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by: /s LoriPetersen

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This filing has been electronically filed and deemed to be signed by an authorized
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NPC SPPC
February 28, 2020

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

RE: Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint Natural Disaster Protection Plan.

Dear Ms. Osborne:

Enclosed for filing with the Public Utilities Commission of Nevada (“Commission”) please find the Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint Natural Disaster Protection Plan. Also enclosed is a draft notice of the Petition pursuant to NAC § 703.162.

Should you have any questions regarding this filing, please contact me at (775) 834-3551 or jcaviglia@nvenergy.com.

Respectfully submitted,

/s/ Justina Caviglia
Justina Caviglia
Senior Attorney
EXHIBIT A
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 for Approval of their Joint Natural Disaster Protection Plan. Docket No. 20-02___ /

APPLICATION

Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and together with Nevada Power, the "Companies" or "NV Energy,") make this Application, pursuant to Nevada Revised Statute ("NRS") § 704.7893 for approval by the Public Utilities Commission of Nevada ("Commission") of the First Natural Disaster Protection Plan ("NDPP" or "Plan"). Regulations recently approved by the Commission in Docket No. 19-06009, and approved by the Legislative Commission on February 26, 2020, require that NV Energy file its first NDPP on or before March 1, 2020. Through this application, NV Energy seeks the Commission’s approval and acceptance of its Plan, for the effective period of 2021-2023. Section 8.2 of the regulations requires that the Commission issue an order accepting or modifying the NDPP, or specifying any portions of the plan it deems to be inadequate, within 180 days after its filing. The statutory period within which this matter must be resolved therefore runs on Wednesday, August 26, 2020.

I.

SUMMARY AND INTRODUCTION

SB329 requires NV Energy to file an NDPP that contains information, procedures and protocols relating to the efforts of the electric utility to prevent or respond to a fire or other natural disaster. The regulations define a natural disaster as “any natural catastrophe, including, without limitation, wind, wildfire, storm, high water, earthquake avalanche, landslide, mudslide or heat wave.” This filing represents the culmination of NV Energy’s

1
efforts to timely comply with the requirements and schedule set forth in SB329 and the regulation. The comprehensive analyses used to prepare this NDPP were developed through significant collaboration with stakeholders, and by reviewing and monitoring California utilities’ wildfire mitigation plans. NV Energy has embraced the NDPP concept, and has prepared a comprehensive and complete plan, which focuses on reducing Nevada’s vulnerability to natural disasters.

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 served electronically upon the following address: regulatory@nvenergy.com. Hardcopy documents should be transmitted to NV Energy’s counsel as set forth below:

Justina Caviglia
Senior Attorney
6100 Neil Road
Reno, NV 89511
Telephone: 775.834.3551
Facsimile: 775.834.4098
jcaviglia@nvenergy.com

Manager, Regulatory Services
6100 Neil Road
Reno, NV 89511
Telephone: 775.834.5823
regulatory@nvenergy.com
III.

APPLICATION EXHIBITS

To aid the Commission in considering this first NDPP, NV Energy has included with this Application and incorporated herein by reference the following Application Exhibits:

- Application Exhibit A is a proposed notice of the Application as required by NAC § 703.162.
- Application Exhibit B is a copy of the “As Enrolled” version of Senate Bill 329 (2019 Legislature).
- Application Exhibit C is a copy of the regulations approved by the Commission in an order in Docket No. 19-06009 dated January 30, 2020, submitted to the Legislative Counsel Bureau and the Office of the Secretary of State on February 5, 2020, and approved by the Legislative Commission on February 26, 2020 (the “Regulations”).
- Application Exhibit D is a complete narrative version of the Natural Disaster Protection Plan.

IV.

SUPPORTING MATERIAL

All material required to adequately demonstrate and defend the substantially accurate data supporting the analysis and the requests for affirmative relief is set forth herein. A summary of this information, which references the NDPP Narrative, technical appendices, and prepared direct testimony making up this filing, is set forth by general topic below. The NDPP Narrative has been presented in ten sections, following the basic outline of the natural disaster protection plan process set out in the Regulations. Mr. Kevin Geraghty, Senior Vice President, Operations, sponsors the Natural Disaster Protection Plan.

Section 1 – Executive Summary. This section provides an overview of the contents in the NDPP Narrative.

Section 2 – Objectives of the plan. This section of the narrative describes the objectives NV Energy followed in developing the NDPP, how the NDPP meets the
requirements of SB329, the stakeholder process used to prepare the NDPP, and definitions and acronyms used in the filing.

Section 3 - Natural Disaster Risk Analysis and Drivers. This section of the narrative describes the risk assessment of natural disaster threats relative to NV Energy’s electric service territory and electrical assets. Based upon the risk assessment the following natural disasters are profiled and discussed in the plan:

- Wildfires and grassland fires;
- Flooding and monsoons;
- High wind gusts, thunderstorm winds, and microbursts;
- Winter storms and blizzards;
- Earthquakes; and
- Landslides and avalanches.

Section 4 - Natural Disaster Protection Strategies and Programs. This section of the narrative describes the strategies and programs to reduce the risk to NV Energy’s assets during a natural disaster. Based upon the requirements of SB329 and the regulations, this section discusses the following strategies and programs in detail:

- Operation practices;
- Inspections and corrections;
- System hardening;
- Vegetation management;
- Emerging technologies & strategies; and
- Situational awareness.

Section 5 – Proactive De-Energization (Public Safety Outage Management). This section discusses the development of the Public Safety Outage Management program for proactive de-energization as a measure of last resort to protect the public.

Section 6- Emergency Response and Restoration. This section describes NV Energy’s emergency response and restoration plan.

Section 7 – Community Outreach. This section of the narrative describes the expert working group workshops and public meetings held during the development of the plan.

Section 8 – Metrics, Performance, Monitoring and Plan Accountability. This Section describes NV Energy’s use of metrics, auditing and monitoring of the plan.
Section 9- Reporting and Filing Timelines. This section of the narrative describes NV Energy’s plan to meet SB329’s annual filing and updates.

Section 10- Plan Implementation Cost Implications. This section shows the cost of implementing all suggested programs and projects.

Appendix A – Natural Disaster Threat Maps. Appendix A provides maps identifying the current conclusions of NV Energy’s threat assessments for all natural disasters the state of Nevada.

Appendix B - Proactive De-Energization Zone Maps. Appendix B provides maps of the areas which are subject to Public Safety Outage Management de-energization.

Appendix C - PSOM Notification Form. Appendix C is the Public Safety Outage Management form, to be used by NV Energy to inform customers of a potential de-energization event.

Appendix D - Mt. Charleston, South Lake Tahoe and Incline Village/North Lake Tahoe Project/Program Implications. Appendix D is a breakdown of projects by areas

V.

CONFIDENTIALITY

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

VI.

REQUESTS FOR RELIEF

NV Energy respectfully requests that pursuant to the regulations adopted in Docket No. 19-06009, LCB File No. R085-19, the Commission issue an order accepting the Plan within 180 days and containing the following findings:

1. Accepting the Plan as it is set forth in Exhibit D to this Application;

2. Finding that this filing fully satisfies the reporting requirements of NRS § 704.7983 and Docket No. 19-06009, LCB File No. R085-19;
3. Granting 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

4. Granting such additional other relief as the Commission may deem appropriate and necessary.

Dated and respectfully submitted this 28th day of February, 2020.

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

/s/Justina Caviglia
Justina Caviglia
Senior Attorney
6100 Neil Road
P.O. Box 10100
Reno, Nevada 89520
775-834-3551
jcaviglia@nvenergy.com

/s/Michael Greene
Michael Greene
Deputy General Counsel
Nevada Power Company
6100 Neil Road
Reno, NV 89511
775-834-5692
mgreene@nvenergy.com
EXHIBIT B
"As Enrolled" SENATE BILL 329
Senate Bill No. 329--Senator Brooks

CHAPTER..........

AN ACT relating to the prevention of natural disasters; requiring an electric utility to submit a natural disaster protection plan to the Public Utilities Commission of Nevada; setting forth the requirements for such a plan; authorizing an electric utility to recover costs relating to the development and implementation of a natural disaster protection plan; prohibiting, with certain exceptions, a person who is not a qualified electrical worker from performing certain work on the electric infrastructure of an electric utility; and providing other matters properly relating thereto.

Legislative Counsel's Digest:

Existing law provides for the regulation of electric utilities by the Public Utilities Commission of Nevada. (Chapter 704 of NRS) Section 1.3 of this bill requires an electric utility to, on or before June 1 of every third year, submit a natural disaster protection plan to the Commission. Section 1.3 generally requires a natural disaster protection plan to contain certain information, procedures and protocols relating to the efforts of the electric utility to prevent or respond to a fire or other natural disaster.

Existing law generally requires a public utility to submit an application and obtain the approval of the Public Utilities Commission of Nevada for a change in any schedule of rates or services. (NRS 704.110) Section 1.3 provides that any expenditures made by an electric utility in developing and implementing a natural disaster protection plan are required to be recovered as a separate monthly rate charged to all customers of the electric utility.

Section 1.7 of this bill prohibits a person from performing work on the electric infrastructure of an electric utility unless that person is a qualified electrical worker or an apprentice electrical lineman under the direct supervision of a qualified electrical worker. Section 1.7 authorizes the Commission to authorize persons who are not qualified electrical workers to perform certain tree trimming relating to line clearance under the direction of a certified arborist.

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

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

Section 1. Chapter 704 of NRS is hereby amended by adding thereto the provisions set forth as sections 1.3 and 1.7 of this act.

Sec. 1.3. 1. An electric utility shall, on or before June 1, 2020, and on or before June 1 of every third year thereafter, in the manner specified by the Commission, submit a natural disaster protection plan to the Commission.

2. A natural disaster protection plan submitted to the Commission pursuant to subsection 1 must:

80th Session (2019)
(a) Identify areas within the service territory of the electric utility that are subject to a heightened threat of a fire or other natural disaster.

(b) Propose an approach for the mitigation of potential fires or other natural disasters that is cost effective, prudent and reasonable.

(c) Describe the preventive measures and programs the electric utility will implement to minimize the risk of its electric infrastructure causing a fire.

(d) Describe the participation of the electric utility, including, without limitation, any commitments made, in any community wildfire protection plans, as defined in 16 U.S.C. § 6511, established in this State.

(e) Propose protocols for de-energizing distribution lines and disabling reclosers on those lines in the event of a fire or other natural disaster. Such protocols must consider the associated impact of such actions on public safety and mitigate any adverse impact on public safety plans, including, without limitation, impact on critical first responders and on health and communication infrastructure.

(f) Describe the procedures the electric utility intends to use to inspect the electric infrastructure of the electric utility.

(g) Describe the procedures the electric utility intends to use for vegetation management.

(h) Describe the procedures the electric utility intends to use to restore its distribution system in the event of a natural disaster.

(i) Demonstrate that the natural disaster protection plan is consistent with the emergency response plan submitted by the electric utility pursuant to NRS 239C.270.

(j) Describe the ability of the electric utility to implement the natural disaster protection plan and identify additional funding needed for the implementation of the plan.

3. The procedures, protocols and measures set forth in a natural disaster protection plan submitted pursuant to subsection 1 must comply with all applicable requirements of the most recent version of the International Wildland-Urban Interface Code, published by the International Code Council or its successor organization, including, without limitation, the requirements relating to clearances set forth in Appendix A of the Code. Nothing in this subsection shall be construed to prohibit an electric utility from setting forth in a natural disaster response plan procedures, protocols and measures that are more restrictive than those set forth in the Code.
4. The Commission shall adopt regulations to provide for the method and schedule for preparing, submitting, reviewing and approving a plan submitted pursuant to subsection 1.

5. An electric utility whose natural disaster protection plan has been approved by the Commission in accordance with the regulations adopted by the Commission pursuant to subsection 4 shall provide a copy of the approved plan to the chief officer of each fire department and each state, city and county emergency manager within the service territory of the electric utility.

6. All prudent and reasonable expenditures made by an electric utility to develop and implement a plan submitted pursuant to subsection 1 must be recovered as a separate monthly rate charge to the customers of the electric utility. The electric utility shall designate the amount charged to each customer as a separate line item on the bill of the customer.

7. A rural electric cooperative established pursuant to chapter 81 of NRS may submit to the Commission a natural disaster protection plan containing the information set forth in subsection 2. The Commission shall review a plan submitted by a rural electric cooperative and provide advice and recommendations. The board of directors of a rural electric cooperative may allow the rural electric cooperative to recover expenditures made to develop and implement a natural disaster protection plan from the rates charged to the customers of the rural electric cooperative.

8. As used in this section, “electric utility” has the meaning ascribed to it in NRS 704.7571.

Sec. 1.7. 1. Except as otherwise provided in subsections 2 and 3, a person shall not perform work on the electric infrastructure of an electric utility, including, without limitation, the construction, installation, maintenance, repair or removal of such infrastructure, unless the person is a qualified electrical worker.

2. An apprentice electrical lineman may perform work on the electric infrastructure of an electric utility, including, without limitation, the construction, installation, maintenance, repair or removal of such infrastructure, under the direct supervision of a qualified electrical worker.

3. The Commission may authorize a person who is not an employee of an electric utility to perform tree trimming related to line clearance in an easement or right-of-way dedicated or restricted for use by an electric utility. If a person who is not an employee of an electric utility performs tree trimming related to line clearance in such an easement or right-of-way, the tree
trimming must be performed under the direction of an arborist certified by the International Society of Arboriculture.

4. As used in this section:
   (a) “Apprentice electrical lineman” means a person employed and individually registered in a bona fide electrical lineman apprenticeship program with:
       (1) The Office of Apprenticeship of the Employment and Training Administration of the United States Department of Labor or its successor agency; or
       (2) The State Apprenticeship Council pursuant to chapter 610 of NRS.
   (b) “Electric utility” has the meaning ascribed to it in NRS 704.7571.
   (c) “Qualified electrical worker” means:
       (1) A person who has completed an electrical lineman apprenticeship program lasting at least 4 years that was approved by the Office of Apprenticeship of the Employment and Training Administration of the United States Department of Labor or its successor agency or the State Apprenticeship Council pursuant to chapter 610 of NRS; or
       (2) A person who has completed 10,000 hours or more as a journeyman lineman and has performed at least 1,500 hours of documented live-line work on electrical conductors at a voltage of at least 4,160 kilovolts.

Sec. 2. This act becomes effective upon passage and approval.
EXHIBIT C
ORDER OF JANUARY 30, 2020
BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Investigation and Rulemaking to amend, adopt, and/or repeal regulations in accordance with Senate Bill 329 (2019). Docket No. 19-06009

At a general session of the Public Utilities Commission of Nevada, held at its offices on January 29, 2020.

PRESENT: Chair Hayley Williamson
Commissioner C.J. Manthe
Assistant Commission Secretary Trisha Osborne

ORDER

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

I. INTRODUCTION

On June 6, 2019, the Commission opened a rulemaking docket to implement Senate Bill 329 (2019) ("SB 329"). This matter was designated as Docket No. 19-06009.

II. SUMMARY

The proposed regulation, appended hereto as Attachment 1, is adopted as a permanent regulation.

III. PROCEDURAL HISTORY

• On June 6, 2019, the Commission opened the investigation and rulemaking.

• This rulemaking is being conducted pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 233B, 703, and 704, and SB 329.

• On June 13, 2019, the Commission issued a Notice of Rulemaking, a Notice for Request for Comments, and Notice of Workshop in Docket No. 19-06009.

• The Regulatory Operations Staff of the Commission ("Staff") participates as a matter of right pursuant to NRS 703.301.

• On June 18, 2019, the Commission issued Procedural Order No. 1 and a Notice of Workshop for June 28, 2019.
• On June 26, 2019, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (together, “NV Energy”) filed comments.

• On June 28, 2019, the Tahoe Chamber Board of Directors filed comments.

• On June 28, 2019, the Commission held a workshop.

• On July 16, 2019, the International Brotherhood of Workers Local Union 396 and International Brotherhood of Workers Local 1245 (“IBEW”) filed comments.

• On July 17, 2019, Nevada Rural Electric Association (“NREA”), NV Energy, Nevada Bell Telephone Company d/b/a AT&T Nevada and AT&T Wholesale and New Cingular Wireless PCS, LLC (collectively “AT&T”), Cort Atnman, and Staff filed comments. The Nevada Bureau of Consumer Protection (“BCP”) filed a letter stating that it would not be filing initial comments.

• On July 27, 2019, Mora Snyder submitted comments.

• On July 31, 2019, Allan O’Connor submitted comments.

• On July 31, 2019, NV Energy, Cellco Partnership d/b/a Verizon Wireless (“Verizon”), CTIA—The Wireless Association, BCP, Staff, Central Telephone Company d/b/a CenturyLink and CenturyTel of the Gem State, Inc. d/b/a CenturyLink (collectively “CenturyLink”) filed reply comments.

• On August 20, 2019, the Commission held a workshop and discussed submitted comments and reply comments.

• On August 22, 2019, the Presiding Officer issued Procedural Order No. 2.

• On September 9, 2019, the Commission held an informal workshop.

• On September 20, 2019, participants provided an update to the Commission on the status of the draft regulations.

• On September 23, 2019, the Commission held a workshop.

• On September 26, 2019, the Presiding Officer issued Procedural Order No. 3.

