commission in Docket No. 18-06003.

The 2019 IRPA 2nd Forecast database was updated with actual data through December 2018.[1] Consistent with NAC § 704.923(2), Table LF-1 is a summary of forecasted peaks and energy consumption from 2020 through 2039. For the 10-year period 2020 through 2029 and the 20-year period 2020 through 2039, the Compound Annual Growth Rate (“CAGR”) of the coincident peak for NV Energy is 0.5 percent. Note that the total peak for the combined Companies has been adjusted for diversity. This is because historically, while weather patterns have sometimes resulted in peaks on the same day and hour, the individual Companies have also peaked at different hours on the same day, as well as on different days. The Companies’ combined forecasted energy CAGR is 0.3 percent for both 2020 through 2029 and the 2020 through 2039 periods. The peak demand CAGR is higher than the native energy CAGR due to the anticipated transition of a large mine ion the Sierra system from bundled to distribution-only service (“DOS”) in 2022. The 2019 IRPA 2nd Forecast includes updates to all components of the forecast including: Demand Side Management (“DSM”), Demand Response (“DR”), solar photovoltaic (“solar PV”) net metered reductions, customers transitioning to DOS, electric vehicle growth and large customer changes.

[1] Large customer hourly loads were not available at Sierra for December 2018. Therefore, the Sierra monthly peak forecast model uses historical data through November 2018.

TABLE LF-1
SUMMER PEAK (MW) AND NATIVE ENERGY (GWH)

	Summer Peak (MW)			Native Energy (GWH)		
Year	NVE (1)	NPC (2)	SPPC (2) (3)	NVE	NPC	SPPC (3)
2020	7,468	5,696	1,787	30,505	20,536	9,969
2021	7,501	5,778	1,814	30,960	20,746	10,215
2022	7,404	5,825	1,695	30,383	20,997	9,386
2023	7,553	5,853	1,714	30,485	21,096	9,390
2024	7,615	5,891	1,737	30,829	21,209	9,620
2025	7,662	5,923	1,749	30,994	21,272	9,723
2026	7,687	5,953	1,750	31,102	21,343	9,759
2027	7,656	5,998	1,752	31,189	21,419	9,770
2028	7,769	6,023	1,756	31,331	21,528	9,802
2029	7,809	6,064	1,761	31,423	21,610	9,813
2030	7,856	6,101	1,768	31,471	21,649	9,822
2031	7,903	6,140	1,777	31,524	21,696	9,828
2032	7,950	6,179	1,788	31,636	21,770	9,867
2033	7,908	6,209	1,798	31,683	21,811	9,872
2034	8,037	6,247	1,809	31,791	21,880	9,911
2035	8,085	6,286	1,818	31,902	21,957	9,945
2036	8,157	6,341	1,831	32,064	22,064	10,000
2037	8,200	6,385	1,840	32,146	22,131	10,015
2038	8,175	6,431	1,853	32,272	22,220	10,053
2039	8,226	6,466	1,866	32,417	22,324	10,094
CAGR						
20-30	0.5%	0.7%	-0.1%	0.3%	0.5%	-0.1%
20-39	0.5%	0.7%	0.2%	0.3%	0.4%	0.1%

(1) Adjusted for Diversity.
(2) Company coincident peak.
(3) Liberty Energy becomes a balancing authority customer on 5/1/2019 and a large mine customer transitions to DOS on 2/1/2022.

B. Load Forecast Process and Methods

For both Sierra and Nevada Power, econometric models are used to estimate monthly electric sales and customers' monthly peak for each of the three primary customer groups: residential, small ("Small C&I") and large commercial and industrial ("Large C&I"). For the residential and small commercial classes, separate models are used to estimate customer counts and average use per customer. Total sales are calculated based on the customer count multiplied by average use per customer. Large C&I usage models are at the total sales level due to the diversity of usage levels across the customers in these classes. For Sierra, the Large C&I model excludes mines and other large customers, which are individually forecasted based on direct customer input related to changes in usage and maximum demand. At both Nevada Power and Sierra, new large customer usage is added and known customer transitions from bundled service to DOS is subtracted separately from the regression sales results as necessary. Other classes, including public authority, street lighting and irrigation sales are forecasted based on recent historical data.

The variables that drive the econometric model of sales include:

1. Population, which drives the residential and Small C&I customer count models.

2. For residential use per customer, the models are driven by weather (cooling and heating degree days), average price per kWh, household income and persons per household, and NV Energy-sponsored energy efficiency program adjusted end-use energy intensities – average annual use per customer for heating, cooling, lighting, water heating, etc.

3. Small C&I use per customer and Large C&I total sales models are driven by weather, price, real gross regional product, employment for Sierra's Large C&I model, hotel room counts for Nevada Power's Large C&I model, and the Companies' sponsored energy efficiency adjusted end-use per square foot for business types such as warehouse, office, retail, etc.[2]

4. Adjustments outside the model include forecasted reductions in sales due to incremental rooftop solar PV installations, anticipated reductions attributed to NV Energy-sponsored DR programs, anticipated increases in incremental sales due to electric vehicle charging, and large customer adjustments discussed above.

5. The monthly peak load forecast is created using an econometric model driven by end-use estimates from the sales models and peak temperature as the main drivers. The hourly forecast and final monthly peak forecast are then created by applying the econometric model monthly peaks and monthly sales adjusted for losses to a weather normalized forecasted load shape. Adjustments include large customer hourly loads not included in the econometric peak forecast, including reductions due to customer transitions from bundled service to DOS, the load shape for rooftop solar PV, electric vehicle charging load shape and a demand response load shape provided by the energy efficiency department. The monthly peaks and hourly loads are used for production cost modeling.

C. Important Load Forecast Inputs

The following items are looked at each time a load forecast is being updated. Each item and the manner in which it impacts the 2019 IRPA 2nd Forecast is described below.

POPULATION FORECAST

In the 2019 IRPA 2nd Forecast, the Nevada Power models include a Clark County population forecast based on the historical population series through 2010 (intercensal population series) and the certified series from

[2] At Sierra, employment and real gross regional product have been found to be the best predictors of Sierra Large C&I sales. At Nevada Power, reals gross regional product and the number of hotel/motel rooms are the best predictors of future Large C&I sales.

2011-2018, both prepared by the State Demographer. Annual growth rates are obtained from the June 2018 release of University of Nevada, Las Vegas' Center for Business and Economic Research's ("CBER") long-term forecast. Sierra's models use northern Nevada's population history and forecast (Nevada minus Clark County). The 2019 IRPA 2nd Forecast uses historical population figures from the State Demographer intercensal series through 2010, the certified series from 2011 through 2014 (State Demographer) and Global Insight ("GI") growth rates for 2015 to 2017. Growth rates were obtained from the State Demographer's forecast, but were adjusted upward to reflect recent residential customer growth.

Table LF-2 shows the population forecasts for Nevada Power and Sierra from 2020 through 2039. For the 10-year period from 2020 through 2029, the Nevada Power CAGR used in the forecast is 0.9 percent, lower than the 1.1 percent used for the 2018 IRP Forecast. The Sierra CAGR used in the forecast for that time period is 0.6 percent, the same as that used in the 2018 IRP Forecast.

TABLE LF-2
POPULATION FORECAST

	Population	
Year	NPC (1)	SPPC (2)
2020	2,346,721	836,617
2021	2,380,120	844,942
2022	2,408,606	851,803
2023	2,438,076	857,568
2024	2,462,633	862,909
2025	2,485,226	867,555
2026	2,504,872	871,910
2027	2,522,554	876,270
2028	2,539,253	880,651
2029	2,553,987	885,054
2030	2,568,722	889,480
2031	2,581,492	893,927
2032	2,593,279	898,397
2033	2,604,085	902,889
2034	2,614,890	907,403
2035	2,624,713	911,940
2036	2,634,536	916,500
2037	2,644,359	921,082
2038	2,653,200	925,688
2039	2,662,041	930,316
CAGR		
20-30	0.9%	0.6%
20-39	0.7%	0.6%
20-22	1.3%	0.9%

(1) Clark County.
(2) Northern Nevada population defined as Nevada population less Clark County population.

DETERMINING NORMAL WEATHER

The 2019 IRPA 2nd Forecast is based on a 20-year normal weather period of historical and forecasted "normal" monthly heating degree days ("HDD" or "HDDs") and cooling degree days ("CDD" or "CDDs"). Weather normalization involves determining the number of monthly HDD and CDD, and peak day temperatures. Weather normalization for the 2019 IRPA 2nd Forecast utilized the historical period January 1999 through December 2018.

NO NEW IMPACTS FROM BEHIND THE METER ENERGY STORAGE

No adjustments were made to the 2019 IRPA 2nd Forecast for energy storage. At the time the 2019 IRPA 2nd Forecast was completed (February 2019) only five behind-the-meter storage projects had been installed. Until sufficient data regarding the operating characteristics of behind-the-meter storage, either stand-alone or coupled with solar PV, adjustments (increases, decreases, and/or shifts in load) to the load forecast will not be possible. Storage will be included in future forecasts as storage operating data is gathered from meters installed on all new storage devices.

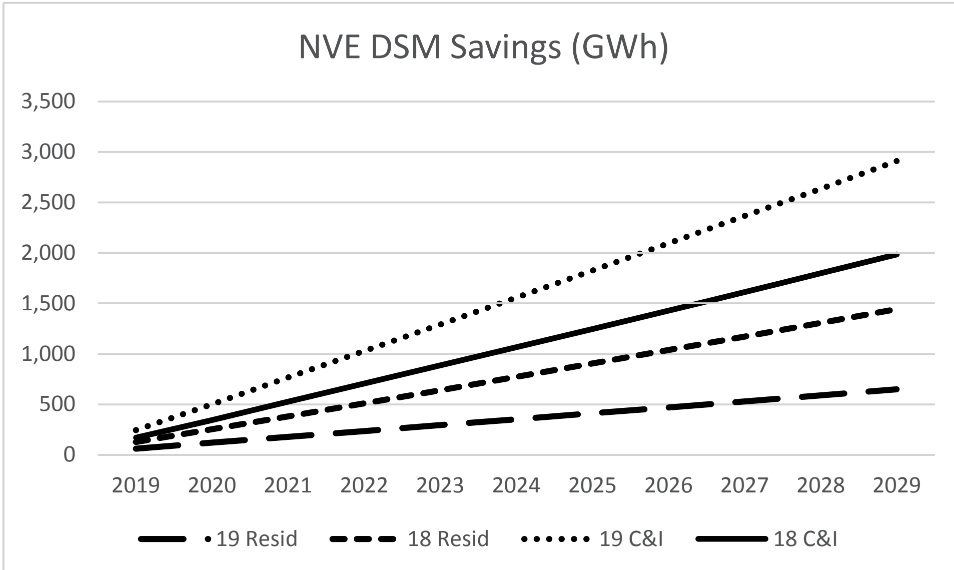
IMPACTS OF DELAYS IN CUSTOMER TRANSITIONS TO DOS

Adjustments to the 2019 IRPA 2nd Forecast were made to reflect customer applications under NRS Chapter 704B. For Sierra, the 2019 IRPA 2nd Forecast assumes that in northern Nevada, the Golden Road Motor Inn d/b/a Atlantis Casino Resort and Spa ("Atlantis") transitions to DOS on April 1, 2019, while the MEI-GSR Holdings LLC d/b/a Grand Sierra Resort is assumed to transition on October 1, 2019. Based on a letter received in January 2019, Newmont Mining Corp. is assumed to move its bundled load to DOS on February 1, 2022. Since the Atlantis is not likely to transition as assumed in the model, the 2019 Sierra forecast is approximately 20 GWh lower than it would be. Atlantis' delay does not impact 2020 or subsequent years' results. In southern Nevada, Nevada Power DOS customers in 2019 include: Station Casinos' properties and Georgia Pacific on January 1, 2019, Boyd Gaming, Cosmopolitan, South Point, Las Vegas Resort Holdings d/b/a SLS, and the Las Vegas Convention and Visitors Authority on September 1, 2019. Since Georgia Pacific and Station Casinos have not transitioned to DOS, the 2019 Nevada Power sales forecast is understated by about 180 GWh for 2019. Assuming that these customers transition by January 1, 2020, there will be no impact on sales from 2020 on.

IMPACTS ON ANNUAL ENERGY SAVINGS FROM AMENDED DSM ACTION PLAN

The incremental annual reductions in load attributed to DSM in the 2019 IRPA 2nd Forecast are based on the 2018 DSM plan filed as a part of the 2018 Joint IRP, adjusted to reflect the increase in DSM savings proposed in this amendment to the 2018 Joint IRP. These forecasted sales reductions are based on an eventual goal of 1.4 percent of forecasted sales statewide. This compares to the 1 percent goal used in the 2018 Joint IRP Forecast. Figure LF-3 is a graphical summary of the projected DSM savings for the 2019 IRPA 2nd Forecast and the 2018 IRP Forecasts. Further details are discussed in Technical Appendix LF-1.

FIGURE LF-3
DSM SAVINGS COMPARISON



UPDATED DATA FROM ROOFTOP SOLAR PV PROGRAMS

Projected reductions in system demand and energy requirements attributable to solar PV energy production that is used by customers at their premises are included in the 2019 IRPA 2nd Forecast. The forecasted residential and small commercial net metering reductions from the 2018 Joint IRP were updated to reflect the most recent installation data available. The impact on the overall 2019 IRPA 2nd Forecast was small compared to the 2018 IRP Forecast. Of note, projected reductions in load attributable to rooftop solar PV for large commercial customers at Nevada Power are less in the update due to lower activity than forecasted last year. More discussion of the impact of net metering on the load forecast is contained in Technical Appendix Item LF-1.

IMPACTS OF UPDATE TO MINING INDUSTRY FORECASTS

Mining load in Sierra's territory is expected to increase by about 73 GWh through 2021 in the 2019 IRPA 2nd Forecast compared to the 2018 IRP Forecast. Both forecasts show a drop in mining load in 2022 due to the transition of Newmont from bundled to DOS service. The 73 GWh increase from the 2018 IRP Forecast is mainly due to announced expansions at two existing mines. Nevertheless, the percentage of mine sales to total weather normalized sales drops from 20.6 percent in 2019 to 8.9 percent in 2024. More details of the mine load forecast are contained in Technical Appendix LF-1.

FORECASTS OF LOAD FOR OTHER LARGE CUSTOMERS

In Sierra's service territory, the 2019 IRPA 2nd Forecast assumed that load at the Tesla Gigafactory will ramp up to [redacted] MW by 2021 and [redacted] GWh by 2022. This will be partially offset by a reduction of [redacted] GWh expected with the completion of a [redacted] MW rooftop solar array ([redacted] GWh total). The 2018 IRP Forecast assumed [redacted] MW and [redacted] GWh by 2022 with an offset of [redacted] GWh from a [redacted] MW solar rooftop array ([redacted] total GWh). Both forecasts assume that Tesla's load remains flat for the remainder of the forecast. The 2019 IRPA 2nd Forecast assumes that as of 2026, load at the Apple data center will be [redacted] MW, and [redacted] GWh. This compares with [redacted] MW and [redacted] GWh by 2022, as assumed in the 2018 IRP Forecast. Both forecasts assume that Apple's load remains flat for the remainder of the forecast. The forecasted increase in Apple's load is based on a High Voltage Distribution agreement signed in May 2018, which provides for a buildout of [redacted] MW of additional facilities, for a total of [redacted] MW. In Nevada Power's service territory, the only large customer added outside the model is Resorts World. Based on a change in the announced opening date for the facility[3], the 2019 IRP 2nd Forecast assumes [redacted] MW and [redacted] GWh by 2022, while the 2018 IRP Forecast assumed [redacted] MW and [redacted] GWh by 2021. More details of these forecasts are contained in Technical Appendix LF-1.

NO NEW IMPACTS FOR ELECTRIC VEHICLES

Similar to the 2018 IRP Forecast, the 2019 IRP 2nd Forecast assumes that by 2022, approximately 1 percent of new cars on the road in Nevada will be EV, and remain flat thereafter. As a result, the 2019 IRP 2nd Forecast projects statewide incremental EV energy sales (beginning with 2019) of approximately 51 GWh in 2029 (combined for both companies).

END-USE SATURATION AND EFFICIENCY TRENDS

End-use saturation and average stock efficiency projections are combined to generate projected annual energy intensities (annual KWh per end-use). The census-level residential end-use saturations are calibrated to appliance ownership reported by Nevada Power and Sierra customers. For Sierra, residential lighting intensity was updated last year based on the results from a Market Potential study performed by Applied Energy Group ("AEG"), which significantly increased the lighting use per customer and decreased total use per customer due to the LED lighting standard taking effect in 2020. Also last year, the Energy Information Administration updated the 2004 base year historical commercial intensities developed from the 2003 Commercial Buildings Energy Consumption Survey ("CBECS") to 2013 based on the 2012 CBECS data, which significantly changed the historical and forecasted intensities and reduced Sierra's Small C&I average use per customer. This year, Sierra updated the energy-by-building-type analysis based on a classification study performed by AEG as part of the 2017-18 DSM technical potential study. Weighted intensities are developed from these building type energy estimates. See Technical Appendix LF-1 for more details.

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[3] See Technical Appendix LF-8, LVCVA Tourism and Construction Bulletin, December 5, 2018 for the expected opening date of Resorts World.

SECTION 4. AMENDMENT TO DEMAND SIDE PLAN

A. Introduction to Action Plan Amendment

Nevada Power and Sierra are requesting authority to amend their 2019-2021 DSM Action Plan to incorporate the FlexPay program into their DSM portfolio. The effect of this request is to increase the net benefits to be delivered by the approved DSM portfolio by $1,526,075.

The FlexPay program was initially considered by the Commission in Docket Nos. 15-11003 and 15-11004. FlexPay is an alternative bill payment option for customers that provides behavioral signals that stimulate bill reductions and enable energy savings. At Nevada Power, the proposed budget for FlexPay in 2020 is $1,000,000 and in 2021 is $1,100,000. At Sierra, the proposed budget for FlexPay in 2020 is $450,000 and in 2021 is $500,000. The Companies are proposing to deploy these budget dollars as part of their DSM portfolio and to deliver the Flex Pay program from within the DSM umbrella.

B. Flexpay Program Described

In its May 31, 2016 Order in Docket Nos. 15-11004 and 15-11005, the Commission determined that the FlexPay Program delivered on the promise of the Smart Grid to provide additional services for customers. FlexPay was launched as a pilot in November 2017 to a small group of NV Energy employees for quality testing to ensure that all automated processes worked as designed before external customers were invited to participate. A pilot program was rolled out to eligible customers in May 2018. The full scale launch of FlexPay is scheduled to occur in the second quarter of 2019.

FlexPay empowers and engages residential customers with a rich stream of personalized information that enables customers to manage their electric energy usage patterns. FlexPay proactively reaches out to customers with messaging features to provide energy usage feedback, actionable energy efficiency and conservation information, and account status. FlexPay provides this new customer experience while at the same time delivering energy savings that on average are projected to achieve 10 percent at Nevada Power and eight percent at Sierra. Some customers in the program will save considerably more.

The Program combines the best features of what has been referred to as "prepay" with cutting edge new technologies. Bringing FlexPay into the PowerShift family of products and services is projected to attract thousands of residential customers. FlexPay is premised on providing participating customers with conservation tools and a new payment option that truly put the "power in their hands." Participation in FlexPay is voluntary and participating customers are expected to find that it gives them a greater sense of control over their energy usage and their energy costs.

FlexPay is expected to deliver significant energy savings for Program participants. Other jurisdictions implementing similar programs have demonstrated energy savings ranging from 8-12 percent of the participating customer's energy usage. Customers with the Oklahoma Electric Cooperative have demonstrated energy savings in the range of 8-11 percent.[4] Salt River Project ("SRP") customers have shown energy savings of, on average, 12 percent.[5]

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[4] CPUC, A Review of Prepay Programs for Electricity Service, July 26, 2012, Villareall and Zafar at 22

[5] EPRI, October 2012, Paying Upfront: A Review of Salt River Project's M-Power Prepaid program at 5-6. See also, *e.g.*, "Salt River Project: Delivering Leadership on Smarter Technology& Rates," Institute for Energy and the Environment,

FlexPay is designed to provide participating customers choices as to how and when they interact with the Companies, as well as an alternative method of managing their energy usage, reducing their bill, and paying for their electric energy usage.

Applying the total resource cost ("TRC") test, the benefits-to-cost ratio for the FlexPay program has a combined Company benefits-to-costs ratio of 1.31 The Companies also present the results of a modified TRC benefits-to-cost ratio test that considers non-energy benefits ("NTRC"), which has a combined Company benefits-to-costs ratio of 1.60. The program scope and supporting data are provided in program data sheets below. Tables DSM-1 through DSM-6 present the budgets and targets proposed for the 2020 and 2021 program years. The new program, FlexPay is bold and italicized in the tables.

Table DSM-1: Statewide Target for Program Years 2020 and 2021

Nevada Power Company	**2020**	**2021**
Budget	$51,200,000	$51,700,000
Retail Sales (kWh)	19,400,367,112	19,597,843,025
1.1% Target (kWh)	213,404,038	215,576,273
Energy Savings Target (kWh)	280,913,300	286,203,100
% Energy Savings to Retail Sales	**1.45%**	**1.46%**
Sierra Pacific Power Company	**2020**	**2021**
Budget	$15,950,000	$16,600,000
Retail Sales (kWh)	9,332,961,320	9,586,206,355
1.1% Target (kWh)	102,662,575	105,448,270
Energy Savings Target (kWh)	90,912,900	94,661,820
% Energy Savings to Retail Sales	**0.97%**	**0.99%**
NV Energy Statewide	**2020**	**2021**
Budget	$67,150,000	$68,300,000
Retail Sales (kWh)	28,733,328,433	29,184,049,380
1.1% Target (kWh)	316,066,613	321,024,543
Energy Savings Target (kWh)	371,826,200	380,864,920
% Energy Savings to Retail Sales	**1.29%**	**1.31%**

Vermont Law School, at 18.

Table DSM-2a: Proposed Nevada Power Company 2020 and 2021 Budget

Budget	2020	2021	Total
Energy Education	$600,000	$600,000	$1,200,000
Energy Reports	$800,000	$800,000	$1,600,000
Energy Assessments	$2,500,000	$2,500,000	$5,000,000
FlexPay	***$1,000,000***	***$1,100,000***	***$2,100,000***
Program Development	$300,000	$300,000	$600,000
Subtotal - Outreach & Program Development	**$5,200,000**	**$5,300,000**	**$10,500,000**
Residential Lighting	$1,700,000	$1,100,000	$2,800,000
Pool Pumps	$1,200,000	$1,200,000	$2,400,000
Low Income	$2,000,000	$2,000,000	$4,000,000
Residential Air Conditioning	$7,000,000	$7,000,000	$14,000,000
Direct Install	$500,000	$500,000	$1,000,000
Residential Demand Response - Manage	$7,500,000	$7,700,000	$15,200,000
Residential Demand Response - Build	$7,100,000	$7,300,000	$14,400,000
Subtotal - Home Services	**$27,000,000**	**$26,800,000**	**$53,800,000**
Schools Program	$1,700,000	$1,700,000	$3,400,000
Commercial Services	$14,700,000	$15,200,000	$29,900,000
Commercial Demand Response Program - Manag	$900,000	$1,000,000	$1,900,000
Commercial Demand Response Program - Build	$1,700,000	$1,700,000	$3,400,000
Subtotal - Business Services	**$19,000,000**	**$19,600,000**	**$38,600,000**
Total DSM Programs	**$51,200,000**	**$51,700,000**	**$102,900,000**

Table DSM-2b: Proposed Sierra Pacific Power Company 2020 and 2021 Budget

Budget	2020	2021	Total
Energy Education	$475,000	$475,000	$950,000
Energy Reports	$500,000	$500,000	$1,000,000
Energy Assessments	$1,375,000	$1,375,000	$2,750,000
FlexPay	***$450,000***	***$500,000***	***$950,000***
Program Development	$100,000	$100,000	$200,000
Subtotal - Education	**$2,900,000**	**$2,950,000**	**$5,850,000**
Residential Lighting	$800,000	$600,000	$1,400,000
Low Income	$700,000	$700,000	$1,400,000
Direct Install	$150,000	$150,000	$300,000
Residential Demand Response - Manage	$900,000	$1,100,000	$2,000,000
Residential Demand Response - Build	$2,600,000	$2,700,000	$5,300,000
Subtotal - Residential	**$5,150,000**	**$5,250,000**	**$10,400,000**
Schools Program	$600,000	$600,000	$1,200,000
Commercial Services	$5,900,000	$6,300,000	$12,200,000
Commercial Demand Response Program - Manage	$500,000	$600,000	$1,100,000
Commercial Demand Response Program - Build	$900,000	$900,000	$1,800,000
Subtotal - Commercial	**$7,900,000**	**$8,400,000**	**$16,300,000**
Total DSM Programs	**$15,950,000**	**$16,600,000**	**$32,550,000**

Table DSM-2c: Proposed NV Energy Combined 2020 and 2021 Budget

Budget	2020	2021	Total
Energy Education	$1,075,000	$1,075,000	$2,150,000
Energy Reports	$1,300,000	$1,300,000	$2,600,000
Energy Assessments	$3,875,000	$3,875,000	$7,750,000
FlexPay	***$1,450,000***	***$1,600,000***	***$3,050,000***
Program Development	$400,000	$400,000	$800,000
Subtotal - Education	**$8,100,000**	**$8,250,000**	**$16,350,000**
Residential Lighting	$2,500,000	$1,700,000	$4,200,000
Pool Pumps	$1,200,000	$1,200,000	$2,400,000
Low Income	$2,700,000	$2,700,000	$5,400,000
Residential AC Program	$7,000,000	$7,000,000	$14,000,000
Direct Install	$650,000	$650,000	$1,300,000
Residential Demand Response - Manage	$8,400,000	$8,800,000	$17,200,000
Residential Demand Response - Build	$9,700,000	$10,000,000	$19,700,000
Subtotal - Residential	**$32,150,000**	**$32,050,000**	**$64,200,000**
Schools Program	$2,300,000	$2,300,000	$4,600,000
Commercial Services	$20,600,000	$21,500,000	$42,100,000
Commercial Demand Response Program - Mana	$1,400,000	$1,600,000	$3,000,000
Commercial Demand Response Program - Build	$2,600,000	$2,600,000	$5,200,000
Subtotal - Commercial	**$26,900,000**	**$28,000,000**	**$54,900,000**
Total DSM Programs	**$67,150,000**	**$68,300,000**	**$135,450,000**

Table DSM-3a: Nevada Power Company 2020 and 2021 Energy and Demand Savings

Program	Demand Savings (kW)	Annual Energy Savings (kWh)	Demand Savings (kW)	Annual Energy Savings (kWh)
Year	**2020**		**2021**	
Energy Education	40	417,000	40	417,000
Energy Reports	1,000	8,867,000	1,000	8,867,000
Energy Assessments	300	2,700,000	300	2,700,000
FlexPay	***6,883***	***22,491,000***	***7,866***	***25,704,000***
Program Development	N/A	N/A	N/A	N/A
Subtotal - Outreach & Program Development	**8,222**	**34,475,000**	**9,205**	**37,688,000**
Residential Lighting	1,010	9,071,800	660	5,848,600
Pool Pumps	700	6,490,000	700	6,490,000
Low Income	160	1,435,000	160	1,435,000
Residential Air Conditioning	1,500	13,543,000	1,500	13,543,000
Direct Install	110	1,000,000	110	1,000,000
Residential Demand Response - Manage	TBD	27,413,700	TBD	27,413,700
Residential Demand Response - Build	28,000	3,600,200	28,000	3,600,200
Subtotal - Home Services	**31,480**	**62,553,700**	**31,130**	**59,330,500**
Schools Program	1,750	15,500,000	1,750	15,500,000
Commercial Services	17,929	157,237,000	18,529	162,537,000
Commercial Demand Response Program - Manage	TBD	10,147,600	TBD	10,147,600
Commercial Demand Response Program - Build	4,000	1,000,000	4,000	1,000,000
Subtotal - Business Services	**23,679**	**183,884,600**	**24,279**	**189,184,600**
Total DSM Programs	**63,381**	**280,913,300**	**64,614**	**286,203,100**

Table DSM-3b: Sierra Pacific Power Company 2020 and 2021 Energy and Demand Savings

Program	Demand Savings (kW)	Annual Energy Savings (kWh)	Demand Savings (kW)	Annual Energy Savings (kWh)
Year	**2020**		**2021**	
Energy Education	58	559,600	58	559,600
Energy Reports	749	6,667,000	738	6,667,000
Energy Assessments	150	1,300,000	150	1,300,000
FlexPay	***2,013***	***6,228,900***	***2,281***	***7,059,420***
Program Development	N/A	N/A	N/A	N/A
Subtotal - Outreach & Program Development	**2,970**	**14,755,500**	**3,226**	**15,586,020**
Residential Lighting	450	4,038,000	300	2,804,400
Low Income	55	483,000	55	483,000
Direct Install	45	400,000	45	400,000
Residential Demand Response - Manage	TBD	2,784,600	TBD	2,784,600
Residential Demand Response - Build	6,000	909,100	6,000	909,100
Subtotal - Home Services	**6,550**	**8,614,700**	**6,400**	**7,381,100**
Schools Program	500	4,300,000	500	4,300,000
Commercial Services	7,069	62,116,000	7,566	66,268,000
Commercial Demand Response Program - Mana	TBD	626,700	TBD	626,700
Commercial Demand Response Program - Build	2,000	500,000	2,000	500,000
Subtotal - Business Services	**9,569**	**67,542,700**	**10,066**	**71,694,700**
Total DSM Programs	**19,089**	**90,912,900**	**19,693**	**94,661,820**

Table DSM-3c: NV Energy Combined 2020 and 2021 Energy and Demand Savings

Program	Demand Savings (kW)	Annual Energy Savings (kWh)	Demand Savings (kW)	Annual Energy Savings (kWh)
Year	**2020**		**2021**	
Energy Education	98	976,600	98	976,600
Energy Reports	1,749	15,534,000	1,738	15,534,000
Energy Assessments	450	4,000,000	450	4,000,000
FlexPay	***8,895***	***28,719,900***	***10,146***	***32,763,420***
Program Development	N/A	N/A	N/A	N/A
Subtotal - Outreach & Program Development	**11,192**	**49,230,500**	**12,432**	**53,274,020**
Residential Lighting	1,460	13,109,800	960	8,653,000
Pool Pumps	700	6,490,000	700	6,490,000
Low Income	215	1,918,000	215	1,918,000
Residential Air Conditioning	1,500	13,543,000	1,500	13,543,000
Direct Install	155	1,400,000	155	1,400,000
Residential Demand Response - Manage	TBD	30,198,300	TBD	30,198,300
Residential Demand Response - Build	34,000	4,509,300	34,000	4,509,300
Subtotal - Home Services	**38,030**	**71,168,400**	**37,530**	**66,711,600**
Schools Program	2,250	19,800,000	2,250	19,800,000
Commercial Services	24,997	219,353,000	26,095	228,805,000
Commercial Demand Response Program - Manag	TBD	10,774,300	TBD	10,774,300
Commercial Demand Response Program - Build	6,000	1,500,000	6,000	1,500,000
Subtotal - Business Services	**33,247**	**251,427,300**	**34,345**	**260,879,300**
Total DSM Programs	**82,469**	**371,826,200**	**84,307**	**380,864,920**

Table DSM-4a: 2020 and 2021 Nevada Power Total Resource Cost Benefits/Costs Results

Program	Benefits	Costs	Net Benefits	TRC B/C Ratio
Energy Education	$280,635	$1,190,174	($909,539)	0.24
Energy Reports	$7,451,199	$2,856,417	$4,594,782	2.61
Energy Assessments	$835,564	$5,950,869	($5,115,305)	0.14
FlexPay	***$2,680,116***	***$1,732,563***	***$947,553***	***1.55***
Program Development	N/A	N/A	N/A	N/A
Subtotal - Outreach & Program Development	**$11,247,514**	**$11,730,023**	**($482,509)**	**0.96**
Residential Lighting	$7,876,752	$3,508,835	$4,367,917	2.24
Pool Pumps	$5,906,496	$2,318,952	$3,587,544	2.55
Low Income	$1,253,520	$5,312,936	($4,059,416)	0.24
Residential Air Conditioning	$32,465,400	$28,962,305	$3,503,095	1.12
Direct Install	$409,627	$1,190,174	($780,547)	0.34
Residential Demand Response - Manage	$97,224,604	$14,550,920	$82,673,684	6.68
Residential Demand Response - Build	$79,868,419	$30,476,816	$49,391,603	2.62
Subtotal - Home Services	**$225,004,818**	**$86,320,938**	**$138,683,880**	**2.61**
Schools Program	$17,418,857	$11,169,647	$6,249,210	1.56
Commercial Services	$146,510,707	$79,039,392	$67,471,315	1.85
Commercial Demand Response Program - Manage	$13,338,910	$2,501,403	$10,837,507	5.33
Commercial Demand Response Program - Build	$11,106,841	$5,745,029	$5,361,812	1.93
Subtotal - Business Services	**$188,375,315**	**$98,455,471**	**$89,919,844**	**1.91**
Total DSM Programs	**$424,627,647**	**$196,506,432**	**$228,121,215**	**2.16**

Table DSM-4b: 2020 and 2021 Sierra Total Resource Cost Benefits/Costs Results

Program	Benefits	Costs	Net Benefits	TRC B/C Ratio
Energy Education	$234,315	$990,600	($756,285)	0.24
Energy Reports	$5,887,764	$1,661,016	$4,226,748	3.54
Energy Assessments	$455,899	$3,185,394	($2,729,495)	0.14
FlexPay	***$856,286***	***$808,224***	***$48,062***	***1.06***
Program Development	N/A	N/A	N/A	N/A
Subtotal - Outreach & Program Development	**$7,434,264**	**$6,645,234**	**$789,030**	**1.12**
Residential Lighting	$4,764,453	$2,041,646	$2,722,807	2.33
Low Income	$401,998	$1,814,958	($1,412,960)	0.22
Residential Air Conditioning	$800,953	$2,763,056	($1,962,103)	0.29
Direct Install	$163,220	$371,476	($208,256)	0.44
Residential Demand Response - Manage	$17,091,395	$2,853,354	$14,238,041	5.60
Residential Demand Response - Build	$22,612,124	$12,300,898	$10,311,226	1.84
Subtotal - Home Services	**$45,834,143**	**$22,145,388**	**$23,688,755**	**2.07**
Schools Program	$6,237,091	$2,216,527	$4,020,564	2.81
Commercial Services	$58,457,555	$26,270,969	$32,186,586	2.23
Commercial Demand Response Program - Manage	$5,875,867	$1,573,863	$4,302,004	3.73
Commercial Demand Response Program - Build	$7,226,423	$3,798,561	$3,427,862	1.90
Subtotal - Business Services	**$77,796,936**	**$33,859,920**	**$43,937,016**	**2.30**
Total DSM Programs	**$131,065,343**	**$62,650,542**	**$68,414,801**	**2.09**

Table DSM-4c: 2020 and 2021 Combined Company Total Resource Cost Benefits/Costs Results

Program	Benefits	Costs	Net Benefits	TRC B/C Ratio
Energy Education	$514,950	$2,180,774	($1,665,824)	0.24
Energy Reports	$13,338,963	$4,517,433	$8,821,530	2.95
Energy Assessments	$1,291,463	$9,136,263	($7,844,800)	0.14
FlexPay	***$3,536,402***	***$2,540,787***	***$995,615***	***1.31***
Program Development	N/A	N/A	N/A	N/A
Subtotal - Outreach & Program Development	**$18,681,778**	**$18,375,257**	**$306,521**	**1.02**
Residential Lighting	$12,641,205	$5,550,481	$7,090,724	2.28
Pool Pumps	$5,906,496	$2,318,952	$3,587,544	2.55
Low Income	$1,655,518	$7,127,894	($5,472,376)	0.23
Residential Air Conditioning	$33,266,353	$31,725,361	$1,540,992	1.05
Direct Install	$572,847	$1,561,650	($988,803)	0.37
Residential Demand Response - Manage	$114,315,999	$17,404,274	$96,911,725	6.57
Residential Demand Response - Build	$102,480,543	$42,777,714	$59,702,829	2.40
Subtotal - Home Services	**$270,838,961**	**$108,466,326**	**$162,372,635**	**2.50**
Schools Program	$23,655,948	$13,386,174	$10,269,774	1.77
Commercial Services	$204,968,262	$105,310,361	$99,657,901	1.95
Commercial Demand Response Program - Manag	$19,214,777	$4,075,266	$15,139,511	4.71
Commercial Demand Response Program - Build	$18,333,264	$9,543,590	$8,789,674	1.92
Subtotal - Business Services	**$266,172,251**	**$132,315,391**	**$133,856,860**	**2.01**
Total DSM Programs	**$555,692,990**	**$259,156,974**	**$296,536,016**	**2.14**

Table DSM-5a: 2020 and 2021 Nevada Power Company NTRC Benefits/Costs Results

Program	Non Energy Benefit (%)	Benefits	Costs	Net Benefits	NTRC B/C Ratio
Energy Education	15	$322,730	$1,190,174	($867,444)	0.27
Energy Reports	15	$8,568,879	$2,856,417	$5,712,462	3.00
Energy Assessments	15	$960,898	$5,950,869	($4,989,971)	0.16
FlexPay	***15***	***$3,082,133***	***$1,732,563***	***$1,349,570***	***1.78***
Program Development	N/A	N/A	N/A	N/A	N/A
Subtotal - Outreach & Program Development		**$12,934,640**	**$11,730,023**	**$1,204,617**	**1.10**
Residential Lighting	15	$9,058,265	$3,508,835	$5,549,430	2.58
Pool Pumps	15	$6,792,471	$2,318,952	$4,473,519	2.93
Low Income	25	$1,566,900	$5,312,936	($3,746,036)	0.29
Residential Air Conditioning	15	$37,335,210	$28,962,305	$8,372,905	1.29
Direct Install	15	$471,071	$1,190,174	($719,103)	0.40
Residential Demand Response - Manage	15	$111,808,294	$14,550,920	$97,257,374	7.68
Residential Demand Response - Build	15	$91,848,682	$30,476,816	$61,371,866	3.01
Subtotal - Home Services		**$258,880,893**	**$86,320,938**	**$172,559,955**	**3.00**
Schools Program	10	$19,160,742	$11,169,647	$7,991,095	1.72
Commercial Services	10	$161,161,777	$79,039,392	$82,122,385	2.04
Commercial Demand Response Program - Manage	10	$14,672,801	$2,501,403	$12,171,398	5.87
Commercial Demand Response Program - Build	10	$12,217,525	$5,745,029	$6,472,496	2.13
Subtotal - Business Services		**$207,212,845**	**$98,455,471**	**$108,757,374**	**2.10**
Total DSM Programs		**$479,028,378**	**$196,506,432**	**$282,521,946**	**2.44**