• On October 10, 2019, NV Energy, BCP, Staff and CenturyLink filed comments.

• On October 14, 2019, the Presiding Officer sent proposed regulations to the Legislative Counsel Bureau (“LCB”) for review.

• On October 15, 2019, Procedural Order No. 4 was issued.

• On October 29, 2019, the Commission received revised regulations from LCB.
On October 30, 2019, CenturyLink filed comments.


On November 1, 2019, the Presiding Officer issued Procedural Order No. 5 directing Staff to conduct an investigation pursuant to NRS 233B.0608(1) to determine whether the proposed regulations were likely to impose a direct and significant economic burden upon small businesses or likely to directly restrict the formation, operation, or expansion of a small business.

On November 1, 2019, the Commission issued a Notice of Workshop, and Notice of Hearing.

On November 5, 2019, the Presiding Officer issued Amended Procedural Order No. 5.

On November 5, 2019, the Commission issued an Amended Notice of Workshop and Amended Notice of Hearing.

On November 5, 2019, CTIA filed comments.

On December 10, 2019, LCB returned revised proposed regulation in revised form.

On December 12, 2019, Staff filed a briefing memorandum recommending that the Commission find that a small business impact statement pursuant to NRS 233B.0608(2) is not required.

On December 18, 2019, the Commission issued an Order finding that the proposed regulation is not likely to impose a direct and substantial economic burden upon small businesses nor is it likely to directly restrict the formation, operation, or expansion of a small business.

On December 19, 2019, the Commission held a workshop pursuant to NRS 233B.061(2).

On December 20, 2019, the Commission held a hearing pursuant to NRS 233B.061(3).

On December 20, 2019, the Commission issued a Notice of Intent to Act Upon a Regulation for the Adoption, Amendment and Repeal of Regulations.

IV. REGULATIONS

1. The proposed regulations, appended hereto as Attachment 1, implement SB 329, which requires electric utilities to submit to the Commission a natural disaster protection plan.
2. Sections three through six of the proposed regulations define “critical fire weather conditions,” “ignition event,” “natural disaster,” and “natural disaster protection plan.”

3. Section seven requires an electric utility to, on or before March 1 of every third year, submit a natural disaster protection plan (“NDPP”) to the Commission, provides for joint utilities affiliated through common membership to file a joint natural disaster plan, and permits an NDPP to be an amended version of a previous plan. (Id.) Section seven also outlines the details and requirements that must be included in a NDPP. Section seven includes requirements related to Public Safety Outage Management events, vegetation management standards, and protocol requirements to ensure an electric system’s reasonable level of safety, reliability, and resiliency in the event of a natural disaster.

4. Section eight of the regulation outlines treatment of an expedited element of a NDPP, the timeframe permitted for the Commission to approve an NDPP, requests by an electric utility to amend an NDPP, and persons who may petition the Commission for modification of an NDPP. Section eight provides that the Commission will issue an order approving or modifying an NDPP not later than 180 days after the date on which the plan was submitted.

5. Section nine relates to rural electric cooperatives and provides that the Commission shall issue an advisory opinion when concerning an NDPP submitted by a rural electric cooperative not later than 150 days after the date on which the plan is submitted.

6. Section ten permits an electric utility, on or before September 1 of the first and second years, to file a progress report concerning the NDPP that will apply to each year remaining for the period covered by the NDPP.

7. Section 11 relates to ignition events and reporting requirements for various events. Section 11 requires that an electric utility submit a monthly report to the Commission
consisting of comprehensive data concerning the cause of each event occurring in the service
territory of the electric utility during the immediately preceding month that: a) was determined
by the agency responsible for fire protection in the area where the event occurred to be an
ignition event; and b) took place in an extreme fire risk area or high fire risk area. Section 11
also imposes reporting requirements regarding outages initiated to preserve public safety,
proactive de-energization events, and wildfires caused by utility infrastructure that burn more
than an acre of land.

8. Section 12 relates to NDPP accounting and requires an electric utility to
separately track and account for all prudent and reasonable expenditures made by the electric
utility to develop and implement the NDPP. Section 12 also requires that on or before March 1
of each year, an electric utility shall submit to the Commission an application to recover the cost
of prudent and reasonable expenditures made by the electric utility during the immediately
preceding year to develop and implement the NDPP. Section 12 provides that the Commission
will issue a final decision on the application not later than 180 days after the date on which the
application was submitted.

9. Section 13 details the construction or acquisition of a capital project owned by the
electric utility pursuant to the NDPP and requires that the electric utility create a regulatory asset
or liability account for the capital project. (Iid. at 7-8.) Section 13 outlines how the electric utility
shall calculate and record in the account a return on investment, depreciation expenses related to
the capital projects included in the NDPP, actual incremental monthly operations and
maintenance costs incurred to carry out the NDPP and carrying charges on the costs.

10. Section 14 details the process for an electric utility to apply for authorization from
the Commission to utilize a person, who is not employed by the electric utility, to perform tree
trimming. Section 14 also imposes certain record keeping requirements on electric utilities that utilizes a person who is not an employee to perform tree trimming. (Id.)

Summary of Public Comments in 233B Workshop and Hearing

11. Staff, NV Energy, BCP, AT&T, CenturyLink and NREA filed comments and participated in the workshop and hearing held pursuant to NRS 233B. 061. All workshop participants support adoption of the proposed regulation in its final form, attached hereto as Attachment 1.

12. Comments filed by participants in response to Procedural Order No. 4 raised issues regarding utility infrastructure colocation that were not expressly addressed by SB 329 or the proposed regulations. Amended Procedural Order No. 5 determined that given time constraints and the Parties’ concerns, such issues should be addressed in a separate proceeding.

Commission Discussion and Findings

13. Based on the foregoing, the Commission finds that it is in the public interest to adopt as permanent the proposed regulations attached hereto as Attachment 1.

14. The Commission finds that a separate investigation and rulemaking is necessary to address utility infrastructure colocation issues and associated costs related to the implementation of NDPPs.

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THEREFORE, it is ORDERED:

1. The proposed regulations, attached hereto as Attachment 1, are ADOPTED AS PERMANENT.

2. The Assistant Commission Secretary SHALL open an investigation and rulemaking docket with the following caption: Investigation and Rulemaking into utility infrastructure colocation issues and associated costs related to implementing Natural Disaster Protection Plans.

By the Commission,

HAYLEY WILLIAMSON,
Chair and Presiding Officer

C.J. MANTHE, Commissioner

Attest: TRISHA OSBORNE,
Assistant Commission Secretary

Dated: Carson City, Nevada

1/30/20

(SEAL)
ATTACHMENT 1
REVISED PROPOSED REGULATION OF THE PUBLIC UTILITIES
COMMISSION OF NEVADA

PUCN Docket No. 19-06009

LCB File No. R085-19

December 20, 2019

Explanation – Matter in bold italics is new; matter in bracket [omitted material] is material to be omitted

Section 1. Chapter 704 of NAC is hereby amended by adding thereto the provisions set forth as sections 2 to 14, inclusive, of this regulation.

Sec. 2. As used in sections 2 to 14, inclusive, of this regulation, unless the context otherwise requires, the words and terms defined in sections 3 to 6, inclusive, of this regulation have the meanings ascribed to them in those sections.

Sec. 3. "Critical fire weather conditions" means a combination of weather and fuel conditions that are ideal for the ignition and rapid spread of wildfires.

Sec. 4. "Ignition event" means an event in which electric utility infrastructure starts a fire or scorches combustible material.

Sec. 5. "Natural disaster" means any natural catastrophe, including, without limitation, wind, wildfire, storm, high water, earthquake, avalanche, landslide, mudslide or heat wave.

Sec. 6. "Natural disaster protection plan" means a natural disaster protection plan submitted to the Commission pursuant to section 1.3 of Senate Bill No. 329, chapter 102, Statutes of Nevada 2019, at page 555.

Sec. 7. 1. An electric utility shall, on or before March 1, 2020, and on or before March 1 of every third year thereafter, submit a natural disaster protection plan to the Commission. Two or more electric utilities that are affiliated through common ownership and that have
an interconnected system for the transmission of electricity may submit a joint natural disaster protection plan. A natural disaster protection plan may be an amended version of a previous plan.

2. An electric utility shall include in its natural disaster protection plan all of the following information:

(a) A description of a risk-based approach used by the electric utility to identify areas within the service territory of the electric utility that are prone to different types of natural disasters and an identification of potential threats in the foreseeable future, including, without limitation, an identification of areas within the service territory of the electric utility that are subject to a heightened threat of a fire or other natural disaster.

(b) A description of the preventive strategies and programs, including, without limitation, operational practices, inspections and corrections, and system hardening that the electric utility will adopt to minimize the risk of its electric lines and equipment causing catastrophic wildfires. In determining which preventive strategies and programs to include in the description required by this paragraph, the electric utility shall consider dynamic climate change and other natural disaster risks.

(c) A description of the metrics that the electric utility plans to use to evaluate the performance of the natural disaster protection plan and the assumptions underlying the use of those metrics.

(d) The threshold criteria for the de-energization of portions of the distribution and transmission system of the electric utility due to a natural disaster that considers the associated impacts on public safety.
(e) The protocols that the electric utility plans to use:

(1) For disabling reclosers and de-energizing portions of the distribution and transmission system of the electric utility that considers the associated impacts on public safety; and

(2) To mitigate the public safety impacts of the protocols described in subparagraph (1), including, without limitation, impacts on critical first responders and on health and communication infrastructure.

(f) A description of the procedures the electric utility intends to use to restore its distribution and transmission systems in the event of the de-energization of those systems or a portion of those systems.

(g) A communication plan related to public safety outage management, which includes, without limitation, communication plans specific to customers, stakeholders and communication infrastructure providers. Before filing a natural disaster protection plan, each electric utility shall meet with communication infrastructure providers in an effort to develop a mutually agreeable plan for public safety outage management notification protocols and format.

(h) A description of the standard for vegetation management to be used by the electric utility and, if that standard exceeds any other standard for vegetation management required by any applicable statute or regulation, a description of how and why the standard exceeds those requirements.

(i) A description of the standard for patrols and detailed inspections of electric utility infrastructure and, if that standard exceeds any other standard for such patrols and inspections required by any applicable statute or regulation, a description of
how and why the standard exceeds those requirements.

(j) A description of the actions that the electric utility will take to ensure that its system will achieve a reasonable level of safety, reliability and resiliency and to ensure that its system is prepared for a natural disaster, including, without limitation, vegetation management, patrols, inspections, testing, and hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment and facilities, such as undergrounding, insulation of distribution wires, pole replacement and other measures. An electric utility shall use prudent practices commonly used in the electric utility industry for utility design, operating practices and telecommunications to prevent its infrastructure from causing a fire and to maintain resiliency during a natural disaster.

(k) An explanation that the electric utility has an adequately sized and trained workforce to execute the natural disaster protection plan and promptly restore service after a major event, taking into account employees of other utilities available to the electric utility pursuant to mutual aid agreements and employees of entities with which the electric utility has entered into contracts.

(l) A description of how the natural disaster protection plan is consistent with the emergency response plan submitted by the electric utility pursuant to NRS 239C.270.

(m) A description of the processes and procedures that the electric utility will use to monitor and audit the implementation of the natural disaster protection plan and to take actions to correct any deficiency that is identified.

(n) A description of the participation of the electric utility, including, without limitation, any commitments made, in any community wildfire protection plans, as
defined in 16 U.S.C. § 6511, established in this State.

3. For each element that an electric utility is required by subsection 2 to include in its natural disaster protection plan, the electric utility shall include in its natural disaster protection plan:

(a) An identification of how the element is expected to reduce:

(1) Ignition events in high fire risk areas and extreme fire risk areas during critical fire weather conditions; and

(2) Equipment damage and loss of power caused by a natural disaster;

(b) A cost-benefit analysis for the element; and

(c) The input relating to the element that has been provided by:

(1) Each fire protection district in the service territory of the electric utility that is covered by the plan;

(2) The office of emergency management for each county covered by the plan;

(3) The Division of Forestry, Division of State Lands and Division of State Parks of the State Department of Conservation and Natural Resources; and

(4) The Division of Emergency Management of the Department of Public Safety.

4. In addition to the information that an electric utility is required by subsections 2 and 3 to include in its natural disaster protection plan, the electric utility shall include in its natural disaster protection plan:

(a) A summary of the projected 3-year budget for the natural disaster protection plan, an identification of the projected cost elements of the plan and the projected cost for each element that the electric utility is required by subsection 2 to include in the plan;
(b) If two or more electric utilities submit a joint natural disaster protection plan, the proposed joint and direct allocation of costs between the service territories of the electric utilities; and

c) Annual data tracking trends associated with:

(1) Ignition events, separated for ignition events:

(I) During critical fire weather conditions and during all other days in high and extreme risk fire areas; and

(II) The involvement of transmission or distribution infrastructure; and

(2) Equipment damage and loss of power caused by natural disasters.

Sec. 8. 1. If an electric utility will require additional time to implement an element of a natural disaster protection plan before the next fire season, the electric utility may request expedited treatment of that element.

2. The Commission will issue an order approving or modifying a natural disaster protection plan not later than 180 days after the date on which the plan was submitted.

3. At any time after a natural disaster protection plan has been approved and before the date on which a new plan must be submitted pursuant to section 1.3 of Senate Bill No. 329, chapter 102, Statutes of Nevada 2019, at page 555:

(a) An electric utility may submit to the Commission a request to amend a natural disaster plan; and

(b) Any person may petition the Commission for the modification of a natural disaster protection plan.

Sec. 9. The Commission shall issue an advisory opinion concerning a natural disaster protection plan submitted by a rural electric cooperative pursuant to subsection 7 of section
13 of Senate Bill No. 329, chapter 102, Statutes of Nevada 2019, at page 555, not later than
150 days after the date on which the plan is submitted.

Sec. 10. On or before September 1 of the first and second years after an electric
utility has submitted a natural disaster protection plan to the Commission pursuant to
section 7 of this regulation, the electric utility may file with the Commission a progress
report concerning the natural disaster protection plan that will apply to each year
remaining for the period covered by the natural disaster protection plan.

Sec. 11. An electric utility shall:

1. Submit to the Commission a monthly report of comprehensive data concerning the
cause of each event occurring in the service territory of the electric utility during the
immediately preceding month that:

(a) Was determined by the agency responsible for fire protection in the area where the
    event occurred to be an ignition event; and

(b) Took place in an extreme fire risk area or high fire risk area.

2. Notify the Commission not later than 24 hours after:

(a) A power outage initiated to preserve public safety or a proactive de-energization event;
    or

(b) A wildfire that occurs in the vicinity of the infrastructure of the electric utility that
    burns more than 1 acre of land.

3. Not later than 1 month after an event described in subsection 2, submit to the
Commission a report containing a full description of the event.

Sec. 12. 1. An electric utility shall separately track and account for in its books and
records all prudent and reasonable expenditures made by the electric utility to develop and
implement its natural disaster protection plan.

2. On or before March 1 of each year, an electric utility shall submit to the Commission an application to recover the cost of prudent and reasonable expenditures made by the electric utility during the immediately preceding year to develop and implement the natural disaster protection plan of the electric utility pursuant to subsection 6 of section 1.3 of Senate Bill No. 329, chapter 102, Statutes of Nevada 2019, at page 555. The Commission will issue a final decision on the application not later than 180 days after the date on which the application was submitted.

Sec. 13. 1. An electric utility may, upon placing into operation a new capital project constructed or acquired by and owned by the electric utility pursuant to a natural disaster protection plan, create a regulatory asset or liability account for the capital project.

2. Beginning 1 month after the date on which a new capital project for which a regulatory asset or liability account is created pursuant to subsection 1 is placed into plant in service, the electric utility that maintains the account shall separately calculate and record in the account:

(a) A return on investment for the capital project using the most recently authorized pretax rate of return on the net plant balance of the capital project. The net plant balance of the capital project must be calculated by subtracting from the costs of the capital project the sum of the accumulated depreciation and the accumulated deferred income tax for the capital project.

(b) Depreciation expenses related to capital projects included in the natural disaster protection plan pursuant to paragraph (c) of subsection 2 of section 1.3 of Senate Bill No. 329, chapter 102, Statutes of Nevada 2019, at page 555.

(c) Actual incremental monthly operations and maintenance costs incurred to carry
out the natural disaster protection plan.

(d) Carrying charges on the costs described in paragraph (c) at the most recently authorized rate of return.

3. The amounts recorded in a regulatory asset or liability account pursuant to subsection 2 must be separately identified and excluded from a general rate case.

4. An electric utility shall annually submit to the Commission a request to clear the accumulated balance in a regulatory asset or liability account created pursuant to subsection 1 and include the account in the request. The request must include:

   (a) A proposed period for recovery and amortization of the regulatory asset or liability that ensures that the utility does not recover more than the actual accumulated balance of the account;

   (b) A detailed reconciliation of the amount of recovery requested to the approved budget items, showing carrying charges separately; and

   (c) Proposed rate design and rates by customer class for the annual recovery requested in a separate line item on a customer's bill.

Sec. 14. 1. An electric utility may apply to the Commission for authorization for a person who is not an employee of the electric utility to perform tree trimming related to line clearance in an easement or right-of-way dedicated or restricted for use by the electric utility pursuant to subsection 3 of section 1.7 of Senate Bill No. 329, chapter 102, Statutes of Nevada 2019, at page 556. The application must include:

   (a) The name, telephone number, mailing address, electronic mail address and physical street address of the person;

   (b) A copy of each business license or certificate issued by this State or any political
subdivision thereof to the person; and

(c) Proof that the tree trimming will be performed under the direction of an arborist certified by the International Society of Arboriculture.

2. If an electric utility utilizes a person not employed by the electric utility to perform tree trimming related to line clearance in an easement or right-of-way dedicated or restricted for use by the electric utility, the electric utility shall maintain records confirming that (1) the person has been authorized to perform tree trimming by the Commission, and (2) the person performs the tree trimming under the direction of an arborist certified by the International Society of Arboriculture.
EXHIBIT D
THE PLAN
Natural Disaster Protection Plan

Supported by:
Navigant Consulting, Inc.
A Guidehouse company
35 Iron Point Circle
Suite #225
Folsom, CA 95630

guidehouse.com

Reference No.: 211123
February 28, 2020
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EXECUTIVE SUMMARY

The State of Nevada is embarking on a proactive plan to protect the public from the impacts of natural disasters in areas where there are high-voltage electric grid assets. As headlines from neighboring states make clear, due to the vulnerabilities and impacts from damage to power lines and other equipment caused by natural disasters, best practices are emerging. Senate Bill 329 ("SB 329") directs regulated electric utilities to establish a Natural Disaster Protection Plan ("NDPP" or "Plan"). Nevada’s vision goes beyond wildfire mitigation. It requires utilities to examine all high-likelihood and high-impact natural disasters that could impact its electric infrastructure. 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") retained Navigant Consulting, Inc., a Guidehouse Company ("Navigant"), to support the development of their Plan. Historically, NV Energy's infrastructure has not started catastrophic wildfire events. However, overhead ("OH") electric infrastructure in general as well as the Companies' overhead infrastructure have had both failure and weather-related ignitions. The primary changes that have resulted in the natural disaster risk evolution are:

- **Aging electric infrastructure:** Over the years, NV Energy's overhead and underground electric transmission and distribution and assets (e.g., wooden poles, overhead conductors, substations, etc.) have aged and need upgrades or replacements for safety purposes. This Plan includes infrastructure assessment, replacement, and improvement programs. These programs will help mitigate natural disaster risks by improving electric grid resiliency.

- **Fuel risk and human land use practices:** Human land use practices and fuel risk have increased the frequency of large wildfires several-fold. In drier forested ecosystems, fire exclusion over many years has resulted in unnatural fuel builds ups that are now leading to fires of uncharacteristic size and severity. Average fire season lengths have increased by at least a couple of months owing to earlier springs and later winters in mountainous regions. Finally, human populations continue to spread into flammable ecosystems.

- **Climate:** Within the 21st century, the United States ("U.S.") has witnessed a large number of 100, 500 and 1,000-year weather events. The National Weather Service ("NWS") reported that eight 500-year flood events occurred in the U.S. between August 2015 and August 2016 alone. Hotter and drier summers have led to historic wildfires. During October 2017, there were 21 major wildfires in northern California ("CA"). These massive impacts have motivated government and regulatory entities to require grid hardening initiatives. For example, the New Jersey Board of Public Utilities approved 103 measures for the state’s electric utilities to undertake to improve preparedness and responses to severe storms. This led to $1.2 billion in investments to strengthen electric and gas systems against severe weather events. Similarly, one Florida utility invested $3 billion to harden its facilities. Slowly but surely, utilities, regulators, and customers are beginning to realize that simply restoring the grid to its previous state is inadequate to ensure greater resilience in the face of worsening conditions.

Based on the above, the natural disaster risk to the electric infrastructure has increased significantly and must be mitigated through a combination of operations, maintenance, system hardening, public safety preparation, and prevention programs. Keeping this in mind, the Nevada legislature enacted SB 329 to allow for execution of these programs.

NV Energy’s Plan includes a comprehensive assessment of natural disasters (Section 3) and an evaluation of potential mitigation measures. The Plan considers public safety in four steps: prepare in advance; mitigate potential harm using a risk-based assessment; respond in a coordinated and structured manner; and recover using safe inspection and restoration practices. The Plan protects the public safety most effectively when all four steps related to natural disaster actions are considered and implemented. Ongoing public outreach from NV Energy and its collaboration partners, which include first responders, government
agencies, and other entities identified by SB 329 and the related regulations, are coordinated for effectiveness. The Plan also leverages existing plans and programs to improve their effectiveness and aligns actions and options that reach across vulnerable communities to ensure coordinated preparation for, and responses to, natural disasters.

The controllable natural disaster risks are presented in the Companies’ electric infrastructure right of way ("ROW") and uncontrollable risks are presented by debris, vegetation, birds, animals, other foreign materials, and extreme weather outside the ROW that may impact the electric infrastructure to cause failures and ignitions. Therefore, it is necessary to have a risk mitigation strategy for both controllable and uncontrollable risks. In order to mitigate controllable natural disaster risks and infrastructure failures, the Companies have examined their operations and maintenance ("O&M") practices and are proposing changes to reduce the risk of ignition and other natural disaster impacts caused by electric infrastructure failure and vegetation management issues (Sections 4.1, 4.2 and 4.4). For mitigating uncontrollable natural disaster risks, the Companies have examined alternative or bolstered designs to be applied to aging systems assessments, replacements, and improvements (Sections 4.3). It is also important to explore emerging technologies (Section 4.5) and understand evolving climate and electric grid behavior (Section 4.6) to manage the uncontrollable portion of the risk. Finally, for mitigating the greatest possible public impacts from uncontrollable ignition risks, the Companies have examined their operating and public safety practices and propose changes, including Public Safety Outage Management ("PSOM") as a last resort when unmitigated risk is just too high (Section 5).

The Plan is structured to conform to requirements set by legislation and regulation while targeting both controllable and uncontrollable natural disaster risks:

**RISK-BASED APPROACH** – The Plan uses modeling to identify geographic areas where electrical infrastructure is most likely to impact public safety during natural disasters. This analysis underpins the Plan and allows resources to be directed to areas where they make the most impact. Programs and projects have been developed, then prioritized based on this risk-based approach.

**OPERATIONAL PRACTICES** – The Plan identifies field and systems operations practices used to mitigate natural disaster impacts, including but not limited to field procedures, reclosing strategy and no-test policy during high fire threat season.

**INSPECTIONS AND CORRECTIONS** – Shortening the inspection interval, increasing inspection frequency, and a framework of prioritized correction timeframes are designed to mitigate against ignition from utility infrastructure and improve resiliency during other natural disasters. Qualified inspectors, foresters, arborists, and other professionals coordinate with an eye toward public safety where infrastructure lies within a natural disaster area.
SYSTEM HARDENING – Programs and projects to improve and ruggedize the system include converting to equipment with less ignition risk, using covered conductor instead of bare wires, and installing new poles that are less vulnerable to natural disasters. Hardening the grid includes non-expulsion fuses, advanced technology relays, fire retardant pole wrap, and other protective devices.

VEGETATION MANAGEMENT – Vegetation management practices focus on clearance distances and removal of hazardous trees to minimize the chances of vegetation striking lines. Targeted programs include removal of ground vegetation in easements, pole grubbing so ground areas are clear, and fuel breaks compatible with infrastructure clearing programs. NV Energy will work to improve vegetation management awareness and to coordinate with government agencies, such as the Bureau of Land Management (“BLM”) and the United States Forest Service (“USFS”), to ensure that NV Energy’s Plan complements and enhances those agencies’ vegetation management programs.

SITUATIONAL AWARENESS – Improved, up-to-date information about fire conditions that guides appropriate mitigation actions. Situational awareness enhancement projects use information from other organizations, including fuel mapping and information from weather stations and cameras, to corroborate and expand NV Energy’s existing informational tools, prioritized to provide additional data for the areas that have been determined to be at the highest risk.

PROACTIVE DE-ENERGIZATION – Under extreme wildfire weather conditions, and as a last resort to protect public safety, proactive de-energization of pre-identified circuits, or sections of circuits, to mitigate against potential electric facility-caused ignitions may be required. Extensive preparation and outreach has been conducted in this area, including outreach to emergency responders and the public in Tier 3 areas that could be impacted.

Extensive research was conducted that identified the following natural disasters for this iteration of the Plan:

- Wildfires and grassland fires;
- Flooding and monsoons;
- High wind gusts, thunderstorm winds, and microbursts;
- Winter storms and blizzards;
- Earthquakes; and
- Landslides and avalanches.

Future iterations of the Plan will include an updated assessment to adjust the identified disasters should the likelihood or impact of each assessed disaster change. NV Energy believes that the Plan is most effective when it is developed and implemented broadly. Community outreach underpins the development of this Plan. NV Energy held three Expert Working Group (“EWG”) meetings with fire agencies, emergency responders, government agencies, telecommunications companies, and others identified by the regulators. This expert team was consulted with and provided input on each section of the Plan as it was being developed. Core aspects of the draft plan were also vetted in a series of six public meetings and a Facebook Live presentation. Region-specific maps were discussed by members of the EWG and NV Energy’s experts. In developing its Plan, NV Energy learned valuable lessons about collaboration opportunities with other entities and agencies, as well as how to harmonize its Plan for maximum effectiveness with other community and government programs. NV Energy identified a number of follow-up activities including continued collaboration with other stakeholders to share data, information, and best practices.

Based on these activities, NV Energy developed specific portions of the Plan to mitigate risk in the highest threat areas, along with initial estimates for implementation of the Plan. Projects and programs included in this Plan are tailored for maximum benefit and focused on extreme- and high- threat regions. Alternative mitigation options were explored to identify the “best fit” solution for potential risks. The Plan provides particular focus to projects to harden the grid where it has become vulnerable, the adoption of more robust
vegetation management strategies, enhancement to information gathering and processing, and improvement of the visibility into the health and status of the grid.

Although preference will be to not de-energize the power grid as part of normal operations, there may be times when an energized grid puts the public at risk under extreme weather conditions. NV Energy has developed the PSOM program for proactive de-energization as a measure of last resort to protect the public. PSOM practices were discussed with the EWG and the general public. NV Energy’s aim is to provide notification of high-threat conditions, such as fire weather, as far in advance as possible. In anticipation of a PSOM event, NV Energy evaluated and refined its procedures by using simulation drills to identify areas of improvement before an actual event occurred. NV Energy continues to review and refine its PSOM procedures, including the use of Customer Resource Centers, improved Green Cross customer support, improved emergency responder communications, and enhanced telecommunications. NV Energy’s goal is to minimize public impact when a PSOM event occurs, and therefore its Plan includes increased sectionalization of the grid, which is a best practice to minimize the public impact of a proactive de-energization event.

This Plan represents months of intense research, collaboration, and outreach. Using a risk-based approach allows NV Energy to utilize its resources for maximum impact. NV Energy will continue to review and evaluate the Plan based on its own experience during implementation and the input from other stakeholders. NV Energy appreciates the opportunity to present this Plan in compliance with the requirements of SB 329 and related regulations.
1 BACKGROUND

NV Energy is a vertically integrated electric and gas utility based in Nevada. NV Energy’s service territory includes population centers in the northern and southern parts of the state, covers nearly 46,000 square miles, and reaches approximately 90 percent of the state’s population. The Companies serve more than 1.4 million customers (approximately 1.29 million electric customers and 168,000 gas customers) across Nevada and have more than 2,470 employees.

NV Energy prides itself on delivering exceptional service, ensuring customer reliability, and deploying low-cost and sustainable renewable energy resources. The Companies are developing nine new solar energy projects, totaling 2,191 megawatts ("MWs"), and nearly 690 MWs of battery energy storage to help meet future customer needs. With a vast service territory comprising a majority of the state, the Companies understand that continuing to strive for safe, reliable electric service necessitates the need to evaluate external threats conditional to the local topography and its associated climatological impacts. Due to hazardous weather events exacerbated by climate change, the state of Nevada has evaluated the potential adverse effects of catastrophic natural occurrences. The vulnerability of the public in natural disaster threat areas where utility electrical equipment is located led to the signing of SB 329 into law on May 22, 2019.¹ SB 329 requires electric utilities to develop and file an NDPP with the Public Utilities Commission of Nevada ("Commission" or "PUCN") and then file the Plan every three years thereafter for review and approval by the Commission.

This Plan is filed in accordance with SB 329 and regulations adopted by the Commission in Docket No. 19-06009. The Plan presents existing and proposed initiatives that are intended to mitigate natural disaster risk impacts on utility infrastructure. Those initiatives include a program for proactive de-energization in certain, limited circumstances. The activities outlined in this Plan form the basis of an effective natural disaster mitigation program. NV Energy’s experience implementing its Plan will provide opportunities to apply lessons learned to future iterations of the Plan. The mitigation strategies in this Plan reflect NV Energy’s commitment to exceptional service, grid resiliency, and public safety.

1.1 Natural Disaster Risk in Nevada

SB 329 mandates that a utility’s NDPP focus on geographic areas where the utility’s electrical infrastructure is situated in locations vulnerable to natural disaster threats. NV Energy therefore conducted a comprehensive evaluation of its service territory and concluded that the following types of natural disaster threats should be included in the first iteration of the Plan:

- Wildfires and grassland fires;
- Flooding and monsoons;
- High wind gusts, thunderstorm winds, and microbursts;
- Winter storms and blizzards;
- Earthquakes; and
- Landslides and avalanches.

Risk profiles for each category of natural disaster are explored in greater detail in Section 3 of this Plan. NV Energy considers the Plan a "living document" such that future iterations may add natural disaster types that emerge as high frequency or high impact threats. Only natural disasters are part of this Plan’s scope.

¹ NV Electronic Legislative Information System. “SB 329 Bill Text.”
1.2 SB 329 and Regulatory Overview

1.2.1 SB 329

SB 329 was signed into law on May 22, 2019. The law aims to reduce Nevada’s vulnerability to natural disasters by requiring that electric utilities take steps to prevent, plan for, and respond to natural disasters. SB 329 mandates that electric utilities identify areas at high-risk for natural disasters, implement protocols to inspect electrical infrastructure, perform vegetation management, propose preventative steps to mitigate disaster risks, provide adequate natural disaster response, and establish proactive de-energization protocols for the utilities’ electric assets in the event of fire weather conditions or related natural disasters. The law also ensures that electric utilities can recover the costs associated with the disaster-related efforts included in a NDPP.

1.2.2 Regulatory Overview

The Commission finalized relevant regulations on January 29, 2020, in Docket No. 19-06009, which were codified by the Legislative Counsel Bureau ("LCB") in LCB File No. R085-19 ("Regulations") on February 26, 2020. These Regulations further clarify electric utilities’ responsibilities in creating natural disaster protection plans, establish specific timelines for Plan submission and updates, and provide instructions related to the Plan’s cost recovery. Regulatory timelines are discussed in Section 9 of this Plan.

Per SB 329, codified as Nevada Revised Statute ("NRS") § 704.7983, and Section 7.2 of the Regulations, the Plan is required to be structured as follows:

- **Risk-based Approach** – Involves the use of modeling to identify geographic areas particularly vulnerable to natural disaster threats, preparation of plans and continued weather monitoring and analytics.
- **Operational Practices** – Involves practices used to mitigate wildfire risk, including non-reclosing strategy, conduct wildfire safety training and implement applicable procedures.
- **Inspections and Corrections** – Involves inspection frequency, identification of fire-risk conditions, and correction-related processes designed to mitigate against utility ignition and improve electric infrastructure-related resiliency during other natural disasters.
- **System Hardening** – Involves deployment of equipment with less ignition risk, including covered conductors, poles, non-expulsion cutouts, relays, pole wraps, and protective devices.
- **Vegetation Management** – Involves clearance distances, pole grubbing, fuel breaks, and the removal of hazard trees to minimize the chances of vegetation striking lines.
- **Situational Awareness** – Involves the use of information about fire conditions and weather during other natural disasters to help guide mitigation measures, including fuel mapping and information from weather stations and cameras.
- **Proactive De-Energization** – Involves de-energization of pre-identified circuits, or sections of circuits, to mitigate against potential electric facility-caused ignitions.
- **Coordination with emergency responders, local, government, public agencies, and community wildfire protection plans ("CWPPs").**

1.3 NV Energy Vested Engagement

On the heels of devastating wildfires across the region, NV Energy joined various firefighter organizations, environmental groups, organized labor, local government, and other concerned stakeholders to create and pass SB 329, which requires Nevada’s utilities to make their infrastructure systems safer, more reliable, and more resilient. After passage, NV Energy continued its collaboration with these stakeholders during the
rulemaking process and has developed the Plan with a focus on extreme, high, and moderate fire threat areas, along with risk zones for other natural disasters. In creating the Plan, NV Energy has leveraged existing community preparedness efforts and local wildfire protection plans. NV Energy has also engaged in a robust communication effort holding customer information and education sessions in each of the extreme fire threat areas to highlight its efforts around wildfire prevention and its PSOM procedures. This outreach has been widespread to ensure NV Energy’s Plan and priorities align with the state’s goals and those of all impacted stakeholders.