Table DSM-5b: 2020 and 2021 Sierra Pacific Company NTRC Benefits/Costs Results

Program	Non Energy Benefit (%)	Benefits	Costs	Net Benefits	NTRC B/C Ratio
Energy Education	15	$269,463	$990,600	($721,137)	0.27
Energy Reports	15	$6,770,928	$1,661,016	$5,109,912	4.08
Energy Assessments	15	$524,284	$3,185,394	($2,661,110)	0.16
FlexPay	***15***	***$984,729***	***$808,224***	***$176,505***	***1.22***
Program Development	N/A	N/A	N/A	N/A	N/A
Subtotal - Outreach & Program Development		**$8,549,404**	**$6,645,234**	**$1,904,170**	**1.29**
Residential Lighting	15	$5,479,121	$2,041,646	$3,437,475	2.68
Low Income	25	$502,498	$1,814,958	($1,312,460)	0.28
Residential Air Conditioning	15	$921,096	$2,763,056	($1,841,960)	0.33
Direct Install	15	$187,703	$371,476	($183,773)	0.51
Residential Demand Response - Manage	15	$19,655,104	$2,853,354	$16,801,750	6.89
Residential Demand Response - Build	15	$26,003,942	$12,300,898	$13,703,044	2.11
Subtotal - Home Services		**$52,749,464**	**$22,145,388**	**$30,604,076**	**2.38**
Schools Program	10	$6,860,800	$2,216,527	$4,644,273	3.10
Commercial Services	10	$64,303,310	$26,270,969	$38,032,341	2.45
Commercial Demand Response Program - Manage	10	$6,463,453	$1,573,863	$4,889,590	4.11
Commercial Demand Response Program - Build	10	$7,949,065	$3,798,561	$4,150,504	2.09
Subtotal - Business Services		**$85,576,628**	**$33,859,920**	**$51,716,708**	**2.53**
Total DSM Programs		**$146,875,496**	**$62,650,542**	**$84,224,954**	**2.34**

Table DSM-5c: 2020 and 2021 Combined NTRC Benefits/Costs Results

Program	Non Energy Benefit (%)	Benefits	Costs	Net Benefits	NTRC B/C Ratio
Energy Education	15	$592,193	$2,180,774	($1,588,581)	0.27
Energy Reports	15	$15,339,807	$4,517,433	$10,822,374	3.40
Energy Assessments	15	$1,485,182	$9,136,263	($7,651,081)	0.16
FlexPay	***15***	***$4,066,862***	***$2,540,787***	***$1,526,075***	***1.60***
Program Development	N/A	N/A	N/A	N/A	N/A
Subtotal - Outreach & Program Development		**$21,484,044**	**$18,375,257**	**$3,108,787**	**1.17**
Residential Lighting	15	$14,537,386	$5,550,481	$8,986,905	2.62
Pool Pumps	15	$6,792,471	$2,318,952	$4,473,519	2.93
Low Income	25	$2,069,398	$7,127,894	($5,058,496)	0.29
Residential Air Conditioning	15	$38,256,306	$31,725,361	$6,530,945	1.21
Direct Install	15	$658,774	$1,561,650	($902,876)	0.42
Residential Demand Response - Manage	15	$131,463,398	$17,404,274	$114,059,124	7.55
Residential Demand Response - Build	15	$117,852,624	$42,777,714	$75,074,910	2.76
Subtotal - Home Services		**$311,630,357**	**$108,466,326**	**$203,164,031**	**2.87**
Schools Program	10	$26,021,542	$13,386,174	$12,635,368	1.94
Commercial Services	10	$225,465,087	$105,310,361	$120,154,726	2.14
Commercial Demand Response Program - Manag	10	$21,136,254	$4,075,266	$17,060,988	5.19
Commercial Demand Response Program - Build	10	$20,166,590	$9,543,590	$10,623,000	2.11
Subtotal - Business Services		**$292,789,473**	**$132,315,391**	**$160,474,082**	**2.21**
Total DSM Programs		**$625,903,874**	**$259,156,974**	**$366,746,900**	**2.42**

Table DSM-6a Nevada Power Company Multiplier Methodology ("RAM")

NPC Programs 2020-2021	2020 Plan Budget	2020 Multiplier Value	2021 Plan Budget	2021 Multiplier Value
Energy Education	$600,000	$55,200	$600,000	$55,200
Energy Reports	$800,000	$73,600	$800,000	$73,600
Energy Assessments	$2,500,000	$230,000	$2,500,000	$230,000
FlexPay	***$1,000,000***	***$92,000***	***$1,100,000***	***$101,200***
Program Development	$300,000	$27,600	$300,000	$27,600
Subtotal - Outreach & Program Development	**$5,200,000**	**$478,400**	**$5,300,000**	**$487,600**
Residential Lighting	$1,700,000	$156,400	$1,100,000	$101,200
Pool Pumps	$1,200,000	$110,400	$1,200,000	$110,400
Low Income	$2,000,000	$184,000	$2,000,000	$184,000
Residential Air Conditioning	$7,000,000	$644,000	$7,000,000	$644,000
Direct Install	$500,000	$46,000	$500,000	$46,000
Residential Demand Response - Manage	$7,500,000	$690,000	$7,700,000	$708,400
Residential Demand Response - Build	$7,100,000	$653,200	$7,300,000	$671,600
Subtotal - Home Services	**$27,000,000**	**$2,484,000**	**$26,800,000**	**$2,465,600**
Schools Program	$1,700,000	$156,400	$1,700,000	$156,400
Commercial Services	$14,700,000	$1,352,400	$15,200,000	$1,398,400
Commercial Demand Response Program - Manag	$900,000	$82,800	$1,000,000	$92,000
Commercial Demand Response Program - Build	$1,700,000	$156,400	$1,700,000	$156,400
Subtotal - Business Services	**$19,000,000**	**$1,748,000**	**$19,600,000**	**$1,803,200**
Total Demand Side	**$51,200,000**	**$4,710,400**	**$51,700,000**	**$4,756,400**

Table DSM-6b Sierra Pacific Power Company Multiplier Methodology ("RAM")

SPPC Programs 2020-2021	2020 Plan Budget	2020 Multiplier Value	2021 Plan Budget	2021 Multiplier Value
Energy Education	$475,000	$37,445	$475,000	$37,445
Energy Reports	$500,000	$39,416	$500,000	$39,416
Energy Assessments	$1,375,000	$108,393	$1,375,000	$108,393
FlexPay	***$450,000***	***$35,474***	***$500,000***	***$39,416***
Program Development	$100,000	$7,883	$100,000	$7,883
Subtotal - Outreach & Program Development	**$2,900,000**	**$228,611**	**$2,950,000**	**$232,553**
Residential Lighting	$800,000	$63,065	$600,000	$47,299
Low Income	$700,000	$55,182	$700,000	$55,182
Direct Install	$150,000	$11,825	$150,000	$11,825
Residential Demand Response - Manage	$900,000	$70,948	$1,100,000	$86,715
Residential Demand Response - Build	$2,600,000	$204,962	$2,700,000	$212,845
Subtotal - Home Services	**$5,150,000**	**$405,982**	**$5,250,000**	**$413,865**
Schools Program	$600,000	$47,299	$600,000	$47,299
Commercial Services	$5,900,000	$465,106	$6,300,000	$496,638
Commercial Demand Response Program - Manag	$500,000	$39,416	$600,000	$47,299
Commercial Demand Response Program - Build	$900,000	$70,948	$900,000	$70,948
Subtotal - Business Services	**$7,900,000**	**$622,769**	**$8,400,000**	**$662,185**
Total Demand Side	**$15,950,000**	**$1,257,362**	**$16,600,000**	**$1,308,603**

Table DSM-6c Combined Company Multiplier Methodology ("RAM")

Combined Programs 2020-2021	2020 Plan Budget	2020 Multiplier Value	2021 Plan Budget	2021 Multiplier Value
Energy Education	$1,075,000	$92,645	$1,075,000	$92,645
Energy Reports	$1,300,000	$113,016	$1,300,000	$113,016
Energy Assessments	$3,875,000	$338,393	$3,875,000	$338,393
FlexPay	***$1,450,000***	***$127,474***	***$1,600,000***	***$140,616***
Program Development	$400,000	$35,483	$400,000	$35,483
Subtotal - Outreach & Program Development	**$8,100,000**	**$707,011**	**$8,250,000**	**$720,153**
Residential Lighting	$2,500,000	$219,465	$1,700,000	$148,499
Pool Pumps	$1,200,000	$110,400	$1,200,000	$110,400
Low Income	$2,700,000	$239,182	$2,700,000	$239,182
Residential Air Conditioning	$7,000,000	$644,000	$7,000,000	$644,000
Direct Install	$650,000	$57,825	$650,000	$57,825
Residential Demand Response - Manage	$8,400,000	$760,948	$8,800,000	$795,115
Residential Demand Response - Build	$9,700,000	$858,162	$10,000,000	$884,445
Subtotal - Home Services	**$32,150,000**	**$2,889,982**	**$32,050,000**	**$2,879,465**
Schools Program	$2,300,000	$203,699	$2,300,000	$203,699
Commercial Services	$20,600,000	$1,817,506	$21,500,000	$1,895,038
Commercial Demand Response Program - Manag	$1,400,000	$122,216	$1,600,000	$139,299
Commercial Demand Response Program - Build	$2,600,000	$227,348	$2,600,000	$227,348
Subtotal - Business Services	**$26,900,000**	**$2,370,769**	**$28,000,000**	**$2,465,385**
Total Demand Side	**$67,150,000**	**$5,967,762**	**$68,300,000**	**$6,065,003**

C. Standard Program Data Sheet For Flexpay Program

2018 Results

This Program was not offered as a demand side management program in 2018.

2019 Status

This Program is currently offered to eligible residential customers as a customer operations offering rather than DSM program.

2020 and 2021 Plan

The Companies propose to reclassify and deliver the currently approved FlexPay as a DSM program in 2020 and 2021 at the budget levels and targets show below:

Nevada Power Company	2020	2021
Budget	$1,000,000	$1,100,000
Energy Savings Target (kWh)	22,491,000	25,704,000
Demand Savings Target (kW)	6,883	7,866
Sierra Pacific Power Company	**2020**	**2021**
Budget	$450,000	$500,000
Energy Savings Target (kWh)	6,228,900	7,059,420
Demand Savings Target (kW)	2,013	2,281
NV Energy Statewide	**2020**	**2021**
Budget	$1,450,000	$1,600,000
Energy Savings Target (kWh)	28,719,900	32,763,420
Demand Savings Target (kW)	8,895	10,146

Financial Tracking

As approved, the fixed costs of FlexPay are to be deferred into a regulatory asset and the benefits of the program are to be tracked. Five years after the Program is fully implemented, if the benefits of FlexPay exceed the costs of the Program, carrying charges will be included and the full costs of the program will be recoverable in a future general rate review proceeding. If, on the other hand, the benefits of FlexPay do not exceed the costs of the Program, carrying charges on the costs deferred to the regulatory asset will not be applied, and only a percentage of net benefits will be recoverable in a general rate case. The Companies propose that this cost recovery mechanism remain in place. DSM program costs will not be charged to the FlexPay regulatory asset but will be included in the Energy Efficiency Program Rates.

Target Audience

FlexPay will be offered to eligible residential customers who have smart phones, tablet computers, home computers or other access to the Internet. FlexPay is intended to resonate with the technically engaged customers who have altered their daily routines around smart phones and tablet computers and who use those devices to interact with the world around them. FlexPay is also expected to appeal to customers who would like an alternative way to manage the payment of their bills. The success of this program relies on outbound communicators with customers regarding energy usage and account balances. For many customers, interactions with smart phones and tablet devices are quite frequent during the day.

Energy Savings

Energy savings that have been achieved by similar programs are documented as both significant and sustained over a number of years. The Oklahoma Electric Cooperative's Pre-Pay customers consume, on average, 8-11 percent less than customers not participating in the program. Participants in SRP's "M Power" program consume, on average, 12 percent less than customers who are not participating in the program.[6] Both of these programs have been offered over a number of years and have been well received by

[6] EPRI Report at 5-10. See also, *e.g.*, "Salt River Project: Delivering Leadership on Smarter Technology & Rates," Institute for Energy and the Environment, Vermont Law School, at 18.

customers. Nevada Power is projecting that on average the Program will result in a 10 percent energy savings for participants based on Program design and consumption levels forecasted in southern Nevada. Sierra is projecting that on average the Program will result in an 8 percent energy savings for participants based on Program design and consumption levels forecasted in northern Nevada.

Outreach and Recruitment

The Program will be a new offering promoted through PowerShift by NV Energy. The ongoing messaging will focus on energy savings and bill savings. Key areas of promotion will include the Companies' web site, MyAccount, and cross-marketing with other DSM programs.

This program leverages the changes taking place in the market place due to the introduction of new disruptive technologies to provide customer choice. Smart phones, tablet devices, home computers and the smart grid provide additional opportunities for the customer-utility interface.

Measurement & Verification

This section outlines Measurement & Verification ("M&V") activities that will be performed by the independent, third-party M&V Contractor.

The M&V Contractor will determine energy savings by employing the difference-in-differences regression analysis method. In the regression analysis, energy consumption data for a census of the treatment group (i.e., program participants) will be analyzed across the following two time intervals:

- the baseline time period consisting of the 12 months immediately prior to participants' entry in the program (i.e., the "pre-program" interval)

- a similar time period that commences when participants' enter the program (i.e., the "post-program" interval, which does not necessarily need to be 12 months)

The regression analysis also includes a control group of the Companies' customers. The control group is matched to the treatment group to ensure that the control group is statistically comparable to the treatment group; matching is based on physical proximity, property characteristics, and load similarity. In the regression analysis, control group energy consumption will be analyzed for the same pre- and post-program time intervals specified for the treatment group.

For each group (treatment and control) analyzed in the regression analysis, one can think of the difference in energy consumption for the pre- and post-program intervals as being essentially year-to-year changes in energy use. Systematic intervention with a treatment group (through a utility program, for example) typically causes the treatment group's year-to-year changes in energy use to differ from the control group's year-to-year changes in energy use.

The regression model enables the M&V Contractor to prove or disprove the hypothesis that program intervention corresponds to a statistically significant difference between a) treatment group year-to-year changes in energy use and b) control group year-to-year changes in energy use. The difference-in-differences regression analysis provides a well understood statistical model through which the net energy savings resulting from program intervention can be explained and the magnitude of net energy savings can be quantified.

It is noteworthy that a difference-in-differences regression model controls for weather effects and other exogenous factors. The M&V Contractor will also control for participation in other programs to ensure that there cannot be any double-counting of savings across multiple programs. Further, data for periods when any given program participant exhibits zero energy consumption will be taken to indicate a service termination: the subject data will be excluded from the regression analysis. In other words, termination or significant interruption of service will not be considered energy conservation and will not count toward energy savings for the program. Energy savings attributable to conservation occur only when participants voluntarily curb usage during periods of regular service.

In summary, energy savings for the Program occur only when participants (i.e., the treatment group) use less electricity during the year when compared to a control group of similar households that are not participating in the program. The M&V Contractor will determine such savings using the "difference in differences" regression analysis approach described herein.

The M&V Contractor may also conduct participant surveys to evaluate customer satisfaction and collect additional qualitative data related to program implementation and customer feedback.

Financial Analysis

The cost/benefit analysis for this Program was performed utilizing the PortfolioPro financial modeling software created by the Cadmus Group for the Company. This comprehensive modeling software utilizes a stream of avoided costs broken down by each of the 8,760 hours for each year of the useful life of a measure.

A copy of the input data sheets and the financial model output sheets are provided at the end of this section. These figures were all calculated based upon the information contained in this Program data sheet and the materials referenced herein. Output sheets provide the results for the cost-benefit analysis. The assumptions used in the creation of these results are described below.

Energy Savings Curves

To allocate energy, kWh, savings per month by rate class and critical peak demand, kW, savings per month by rate class for the Energy Reports Program, ADM developed a program-specific "Energy Savings Curve" from the same Residential Demand Response control group 15-minute interval meter data captured during calendar year 2018. Given that the Energy Reports Program is a behavioral program, the inherent assumption is that its Energy Savings Curve is proportional to the Companies' customers' actual energy usage for any given period, including hourly energy usage.

Incremental Costs

There are no incremental costs because there are no out of pocket costs for the customer.

Incentives/Rebates

Incremental cost is the difference between the cost of the energy-efficient measure and the cost of the base case or baseline measure experienced by the Program participant. In the case of the FlexPay Program, there is no incremental cost because participation in the program does not involve any out-of-pocket expense to the customer.

Measure Life

The derived effective useful life for this Program is assumed to be the same as the 1.0 years as presented in the Home Energy Reports M&V Report for 2018.

Units

Unit is defined as a customer.

Savings

The savings for the per unit residential program are those estimated by literature research from various utilities offering similar programs.

Inputs and Outputs of Portfolio Pro Cost Benefit Model

The following pages provide the input and output sheets for the cost benefit analysis. The benefits, costs, net benefits and benefits/cost ratios for the five tests are provided in the "Stakeholder Perspectives and Tests" section of the output sheet. The section "Utility Savings and Costs" provides the annual and lifetime costs and savings from the utility perspective. Assumptions used to obtain the results are provided in the 'Financial Data' section of the output sheet.

NPC- FlexPay

2020	Total Budget	Utility & Admin M&V	Implementation Costs	# of Units	kWh Saved per Unit*	kWh Saved per Year	Effective Useful Life	Incremental Cost per Unit	Net-to-Gross
FlexPay	$1,000,000	$150,000	$850,000						
				17,500	1,285	22,491,000	1.0	$0.00	100.0%
Total									

NPC- FlexPay

2021	Total Budget	Utility & Admin M&V	Implementation Costs	# of Units	kWh Saved per Unit*	kWh Saved per Year	Effective Useful Life	Incremental Cost per Unit	Net-to-Gross
FlexPay	$1,100,000	$165,000	$935,000						
				20,000	1,285	25,704,000	1.0	$0.00	100.0%
Total									

Name:	2020-21 NPC Flex Pay	**Last Updated:**	4/10/2019 16:03
Customer Sector:	Residential	**Avg Measure Life:**	1.00
Region :	Vegas	**Energy Savings Curve:**	Home_Energy Reports
Start Year:	2020	**Model File Name:**	DSM_PortPro_April2019_AY.xlsm
End Year:	2021	**CAD File Name:**	Vegas_CAD_April2019_AY.xlsx.xls
Notes:		**Program DB Name:**	PD_Vegas_April2019_AY.xlsx

Stakeholder Perspectives & Tests	Benefits (PV)	Costs (PV)	Net Benefits (PV)	B/C Ratio	Cost of Conserved Energy ($/kWh)
NEB Total Resource Cost (NTRC)	$3,082,133	$1,732,563	$1,349,570	1.78	$0.042
Total Resource Cost (TRC)	$2,680,116	$1,732,563	$947,553	1.55	$0.042
Utility Cost Test (UCT)	$2,680,116	$1,732,563	$947,553	1.55	$0.042
Participant Cost Test (PCT)	$4,370,663	$0	$4,370,663		$0.000
Ratepayer Impact (RIM)	$2,680,116	$6,103,226	($3,423,110)	0.44	$0.148
Societal Cost (SCT)	$3,184,190	$1,732,563	$1,451,628	1.84	$0.042

*Includes rebates paid to freeriders

Utility Savings & Costs*	2020	2021	2022	Total Project
Total Utility Investment ($)	$1,000,000	$1,100,000	$0	$2,100,000
Electric Benefits ($)	$1,475,852	$1,778,305	$0	$2,680,116
Gas Benefits ($)	$0	$0	$0	$0
Incremental Energy & Demand Savings:				
Electric Savings (kWh)	23,383,928	26,724,489	0	50,108,417
Critical Peak Hour Demand (kW)	7,156	8,178	0	8,178
Gas Savings (therms)	0	0	0	0
Total On Peak Hours (kWh)	4,540,217	5,188,819	0	9,713,701
Total On Peak Hours (%)				19.39%

*Savings in this section are adjusted for line loss and net-to-gross

Financial Data		Secondary Benefits	
Discount Rate:	7.95%	Other Savings	$0
Rate Escalator:	0.00%		
Inflation Rate (T&D):	2.00%	**Scenarios:**	
Line Loss (Energy):	3.82%	Measure Life	100%
Line Loss (Demand):	7.60%	Energy Savings	100%
Avoided T&D Capacity $/MW:	$53,812	Avoided Energy Cost	100%
Environmental Adder (SCT only)	10.00%	Avoided Capacity Cost	100%
Non-Energy Benefit Adder (NTRC and SCT)	15.00%	Incremental Measure Cost	100%
Electric Retail Rate ($/KWh):	$0.11		
Gas Retail Rate ($/therm)	$0.54		
Net-To-Gross Ratio	100.0%		

SPPC- FlexPay

2020	Total Budget	Utility & Admin M&V	Implementation Costs	# of Units	kWh Saved per Unit*	kWh Saved per Year	Effective Useful Life	Incremental Cost per Unit	Net-to-Gross
FlexPay	$450,000	$67,500	$382,500						
				7,500	831	6,228,900	1.0	$0.00	100.0%
Total									

SPPC- FlexPay

2021	Total Budget	Utility & Admin M&V	Implementation Costs	# of Units	kWh Saved per Unit*	kWh Saved per Year	Effective Useful Life	Incremental Cost per Unit	Net-to-Gross
FlexPay	$500,000	$75,000	$425,000						
				8,500	831	7,059,420	1.0	$0.00	100.0%
Total									

Name:	2020-21 SPPC Flex Pay	**Last Updated:**	4/10/2019 16:25
Customer Sector:	Residential	**Avg Measure Life:**	1.00
Region :	Reno	**Energy Savings Curve:**	Home_Energy Reports
Start Year:	2020	**Model File Name:**	DSM_PortPro_April2019_AY.xlsm
End Year:	2021	**CAD File Name:**	Reno_CAD_April2019_AY.xlsx.xls
Notes:		**Program DB Name:**	PD_Reno_April2019_AY.xlsx

Stakeholder Perspectives & Tests	Benefits (PV)	Costs (PV)	Net Benefits (PV)	B/C Ratio	Cost of Conserved Energy ($/kWh)
NEB Total Resource Cost (NTRC)	$984,729	$808,224	$176,505	1.22	$0.067
Total Resource Cost (TRC)	$856,286	$808,224	$48,062	1.06	$0.067
Utility Cost Test (UCT)	$856,286	$808,224	$48,062	1.06	$0.067
Participant Cost Test (PCT)	$1,016,626	$0	$1,016,626		$0.000
Ratepayer Impact (RIM)	$856,286	$1,824,850	($968,564)	0.47	$0.151
Societal Cost (SCT)	$1,014,477	$808,224	$206,253	1.26	$0.067

*Includes rebates paid to freeriders

Utility Savings & Costs*	2020	2021	2022	Total Project
Total Utility Investment ($)	$450,000	$500,500	$0	$950,500
Electric Benefits ($)	$461,791	$546,227	$0	$856,286
Gas Benefits ($)	$0	$0	$0	$0
Incremental Energy & Demand Savings:				
Electric Savings (kWh)	6,647,634	7,533,986	0	14,181,620
Critical Peak Hour Demand (kW)	2,148	2,434	0	2,434
Gas Savings (therms)	0	0	0	0
Total On Peak Hours (kWh)	403,706	457,533	0	3,039,633
Total On Peak Hours (%)				21.43%

*Savings in this section are adjusted for line loss and net-to-gross

Financial Data		Secondary Benefits	
Discount Rate:	6.65%	Other Savings	$0
Rate Escalator:	0.00%		
Inflation Rate (T&D):	2.00%	**Scenarios:**	
Line Loss (Energy):	6.30%	Measure Life	100%
Line Loss (Demand):	14.31%	Energy Savings	100%
Avoided T&D Capacity $/MW:	$63,492	Avoided Energy Cost	100%
Environmental Adder (SCT only)	10.00%	Avoided Capacity Cost	100%
Non-Energy Benefit Adder (NTRC and SCT)	15.00%	Incremental Measure Cost	100%
Electric Retail Rate ($/KWh):	$0.09		
Gas Retail Rate ($/therm)	$0.33		
Net-To-Gross Ratio	100.0%		

SECTION 5. AMENDMENTS TO SUPPLY SIDE PLAN (GENERATION)

A. Existing Generation

The following information has not changed since the Companies filed their 2018 Joint IRP. Together the Companies currently hold ownership interests in approximately 6,011 MW (total peak summer capacity) of generation from the following electric generating facilities (figures reflect summer capacities):

- Chuck Lenzie Generating Station – Nevada Power: 1,102 MW of total peak summer capacity including duct burners and inlet chillers. The plant is located approximately 24 miles northeast of Las Vegas, Nevada, and is comprised of two 2x1 natural gas-fired combined cycle units (551 MW each).

- Clark Generating Station – Nevada Power: 1,102 MW of total peak summer capacity, located in Las Vegas, Nevada. Clark Station is comprised of two 2x1 natural gas-fired combined cycle units (430 MW), one natural gas-fired combustion turbine unit (54 MW), and 12 natural gas- fired simple cycle combustion turbines (618 MW).

- Clark Mountain Station - Sierra: Two dual-fuel (gas/diesel) combustion turbines with a peak summer capacity of 132 MW. The Clark Mountain units are co-located with the Tracy Station east of Reno.

- Ft. Churchill Station - Sierra: Two natural gas- fired condensing steam turbine units located 10 miles north of Yerington, Nevada. Total peak summer capacity of these units is 226 MW.

- Goodsprings Heat Recovery – Nevada Power: Five MW of total peak summer capacity located adjacent to the Kern River Goodsprings compressor station. The waste heat recovery unit captures waste heat from Kern River Gas's natural gas-fueled compressors, and uses a separate generator to produce electricity.

- Harry Allen Generating Station – Nevada Power: 628 MW of total peak summer capacity located 24 miles northeast of Las Vegas, Nevada. The Harry Allen Generating Station is comprised of the 484 MW natural gas-fired Harry Allen Combined Cycle facility, as well as 144 MW of natural gas-fired combustion turbine peak summer capacity generated by two gas- fired turbine units (72 MW each).

- Las Vegas Generating Station – Nevada Power: 272 MW Summer capacity located in North Las Vegas, Nevada. Formerly referred to as the Las Vegas Cogen facility, the Las Vegas Generating Station is comprised of one (1x1) natural gas-fired aero derivative combined cycle rated at 48 MW, and two (2x1) natural gas-fired aero-derivative combined cycle units rated at 112 MW each.

- Navajo Generating Station – Nevada Power: Nevada Power has undivided ownership rights to 255 MW of net capacity, which reflects an 11.3 percent ownership share of the Navajo Generating Station, a 2,250 MW total net capacity facility located near Page, Arizona. The facility is composed of three similar coal-fired steam turbine units (750 MW each). The Navajo Project includes the generating station, transmission lines and interconnections, water, and rail facilities, and is co-owned by five parties as tenants-in-common ("Co-Tenants"), who together with the United States are "Participants" in the Navajo Project. The Participants' relative interests in the non-transmission facilities are as follows:

- SRP (42.9%);
- U.S. Bureau of Reclamation (24.3%), whose share is owned by SRP;
- Arizona Public Service (14%);
- Nevada Power (11.3%); and
- Tucson Electric Power (7.5%)

SRP serves as the operator. Los Angeles Department of Water and Power ("LADWP") previously had an ownership interest in the generating facility and continues to have an ownership share in the transmission facilities. LADWP has decommissioning responsibilities associated with its former interest in the generating facility.

- Nellis Solar PV II - Nevada Power: 15 MW AC capacity, located on the Nellis Air Force Base in North Las Vegas, Nevada. The Nellis PV plant is a single axis tracker, consisting of 10 1.5 MW blocks. The plant went into service in November of 2015.

- North Valmy Station - Sierra: Sierra owns 50 percent of two coal-fired condensing steam units with a peak summer capacity of 522 MW. IPCo owns the other 50 percent share of the two coal-fired units at Valmy. Sierra's share of capacity from the two Valmy units is 261 MW. North Valmy Station is located 19 miles west of Battle Mountain, Nevada.

- Silverhawk Generating Station – Nevada Power: 520 MW of total peak summer capacity, including duct burners, located approximately 26 miles northeast of Las Vegas, Nevada. The plant is comprised of one 2x1 natural gas-fired combined cycle unit.

- Sun Peak Generating Station – Nevada Power: 210 MW of net summer peak capacity located in Las Vegas, Nevada. Sun Peak Generating Station is comprised of three dual fuel (natural gas and No. 2 fuel oil) simple-cycle combustion turbine units (each capable of producing 70 MW).

- Tracy Station - Sierra: 753 MW of total peak summer capacity, located approximately 15 miles east of Reno, Nevada. The Tracy Station is comprised of one natural gas-fired steam unit with a total peak summer capacity of 108 MW, and two natural gas- fired combined cycle blocks with a peak summer capacity of 645 MW.

- Walter Higgins Generating Station - Nevada Power: 530 MW of total peak summer capacity including duct burners, located approximately 35 miles southwest of Las Vegas, comprised of one 2x1 natural gas-fired combined cycle unit.

Figure GEN-1 lists in tabular form Nevada Power's and Sierra's generating units and summarizes their respective operating characteristics including: name plate ratings, and winter, summer and peak capacities, commercial operation dates, deprecation-based retirement dates and fuel types.

FIGURE GEN-1 GENERATING UNITS SUMMARY

Unit	Commercial Operation Date	Depreciation Based Retirement Date	Prime Mover[7]	Designation	Name Plate (MW)	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Primary Fuel Storage Capacity[8]	Secondary Fuel Storage
Sierra[9]										
Clark Mt. 3	1994	2024	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Clark Mt. 4	1994	2024	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Ft. Churchill 1	1968	2025	Steam	Intermediate	105	113	113	Nat Gas	0	0
Ft. Churchill 2	1971	2028	Steam	Intermediate	105	113	113	Nat Gas	0	0
Tracy 3	1974	2028	Steam	Intermediate	110	108	108	Nat Gas	0	0
Tracy 4&5 (Pinon)	1996	2031	CC /Steam	Intermediate	113	108	104	Nat Gas	0	0
Tracy 8, 9, 10	2008	2043	CC /Steam	Base	623	578	553	Nat Gas	0	0
Valmy 1	1981	2021	Steam	Intermediate	127	127	127	Coal	200 days	200 days
Valmy 2[10]	1985	2025	Steam	Intermediate	134	134	134	Coal	200 days	200 days
Nevada Power										
Clark 4	1973	2020	CT	Peaker	60	63	55	Nat Gas	0	0
Clark 5, 6, 7	1979. 1979, 1994	2034	CC /Steam	Intermediate	236	84	73	Nat Gas	0	0
Clark 7, 8, 9	1980, 1982, 1994	2033	CC /Steam	Intermediate	236	84	73	Nat Gas	0	0
Clark 11 – 22	2008	2038	CT	Peaker	726	57	52	Nat Gas	0	0
Goodsprings	2010	2040		Base	7.5			Waste Heat	0	0
Harry Allen 3	1995	2025	GT	Peaker	72	84	74	Nat Gas	0	0
Harry Allen 4	2006	2036	GT	Peaker	72	84	74	Nat Gas	0	0
Harry Allen CC	2011	2046	CC /Steam	Base	558	524	510	Nat Gas	0	0
Chuck Lenzie 1	2006	2041	CC /Steam	Intermediate	610	601	585	Nat Gas	0	0
Chuck Lenzie 2	2006	2041	CC /Steam	Intermediate	610	601	585	Nat Gas	0	0
Silverhawk CC	2004	2039	CC /Steam	Intermediate	599	599	560	Nat Gas	0	0
Walt Higgins CC	2004	2039	CC /Steam	Intermediate	688	600	550	Nat Gas	0	0
Navajo 1, 2, 3[11]	1974	2019	Steam	Base	255	255	255	Coal	180 Days	180 Days
LV Gen 1	1994	2029	CC /Steam	Intermediate	61.3	51	48	Nat Gas	0	0
LV Gen 2	2004	2039	CC /Steam	Intermediate	148.8	115	112	Nat Gas	0	0
LV Gen 3	2004	2039	CC /Steam	Intermediate	148.8	115	112	Nat Gas	0	0
Sun Peak 3	1991	2026	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 4	1991	2026	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 5	1991	2026	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	180 hours[12]

[7] "CT" indicates combustion turbine, "CC" indicates combined cycle.
[8] Fuel Storage Capacity Assumes Full Load Operation.
[9] Brunswick is not listed because it is a Black Start Only unit and is not available for capacity.
[10] The two Valmy units are 50% owned by Idaho Power Company. Figure GEN-1 shows only Sierra's 50% share of the capacity of the two Valmy units.
[11] Navajo Generating Station is a 2,250 MW Station. Nevada Power owns 11.5 percent interest in Navajo. Table GEN-1 only shows Nevada Power's 11.5 percent share of the capacity of Navajo.
[12] No Diesel fuel is currently stored on site.

B. Other Generation Assets

The following information has not changed since the Companies filed their 2018 Joint IRP. Nevada Power and Sierra hold ownership interests in three other generation assets:

- Brunswick Diesel Plant - Sierra: The Brunswick Diesel Plant is a six MW Emergency "Black Start Only" plant, comprised of three reciprocating diesel fired engines located on approximately 10 acres in Carson City, Nevada. This Plant is operational; however, since it is black start only, it cannot be used to serve customer load and so does not provide system capacity.

- Mohave Generating Station – Nevada Power: The Mohave site is located in Laughlin, Nevada and is the previous site of a 1,500 MW coal-fired generating plant. The site is co-owned by Southern California Edison ("SCE") (56%), SRP (20%), Nevada Power (14%) and LADWP (10%). SCE is the controlling partner of the facility. Mohave ceased operations January 1, 2006 and has been decommissioned.[13] In 2015, the co-owners agreed to proceed with selling the majority of the property through a public sale process. The property was listed by a nationwide commercial real estate firm in October 2016. No sales transactions have been executed at this time.

- Reid Gardner Generating Station – Nevada Power: The last unit at the Reid Gardner Generating Station ceased operations in March 2017 and the plant is in a state of Post-Operational Reserve.[14] The units are currently being dismantled. Dismantling and demolishing of the units will be completed over the next 12 months and site remediation and site restoration will follow. Nevada Power is continuing with the decommissioning and demolition plan approved by the Commission in Docket No. 15-05004. A final disposition plan for the site will be developed as the scope of site remediation work is better known.

C. Generation Retirement Dates

In Docket No. 08-08002, Nevada Power proposed and the Commission approved the Life Span Analysis Process ("LSAP") to determine and reevaluate the economic useful lives of the Companies' generating units. Since that proceeding, both the Companies and the Commission have come to rely on this process (rather than depreciation studies filed with general rate case reviews), for determining the appropriate planning retirement dates to be used for the Companies' generating units.

[13] As defined in NRS § 704.7332.
[14] As defined in NRS § 704.7335.

The LSAP provides an initial life span estimate based on a unit's design and intended mode of operation. For a generating facility that has joined the Companies' fleet since the adoption of the LSAP, a unit's initial life span is established when the unit is first put in service. In the case of units that were already in-service when the Commission approved the LSAP, the Reassessment Protocol set forth in the LSAP was used to set an initial life.

After a unit is commissioned and has been in operation, its life span will eventually be reassessed at least once, sometimes more often, to ensure that the Initial Life Span Assessment is still valid, or to determine whether a new plan is more appropriate for the unit. The reassessment of unit life span can be undertaken for any of the following Reassessment Criteria:

- Annual Business Plan Review
- Last Decade of Unit Life Span
- Change in Environmental Compliance Requirements
- Change in Infrastructure
- Significant Event
- Commission-Ordered Reassessment.

When a reassessment is undertaken, it can range from cursory to detailed, depending on the nature of the revisit. For example, during the initial years of operation, the reassessment due to an Annual Business Plan Review may result in a business decision to maintain the Initial Life Span Assessment. At the other end of the spectrum, a unit entering its planned last decade of operations may implicate operations, maintenance, environmental and infrastructure considerations and dictate a detailed review to assess the unit's remaining life span. No matter the nature of the review, the key steps of the Reassessment Protocol are as follows:

- Unit Assessment
- Environmental Assessment
- Infrastructure Assessment
- Development of Options
- Options Input to Resource Planning and Financial Analysis
- Final Decision on Life Span Assessment and Implementation Plan

1. 2019 LSAP AND RETIREMENT DATE CHANGES

During 2019, 14 units will enter into the Last Decade of Life Span, thereby triggering LSAP review. Thus, LSAPs were prepared in 2018 for all units subject to the Last Decade of Life Span criterion, and were filed with the Commission as part of the Companies' 2018 Joint IRP.

An updated LSAP report for Sierra's Tracy Unit 3 has been prepared and is included in Technical Appendix GEN-01. This LSAP was triggered by the age of the unit (current retirement date of December 31, 2028), and modification of an environmental permit requiring that the use of the Tracy Station cooling water pond as a discharge point for processed water from Tracy Unit 3 must cease by December 31, 2020. The Companies are seeking approval to amend the 2018 Joint IRP to implement the recommendations set forth in the new Tracy Unit 3 LSAP, namely investing approximately $12.9 million (without AFUDC)($13.6 million with AFUDC) to replace the existing Tracy 3 water treatment equipment and pond. Based on the analysis performed and presented in the GEN-01, investment in the new pond and water treatment equipment is cost effective and will maintain the depreciation planning retirement date of 2028.[15]

2. NAVAJO UNITS 1-3

The 2019 planned retirement of the Navajo Generating Station was approved by the Commission in Nevada Power's 3rd Amendment to the Emissions Reduction and Capacity Replacement ("ERCR") Plan, Docket No. 17-11005, which was filed on November 6, 2017. The Companies are not proposing to make any changes to the December 22, 2019 retirement date for Navajo Units 1-3.

3. NORTH VALMY UNIT 2

Sierra completed an LSAP for North Valmy Units 1 and 2 in 2018, which was filed with the Commission on February 16, 2018 in a compliance with Docket No. 16-07001. The February 16, 2018 LSAP recommended maintaining the current Commission approved retirement dates of 2025 for both Units 1 and 2. For Valmy Unit 2, Sierra proposed and the Commission accepted to make no changes in the retirement date. A discussion of the potential early retirement of North Valmy Unit 1 follows.

4. NORTH VALMY UNIT 1

In its order in Docket No. 18-06003, the Commission approved the conditional early retirement date for Valmy Unit 1 of December 31, 2021. The Companies continue to monitor the conditions related to the conditional early retirement of Valmy Unit 1 and have committed to keep the Commission apprised of the status of the reliability and cost-related conditions for this Unit.

Both Valmy Units are co-owned by IPCo. In its 2017 IRP, IPCo modified its contemplated retirement of both Valmy units at year-end 2025. Based on modifications to its baseline assumptions regarding risk, IPCo changed its preferred portfolio to reflect the retirement of Unit 1 in 2019. IPCo indicated in its 2017 IRP that economic benefits to its customers of retiring Valmy Unit 1 in 2019 outweighed the risks of continuing to operate the unit through 2025. As a result, IPCo recommended changing the retirement of its share of Valmy Unit 1 to 2019, while maintaining the assumption that its share of Valmy Unit 2 will continue to operate to year-end 2025.

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[15] Additional cost analysis is set forth in an Authorization for Expenditure ("AFE") memorandum that is included in the filing as Technical Appendix GEN-2. Portions of GEN-2 are confidential.

In its Order Number 33771 to Docket IPC-E-16-24, a depreciation rate filing, the Idaho Public Utilities Commission approved a Settlement Stipulation between the parties. In the Settlement Stipulation, IPCo agreed: "The estimated target shutdown dates for the two coal-burning units at Valmy are the end of 2019 for Unit 1, and end of 2025 for Unit 2…."[16] The Settlement Stipulation also provides that IPCo "will negotiate with co-owner NV Energy — using prudent and commercially reasonable efforts — to accomplish a permanent end to coal-burning operations of Valmy Unit 1 by December 31, 2019, and of Valmy Unit 2 by December 31, 2025."[17] Alternatively, the Parties agreed that IPCo would use prudent and commercially reasonable efforts to "end its participation in the operation of [Valmy] Unit 1 by December 31, 2019, and [Valmy] Unit 2 by December 31, 2025."[18]

D. Update To Previously-Approved Generation Projects

The Companies included comprehensive updates to previously-approved generation projects in their 2018 Joint IRP. This information has not changed and thus further updates have not been prepared.