The Companies’ extensive stakeholder outreach effort included an average of 40-50 community partners and experts attending each of the three EWG sessions to provide feedback into the development of a draft Plan. This process was followed by a series of six public stakeholder engagement sessions to discuss key aspects of the Plan and a Facebook Live video presentation of the Plan’s elements, which has reached over 15,000 viewers at the time of this Plan’s filing. These outreach activities advanced SB 329 priorities, developed a common understanding, provided the opportunity to seek further details from subject matter experts (“SMEs”), and established effective partnerships for Plan implementation. The Companies’ stakeholder engagement-related efforts are discussed in greater detail in Section 7 of the Plan.

NV Energy shares the State Legislature’s and the Commission’s commitment to prioritize public safety and respond proactively to the threats and challenges that natural disasters pose to the electric grid.
2 OBJECTIVES OF THE PLAN

Public safety was the Companies’ primary objective in developing the Plan while managing both controllable and uncontrollable risks. The NDPP allows the Companies to help safeguard Nevada communities by mitigating, preparing for, and responding to natural disasters effectively and efficiently. The Plan also allows the Companies to meet the statutory requirements of SB 329, comply with the Regulations, and prioritize resources toward electric infrastructure located in areas particularly vulnerable to natural disaster threats.

The Companies believe that the establishment of a well-coordinated and actionable plan helps promote public safety by abating the adverse impacts of natural disasters. The Plan is designed to minimize the potential that a natural disaster will cause damage to the Companies’ equipment and result in situations that are hazardous to the public.

2.1 Objectives

The Companies deployed a risk-based approach in aligning the Plan with SB 329 and the Regulations. This approach allows the Companies to direct available resources where they are needed most. Public safety is the Companies’ number one priority, is embedded in core company values, and was foundational in guiding the creation of the Plan.

Grid resiliency is a second central objective of the Plan. The plan allows the Companies to reduce electric infrastructure risk in targeted areas and to strengthen community resiliency efforts through coordinated system hardening and ruggedization. By targeting the Companies’ projects and programs toward high-threat areas, NV Energy aims to minimize short-term impacts related to grid outages and to maximize long-term economic and operational benefits for customers.

See Figure 1 for an overview of the rings of benefit identified in development of this Plan.
2.2 Approach

The Companies took a risk-based approach in developing the Plan, as required by the Regulations. Early collaboration with relevant SMEs allowed the Companies to identify informational gaps during the Plan development phase.

A key first step was to identify the community partners and wildfire experts, including those specified in the Regulations:

- Local & Regional Fire Districts;
- Nevada Department of Public Safety, Division of Emergency Management;
- Emergency Managers of each county of the service territory (Counties & other authorities having jurisdiction (“AHJs”) - Washoe, Douglas, Tahoe area, Mt. Charleston area, Tribal Governments);
- Nevada Division of Forestry;
- Telecommunication Companies – (e.g., AT&T, Century Link, Sprint/Nextel, T-Mobile, Verizon Wireless);
- Nevada Division of Lands;
- Nevada Division of State Parks; and
- Nevada Department of Conservation & Natural Resources.

The Companies coordinating three on-site meetings (with remote participation available) attended by an average of 40-50 identified expert representatives per working group meeting. Key elements of the draft Plan were developed with these experts. The Companies also went beyond the requirements of the Regulations by including additional experts in this process. The Companies participated in several meetings with the Northern Nevada Fire Chiefs (“NNFC”), Southern Nevada Fire Operations Group (“SNOPS”), Northern Nevada Emergency Managers ("NNEM"), and one-on-one meetings with the Clark County Emergency Managers, local fire agencies within the service territory, the BLM, and the USFS.

NV Energy also vetted key elements of the Plan through a series of six public stakeholder meetings. A Facebook Live session supplemented these open forum events. These sessions enabled the Companies to receive further input prior to Plan filing. Stakeholder comments were collected and organized for further consideration. Stakeholder engagement is discussed more broadly in Section 7 of this Plan.

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3 NATURAL DISASTER RISK ANALYSIS AND DRIVERS

The Companies design, maintain, and operate utility equipment in accordance with industry standards. A risk-based approach forms the basis to identify potential threats, prioritize areas for enhancement, and adopt mitigation strategies. The risk assessment process (Section 3.2 below) sets the foundational understanding of areas and assets within the service territory that are prone to natural disasters. Identification of potential triggering events that pose the greatest concern for the Companies are based on several factors, including historical and forecasted natural hazard data. This is also an important step in understanding the evolving climate that is an uncontrollable risk to the Companies’ electric infrastructure and will be reevaluated in subsequent Plan filings to remain current.

Consistent with the requirements set by the Commission in Docket No. 19-06009, the Companies performed a risk assessment of natural disaster threats relative to their electric service territory and electrical assets. This occurred over several months in 2019 and early 2020, relying on internal information within the Companies, publicly available weather event data, industry expert input using stakeholder working groups, and academic research. The Companies consulted several partners to review this assessment including, but not limited to, the NWS, REAX Engineering, the University of Nevada, Reno’s (“UNR”) Department of Physics and Seismological Lab, regional fire agencies, the Division of State Lands, the Division of State Parks, the Division of Forestry, and other government and industry entities. Additionally, the Companies monitored the progress of California utilities’ wildfire mitigation plans (“WMPs”), filed with and approved by the California Public Utilities Commission (“CPUC”) in 2019. Information from these WMPs indicated there are several potential opportunities for NV Energy to consider to significantly reduce wildfire risk by focusing on measures that prevent contact-related faults. The Companies’ electric infrastructure has not historically caused large-scale fires; therefore, the CPUC WMP filings were reviewed and referenced to support criteria of wildfire risks. After evaluating visualization tools for natural disaster risks, NV Energy determined that the industry standard for presenting natural disaster threats was through mapping.

Profiled natural disasters discussed in this plan include:

- Wildfires and grassland fires;
- Flooding and monsoons;
- High wind gusts, thunderstorm winds, and microbursts;
- Winter storms and blizzards;
- Earthquakes; and
- Landslides and avalanches.

The Companies found that particular areas of the territory are subject to greater natural disaster threat, and the Plan prioritizes strategies for those high-risk regions. As a result of this exercise, wildfire threat presented as the highest risk. The Companies also compiled a list of unprofiled natural disaster threats that may be considered for future Plan iterations, should they begin to pose a credible threat. The following sections detail the Companies’ operations and the results of the natural disaster risk assessment process.

3.1 Service Territory Description & Electrical Assets

The Companies own 5,756 MWs of generation assets and about 6,259 miles of transmission lines across its northern and southern operations, with most capacity and load concentrated in the Las Vegas region. All but 38 miles of transmission lines are overhead. The Companies also own approximately 40,863 miles of distribution lines across both regions, of which, 11,584 miles are overhead and 29,279 miles are underground. Additional electrical assets include 437 substations, 110 microwave towers, over 286,000

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3 Transmission lines, including sub-transmission, are rated at 55 kilovolt (“kV”) and above.
poles, and numerous telecommunication and communication devices across its vast territory. The Companies serve customers’ electricity needs through company-owned generation assets, long-term power purchase agreements, and purchases from other utilities and independent power producers. Sierra’s operations serve approximately 350,337 electric customers and 168,621 gas customers. In 2018, Sierra’s operations had a peak load of 1,860 MW and a peak generating capacity of 1,372 MW. Nevada Power’s operations serve 941,853 total electric customers. In 2018, Nevada Power recorded peak load in the region to be 5,956 MW with a peak generating capacity of 4,384 MW. See Figure 2 for the Companies’ service territory map.

Figure 2: NV Energy Service Territory Map

![NV Energy Service Territory Map](image)

Source: NV Energy, 2014

3.2 Risk-Driven Decision-Making Framework

The Companies completed a risk assessment to identify, evaluate, control, mitigate, and monitor electric utility-related natural disaster risks. This risk assessment directs investments and operational enhancements to reduce risk exposure. The risk assessment also provided insights into where mitigation strategies can effectively reduce risk through metrics and measurements (once a foundational baseline is established).
3.2.1 Modeling Assumptions for Natural Disasters

Information such as insurance reports, vulnerable asset locations, outage events, major event day ("MED") data, and corresponding incremental costs provided the underlying utility-specific assumptions. Data from publicly available resources supported this assessment, serving as the base layer information incorporated into the natural disaster risk maps. Appendix A provides the compiled risk maps identified for this evaluation. Each cycle of the risk assessment refines risk framework for subsequent Plan updates. Further tuning of this assessment will occur over time, as targeted data becomes available and Plan metric tracking is implemented.

3.3 Natural Disaster Threats

In consideration of multiple local, state, and federal hazard rankings on natural disaster threat, and engagement through EWG meetings, the Companies refined the list of natural disaster risks. Pursuant to the definition presented in Docket No. 19-06009, a natural disaster is identified by any natural catastrophe, including but not limited to wind, wildfire, storm, high water, earthquake, avalanche landslide, mudslide, or heat wave. The first iteration of the Plan profiles the following natural disaster threats:

- Wildfires and grassland fires;
- Flooding and monsoons;
- High wind gusts, thunderstorm winds, and microbursts;
- Winter storms and blizzards;
- Earthquakes; and
- Landslides and avalanches.

3.3.1 Wildfire Threat Profile

The Companies compiled an assessment of Tier 1 – Elevated (moderate), Tier 2 (high), and Tier 3 (extreme) fire risk zones. This process included developing three map tiers and integrating several mapping layers intended to characterize risks across Nevada and the Companies’ CA distribution, telecommunication, and transmission assets. NV Energy owns electric infrastructure in CA, but does not serve any retail customers. A baseline map with risk tiers, discussed in Table 1, resulted from this effort. The three-tier definitions summarize (1) the distribution of extreme fire weather conditions, (2) the historical distribution of wildfires, and (3) a wildfire hazard potential, which includes information about fuels and fire

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5 Risk tier definitions should not be correlated with the high fire-threat district tiers established by the CPUC. These risk tiers were developed to establish a foundation for wildfire specific threats within the service territory. NV Energy also sought to normalize language consistent with local jurisdictions’ CWPPPs and the terminology used by regional fire agencies to ensure consistency.
6 See Appendix A: Map 1 for the high and extreme designations of the developed fire hazard map.
behavior. Two additional layers that were introduced are the Companies’ service territories and urban interfaces. The maps were combined with additional layers to assess the wildfire risk to specific infrastructure, population centers, and other risk-prone factors.

No one tier explicitly evaluates the Wildland-Urban Interface (“WUI”) fire threat; however, collectively, the risk is depicted through map layer combinations that indicate severity of ignition and fire spread potential. The following risk tier definition matrix establishes the wildfire risk tiers.

Table 1: Wildfire Risk Tier Definitions

<table>
<thead>
<tr>
<th>Extreme Risk (Tier 3)</th>
<th>High Risk (Tier 2)</th>
<th>Moderate Risk (Tier 1 Elevated)</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Within one mile from a company-owned transmission, distribution or telecommunications asset (Ignition source)¹</td>
<td>• Within two to five miles from a company-owned transmission or telecommunications asset (Ignition source)³</td>
<td>• Areas where the Bureau of Land Management recorded fire history (1973-2019) perimeter crossed the Companies’ assets (including human/natural caused and other fires)</td>
</tr>
<tr>
<td>• Large and dense vegetation areas are included (fuel loading)²,³</td>
<td>• Some sparse vegetation and grassland areas are included (fuel loading)</td>
<td>• Some sparse vegetation and grassland areas (fuel loading)</td>
</tr>
<tr>
<td>• Areas with a population density greater than 4,000 per square mile in the above electric assets corridor are included (urban interface).⁴</td>
<td>• Areas with a population density between 1,000 to 3,999 per square mile in the above electric assets corridor are included (urban interface)</td>
<td>• Areas with a population density between 500 to 999 per square mile</td>
</tr>
<tr>
<td>• Areas with 98&lt;sup&gt;th&lt;/sup&gt; percentile Fosberg Fire Weather Index are included (extreme fire weather condition)</td>
<td>• Areas between 98&lt;sup&gt;th&lt;/sup&gt; and 90&lt;sup&gt;th&lt;/sup&gt; Fosberg Fire Weather Index are included (elevated fire weather condition)</td>
<td></td>
</tr>
</tbody>
</table>

Wildfire Risk Map Tier Legend

- Tier 3
- Tier 2
- Tier 1 (Elevated)

State Line
County Line

Winnemucca & Elko Fire Threat (Tiers 1 and 2)
1. Confirmed that all distribution assets do not fall within the five-mile buffer of transmission lines.
2. Moderate, Low, Very Low, Non-burnable and Water only wildfire hazard potential layers are excluded from the risk tier classification.
3. Lake Tahoe and Mt. Charleston areas are fully classified as Tier 3 due to high impact or consequential risk. It is worthwhile to note that the intersection of layers in the table above resulted in a Tier 3 definition of partial sections of these two areas.
4. Population data is from U.S. Census Bureau, 2017 American Community Survey Five-Year Estimates aggregated by census tract.
5. Per the Companies’ existing procedures to map existing fire events, a five-mile buffer to the Companies’ assets is used.
Combined maps provide a qualitative assessment of infrastructure risk and focus risk-based investments such as placement of wildfire cameras to reduce the response time to new fire starts. Overlaying the Companies’ assets on the maps identifies regions with higher hazard potential to prioritize risk mitigation efforts.

These maps do not provide a categorical risk assessment for the Companies’ assets and do not present a time-based spatial analysis. Future research could evaluate different factors (weather, fuels, historical fires, population density, asset distribution etc.) if an alternative analysis is warranted.

### 3.3.1.1 Grassland Fire Threat

Grassland fires pose a unique wildland threat due to the rate of spread that can occur upon ignition. Sagebrush habitats, non-invasive annual grasses, and cheatgrass have been identified as principal drivers in exacerbating grassland fires by regional fire agencies and the BLM.\(^7\) Several grassland areas are included in the Tier 2 and elevated Tier 1 areas. Additional areas may be added or removed in future iterations of the Plan based on further refinements to the risk analysis.

### 3.3.1.2 Establishing & Refining Wildfire Risk Tiers

The initial Tier 3, Tier 2, and Tier 1 elevated polygon designations (including landmass within a 10-mile buffer of existing Tiers) will be refined after assessing fine-scale landscape features and other factors that may affect fire risk. To guide this refinement process, additional criteria that are currently being evaluated are detailed below:

1. **Granular building footprints**: Census-based metrics provide structure density at the census block level but highly granular building footprints, such as the Microsoft building footprint dataset, provide more recent, more accurate structure location/density data to supplement existing census data.
2. **Tree mortality**: Widespread tree mortality due to drought and the bark beetle infestation in the forests may increase surface fuel loads and ignition probability due to hazard trees contacting overhead electrical utilities.
3. **Topography**: Steep slopes and complex terrain may make direct attack difficult or impossible, allowing fires to grow more than they would in areas without such firefighting challenges.
4. **Assets at risk in addition to structures / population density**: Exposure due to loss of non-market environmental services, destruction of merchantable timber, and impacts to sensitive habitat all contribute to fire consequence and will be further evaluated.
5. **Fire spread modeling under representative high fire risk wind patterns**: Landscape features (water bodies, rocky/barren areas, fuel break, etc.), interaction between wind and topography, and the location of utilities’ structures may significantly impact fire risk associated with an ignition location. Granular variations in risk are not captured by coarse-grained metrics. Similar modeling has been performed for other electric utilities to prioritize fire hardening and create proactive de-energization zones.
6. **Local/institutional knowledge**: Newer communities and those with defensible spaces and/or enforced weed abatement ordinances are more resilient to fire losses than communities that have not widely implemented mitigation measures.

This is not an inclusive list and factors may be added or removed upon further evaluation. The Companies will continue to evaluate the risk assessment methodology and include any relevant mapping updates from this process in subsequent Plan filings.

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3.3.2 Earthquakes

The USGS identifies active faults and earthquake probability based on historical events and potential energy release. The USGS and the Nevada Bureau of Mines identified ten active faults with high potential earthquake magnitude across the state, though the events are infrequent (if not rare). Even in areas where earthquakes are experienced frequently, they most often occur in smaller magnitudes and pose little infrastructure or public safety risk. The aftermath of a major earthquake, however, presents the greatest risk consequence as lateral or vertical shaking can dislodge footings, sway poles and lines, and impact foundational pads in substations, among other consequences. For the purpose of this risk assessment, the threshold for a damaging earthquake was set at magnitude 6.0 with a moderate to severe Mercalli intensity.

Seiche (also known as a lake tsunami) risk is greatest in the Lake Tahoe Basin, followed by lower risk impact for Lake Las Vegas and Lake Mead in the southern portion of the state, as conveyed by EWG members during the EWG meetings. This is primarily supported by the energy release potential of the active faults near the Lake Tahoe basin (“Basin”). The Basin has historically experienced high-magnitude earthquakes, magnitude 6.0+. Historical records illustrate tsunamis forming as high as 30 feet in the impacted basin, creating the potential for high, forceful water flow into the transmission and adjacent substation assets bordering California.

Earthquakes likewise pose a risk in elevating the threat of land subsidence, which is dependent on several factors, including the soil consistency, moisture level, related aquifer draining (over pumping activities), and liquefaction zones. The Companies will continue to understand land subsidence threat in the service territory as this Plan is tailored to address natural disasters that pose a materially greater risk.

Figure 4: Earthquake Risk Legend

<table>
<thead>
<tr>
<th>Chance of NVE asset experiencing moderate or greater shaking (MMI 6+) in 100-year period</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image_url" alt="Legend Image" /></td>
</tr>
</tbody>
</table>

Source: USGS

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Figure 5: Earthquake Risk Surrounding the Tahoe Basin
3.3.2.1 Earthquake Mapping Process

Earthquake mapping utilized data from the USGS assessing the risk of moderate or greater shaking over 100 years. Moderate shaking, defined by the Modified Mercalli Index ("MMI") as any seismic event rated at 6 or greater on a scale of 10, represents the threshold for potential damage to infrastructure. MMI should not be confused with Richter Scale assessments of damage potential, as the metrics utilized are different for each scale. Events with higher MMI scores will pose more threat to fixed infrastructure and the Companies’ assets. Assets are color-coded based on the identified chance of a 6+ MMI event occurring.
within 100 years. Extreme risk zones are defined as areas that have 74 percent chance or greater. Population density is also a component of risk in the case of asset failure. Only assets within an extreme risk zone that also sit in census tracts with population densities greater than 1,000 people per square mile are included.

Large swaths of the Companies’ service territory have at least low to moderate risk of seismic activity. These assets are not visualized due to the desire to focus on high and extreme risk areas in this Plan. Next steps include research to identify what specific circuits and assets, both within extreme risk zones and across the Companies’ service territory in general, are most susceptible to seismic activity and apply system hardening techniques.

3.3.3 Landslides and Avalanches

Per the USGS, the movement of a mass of rocks, debris, or earth down a slope is referred to as a landslide.\textsuperscript{9} This event occurs when forces acting on a slope, including gravity, exceed the strength of the materials forming the slope. Both debris flows (mudslides) and falling rocks or soil are encompassed by this definition. Landslides are nearly always caused by the interaction of gravity with one or more other external factors and most often occur when a slope is already primed for movement. External influences may include rainfall, snowmelt, erosion from water or wind, earthquakes, and human disturbance. Landslide hazards exist throughout the state of Nevada but are largely concentrated in mountainous regions that are exposed more routinely to external factors like snow, rain, and earthquakes. Service territory and assets in California and in hilly or mountainous areas surrounding Carson City and Reno are at greatest risk. Little to no risk is posed to assets in the Las Vegas Valley or surrounding areas, with the exception of Mt. Charleston and the mountains to the south of Sunrise Manor and Henderson. Despite differences in substrate, many of the same triggers and effects of landslides are also shared by avalanches.

An avalanche occurs when a layer of snow collapses and cascades down a slope. Factors that lead to an increased avalanche hazard include steep slopes, heavy snow cover, weak snow layers, and the prevalence of triggers.\textsuperscript{10} Avalanches can be triggered by one or more of a variety of vibrations caused by human activity (heavy machinery, railways, and snow vehicles), sonic booms, unusually heavy snow, or seismic activity such as earthquakes. Avalanche risk is limited almost exclusively to the western portion of Sierra Nevada Mountains, including Tahoe, Truckee, Reno, and Carson City due to the concentration of annual snowfall in these areas, and in Mt. Charleston and assets surrounding Henderson.

Both landslides and avalanches pose a significant threat to all nearby assets in affected areas. Transmission lines, distribution lines, substations, and other assets (e.g. telecommunications equipment) may be knocked over or buried by either type of event. Debris collected by a landslide or avalanche may also impact the Companies’ infrastructure or become entangled with lines and exposed equipment.


Figure 7: Landslide and Avalanche Risk Legend

Overhead assets in high landslide or avalanche risk areas

- Very High Landslide Susceptibility
- High Landslide Susceptibility
- NVE Substation

Global landslide susceptibility is estimated by NASA through a model that incorporates geology, seismic risk, forest cover, slope, the prevalence of roads, and past recorded landslides. Relative landslide risk is based on landslide susceptibility values that consider these factors. NV Energy incorporated these values without any additional modifications. Only 3% of the global area studied is deemed very highly susceptible, and these areas within NVE service territory will be studied further to identify historical events and electric infrastructure impacts.

Source: NASA

Figure 8: Landslide and Avalanche Risk in the Northeast
Figure 9: Landslide and Avalanche Risk in the Reno / Carson City Area
3.3.3.1 Landslide and Avalanche Mapping Process

The National Aeronautics and Space Administration ("NASA") identifies high and very high landslide susceptibility zones through a quantitative analysis of geology, seismic risk, topography, forest cover, the prevalence of roads, and past recorded landslides. These factors inform a model that rates locations by landslide susceptibility risk on a relative scale of 0 to 1, where zero is lowest risk and one is highest. High landslide susceptibility refers to a value higher than 0.671 on this scale, while Very High susceptibility represents a value over 0.75. Annual snowfall totals are included as another layer to identify avalanche risk through similar methodology. Quantitative data points (snow fall, precipitation, slope, elevation) are considered as inputs, but final outputs are qualitative (i.e. low, moderate, high risk of landslides). Assets within an identified "high" landslide and/or avalanche susceptibility zone are color coded orange, while those within a "very high" or extreme risk area are denoted in red. Global landslide susceptibility is estimated by NASA through a model that incorporates geology, seismic risk, forest cover, slope, the prevalence of roads, and past recorded landslides. Relative landslide risk is based on landslide susceptibility values that consider these factors. NV Energy incorporated these values without any additional modifications. Only three percent
of the global area studied is deemed very highly susceptible. This determination will be reviewed as additional data is identified to evaluate the potential effect of that information on future iterations of the Plan.

3.3.4 Flooding, Flash Flooding, and Monsoon Events

Areas at risk of periodic flooding are defined as Special Flood Hazard Areas ("SFHAs") by FEMA.\textsuperscript{11} SFHAs are identified as any area that has a one percent or greater chance of inundation in any given year. More commonly, these SFHAs are referred to as base flood or 100-year flood zones. Hazard areas typically lie adjacent to natural and manmade waterways (including lakes, rivers, and canals) with elevated risk of seasonal flooding due to prolonged rain patterns or snowpack melt. Seasonal flooding risk is more significant in the areas adjacent to the Sierra Nevada mountain range, including the Reno, Carson City, and Lake Tahoe areas. Parts of the Las Vegas metropolitan area also lie in seasonal 100-year flood zones, but flash flooding events are perhaps the primary concern in the Las Vegas Valley due to lower average annual precipitation.

Flash floods are defined as any flooding event that occurs within six hours of a heavy rainfall event.\textsuperscript{12} Damaging flash floods may occur both within and outside 100 and 500-year flood zones as the direct result of a downpour, often caused by severe thunderstorms. These floods often occur in urban areas, where physical infrastructure prevents the seeping of rainwater into the soil. Flash floods may also occur due to dam, levee, or drainage system failure. While this can occur at random due to standard stress, flash floods due to failure are often caused by other disasters like earthquakes and landslides. Historic flash flood events reported to NOAA are concentrated around population centers, including Carson City, Reno, and Las Vegas. Las Vegas in particular has a history of flash flood events caused by seasonal monsoons. Hundreds of miles of storm drains, canals, and levees have been constructed in the Las Vegas metropolitan area to reduce the risk of both flash and seasonal flooding.

Substations and other low-lying assets are at the greatest risk of impact from all types of flooding. Water caused by conventional seasonal flooding may penetrate substation facilities and cause interaction with exposed components. Flash flooding events, particularly those caused by infrastructure failure, may in contrast affect all types of neighboring assets (including susceptible poles) due to the force of rushing water. Flooding events may also contribute to instances of landslides and land subsidence. The Companies will continue to understand land subsidence threat in the service territory as this Plan is tailored to address natural disasters that pose a materially greater risk.

Figure 11: Flooding and Monsoon Risk Legend

\begin{figure}
\centering
\includegraphics[width=\textwidth]{flood_legend.png}
\caption{Flooding and Monsoon Risk Legend}
\end{figure}


Figure 12: Flooding and Monsoon Risk Surrounding the Lake Tahoe Basin

Figure 13: Flooding and Monsoon Risk in the Northeast
3.3.4.1 Flooding Mapping Process

FEMA shapefiles for 100-year flood zones were used to identify areas of significant flooding risk in the Companies’ service territory. Historic heavy rain and flash flood data collected by the NOAA National Climatic Data Center (“NCDC”) informed areas outside of 100-year flood zones most at risk for inundation. The Companies’ assets in an identified 100-year flood plain or in proximity to an historic flash flood event were color coded as high risk. Internal company data provided locations for dams within the Companies’ service territory. Dams were considered to be an inherent flooding hazard in the unlikely case of failure caused by a natural disaster. The Companies will continue to understand the assets adjacent or downstream of relevant dams as this Plan is tailored to address natural disasters that pose a materially greater risk.

3.3.5 High Winds and Thunderstorm Winds

High wind events are defined in this Plan as any wind event that reaches recorded speeds of at least 60 miles per hour ("mph"), regardless of whether recorded speeds are a gust or sustained. Per NOAA, reported high wind events are typically split into high wind and thunderstorm wind categories. Winds occurring within

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30 minutes of lightning being detected are classified as arising from convection. Convective winds above 58 mph and any other wind causing damage during a thunderstorm are jointly classified as significant thunderstorm wind events. Downbursts or microbursts, both dry and wet, are considered to be thunderstorm wind events. Thunderstorm winds, particularly downbursts, may affect less expansive areas than other high wind events due to their concentrated effects on the land area directly below or adjacent to a thunderstorm front.

Criteria for classification as a non-convective high wind event, meanwhile, may vary based on local or regional definitions. Generally, sustained winds of 40 mph or greater lasting for at minimum one hour qualifies, as does any single gust (sustained or unsustained) of 58 mph or greater, so long as those measurements did not occur in conjunction with a thunderstorm. Size of area affected is not considered when classifying wind events in this manner. In the absence of measurement equipment, observers often rely on a damage assessment to retroactively estimate wind speed. Caution must be used with this approach, however; observed damage after a wind event does not automatically imply wind speeds above 40 mph were achieved, just as high wind events do not necessarily imply damage will be caused. Damage, or the lack thereof, is a function of wind speed, lifted debris, and the structural integrity of affected assets.

High winds can threaten overhead lines. Wood poles that have experienced weakening through weathering, water damage, physical impacts, or animal and insect boring may be susceptible to toppling in high winds. Fallen lines pose a significant ignition risk, particularly when fire conditions are elevated. Wind events can also lead to sandstorms. High wind risk is ubiquitous throughout the Companies’ service territory, despite incident reporting being higher in more populated areas due to the higher concentration of weather arrays and trained spotters. The hazard is not homogenous, however. For example, risk in urban areas may be either reduced by obstacles or elevated by artificial wind tunnels created by the constructed environment. Asset-level susceptibility to future wind events throughout the Companies’ service territory must consider local currents and surrounding infrastructure or topography when evaluating system hardening needs. High wind events can also include sandstorms, but sandstorms do not pose a unique threat to infrastructure. Moreover, any damage from high wind or debris carried by a sandstorm can be classified as a high wind incident.

Figure 15: Wind and Thunderstorm Risk Legend

<table>
<thead>
<tr>
<th>NVE overhead assets within a 1 mile radius of a past recorded wind event of 60 mph or greater</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Assets with Extreme High Wind Risk</td>
</tr>
<tr>
<td>NVE Substation with Extreme High Wind Risk</td>
</tr>
</tbody>
</table>

The areas were identified by applying a 1 mile buffer radius of past recorded high wind events obtained from the National Weather Service and census tract areas with a population density of 1000 or more per square mile.

Sources: National Weather Service, US Census Bureau, and Internal NVE Data

High wind events are defined as sustained winds of 60 mph or greater.
Figure 16: Wind and Thunderstorm Risk Surrounding Reno
Figure 17: Wind and Thunderstorm Risk Surrounding Las Vegas
3.3.5.1 Wind Event Mapping Process

Historic high wind and thunderstorm wind event data from the NCDC were combined and organized by NWS forecast zone. Zones with more past incidents were assumed to have a higher probability of future high wind events. Assets within identified high risk zones were then color-coded for high risk. Initial mapping revealed much of the Las Vegas Valley to be high risk, but excluded internally identified high risk areas, including Mt. Charleston. This discrepancy was due to NCDC data for wind events being biased towards highly populated areas, where more measurement devices and trained spotters reside. To narrow the frame of reference and ensure internally identified high risk zones were included, the Companies’ data was used to supplement NCDC records. Assets within one mile of events included in this modified data set (e.g. those likely exposed to recorded wind speeds of 60+ mph) were considered. Assets within census tracts that report a population density of at least 1,000 people per square mile were visualized. As a result, this map identifies specific assets exposed to past risk events in high population areas, which may or may not correlate with future asset-level risk or risk to customers. This approach stands in contrast to the previous four disaster categories included in the risk assessment, which each relied partially or completely on predictive data sets showing future risk.

3.3.6 Winter Weather Events

Winter weather is defined in this Plan as any snow event that either i) meets or exceeds designated 12 and 24-hour snow accumulation thresholds or ii) poses a threat to life or physical infrastructure. Three separate event designations – heavy snow, winter storms, and blizzards – are included under this disaster category. Heavy snow events refer to any accumulation of snow in excess of locally and regionally defined 12 and 24-hour accumulation thresholds.\(^{14}\) Per NOAA, this could correlate to values of at least four to eight inches in a 12-hour period or six to ten inches in 24 hours, varying by locality. Heavy snow events may cause damage to infrastructure multiple days after the conclusion of snow fall due to strain from snow loading on physical infrastructure.

Winter storms and blizzards are distinct from heavy snow events in that they exhibit multiple hazards aside from snow deposits. Winter storms may combine two or more hazards including snow, wind, sleet, and ice.\(^{15}\) They do not require snow deposits to pass a certain threshold for inclusion as a potentially disastrous event, due to the combination of multiple risk factors. Blizzards are a specific category of winter storm defined by a sustained reduction in visibility to a quarter-mile or less for three hours or more.\(^{16}\) Winter storm events, particularly blizzards, may have sustained winds that meet or exceed criteria for inclusion as a high wind event, which are recorded sustained winds 40 mph or higher.

While snow fall from winter weather events typically does not threaten the Companies’ infrastructure, extreme events may bury assets or lead to an increased risk of avalanche activity. Weighted snow caused by a higher moisture content, colloquially known as “Sierra cement,” can weigh down lines and poles with minimal collected material. When combined with high winds and low visibility, winter weather can also increase the difficulty of monitoring and servicing infrastructure or responding to outages. These risks are concentrated in and around the Sierra Nevada mountain range, where snow loading is more common due to the high prevalence of winter weather.


\(^{15}\) Id.

\(^{16}\) Id.
Figure 18: Winter Weather Event Risk Legend

**NVE Overhead Assets**

- Overhead Wires in High Risk Area
- Overhead Wires in Moderate Risk Area
- NVE Substation

High risk areas are defined as National Weather Service forecast zones that have a class range of 7% - 24% (Snow Events / NWS Zone Sq Miles)

Moderate risk areas are defined as National Weather Service forecast zones that have a class range of 1% - 7% (Snow Events / NWS Zone Sq Miles)

The risk was determined by recording the total number of heavy snow/blizzard events from 2000-2019 that occurred in each NWS forecast zone and then dividing that number by the zones total area (square miles). This process normalizes the data to create a proportion or ratio for each zone that is then separated into risk classes (e.g., The Lake Tahoe area had 65 events and an area of 340 sq miles for a ratio of 0.19 or 19%).

Source: National Weather Service

Figure 19: Winter Event Risk Surrounding the Lake Tahoe Basin

Map showing winter event risk surrounding the Lake Tahoe Basin with a focus on the Reno area.
3.3.6.1 Winter Weather Mapping Process

Data from the NCDC for blizzards, winter storms, and heavy snow events was collected and aggregated as a single winter weather dataset encompassing events in Nevada and eastern California.\textsuperscript{17} Due to the high frequency of heavy snow and winter storms in these areas, only the most recent 500 events of each type were included in this dataset. All winter weather events were then sorted by the NWS forecast zone.\textsuperscript{18} The Companies’ assets within each forecast zone were color-coded based on the number of winter weather events observed in the aggregated dataset. Assets in areas of high or very high incidence of winter storms were included in the final visualization.

3.3.7 Natural Disaster Profiling Next Steps

Disaster preparedness traditionally follows a “Mitigate-Prepare-Respond-Recover” progression. Mitigation and preparedness come in advance of a disaster event, while response and recovery efforts follow an event’s occurrence. In the case of wildfires, robust analysis has been conducted to allow the Companies to develop plans covering all four disaster mitigation phases down to the circuit level. In addition, inspections and corrections and system hardening programs are included in this Plan to mitigate other natural disaster risks. As additional data is collected and analyzed on the risk to specific circuits caused by other disaster types, mitigation and preparedness processes will be enhanced for other natural disasters. Certain system hardening efforts, described further in Section 4.3, that are targeted toward reducing ignition risk will also reduce risk for other disasters as an added benefit. For example, undergrounding assets will reduce risk of failure in the event of a high wind event or earthquake in addition to reducing ignition threat. Potential external benefits will be included when evaluating proposed system hardening upgrades to specific assets.

\textsuperscript{17} NOAA. “Storm Events Database.” https://www.ncdc.noaa.gov/stormevents/choosedates.jsp?statefips=32%2CNEVADA.