E. Emission Reduction And Capacity Replacement Projects

Senate Bill 123 ("SB 123") (2013 Nevada Legislature) and its associated regulations required the orderly retirement or divestiture of coal fired generating assets owned by Nevada Power. Nevada Power filed its initial ERCR plan on May 1, 2014, in Docket No. 14-05003, which the Commission approved on October 28, 2014. The initial ERCR plan called for the retirement of Reid Gardner Units 1, 2 and 3 on or before December 31, 2014, Reid Gardner Unit 4 by December 31, 2017, and divestiture or elimination[19] of Nevada Power's interest in the Navajo Generating Station by December 31, 2019. In the ERCR Second Amendment, Docket No. 16-08026, the Commission approved the accelerated retirement of Reid Gardner Unit 4, from December 31, 2017 to on or about February 28, 2017. In the ERCR Third Amendment, Docket No. 17- 11005, the Commission approved a stipulation on February 1, 2018, allowing the retirement of Nevada Power's share of Navajo on or before December 22, 2019.

1. Decommissioning and Demolition of Reid Gardner Station

Reid Gardner Units 1-3 ceased operation in December 2014 and Reid Gardner Unit 4 ceased operation in March 2017. Decommissioning of Reid Gardner Units 1-3 began in January 2015 and April 2017 for Reid Gardner 4. Nevada Power awarded a contract for demolition of Reid Gardner Units 1-4 in January 2018. The demolition contractor began work on site in February 2018. The

[16] IPUC Order No. 33771, Settlement.
[17] *Id*. at 6.
[18] *Id.*
[19] *See*, Nev. Admin. Code § 704.90593 (defining "eliminate" and "elimination" for the purposes of the Commission's ERCR plan regulations).

demolition portion of the project is expected to be completed by May 2020. Site remediation and restoration work will follow the plant demolition.

2. DECOMMISSIONING AND DEMOLITION OF NAVAJO GENERATING STATION

As approved by the Commission in Docket No. 17-11005, Nevada Power continues to work with the other owners of the Navajo Generating Station to develop plans for the December 22, 2019 shutdown of the generating units and the decommissioning and demolition of the station that will follow.

3. ERCR CAPACITY REPLACEMENT PROJECTS

The Companies included a comprehensive description of previously-approved ERCR Capacity Replacement Projects in their 2018 Joint IRP. This information has not changed and thus further updates have not been prepared.

F. New Generation Projects

1. TRACY POND PROJECT

The Tracy Power Generating Station ("Tracy") is located on the banks of the Truckee River, in Washoe County. The source of water for plant operations is an unlined cooling pond. Cooling pond water is used as make up water in the Tracy Unit 3 cooling tower, and the water from the cooling tower blowdown is discharged back into the cooling pond. The unlined cooling pond is also fed by water from Clark Mountain evaporative cooler blowdown, and its oily water separator recovery. This discharge back to the cooling pond is currently authorized by groundwater authorization to discharge permit (No. NS0097023) issued from the Nevada Division of Environmental Protection, Bureau of Water Pollution Control ("NDEP-BWPC"). In conformance with this permit, Tracy must cease all discharges to the existing cooling pond by December 31, 2020.

In 2015, when NV Energy submitted its permit renewal application to the NDEP-BWPC, the NDEP-BWPC deemed the cooling pond to be a jurisdictional waterbody and determined that a non-National Pollutant Discharge Elimination System ("non-NPDES") permit could not continue to be issued for discharges into the cooling pond. However, NDEP-BWPC determined it would allow another non-NPDES permit to be issued if NV Energy agreed to cease discharges into the unlined cooling pond. On April 10, 2015, NV Energy sent a letter to NDEP-BWPC committing to cease discharge into the unlined cooling pond at Tracy at a yet to be determined date.

Based on this commitment by NV Energy, a new non-NPDES permit was issued (Permit No. NS0097023), which became effective on July 1, 2016. This permit currently lists the following authorized discharges into the unlined Tracy cooling pond: "groundwater, Truckee River water, cooling tower blowdown water, storm water, reverse osmosis process wastewater, and other various process wastewaters from the plant."

In accordance with the new non-NPDES permit, a Schedule of Compliance Table required the submittal of a plan for ceasing discharge to the cooling pond to NDEP-BWPC by December 31, 2017, and discharges to the cooling pond to cease by December 31, 2020. On December 20, 2017, NV Energy submitted its plan for ceasing discharge to the current cooling pond, which introduced the option to permit, construct and place a new pond into service. That option identified a site southwest of the current cooling water pond and an in-service date on or before December 31, 2020.

Before committing to the new Tracy pond project, Sierra employed the LSAP process and prepared an engineering analysis to understand the needs of all process water users, the capabilities of the existing equipment, and the capabilities of available alternative technologies. Known safety and reliability considerations associated with the existing waste water treatment plant, clarifier, and reverse osmosis water treatment units were taken into account and addressed in the comprehensive solution. Many alternatives were considered, including retiring Tracy Unit 3, adding thermal evaporators, replacing Tracy Unit 3 with peaking units, adding high efficiency water recovery equipment, building a new pond, lining the Tracy pond, and modernizing the existing equipment. Most options were not technically viable and would have generated more waste water than the existing waste water evaporation ponds could reasonably evaporate. The LSAP for the Tracy project is set forth in Technical Appendix GEN-1.

Based on this engineering analysis, an economic analysis was performed to determine the most cost-effective means of addressing the impact of NDEP-BWPC's modifications to the environmental permits governing the utilization of the unlined Tracy cooling pond. The lowest cost, technically viable alternative was a combination of modernizing the existing equipment and selectively adding upgrades (e.g. control valves, DCS connection, modern chemistry sensors) to improve operability and reliability. The economic analysis supporting the decision to move forward with the new Tracy 3 cooling pond is set forth in Technical Appendix GEN-2 (a portion of which is redacted in the public version of the filing).

As a result of these analyses, the Company recommends that a new Tracy pond be constructed and brought into service prior to December 31, 2020. The new Tracy pond will serve the equalization and retention needs for blowdown from the Tracy Cooling Tower 3, Tracy Cooling Tower 4/5 and the evaporative cooling blowdown from Clark Mountain units 3 & 4. Existing water treatment systems, including the clarifier, drift eliminators, and waste water reverse osmosis plant will be modernized and upgraded to reduce discharge into the existing evaporation ponds, reduce hazards, and improve operability of reverse osmosis membranes/microfilters.

At the time the new pond is placed into service, discharge from Tracy Unit 3 to the unlined cooling pond will cease. However, the cooling pond will remain in-service, and continue to be a major source of water supply to the Station. The old pond may be used to store makeup water from the Truckee River.

This solution has been authorized by NV Energy's management, and is included in this amendment to the 2018 Joint IRP for Commission review and approval. The estimated total costs to construct the new Tracy Pond and upgrade the existing waste water treatment system is $12.9 million (without AFUDC) ($13.6 million with AFUDC). The expected in-service date for the project is

December 11, 2020. Cash flows for the Tracy Pond project are reflected in the Figure GEN-2 below.

Figure GEN-2
TRACY 3 POND REPLACEMENT
Cash Flows (with AFUDC)

	2017	2018	2019	Beyond	
1st Qtr		$ (9,546)	$ 440,791	$ 2,875,648	
2nd Qtr		$ 37,695	$ 499,242	$ 2,445,780	
3rd Qtr	$ 51,615	$ 75,625	$ 955,637	$ 2,484,447	
4th Qtr	$ 79,347	$ 64,380	$ 2,254,289	$ 1,338,721	
Total	$ 130,962	$ 168,154	$ 4,149,958	$ 9,144,596	**$ 13,593,670**

2. NEW NORTH VALMY PROJECT FRAMEWORK AGREEMENT

The current Ownership and Operating Agreements between Sierra and IPCo govern their involvement in the Valmy Station, but do not address the circumstance in which one party chooses to end its involvement in one or both units. Sierra and IPCo negotiated the North Valmy Project Framework Agreement ("Framework Agreement") to provide a mechanism for either owner to cease its participation in one or both units based on end of operation scenarios that were not be contemplated in the original ownership agreement. The Framework Agreement establishes a unit-specific exit fee for the exiting participant that allows the remaining participant in a unit to maintain unit capacity and availability without additional financial burden between 2020 and 2025. The Agreement also addresses the Station's decommissioning requirements in more detail than in the previous Operating and Ownership Agreements. The Framework Agreement is included in this filing for approval by the Commission in Appendix GEN-3 (Confidential).

SECTION 6. AMENDMENTS TO TRANSMISSION PLAN

A. Introduction

This transmission plan is built upon the load forecasts, system characteristics, existing and future transmission facilities and obligations as described in this section. Based in part on these key system characteristics, the transmission plan examines the capabilities of the existing transmission system in order to determine the need for, and timing of, any additional transmission facilities.

As part of this IRP Amendment filing, the Companies are providing a discussion regarding updated to the Tracy Area Master Plan, as well as a discussion of updates to the system import limits on the Northern portion of the Companies' transmission system. These updates are provided for informational purposes only.

The Companies also provide informational updates to three previously approved projects that impact project costs. First, by deploying a spare transformer, the costs of the McDonald 230/138 kV Substation Upgrade and 230 kV Arden to McDonald Line Upgrade Project have been reduced from approximately $12.8 million to cost $7 million. Second, due to increases in the cost of raw materials, the delivered cost of the five spare transformers approved as part of the Grid Resilience Program have increased from $17 million to $20.5 Finally, the costs of the Frontier 230 kV Breaker Addition Project have increased from $737,000 to $1.480 million. During construction, the infrastructure of the old substation was determined to be insufficient to support the required upgrades. The Companies incurred additional material and construction costs to rebuild foundations, additional steel structures and bus work.

Additionally, the Companies are providing updates regarding three previously approved projects that include scope changes and/or budget revisions for which the Companies are seeking Commission review and approval: (1) the previously approved West Tracy 345/120 kV Transformer addition (northern system), (2) the previously approved Bordertown to California 120 kV Project (northern system), and (3) the previously approved Dodge Flat Generation Interconnection (northern system).

The Companies are requesting Action Plan approval to begin work on six new transmission growth and reliability projects. These projects include: (1) the Comstock Meadows 345/120 kV Substation, (2) permitting for a Major Northern Nevada Transmission Addition, (3) a second Reid Gardner to Tortoise 230 kV transmission line, (4) the Shaffer 345 kV Substation, (5) the Bighorn 230/69 kV Transformer addition, and (6) routing and siting for the West Henderson SE2 Substation.

The Companies are requesting Action Plan approval to begin network upgrades associated with four new Generator Interconnection projects. These include network upgrades required to support the development of the following renewable generation projects: Carson Lake Geothermal, Harry Allen Solar, Aiya Solar, and Pershing Solar.

B. Overview of the Companies' Transmission System

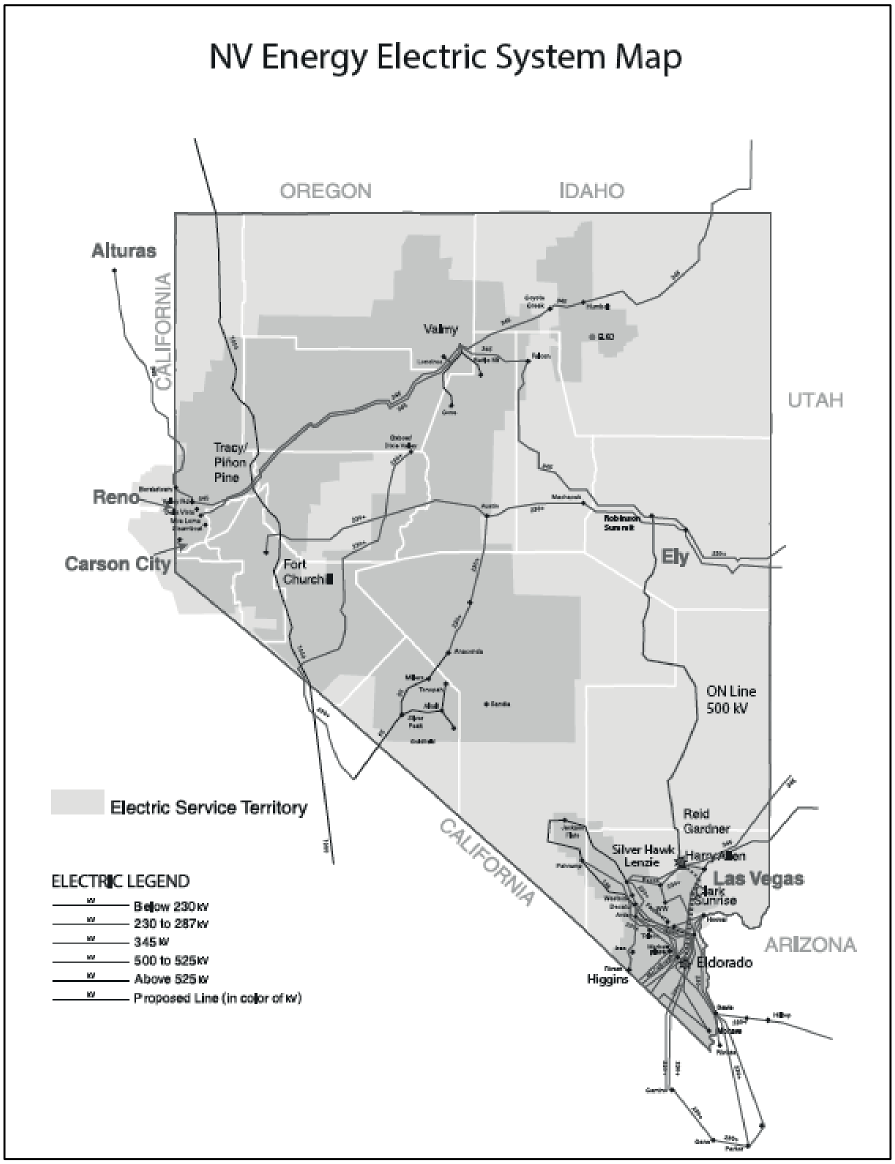
The following information has not changed since the Companies filed their 2018 Joint IRP. Section

704.9321(3)(e) of the NAC requires the Companies to provide maps depicting facilities required for the transmission of electric energy. This information is set forth in the map marked as Figure TP-1 below. This map shows the transmission system in both the northern and southern parts of Nevada, at each voltage.

The consolidated Nevada Power and Sierra transmission balancing authority area ("BAA") encompasses approximately 50,000 square miles. Nevada Power owns 1,665 miles of FERC-jurisdictional transmission lines with voltages ranging from 69 kV to 500 kV. The Sierra transmission service area encompasses more than 40,000 square miles, with approximately 330,000 electric customers and 2,151 miles of FERC-jurisdictional transmission lines ranging from 55 kV to 345 kV.[20]

[20] Total Sierra transmission line mileage for both FERC-jurisdictional and Nevada jurisdictional facilities is 4,157 miles with voltages ranging from 55 kV – 345 kV. This excludes the 235 mile, 500 kV One Nevada Transmission Line ("ON Line"). ON Line is included as part of Nevada Power's overall transmission system.

FIGURE TP-1
NV ENERGY TRANSMISSION SYSTEM DIAGRAM



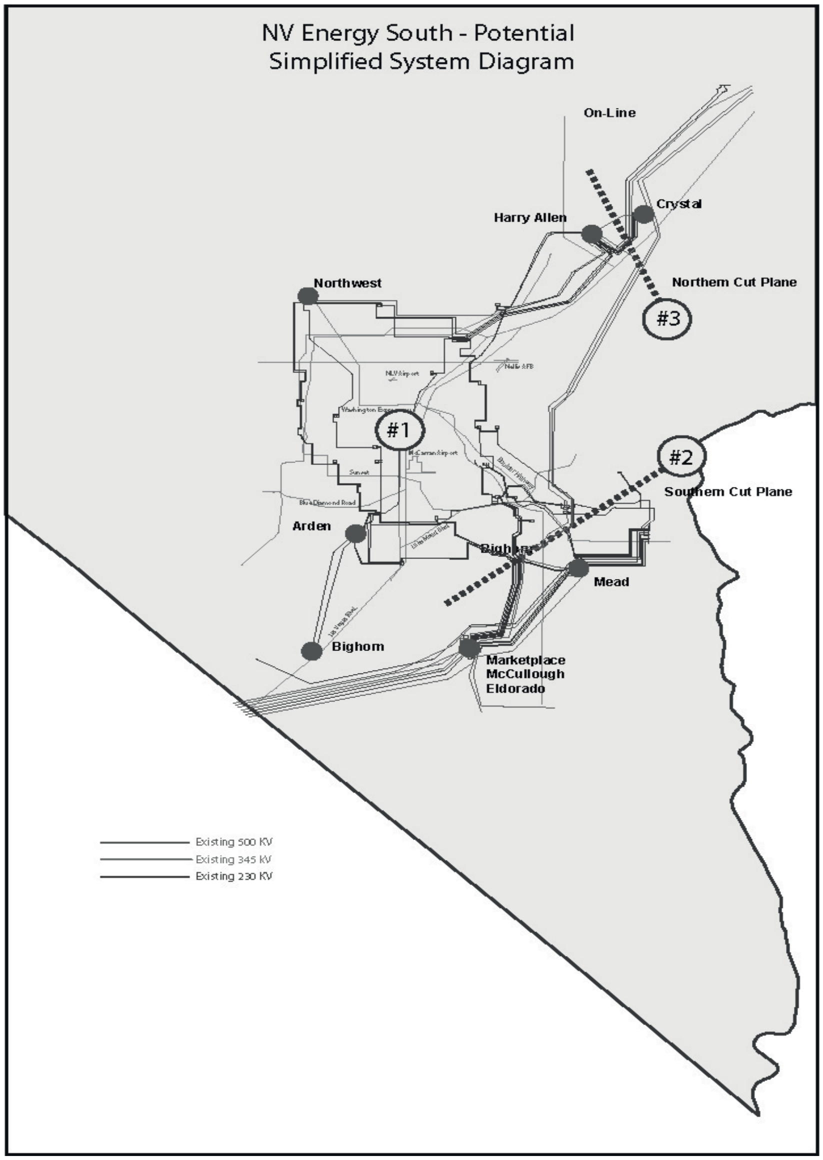
1. NEVADA POWER TRANSMISSION SYSTEM

The existing Nevada Power transmission system can be described in three sections, each of which is depicted in Figure TP-2. The first section, generally referred to as the Nevada Power internal system, is designated by the "#1", and is shown as the area between the cut plane lines (the heavy dashed lines). A cut plane is a reference to a combination of lines, either internal or external to a transmission system, which due to loading capabilities are collectively monitored or examined for limitations. The Nevada Power internal system is located within the Las Vegas Valley where the vast majority of Nevada Power's customers reside.

Two import/export paths are also depicted. The second section, designated with a "#2", is identified by the dashed line on the bottom-right of Figure TP-2. This transmission path is known as the Southern Cut Plane ("SCP"), and shows the transmission lines Nevada Power uses to transfer power through major substations on the southern interface of its transmission system – namely Mead, McCullough, and Eldorado – located south of Las Vegas in the Eldorado Valley. As detailed later under the Transmission Path Ratings portion of this plan, the SCP has been replaced by the formally accepted Western Electricity Coordinating Council ("WECC") path known as the Southern Nevada Transmission Interface ("SNTI"). The SNTI is composed of numerous transmission lines electrically situated in parallel with each other. These lines are connected to the Mead, McCullough, and Eldorado substations, which are prominent trading hubs south of Nevada Power's transmission system, and are used to import and export energy that is scheduled across this newly rated path.

The third section is represented by the dashed line on the top-right of Figure TP-2, designated with a "#3", is referred to as the Northern Cut Plane ("NCP"), and comprises the Red Butte-Harry Allen 345 kV interconnection with PacifiCorp, and the Crystal interconnection with the Navajo-Crystal-McCullough 500 kV line. Annual studies are conducted in coordination with PacifiCorp to verify the capability of this cut plane.

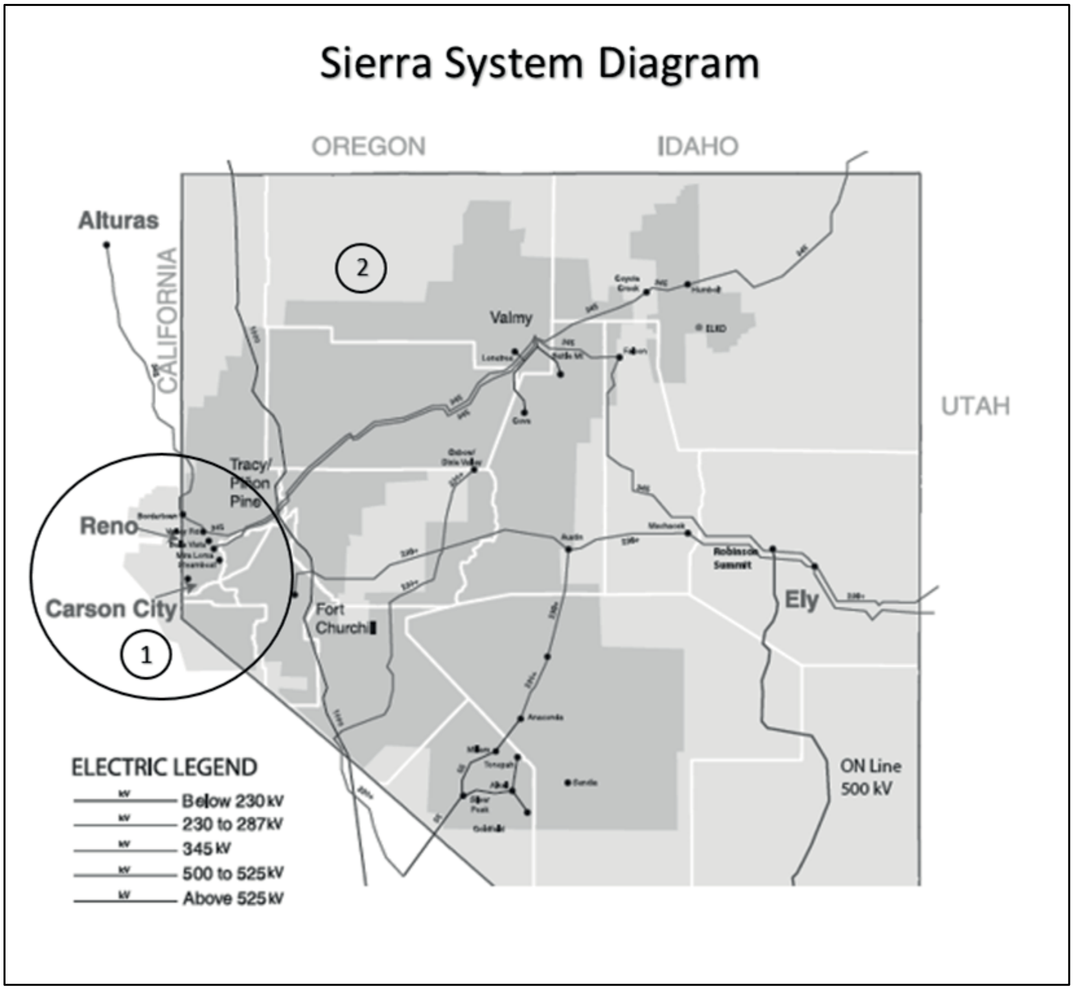
FIGURE TP-2
NEVADA POWER TRANSMISSION SYSTEM DIAGRAM



2. SIERRA TRANSMISSION SYSTEM

The Sierra system is best described as two sections as shown in the map in Figure TP-3 below. The first section, depicted as the area within the circle, encompasses the Reno, Tracy and Carson City areas. Designated with a "1", this section represents the majority of Sierra's system load, and is where the majority of Sierra's customers reside. The second section of the Sierra service area is the area outside the inner circle, designated with the "2", in the northern portion of the state. This section is characterized by long transmission lines serving heavy industrial (i.e., mining) and rural load widely dispersed throughout the northern portion of the state.

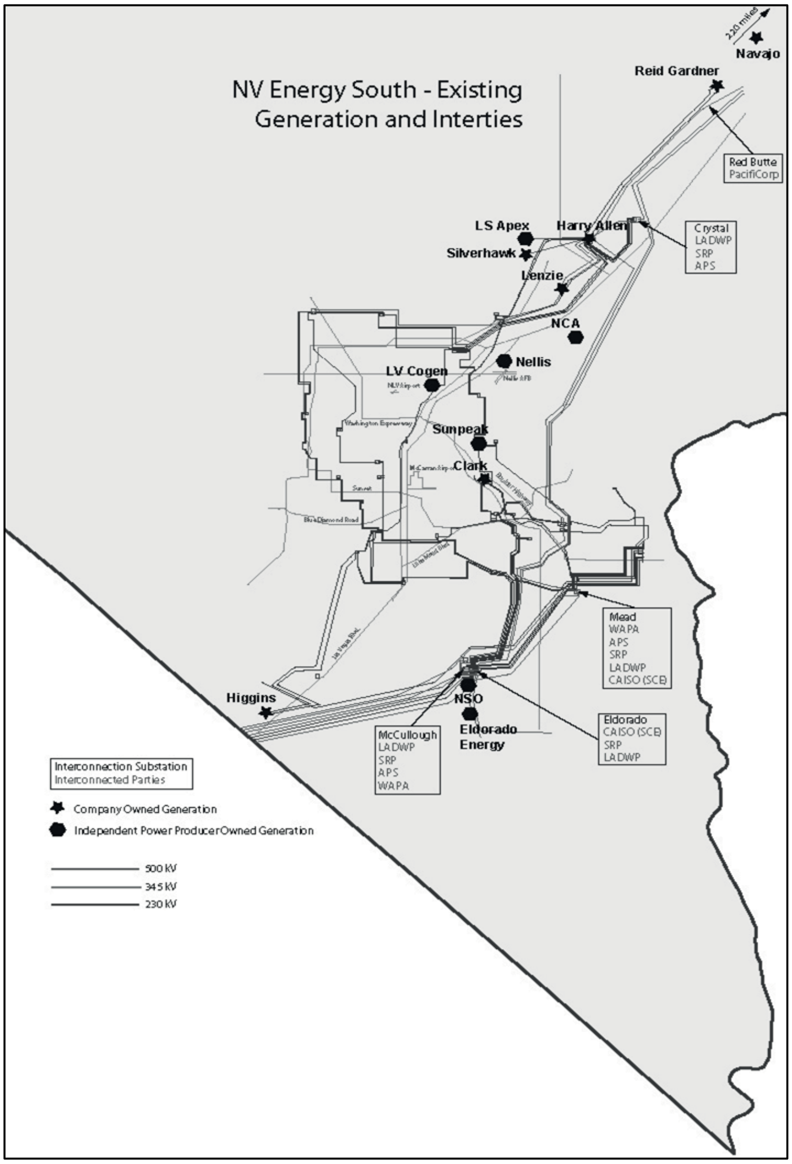
FIGURE TP-3
SIERRA TRANSMISSION SYSTEM DIAGRAM



3. TRANSMISSION PATH RATINGS

The following information has not changed since the Companies filed their 2018 Joint IRP. Per NAC §704.9385(3)(a), the Transmission Plan must provide a summary of the capabilities of the transmission system, including import and export capabilities and the rating of significant transmission paths. NAC §704.9321(3)(d) requires the Companies to provide information regarding interconnections with other utilities and independent power producers. Nevada Power owns three significant rated transmission paths, as shown below in Figure TP-4, each consisting of one or more transmission lines that are granted a rating by the WECC. Nevada Power is a partial owner of one additional WECC-rated transmission path, that being the WECC East of River ("EOR") Path 49.

FIGURE TP-4
DIAGRAM OF NEVADA POWER TIE LINES, EXISTING COMPANY-OWNED GENERATION, AND EXISTING INDEPENDENT GENERATION



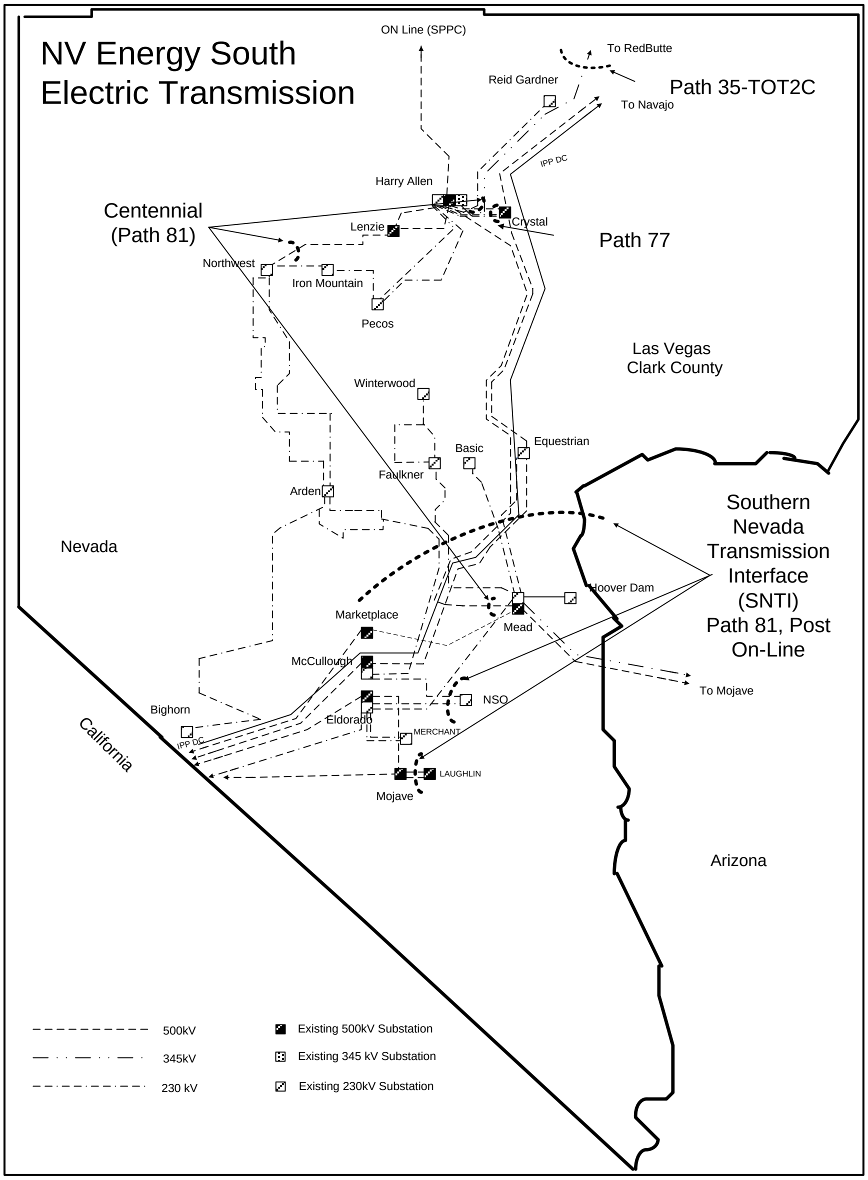
Crystal 500 / 230 kV Path (WECC Path # 77). The Crystal 500/230 kV path allows energy to be moved from the Navajo-Crystal-McCullough 500 kV transmission line into the northeast boundary of the Nevada Power system via its Crystal Substation. This path is rated for 950 MW of inbound flow measured at the Crystal Substation. This is a 230 kV phase shifter-controlled path.

Harry Allen – Red Butte 345 kV Path (WECC Path # 35 – TOT2C). The Harry Allen to Red Butte 345 kV path allows energy to be moved to and from Utah (PacifiCorp – East) and the northeast corner of the Nevada Power system at the Harry Allen switching station. The two-phase shifters at Harry Allen control the flow on this path and they are occasionally used to mitigate unscheduled flow in the WECC interconnection. This path has a north to south rating of 600 MW and a south to north rating of 580 MW

Southern Nevada Transmission Interface (WECC Path #81). Nevada Power owns and operates the Southern Nevada Transmission Interface, or SNTI, shown below in Figure TP-5. SNTI is comprised of 21 transmission tie-lines between the Nevada Power/Sierra combined BAA and the neighboring BAAs in southern Nevada (Western Area Power Administration, Lower Colorado, Los Angeles Department of Water and Power, and the California Independent System Operator ("CAISO"). This can be seen in Figure TP-4. The SNTI represents existing lines, and the path is routinely evaluated and annually updated as a part of the NV Energy seasonal operating studies. The accepted SNTI rating as approved by WECC is 4,533 MW North-to-South and 3,970 MW South-to-North.

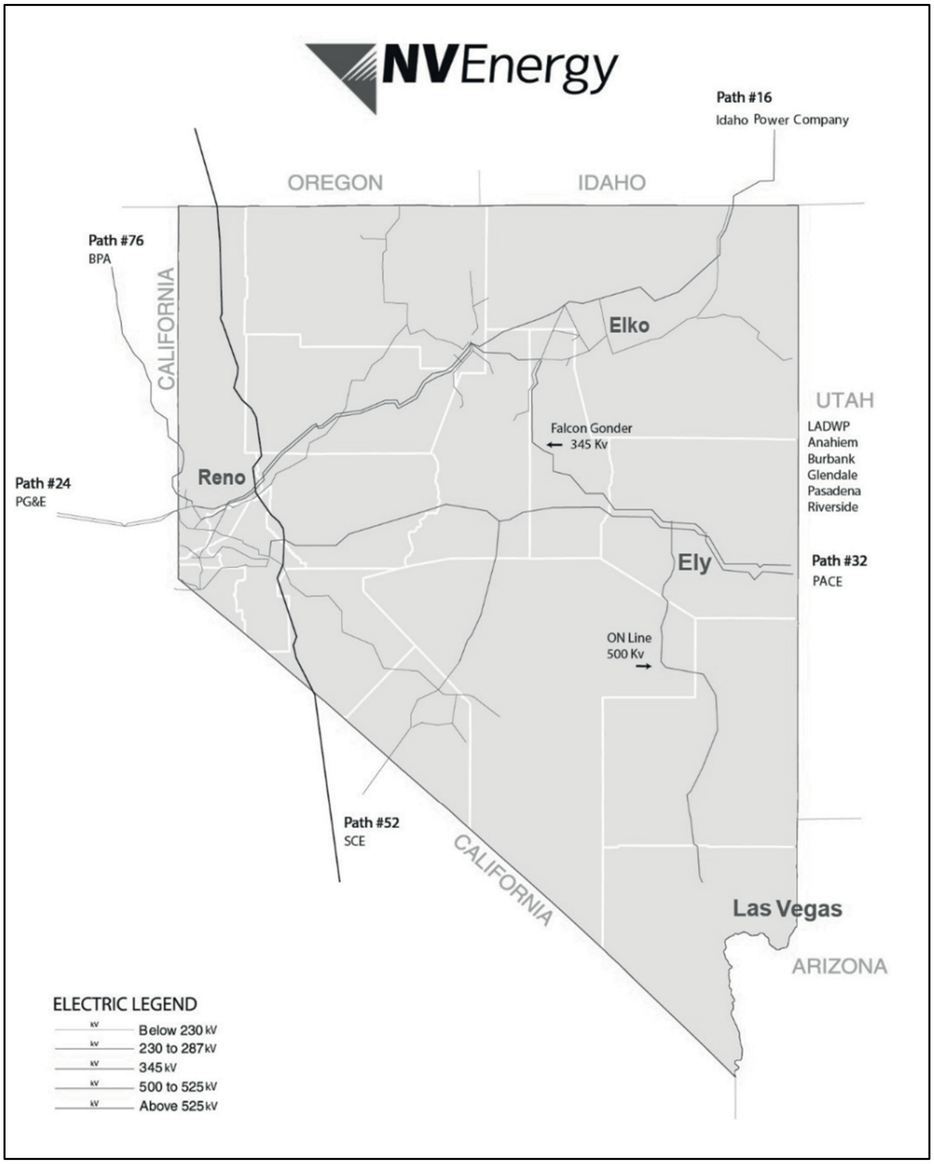
Regional Projects Affecting Nevada Power Capacity Rights. In 2014, the CAISO announced its intent to seek bids for the construction a new 500 kV transmission line between Nevada Power's Harry Allen substation and Southern California Edison's ("SCE") Eldorado substation ("HAE Project"). CAISO is sponsoring the line for the benefit of CAISO and its customers. The expected in service date of the HAE Project is May 2020. LS Power Associates, L.P. ("LS Power") has been awarded the bid. Nevada Power and Sierra have executed certain agreements with LS Power to support LS Power's bid and continue to work with LS Power, CAISO and SCE on the project. The line will improve reliability of Nevada and California systems, enhance import capabilities by approximately 100 MW and increase total Nevada Power's export capability through the SCP by approximately 1,000 MW.

FIGURE TP-5
SOUTHERN NEVADA TRANSMISSION INTERFACES



Sierra owns five WECC rated transmission paths, each consisting of one or more transmission lines. Rated transmission paths are identified in Figure TP-6 below. Ratings are established through the WECC process on a non-simultaneous basis. These transmission path ratings may be subject to change over the 20-year planning period, depending on changes to the system configuration. Operation of the paths are based on simultaneous limits described as Operational Transfer Capabilities and are posted on Sierra's Open Access Same-time Information System ("OASIS").

FIGURE TP-6
SIERRA RATED TRANSMISSION PATHS



__Idaho – Sierra (WECC Path # 16)__. This path is rated for 500 MW of inbound flow and 360 MW of outbound flow. The path is a 345 kV line from Idaho Power's Midpoint Substation, near Twin Falls, Idaho that connects to Sierra's Humboldt Substation in the northeast corner of the Sierra's transmission system.

__Pacific Gas and Electric – Sierra (WECC Path # 24)__. This path has two 120 kV lines and one 60 kV line and is rated for a total flow of 160 MW in-bound and 150 MW out-bound. The path connects Pacific Gas and Electric's 115 kV system near Donner Summit, California, to Sierra's 120 kV and 60 kV transmission near Truckee, California. This path has a 150 MVA phase shifter at California Substation near Verdi, Nevada, to control the path flow.

__Pavant – Gonder 230 kV and Intermountain – Gonder 230 kV (WECC Path #32).__ This path has two 230 kV tie lines. Total flow is rated 440 MW in-bound and 235 MW out-bound.

PacifiCorp's Pavant and Los Angeles Department of Water and Power's Intermountain substations are both in Utah and each has a 230 kV line that connects to the Gonder Substation near Ely, Nevada. A 150 MVA 120 kV phase shifter at the Ft. Churchill Substation near Yerington, Nevada, has some control of the line flows on this rated path.

Silver Peak – Control 55 kV (WECC Path #52). This path is rated 17 MW bi-directionally. The path starts at Silver Peak, Nevada and ends at SCE's Control Substation, which is located near Bishop, California. This path includes two 60 kV lines and two 17 MVA phase shifters in series to control the path flows.

Alturas Project (WECC Path # 76). This path is rated at 300 MW bi-directionally. The Alturas path is connected to Bonneville Power Authority's 230 kV transmission at Hilltop 230 kV Substation near Alturas, California. Voltage is stepped-up to 345 kV at Hilltop with a 300 MVA transformer. From Hilltop, the path continues south where it interconnects with Ft. Sage Substation. This path has a 300 MVA phase shifter at Bordertown Substation to control the path flows.