NV Energy has applied a thoughtful approach in initially vetting the relevant natural disasters that have historically impacted its electrical system or have had significant frequency and/or severity in occurrence throughout the state. Mitigating impacts of these events occur under the approaches proactive (mitigate and prepare) and reactive (respond and recover) strategies. As programs and projects are executed, the Companies will gain lessons learned into the most effective mechanisms to protect the public from adverse impacts as a result of utility practice and/or electrical infrastructure during extreme weather incidents.

The Companies will continue to evaluate all natural disasters as stakeholder feedback is received and additional explorations into state-level risk analyses are measured against electrical asset risk. Under direction of the Commission, natural disasters are not limited to the identified types presented in the Regulations or this Plan. Data analytics and probability modeling will also occur in future revisions of the Plan to supplement the understanding of the baseline threats that exist with natural disasters. NV Energy will also be investigating alternative methods to illustrate aggregated risk when considering the rare occurrence of multiple catastrophic natural disasters occurring simultaneously.

### 3.3.8 Excluded Natural Disasters

The risk assessment process considered natural disaster threats that may impact the Companies’ electrical system in the foreseeable future. Feedback received from the EWG meetings has been integrated in the risk assessment, producing a prioritized natural disaster threat list. The Companies will continually evaluate threats to determine if the risk potential threat has elevated enough to include in future Plan filings.\(^\text{19}\)

<table>
<thead>
<tr>
<th>Natural Hazard</th>
<th>Understanding of Present Risk</th>
<th>Forecasted Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Section 3.3</strong></td>
<td><em>Immediate Profiling: 2020 Plan</em></td>
<td><em>Included in the Plan</em></td>
</tr>
<tr>
<td></td>
<td>• Wildfires and grassland fires;</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Flooding and monsoons;</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• High winds and thunderstorm winds;</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Winter weather events;</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Earthquakes; and</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Landslides and avalanches.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Triennial Plan Filing</strong></th>
<th><strong>Volcanic Eruption</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>No active volcanoes are present within the Companies’ service territory (in Nevada or CA transmission asset locations). Small eruptions from the Mono Craters area near Lee Vining and Mono Lake in CA have historically impacted Nevada through ash travel, which can result in several inches of cement-like coating, weighing down and potentially impacting wires and other electrical infrastructure. Other volcanoes that pose ash threat include Mount Lassen, Mount Shasta, and the Long Valley Caldera in California as well as volcanoes in the Cascade</td>
</tr>
<tr>
<td></td>
<td>Triennial Plan Filing</td>
</tr>
</tbody>
</table>

\(^{19}\) Stakeholder feedback included discussions of human-involved hazards, as historical evidence supports the need to harden system assets against activities such as disaster-level vandalism or electric magnetic pulse attacks on the grid. NV Energy considered the discussion as a general utility operational concern, though this hazard is out of scope pursuant to SB 329 and the Regulations and was not included in the risk assessment process.
<table>
<thead>
<tr>
<th><strong>Hailstorms</strong></th>
<th>Mountains in the Pacific Northwest.(^{20}) It was determined that while there are several active or at-risk volcanoes along the CA border and a greater risk with western U.S. super volcanoes, this risk assessment process would require a comprehensive analysis and understanding of intrastate risk profiles, tangential to the baseline assessment. Input from the EWG encouraged the Companies to include this natural disaster risk in future Plan updates.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Heat Waves / Droughts</strong></td>
<td>The severity of hail storm events is typically defined by the diameter of the ice particles. Small diameter hail (under 0.75 inches) does not pose a significant threat to life or property. Hail storms that may damage infrastructure do occur within the Companies' service territory, however, approximately 16 significant storm events were registered as causing damage to life and property since 1951, according to NOAA. As with tornadoes, the majority of these events occurred outside of the Companies' service territory. The combined infrequency and limited range of these events resulted in the determination that, at this time, it is a low priority for this Plan filing.(^{21})</td>
</tr>
<tr>
<td><strong>Tornadoes</strong></td>
<td>Heat waves and extreme drought are common in the Companies’ service territory; however, this will need further analysis to assess the physical threat to fixed electric infrastructure. Conditions may lead to other natural disaster risk conditions, as noted by the EWG members (e.g., wildfire risk). Wear and physical degradation from heat events does occur, though may not require an immediate response, in many cases. Failures relating to extreme heat have not been uniquely identified. Droughts are another persisting condition that presents concerns with hydroelectric generation and other water-intensive generating stations. The Companies determined that this category presents a greater risk related to energy Resource Adequacy, and this assessment would require additional resources and analyses to support the justification of independent risk. If higher temperatures result in Resource Adequacy issues in the Companies’ service territory, these would need to address in Integrated Resource Plan or other regulatory filings. The Companies will consider profiling these weather conditions in future Plan updates.</td>
</tr>
<tr>
<td><strong>Triennial Plan Filing</strong></td>
<td>Triennial Plan Filing; as a subset of risk relating to thunder and severe storms</td>
</tr>
<tr>
<td><strong>Low risk; NV Energy will reconsider for profiling in future updates</strong></td>
<td>Heat Waves and extreme drought are common in the Companies’ service territory; however, this will need further analysis to assess the physical threat to fixed electric infrastructure. Conditions may lead to other natural disaster risk conditions, as noted by the EWG members (e.g., wildfire risk). Wear and physical degradation from heat events does occur, though may not require an immediate response, in many cases. Failures relating to extreme heat have not been uniquely identified. Droughts are another persisting condition that presents concerns with hydroelectric generation and other water-intensive generating stations. The Companies determined that this category presents a greater risk related to energy Resource Adequacy, and this assessment would require additional resources and analyses to support the justification of independent risk. If higher temperatures result in Resource Adequacy issues in the Companies’ service territory, these would need to address in Integrated Resource Plan or other regulatory filings. The Companies will consider profiling these weather conditions in future Plan updates.</td>
</tr>
</tbody>
</table>

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\(^{21}\) NOAA. "Storm Events Database: Nevada." [https://www.ncdc.noaa.gov/stormevents/listevents.jsp?eventType=%28C%29+Hail&beginDate_mmm=01&beginDate_dd=01&beginDate_yyyy=1950&endDate_mmm=12&endDate_dd=30&endDate_yyyy=2019&county=ALL&hailfilter=0.00&tcnfilter=0.00&windfilter=0.00&sort=DT&submifBtn=Search&state�플스=32%2CNEVADA](https://www.ncdc.noaa.gov/stormevents/listevents.jsp?eventType=%28C%29+Hail&beginDate_mmm=01&beginDate_dd=01&beginDate_yyyy=1950&endDate_mmm=12&endDate_dd=30&endDate_yyyy=2019&county=ALL&hailfilter=0.00&tcnfilter=0.00&windfilter=0.00&sort=DT&submifBtn=Search&state�플스=32%2CNEVADA). 2019.

| Natural Disaster Protection Plan |

| **Impacting the northeast region of the state. Depending on the Enhanced Fujita Scale rating of the natural hazard, the effects of tornados on the Companies’ infrastructure can align with those from microburst or high wind gust events requiring overlapping mitigation measures.** |

| Currently at Low Risk or Not Applicable |

| **Hurricanes** | Little change of hurricane-like conditions or a tropical depression impacting the southern region of the state. Nevada’s geographic position is far enough inland making impact extremely unlikely. Hurricanes have carried heavy precipitation and winds into southern areas of the state, though, and extreme precipitation and wind gusts are captured as subsequent risks within several of the profiled natural disasters. | Unlikely risk in the foreseeable future |

| **Radon Gas** | Naturally-occurring radon gas has been identified as a state hazard as illustrated in the UNR’s MyHAZARDS map, but poses no risk to the Companies’ service territory, assets, or operational practices. | Not applicable |

| **Solar Flares / Coronal Mass Ejections** | Solar flares and other geomagnetic disturbances have the ability to affect the bulk electric power system, transmission-level assets, and communications infrastructure. Preparation requirements for these events are already outlined for transmission planners, transmission owners, and generation owners by the North American Electric Reliability Corporation’s (“NERC”) Reliability Standard TPL-007-1, contained under Federal Energy Regulatory Commission (“FERC”) Order No. 830. EWG discussions also revealed that astronomical hazard profiling may be tangential to the natural disaster considerations in SB 329. | External to natural Earth events; currently being addressed in compliance with federal regulatory requirements |

### 3.4 Data Tracking for Risk Analysis

Data used for this asset risk assessment and mapping exercise were sourced from federal agencies (e.g., the NOAA, the NASA, and the NWS), state agencies and universities (e.g., the UNR), and internal records (e.g., wind event outage information). Specific data sources and assumptions for the six types of disasters included in this Plan are included above in Section 3.3 under each disaster subheading. The Companies will further evaluate these data sources, methodologies, and assumptions in a subsequent Plan update. Improvements or adjustments will be recorded.

As the Companies continue risk assessment for disasters included in this Plan and begin follow-up activities, internal data on outages and system impacts will be incorporated to pinpoint specific assets at greatest risk from each disaster type. System hardening efforts will be coordinated based on this tracked and updated information.

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3.4.1 Trending Ignition Events

Future ignition events will be tracked and compared to internal data on past ignition events. This will be used to evaluate the effectiveness of wildfire-specific system hardening and coordinated response efforts detailed further in Section 4.3 of this Plan. Further description of metrics-related data tracking for ignition events and hazardous weather conditions are included in Section 8.

3.4.2 Trending Equipment Damage Events

Any event that damages the Companies' infrastructure or causes the failure of an asset will be recorded. Incidents of equipment damage will help prioritize future system hardening efforts and equipment replacement to reduce susceptibility to disaster events.

3.4.3 Trending Outage Incidents due to Natural Disasters

Record of outages caused by natural disasters identified in this Plan will be maintained by the Companies. Similar records of outage events caused by disasters excluded from this plan will also be considered and used to update which disasters are included or excluded in future Plan filings. Identified Major Event Days ("MEDs") will be recorded for each disaster type, and will be considered for further evaluation.
4 NATURAL DISASTER PROTECTION STRATEGIES AND PROGRAMS

In order to reduce potential wildfire ignitions and other natural disaster impacts, NV Energy has considered industry best practices as they are applicable, feasible, and cost appropriate to NV Energy’s risk exposure. The Companies’ goal is to minimize ignition risk and the frequency of PSOM events through internal controls and mitigation strategies for outside threats. The programs and projects, along with traditional overhead rebuilds, do not completely eliminate the potential consequences of external events impacting the utility’s electrical assets, which may lead to equipment fires or faults, worsening outcomes for the public and causing additional safety concerns. The Companies are seeking to balance the need for a more resilient electric grid with increased cost implications in order to abate internal and external threats with practical and achievable approaches wherever cost-effective.

4.1 Operational Practices

Operational Practices are those followed by the Companies to minimize or eliminate the risk of a natural disaster. This is important in managing the controllable risk to the Companies’ electric infrastructure. For example, Operational Practices may include locking out or changing the mode of operation for reclosers during periods of high fire threat. The Companies also have seasonal safety operating procedures to follow during declared fire season.

4.1.1 Protocols Complying with the Wildland-Urban Interface Code

Compliant vegetation management will mitigate vegetation encroaching on electric lines in WUI. Annual system inspections will pay particular attention near the WUI. NV Energy will work with impacted counties to ensure alignment with the requirements. See Section 4.4 for a detailed discussion relating to activities meeting the International Wildland-Urban Interface Code (“IWUIC”), including Appendix A.\(^{25}\)

4.1.2 Recloser Protocols

NV Energy disables reclosers on circuits during periods of high fire threat. This avoids the potential for sparking during multiple reclosing events that may ignite a wildfire. Specific circuits, not limited to circuits in Tier 3, are set for fire season operation mode.

4.1.2.1 Protocols for Disabling Reclosers

Automatic reclosers are disabled and any trip requires patrol of the main line before reclosing. This operation mode is also used on transmission circuits. The Companies will continue disabling reclosers in 2020 and will increase cooperation with Liberty Utilities in the Lake Tahoe area. The Companies also have seasonal safety operating procedures to follow during declared fire season.

4.1.3 Wildfire Safety Training

NV Energy conducts safety training class for First Responders in electrical and gas system safety.

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Classes are taught onsite by industry professionals around the state of Nevada, within the NV Energy service territory.

Training modules include:

- Basic Electrical Safety Academy Training;
- Electrical Safety for First Responders;
- Solar Safety for First Responders;
- Emergency Response to Battery Storage;
- Natural Gas Safety for First Responders;
- Identification of Parts training for Fire Investigators; and
- Generating Plant Safety for Emergency Responders.

Additional training requests are done through FirstResponderTraining@nvenergy.com and are accommodated on a case-by-case basis.

NV Energy conducts yearly internal wildland safety classes for all field personnel. The training covers wildland personal protective equipment, preventive measures when working in the wildland, fire terminology, safety lookouts and escape routes, fire shelter deployment and basic incident command system review. This training is provided by local, state and federal fire departments.

### 4.2 Inspections & Corrections

The Companies’ plan to maintain procedures and inspection cycles for electric equipment inspections and corrections as proposed in this section. Those activities are designed to meet evolving prudent utility practices for utilities managing increased fire risk and are based on benchmarking of other electric utilities facing similar risks. This is also important in managing the controllable risk associated to the Companies’ electric infrastructure within its ROW. Inspections are performed with proactive intent to identify, triage, and remediate hazardous findings either related to the Companies’ assets or easement vegetation. As it relates to the Plan, the proposed initiatives for anticipated corrections aim to mitigate the ignition risk associated with the Companies’ assets, create grid resiliency improvement opportunities sufficient to withstand a natural disaster event, and minimize the need for initiating PSOM events. Per good utility practice, proactive inspections identify needed corrective actions early to increase resiliency of the grid by reducing equipment failure instances and lowering wildfire ignition risk. When failing equipment is identified and repaired or replaced in time, customer reliability likewise benefits. Inspections establish a baseline for future fire and natural disaster initiatives, to ensure that equipment has been routinely assessed to determine any corrective needs or potential upgrades before reaching a critical point of failure.

Equipment inspections may be either “patrols” or “detailed inspections.” Patrols are defined as a simple visual inspection of utility equipment and structures to identify obvious structural problems and hazards. These involve spot checks of the system, to identify and prioritize corrections or repairs. A detailed inspection is defined as a careful examination of overhead equipment and structures that is carried out on a structure-by-structure basis. Detailed inspections are visual, where practical, and use routine diagnostic tests. During a detailed inspection the condition of the equipment is recorded. Corrective action or corrections are defined as maintenance, repair, or replacement of utility equipment and structures so that they function properly and safely. This inspections and corrections program identifies and corrects overhead equipment problems to mitigate the potential effects of natural disasters on the Companies’ grid and reduce risk of wildfire due to equipment failure.

Detailed inspections are performed in accordance with the criteria listed below for overhead electrical infrastructure. However, the inspection is not limited to these checklist items and all abnormal conditions are identified and reported. This also includes vegetation hazard notifications in the vicinity of NV Energy lines.
An inspector will complete an inspection form in the application for each structure individually and will take photos for documentation. The structure inspections focus on the wood poles, hardware and conductor conditions, including, but not limited to the following:

- Corrosion;
- Vandalism;
- Loose Hardware;
- Missing Hardware;
- Clearance Issues; and
- Vegetation Hazards.

The crews also conduct a visual inspection of overhead conductor attachment points and visual inspection of conductor spans between the pole locations.

### 4.2.1 Requirements & Best Practices

NV Energy has proposed a patrol and detailed inspections schedule per the table below. This is a proposed standard for electric equipment inspections for the NV Energy electric system. Frequency of patrols or detailed inspections may be increased if deemed necessary for safe operation of the electric system.

<table>
<thead>
<tr>
<th>Table 3 - Proposed NV Energy Inspection Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>Identified Fire Risk Tiers</td>
</tr>
<tr>
<td>---------------------------</td>
</tr>
<tr>
<td>Overhead Transformers, Switching / Protective Devices, Regulators / Capacitors, Conductor and Cables, Wood Poles and other overhead assets</td>
</tr>
</tbody>
</table>

### 4.2.2 Corrective Actions from Patrol & Detailed Inspections

A circuit patrol or detailed inspection calls for a crew to patrol the circuit with the main objective to identify eminent hazards that require immediate corrective actions. The crew identifies repairs and equipment change outs and generates an associated corrective maintenance work order for the repairs in NV Energy’s or NV Energy’s contractor’s work management system. The crew will set a priority for each project. Upon completion of work, the circuit will be monitored for any further interruptions. In order to remain in a proactive stage, applicable metrics in Section 8 will also be tracked to monitor progress and update next steps accordingly.

Detailed inspections on the Companies’ system were initiated in 2019. Inspections and corrections continue in the Tier 3 and 2 areas and NV Energy also plans to initiate them in the Tier 1 elevated areas. This is the first time NV Energy has conducted this level of detailed inspections in the wildfire risk tiers and proposed to conduct them going forward on the cycle proposed in Table 3 above.

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26 Refer to Section 3.3.1 for wildfire risk tier definitions.
4.2.3 Program Costs

Inspections and corrections cost projections are included in Table 4 below, as are costs associated with program management and oversight tasks. These costs are estimates and may vary based on the actual condition of the assets that are inspected.

<table>
<thead>
<tr>
<th>Table 4: Wildfire Safety Inspections &amp; Corrections Projected Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inspections &amp; Corrections (Total)</td>
</tr>
<tr>
<td>----------------------------------</td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>

In addition, the Companies also propose the following methodology to identify impacted distribution circuits in southern Nevada (under non-wildfire natural disaster risk zones) in accordance with risk assessment based approach outlined above in Section 3. The purpose of the analysis is to:

- Identify territory under increased threat of natural disasters based on the last five years of nature-caused outages data in addition to work already completed per Section 3.
- Identify the top 20 impacted distribution circuits.
- Patrol the top 20 circuits and identify issues and priorities. The patrol costs will be classified as operations and maintenance expenses. The list of issues will be documented and distributed to the appropriate business unit to issue Work Orders, plan, and schedule the resources to address and make necessary repairs.
- Inspect the top 10 circuits identify issues and priorities. The detailed inspection costs will also be classified as operations and maintenance expenses. The detailed inspection report will be documented and distributed to the appropriate business unit to issue Work Orders, plan and schedule the resources to address and make necessary repairs.
- Circuit patrols and detailed inspections will follow the established process of once a year and once every four years respectively or as specified in the approved Plan.
- Propose cost effective mitigation plan through work management and work planning. Capital and operations and maintenance expenditures will be identified per established processes and will be filed for cost recovery.
- The Companies estimated that approximately 100 wood poles per year will be replaced with metal poles under this program for the next three years. NV Energy anticipates replacing approximately 25 wood poles in 2020, as approval of the Plan and permitting timelines may result in a late start for the year.

The Companies have had extreme weather-related outages in southern Nevada every year, especially during the monsoon season in July through September. These outages result in wood pole failures with energized conductor on the ground that presents significant public safety risks. As described under the pole stopper and critical crossing programs and also noted in Executive Summary above, NV Energy has witnessed a degradation in electric service due to a number of factors, including aging infrastructure, changing climate conditions, extended drought, extreme weather events, extreme wind, etc. Therefore, this proactive program is prudent and reasonable.

The Companies have never performed similar proactive programmatic replacement of wood poles in high risk zones; therefore, the program is incremental. The alternative to not perform this replacement will continue to result in overhead conductor failures that may result in catastrophic events or public safety impacts. These operational, maintenance, administrative and general ("OMAG") impacts may be significantly more costly when compared to the program costs.
Table 5: Other Natural Disaster Inspections Costs

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit Resiliency Patrols</td>
<td>$1,666,732</td>
<td>$1,700,067</td>
<td>$1,734,068</td>
<td>$1,768,749</td>
</tr>
<tr>
<td>and Inspections-Natural</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Disaster Risk Zones (non-wildfire) (OMAG)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Performing these inspections is essential both to enhancing the resiliency of the Companies’ grid and identifying and mitigating any preventable ignition risks that could affect the Companies’ assets. Because there is no alternative that would provide equivalent results, no additional alternatives were evaluated.

4.3 System Hardening

System hardening relates to design enhancements that reduce the likelihood of the electric infrastructure igniting a wildfire and making it more resilient to natural disasters. System hardening investments were developed and targeted based on the greatest impact in high-risk areas and based on historical natural disaster events such as flooding, earthquakes, and winter storms. The system hardening evaluation considered historical outage data to assure the investments provide safe and reliable service to the customers.

4.3.1 Grey Wire Replacement Program

The grey wire program replaces specific obsolete service wire and secondaries that have deteriorated to the point where the wire is a risk of becoming an ignition source for a wildfire. The grey wire used a type of rubber insulation material to cover the wire, which over time has aged to the point where it is no longer insulating the wire. Grey wire replacement is an industry practice to reduce ignition sources that can cause a wildfire.

Grey wire conductors were installed from the late 1960s through early 1980s. It features a grey-colored rubber insulation as opposed to the more modern and reliable black insulation used today. After many decades of exposure to the sun, the grey insulation has become brittle and flakes from the conductor creating exposed, uninsulated wires. Should vegetation such as tree limbs, vines, or brush come in contact with areas no longer covered by the grey insulation, ignition and a fire can result.

It is an unacceptable ignition risk to maintain the grey wire services and secondary conductors in the Tier 3, Tier 2 and elevated Tier 1 wildfire areas. There are 2357 locations or conductor spans of grey wire in the Companies’ system, encompassing a total of 256,171 feet of conductor.

Incremental Spending Justification

NV Energy has already recognized the need to replace the grey wire due to the risk of starting a wildfire. The grey wire replacement program started several years ago. At historical funding levels, the grey wire replacement would not be completed for many years. Because the replacement of grey wires in NV Energy’s system is necessary to address the risks identified in NV Energy’s risk assessment, NV Energy’s Plan incorporates the pre-existing grey wire replacement program and proposes that the program be expanded, subject to Plan approval, to incrementally increase spending levels so that grey wire in the highest risk areas can be completed much more quickly. NV Energy’s Plan provides for complete replacement of grey wire in high risk areas over a two-year period, spending approximately $2.5 million (“M”) in year 2020 and $2.0 M in year 2021. The replacement will be prioritized, based on the higher risk, to complete work in Tier 3 areas (such as the Incline and South Tahoe areas), followed by Tier 2 and elevated Tier 1 areas.
Alternative Strategy Review
Leaving the wire in place will continue to present significant ignition risk that cannot be adequately mitigated in another way. Therefore, no additional alternatives were evaluated or cost benefit review performed. The replacement of the grey wire will improve public safety and reduce the system’s susceptibility to damage caused by natural disasters. An ancillary benefit will be an improvement in grid reliability.

<table>
<thead>
<tr>
<th>Table 6: Grey Wire Proposed Spending Levels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grey Wire Replacement (Capital)</td>
</tr>
<tr>
<td>2020</td>
</tr>
<tr>
<td>$2,500,000</td>
</tr>
<tr>
<td>Locations for Replacement</td>
</tr>
<tr>
<td>1,585</td>
</tr>
</tbody>
</table>

4.3.2 Pole Wrapping: (Fire Mesh) Installation in High Fire Consequence Area

Changes in the climate and environment are contributing to an increased risk of wildfires in NV Energy’s service territory. As part of efforts to protect its customers, the environment, and the electric system, NV Energy is proposing to deploy a fire-resistant pole wrap technology known as a fire mesh. The Companies propose to install fire mesh technology on all poles in the high-risk wildfire areas of Tier 3, Tier 2 and Tier 1-elevated areas.

Fire mesh is designed to protect wood structures from burning or scorching, which significantly weakens the poles. The fire mesh forms a barrier by expanding at temperatures greater than 300°F that will shield the wooden pole structure from radiant heat and fire. The coating on the mesh expands to prevent ignition and will not contribute to the burning of the pole.

Investment Resource and Schedule
There are approximately 52,150 poles in the high-risk wildfire areas: 7,550 poles in the Tier 3 areas; 10,660 poles in the Tier 2 areas; and 33,940 poles in the elevated Tier 1 areas. The fire mesh material is a long lead time item with an uncertain delivery schedule. Based on estimates provided by the manufacturer, it could take up to eight weeks to receive the material. Resources (labor) to install the fire mesh material are presently being determined. The Companies have been provided some high-level cost estimates to install the fire mesh. To assure best pricing, the Companies will be issuing a request for proposal (“RFP”) to have the fire mesh installed. Until proposals are received from qualified contractors, the cost to install the fire mesh material remains uncertain.

The Companies have developed a fire mesh deployment schedule based on the Plan approval, an eight-week lead time for material and the high-level installation cost estimate that is currently available. The schedule is to install fire mesh on all Tier 3 poles in 2020 and the Tier 2 and elevated Tier 1 poles between 2021 and 2023. NV Energy will also provide an updated cost estimate during a subsequent Plan filing. (See Table 7 for schedule and yearly costs).

Incremental Spending Justification
NV Energy has not installed fire mesh on any of its poles aside from a few test cases completed to help with estimating the time to install and in identifying possible installation challenges. Therefore, this program would be an incremental risk mitigation program.

Cost Benefit Review
Following a wildfire and before receiving the “all clear” to re-energize the circuits, the existing poles that were in the path of the wildfire could be identified as structurally compromised and would need to be replaced. Poles installed with the fire mesh technology, after being cleaned to have the soot removed and inspected, can remain in place. The associated equipment on the poles, will also need to be cleaned prior to be re-energized. Installing the fire mesh technology will significantly reduce the amount of time to restore
power following a wildfire. As the new standard for Tier 3 areas will require metal pole replacements for wood, this activity will be fully executed as lines are rebuilt over a significant period of time.

The two alternatives to installing fire mesh are:

1) **Replace the wood poles after a wildfire:** The average cost to replace a pole is $10,000. There are 52,000 poles in the Tier 3, Tier 2, and Tier 1-elevated. Total cost: $520 Million

2) **Install metal poles:** The average cost to install metal poles is $15,000. NV Energy does not have a standard for concrete material for pole replacements at this time but understands this alternative exists. The advantage of either concrete or metal infrastructure is that the poles will have a longer life cycle. There are 52,000 poles in the Tier 3, Tier 2, and Tier 1-elevated. Total cost: $780 Million

Fire mesh at $42.5 million is significantly less expense then the alternatives. As detailed in the Plan, NV Energy will continue to improve grid resiliency by installing metal poles as part of line rebuild projects and fire mesh will not be installed on those poles.

### Table 7: Fire Mesh Costs and Schedule

<table>
<thead>
<tr>
<th>RFP Process (Admin.)</th>
<th>2020</th>
<th>2021 Tier 3</th>
<th>2022 Tier 2 and 1</th>
<th>2023 Tier 2 and 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Poles Wrapped</td>
<td>$100,000</td>
<td>--</td>
<td>14,000</td>
<td>15,000</td>
</tr>
<tr>
<td>Material: $439 / pole</td>
<td>--</td>
<td>$3,315,000</td>
<td>$6,150,000</td>
<td>$6,590,000</td>
</tr>
<tr>
<td>Labor: $381 / pole</td>
<td>--</td>
<td>$2,877,000</td>
<td>$5,330,000</td>
<td>$5,720,000</td>
</tr>
<tr>
<td>Total ($)</td>
<td>100,000</td>
<td>6,200,000</td>
<td>11,500,000</td>
<td>12,300,000</td>
</tr>
</tbody>
</table>

### 4.3.3 Fuses: Non-Expulsion Fuse Standardization

**Program Overview**

Fuses refer to protective devices that protect the distribution system from faulted or damaged lines and equipment. There are essentially three different types of fuses that are used to protect the overhead distribution system. These are conventional fuses, current limiting fuses and electronic fuses. Historically, the Companies and other utilities across the country, including California, have used conventional fuses to protect “lines and equipment.” Conventional fuses, when operated, expel hot particles and gases, which can be an ignition source to start a wildfire. In contrast, current limiting fuses, that traditionally were used for protecting “sensitive equipment” expel no materials, limit the available fault current, and in many cases can reduce the duration of faults. Manufacturers have introduced electronic fuses which also do not expel hot particles and gases but have similar protective characteristics as conventional fuses. The use of conventional fuses, current limiting fuses and electronic fuses provides for a high level of reliability and grid resiliency with various pros and cons.

**Detail Program Description**

NV Energy has approximately 3,200 fuses in the Tier 3, 4,200 in Tier 2 and 14,000 elevated Tier 1 high-risk wildfire areas. Lateral fuses, which account for 527 fuses, have been identified for having a higher risk threat followed by riser pole fuses, accounting for 952 of the fuses in the high risk areas of NV Energy’s system. In order to mitigate fires, the Companies propose to begin replacing conventional fuses with current limiting fuses or electronic fuses in the Tier 3 area wildfire risk areas. Branch lines (segments of overhead wire) that are single phase, two phase and three phase, that are presently protected with conventional fuses, will be replaced with electronic fuses. Pole mounted transformers and other pole mounted equipment that have conventional fuses will be replaced with current limiting fuses. The Companies’ plan is to replace
these fuses with a principal focus on the Tier 3, and then beginning Tier 2 and Tier 1-elevated in later years. Table 8 outlines the proposed schedule and cost estimates.

**Program Cost – Tier 3 Area**

**Material**

Electronic Fuse: $7,000 for a single phase location  
$10,500 for a three-phase location

Current Limiting Fuse: $1,000 per single phase location  
$1,500 for a three-phase location

Labor to install: $1,500 per location (assumes two hours of crew time per location)

**Example per Location Cost:**

Electronic Fuse 3 phase location: $10,500 material plus $1,500 labor = $12,000  
Current limiting 1 phase location: $1,000 material plus $1,500 labor = $2,500

**Incremental Spending Justification**

The Companies have not previously implemented a program to install current limiting or electronic fuses. Therefore, all spending for this program would be incremental.

**Resource (Labor) to support Program**

Since this is a new program, the Companies do not have internal resources to support the replacement of the fuses. The Companies propose to out-source the work using contractors.

**Cost Benefit Review and Alternative Approaches**

Two options were considered and evaluated with Option 2) being recommended here:

1. **Combined Fuse and Covered Wire Programs:** There could be some labor savings by combining the other conductor replacements (outlined in Section 4.3.5) with the fuse replacement program. Covered conductor replacements are more involved due to designing, permitting, and construction challenges. This approach would significantly delay the speed to execute the fuse replacement. This option would continue to present the ignition risk until replacement; therefore, this option was not selected.

2. **Develop a Stand-Alone Program:** An independent fuse replacement program is proposed to rapidly execute fuse replacements with an emphasis to quickly reduce the ignition from faster fault isolation and fault energy reduction.

**Table 8: Tier 3 Fuse Replacement Costs**

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lateral Fuses</td>
<td>$400,000</td>
<td>$1,000,000</td>
<td>$800,000</td>
<td>--</td>
</tr>
<tr>
<td>Riser Pole Fuses</td>
<td>$100,000</td>
<td>$500,000</td>
<td>$1,000,000</td>
<td>$1,400,000</td>
</tr>
<tr>
<td>Overhead</td>
<td>$50,000</td>
<td>$500,000</td>
<td>$1,200,000</td>
<td>$1,600,000</td>
</tr>
<tr>
<td>Total ($)</td>
<td>550,000</td>
<td>2,000,000</td>
<td>3,000,000</td>
<td>3,000,000</td>
</tr>
</tbody>
</table>
4.3.4 High-Speed Clearing and No Circuit Reclosing

High speed clearing refers to the ability to clear faults using automatic breakers or reclosers with fast-curve sensitive relay settings. Traditionally electrical circuits were designed to automatically open and close to detect and isolate faults. In many cases the relays would make three attempts to isolate a fault condition, each potential attempt could cause an electrical spark, which could be a source of ignition. Today, many utilities, including the Companies, are implementing modern controls on the distribution lines that allow them to designate two settings: a normal setting and a fire season setting. The latter setting allows utilities to reduce the number of corrective attempts to prevent sparks. Presently all of the Companies’ transmission circuits, while in Fire Season Mode, have high-speed clearing with no circuit reclosing (one trip to lockout).

The Fire Season Mode of substation breakers and reclosers in the Tier 3 and additional wildfire risk areas will be coupled with Supervisory Control and Data Acquisition (“SCADA”) technology for remote control of the equipment. Fire Season Mode description is also included above in Section 4.1 of the Plan.

The list below details the Companies’ incremental investment plans with regard to these technologies.

- SCADA Installations: The Companies presently have SCADA installed at substations located in Tier 3 and additional wildfire areas which will allow for remote control and monitoring of substation equipment. Currently, the Companies have limited SCADA capability on the installed automatic reclosers on the distribution system but will be expanding the capability as outlined under Section 4.3.9, “telecommunications investments.” SCADA will control and monitor the automatic reclosers and at selected locations be able to turn the Fire Season Mode on and off. Additionally, remote monitoring of system assets will promote faster outage response.

- Automatic Recloser Installations: The Companies’ plan is to install two new modern automatic pole top reclosers on the distribution lines, using electronic supervisory controls. This technology provides the settings necessary to reduce electrical sparks, while also helping to mitigate power outages.

Incremental Justification

Several of the existing reclosers/breakers at the Glenbrook Substation are old and obsolete. Glenbrook circuit 2505 has electro-mechanical relays that are considered obsolete. Modern reclosers use microprocessor relays that can detect and isolate faults (problem areas) much more quickly. Glenbrook circuit 2600 has a hydraulic recloser that has an integrated controller. This equipment is considered slow to operate and has limited capability to detect faults. In order to reduce the ignition risk of a wildfire, two additional pole top reclosers will be installed.

It is proposed that the following two circuits, located in the Tier 3 high risk wildfire area of South Lake, will have two pole-mounted modern automatic reclosers installed:

- Glenbrook circuit 2505: One installed outside the substation.
- Glenbrook 2600: One installed outside the substation.

Cost Estimates and resources

Considering materials, labor, vouchers, and engineering needs, total recloser installations are estimated to be roughly $160,000. The Companies would contract for additional resources to perform this work on an as needed basis. The material is not considered a long lead time item. The Companies plan is to proceed with these installations as it a known risk needing immediate action.
Table 9: Planned Recloser Replacements

<table>
<thead>
<tr>
<th>Capital Expenditures</th>
<th>2020*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Costs to Install 2 Reclosers</td>
<td>$160,000</td>
</tr>
</tbody>
</table>

(*) Schedule may be updated based on the Plan approval and project implementation timelines.