4. IMPORT CAPABILITY

The following information has changed since the Companies filed their 2018 Joint IRP. Section §704.9385(3)(a) of the NAC requires that the Transmission Plan describe the import capability of the transmission system. The term "import capability" is defined as the energy that can be transferred into a BAA and should not be confused with long-term firm transmission capability under the OATT. Import capability is determined in accordance with WECC and North American Electric Reliability Corporation ("NERC") reliability criteria. Under WECC and NERC criteria, a system must be capable of meeting all performance criteria for steady state and single contingency outage conditions at the stated import level. Thus the Companies' system import capabilities are dependent on transmission line flows, generation dispatch patterns, and system loads. "Imports" equal load plus losses minus internal generation, or:

$$\text{Imports} = \text{load} + \text{losses} - \text{internal generation}$$

In real time, when all available generating units are being used to serve system load, imports will be equal to the difference between load, losses and generation. Whether the system has the capacity to perform a system wheel (*i.e.*, an import at one location in the system with a corresponding export at a different location in the system) under these circumstances is determined through studies, which the Companies routinely complete in response to transmission service requests.

Figure TP-7 below shows the individual Sierra and Nevada Power system import capabilities through 2023 using the FERC's prescribed methods. These values reflect the system import limit using balanced line flows. Internal generation is adjusted in the study to allow maximum system import capability. This figure does not provide a complete representation of each system's real-time import capabilities, as imports are dependent on load and the generation used to meet such load.

FIGURE TP-7
SUMMARY OF SYSTEM IMPORT CAPABILITY

Summary of Import Capability (MW)					
	2019	**2020**	**2021**	**2022**	**2023+**
Nevada Power	5100	5200	5200	5200	5200
Sierra	1275	1275	1275	1275	1275

Maximum import capability (distinct from long-term, firm transmission capability under the OATT) is measured using maximum load and minimum generation, where actual imports are highly dependent on load, generation and available voltage support. Long-term, firm transmission service under the OATT, on the other hand, must be available without limits imposed by load variations or other transmission customers' actions.

The Nevada Power import limit increases from 5100 MW to 5200 MW in 2020. This increase is attributed to the results of an initial analysis performed to address the addition of the Harry Allen to Eldorado 500 kV line. The natural flow of the system is from Harry Allen substation into Eldorado and Mead. The moderate 100 MW increase of import is not unexpected for this connection. The company will re-evaluate the impact on import capability before the project goes into service in May 2020.

In November 2018, a restudy of the northern Nevada system identified discrepancies that impacted the calculation of the import capability of the northern Nevada system. The study was triggered by substantial changes in transmission planning reliability criteria since ON Line went into service, as well as decreases in facility ratings resulting from a 2017 review and overhaul of facility ratings throughout the system. As a result of this work, ratings on some 345/120 kV transformers were decreased. These transformers are key to the import capability of the system because they deliver energy from the overarching 345 kV system to the load on the 120 kV system.

It should be noted that the system import limit is not a theoretical maximum, but rather an operational limit that can be managed every day of every year. The reassessment of the import limit affirmed the 1275 MW limit that currently exists and does not propose any changes to it. The reassessment is provided in Technical Appendix item TRAN-1 (Confidential).

5. EXPORT CAPABILITY

The following information has changed since the Companies filed their 2018 Joint IRP. Section 704.9385(3)(a) of the NAC requires that the Transmission Plan describe the export capability of the transmission system. Nevada Power's and Sierra's system export capability are set forth in Figure TP-8 below. Export capability is limited by the capability of the transmission system, including load and generation. Export capability of the system is generally limited by the loss of the highest rated intertie.

Maximum export capability should not be confused with the Companies' long-term, firm transmission capability under the OATT. Each system's maximum export capability is determined using minimum load and maximum generation resources within the system. Thus actual exports are highly dependent on load and generation. Long-term, Firm Transmission Service under the OATT must be deliverable without limits imposed by load variations or other transmission customers' actions.

FIGURE TP-8
SUMMARY OF EXPORT CAPABILITY

Summary of Export Capability (MW)					
	2019	**2020**	**2021**	**2022**	**2023+**
Nevada Power	4533	6090	6090	6090	6090
Sierra	1125	1125	1330	1330	1330

The Nevada Power export limit increases from 4533 MW to 6090 MW in 2020. This increase is attributed to the results of an initial analysis performed to address the addition of the Harry Allen to Eldorado 500 kV line. The natural flow of the system is from Harry Allen substation into Eldorado and Mead. The high capacity 500 kV line provides significant additional export capability. At this time, this limit is subject to change based on discussion and additional analysis being conducted with the developer of the Harry Allen to Eldorado line. The company will re-evaluate the impact on export capability before the project goes into service in May 2020.

In parallel with the Sierra import limit analysis, the Sierra export limit was also reassessed in 2019. Established in 2011, the published export limit of 750 MW was a resource rather than reliability limited capacity. Since the 750 MW export level was last established, several new resources have been added to the Sierra system. The updated export capacity for the Sierra system is 1125 MW and this limit will be increased to 1330 MW when the Bordertown to California project is constructed along with associated facility rating updates at California Substation. The updated export analysis is attached as Technical Appendix TRAN-2 (Confidential).

6. TRANSMISSION SERVICE OBLIGATIONS

The following information has changed since the Companies filed their 2018 Joint IRP. Per NAC §704.9385(3)(c) and NAC §704.9385(3)(d), the transmission plan must identify the transmission capacity required to serve bundled and unbundled retail transmission customers, and wholesale transmission customers the Companies are obligated to serve, as well as all existing and proposed transmission service agreements ("TSAs") with transmission customers. The regulations require that the transmission plan identify the expiration dates of all such obligations and their impacts on the transmission capacity available for use by bundled retail customers.

Nevada Power and Sierra provide transmission-only service to several transmission-only customers under TSAs. Existing Nevada Power TSAs are listed in Figures TP-9 and TP-10. Figure TP-9 lists Nevada Power's long-term transmission obligations for import into the BAA. Figure TP-10 lists Nevada Power's long-term transmission obligations for exports out of the BAA. Existing Sierra TSAs are listed in Figures TP-11 and TP-12. Figure TP-11 shows Sierra's long term transmission obligations for import into the BAA, and Figure TP-12 shows Sierra's long term transmission obligations for exports out of the BAA. Figure TP-13 shows a summary of the

Northern and Southern import and export obligations by point of delivery.

FIGURE TP-9
NEVADA POWER'S LONG-TERM BAA TRANSMISSION IMPORT OBLIGATIONS (NETWORK CUSTOMERS)

Agreement	Delivery Interface	MW	Term
SNWA	Mead 230 kV	30	6/1/2013 - 5/31/2023
LVVWD	Mead 230 kV	60	6/1/2013 - 5/31/2023
City of Las Vegas	Mead 230 kV	8	6/1/2013 - 5/31/2023
City of Henderson	Mead 230 kV	10	6/1/2013 - 5/31/2023
City of North Las Vegas	Mead 230 kV	4	6/1/2013 - 5/31/2023
Clark County Water Reclamation District	Mead 230 kV	13	6/1/2013 - 5/31/2023
Wynn Las Vegas	Mead 230 kV	31	10/1/2016 - 10/1/2036
MGM Resorts Inc.	Mead 230 kV	174	10/1/2016 - 10/1/2021
Switch Ltd.	Mead 230 kV	87	6/1/2017 - 6/1/2047
Caesar's Enterprises	Mead 230 kV	87	2/1/2018-2/1/2023

FIGURE TP-10
NEVADA POWER POINT OF DELIVERY LONG-TERM BAA TRANSMISSION EXPORT OBLIGATIONS

Agreement	Delivery Interface	MW	Term
ONGP – ORNI 43	Crystal 500 kV	24	02/01/2019 - 10/1/2022
ONGP - Steamboat	Crystal 500 kV	14	2/1/2019-2/1/2023
ONGP – ORNI 39	Crystal 500 kV	30	2/01/2019 - 12/1/2023
ONGP – ORNI 39	Crystal 500 kV	24	1/1/2019 - 1/1/2024
ORNI 43	Crystal 500 kV	8	1/1/2019 - 1/1/2020
ONGP – ORNI 39	Crystal 500 kV	6	1/1/2019 - 1/1/2020
ORNI 32	Crystal 500 kV	24	1/1/2020-1/1/2025
ORNI 52	Crystal 500 kV	24	1/1/2020-1/1/2025
Ormat - Dixie Comstock	Crystal 500 kV	25	01/01/2022-01/01/2027
Ormat - Brady	Crystal 500 kV	16	8/1/2022-8/1/2027
Ormat - Steamboat	Crystal 500 kV	24	12/1/2022-12/1/2027
ORNI 43	Crystal 500 kV	8	1/1/2018 - 1/1/2019
Ormat - Alum	Crystal 500 kV	25	1/1/2025-1/1/2030
ORNI 32	Crystal 500 kV	6	1/1/2020-1/1/2025
Ormat - Steamboat	Crystal 500 kV	24	1/1/2020-1/1/2025
MSCG – Midpoint 345 kV	Eldorado 230 kV	50	3/1/2016 - 3/1/2021
SCPPA - Harry Allen 500 kV	McCullough 500 kV	500	12/1/2015 -7/30/2023
ORNI 47	Mead 230 kV	24	1/1/2014 - 12/31/2033
ORNI 37	Mead 230 kV	21	10/1/2016 - 1/1/2021
ORNI 37	Mead 230 kV	3	10/1/2016 - 12/31/2033
Patua - Ragtown 63 kV	Mead 230 kV	6	4/1/2018-10/1/2021
Salt River Project	Navajo 500 kV	25	12/1/2018 -12/01/2023

FIGURE TP-11
SIERRA LONG TERM BAA TRANSMISSION IMPORT OBLIGATIONS

Agreement	Delivery Interface	MW	Term
Truckee Donner PUD	Gonder Pavant	41	11/1/2016 - 1/1/2025
Barrick	Gonder Pavant	75	1/1/2014 - 1/1/2024
Mt Wheeler	Gonder Pavant	80	6/1/2016 - 6/1/2021
City of Fallon	Gonder IPP	15	4/1/2017 - 4/1/2022
Mt Wheeler	Gonder IPP	25	1/26/2017 - 6/1/2021
BPA – Wells	Hilltop 345 kV	85	10/1/2016 - 10/1/2028
BPA – Harney	Hilltop 345 kV	35	10/1/2016 - 10/1/2028
City of Fallon	Midpoint 345 kV	10	4/1/2017 – 4/1/2022
Barrick	Midpoint 345 kV	18	1/1/2016 - 1/1/2020
Barrick	Midpoint 345 kV	82	1/1/2016 - 1/1/2029
Barrick	Midpoint 345 kV	6	1/1/2016 - 1/1/2028
Switch Ltd.	Midpoint 345 kV	23	6/1/2017 - 6/1/2047
Caesar's Enterprises	Midpoint 345 kV	10	9/1/2017 - 9/1/2022
Peppermill Resorts	Midpoint 345 kV	9	1/1/2018 - 1/1/2048
Liberty Utilities	Midpoint 345 kV	11	5/1/2019 - 5/1/2049

[1] Network Customers' import rights are equal to Designated Network Resources ("DNRs") and may not have a termination date based on contract and roll-over rights.
[2] DNRs that impact transmission capacity on Path 32.

FIGURE TP-12
NORTHERN POINT OF DELIVERY LONG TERM BAA TRANSMISSION EXPORT OBLIGATIONS

Agreement	Delivery Interface	MW	Term
Patua Project LLC - Eagle 120 kV	Hilltop 345 kV	18	10/1/2018 - 10/1/2023[1]
Patua Project LLC - Eagle 120 kV	Hilltop 345 kV	4	1/1/2019 - 10/01/2021[1]
Patua Project LLC - Ragtown 63 kV	Gonder Pavant	7	1/1/2019 - 10/1/2021[1]
Patua Project LLC - Ragtown 63 kV	Gonder Pavant	13	1/1/2019 - 10/1/2021[1]
ARP - Loyalton 63 kV	Summit 120 kV	18	4/1/2018 - 4/1/2023[1]
Idaho Valmy	Midpoint 345 kV	262	N/A

1. Subject to roll over rights.

Figure TP-13 below is a summary of the long term transmission import and export obligations at each point of delivery in Figures TP-9 through TP-12.

FIGURE TP-13
NV ENERGY LONG TERM BAA TRANSMISSION OBLIGATIONS SUMMARY

		Point of Delivery	MW Total
Nevada Power	**Import Obligations**	Mead 230 kV	**504**
	Export Obligations	Crystal 500 kV	**282**
		Eldorado 230 kV	**50**
		McCullough 500 kV	**500**
		Mead 230 kV	**54**
		Navajo 500 kV	**25**
Sierra	**Import Obligations**	Gonder/ Pavant 230 kV	**196**
		Gonder IPP	**40**
		Hilltop 345 kV	**120**
		Midpoint 345 kV	**169**
	Export Obligations	Hilltop 345 kV	**22**
		Gonder/ Pavant 230 kV	**20**
		Summit 120 kV	**18**
		Midpoint 345 kV	**262**

NAC 704.9385(3)(e) requires the Companies provide "a table identifying all the transmission

capacity that the utility has secured for its bundled retail transmission customers on both its transmission system and the transmission systems of other utilities." Figure TP-14 and TP-15 below show the Companies' long-term secured transmission capacity for bundled retail customers.

FIGURE TP-14
NEVADA POWER TRANSMISSION CAPACITY SECURED FOR BUNDLED RETAIL TRANSMISSION CUSTOMERS

	Firm Capacity Reserved by Nevada Power for Native Load									
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Mead (Hoover)	355	355	355	355	355	355	355	355	355	355
Red Butte	0	0	0	0	0	0	0	0	0	0
McCullough	0	0	0	0	0	0	0	0	0	0
Crystal (Navajo)	260	260	260	260	260	260	260	260	260	260
Eldorado	0	0	0	0	0	0	0	0	0	0
Mohave (Laughlin)	50	50	50	50	50	50	50	50	50	50
ON Line (Sierra)	526	526	526	526	526	526	526	526	526	526
Total	1191	1191	1191	1191	1191	1191	1191	1191	1191	1191
	Firm Capacity Reserved by Nevada Power on Other Systems									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	0	0	0	0	0	0	0	0	0	0

FIGURE TP-15
SIERRA TRANSMISSION CAPACITY SECURED FOR BUNDLED RETAIL TRANSMISSION CUSTOMERS

	Firm Capacity Reserved by Sierra for Native Load									
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Nevada Power (ON Line)	600	600	600	600	600	600	600	600	600	600
Total	600	600	600	600	600	600	600	600	600	600
	Firm Capacity Reserved by Sierra on Other Systems									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	0	0	0	0	0	0	0	0	0	0

NAC § 704.945(4) requires "a graph or table" that depicts "the allocation of the capacity of the transmission system of the utility between bundled retail transmission customers, unbundled retail transmission customers and wholesale transmission customers." This information is provided for the Companies in TP-16, below.

FIGURE TP-16
NV ENERGY TRANSMISSION SYSTEM CAPACITY ALLOCATION

	Nevada Power		Sierra	
Transmission Allocation	**MW**	**Percentage**	**MW**	**Percentage**
Unbundled/ Wholesale Transmission	504	9.9%	525	41.2%
Bundled Transmission	1191	23.4%	600	47.1%
Transmission Reliability Margin	175	3.4%	150	11.8%
Unallocated Transmission	3230	63.3%	0	0.0%
Total Import Capacity	**5100**		**1275**	

7. TRACY AREA MASTER PLAN UPDATE

The following information has changed since the Companies filed their 2018 Joint IRP. In Docket No. 17-11003, Sierra supported the need for additional transmission investment in the Tahoe Reno Industrial Center ("TRIC") area with the Tracy Area Master Plan. The Tracy Area Master Plan discussed the significant load growth occurring in the Tracy area and identified investment in transmission facilities necessary to serve this load. The Tracy Area Master Plan discussed and identified need to expand the 120 kV infrastructure serving the TRIC area in direct response to the growing load demand, as well as the reinforcement of the 120 kV system using 345 kV support. This information was provided to the Commission in order to communicate the dynamic nature of growth in the area.

While significant additional load continues to be proposed in the Tracy area, timing for many of the proposed customers' projects remains uncertain. The most recently proposed customer ramping schedule and required transmission additions are reflected in the updated Tracy Area Master Plan. As confidence in the timing of these projects is reached, the need to proceed toward construction of the transmission infrastructure necessary to serve these projects will be triggered. Depending on the voltages of the projects identified in the Tracy Area Master Plan, Commission approval may be required and will be obtained through the appropriate regulatory filings. Additional information regarding the Tracy Area Master Plan is included in the confidential Technical Appendix item TRAN-3 (a portion of which is confidential).

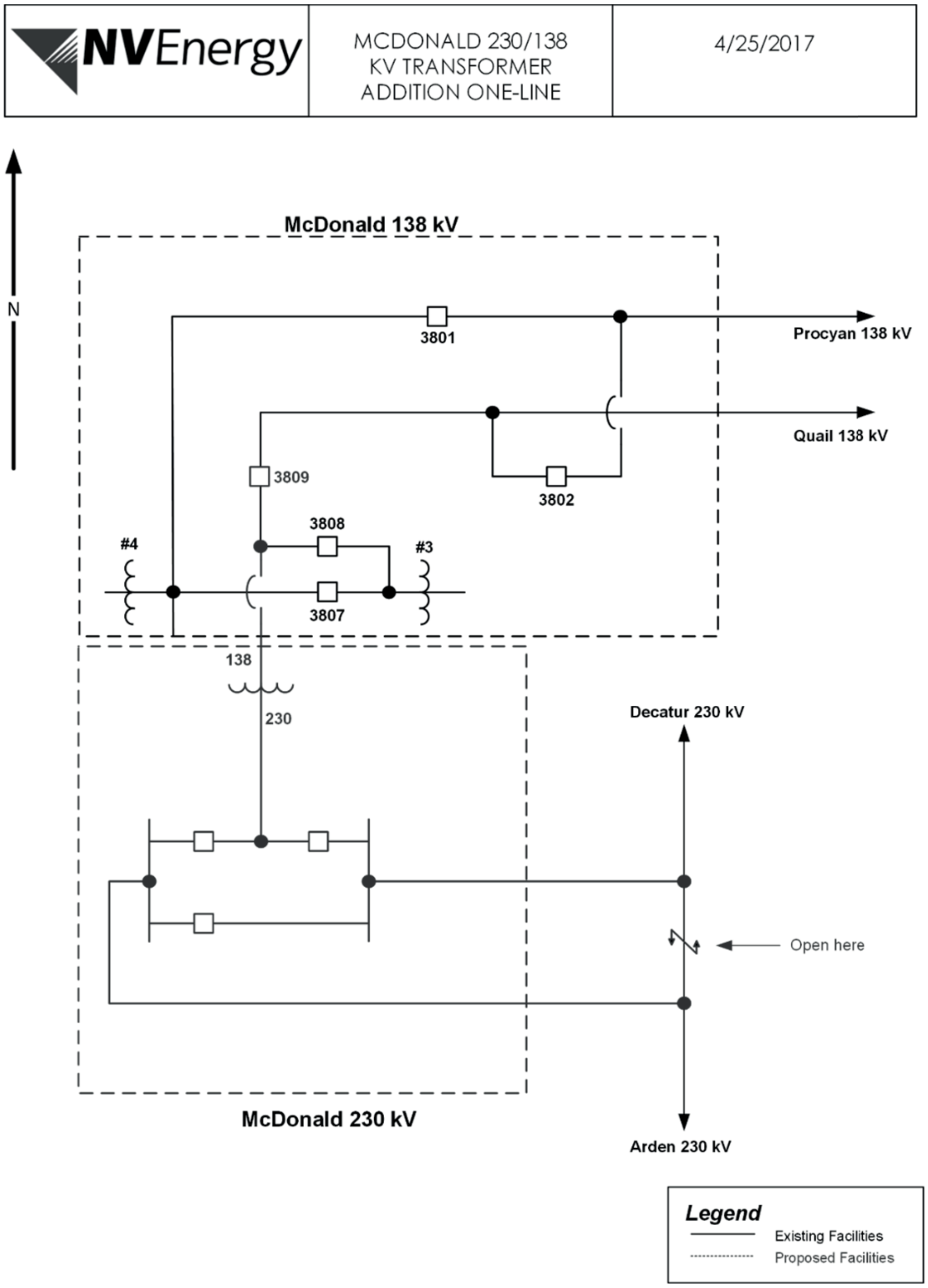
8. UPDATES ON PREVIOUSLY APPROVED TRANSMISSION PROJECTS

Updates regarding three previously approved transmission projects, the McDonald 230/138 kV Substation upgrade, the Grid Resilience Program, and the Frontier 230 kV Breaker addition, are provided for informational purposes. The Companies are seeking integrated resource plan approval of updates to three previously approved projects, the West Tracy 345/120 kV Transformer addition (modified from the previously approved East Tracy Transformer project), the California to Bordertown 120 kV project, and the Dodge Flat Interconnection Request.

A. McDonald 230/138 kV Substation Upgrade & 230 kV Arden to McDonald Line Upgrade

The Commission approved the McDonald 230/138 kV Substation upgrade in Docket No. 17-11004, Nevada Power's third amendment to its 2015 IRP. In that docket, the Commission approved the installation of a 230/138 kV transformer at the McDonald 138 kV Substation, conversion of the substation to a three breaker ring configuration, and associated substation upgrades. See the one-line diagram of the project in Figure TP-17 below.

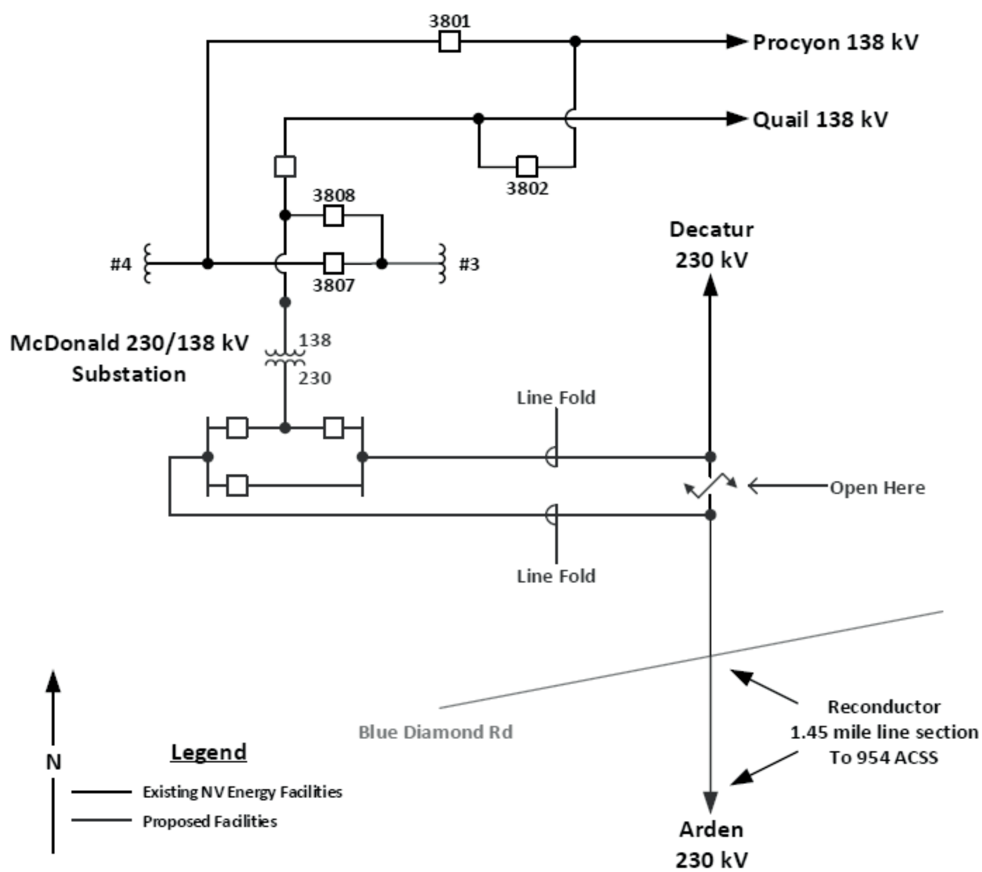
FIGURE TP-17
MCDONALD 230/138 KV SUBSTATION UPGRADE



Additionally, the Commission approved the upgrade to the 1.45 mile Arden to McDonald 230 kV line in Docket No. 18-06003, the Companies' Joint IRP. In that docket, the Commission approved replacement of the existing 954 ACSR conductor to 954 ACSS to mitigate overloads during contingency conditions following the McDonald 230/138 kV Transformer Addition. See the one-line diagram describing the project included in Figure TP-18 below.

FIGURE TP-18
ARDEN TO MCDONALD 230 KV LINE UPRATE

NVEnergy	McDonald 230/138 kV XFMR Addition – Line Uprate	4/19/2018



The use of an existing spare 230/138 kV transformer has allowed the project to remain on schedule to meet the requested in service date of May 31, 2019. The reconductoring of the 1.45 mile section of the 230 kV Arden to McDonald line has been completed. The original approved budget was approximately $12.8 million, but due to significant savings in transformer costs, the project is now expected to cost approximately $7 million. See the updated expected cash flow in Figure TP-19 below.

FIGURE TP-19
MCDONALD 230/138 KV SUBSTATION UPGRADE BUDGET

McDonald 230/138 kV Substation Upgrade Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total (2018-2020)**	**Post 2020**
$7,000,000	$0	$1,500,000	$5,500,000	$0	$7,000,000	$0

B. Grid Resilience Program

The Grid Resilience program was first approved by the Commission in Nevada Power's third amendment to its 2015 IRP, Docket No. 17-11004. The program addresses the increasing risk to utilities of catastrophic damage to critical substations as a result of physical attack, natural disaster, or extreme weather conditions.

As approved, five transformers were identified for procurement: one 230/138 kV 336 MVA transformer, one 525/230 kV 600 MVA transformer, and three single phase 525/230 kV 500 MVA transformers. The Companies have purchased each of the five transformers, and they are projected to be delivered in late 2019. The original approved project budget was approximately $17 million. Due to an increase in the expected cost of transformers with these specifications, the project budget is now projected to be approximately $20.5 million. Figure TP-20 below shows the estimated cost and cash flow for the project:

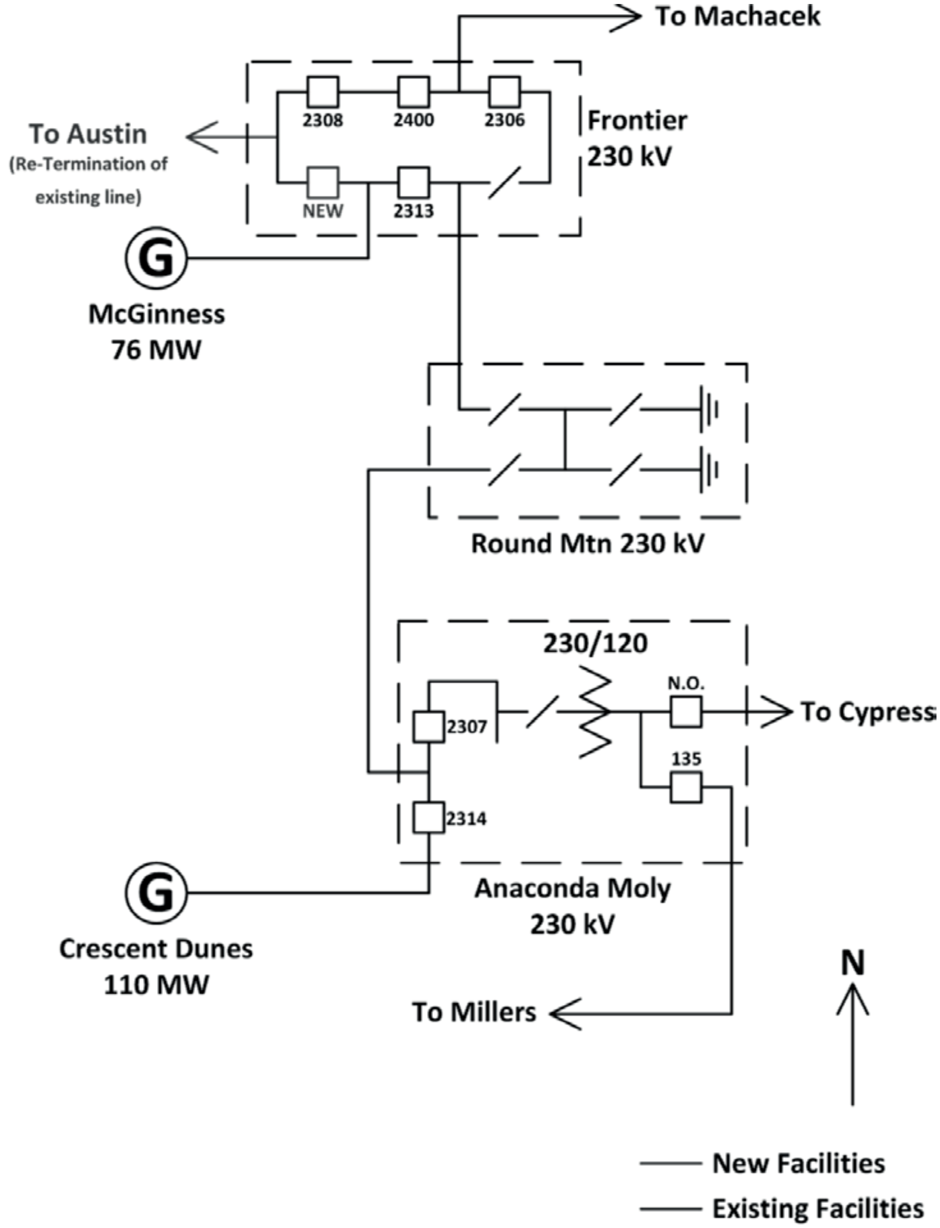
FIGURE TP-20
GRID RESILIENCE TRANSFORMER ACQUISITION BUDGET

Grid Resilience Transformer Acquisition Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total (2018-2020)**	**Post 2020**
$20,500,000	$0	$4,900,000	$15,380,000	$220,000	$20,500,000	$0

C. Frontier 230 kV Breaker Addition

The Frontier 230 kV Breaker addition was approved by the Commission in Docket No. 16-07001, Sierra's 2016 IRP. The breaker addition and line re-termination were necessary to mitigate a TPL-001-4 non-compliance issue, see the single line diagram of the project in Figure TP-21 below.

FIGURE TP-21
FRONTIER BREAKER ADDITION SINGLE LINE DIAGRAM



The breaker addition and line re-termination were completed as of November 20, 2018 and the project is in service. The original request for the project was $737,000. The actual project cost is $1.480 million. This cost variance is primarily due to increased material and construction costs required to rebuild a larger-than-expected section of the existing substation found during construction to be insufficient. These additional costs include re-building foundations, additional steel structures and bus work as well as required upgrades to the approximately five-mile dirt access road that failed during construction. The revised cash flow for the project is in Figure TP-22 below.

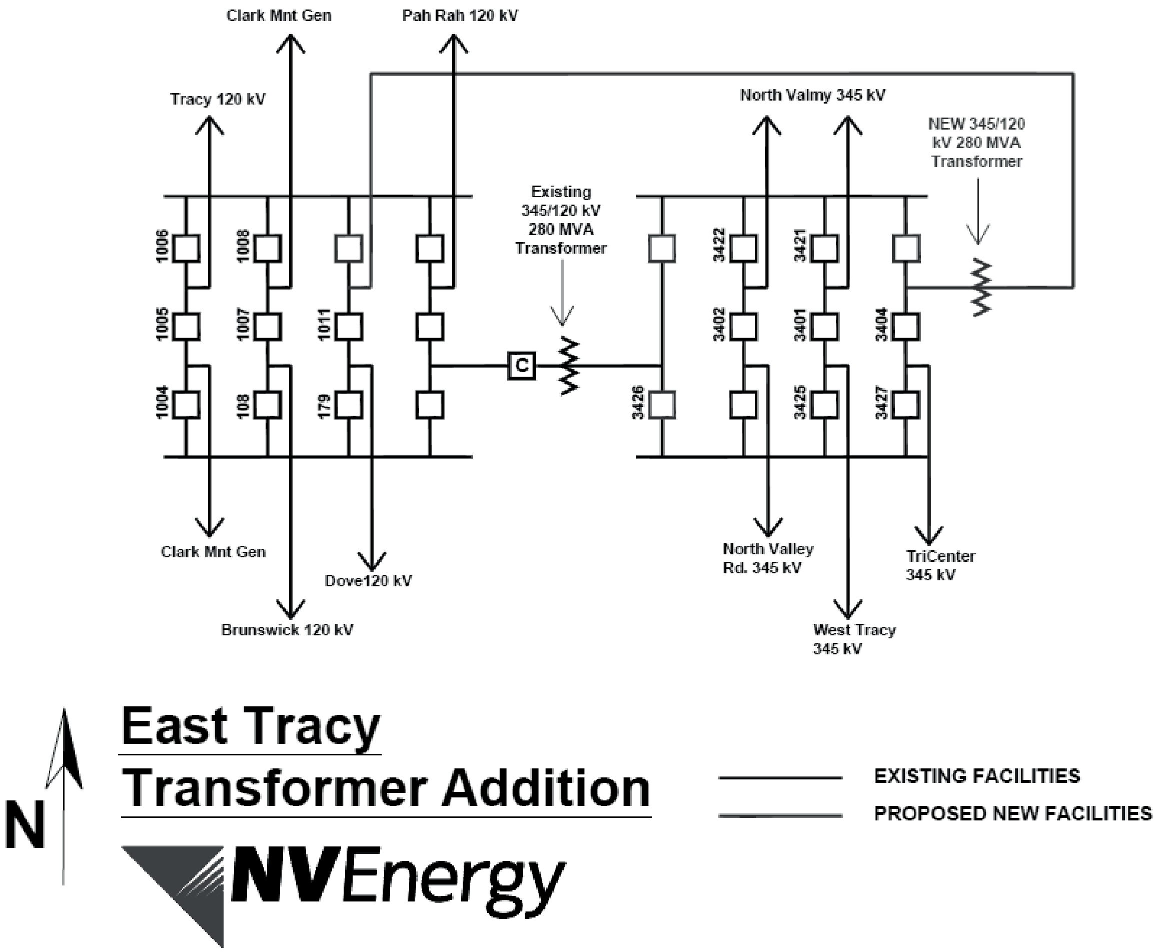
FIGURE TP-22
FRONTIER BREAKER ADDITION PROJECT BUDGET

Frontier Breaker Addition Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total (2018-2020)**	**Post 2020**
$1,480,000	$0	$1,450,000	$30,000	$0	$1,480,000	$0

D. West Tracy 345/120 kV Transformer Addition

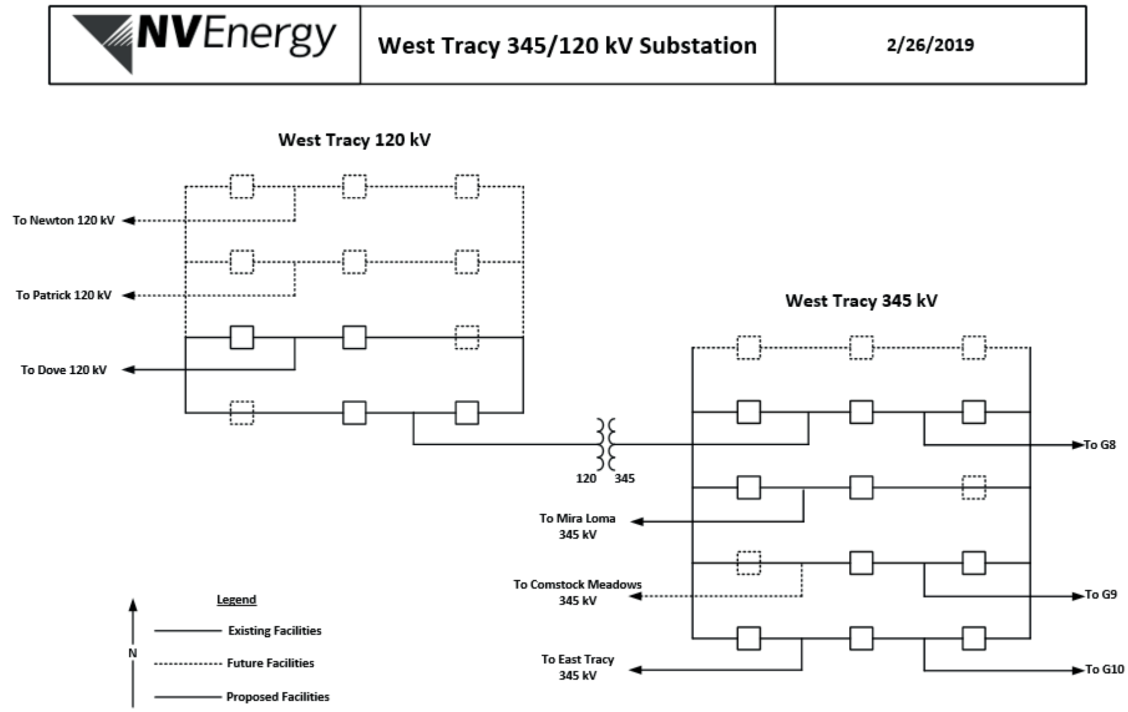
The Commission approved the East Tracy 345/120 kV Transformer addition in Docket No. 17-11003. The approval included a new 345/120 kV 280 MVA transformer at the existing East Tracy 345/120 kV substation, along with necessary communication and protection upgrades. The one-line diagram of the project as approved is shown in Figure TP-23 below. The project scope also included replacing underrated breakers at the East Tracy, Tracy, Pah Rah and Dove substations to mitigate an increase in fault duty.

FIGURE TP-23
EAST TRACY 345/120 KV TRANSFORMER ADDITION SINGLE LINE DIAGRAM



After further assessment, with consideration toward the dynamic nature of new and proposed construction in the area, to align with the updated Tracy Area Master Plan, remain flexible, and provide a comprehensive approach to reliability in the Tracy area, Sierra is now requesting integrated resource plan approval to cancel the East Tracy 345/120 kV transformer addition and to instead construct a 345/120 kV transformer with related facilities at the West Tracy substation. In addition to moving the previously approved 345/120 kV transformer for East Tracy to the West Tracy 345 kV substation, the updated project will include the addition of a 120 kV switchyard at West Tracy, re-termination of the existing 345 kV line from West Tracy to Mira Loma, and a new 120 kV line from West Tracy to Dove 120 kV substation. See the single line diagram of the project in Figure TP-24 below.

FIGURE TP-24
WEST Tracy 345/120 kV Transformer Addition Single Line Diagram



The updated transmission solution better addresses the significant system load proposed by customers who have executed High Voltage Distribution agreements since May 2018, when the 2018 Joint IRP filing (Docket No. 18-06003) was prepared. The West Tracy 345/120 kV Transformer addition meets the reliability requirement for which the original East Tracy 345/120 kV Transformer addition was approved, as well as an integrated and more comprehensive benefit including: relief of existing physical line congestion around the East Tracy 120 kV switchyard; elimination of necessary underrated breaker replacement at the Pah Rah 120 kV substation; elimination of the #108 line fold project; and the provision of additional 120 kV terminals where increased flexibility for future expansion and increased reliability for existing customers are a priority. The West Tracy 345/120 kV Transformer addition is also easier to construct and allows space for a future additional 345/120 kV transformer. This request is further discussed in the included Technical Appendix item TRAN-4 (a portion of which is confidential).

In response to customer load ramping, the new projected in service date for the West Tracy transformer is May 2021. This in service date coincides with the load ramping demand for which the East Tracy 345/120 kV Transformer addition was originally requested. For the 345 kV facilities and transformer, the cost of the West Tracy Plan is $14.620 million as compared to the previously approved cost of the East Tracy Plan of $10.100 million. The project cash flows are in Figure TP-25 below.

FIGURE TP-25
WEST TRACY 345/120 KV TRANSFORMER ADDITION PROJECT BUDGET

West Tracy 345/120 kV Transformer Addition Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total (2018-2020)**	**Post 2020**
$14,620,000	$0	$0	$7,300,000	$6,600,000	$13,900,000	$720,000

Non-Wire Alternative Analysis: Sierra performed a non-wire alternative ("NWA") analysis for the West Tracy 345/120 kV Transformer Addition project. However, the NWA failed the Critical Suitability Criteria Screening B: "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." The project scope is driven by 24-hour increase in demand and the need to increase transmission system operational flexibility.

E. Bordertown to California 120 kV Project

The Commission originally approved the Bordertown to California Substation ("Cal Sub") 120 kV project in Docket No. 07-06049. As approved, the project contemplated a 345/120 kV transformer at Bordertown Substation and 120 kV line from Bordertown to Cal Sub. The original approved project budget was $27 million: $22 million for the line between Bordertown and Cal Sub, and $5 million for relocating the phase shifter from Bordertown to Hilltop Substation.

In Sierra's 2010 IRP, Docket No. 10-07003, the project scope was reduced to eliminate the relocation of the phase shifter, and the scheduled in-service date was extended from 2012 to 2014. The budget for the project was revised downward to $20.24 million. In that docket, the Commission approved a stipulation recommending approval of the revised project schedule.

In Docket No. 13-07005, Sierra again revised the project scope, schedule and budget. The budget estimate was increased to $30.4 million and the in-service date was updated from 2014 to 2016. The Commission approved a stipulation recommending approval of the revised project schedule.

In Docket No. 15-08011, Sierra informed the Commission that the Bordertown to California Substation project would be completed and placed in service in December 2016. Sierra indicated that it anticipated receiving permitting approvals in the fall of 2015.

However, in the fall of 2015, the U.S. Forest Service ("Forest Service") completed the draft environmental impact statement ("EIS") for the project. On March 9, 2018, the Forest Service released a draft Record of Decision and final EIS for a 45-day formal objection period. The Forest Service accepted objections through April 23, 2018 from people who have previously submitted specific written comments regarding the proposed project during scoping or other designated comment periods. The Forest Service selected the Peavine/Poeville route alternative based upon review of analysis disclosed in the final EIS, project record, and evaluation of the information provided by the applicant.

Given the delays in the permit process, in late 2017 Sierra sought to 1) confirm that the project was still needed, and 2) determine how to reliably serve customers until the project could be completed under the new schedule. This analysis was attached to Sierra's November 2017 amendment to its 2017-2036 integrated resource plan as Technical Appendix TRAN-3. That analysis concluded that the project was still needed under the current system configuration to mitigate multiple potential NERC TPL-001-4 violations, improve operation of the bulk electric system in northwest Reno, and to serve balancing area load through the California phase shifter. However, the current operational limitations could continue to be utilized to ensure system reliability until the project went into service.

The Forest Service's decision is conditioned on the terms of a special use permit, implementation of project design features, and mitigation and monitoring as identified in the final EIS and attached to the draft Record of Decision. To implement and comply with the conditions in the decision, Sierra will complete and the Forest Service must approve a Construction, Operation, and Maintenance Plan ("COM Plan") for the selected route alternative. A preliminary draft COM Plan is under development and Forest Service approval is anticipated in late 2019. In addition, the Forest Service continues work on a Historic Properties Treatment Plan and Memorandum of Agreement for cultural resource mitigation. The agreement must be signed by the Forest Service, State Historic Preservation Offices and local tribes. All parties have reviewed and commented on draft documents and a final review should be complete in the second quarter of 2019. Signatures should be complete in mid-2019, and cultural resource site treatment is anticipated to be complete by the end of 2019.

In parallel with these permitting activities, Sierra is working to complete the final design, acquire easements on private lands, and obtain local jurisdictional use permits. A Notice to Proceed is currently anticipated in late 2019 and the in-service date is currently estimated for late 2021. The in-service date may be extended beyond that date if the Forest Service requires additional time to complete and sign the Memorandum of Agreement and release a Final Record of Decision, or if the acquisition of easements on private lands takes longer to complete. Single Line diagrams depicting the Bordertown and California substation configuration are shown in Figure TP-26 and TP-27 below.

FIGURE TP-26
BORDERTOWN SUBSTATION ONE-LINE DIAGRAM

NVEnergy	Bordertown 345/120 kV Substation	2/25/2019

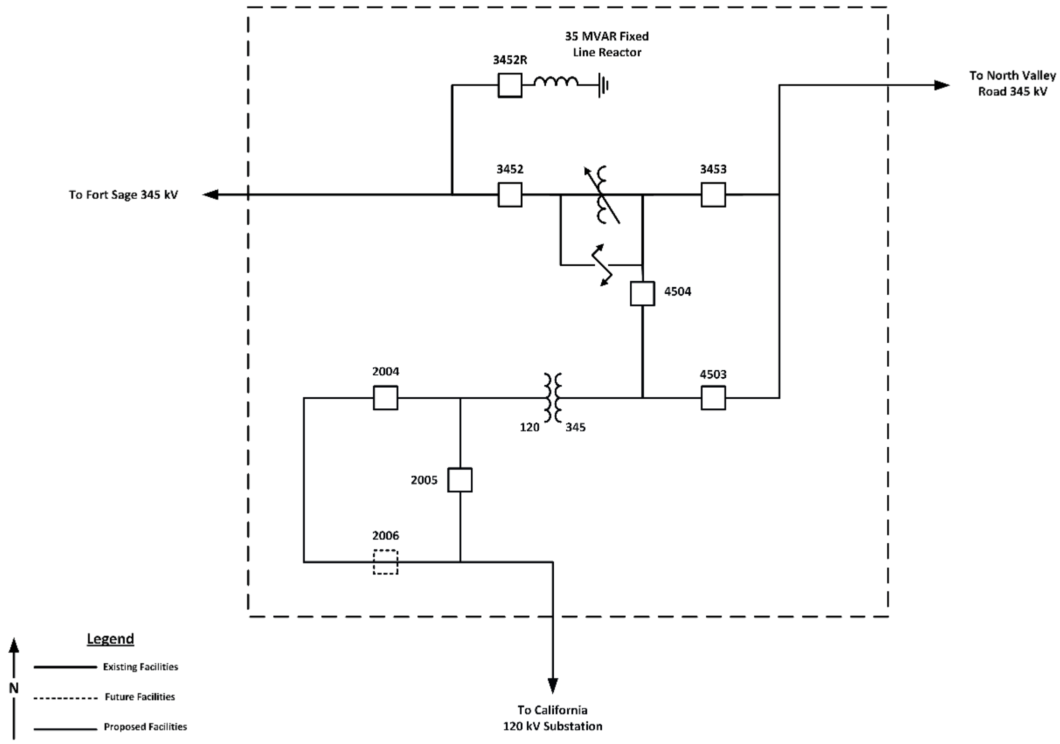
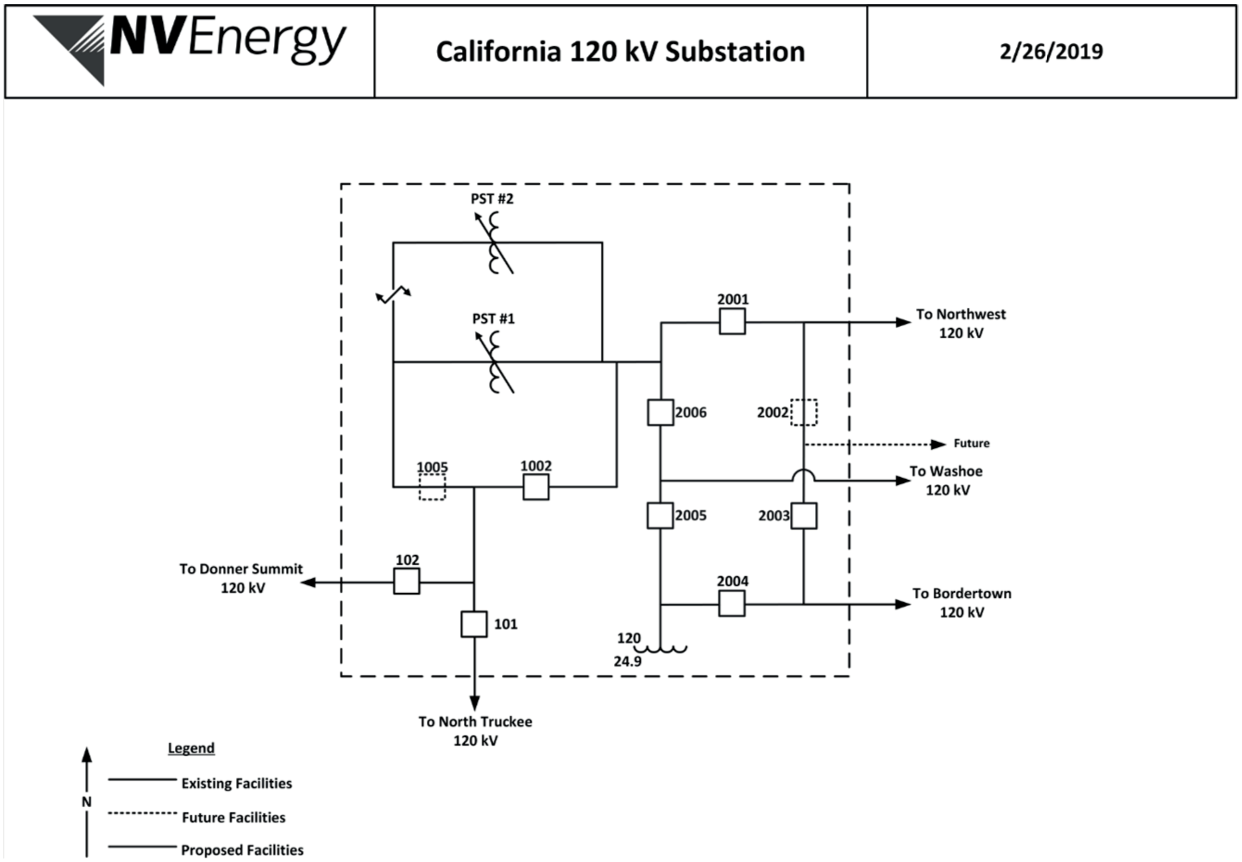


FIGURE TP-27
CALIFORNIA SUBSTATION ONE-LINE DIAGRAM



Expenditures on the Bordertown to Cal Sub project through 2018 total $4.146 million and current projected expenditures through the 2019-2021 Action Plan period are anticipated to be $40.507 million. The current estimated cost at completion is $44.692 million, approximately $13.321 million higher than the 2018 estimated cost at completion amount of $31.371 million. Sierra recently updated all project cost estimates and the increased estimated cost at completion accounts for a number of scope revisions and cost refinements. The larger cost variances are due to:

(1) A longer alignment and change to single pole construction for the northern 3.3 miles to accommodate private landowner requests through two master planned communities.

(2) Environmental mitigation measures identified in the Forest Service's Final EIS and Record of Decision including a mitigation account for mule deer, Native American monitors during construction, and helicopter construction techniques to minimize environmental impacts.

(3) Cost refinements for the substations to include additional facilities for reliability and operations, and current prices for commodities and services. The Company is requesting approval for the updated cost estimate for this project. Figure TP- 28 below shows the estimated cost and cash flow for the project.

FIGURE TP-28
BORDERTOWN TO CALIFORNIA SUBSTATION BUDGET

Bordertown to California Substation Project Cash Flow						
Description	**Prior**	**2019**	**2020**	**2021**	**Post**	**Total Cost**
Bordertown to Cal Sub - Lands	1,398,285	813,342	195,643	-	-	**2,407,270**
Bordertown to Cal Sub - Environmental	2,534,389	1,583,971	1,199,044	1,636,537	-	**6,953,941**
Bordertown to Cal Sub - 120kV Line	109,390	151,661	252,075	15,971,361	-	**16,484,487**
Bordertown 345/120kV Substation	75,293	907,413	1,691,850	7,955,576	-	**10,630,132**
California Substation Rebuild	29,028	777,790	1,042,980	3,592,189	39,697	**5,481,684**
Bordertown to N Valley Road RAS	-	92,430	15,540	68,845	-	**176,815**
106 Line Relay Upgrades - Reno Sub	-	81,398	27,131	123,968	-	**232,497**
106 Line Relay Upgrades - Mt Rose Sub	-	81,398	27,131	123,968	-	**232,497**
Bordertown to Cal Sub - 120kV Line Comm	-	45,997	345,343	487,280	-	**878,620**
Bordertown Substation Comm	-	-	31,773	304,756	-	**336,529**
California Substation Comm	-	-	339,209	539,102	-	**878,311**
Bordertown to Cal Sub - Total	**4,146,385**	**4,535,401**	**5,167,716**	**30,803,583**	**39,697**	**44,692,782**

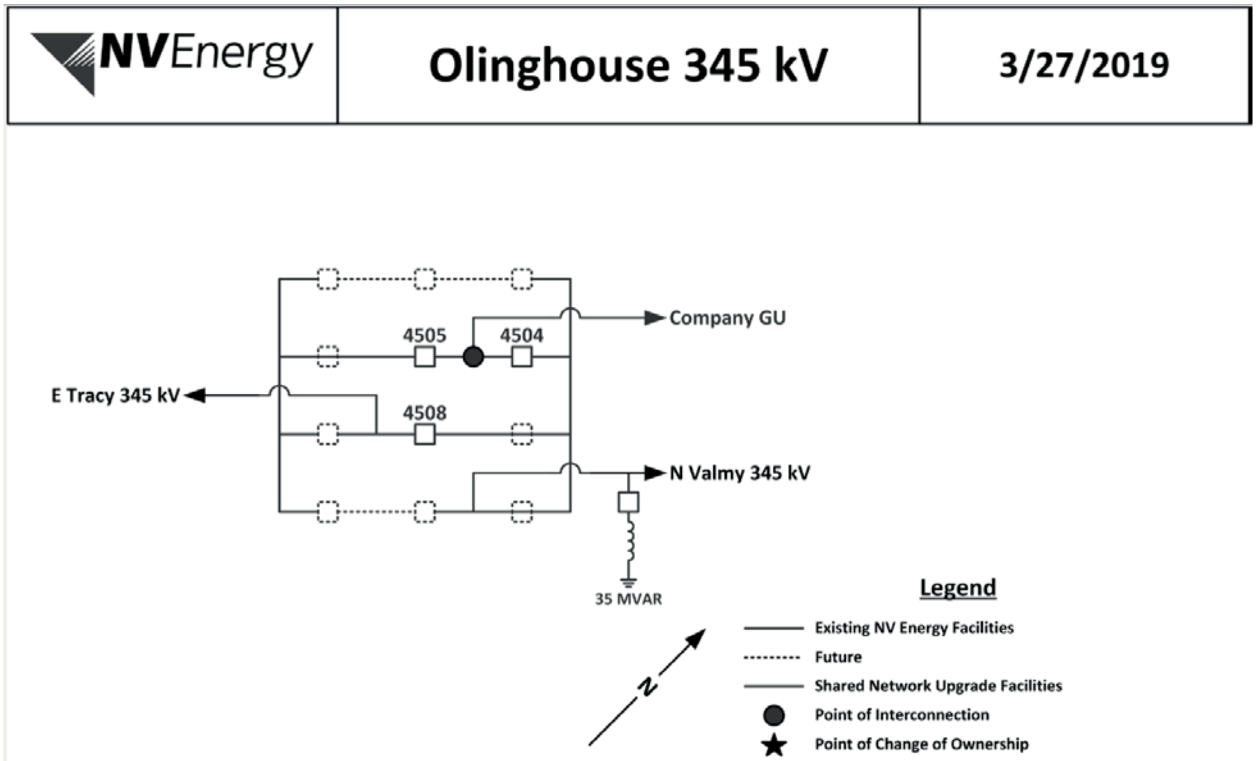
F. Dodge Flats (Company GU) Interconnection

The Dodge Flat Interconnection was approved by the Commission in Docket No. 18-06003. As described in that docket, Sierra is to provide interconnection and necessary network upgrades to support the addition of the Dodge Flats Solar project, a 200 MW solar PV generating facility at the new Olinghouse 345 kV substation located on the existing Tracy to Valmy 345 kV line.

With consideration towards additional consequent requests for interconnection at and near the proposed Olinghouse 345 kV location, Sierra is requesting IRP approval to increase the footprint of the previously approved substation configuration to include an expandable breaker and a half configuration in order to cost effectively accommodate future interconnection requests to compliment the Companies' continuing effort to increase renewable generation projects in the area. The planned in service date of April 1, 2021 is not affected by the change.

Construction Scope: Sierra is requesting an expansion of the previously approved three-breaker ring substation configuration to include an expandable breaker-and-a-half configuration, in order to accommodate additional interconnection requests. The breaker-and-a-half configuration allows for reliable and efficient future expansion of the Olinghouse substation. Figure TP-29 below depicts a single line diagram of the proposed project.

FIGURE TP-29
ONE LINE DIAGRAM OF DODGE FLATS (COMPANY GU)
GENERATION INTERCONNECTION



<u>Budget and Cost Responsibility</u>: NextEra, the developer of Dodge Flats solar project, is responsible for the cost of building its generator, lead line, and associated interconnection facilities, including required communications, protections and metering facilities. Sierra is responsible for the cost associated with Network Upgrades, per the OATT, which includes the new Olinghouse 345 kV Substation. The Company estimates that for an expandable breaker-and-a-half configuration, the required communications for the substation, and associated protections equipment will be approximately $20.000 million. The previously approved three-breaker ring resulted in a network upgrade investment of $12.565 million. Sierra is requesting approval for the increased cost of the project. Projected cash flows for the project are shown in Figure TP-30 below.

FIGURE TP-30
PROJECTED CASH FLOWS FOR DODGE FLATS GENERATION INTERCONNECTION

Carson Lake Solar (Company HJ) Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$20,000,000	$0	$0	$2,000,000	$12,000,000	$14,000,000	$6,000,000

9. SPECIFIC REQUESTS FOR COMMISSION APPROVAL FOR NEW TRANSMISSION PROJECTS

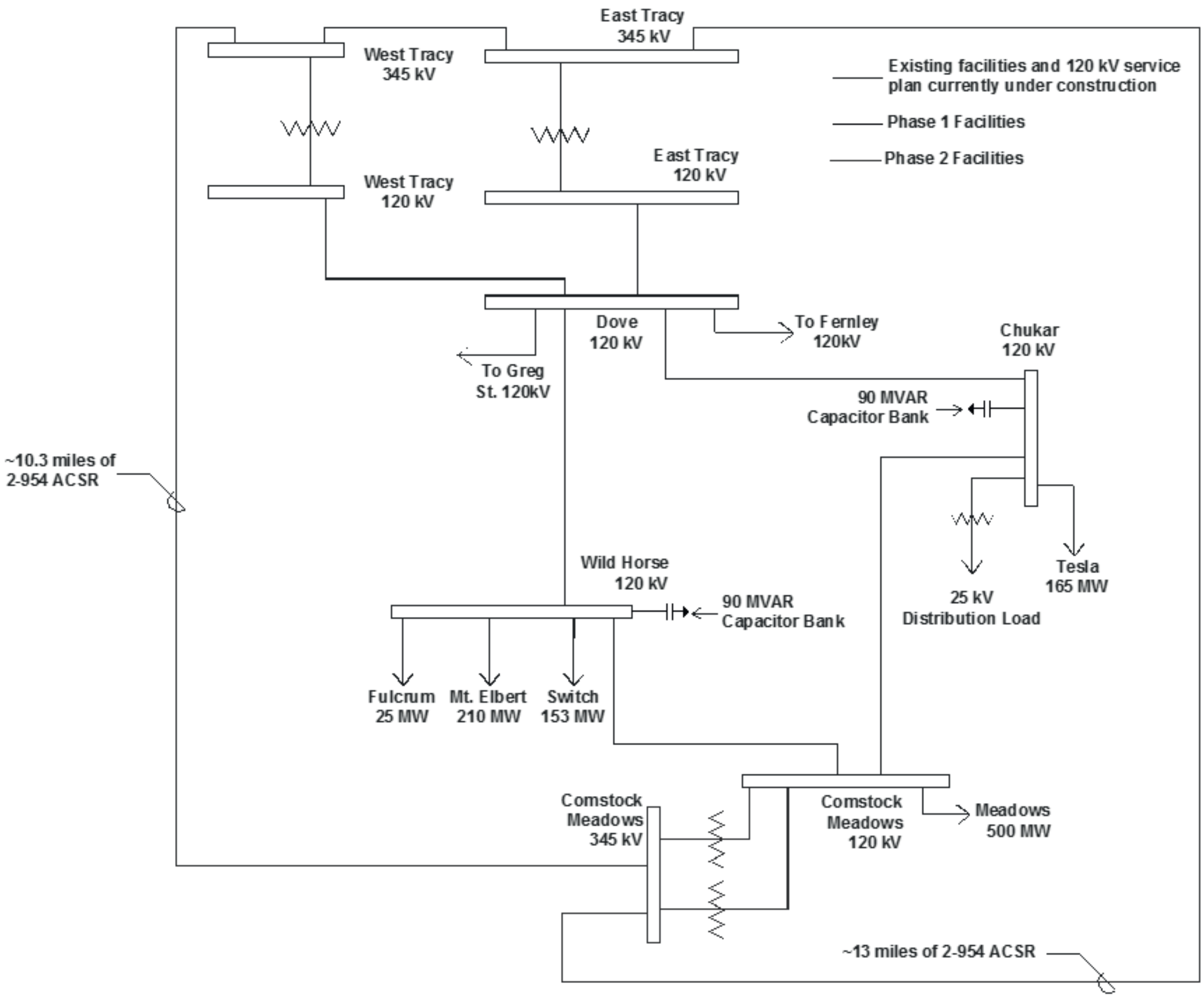
NAC § 704.9385(3)(b) requires that the Transmission Plan include a description of transmission projects that the Companies are considering to expand or upgrade. NAC § 704.9355(1)(b) and (1)(c) require that the utilities develop a set of analyses of its options for supply to be considered for meeting the expected future demand on its system. These analyses must include an examination of the environmental impact of each option, taking into account the best available technologies and the environmental benefit of renewable resources, including construction of new transmission facilities or upgrades to existing transmission facilities and purchase of long-term transmission rights on third party transmission facilities. The Companies are requesting Commission IRP approval of six new transmission facilities necessary accommodate growth and address reliability concerns. These projects include: the Comstock Meadows 345/120 kV Substation, permitting for a Major Northern Nevada Transmission Addition, a second Reid Gardner to Tortoise 230 kV Transmission Line, the Shaffer 345 kV Substation, the Bighorn 230/69 kV Transformer addition, and routing and siting for the West Henderson SE2 distribution substation.

The Companies are also requesting Action Plan approval to begin network upgrades associated with four new Generator Interconnection projects. These include network upgrades required to support the development of the following renewable generation projects: Carson Lake Geothermal, Harry Allen Solar, Aiya Solar and Pershing Solar.

A. Comstock Meadows 345/120 kV Substation

In the Transmission Plan filed in the 2018 Joint IRP, Docket No. 18-06003, the Companies discussed the need for future 345 kV support in the Tracy area. In a section of the narrative entitled "Sierra Load Growth and Timing," the Companies discussed how the additional injection of 345 kV support into the 120 kV system was required for stability and reliability if load continued to grow. As discussed in the updated Tracy Area Master Plan, Comstock Meadows has been identified as the most optimal strategic location for the next increment of 345 kV support for the 120 KV system. An initial phase of upgrades at Comstock Meadows Substation completes the 120 kV loop that runs from Dove 120 kV substation to Chukar to Comstock Meadows to Wild Horse and back to Dove. Once the load on this 120 kV system exceeds approximately 300 MW, the existing 120 kV system, together with the existing 345/120 kV capacity, cannot reliably accommodate system load. As a result, Sierra is requesting approval of a new 345 kV injection point into the 120 kV system, a switchyard at Comstock Meadows, two 345/120 kV 280 MVA transformers, a 345 kV line from East Tracy to Comstock Meadows, a 345 kV line from West Tracy to Comstock Meadows, and associated required communications to support these additions. A single line diagram depicting the proposed Comstock Meadows 345/120 kV substation is shown in Figure TP-31 below.

FIGURE TP-31
ONE LINE DIAGRAM OF COMSTOCK MEADOW 345/120 KV SUBSTATION



<u>Construction and Budget Scope:</u> The proposed Comstock Meadows 345 kV facilities include a 345 kV switchyard, a 345 kV line from East Tracy to Comstock Meadows, a 345 kV line from West Tracy to Comstock Meadows and two 345/120 kV 280 MVA transformers. Comstock Meadows is also a planned site for interconnection of a major transmission project as discussed later in this section for approval. The Companies are requesting approval of investment of $9.582 million during the remaining Action Plan period, and a total investment of $52.684 million for the Comstock Meadows 345 kV transmission upgrades. Projected cash flows for the project are shown in Figure TP-32 below.

FIGURE TP-32
PROJECTED CASH FLOWS FOR COMSTOCK MEADOWS 345/120 KV SUBSTATION

Comstock Meadow 345/120 kV Substation Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$52,684,000	$0	$0	$2,634,000	$6,948,000	$9,582,000	$44,102,000

The planned in service date for the Comstock Meadows 345 kV/120 kV substation is May 1, 2021. The Companies continue to monitor the actual and forecasted customer load demand in the Tracy area to ensure the necessary facilities are appropriately and prudently designed, planned and implemented. In an effort to ensure reliability for the proposed loads, while building new facilities appropriate to serve the load demand, the schedule for all Tracy area facilities will be continue to be monitored as adjustments in local load forecasts are made. This is also further discussed in Technical Appendix item TRAN-4 as part of the Tracy Area Master Plan.

NWA Analysis: The Companies preformed a NWA analysis for the Comstock Meadows project. However, the project failed the Critical Suitability Criteria Screening B: "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." The project scope is driven by 24-hour increase in demand and adding a source to serve load.

B. Major Northern Nevada Transmission Addition – Permitting

As discussed in the Sierra Load Growth, Timing and System Limitations section of the Transmission Plan narrative of the 2018 Joint IRP filing, Docket No. 18-06003, the unprecedented load growth that is taking place in and proposed for northern Nevada will require the addition of new transmission or generation assets.

Sierra currently has 1,448 MW of signed High Voltage Distribution agreements in northern Nevada. Of these, customers who have asked Sierra not to plan for their energy supply make up approximately 673 MW. Consistent with traditional resource planning concepts, Sierra is seeking the most appropriate means of reliably serving its retail customers, whether that solution is transmission or generation.

As the experience with the Bordertown transmission addition demonstrates, the design and construction of any new major transmission resource can take many years to complete: generally, seven to 10 years, assuming no interruption in critical path items. The initial step is a routing and constraint study, which typically takes approximately six months to one year to prepare. Given the predominance of federal lands in Nevada, new transmission into and through Nevada generally requires preparation by either the Bureau of Land Management (“BLM”) or the U.S. Forest Service of either an Environmental Assessment or an EIS. These analyses can take up to four years to complete. Line design and construction can take two to four years to complete.

Due to the long lead times associated with a major transmission addition, Sierra is requesting approval to begin initial permitting activities necessary to add a major transmission project capable of providing connection at Ft. Churchill Substation in Northern Nevada. There are two primary options for this major transmission project, the first is a Robinson Summit to Ft. Churchill 345 kV line; the second is a Harry Allen to Northwest to Ft. Churchill 500 kV line. The Robinson to Ft. Churchill 345 kV line might also be pursued at 500 kV. The new Ft. Churchill hub would be used to distribute 345 or 500 kV transmission into Reno via three new transmission lines:

1. Ft. Churchill to Mira Loma 345 kV ~45 mi
2. Ft. Churchill to Comstock Meadows 345 kV #1 ~40 mi
3. Ft. Churchill to Comstock Meadows 345 kV #2 ~40 mi

The connections between Ft. Churchill and the Reno transmission system are beneficial in two stages.

1. The initial stage is the creation of a strong outlet from the central Nevada system into the Reno load pocket. Several renewable generation projects have sought to interconnect with the 230 kV and 120 kV systems in central Nevada. Due to the limited capacity of this area of the system, additional generation cannot be injected without the construction of the Ft. Churchill to Mira Loma and Ft. Churchill to Comstock Meadows lines. Additionally, these connections would facilitate retirement of Ft. Churchill generation and eliminate the existing summer must run requirement.

2. The second stage and benefit of these transmission connections is a pathway from a major transmission project to the Reno and Tracy area load pockets. Either of the high capacity projects discussed below will efficiently transfer energy from southern Nevada into the Reno and Tracy area's and increase the overall northern system import limit.

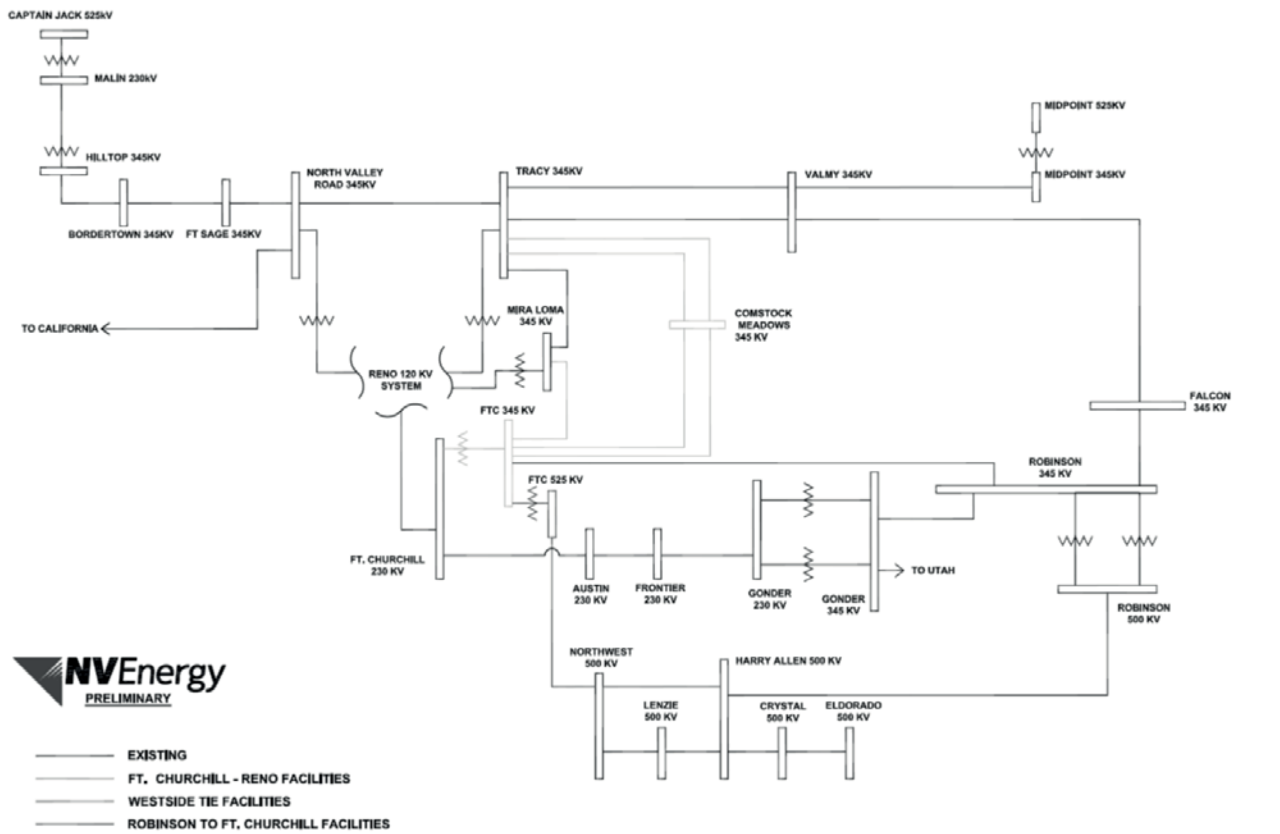
The sourcing to Ft. Churchill is accomplished through either:

1. Northwest to Harry Allen to Ft. Churchill 500 kV (aka Westside Tie), ~350 miles. Initial analysis has identified an increase in northern Nevada import by ~900 MW. This 500 kV line would travel the west side of Nevada creating a second tie between northern and southern NV Energy systems, and create access to more NV Energy south generation as well as to markets such as Mead, Eldorado and McCullough. The line would also pass through the Amargosa Valley, Gold Point and Millers BLM designated Renewable Energy Zones. A major barrier of entry to interconnecting to these renewable energy zones will be eliminated by the access created by this line.

2. Robinson to Ft. Churchill 345 kV line, ~235 miles. Initial analysis has identified an increase in northern Nevada import capability of ~400 MW. This 345 kV line would follow the existing 230 kV transmission line and terminate at Ft. Churchill substation in central Nevada. With the underlying interconnection from Ft. Churchill to Reno discussed above, the capability of the On Line transmission line is further strengthened. The project also supports renewable integration within central Nevada by reinforcing the weaker 230 kV and 120 kV systems between Robinson and Ft. Churchill. This line may alternatively be constructed at 500 kV.

A simplified single line diagram depicting the proposed major transmission additions is shown in Figure TP-33 below.

FIGURE TP-33
SIMPLIFIED SINGLE LINE DIAGRAM FOR MAJOR TRANSMISSION ADDITIONS



The Companies are requesting approval to conduct routing and constraint studies for both the Robinson to Ft. Churchill and the Harry Allen to Ft. Churchill projects. The Companies are also requesting approval for both the routing and constraint studies and the permitting for the Ft. Churchill to Reno 345 kV lines. A year-by-year description of projected permitting costs are provided in the figure TP-34 below.

FIGURE TP-34
ESTIMATED COST SUMMARY FOR MAJOR TRANSMISSION ADDITIONS

Transmission Project	Constraint Study Cost	Year 1 Permitting Cost	Year 2 Permitting Cost	Year 3 Permitting Cost	Year 4 Permitting Cost	Year 5 Permitting Cost	Total Permitting Costs
Ft Churchill to Mira Loma	$160,000	$625,000	$937,500	$937,500	$312,500	$312,500	**$3,125,000**
Ft Churchill to Comstock	$160,000	$660,000	$990,000	$990,000	$330,000	$330,000	**$3,300,000**
Robinson to Ft Churchill	$250,000	$2,823,200	$4,234,800	$4,234,800	$1,411,600	$1,411,600	**$14,116,000**
Westside Tie	$275,000	$4,200,000	$6,300,000	$6,300,000	$2,100,000	$2,100,000	**$21,000,000**

Of the total estimated cost for all permitting activities ($41.500 million), the Companies' are requesting approval for $6.950 million for initial permitting activities. This $6.950 million encompasses the total permitting activities for the Ft. Churchill to Reno ties ($6.425 million) and the routing and constraint studies for both major transmission additions ($525,000). Once enough data is gathered through the routing and constraint studies for either major transmission project, a decision will be made as to which of the two projects to pursue. The Companies will request Commission approval for future activities as soon as possible. The project cash flows are shown in figure TP-35 below.

FIGURE TP-35
PROJECTED CASH FLOWS FOR MAJOR NORTHERN NEVADA TRANSMISSION ADDITION PERMITTING

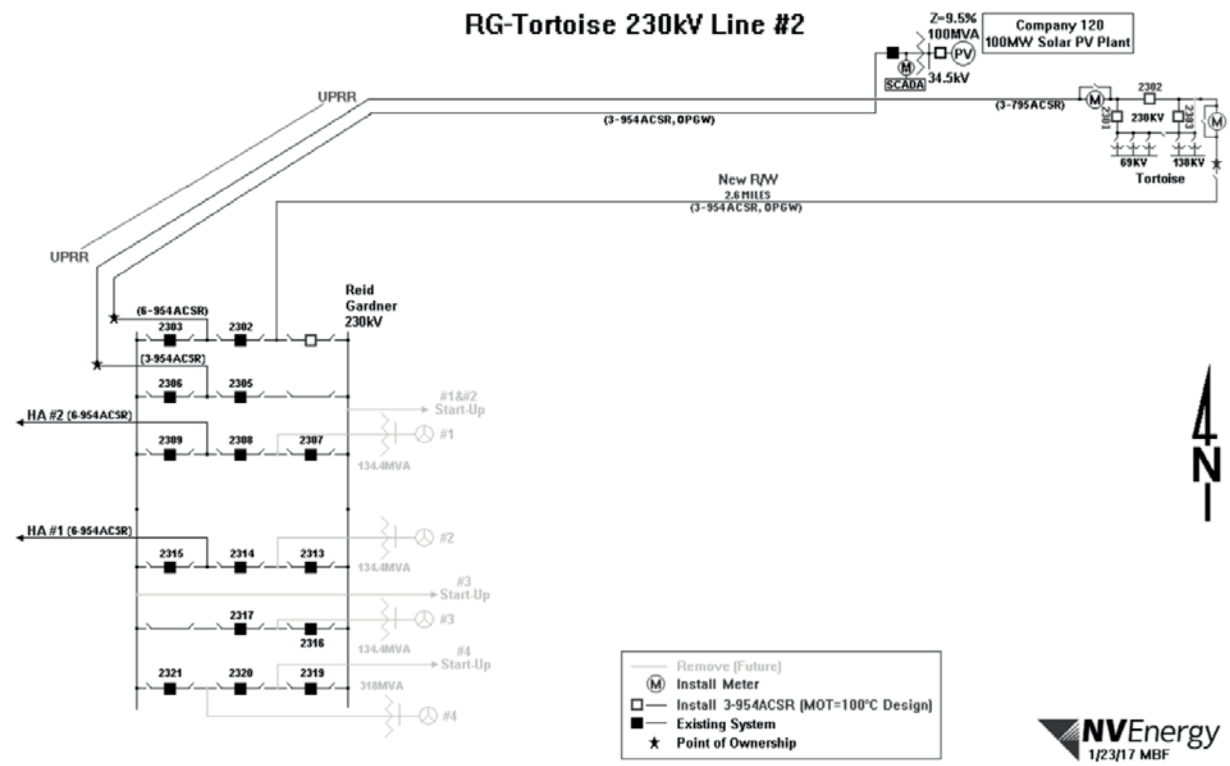
Major Northern Nevada Transmission Project Permitting Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$6,950,000	$0	$0	$845,000	$1,285,000	$2,130,000	$4,820,000

C. Reid Gardner to Tortoise 230 kV Transmission Line #2

Overton Power District is currently served via a 2.6 mile 230 kV radial line out of the NV Energy-owned Reid Gardner Substation. This radial line terminates at the Tortoise Substation, which is jointly-owned by Overton Power District and Lincoln County Power District. Overton's load of approximately 100 MW is subject to extended outages following the loss of this single source out of Reid Gardner, with no possibility for backup service until the single line can be returned to service. In order to provide additional reliability to these customers, the Companies are proposing to construct a second 2.6 mile 230 kV line from Reid Gardner to Tortoise Substation to provide redundant service to Overton Power District. The parallel source means a single contingency will not affect the reliability of the Overton and Lincoln County Power districts, as well as allow for maintenance as needed on both the transmission lines and associated 230 kV terminals. See the single line diagram in Figure TP-36 below. This project was also included in a recently updated

Tri-Party agreement with Lincoln County Power District, Overton Power District and the Company. The application for FERC approval of the new Tri-Party agreement and FERC's order approving the new agreement are included in Technical Appendix item TRAN-5.

FIGURE TP-36
SINGLE LINE DIAGRAM FOR REID GARDNER TO TORTOISE REDUNDANT SERVICE



Construction Scope: The project requires the addition of a new 230 kV breaker at Reid Gardner Substation, a new 2.6 mile 230 kV line from Reid Gardner to Tortoise Substation, associated communications and permitting. The planned in service date for this project is June, 2022 The total estimated cost for this project is $7.210 million, as shown in the cash flow in figure TP-37 below.

FIGURE TP-37
PROJECTED CASH FLOWS FOR THE REID GARDNER TO TORTOISE 230 KV LINE #2

Reid Gardner to Tortoise 230 kV Line #2 Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$7,210,000	$0	$0	$0	$721,000	$721,000	$6,489,000

NWA Analysis: The project scope has been defined under specific requested service needs of a transmission customer: the addition of a second source for redundant transmission service. As a result, a NWA analysis is not applicable. Regardless, this project failed the Critical Suitability

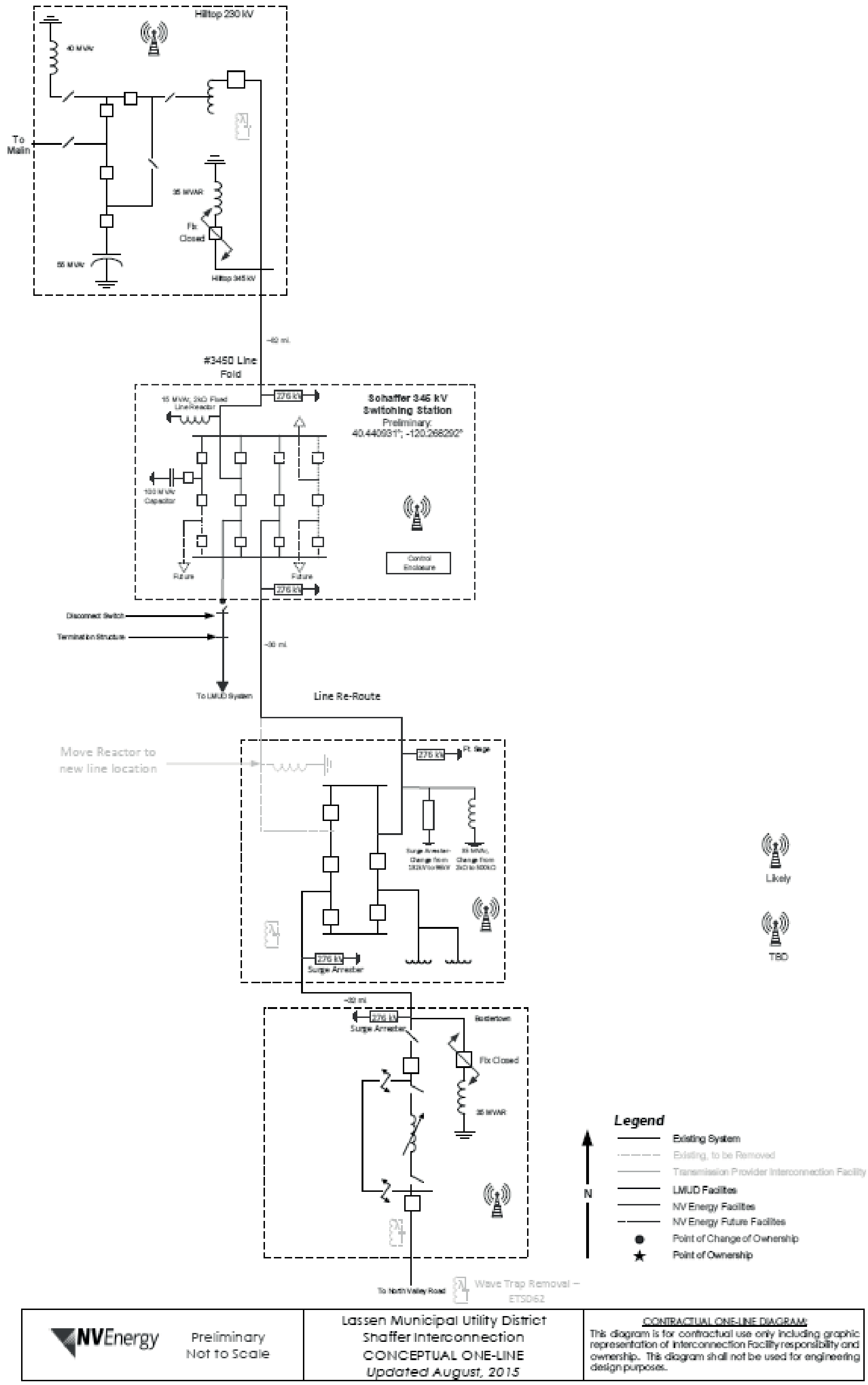
Criteria Screening A: "Constraint anticipated to occur between January 1, 2020 and December 31, 2025." The constraint exists on the current system with the current load forecast.

D. Shaffer 345 kV Substation

On October 2, 2012, Lassen Municipal Utility District ("LMUD") submitted a request to interconnect its transmission system to Sierra's Ft. Sage to Hilltop 345 kV line, approximately 26 line miles out of Ft. Sage Substation. Sierra performed a System Impact Study that was finalized in October of 2013. Powerflow and contingency analysis was performed to ensure the reliable connection of the LMUD system to the Sierra transmission system. This study identified the required facilities for the connection between the two systems, including a new 345 kV substation, called Shaffer, and a fold of the Hilltop to Ft. Sage 345 kV line into the new substation. The Shaffer Substation configuration is a ring bus, expandable to a breaker and a half, that will accommodate three line terminals: Ft. Sage 345 kV, Hilltop 345 kV, and Skedaddle 345 kV, which serves LMUD's load via a 345/60 kV transformer. A subsequent electromagnetic transient pole ("EMTP") study was performed and identified the need for two 50 MVAR capacitor banks at the new Shaffer 345 kV substation as well as a 15 MVAR line reactor on the Hilltop 345 kV side. The EMTP study also required a change of the existing switchable line reactors at Hilltop and Bordertown substations to fixed reactors, required to reduce transient overvoltage during line switching.

Following the initial request, LMUD has since requested to become a Network Integration Transmission Service customer. The facilities identified in the System Impact Study and Facilities Study, with the exception of the Skedaddle Substation, are classified as Network Upgrades due to the requested service. Under the transmission pricing policies of the FERC, a customer can be charged the higher of a rate based on the incremental costs of the facilities needed to enable their service, or a rolled-in system rate, but not both. As these facilities are to be constructed to enable LMUD's transmission service, the Companies decided to pursue the option of developing an incremental transmission service rate for LMUD. In addition, this option will not increase the transmission revenue requirements for Sierra's bundled retail and other third-party OATT customers. LMUD will pay a rate based on the construction costs of the Network Upgrades necessary to connect the LMUD and Sierra systems and all associated costs of operations, maintenance, administrative and general expenses related to the interconnection facilities. LMUD will prepay all expenses associated with the interconnection facilities and will receive transmission service credits for a period of 20 years. The proposed in service date for this project is June 30, 2022. This proposal is further discussed in the Facilities Study included as Technical Appendix item TRAN-6. A one line diagram depicting the proposed project is provided in figure TP-38 below.

FIGURE TP-38
SINGLE LINE DIAGRAM FOR SHAFFER SUBSTATION



Budget and Cost Responsibility: LMUD will be responsible for the associated communications at Skedaddle 345 kV and the 345 kV interchange metering. LMUD will prepay, and be reimbursed by Sierra in an incremental rate over 20 years, for the addition of Shaffer 345 kV substation, the required transient stability solutions, and associated metering, communications and permitting. The FERC filing requesting the incremental rate is planned to be made in quarter two of 2019. The outcome of the filing can affect the method in which the project is funded. If the FERC filing is not approved, the project investment will need to be re-evaluated by Sierra prior to moving forward with construction of any facilities. Sierra is requesting approval for this project conditioned on FERC's approval of the proposed incremental rate. The Transmission to Transmission Facilities Study is attached as Appendix TRAN-6. It should be noted that the cost were initially directly assigned to LMUD as reflected in this document. The investment is now being pursued under the incremental rate discussed here. The total estimated cost for this project is $24.880 million, as shown in the cash flow in Figure TP-39 below.

FIGURE TP-39
PROJECTED CASH FLOWS FOR SCHAFFER 345 KV SUBSTATION ADDITION

Schaffer 345 kV Substation Addition Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$24,880,000	$0	$0	$0	$2,500,000	$2,500,000	$22,380,000

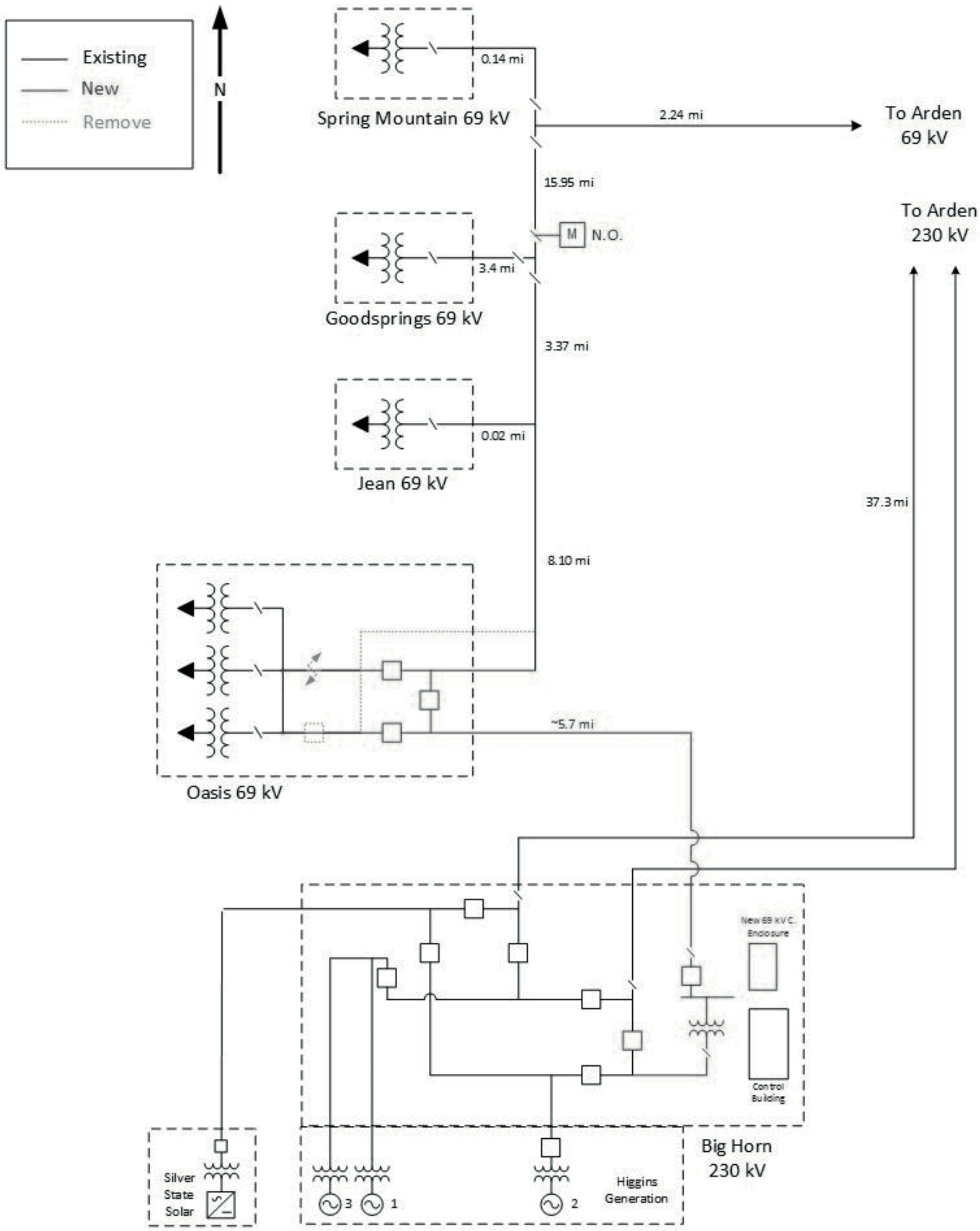
NWA Analysis: This project provides a new point of service for a customer and is not eligible for a NWA analysis.

E. Bighorn 230/69 kV Transformer Addition

Nevada Power is requesting Commission approval to install a 230/69 kV transformer at Bighorn Substation to increase reliability and mitigate service quality issues for approximately 21 MW of customer load currently being served radially out of Arden 69 kV. The existing configuration subjects this customer load to frequent outages with potentially long duration.

Construction Scope: The project requires the addition of a new 230/69 kV transformer at Bighorn Substation, one 230 kV breaker and one new 69 kV breaker, with associated bus work. Also, a new 5.7 mile 69 kV line is required to provide the second source to the Oasis 69 kV Substation, where expansion of Oasis 69 kV substation is required, to a three breaker ring configuration. The planned in service date for this project is December, 2020. This proposal is further discussed Technical Appendix item TRAN-7 A single line diagram depicting the proposed project is provided in Figure TP-40 below.

FIGURE TP-40
Single Line Diagram for Bighorn 230/69 kV Transformer addition



Budget and Cost Responsibility: Nevada Power is responsible for the transmission upgrades associated with increasing reliability to these customers. The total estimated cost for this project is $23.600 million, as shown in the cash flow in figure TP-41 below.

FIGURE TP-41
PROJECTED CASH FLOWS FOR BIGHORN 230/69 KV TRANSFORMER ADDITION

Bighorn 230/69 kV Transformer Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$23,600,000	$0	$0	$7,080,000	$16,520,000	$23,600,000	$0

NWA Analysis: A NWA analysis was performed, however, this project failed the Critical Suitability Criteria Screening A: "Constraint anticipated to occur between January 1, 2020 and December 31, 2025." The constraint exists on the current system with the current load forecast.

F. West Henderson SE2 Substation Project – Routing and Siting

The City of Henderson requires additional transmission service in order to serve the growing load on the distribution system in the West Henderson area. Nevada Power is requesting Commission approval to commence routing and siting to determine the optimal location for a new SE2 distribution substation in the area.

Budget and Cost Responsibility: Nevada Power is responsible for providing additional transmission resources to the West Henderson area. The preliminary request in this filing is for routing, siting and land acquisition for a new 230 or 138 kV substation and associated Transmission line routes required to provide necessary Transmission infrastructure. The total estimated cost for this project is $4.170 million, as shown in the cash flow in figure TP-41 below.

FIGURE TP-42
PROJECTED CASH FLOWS FOR ROUTING AND SITING FOR SE2 SUBSTATION

West Henderson Project - Routing, Siting, Acquisition Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$4,170,000	$0	$0	$400,000	$2,500,000	$2,900,000	$1,270,000

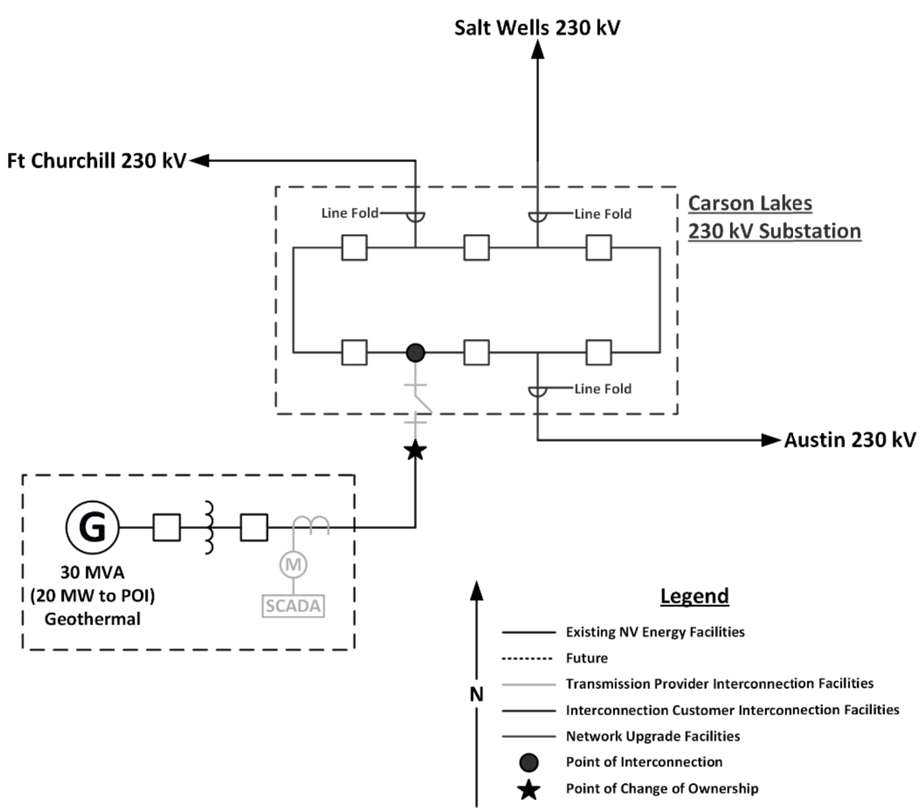
G. Carson Lake (Company HJ) Generator Interconnection

Ormat (Company HJ), has requested interconnection and necessary network upgrades to support the addition of its Carson Lake project, a 20 MW geothermal generating facility at the new Carson Lake 230 kV Substation. The new Carson Lake 230 kV Substation will tap the 230 kV transmission line between the existing Fort Churchill and Austin 230 kV substations. The Small Generator Interconnection Agreement ("SGIA") for this project is included in the Technical Appendix Item TRAN-8.

Construction Scope: Sierra will construct the new Carson Lake 230 kV Substation in a six-breaker ring, breaker-and-a-half configuration, on the #2309 line between the existing Ft. Churchill and Austin 230 kV substations including the required communication, metering and system protection facilities. The planned in service date for this project is December, 2021. Figure TP-43 below depicts a single line diagram of the proposed project.

FIGURE TP-43
ONE LINE DIAGRAM OF CARSON LAKE (COMPANY HJ) GENERATION INTERCONNECTION

NVEnergy	**Carson Lakes 230 kV Substation Company HJ Interconnection**	**9/13/2017**



<u>Budget and Cost Responsibility</u>: Ormat is responsible for the cost of building its generator, lead line, and associated interconnection facilities, including required communications, protections and metering facilities. Sierra is responsible for the cost associated with Network Upgrades, per the OATT, which include the new Carson Lake 230 kV Substation in a six-breaker ring, breaker-and-a-half configuration, the required communications for the substation, with an estimated cost of approximately $15.338 million. Projected cash flows for the project are shown in Figure TP-44 below:

FIGURE TP-44
PROJECTED CASH FLOWS FOR CARSON LAKE GENERATION INTERCONNECTION

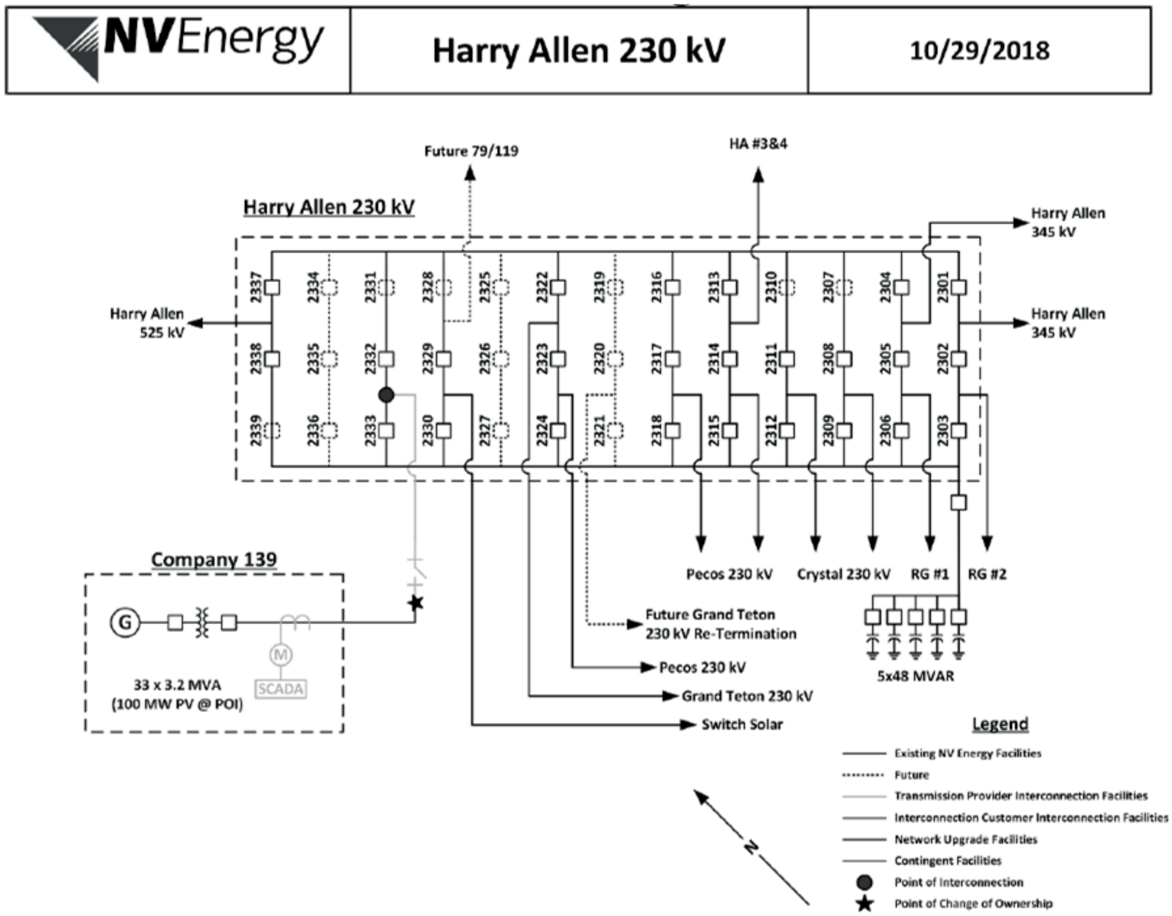
Carson Lake Solar (Company HJ) Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$15,338,000	$0	$0	$1,540,000	$9,200,000	$10,740,000	$6,138,000

H. Harry Allen Solar (Company 139) Generator Interconnection

Invenergy (Company 139) has requested to interconnect Nevada Power's transmission system at the Harry Allen 230 kV Substation. Invenergy's project, the Harry Allen Solar Project, is a 100 MW solar PV generating facility. Invenergy will require the construction of a new terminal position at the existing Harry Allen substation, as well as necessary network upgrades to support the addition of its Harry Allen Solar project, a 100 MW solar PV generating facility at the Harry Allen 230 kV Substation. The planned in service date for this project is September, 2020. The Large Generator Interconnection Agreement ("LGIA") for this project is included in the Technical Appendix Item TRAN-9.

Construction Scope: Nevada Power will construct the new Harry Allen 230 kV terminal position at the existing Harry Allen 230 kV substation, including installation of two new 230 kV breakers. Figure TP-45 below depicts a single line diagram of the proposed project.

FIGURE TP-45
ONE LINE DIAGRAM OF HARRY ALLEN SOLAR (COMPANY 139)
GENERATION INTERCONNECTION



<u>Budget and Cost Responsibility</u>: Invenergy is responsible for the cost of building its generator and associated interconnection facilities, including required communications, protections and metering facilities. Nevada Power is responsible for the cost associated with Network Upgrades, per the OATT, which include the new terminal position at the existing Harry Allen 230 kV substation with an estimated cost of approximately $2.1 million. Projected cash flows for the project are shown in Figure TP-46 below:

FIGURE TP-46
PROJECTED CASH FLOWS FOR HARRY ALLEN SOLAR GENERATION INTERCONNECTION

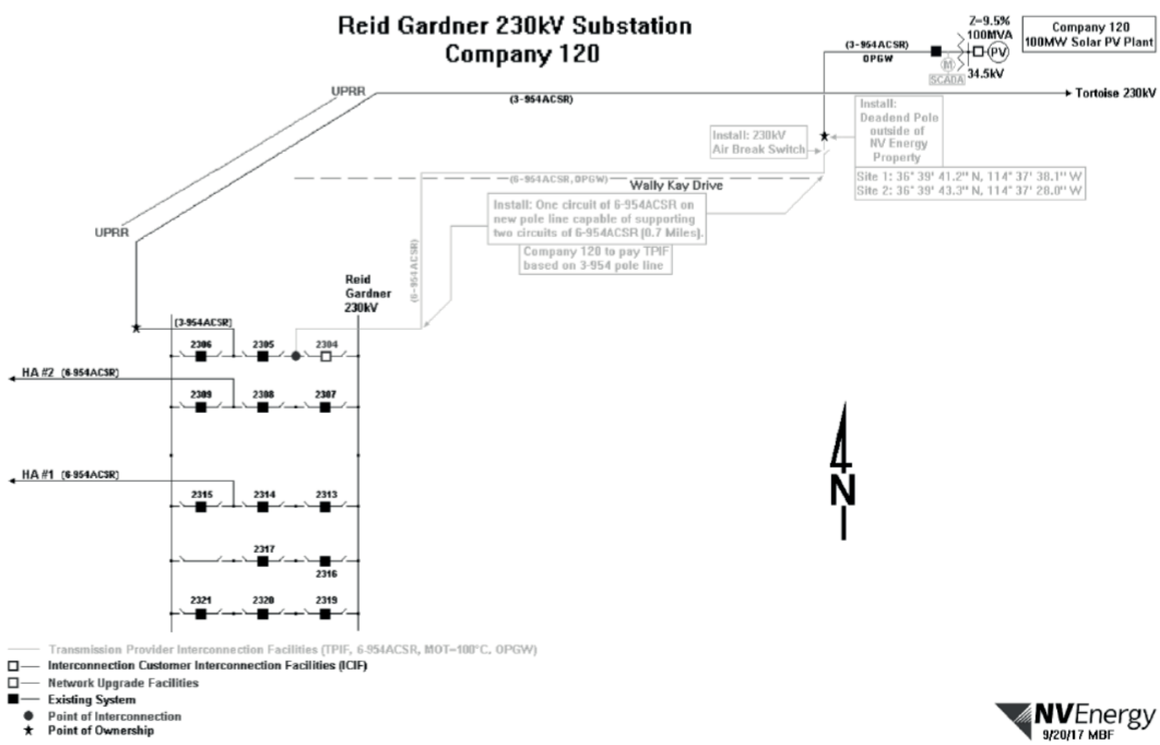
Harry Allen Solar (Company 139) Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$2,100,000	$0	$0	$1,370,000	$730,000	$2,100,000	$0

I. Aiya Solar (Company 120) Generator Interconnection

First Solar has requested Nevada Power provide interconnection and necessary network upgrades to support the addition of its Aiya Solar project, a 100 MW solar PV generating facility, at the existing Reid Gardner 230 kV Substation. The planned in service date for this project is June, 2022. The LGIA for this project is included in the Technical Appendix Item TRAN-10.

Construction Scope: Nevada Power will construct a new terminal position at Reid Gardner 230 kV substation, including one 230 kV breaker. Figure TP-47 below depicts a single line diagram of the proposed project.

FIGURE TP-47
ONE LINE DIAGRAM OF AIYA SOLAR (COMPANY 120)
GENERATION INTERCONNECTION



Budget and Cost Responsibility: First Solar is responsible for the cost of building its generator and associated interconnection facilities, including required communications, protections and metering facilities. Nevada Power is responsible for the cost associated with Network Upgrades, per the OATT, which includes the terminal position at the existing Reid Gardner 230 kV Substation, with an estimated cost of approximately $2.650 million. Projected cash flows for the project are shown in Figure TP-48 below:

FIGURE TP-48
PROJECTED CASH FLOWS FOR AIYA SOLAR GENERATION INTERCONNECTION

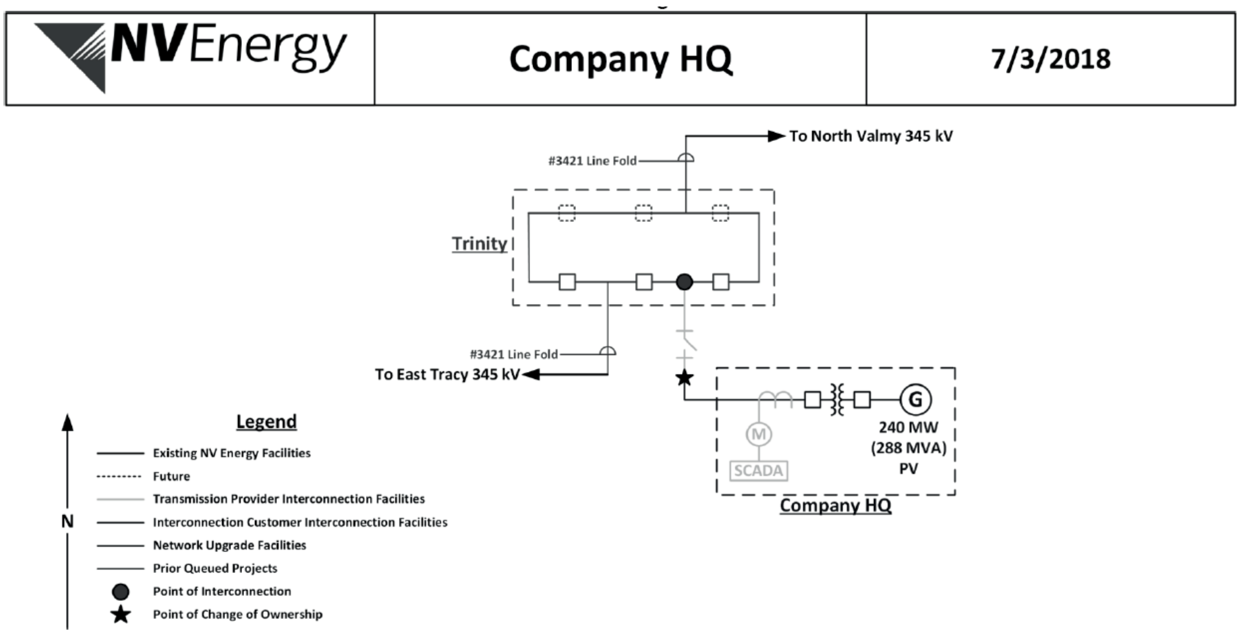
Aiya Solar (Company 120) Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$2,650,000	$0	$0	$0	$265,000	$265,000	$2,385,000

J. Pershing Solar (Company HQ) Generator Interconnection

S Power (Company HQ) has requested interconnection and necessary network upgrades at the new Trinity Peak 345 kV Substation to support the addition of its Pershing Solar project, a 240 MW solar PV generating facility. The new Trinity Peak 345 kV Substation will tap the 345 kV transmission line between the existing East Tracy and North Valmy 345 kV substations. The LGIA for this project is included in the Technical Appendix Item TRAN-11.

<u>Construction Scope</u>: Sierra will construct the new Trinity Peak 345 kV Substation in a three-breaker ring, expandable to breaker-and-a-half configuration, on the #3421 line between the existing East Tracy and North Valmy 345 kV substations including the required communication, metering and system protection facilities. The planned in service date for this project is November, 2021. Figure TP-49 below depicts a single line diagram of the proposed project.

FIGURE TP-49
ONE LINE DIAGRAM OF PERSHING SOLAR (COMPANY HQ) GENERATION INTERCONNECTION



<u>Budget and Cost Responsibility</u>: S Power is responsible for the cost of building its generator, lead line, and associated interconnection facilities, including required communications, protections and metering facilities. Sierra is responsible for the cost associated with Network Upgrades, per the OATT, which include the new Trinity Peak 345 kV Substation in a three breaker ring, expandable to breaker-and-a-half configuration, and the required communications for the substation, with an estimated cost of approximately $15.795 million. Projected cash flows for the project are shown in Figure TP-50 below:

FIGURE TP-50
PROJECTED CASH FLOWS FOR PERSHING SOLAR GENERATION INTERCONNECTION

Pershing Solar (Company HQ) Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$15,795,000	$0	$0	$1,580,000	$9,490,000	$11,070,000	$4,725,000

WestConnect Membership

The following information has not changed since the Companies filed their 2018 Joint IRP. Per NAC § 704.9385(3)(f), the Companies are required to describe their participation in regional planning organizations, as well as the role of these organizations in the Companies' transmission planning activities. The Companies are requesting permission to continue participation in WestConnect with funding of approximately $225,000 distributed equally over the three-year Action Plan period, as shown in Figure TP-56 below:

The Companies have participated in transmission planning activities associated with WestConnect since the 2015 formation of the organization, pursuant to the requirements laid forth in FERC Order No. 1000. WestConnect has a FERC-approved Planning Participation Agreement setting forth the rights and obligations of members who pay dues to WestConnect, stakeholders who participate in WestConnect open activities, and the Planning Management Committee that steers WestConnect.

FIGURE TP-56
WESTCONNECT MEMBERSHIP DUES (IN THOUSANDS)

	2019	**2020**	**2021**	**2019-2021** (3-Year Total)
NV Energy	**$225**	**$225**	**$225**	**$675**
TOTAL	**$225**	**$225**	**$225**	**$675**

Transmission Losses

The following information has not changed since the Companies filed their 2018 Joint IRP. NAC § 704.9385(3)(h) requires the Companies include in its Transmission Plan a description of efforts to reduce the impact of line losses on future resource requirements. The Companies' efforts to evaluate and mitigate line losses are ongoing. Line losses are calculated into the overall plan of service for load growth, selection of company-owned generation, independent power producer development, and renewable energy evaluations in order to develop the most cost effective facilities (*i.e.*, the impact of losses is evaluated in those cases where the Companies have the ability to select from various options).

Renewable Energy Zone Transmission Plan

The following information has not changed since the Companies filed their 2018 Joint IRP. In response to the requirements provided for in NAC § 704.9385(6) and NAC § 704.9489(5), regarding the development of transmission facilities to serve renewable energy zones within the State of Nevada, the Companies have prepared a Conceptual Renewable Energy Zone Transmission Plan ("REZTP" or "Plan").

The REZTP is a conceptual plan for transmission facilities that shows possible transmission access to areas of Nevada that have been designated as renewable energy zones. The REZTP does not request any funds construction nor does it request Commission approval of any facilities associated with the REZTP.

The Companies did not produce new studies for the REZTP for this filing. There has been no interest by any parties outside the Companies to pursue any studies with respect to this plan. Upon a new identification of renewable energy zones by the Commission, or new interest by outside parties, the Companies will revisit the REZTP and update accordingly.

Federal Regulatory Filings

NAC § 704.9385(3)(g) requires the Companies include in the Transmission Plan a summary of the impacts of relevant orders issued by FERC. This information has not changed since the Companies filed their 2018 Joint IRP, docket 18-06003.

Transmission Technical Appendices

The following transmission-related information is set forth in the Technical Appendix volume as:

Technical Appendix TRAN-1: Northern Import Limit Assessment
Technical Appendix TRAN-2: Northern Export Limit Assessment
Technical Appendix TRAN-3: Tracy Area Master Plan
Technical Appendix TRAN-4: West Tracy 345/120 kV Transformer
Technical Appendix TRAN-5: Reid Gardner to Tortoise 230 kV Line
Technical Appendix TRAN-6: Schaffer 345 kV Substation Facilities Study
Technical Appendix TRAN-7: Bighorn 230/69 kV Transformer Addition
Technical Appendix TRAN-8: Company HJ - Carson Lake SGIA
Technical Appendix TRAN-9: Company 139 – Harry Allen Solar LGIA
Technical Appendix TRAN-10: Company 120 -- Aiya LGIA
Technical Appendix TRAN-11: Company HQ – S Power Pershing Solar LGIA

EXHIBIT B

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 Second Amendment to 2018 Joint Integrated Resource Plan, including a change to the Demand-Side Action Plan to achieve 1.25% annual energy savings target, additions to the generation portion of the Supply-Side Action Plan including a new cooling pond for Tracy Unit 3 and a new agreement with Idaho Power Company for the orderly retirement of the North Valmy Station, updates to the Transmission Action Plan including several new transmission projects needed to serve growing distribution and transmission load.**

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 a second amendment to their 2018 Joint Integrated Resource Plan. The Companies are seeking to modify the approved Demand-Side Action Plan to add investment in the Flex Pay Program to the DSM portfolio, bringing their annual energy savings target to 1.25%. The Companies are seeking to modify the generation portion of the Supply-Side Action Plan to add a new cooling pond for Tracy Unit 3 in time to address a change in an environmental permit, and to gain approval of a new agreement with Idaho Power Company that will facilitate the orderly retirement of the North Valmy Station. Finally, the Second Amendment includes updates to several already-approved transmission projects, some of which require Commission approval, as well as authority to construct several new transmission projects, some of which are driven by growth on the transmission and distribution systems, and some of which are necessary to interconnect new renewable energy projects to the transmission grid.**

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.

EXHIBIT C

NV Energy
LOADS AND RESOURCES TABLE
Current_all placeholder

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Gross Peak	7,725	7,839	7,984	7,965	8,171	8,294	8,411	8,494	8,535	8,695	8,793	8,898	9,011	9,115	9,141	9,317	9,426	9,563	9,654	9,707	9,817	10,027	10,145	10,275	10,385	10,513	10,621	10,741	10,866	10,995
DSM	49	97	147	196	245	294	344	394	445	496	547	599	651	703	755	807	859	912	965	1,018	1,071	1,124	1,178	1,232	1,286	1,340	1,395	1,450	1,505	1,560
Private Generation	39	75	107	127	137	145	152	157	161	165	170	175	179	183	188	192	197	200	205	210	214	218	224	228	232	236	241	245	250	253
Avoided Capacity	177	199	229	239	236	241	253	257	272	265	267	268	278	280	291	281	285	293	284	305	306	298	295	312	308	323	315	318	314	327
Forecast System Peak	7,459	7,468	7,501	7,404	7,553	7,615	7,662	7,687	7,656	7,769	7,809	7,856	7,903	7,950	7,908	8,037	8,085	8,157	8,200	8,175	8,226	8,387	8,448	8,503	8,558	8,615	8,670	8,728	8,797	8,854
Sales Obligations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NET System Peak	7,459	7,468	7,501	7,404	7,553	7,615	7,662	7,687	7,656	7,769	7,809	7,856	7,903	7,950	7,908	8,037	8,085	8,157	8,200	8,175	8,226	8,387	8,448	8,503	8,558	8,615	8,670	8,728	8,797	8,854
Planning Reserves (13%)	950	952	965	953	959	967	973	977	983	986	992	997	1,003	1,010	1,015	1,021	1,027	1,036	1,042	1,050	1,056	1,063	1,070	1,077	1,084	1,091	1,098	1,106	1,114	1,122
REQUIRED RESOURCES	8,409	8,420	8,466	8,357	8,512	8,582	8,635	8,664	8,639	8,755	8,801	8,853	8,906	8,960	8,923	9,058	9,112	9,193	9,242	9,225	9,282	9,450	9,518	9,580	9,642	9,706	9,768	9,834	9,911	9,976
AVAILABLE RESOURCES	7,172	7,000	7,110	6,874	7,092	7,104	7,155	7,293	7,357	7,237	7,359	7,476	7,402	7,165	7,135	7,307	7,511	7,511	7,302	6,860	7,053	7,072	6,990	7,698	7,698	8,001	7,976	7,981	7,543	7,543
OPEN Position	1,237	1,420	1,356	1,483	1,420	1,478	1,480	1,371	1,282	1,518	1,442	1,377	1,504	1,795	1,788	1,751	1,601	1,682	1,940	2,365	2,229	2,378	2,528	1,882	1,944	1,705	1,792	1,853	2,368	2,433

Company	(All)

Row Labels	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**
existing																														
NVE.existing.Coal																														
Valmy 2 (12/2025)	134	134	134	134	134	134	134	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Valmy 1 (12/2021)	127	127	127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Navajo 1-3 (10/2019)	255	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NVE.existing.Coal Total	**516**	**261**	**261**	**134**	**134**	**134**	**134**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
NVE.existing.Gas																														
Clark 10 (12/2034)	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark 11 - 22 (12/2038)	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	-	-	-	-	-	-	-	-	-	-
Clark 4 (12/2030)	54	54	54	54	54	54	54	54	54	54	54	54	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark 9 (12/2033)	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark Mt. 3 (12/2034)	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark Mt. 4 (12/2034)	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ft. Churchill 1 (12/2028)	113	113	113	113	113	113	113	113	113	113	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ft. Churchill 2 (12/2028)	113	113	113	113	113	113	113	113	113	113	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Harry Allen 4 (12/2036)	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-	-	-	-
Harry Allen CC (12/2046)	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	-	-
Higgins CC (12/2039)	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	-	-	-	-	-	-	-	-	-
Lenzie CC 1 (12/2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	-	-	-	-	-	-	-
Lenzie CC 2 (12/2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	-	-	-	-	-	-	-
LV Gen 1 (12/2029)	48	48	48	48	48	48	48	48	48	48	48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LV Gen 2 (12/2039)	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	-	-	-	-	-	-	-	-	-
Silverhawk CC (12/2039)	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	-	-	-	-	-	-	-	-	-
Sunpeak 3-5 (12/2031)	210	210	210	210	210	210	210	210	210	210	210	210	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tracy 3 (12/2028)	108	108	108	108	108	108	108	108	108	108	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tracy 4&5 (12/2031)	104	104	104	104	104	104	104	104	104	104	104	104	104	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tracy CC (12/2043)	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	-	-	-	-	-
Harry Allen 3 (12/2036)	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-	-	-	-
NVE.existing.Gas Total	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,141**	**5,093**	**5,039**	**4,725**	**4,725**	**4,510**	**4,163**	**4,163**	**4,019**	**4,019**	**3,401**	**2,127**	**2,127**	**1,025**	**1,025**	**484**	**484**	**484**	**-**	**-**
NVE.existing.Renewable.PV	**5**	**5**	**5**	**4**	**4**	**4**	**4**	**4**	**4**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
NVE.existing.Renewable.WH	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
PPA.existing.Conventional	**619**	**636**	**638**	**384**	**211**	**204**	**205**	**206**	**205**	**210**	**210**	**210**	**210**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**
PPA.existing.Renewable.BESS																														
Dodge Flat BESS (12/2036)	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-
Battle Mtn BESS (12/2030)	-	-	25	25	25	25	25	25	25	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fish Spgs Ranch BESS (12/2036)	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-
PPA.existing.Renewable.BESS Total	**-**	**-**	**25**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**75**	**75**	**75**	**75**	**75**	**75**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
PPA.existing.Renewable.CSP	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
PPA.existing.Renewable.GEO	**166**	**165**	**165**	**158**	**149**	**149**	**149**	**136**	**126**	**118**	**108**	**67**	**67**	**63**	**7**	**7**	**7**	**7**	**7**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
PPA.existing.Renewable.HYDRO	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**5**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
PPA.existing.Renewable.LFG	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
PPA.existing.Renewable.PV	**203**	**270**	**353**	**431**	**431**	**431**	**431**	**431**	**431**	**342**	**342**	**338**	**338**	**338**	**338**	**338**	**334**	**334**	**314**	**254**	**248**	**244**	**240**	**240**	**240**	**220**	**180**	**150**	**-**	**-**
PPA.existing.Renewable.WIND																														
Spring Valley (12/2032)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PPA.existing.Renewable.WIND Total	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
existing Total	**7,172**	**7,000**	**7,110**	**6,874**	**6,692**	**6,685**	**6,686**	**6,540**	**6,529**	**6,382**	**6,036**	**5,943**	**5,864**	**5,534**	**5,454**	**5,239**	**4,888**	**4,888**	**4,649**	**4,582**	**3,955**	**2,677**	**2,565**	**1,463**	**1,463**	**902**	**862**	**832**	**198**	**198**
placeholder																														
NVE.placeholder.Gas																														
1-1x1 CC SN 382 MW_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	382	382	382	382	382	382	382	382	382

1-1x1 CC SN 382 MW_34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382
1-1x1 CC SN 382 MW_35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	382	382	382	382	382	382	382	382	382	382	382	382	382	382
9-CT SN 90 MW_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	810	810	810	810	810	810	810	810	810	810
1-1x1 CC NN 358 MW_29	-	-	-	-	-	-	-	-	-	-	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358
2-CT NN 84 MW_35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	168	168	168	168	168	168	168	168	168	168	168	168	168	168
1-2x1 CC NN 839 MW_44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	839	839	839	839	839
1-1x1 CC NN 358 MW_32	-	-	-	-	-	-	-	-	-	-	-	-	-	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358
1-2x1 CC SN 900 MW_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900	900	900	900	900	900	900	900
2-2x1 CC SN 900 MW_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,800	1,800	1,800	1,800	1,800	1,800	1,800
NVE.placeholder.Gas Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**358**	**358**	**358**	**716**	**716**	**1,098**	**1,648**	**1,648**	**1,648**	**1,648**	**2,458**	**3,740**	**3,740**	**5,540**	**5,540**	**6,379**	**6,379**	**6,379**	**6,379**	**6,379**
PPA.placeholder.Gas																														
1-Summer Toll_265 MW_26	-	-	-	-	-	-	-	265	265	265	265	265	265	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1-Summer Toll_400 MW_23	-	-	-	-	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	-	-	-	-	-	-	-	-	-	-	-
PPA.placeholder.Gas Total	**-**	**-**	**-**	**-**	**400**	**400**	**400**	**665**	**665**	**665**	**665**	**665**	**665**	**400**	**400**	**400**	**400**	**400**	**400**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
PPA.placeholder.renewable.GO																														
GO2N_47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
GO4_33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PPA.placeholder.renewable.GO Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**21**	**21**
PPA.placeholder.renewable.PV																														
PV4N_47A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV4N_47B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV1N_31	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
PV4_30A	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_30B	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_33A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_33B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20
PV1_30	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
PV1N_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5
PV1N_47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
PV4_41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20
PV4_47A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV4_47B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV4_47C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV4_47D	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV4_47E	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV3N_29	-	-	-	-	-	-	-	-	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PV1N_30	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
PV2N_38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10	10	10
PV3_46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15	15
PV1N_37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5
PV4N_30A	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4N_30B	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_28A	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_28B	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV3_28	-	-	-	-	-	-	-	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PV4_29A	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_29B	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_29C	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_29D	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV3_29	-	-	-	-	-	-	-	-	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PV4_30C	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_30D	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_30E	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_30F	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_30G	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_30H	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV1_35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5
PV4_37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
PV2_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10
PV4_47F	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV2_47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
PV3N_24	-	-	-	-	-	19	19	19	19	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PV4N_25A	-	-	-	-	-	-	25	25	25	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4N_25B	-	-	-	-	-	-	25	25	25	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV3N_26	-	-	-	-	-	-	-	19	19	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PV4N_27A	-	-	-	-	-	-	-	-	25	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4N_27B	-	-	-	-	-	-	-	-	25	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4N_27C	-	-	-	-	-	-	-	-	25	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20

PV1N_34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
PV1N_41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5
PV1N_44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5
PV3N_45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15	15	15
PV4N_46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20
PV2_33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PV1_37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5
PV3_38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15	15	15	15	15	15	15	15	15	15
PV2_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10	10
PV1_41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5
PV2_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10
PV1N_28	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
PPA.placeholder.renewable.PV Total	**-**	**-**	**-**	**-**	**-**	**19**	**69**	**88**	**163**	**190**	**300**	**510**	**515**	**515**	**565**	**570**	**575**	**575**	**605**	**630**	**640**	**655**	**685**	**695**	**695**	**720**	**735**	**770**	**945**	**945**
placeholder Total	**-**	**-**	**-**	**-**	**400**	**419**	**469**	**753**	**828**	**855**	**1,323**	**1,533**	**1,538**	**1,631**	**1,681**	**2,068**	**2,623**	**2,623**	**2,653**	**2,278**	**3,098**	**4,395**	**4,425**	**6,235**	**6,235**	**7,099**	**7,114**	**7,149**	**7,345**	**7,345**

JOHN P. MCGINLEY

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

Second Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-05_____

PREPARED DIRECT TESTIMONY OF

John (Jack) P. McGinley

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

A. My name is John (Jack) P. McGinley. My current position is Vice President of Regulatory 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 in Reno, Nevada. I am filing testimony on behalf of the Companies

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

A. I have been employed by the Companies since May 1984. I have held many positions primarily focused on matters related to resource planning, renewable energy development, power contracts and rates. I hold a Bachelor of Science in Mechanical Engineering from the University of Nevada, Reno. My statement of qualifications is attached as **Exhibit McGinley-Direct-1**.

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

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

A. Yes. I have testified before this Commission many times during my 35 years at the Company related to Integrated Resource Planning ("IRP"), Energy Supply Plan ("ESP") filings, General Rate cases ("GRC"), and various other Company filings. Most recently, I provided testimony in the 2018 and 2019 Deferred Energy cases, and Assembly Bill 405 net metering case, Docket No. 17-07026. In addition, I have testified before the Nevada Legislature on various energy matters.

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY AND HOW IS YOUR TESTIMONY ORGANIZED?

A. The purpose of my testimony is to provide support for Companies' Second Amendment to their 2018 Joint Integrated Resource Plan ("2018 Joint IRP").

5. Q. ARE YOU SPONSORING ANY EXHIBITS OR APPENDICES?

A. Yes. I am sponsoring the Loads and Resources tables attached to the Application as Exhibit C, as well as **Exhibit McGinley-Direct-1**: Statement of Qualifications.

6. Q. WHAT IS THE SUBJECT MATTER OF THE SECOND AMENDMENT TO THE 2018 JOINT IRP?

A. In the 16 months since preparation on the 2018 Joint IRP began, regulations implementing the numerous energy-related bills from the 2017 Nevada Legislature have been finalized, conditions impacting the operations of two of its generating units have changed, and loads on the Companies' distribution and transmission systems have continued to grow. These and related events have raised the need to amend some aspects the Action Plan approved by the Commission in Docket No.

18-06003. Included in this Second Amendment are requests to amend the Demand-Side Management ("DSM") Plan to add a program that will increase the net benefits of the DSM portfolio to 1.25 percent of retail sales, to amend the generation section of the Supply-Side Plan to obtain approval to construct a replacement for the unlined cooling pond serving the existing Tracy 3 unit and to approve a new agreement with Idaho Power Company ("IPCo.") addressing the North Valmy Station, and to make several updates and additions to the Companies' Transmission Plan.

7. Q. HOW HAVE THE COMPANIES ORGANIZED THE SECOND AMENDMENT?

A. Like most IRP amendments, the Second Amendment includes a Narrative (Application Exhibit A), Technical Appendices and prepared direct testimony. The Narrative addresses each of the areas opened up by the Second Amendment: the load forecast, the DSM plan, the generation portion of the Supply-Side Plan, and the Transmission Plan. The sponsors of each of the substantive portions of the Second Amendment are described below:

- The updated load forecast is addressed in Section 3 of the Narrative, in Technical Appendices LF-1(portions of which are confidential) through LF-8, and supported by the prepared direct testimony of **Mr. Terry Baxter**.
- The updated DSM Action Plan is addressed in Section 4 of the Narrative and supported by the prepared direct testimony **Ms. Anita Hart**.
- The updated portion of the Supply-Side Action Plan addressing the replacement of the Tracy Unit 3 unlined cooling pond is discussed in Section 5 of the Narrative, in Technical Appendices GEN-1 and GEN-2 (a

portion of which is confidential), and in the prepared direct testimony of **Mr. Dariusz Rekowski.**

- The updated portion of the Supply-Side Action Plan seeking approval of the new North Valmy Project Framework Agreement with IPCo is discussed in Section 5 of the Narrative, Technical Appendix GEN-3, and prepared direct testimony of **Mr. Matthew Johns**.
- Updates to the budgets of three previously-approved Transmission Action Plan items, requests for approval of scope changes and budget revisions of three other previously-approved Transmission Action Plan items, Transmission Action Plan additions of six new transmission projects required to meet growth and reliability needs, as well as Transmission Action Plan additions for network upgrades needed to satisfy four new generator interconnection requests are discussed in Section 6 of the Narrative, Technical Appendix TRAN-1 through TRAN-11 (portions of TRAN-1, TRAN-2, TRAN-3 and TRAN-4 contain customer-specific confidential information), and the prepared direct testimony of **Mr. Sachin Verma**.

8. Q. WAS THE SECOND AMENDMENT PREPARED USING PRODUCTION COST ANALYSIS?

A. No. The projects for which approvals are sought in this Second Amendment do not result in material changes to either loads or resources (capacity or energy) and have not been analyzed utilizing production cost modeling. Nevertheless, consistent with NAC § 704.9516(1), which sets forth the requirements of an amendment to an approved Action Plan, an updated current peak demand forecast and a current loads and resources table are provided.

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

A. Yes.

QUALIFICATIONS OF WITNESS
JOHN (JACK) P. MCGINLEY
SIERRA PACIFIC POWER & NEVADA POWER COMPANIES D/B/A NV ENERGY
6100 Neil Road
Reno, Nevada 89511-1137

My name is John ("Jack") P. McGinley. I am the Vice President, Regulatory for Sierra Pacific Power Company and Nevada Power Company.

I graduated from the University of Nevada Reno in 1984 with a Bachelor of Science in Mechanical Engineering. Upon graduating from the University of Nevada, I have been employed full time by the Company for 35 years.

I have held various technical and leadership positions primarily in Resource Planning, Power Contracts, Regulatory and Legislative Strategy. I have participated in and managed the preparation of many regulatory proceedings before the Public Utilities Commission of Nevada. I have provided testimony in numerous regulatory filings before the Commission.

In the early 1990's, I was responsible for the Company's Resource Planning, Research and Development and Demonstration ("RD&D") and Supply Engineering departments. In this position, I was responsible for the Company's RD&D program planning, management, and technical review and evaluation of potential supply side options including conventional generation, renewable generation including private generation solar, storage technologies and electric vehicles.

In 1998, I assumed the duties of Manager of New Product Development. This led to working with a team of individuals to establish two subsidiary companies; E-three and Simple Choice where I held the position of General Manager of Simple Choice. In 2000, I assumed the duties of Principal Consultant in the Strategic Planning Department. In 2001, I assumed the position of Principal Consultant in the Rates and Regulatory Department and was responsible for filing fuel and purchase power rider cases. Later in 2001, I assumed the duties of Manager of Long Term Resource Analysis and in 2005 I assumed the position of Regulatory Strategist. In 2007, I assumed the position of Development Director in the Renewable Energy department where my responsibilities included the formation of the department and development of renewable energy projects. In 2013, I was assigned as the project manager to lead a team of internal technical experts with the responsibility to evaluate the participation in the California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM"). The Company ultimately decided to join the EIM and received approval from the Commission in 2014. The Company went live in December 2015, with 2016 as the first full year of participation.

In 2009, I served on the University of Nevada Chemical Engineering Advisory Board. From 2013 to 2016 I served on the Governor's Workforce Investment Board on the Clean Energy Sector Council. For many years I served as a member of the Governor's New Energy Industry Task Force and in 2016 I was appointed to the New Energy Industry Task Force Technical Advisory Committee on Distributed Generation and Storage.

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF WASHOE)

I, JOHN P. MCGINLEY, 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.

John P. McGinley

JOHN P. MCGINLEY

Subscribed and sworn to before me
this 24th day of April, 2019.

Connie D. Silveira

NOTARY PUBLIC

CONNIE D. SILVEIRA
Notary Public - State of Nevada
Appointment Recorded in Washoe County
No: 97-2188-2 - Expires May 15, 2021

TERRY A. BAXTER

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

Second Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-05_____

PREPARED DIRECT TESTIMONY OF

Terry A. Baxter

1. Q. WOULD YOU PLEASE STATE YOUR NAME, EMPLOYER, JOB TITLE, AND BUSINESS ADDRESS?

A. My name is Terry A. Baxter. I am the Manager of Load Forecasting for Sierra Pacific Power Company d/b/a/ NV Energy ("Sierra") and Nevada Power Company d/b/a NV Energy ("Nevada Power" and together with Sierra, the "Companies" or "NV Energy"). My business address is 6226 West Sahara Avenue, in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

2. Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGER OF LOAD FORECASTING?

A. As the Manager of Load Forecasting, my primary responsibilities include forecasting sales volume, customer counts and peak demand for use in development of financial budgets, general rate cases, Energy Supply Plans ("ESP") and Integrated Resource Plans ("IRP").

3. Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE IN THE UTILITY INDUSTRY.

A. I hold a Master of Arts in Economics from the University of Arkansas located in Fayetteville, Arkansas and a Bachelor of Science in Economics from the University of Missouri at Rolla (now Missouri University of Science and Technology) located in Rolla, Missouri. I have been employed by the Companies since July 2007. Prior to my current position, I served as the Manager of Forecasting and Economic Analysis at Alliant Energy in Cedar Rapids, Iowa, for nine years, where I was responsible for load and revenue forecasting and load research. Prior to that, I was a Group Manager for seven years with Aspen Systems Corporation (now a division of Lockheed-Martin) overseeing analytical consulting projects for utilities and the U.S. government. I also have served as Manager of Load Research at Midwest Resources (now MidAmerican Energy Company) and as the Load Research Analyst at Missouri Public Service Company (now a part of Kansas City Power and Light Co., a division of Great Plains Energy). I have submitted reports and testimony regarding load forecasting and load research before the Iowa Utilities Board, the Wisconsin Public Service Commission, the Illinois Commerce Commission, the Minnesota Department of Commerce, the California Energy Commission, the California Public Utilities Commission and the Public Utilities Commission of Nevada ("Commission").

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

A. Yes, I have testified in numerous proceedings before the Commission including, most recently, in NV Energy's 2018 Joint Integrated Resource Plan, Docket No. 18-06003.

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

A. Yes. Some numbers in the Narrative and Technical Appendices are confidential because they contain usage of discrete and specific customers.

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

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

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

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

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

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

Exhibit Baxter-Direct-1.

9. Q. **WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to support the forecast of native load used in this filing. Specifically, I am sponsoring the long-term load forecast used for the Second Amendment to the 2019 through 2038 Integrated Resource Plan (the "2019 IRPA 2nd Forecast") and the following Technical Appendix Items:

- LF-1 NVE 2020-2049 Load Forecast (portions of which are confidential)
- LF-2 Population Forecasts: Long-Term Projections for Clark County, Nevada 2018-2050, May, 2018
- LF-3 State Demographer 2018 Population Forecasts
- LF-4 Nevada State Demographer Intercensal Population Estimates
- LF-5 Population of Nevada's Counties and Incorporated Cities 2000-2017
- LF-6 Las Vegas Convention and Visitors Year to Date executive summary for 2018
- LF-7 ADM Report on Energy Intensity Development
- LF-8 Las Vegas Convention and Visitor's Authority Construction Bulletin, December 5, 2018

10. Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS REGARDING THE 2019 IRPA 2ND FORECAST.

A. The Companies are making the following requests regarding the 2019 IRPA 2nd Forecast:

- A finding, consistent with NAC § 704.9225, that the base, high and low cases are based upon, and consistent with, the upper and lower limits of expected economic and demographic change in the Companies' service territory for 2020 through 2049.

- A finding, consistent with NAC § 704.9321, that the base, high and low cases are based on substantially accurate data, adequately demonstrated and defended, and adequately documented and justified.

- A finding that the 2019 IRPA 2nd Forecast is suitable for making long term planning decisions.

11. Q. HAVE HIGH AND LOW LOAD FORECAST SCENARIOS BEEN DEVELOPED FOR THIS FORECAST?

A. Yes. High and low load forecasts were produced based on optimistic and pessimistic economic, demographic and, large customer growth assumptions. In addition to those scenarios, a scenario was created assuming all identified eligible customers elect distribution only service. See Technical Appendix LF-1 for more details regarding the development of the high and low load forecast scenarios.

12. Q. DOES THE 2019 IRPA 2ND FORECAST CONSIDER THE LOAD IMPACTS OF CUSTOMERS WHO TRANSITION FROM BUNDLED TO DISTRIBUTED GENERATION SERVICE PURSUANT TO NRS § 704.787 OR NRS CHAPTER 704B (SEE NAC § 704.925(5))?

A. Yes. Customers who are expected to procure energy from an alternative suppler and move to distribution only service ("DOS") have been removed from the load forecast. In northern Nevada, Atlantis' properties were expected to transition to DOS on April 1, 2019, the Grand Sierra Resort is expected to move to DOS on October 1, 2019, and based on a letter received in January 2019, Newmont Mining Corp. will move its bundled load to DOS on February 1, 2022. During the preparation of this filing, the Atlantis had not yet filed a transmission service request, and on April 29, 2019, Atlantis withdrew is NRS Chapter 704B application.

In southern Nevada, Station Casinos' properties and Georgia Pacific were originally scheduled to transition to DOS on January 1, 2019. In a letter to the Commission dated February 11, 2019, counsel for Station Casinos provided a revised transition date of October 1, 2019. Georgia Pacific had not yet performed its DOS transition. Therefore, 2019 IRPA 2^{nd} Forecast over-estimates the amount of load at Nevada Power that is transitioning to DOS in 2019. Boyd Gaming, the Cosmopolitan, Southpoint, Las Vegas Resort Holdings d/b/a SLS, and the Las Vegas Convention and Visitors Authority are reflected in the 2019 IRPA 2^{nd} Forecast as transitioning to DOS on September 1, 2019.

13. Q. DOES THE 2019 IRPA 2ND FORECAST CONSIDER THE LOAD IMPACTS OF CUSTOMERS INSTALLING PRIVATE GENERATION, PARTICIPATING IN DEMAND SIDE MANAGEMENT PROGRAMS AND INCREASED USE OF ELECTRIC VEHCILE CHARGING?

A. Yes. The 2019 IRPA 2^{nd} Forecast accounts for distributed generation systems, primarily solar PV, installed on residential homes, small business, public buildings and schools, as well as larger customer net metering projects. It also accounts for energy efficiency and demand-response resources, and electric vehicle installations. See Technical Appendix LF-1, for the sales and demand impacts of net metering projects, demand side management ("DSM") and demand response, and electric vehicles.

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

As is set forth in the Narrative, information regarding energy storage devises is not yet available in sufficient detail to incorporate into the 2019 IRPA 2nd Forecast.

14. Q. DOES THE 2019 IRPA 2ND FORECAST CONSIDER THE IMPACT OF APPLICABLE NEW TECHNOLOGIES AND THE IMPACT OF APPLICABLE NEW GOVERNMENTAL PROGRAMS OR REGULATIONS (SEE NAC § 704.925(4))?

A. Yes. The customer class sales regression modeling for the 2019 IRPA 2nd Forecast included variables constructed from estimated historical and forecasted appliance saturations and efficiencies, building characteristics and square footage. These estimates and forecasts include the effects of new technologies and government programs.

15. Q. HAS NV ENERGY MADE ANY CHANGES TO ITS FORECAST METHODOLOGY SINCE THE FILING OF COMPANIES' 2018 IRP FORECAST (SEE NAC § 704.925(11))?

A. No.

16. Q. ARE YOU FILING WORKPAPERS WITH THIS 2019 IRPA 2ND FORECAST?

A. Yes, a comprehensive set of load forecasting files will be supplied on electronic media for this 2019 IRPA 2nd Forecast filing.

17. Q. WHAT IS YOUR OVERALL VIEW OF THIS 2019 IRPA 2ND FORECAST?

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

A. The 2019 IRPA 2nd Forecast is based on substantially accurate data. More specifically, the 2019 IRPA 2nd Forecast is based on data such as DSM plans and economic forecasts that were either gathered from the best sources available to the Companies or, where the validity of the data is inherently uncertain, the use of which does not substantially contribute to the risk of incorrect forecast conclusions. The 2019 IRPA 2nd Forecast covers 2020 through 2049 and takes into consideration, among other things, annual system losses, company usage, the effect of distributed generation, as well as customers who acquire energy pursuant to NRS § 704.787 and NRS Chapter 704B. The 2019 IRPA 2nd Forecast is documented appropriately, and has been adequately explained and defended. The forecast thus is a reasonable basis upon which to make long-term planning decisions for the IRP planning horizon as well as through 2049.

18. Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATEMENT OF QUALIFICATIONS
OF
TERRY A. BAXTER

Education

Master of Arts	University of Arkansas, Fayetteville, AR, 1979, Economics
Bachelor of Science	University of Missouri-Rolla, Rolla, MO, 1976 Economics

Related Professional Experience

2007 to Present — **Manager of Load Forecasting,** Nevada Power Company d/b/a NV Energy
My primary duties are the forecasting of customers, sales, peak demand, gas therms and gas design day therms, for use in supply planning, rate cases and budgeting. Additional responsibilities include production of forecast variance reports actual to budget, weather adjustment of peaks and sales, and participation in local population forecasting working groups. I have filed testimony and supporting documents and testified on numerous occasions before the Public Utility Commission of Nevada.

2003 to 2007 — **Manager, Forecasting and Economic Analysis,** Alliant Energy
Responsible for the direction and technical work in the areas of statistical sample design and evaluation of load research samples, peak and energy forecasting, for both the gas and electric utilities, and associated regulatory filings, including Integrated Resource Plan filings in Iowa, Illinois, Minnesota and Wisconsin. In this position, I was also responsible for the monthly sales and revenue forecast and explanations of the monthly variance analysis, including actual to budget, year-over-year, and outlook for both operating companies: Wisconsin Power and Light Company and Iowa Power and Light Company. Also responsible for rate case sales and demand forecasts in Wisconsin and Minnesota. Filed direct testimony before the Minnesota Department of Commerce.

2001 to 2003 — **Private Consultant**
Assisted utility companies in sample design and analysis of load research programs.

1998 to 2003 — **Team Leader, Forecasting and Economic Analysis**, Alliant Energy
Responsible for the direction and technical work in the areas of statistical sample design and evaluation of load research samples, peak and energy forecasting, for both the gas and electric utilities, and associated regulatory filings for IES Utilities and Interstate Power Company and its successor company, Iowa Power and Light.

1991 to 1998 — **Group Manager**, Aspen Systems Corporation
Responsible for the technical direction of utility consulting projects in the areas of sample design, DSM performance evaluation, market and survey research.

1985 to 1991 — **Rate Engineer and Manager of Load Research, and Forecasting**, Iowa Power, Inc. /Midwest Energy
Responsible for all facets of the load research program, including sample design, analysis and equipment selection, as well as sales forecasting. Filed testimony before the Iowa Utilities Board.

1980 to 1995 — **Load Research Analyst**, Missouri Public Service Company
Responsible for all facets of the load research program as well as class cost of service and marginal cost studies.

1979 to 1980 — **Economic Analyst**, Illinois Commerce Commission
Responsible for examination of utility rate and regulatory filings.

Other

2007 to present	Steering Committee, EEI Load Forecasting Group
1998 to 2007	Member, AEIC Load Research Committee Marketing sub-committee chairman from 2001-2007.

Specialized Training

Econometric Modeling Using SAS/ETS Software, February, 1991.

SAS Macro Language, August 1990.

Forecasting Techniques using SAS/ETS Software, April, 1990.

Sampling Methods and Statistical Analysis in Power Systems Load Research, April, 1989.

A.E.I.C. Seminar in Advanced Sample Design and Analysis of Load Research Data, July 1987.

Itron Statistically Adjusted End Use (SAE) Training Workshop, November 2008.

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

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF CLARK)

I, TERRY BAXTER, 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.

TERRY BAXTER

Subscribed and sworn to before me
This 24th day of April, 2019.

NOTARY PUBLIC

S. MANNSUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023

ANITA L. HART

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

Second Amendment to
2018 Joint Integrated Resource Plan

Docket No. 19-05_____

PREPARED DIRECT TESTIMONY OF

Anita L. Hart

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 holding Director and Consultant Staff positions in the Demand Side Management ("DSM") organization, I have also worked in 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 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 CURRENT RESPONSIBILITIES AS DIRECTOR, DEMAND SIDE MANAGEMENT.

A. As the Director of DSM, I am responsible for the development, analysis and implementation of a cost-effective portfolio of electric and natural gas DSM, including conservation and energy efficiency programs.

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

A. Yes, I have testified in numerous 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, 18-06003 and 19-04003.

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

A. I support the Companies' request to amend their approved DSM Action Plan by bringing the Companies' FlexPay program ("FlexPay") into the DSM portfolio in program years 2020 and 2021.

6. Q. ARE YOU SPONSORING PORTIONS OF THE FILING?

A. Yes, I am sponsoring the portion of the Narrative addressing the request to amend the DSM Action Plan. I also am sponsoring the following exhibit:

Exhibit Hart-Direct-1 Statement of Qualifications

II. FLEXPAY AS A DSM PROGRAM

7. Q PLEASE DESCRIBE THE SCOPE AND SCALE OF THE PROPOSED FLEXPAY PROGRAM.

A. FlexPay empowers and engages residential customers through a rich stream of personalized electronic information that enables customers to directly and continuously manage their electric energy usage patterns. FlexPay proactively reaches out to customers with its digital messaging features, providing energy usage feedback, actionable energy efficiency and conservation information, and account status. FlexPay was launched as a pilot in November 2017 to a small group of the Companies' employees to complete quality testing and ensure that all of the processes worked as designed before external customers were invited to participate. A customer pilot of the program was rolled out to eligible customers in May 2018.

In May 2019, FlexPay will begin its full scale implementation through the customer operations group. The Company is requesting that the transfer of FlexPay to the DSM portfolio take effect during program years 2020 and 2021.

8. Q. WHY ARE THE COMPANIES SEEKING APPROVAL TO ADD THE FLEXPAY PROGRAM TO THE PORTFOLIO OF DSM PROGRAMS?

A. In addition to its customer service attributes, FlexPay will deliver energy savings that, on average, are projected to achieve an 8 percent reduction in a participant's energy use at Sierra and 10 percent at Nevada Power. Some participating customers will see considerably higher savings. Given this level of projected energy savings, the Companies are seeking to deliver FlexPay in conjunction with the portfolio of DSM programs presented and approved in the Docket No.18-06003. FlexPay will also act as a gateway inviting customer participation in other DSM programs. In this manner, FlexPay will become an integrated element of the Companies' overall DSM portfolio.

The measureable energy savings from the FlexPay program will contribute to the existing DSM portfolio, allowing the Companies to achieve the required percent of forecasted weather normalized sales over the period of 2020 through 2021. Given the uncertainty of future codes and standard changes, such as LED lighting baselines, the Companies continue to look for cost-effective ways to achieve the goals set forth by the Nevada Legislature and the Commission.

9. Q. HAS THE ENERGY SAVINGS ASPECT OF THE FLEXPAY PROGRAM BEEN PREVIOUSLY RECOGNIZED BY THE COMMISSION?

A. Yes. In its Order in Docket No. 15-11003, et al. issued on May 31, 2016, the Commission recognized that FlexPay gives customers additional choices in how to manage their electrical usage. The Commission found that:

> The Flex Pay Program provides an entirely voluntary option that will utilize AMI, the My Account web portal, interactive voice recognition, and the 24/7 operation of contact centers, kiosk networks, and mobile device applications to provide customers who are interested, a real sense of awareness and control over their energy usage and costs.[1]

10. Q. HOW WILL THE FLEXPAY PROGRAM SERVE AS A GATEWAY FOR PARTICIPATION IN OTHER DSM PROGRAMS?

A. FlexPay combines the best features of what has been referred to as “prepay” new technologies to deliver a program that is projected to attract thousands of residential customers by including it within the Companies’ PowerShift products and services.

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[1] Order, May 31, 2016, Docket Nos. 15-11003, 15-11004, 15-112005; ¶125, p. 51.

FlexPay is framed around providing the customer with conservation tools and new payment options, providing participants with greater control over their energy usage and their energy costs.

11. Q. HOW DOES FLEXPAY IMPACT THE DSM BUDGET AND THE COST EFFECTIVENESS OF THE DSM PORTFOLIO?

A. The proposed budget at Nevada Power for FlexPay is $1,000,000 in year 2020 and $1,100,000 in year 2021. The attendant energy savings are 22,491 MWh in year 2020 and 25,704 MWh in year 2021. The projected demand savings are 6.9 MW in year 2020 and 7.9 MW in year 2021. The Total Resource Cost ("TRC") for this program is 1.55 and the non-energy benefits TRC ("NTRC") is 1.78.

At Sierra, the proposed budget for FlexPay is $450,000 in year 2020 and $500,000 in year 2021. The attendant energy savings are 6,229 MWh in year 2020 and 7,059 MWh in year 2021. The projected demand savings are 2.0 MW in year 2020 and 2.3 MW in year 2021. The Total Resource Cost ("TRC") for this program is 1.06 and the NTRC is 1.22.

The proposed 2020 and 2021 budgets, energy and demand savings, total resource cost ("TRC") benefits/costs results, and Multiplier Methodology for the entire portfolio including the FlexPay Program are shown on Tables DSM-2a through DSM-6c of the DSM portion of the narrative.

III. PROPOSED CHANGES TO FLEXPAY TO BRING IT UNDER THE DSM PORTFOLIO

12. Q. FLEXPAY HAS BEEN APPROVED BY THE COMMISSION AS A CUSTOMER SERVICE PROGRAM. ARE YOU SEEKING TO MODIFY ANY ASPECTS OF THE FLEXPAY PROGRAM TO BRING IT UNDER THE DSM PORTFOLIO?

A. Two changes are being requested. First, the Companies are seeking to absorb the $2.50 monthly customer participation fee as a program cost. The second addresses cost recovery beginning January 1, 2020.

13. Q. PLEASE DESCRIBE THE COMPANIES' PROPOSAL TO ABSORB THE $2.50 PARTICIPATION FEE.

A. As currently approved by the Commission, FlexPay participants are assessed a $2.50 monthly "PayGo" license fee that affords participants access into the FlexPay system. The Companies propose that in exchange for the ability to claim the energy and demand savings realized by participants, the PayGo license fee will be absorbed by the Companies as a program cost. In other words, participating customers will not be charged to participate in the FlexPay program. In addition to absorbing the PayGo license fee, DSM will also take over customer recruitment and outreach through PowerShift by NV Energy, and be responsible for utility administration, and third-party measurement and verification ("M&V").

14. Q. PLEASE DESCRIBE THE COMPANIES' PROPOSED CHANGES TO THE COST RECOVERY MECHANISM APPROVED BY THE COMMISSION FOR FLEXPAY.

A. Currently, the fixed costs of FlexPay are being deferred into a regulatory asset. In its final order in Docket Nos. 15-11003 and 15-11004 the Commission ordered the Companies' to measure the benefits of the FlexPay program five years after it is implemented, at which time if benefits do not exceed costs, carrying charges on the deferred balance will not be allowed and only a percentage of net benefits will be recoverable in a general rate case. The Companies propose the approved FlexPay program fixed cost recovery methodology continue. The DSM program costs (license fees, customer recruitment and outrach, utility administration and third-party M&V) for the transferred FlexPay program will not be part of the charges in the regulatory asset set up for FlexPay but will be included in the Energy Efficiency Program Rates pursuant to NAC § 702.95225 "Recovery of costs of implementing programs for energy efficiency and conservation programs" and NAC § 704.9523 "Accounting for and recovery of costs of implementing programs for energy efficiency and conservation."

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

A. Yes

STATEMENT OF QUALIFICATIONS

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

EDUCATION

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

PROFESSIONAL EXPERIENCE

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

Director – 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.

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

Student Intern – Regulation and Market Communication

- Completion of a retail wheeling study.

BOARDS AND HONORS

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

- 2016 Board of Directors, Member

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

- 2015 Leadership Las Vegas, Graduate

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 L Hart

ANITA L. HART

Subscribed and sworn to before me
this 24th day of April, 2019.

S. Mansur

NOTARY PUBLIC

S. MANNSUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023

DARIUSZ REKOWSKI

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

Second Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-05_________

PREPARED DIRECT TESTIMONY OF

Dariusz Rekowski

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

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

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS GENERATION EXECUTIVE.

A. As Generation Executive I am responsible for the oversight of all of the Companies' generating plants. My responsibilities include managing plant engineering and providing project management support, outage planning and management, training, management of the Long-Term Service Agreements ("LTSAs") for gas and steam turbines, and warehouse management.

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

A. Yes. I provided written testimony for the 2017, 2018 and 2019 electric deferred energy proceedings, Docket Nos. 17-03001 and 17-03002, 18-03002 and 18-03003, and 19-03001 and 19-03002.

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

A. My testimony supports the Tracy 3 Life Span Analysis Process ("LSAP") report and the request for integrated resource planning ("IRP") approval of the new Tracy Evaporation Pond Project (the "Project").

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

A. Yes, in addition to my statement of qualifications (**Rekowski Exhibit Direct-1**), I am sponsoring Technical Appendix Items GEN-01, LSAP results for Tracy Unit 3 and Confidential GEN-02, Key Decision Report and Business Case for Tracy 3 Pond Project.

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

A. Yes. GEN-02 includes a key decision-making document entitled Authorization For Expeneditures and Key Decision Report ("KDR"). The KDR lays out the Generation Business Case for the Project. Portions of the KDR, including the Generation Business Case, are confidential.

7. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.

A. The confidential material includes cost estimates for elements of the Project that have not yet been procured. Procurement will involve competitive solicitations. If made available to the public, the Project cost estimates would provide prospective bidders with Sierra’s expections of prices, which would affect the competitieve bidding process to the detriment of customers. Additionally, the business case writeup shows the operating and maintenance costs utilized for economically dispatching the generating fleet. This information is commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information to any market participant would disadvantage the Companies’ customers by limiting the Companies’ ability to foster competition among prospective suppliers, compromising the Companies’ negotiating position and reducing its bargaining leverage. Publication of this information would also unfairly advantage competing suppliers and impair the Companies’ ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of their customers.

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

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

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

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

10. Q. WHAT IS AN LSAP PLAN AND WHY WAS ONE PREPARED FOR TRACY UNIT 3 NOW?

A. Ten years ago, in Docket No. 08-08002, the Commission adopted a formal process for investigating the physical and economic useful lives of the Companies' generating units. Since its adoption, the appropriate planning retirement dates for the Companies' generating units have been determined through the Life Span Analysis Process or LSAP. As approved, an LSAP is required to be prepared if certain triggering criteteria are met. For Tracy Unit 3, the LSAP review was triggered by two conditions. First, Tracy Unit 3, which has a retirement date of 2028, had reached the last decade of its established unit life span. Second, the Nevada Division of Environmental Protection ("NDEP") modified the terms of an environmental permit authorizing Sierra's use of the unlined cooling pond at Tracy as the discharge point for processed water from Tracy Unit 3. Specifically, through its Bureau of Water Pollution Control ("BWPC"), NDEP determined that all discharges from Tracy Unit 3 into the unlined cooling pond were to cease as of December 31, 2020.

11. Q. PLEASE BRIEFLY DESCRIBE THE RESULTS OF THE TRACY 3 LSAP.

A. The LSAP investigated a number of options for addressing NDEP's permit modification, including retiring Tracy Unit 3 on December 31, 2020, adding thermal evaporators, replacing Tracy Unit 3 with peaking units, adding high efficiency water recovery equipment, building a new pond, lining the existing Tracy pond, and modernizing the existing equipment. The LSAP analysis resulted in a determination that the most economic, technically-viable solution was to invest approximately $12.9 million ($13.6 million with AFUDC) in a new pond project so that Tracy Unit 3 could continue to operate to its retirement date of December 31, 2028.

12. Q. WHY IS THE PROJECT NECESSARY?

A. Due to NDEP's modification to Sierra's discharge permit requiring all discharges into the existing pond from Tracy Unit 3 cease by December 31, 2020, Sierra requires an alternative pond for Tracy Unit 3 to remain in service beyond December 31, 2020.

13. Q. PLEASE DESCRIBE THE EVENTS LEADING TO THE DETERMINATION BY NDEP'S BWPC THAT DISCHARGE INTO THE UNLINED COOLING POND FROM TRACY UNIT 3 SHOULD CEASE AS OF DECEMBER 31, 2020.

A. The Tracy Station has an unlined cooling pond that serves as a source of water for the plant operations. The cooling pond water is used as the source water in the Tracy Unit 3 cooling tower, and the cooling tower blowdown water is discharged back to the cooling pond. This discharge to the cooling pond is currently authorized by "groundwater authorization to discharge" permit No. NS0097023 issued by NDEP-BWPC. In conformance with this permit, Sierramust cease all discharges to the cooling pond by December 31, 2020.

In 2015, when Sierra submitted its permit renewal application to the NDEP-BWPC, the NDEP-BWPC deemed that the unlined cooling pond was a jurisdictional waterbody, and then determined that a non-National Pollutant Discharge

Elimination System ("non-NPDES") permit could not continue to be issued for discharges into the cooling pond. However, NDEP would allow another non-NPDES permit to be issued if Sierra agreed to cease discharges into the unlined cooling pond. On April 10, 2015, Sierra sent a letter to NDEP committing to cease discharge into the unlined cooling pond at Tracy at a yet to be determined date in the future.

Based on this commitment by Sierra, a new non-NPDES permit was issued (Permit No. NS0097023), which became effective on July 1, 2016. This permit currently lists the following authorized discharges into the unlined Tracy cooling pond: "groundwater, Truckee River water, cooling tower blowdown water, stormwater, reverse osmosis process wastewater, and other various process wastewaters from the plant."

In accordance with the new non-NPDES permit, a Schedule of Compliance Table required the submittal of a plan for ceasing discharge to the cooling pond to NDEP-BWPC by December 31, 2017, and discharges to the cooling pond to cease by December 31, 2020. On December 20, 2017, Sierra submitted its plan for ceasing discharge to the current cooling pond, which introduced the option to permit, construct and place a new pond into service. That option identified a site for the Project, located southwest of the current cooling water pond, with an in-service date on or before December 31, 2020.

14. Q. WILL THE PROJECT UTILIZE ANY OF THE TRACY WASTE WATER TREATMENT PLANT THAT IS CURRENTLY NOT IN SERVICE AND NOT IN RATE BASE?

A. The engineering team is investigating if any of the Tracy Waste Water Treatment Plant can be economicically repurposed to support the new Project and waste water treatment systems necessary for the ongoing operations. Some of the equipment is similar to what will be needed in the new treatment process, and if it is technically feasible and more economical to repurpose the existing equipment, it will be reused and returned to service. However, the amount of equipment that can be repurposed has not been determined at this time.

15. Q. ARE THERE ANY OTHER GENERATION-RELATED PROJECTS FOR WHICH THE COMPANIES ARE REQUESTING APPROVAL IN THIS FILING?

A. No.

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

A. Yes.

DARIUSZ REKOWSKI
GENERATION EXECUTIVE
NV Energy, Inc
6226 West Sahara Avenue
Las Vegas, NV 89146
(702) 402-5662

Mr. Rekowski joined NV Energy, Inc ("NVE") in February 2006 and is currently Generation Executive for NV Energy. He has over 25 years of experience in power generation with extensive knowledge of design, construction, operations, maintenance, and management of combustion and steam turbine facilities.

PROFESSIONAL EXPERIENCE

01/2013-Present **Generation Executive,** Generation, NV Energy.

- Responsible for providing corporate support to the generating plants. Provided services include engineering and project management support, outage planning and management, training, management of the Long Term Service Agreements for gas and steam turbines, warehouse management, and Generation Business.
- Manage various aspects of NV Energy Generation fleet reliability and availability improvement.
- Responsible for standardization of processes for NV Energy Generation fleet.
- Provide technical assistance and support to the plant O&M managers and regional directors.
- Develop Service Level Agreements with internal suppliers.

01/2009-01/2013 **Director, O&M**, Generation, NV Energy.

- Responsible for various aspects of NV Energy Generation fleet reliability and availability improvement.
- Manage Work Management and Outage Management processes.
- Responsible for standardization of processes for NV Energy Generation fleet.
- Provide technical assistance and support to the plant O&M managers and regional directors.
- Develop Service Level Agreements with internal suppliers.
- Provide oversight to turbine/generator maintenance and overhaul programs.

02/2006-01/2009 **Director, Clark/Sunrise Complex**, Generation, NV Energy.

- Managed operation and maintenance of the Clark/Sunrise power complex.

- Responsible for PSM combustion turbine upgrade and exhaust emission reduction project.
- Provided startup & commissioning support and O&M interface during construction of Clark Peaking plant.
- Represented Generation in latest labor contract negotiation of the Collective Bargaining Agreement with Local 396

10/2000-02/2006 **Plant Manager**, Generation, Dynegy, Riverside/Foothills & Bluegrass Power Plants in Kentucky and Rolling Hills Power Plant in Ohio.

- Managed operation and maintenance of power peaking plants in Kentucky and Ohio region.
- Established O&M staff and provided O&M interface during construction.
- Managed 501FD2 combustion turbine startup reliability improvement project.
- Participated in the periodic and major inspections of gas turbines, generators and auxiliary equipment.

09/1999-10/2000 **Plant Engineer & Maintenance Supervisor**, Generation, Dynegy, Rockingham Power Plant in North Carolina.

- Provided engineering services and managed maintenance crew.
- Provided O&M interface during construction.
- Responsible for planning and coordinating all combustion inspections, hot gas path inspections and major overhauls on a 501FD2 gas turbine.
- Responsible for all engineering activities for power plant startup and commissioning.

05/1996-09/1999 **Plant Engineer**, Generation, Dynegy, Cogen Lyondell Power Plant in Channelview, Texas.

- Responsible for combustion & steam turbine and major equipment upgrades and problem solving.
- Responsible for implementation of capital improvement projects.
- Managed turbine and equipment overhauls and parts repairs.
- Participated in troubleshooting, planning preventive maintenance and compiling statistical reports.
- Provided engineering services for process design modifications including: piping modifications, instrumentation and equipment specification, and control modifications.

04/1992-05/1996 **Senior Mechanical Engineer & Performance Engineer**, Generation, Destec Energy/Dynegy, Corporate Office in Houston, Texas.

- Provided engineering support during construction of the Oyster Creek Combined Cycle Power Plant in Freeport, Texas.
- Provided mechanical engineering services to Destec/Dynegy Generation fleet.
- Performed performance and acceptance testing of the Michigan Power Plant in Ludington, Michigan.

08/1988-04/1992 **Design Drafter**, Interkiln Corporation of America, Houston, Texas.

- Designed structural steel and gasifier components for coal gasification plants in China and Botswana.
- Designed various mechanical, pneumatic and hydraulic systems for commercial ceramic kilns.

09/1987-02/1988 **Motorman**, Polish Steamship Company, Gdansk, Poland.

- Operated and maintained mechanical equipment and engine room machinery on cargo ships as a seaman during ship voyages.

09/1986-06/1987 **Procurement Agent**, Polish Baltic Shipping Company, Kolobrzeg, Poland.

- Responsible for parts and material procurement for Polish Baltic Shipping ferryboats.

EDUCATION **Master of Science Degree in Mechanical Engineering,** Power Systems. Maritime University of Gdynia, Poland, June 1986.

Master of Business Administration, Morehead State University, Morehead, Kentucky, December 2005.

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF CLARK)

I, DARIUSZ REKOWSKI, 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.

DARIUSZ REKOWSKI

Subscribed and sworn to before me
this 24th day of April, 2019.

NOTARY PUBLIC

S. MANNSUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023

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

MATHEW J. JOHNS

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

Second Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-05____

PREPARED DIRECT TESTIMONY OF

Mathew J. Johns

1. Q. PLEASE STATE YOUR NAME, JOB TITLE, EMPLOYER AND BUSINESS ADDRESS.

A. My name is Mathew J. Johns. I am the Director of Environmental Remediation and Resource Development for Nevada Power Company d/b/a NV Energy ("Nevada Power," or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," and together with Nevada Power, the "Companies"). My work address is 6226 West Sahara Avenue, Las Vegas Nevada, 89146. I am filing testimony on behalf of the Companies.

2. Q. WHAT ARE YOUR PRIMARY RESPONSIBILITIES AS DIRECTOR OF ENVIRONMENTAL REMEDIATION AND RESOURCE DEVELOPMENT STRATEGIES FOR THE COMPANIES?

A. I am responsible for managing the Companies' Generation Joint Partnership Contracts, Asset Retirement Obligations ("AROs") and related regulatory assets for the Energy Supply department. These obligations include decommissioning, demolition, and environmental remediation of retiring generating facilities.

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

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

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

A. Yes. I provided written testimony for the 2017 General Rate Case for Nevada Power, Docket No. 17-06003.

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

A. Yes, I am. In addition to my Statement of Qualifications (**Exhibit Johns-Direct-1**), I sponsor the following exhibits:

- Technical Appendix GEN-3, North Valmy Project Framework Agreement Between Sierra Pacific Power Company d/b/a NV Energy and Idaho Power Company, dated as of February 22, 2019.

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

A. My testimony supports the reasonableness of the new North Valmy Project Framework Agreement ("Framework Agreement") between Sierra and Idaho Power Company ("Idaho Power"), and the request for Commission approval in this integrated resource planning docket.

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

A. Yes. IPCo has filed the entire Framework Agreement as confidential at the Idaho Public Utilities Commission.

8. Q. PLEASE DESCRIBE THE NORTH VALMY PROJECT.

A. The North Valmy Project is a 522 MW, coal-fueled, steam-electric generating plant with two operating units. Unit 1 went into service in 1981, producing 254 MW using a Babcock and Wilcox boiler and Westinghouse turbine/generator. Unit 2 went into service in 1985, producing 268 MW using a Foster Wheeler boiler and General Electric turbine/generator.

9. Q. PLEASE GENERALLY DESCRIBE THE OWNERSHIP AND OPERATING AGREEMENT FOR THE FACILITY.

A. The North Valmy Project is jointly owned by Sierra and Idaho Power. Sierra is the operating agent for North Valmy Station. Sierra and Idaho Power each have a 50 percent ownership share in the facility and in each unit's output. Sierra's share of Unit 1 and Unit 2 are 127 MW and 134 MW, respectively.

10. Q. WHAT IS THE PURPOSE OF THE NEW FRAMEWORK AGREEMENT BETWEEN SIERRA AND IDAHO POWER?

A. The Framework Agreement provides a blueprint to be followed in the event either owner elects to cease its participation in one or both units. The "end of operation" scenarios addressed in the Framework Agreement were not contemplated in the original ownership agreement. The Framework Agreement specifically allows either owner to exit participation of one or both units between 2020 and 2025, while allowing the remaining participant to continue to operate its 50 percent share of one or both units. If an owner exits both units, the remaining participant can consolidate operations into one unit at 100 percent of the unit capacity or continue to operate both units at 50 percent of each unit's capacity. Importantly, the Framework Agreement prohibits a remaining participant from choosing to use the exiting participant's share of a unit.

The Framework Agreement also expands upon the original Ownership Agreement, establishing a decommissioning framework and general retirement guidelines for the closure, decommissioning, demolition, remediation, and restoration of the site.

Nevada Power Company
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11. Q. WHY WAS THE FRAMEWORK AGREEMENT NECESSARY?

A. The Framework Agreement was initially necessitated by Idaho Power's 2017 settlement with its regulators and stakeholders, in which it agreed to exit participation in Unit 1 by the end of 2019 and Unit 2 by the end of 2025. The Framework Agreement also provides the mechanism pursuant to which Sierra is able to conditionally exit and retire Unit 1 by the end of 2021 as approved by the Commission in the 2019-2038 Triennial Integrated Resource Plan (Docket No. 18-06003).

12. Q. HOW DOES THE AGREEMENT PROTECT THE INTERESTS OF SIERRA AND ITS CUSTOMERS?

A. The Framework Agreement is founded on the principal that an exiting participant will continue to pay it's share of the fixed costs associated with the unit to be exited through both an annual exit fee reflective of direct-charged unit-specific fixed costs, as well as responsibility for its original 50% obligation of shared or common facility costs The exiting participant no longer participates in unit-specific variable costs, but continues to participate in common variable costs at a revised capacity share. This allows the remaining participant in a unit to maintain the unit capacity and availability without financial harm, while the exiting participant gains surety in the amount of the exit fee for the unit.

The amount of the annual exit fee component was determined based on joint review by the owners of fixed operation and maintenance costs since 2015. This data formed the basis of a derived reasonable annual fee for unit-specific fixed operations and maintenance costs.

The resulting combination of an annual exit fee and continued sharing of common costs results in a balanced and equitable resolution, regardless of whether Sierra is an exiting or a remaining participant.

13. Q. CAN A REMAINING PARTICIPANT OPERATE A UNIT AT FULL CAPACITY AFTER THE EXITING PARTICIPANT HAS EXITED THE UNIT?

A. No. However, the remaining participant may operate the unit above its 50 percent share under certain operational conditions and for very limited timeframes without incurring an inadvertent output operations fee. For example, the participant may operate a unit above its 50 percent share when an environmental permit requires the unit to run at its full capacity for emissions testing, or for unit functional testing, or in certain uncontrollable exclusions (i.e. droop response), without incurring an inadvertent output operations fee. In the event the remaining participant inadvertently operates the unit above its 50 percent share, they will be subject to an inadvertent output operations fee based on the California Independent System Operator Energy Imbalance Market 15-minute North Valmy Locational Marginal

Nevada Power Company
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Pricing. The criteria and formula for determining any exceedance and corresponding inadvertent output operations fee is defined in the Framework Agreement. As noted previously, if an owner exits both units, the remaining participant has the option to consolidate operations into one unit at 100 percent of the unit capacity without incurring an inadvertent output operations fee.

14. Q. PLEASE DESCRIBE THE DECOMMISSIONING AND RETIREMENT GUIDELINES INCLUDED IN THE FRAMEWORK AGREEMENT.

A. The Framework Agreement expands upon the general provisions of the original Ownership Agreement with respect to end of life obligations. The Framework Agreement establishes the decommissioning governance between the parties post-operation, including establishing of a decommissioning committee, planning, budgeting, and funding guidelines. The retirement guidelines in the Framework Agreement provide further definition for the scope of work for plant retirement.

In the event a remaining participant elects to continue to operate one or both units beyond 2025, the Framework Agreement also allows for a one-time payment of decommissioning costs by the exiting party based on a mutually agreed upon detailed decommissioning study and detailed cost estimate to be completed at that time.

15. Q. WHAT ARE THE PROVISIONS IN THE AGREEMENT FOR CONTINUED OPERATION AFTER 2025?

A. It was agreed by both owners that in the event an owner continues to operate one or both units after 2025 and the other owner has exited both units, an exit fee no longer is applicable and the remaining owner will be responsible for 100 percent of continued plant operational costs. The Agreement also includes a provision for the exiting owner to terminate and convey ownership interests to the continuing participant under this scenario. The mutally acceptable form and substance of a termination and conveyance would be contemplated by the owners at that time.

16. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

MATHEW J. JOHNS
DIRECTOR, ENVIROMENTAL REMEDIATION
AND RESOURCE DEVELOPMENT
NV Energy, Inc.
6226 West Sahara Avenue
Las Vegas, NV 89146
(702) 402-5477

Mr. Johns joined NV Energy, Inc. (NV Energy) in August 2015 as Director, Environmental Remediation and Resource Development. He has over 20 years of experience in environmental remediation, project, and program management. Prior to joining NV Energy, Mr. Johns worked as an environmental consultant for industrial companies primarily in the power, manufacturing, mining, oil and gas sectors.

EMPLOYMENT HISTORY

NV Energy, Inc.
8/2015 to Present

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

CH2M HILL
6/2000 to 7/2015

Project and Program Management Assignments:

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

Facilities Operations and Management Assignments:

- Interim Measures and Groundwater Response Action, Power Client, CA (2004-2005). Managed an immediate groundwater response action to establish hydraulic control of chromium-contaminated groundwater near a critical drinking water body in the southwestern United States. Activities included construction of onsite batch treatment and temporary storage facilities, transportation, and offsite disposal.
- Facility Operations and Compliance Groundwater Extraction and Treatment System,

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

Other Project Management and Technical Experience

- Mine site closure and post-closure monitoring, Jamestown, Colorado (2006 to 2015)
- Groundwater Permeable Reactive Barrier design, Escanaba, Michigan (2005).
- Municipal Landfill Closure, Federal facility, Wyoming (2000 to 2004).
- Groundwater remediation and investigations, Federal facility, Wyoming (2000 to 2004).
- Groundwater Permeable Reactive Barrier (PRB) Pilot Study, TX (2002 to 2003).
- Groundwater Treatment Systems, Federal facilities, Florida (2000 to 2005).

ERM-SOUTHWEST
6/1996 – 6/2000

Project Engineering Assignments

- Coal Ash Landfill Closure Design, San Antonio, Texas
- Calcium Carbide Waste Disposal Site Closure, Sault Ste. Marie, Michigan.
- Groundwater Slurry Wall Design, Houston, Texas
- Groundwater Recovery Trench Design, Houston, Texas
- Solid and Hazardous Waste Remediation Management Unit Closures, Seadrift, Texas
- Hazardous and Non-Hazardous Landfill Closures and Design, Texas City, Texas
- Corrective Action Management Unit Application and Design Basis, Texas City, Texas.

EDUCATION

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

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

PROFESSIONAL REGISTRATIONS

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

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF CLARK)

I, MATHEW JOHNS, 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.

MATHEW JOHNS

Subscribed and sworn to before me
This 24th day of April, 2019.

NOTARY PUBLIC

S. MANNSUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023

SACHIN VERMA

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

Second Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-05_____

Prepared Direct Testimony of

PREPARED DIRECT TESTIMONY OF

Sachin Verma

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

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

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

A. I am responsible for all transmission planning associated with Integrated Resource Planning ("IRP"), compliance, generator interconnections and transmission load addition functions for the Companies.

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

A. I have a Bachelor of Science Degree in Electrical Engineering and a Master of Business Administration Degree with a focus in Finance, both from the University of Nevada, Reno. I am a registered Professional Engineer in the State of Nevada. I began my employment with the Companies as a student engineer in 2007. I have experience in transmission planning, distribution service, electric metering and system protection. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Verma Direct-1**.

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

A Yes, I have testified in several IRPs and IRP amendments, including most recently in Docket Nos. 17-11003 17-11004, 18-06003 and 19-04003.

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

A. I sponsor the section of the supply-side narrative discussing the Companies' transmission systems and requests for Action Plan approval of several modifications to projects previously approved by the Commission, as well as requests for Action Plan approval of several new projects. The narrative and my testimony are supported as well with Technical Appendices TRAN 1 through TRAN-11, for which I am also the sponsor.

6. Q. PLEASE DESCRIBE TECHNICAL APPENDICES TRAN-1 THROUGH TRAN 11.

A. Technical Appendix TRAN-1 is an updated analysis of the northern system import limit. This analysis was performed due to several changes in system facility ratings, changes in reliability criteria and the recent discrepancy that was identified on the OASIS regarding Available Import Capacity. The results of this analysis confirm the existing northern Nevada import limit of 1,275 MW.

Technical Appendix TRAN-2 is an updated export analysis for the northern system as well that was performed in parallel with the import analysis set forth in TRAN-1. Historically, the export limit has been resource limited, rather than reliability limited. Several new resources have been added to the system that allow for increased export limit.

Technical Appendix TRAN-3 is an update to the Tracy Area Master Plan. Originally submitted to the Commission in Docket No. 17-11004, the Tracy Area Master Plan was updated to keep pace with the dynamic nature of the load growth occurring in the Tracy Area, reflect changes in the phases of the plan as it was originally conceived, and to update other inputs including the local area load forecasts. The updated plan is being provided for information only.

Technical Appendix TRAN-4 supports the Companies' request to cancel the previously approved East Tracy 345/120 kV project and to move the 345/120 kV transformer and related facilities that had been planned for East Tracy to the West Tracy Substation. Technical Appendix TRAN-4 sets forth the justification for this decision, and is consistent with the updated Tracy Area Master Plan.

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Technical Appendices TRAN 5 through 7 provide supporting documentation for new project requests for approval; a new Reid Gardner to Tortoise 230 kV line to increase reliability to Overton and Lincoln, a new Shaffer 345 kV substation to accommodate the interconnection of Lassen Municipal Utility District, and a new 230/69 kV transformer at Bighorn substation and associated 69 kV line to the Oasis 69 kV substation. This project increases the reliability at three distribution substations and a waste heat generator.

Technical Appendices TRAN 8 through 11 include the Large Generator Interconnection Agreements, Facilities Studies, and System Impact Studies that support the Companies' requests for approval of the network upgrades associated with six renewable generator interconnections.

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

A. Yes. Portions of Appendices TRAN-1, TRAN-2, TRAN-3 and TRAN 4 are confidential, as they set forth customer-specific load information provided to the Companies by customers with the understanding that it would remain confidential. TRAN-2 and the Appendix to TRAN-1 also includes Critical Energy Infrastructure Information that may not be publicly disclosed.

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

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

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

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

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

10. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I sponsor the following exhibit:

Exhibit Verma Direct-1 Statement of Qualifications

11. Q. PLEASE PROVIDE A SUMMARY OF THE NORTHERN NEVADA IMPORT LIMIT REASSESSMENT AND EXPLAIN THE NEED FOR THE REASSESSMENT?

A. The northern Nevada import limit assessment was performed due to the recent influx of proposed transmission only customers, the lack of transmission capacity, reduced facility ratings and changes to associated reliability standards. The last time the northern Nevada import limit was analyzed was prior to the energization of the ON Line project, on January 1, 2014. ON Line was the last major system addition that affected the northern import limit.

In summary, the analysis identified several scenarios and conditions that affect Sierra's ability to import energy into its system. The scenarios and conditions include updated system facility ratings, historical system imports, historical reliability issues, system maintenance, generation dispatch, variable flow conditions and Transmission Reliability Margin. The analysis identifies a theoretical maximum of 1,360 MW of import capacity. However, to achieve this level of import requires perfectly tuned phase shifter settings, generation dispatch and the completion of several system upgrades, as well as new proposed transmission projects. While one scenario of this theoretical maximum import limit was achieved, several scenarios identified reliability issues with a level of import capacity lower than the existing 1,275 MW limit. This updated analysis is attached as Technical Appendix TRAN-1 and identifies a balance between a theoretical maximum and real time operations. The conclusion of the analysis maintains the 1,275 MW import limit. Any system upgrades that are required to maintain this limit will be operated around until the required facilities are completed.

12. Q. HAVE THE COMPANIES TAKEN ANY ACTION TO ENSURE THAT CUSTOMERS ARE USING EXISTING TRANSMISSION CAPACITY APPROPRIATELY?

A. Yes. The Companies are reviewing existing transmission customers' reservations and associated forecasts and have identified several transmission customers that are holding reservations for transmission capacity that far exceed both their actual and forecasted usages.

Historically, applicants for the Companies have permitted Network Integration Transmission Service ("NITS") customers to identify their peak 10-year load forecast as their respective transmission capacity requirement. This conservative estimate of prospective load is then submitted via NITS-on-OASIS (Open Access Same Time Information System) as a reservation for transmission. If the NITS customer has sufficient designated Network Resources to serve its corresponding Network Load, the NITS-on-OASIS system does not limit the capacity quantity a customer may reserve. Additionally, because NITS is charged on a load ratio share of *actual* loads at coincident peak, a NITS customer does not incur a financial penalty for reserving an amount that exceeds the customer's forecasted Network Loads. The Company has identified certain instances where NITS customers have reserved intertie capacity in excess of their own forecasts.

While this practice did not pose problems when ample transmission capacity was available, it is not acceptable under current conditions. The Companies are required to administer the Open Access Transmission Tariff ("OATT") to provide non-discriminatory transmission access, and thus cannot allow NITS customers to take actions that have the effect of withholding limited transmission capacity. The Companies performed the transmission capacity review to ensure compliance with the OATT and fairness to all transmission customers seeking to appropriately utilize Available Transmission Capacity ("ATC").

13. Q. BASED ON THE RESULTS OF THE TRANSMISSION CAPACITY REVIEW, IS TRANSMISSION CAPACITY AVAILABLE ON THE NORTHERN NEVADA SYSTEM?

A. Some new ATC has been identified through the efforts described in Q&A 12. This new capacity must be made available to the next transmission customer in queue. That customer has submitted a request for transmission service that exceeds the amount of ATC that identified from the process

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

described above. Therefore, after the Companies allocate the reclaimed transmission capacity to this customer, there will be no further transmission import capacity available into northern Nevada.

14. Q. DO THE TRANSMISSION OBLIGATIONS SECTION IN THIS IRP FILING REFLECT THE UPDATED TRANSMISSION RESERVATIONS THAT WERE IDENTIFIED AS A RESULT OF THE EFFORTS DESCRIBED IN Q&A 11 AND 12?

A. No, the Companies' are currently working with existing customers to update their transmission reservations. The changes have not been finalized and thus have not been updated in this filing.

15. Q. PLEASE PROVIDE A SUMMARY OF THE NORTHERN NEVADA EXPORT LIMIT REASSESSMENT AND EXPLAIN THE NEED FOR THE REASSESSMENT.

A. The northern Nevada export limit also had last been assessed prior to the energization of ON Line. The Companies set the export limit at 750 MW based on the availability of resources in northern Nevada, not on reliability issues. However, since 2014, several new resources have been constructed in northern Nevada – mainly renewable resources. The new export assessment takes into account the availability of these new resources.

As a result of the new export assessment, a new export limit for the northern Nevada system has been established at 1,125 MW. The limiting factor on the export limit is reliability constraints at the California Substation. These reliability issues will be resolved when the Bordertown-to-California Substation project goes into service in late 2021. Once the Bordertown to

California project is complete, the export limit on the northern Nevada system will increase to 1,330 MW. The updated export analysis is provided in Technical Appendix TRAN-2.

16. Q. WHAT ELEMENTS OF THE TRACY AREA MASTER PLAN HAVE CHANGED SINCE ITS INITIAL SUBMISSION TO THE COMMISSION IN 2017?

A. The updated Tracy Area Master Plan closely follows the initial submission, with the only major change being the move of the previously approved East Tracy 345/ 120 kV transformer to the new West Tracy Substation project. Additionally, the original plan anticipated two 345 kV lines; one from East Tracy and the second from West Tracy, routed around the west side of the Tahoe Regional Industrial Center ("TRI-Center") and terminating into the proposed Comstock Meadows Substation. The updated plan routes the East Tracy 345 kV line around the east side of TRI-Center to accommodate a future fold into Chukar Substation and another 345/120 kV transformer. The timing for this connection will be based off load growth and cannot be predicted at this time. If and when the additional 345 kV injection is required, the 345 kV source will be in place to connect into Chukar Substation.

The updated plan also looked at the potential for load growth above what has been proposed in the area. This is considered a sensitivity analysis and is subject to change based on the location of future loads and resources. In general, the updated plan confirms the near term need to construct the transmission facilities identified in the Transmission Narrative, and proposes future plans for long term load growth solutions. The updated Tracy Area Master Plan is provided as Technical Appendix TRAN-3

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17. Q. HAVE THE COMPANIES FOLLOWED THE ORIGINAL TRACY AREA MASTER PLAN IN PLANNING FOR AND CONSTRUCTING DISTRIBUTION AND TRANSMISSION FACILITIES IN THE TRI CENTER AREA?

A. Yes, the original master plan anticipated the need to construct an initial 120 kV loop to reliability source the major loads in the Tracy area. This 120 kV loop was planned to run from Dove Substation to Chukar to Comstock Meadows to Wild Horse and back to Dove. The Dove to Chukar and Dove to Wild Horse lines have been constructed and the completion of the loop through Comstock Meadows is expected to be completed by the first quarter of 2020. This initial 120 kV loop is adequate to reliably support area load until it reaches approximately 300 MW. Once this threshold is reached, a 345 kV injection is required at Comstock Meadows to reliably support the load growth.

18. Q. DOES THE TRACY AREA MASTER PLAN MAKE ANY ASSUMPTIONS ON MAJOR TRANSMISSION UPGRADES FOR LONG TERM LOAD GROWTH?

A. The near term facilities identified in the Tracy Area Master Plan are based on existing transmission system resources and capabilities. As discussed in the Sierra Load Growth and Timing section of transmission narrative filed in Docket No. 18-06003, at a certain point existing transmission and resources cannot accommodate the unprecedented load growth occurring in northern Nevada and new facilities will need to be developed.

Once the load growth in the Tracy area exceeds approximately 600 MW (an additional 300 MW over the load growth described in Q&A 15), the plan assumes that an additional high voltage north-south interconnection is constructed to increase the import limit into the northern system. Note that the Companies are requesting approval of permitting dollars for this conceptual intertie in this IRPA, which is described in Q&A 21 below.

Additionally, increases in transmission results in unreliable voltage levels within northern Nevada. The long-term analysis in the Tracy Area Master Plan assumes a form of dynamic voltage support in the form of a Static VAR Compensator in the Tracy area. This support could be replaced by generation resources as well. Regardless of the source of voltage support, if only a major transmission facility is constructed, increased voltage support will be required for reliable system operation.

As discussed in the narrative and below, the Companies are requesting approval in this IRP Amendment to begin permitting and route analysis for the future Westside Tie.

19. Q. PLEASE EXPLAIN WHY THE PREVIOUSLY APPROVED EAST TRACY TRANSFORMER PROJECT HAS BEEN MODIFIED TO BE INSTALLED AT WEST TRACY SUBSTATION.

A. After approval for the East Tracy Transformer Project, TRI-Center load growth continued, but in a slightly different location within the Reno Technology Park. Sierra continued to analyze the system and identified the West Tracy substation to be the most strategic location for the next 345/120 kV transformer. This modification allows for the cancellation of certain projects that were associated with the East Tracy 345/120 kV transformer and allows for the reconfiguration of the existing Tracy 120 kV substation.

The Tracy 120 kV substation is in poor physical shape and is improperly configured when compared to the Sierra's current standards. In connection with the West Tracy Transformer Plan, 120 kV lines connected to Tracy substation will be reconnected to reliable breaker and half substations, such as East Tracy, Pah Rah and West Tracy substations. The new plan is described and justified in Technical Appendix TRAN-4.

20. Q. PLEASE EXPLAIN THE SUBSTANTIAL COST INCREASE TO THE BORDERTOWN TO CALIFORNIA SUBSTATION PROJECT AND EXPLAIN WHY THIS PROJECT IS STILL NEEDED FOR RELIABILITY PURPOSES.

A. In this filing, Sierra is requesting approval for increased costs for the Bordertown to California project. The estimated budget has increased from $31.37 million to $44.69 million or by $13.32 million in increased costs.

The cost increase is primarily due to the costs of complying with environmental mitigation measures identified in the U.S. Forest Service's Final Environmental Impact Statement and Record of Decision. These include mitigation for mule deer habitat, securing Native American monitors to oversee potential archeologic sites during construction, and specialized helicopter construction techniques to minimize environmental impacts. Part of the cost increase is due to accommodations for private land owners who have conditioned acceptance of the project on the use of single pole construction for the northern 3.3 miles of the line that pass through two master-planned communities. Finally, the Companies have updated all commodity and service costs to reflect current scope and pricing.

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Even at the higher cost, the project remains the least cost solution for addressing compliance requirements to ensure system reliability. Although load has not grown as originally anticipated, several large housing developments in northern Reno are anticipated. The existing distribution substations in north Reno are limited by the 120 kV transmission that sources them. The construction of the Bordertown to California project accommodates an additional 20 to 40 MW of load growth, and a future planned Bordertown to Red Rock 120 kV line is expected to accommodate an additional 60 to 80 MW.

Given forecasted local area load growth and existing reliability needs, the Bordertown to California project should be the next major transmission addition to support north Reno.

21. Q. PLEASE SUMMARIZE THE MAJOR TRANSMISSION ADDITION PROJECT AND EXPLAIN THE COMPANY'S APPROACH.

A. The Companies are requesting approval to begin permitting three transmission lines that would connect central Nevada to the Reno and Tracy load pockets, as well approval to perform routing and constraint studies for two major transmission interconnections that will increase import capacity into northern Nevada. The two major transmission additions are either a Harry Allen to Northwest to Ft. Churchill 500 kV line, or a Robinson to Ft. Churchill 345 kV line. The former creates a second connection from southern to northern Nevada, while the latter strengthens the existing ON Line intertie. Neither major transmission addition provides significant ATC value without the central Nevada to Reno and Tracy area connections. These lines allow a pathway for the increased import capacity to the major system load pockets.

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At this time, the Companies plan to evaluate both major transmission addition projects through routing and constraint studies and identify which is best for the system based on feasibility and benefit.

22. Q. ARE THE COMPANIES REQUESTING APPROVAL TO CONSTRUCT THE PROJECTS DESCRIBED IN THE MAJOR TRANSMISSION ADDITION SECTION?

A. Not at this time. The Companies are only requesting approval to begin the initial permitting activities in the event these projects are pursued. Since a major transmission project can take seven to 10 years to permit and construct, the request in this filing is to start the process to ensure the Companies are in a position to take the next steps as required.

23. Q. WHY IS A REDUNDANT SOURCE REQUIRED TO OVERTON POWER DISTRICT ("OVERTON") AND LINCOLN COUNTY POWER DISTRICT ("LINCOLN")?

A. Currently Overton and Lincoln are served from Overton's Turquoise Substation, which is radially sourced with a 230 kV line from the Nevada Power's Reid Gardner Substation. The load at the end of the radial line is approximately 100 MW, and is susceptible to outages any time the radial line is out. Lincoln has backup capacity of approximately 20 MW through Nevada Power's 69 kV system but Overton has no backup. Outside unexpected line outages, maintenance of the existing line and 230 kV connections is nearly impossible due to the single source. The proposed redundant 230 kV line will allow for maintenance as well as unplanned outages to occur without disruption of service to Overton and Lincoln.

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24. Q. WHY ARE THE COMPANIES PURSUING AN INCREMENTAL TRANSMISSION RATE FOR THE SHAFFER SUBSTATION PROJECT?

A. The new Shaffer Substation is required to accommodate the interconnection of Lassen Municipal Utility District ("LMUD") to the Sierra's system as a NITS customer. The Ft. Sage to Hilltop 345 kV line is folded into Shaffer Substation, which is connected to LMUD's proposed Skedaddle Substation. The investment required to construct Shaffer Substation far exceeds the revenue LMUD will provide under a standard rolled-in system rate. Under the transmission pricing policies of the Federal Energy Regulatory Commission, a customer can be charged the higher of a rate based on the incremental costs of the facilities needed to enable their service, or a rolled-in system rate. Sierra decided to pursue the option of developing an incremental transmission service rate for LMUD. In addition, this option will not increase the transmission revenue requirements for bundled retail and other third-party OATT customers.

25. Q. HAVE THE COMPANIES ALLOCATED TRANSMISSION CAPACITY TO LMUD AS A NITS CUSTOMER?

A. When the Company initially studied LMUD, it was analyzed as a pass-through or transfer through the Sierra system. The Transmission Planning group later realized that the LMUD load should be considered as an import rather than pass-through. The LMUD load is not expected to be in service until late 2022. The Company is holding a portion of the reclaimed capacity discussed in Q&A 12 for LMUD's use starting in 2022.

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26. Q. PLEASE SUMMARIZE THE NEED FOR THE BIGHORN 230/69 KV RELIABILITY PROJECT.

A. Approximately 30 miles of the 69 kV line from Arden Substation serves just under 20 MW of load at the Oasis and Jean substations. Any outage on this radial line results in loss of this load with no back up capability. The Bighorn 230 kV Substation is 4.5 miles southwest of Oasis Substation. The Companies are requesting approval to install a 230/69 kV transformer at Bighorn Substation and a 69 kV line from this secondary transformer to Oasis Substation. This project increases reliability by providing a second source to the radial 69 kV system. The load at Jean Substation will be still be at risk for a loss of the Arden source, but the load at Oasis Substation will be uninterrupted. With the second source in place, isolation of a transmission line problem and switching will be possible to return loads to service quickly.

27. Q. WHY ARE THE COMPANIES PROPOSING A NEW SUBSTATION IN WEST HENDERSON?

A. Significant developable land exists in West Henderson and Nevada Power has received several requests for new distribution loads throughout the area. Currently, only Keehn and Bicentennial substations are available for accommodating distribution load growth in this area. Although capacity exists within these substations, distribution developers have been turned away due to high cost of distribution line extensions. The proposed SE2 Substation in West Henderson is planned to be located approximately halfway between the two existing distribution substations. The new substation will allow for feasible line extensions and promote growth in the area.

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At this time, the Company is looking into either 230 kV or 138 kV sourcing out of Magnolia Substation. Once the routing and constraint studies are complete, the optimal option will be pursued.

28. Q. REGARDING THE PROPOSED CARSON LAKES SUBSTATION, WHY WAS A SUBSTATION NOT ORIGINALLY BUILT WHEN THE SALT WELLS GENERATOR WAS INTERCONNECTED?

A. When the Salt Wells generator was initially interconnected to the transmission system, it was done via a 230 kV tap. Since that time, the Companies have modified their standards to not allow for that type of configuration for generator interconnections as they result in a three-terminal tap, each being a resource. Protection equipment cannot always locate a system fault under this configuration and it also does not allow for isolation of transmission facilities.

When Company HJ later applied to interconnect to the 230 kV system it was necessary to modify the existing tap to bring it within the current standard. Both the Salt Wells generator and the new generator will be interconnected to a breaker-and-a-half configured substation that meets the Company's current standards.

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

A. Yes it does.

STATEMENT OF QUALIFICATIONS
SACHIN VERMA

My name is Sachin Verma. My business address is 6100 Neil Road, Reno, Nevada. I have been employed with Sierra Pacific Power Company ("Sierra" or "the Company") since 2007. I am currently the Director of Transmission System Planning for NV Energy.

I have been in a transmission planning management role since June of 2015 and have worked as a transmission planning engineer for a cumulative three years. As a transmission planning engineer I have performed studies for significant load and generation additions as well as assisted in the compilation of NERC Compliance studies focused on the reliability of the Company's transmission grid and its ability to serve it's customers.

Also, I have worked in Electric Meter Operations as both a supervisor and an engineer. In this position, I inspected installation of renewable generation, reviewed and approved electrical panels for new service and designed metering installation for high voltage generation projects. As a distribution engineer I worked with commercial and residential customers to analyze power quality concerns, performed distribution design for equipment replacement and additions and coordinated fuse protection on the system.

I am a Registered Professional Engineer in Nevada -- License #021884. I graduated from the University of Nevada, Reno in 2008 with a Bachelor of Science Degree in Electrical Engineering focused in power systems and in 2014 with a Master of Business Administration focused in finance.

By virtue of my employment, background, experience and education, I am a qualified witness in regard to the NV Energy's system and all transmission planning issues associated with the Companies' PUCN and FERC filings.

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF WASHOE)

I, SACHIN VERMA, 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.

SACHIN VERMA

Subscribed and sworn to before me
this 25 day of April, 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