Cost Benefit Review
The Companies have a longer-term plan to replace the Glenbrook Substation (see Section 4.3.7) at a new location. It is expected the new substation will take several years to complete leaving potential ignition risks in place until the work is completed. This investment will mitigate risk until the new substation is in place. The alternative to this investment would be to replace the two breakers/reclosers at the Glenbrook Substation. It is estimated the substation work would cost $500,000.

Table 10: Recloser Alternative Comparison (Costs)

<table>
<thead>
<tr>
<th>Temporary Substation Upgrade</th>
<th>$500,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole Top Recloser Installation</td>
<td>$160,000</td>
</tr>
</tbody>
</table>

The Cost Benefit Ratio is 50 percent less than the next alternative.

4.3.5 Covered Conductor / Selective Undergrounding

The Companies have approximately 1,700 distribution overhead circuit miles (primary only) in Tier 3, 2 and 1-elevated areas. Approximately 1,100 circuit miles, are undergrounded. The undergrounded portion is primarily located in more densely populated urban areas and is generally understood to represent lower wildfire risk. In constructing its overhead distribution system, the Companies have historically relied on bare conductor compared to other options, such as undergrounding or covered conductor. This is consistent with the standard practice used by other utilities across the country. Both covered conductor and undergrounding solutions are important designs to consider in order to manage the uncontrollable risks presented by debris, vegetation, birds, animals, other foreign materials to the Companies’ electric infrastructure.

The Covered Conductor Program (“CCP”) is a system hardening solution for the Companies’ wildfire risk mitigation. The use of covered conductor in Tiers 3, 2, and 1 (elevated) areas (Tier 3 prioritized initially) will significantly reduce the risks of wildfire ignition associated with vegetation contact and downed conductors of overhead electrical distribution system facilities. There are two generic configurations of covered conductor, tree wire and spacer cable. Tree wire consists of semi-insulated conductor framed on a cross arm similar to bare conductor and spacer cable consists of semi-insulated conductor in a condensed phase spacing suspended from a messenger.
Covered conductor configurations achieve many of the same ignition mitigation benefits as converting overhead wire to underground cable, but at a lower cost. It also has similar public safety benefits and less prone to faults by design, but does not suffer from the troubleshooting and restoration delays associated with underground systems, which may be a critical factor during natural disasters or PSOM events, affording faster repairs and shorter outage times for customers. Additional limitations of underground systems include that they i) cannot be visually inspected, ii) could require service interruptions to perform certain maintenance, iii) are difficult to upgrade and often require excavation, and iv) are difficult to troubleshoot during emergencies, resulting in longer outages.

While covered conductor solutions (tree wire or spacer cable systems) provide protection from vegetation ignition, it can be more prone to damage due to lighting strikes. As part of the Plan, the Companies will use covered conductor configurations (tree wire or spacer cable systems) in Tier 3 areas of the wildfire tiers, but bare conductor will remain the primary design standard for new construction and re-construction work throughout the Companies’ service territory outside the designated risk tiers. It is understood that other grid hardening upgrades (e.g., pole replacements to steel/ductile iron etc.) will continue to be evaluated and implemented on a parallel path to conductor upgrades and, as appropriate, will be incorporated into the overall design and standards development. As noted in Section 4.3.10 below, the Companies also propose to re-conductor circuits currently having small sized wire (#2, #4, #6 bare copper circuits), which present the ignition risk and public safety concerns from a wire-down event.

In implementing CCP, the Companies will use both covered conductor solution configurations (tree wire or spacer cable) depending on the individual circumstances of each circuit.

- **Tree wire**: The conventional framing of tree wire will be more beneficial in areas with less vegetation, more equipment, and lateral connections.

- **Spacer cable**: Spacer cable configuration will be more beneficial in areas with dense vegetation, narrow ROW, and fewer laterals.
In addition, undergrounding will be recommended in specific areas that have an ordinance that requires such or precludes overhead reconductoring work. For example, Douglas County requires all new distribution lines, line extensions or modifications to be installed underground. In southern Nevada (Mt. Charleston Tier 3 area), there are existing 4kV circuits that are partially undergrounded and the cable is aged and deteriorated. During heavy rain and water ponding, the cable might also fail. It is also expected that following a proactive de-energization of power, during a high wildfire risk period, when re-energizing the line, the inrush current of turning the power back on might result in the obsolete 4kV cable failing. This might result in an extremely long duration power failure. Therefore, the existing cable on these circuits along with overhead 4kV conductor is recommended to be replaced with modern 12kV cable that can support the NDPP.

An important step in the risk analysis was to map specific mitigation alternatives to the types of faults that can be avoided upon deployment. This analysis relied on engineering subject matter expertise to identify how much of each general fault type (or risk), such as contact from an object, equipment/facility failure, would be mitigated by a specific conductor type. The analysis focused on three key conductor types: (1) reconductoring small size bare conductors with bare conductor size based on present design standards; (2) reconductoring with covered conductor (tree wire or spacer cable) based on present design standards; and (3) relocating distribution lines underground. For example, all three of these mitigation measures were identified as effective at mitigating the connector/tap subtype for overhead transformer equipment failure faults due to the rebuild. Two of these three mitigation measures (tree wire/spacer cable and underground conversion) were identified as effective at reducing the vegetation-related contact faults. One mitigation measure (underground conversion) was identified as effective at reducing the overhead transformer subtype of equipment failure faults. Combining the fault-to-fire mapping and the mitigation-to-fault mapping yields mitigation effectiveness factors for each of the three mitigation measures. Based on this methodology, and on a stand-alone basis, some California investor-owned utilities (“IOUs”) in their approved WMP estimated bare conductor as having a 15 percent mitigation effectiveness factor; covered conductor was calculated as having a 60 percent mitigation effectiveness factor; and underground conversion was used as the reference baseline for mitigation effectiveness because it removes all exposures related to overhead power lines. A mitigation effectiveness factor could be interpreted as an estimate of the percentage of fires avoided with full deployment of the mitigation measure throughout risk tiers, all else equal.

It is important to note that underground conversion as a benchmark for risk reduction effectiveness does not factor in financial implications as undergrounding investments are costlier than the proposed alternatives. Rather, the baseline is justified by the infrequency of fault occurrences experienced on an undergrounded circuit by way of the elimination of overhead line risk drivers (e.g., vegetation or object contacts, wire down events, animal/bird strike, etc.). The risk consequence of an undergrounded circuit fault/failure does introduce negative impacts that are not part of this evaluation, such as delays in troubleshooting and restoration response in the case of a cascading effect of system or equipment failures that could be detrimental during a PSOM event.

Since the Companies have not had large and measurable fire events associated with electric infrastructure within the service territory, NV Energy propose to utilize the California IOUs data for the mitigation effectiveness factor. Specifically, Southern California Edison (“SCE”) estimated full deployment of covered conductor in high risk areas to mitigate approximately 60 percent of fires associated with electrical distribution facilities in defined risk tiers. This analysis of mitigation effectiveness does not account for potential benefits with other mitigation measures, such as fuses and automatic reclosers, which might also reduce the likelihood of fire ignitions. Thus, the mitigation effectiveness factors are appropriately considered as relative (not absolute) measures, with underground conversion providing the baseline (100 percent) for purposes of comparison.

In addition to mitigation effectiveness, it is also important to consider the cost associated with each mitigation option. For bare conductor, the Companies relied on its costs associated with circuit rebuild program, approximately $675,000 per circuit mile (based on average project costs). For comparison, accounting for the differences in material costs for covered conductor as well as the costs of associated upgrades (such as the replacement rate of poles), covered conductor (tree wire or spacer cable) is approximately $850,000 per circuit mile (1.25 times the bare conductor costs above). For underground conversion, the Companies relied on its experience with projects under the underground management plan, which cost approximately $3 million per circuit mile (based on average project costs assuming granite excavation might be needed). These costs, combined with the relative mitigation effectiveness factors, allows comparison of each measure's mitigation-cost ratio, i.e., the relative mitigation effectiveness (using underground conversion as the baseline) achieved per dollar spent. These results are presented below:

<table>
<thead>
<tr>
<th>Mitigation Option</th>
<th>Relative Mitigation Effectiveness Factor</th>
<th>Cost per Mile ($ million)</th>
<th>Mitigation-Cost Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Re-conductor – Bare</td>
<td>0.15</td>
<td>0.68</td>
<td>0.22</td>
</tr>
<tr>
<td>Re-conductor – Covered (tree wire or spacer cable)</td>
<td>0.60</td>
<td>0.85</td>
<td>0.71</td>
</tr>
<tr>
<td>Underground Conversion</td>
<td>1.00</td>
<td>3.00</td>
<td>0.33</td>
</tr>
</tbody>
</table>

The above risk analysis shows that application of covered conductor is the most prudent of the three mitigation measures. Specifically, while reconductoring with bare conductor would have lower cost, and underground conversion would have greater benefit, reconductoring with covered conductor has the greatest overall value. A dollar spent reconductoring with covered conductor provides nearly three times as much value in wildfire risk mitigation as a dollar spent reconductoring with bare conductor, and over double as much value in wildfire risk mitigation as a dollar spent on underground conversion. From these results, the Companies recommend covered conductor as the proposed standard in defined wildfire risk tiers with undergrounding to continue on a parallel path in both northern and southern Nevada as noted above.

Based on the above analysis, the Companies’ new standard specifies the use of covered conductor solutions (tree wire or spacer cable) for new construction and reconductoring projects in Tier 3 areas. In order to gain critical design, construction and maintenance experience with tree wire and spacer cable, it is prudent to conduct pilots for tree wire and spacer cables. These technologies may be mature at other utilities, but NV Energy has not had any permitting, design, construction, operations and maintenance experience. Execution of these initial projects will also support an effective transition of both tree wire and spacer cable technologies to other Tier 3 circuits and other wildfire risk tiers.

As a long-term program, CCP covers all of the Companies’ wildfire risk tier areas, ranking the overhead circuits based on criteria such as specified increased likelihood of wire-down events to address safety risks. This prioritization will be based on fuel loading per USFS data, frequency of circuit breaker operations, customer density, and recent history of fires and wire-down events, among other factors.

4.3.5.1 Covered Conductor and Undergrounding Plan

Using the above proposed criteria, the following projects will be performed:

Tree Wire
Cal 204: Reconductor 2640 feet of the circuit near Verdi.
Incline 4100: Reconductor 2640 feet of the circuits in North Lake Tahoe.
Incline 4200: Reconduct 2640 feet of the circuit in North Lake Tahoe.

Spacer Cable

Kingsbury 2800: Reconduct 2900 feet of the circuit in the South Lake Tahoe area.
Roundhill 1503: Reconduct 1200 feet of the circuit in the South Lake Tahoe area.

Later this year, the Companies will begin the permitting and design process for these five pilot projects. These projects will allow the Companies to gain greater experience and provide key insights in execution of both types of covered conductor solutions (tree wire and spacer cable). For instance, while similar in electrical properties to bare wire conductor, these solutions necessitates greater care when handling to prevent damage to the insulation. The increased diameter and weight of covered conductor increases structure loading and conductor sag that could necessitate stronger poles, and in some cases additional poles, than bare conductor projects.

Following the success of the pilot project, the Companies propose to expand the covered conductor solutions (tree wire and spacer cable) to other circuits in the high-risk Tier 3 areas. Several factors drive the ability to begin reconductoring. These factors include: (1) Development of comprehensive standards, (2) receipt of the construction permit by regulatory authorities, (3) availability of material, (4) resources to perform the work, (5) line clearance (maintaining resiliency and reliability) and (6) planning approval.

As noted above, NV Energy also plans to begin undergrounding portions of the following circuits:

All these circuits are in Tier 3 (extreme) risk areas and there is also community interest in undergrounding portions of these circuits. Therefore, undergrounding portions of these circuits on a parallel path to the above covered conductor solutions is a prudent and reasonable option to mitigate the ignition risk in Tier 3 areas.

**Incline Circuit 4100** - approximate total circuit length is 26 miles. Portions of the circuit will be undergrounded. All circuits listed in this section are Tier 3 circuits and undergrounding will support the Plan by reducing risk of ignition events.

- Design and permitting years 2020 and 2021;
- Construction of one mile in year 2022;
- Construction of one mile in year 2023; and
- Based on initial design, NV Energy plans to underground portions of Lakeshore Boulevard and locations near the east shore bike path. NV Energy is also currently working with the Tahoe Transportation District to assess feasibility of undergrounding along the next phase of the bike path development.

**Glenbrook Circuit 2505** - approximate total circuit length is approximately six miles. Portions of the circuit will be undergrounded. Based on initial design, NV Energy plans to underground portions of conductors along the east side of the lake in coordination with the Tahoe Transportation District in the bike path. Future vaults and conduits are currently planned to be installed along the remaining 3.5 miles to Highway 50, with consideration for a future feeder based on the possible relocation of Glenbrook Substation.

**Incline Circuit 4200** - approximate total circuit length is 27 miles. Portions of the circuit will be undergrounded.

- Design and permitting years 2020 and 2021 with specific areas identified;
- Construction of one mile in year 2022; and
- Construction of one mile in year 2023.
Portions of the following circuits will also be undergrounded with specific areas identified during the design phase:

- Incline Circuit 4300;
- Roundhill Circuit 1502;
- Roundhill Circuit 1504;
- Glenbrook Circuit 2302;
- Glenbrook Circuit 2600; and
- Kingsbury Circuit 2800.\(^{29}\)

In the above northern Nevada Tier 3 areas, approximately two miles of undergrounding is targeted for completion by 2022 and additional four miles by 2023.

**Angel Peak Circuit 401**
Approximately one mile replacement of existing underground cable and conduit in the Mount Charleston area of Nevada. This area is presently undergrounded with an existing 4kV underground cable that has deteriorated with resulting outages. During heavy rain and water ponding, the cable might also fail. It is also expected that following a proactive de-event, during a high wildfire risk period, when re-energizing the line, the inrush current of turning the power back on might result in the obsolete 4kV cable failing. This might result in an extremely long duration power failure. Therefore, the existing cable should be replaced with modern 12kV cable that can support the NDPP. Permitting will begin in 2020 and take 18 months to complete. Construction would be in completed 2023.

**Angel Peak Circuit 402**
Similar to Angel Peak Circuit 401, approximately one mile replacement of existing underground cable and conduit on the Angel Peak Circuit 402 is also targeted for replacement. This area is presently undergrounded with an existing 4kV underground cable that has deteriorated with resulting outages. During heavy rain and water ponding, the cable might also fail. It is also expected that following a proactive de-energization of power, during a high wildfire risk period, when re-energizing the line, the inrush current of turning the power back on might result in the obsolete 4kV cable failing. This might result in an extremely long duration power failure. Therefore, the existing cable should be replaced with modern 12kV cable that can support the NDPP. Permitting will begin in 2020 and take 18 months to complete. Construction is expected to be completed by 2023.

**Angel Peak Circuit 403**
Undergrounding the existing half mile overhead 4 kV line. The above ground conductor spans present a wildfire risk and most of the issues noted for aging 4 kV infrastructure are applicable for this circuit. The existing cable should be replaced with modern 12kV cable that can support the NDPP by reducing risk of ignition events and service reliability.

In the above southern Nevada Tier 3 areas, permitting will begin in 2020 and take 18 months to complete. Construction is expected to be completed by 2023.

**Incremental Spending Justification**
NV Energy has not installed covered conductors (tree wire or spacer cable) on any of its poles and has not performed selective undergrounding on the above Tier 3 area circuits. All spending for this program would be incremental to existing expenditures.

\(^{29}\) NV Energy will also collaborate with the Nevada Tahoe Conservation District who has requested to underground a portion of the overhead line on Roundhill 1504.
The Companies will continue to evaluate the specific circuit miles in risk tiers on a case-by-case basis. Currently covered conductors are limited to 69 kV and below applications, so transmission circuits in defined risk tiers will be evaluated on a case-by-case basis for reconductoring or undergrounding.

The Companies’ CCP and undergrounding execution envisions a multi-year effort with circuits being prioritized based on fuel loading per the USFS’ data, frequency of circuit breaker operations, customer density, and recent history of fires and wire-down events, among other factors. As noted in Section 8, an effective way to measure the benefits of the program upon execution will be to track frequency and trends of ignition events within the risk tiers.

Cost Assumptions (from above):
- Covered conductor installed: $850,000 per circuit mile
- Underground conductor installed: $3,000,000 per circuit mile

Based on the Plan approval, NV Energy proposes the following estimated spending for the covered conductor program.

### Table 12: Tree Wire Costs

<table>
<thead>
<tr>
<th>Circuit</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cal 204- design &amp; permitting</td>
<td>$100,000</td>
<td>$200,000</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Cal 204- Construction</td>
<td>--</td>
<td>--</td>
<td>$212,500</td>
<td>$212,500</td>
</tr>
<tr>
<td>Incline 4100- design &amp; permitting</td>
<td>$100,000</td>
<td>$200,000</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Incline 4100- Construction</td>
<td>--</td>
<td>--</td>
<td>$212,500</td>
<td>$212,500</td>
</tr>
<tr>
<td>Incline 4200- design &amp; permitting</td>
<td>$100,000</td>
<td>$200,000</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Incline 4200- Construction</td>
<td>--</td>
<td>--</td>
<td>$212,500</td>
<td>$212,500</td>
</tr>
<tr>
<td>Covered Conductor Total ($)</td>
<td>300,000</td>
<td>600,000</td>
<td>637,500</td>
<td>637,500</td>
</tr>
</tbody>
</table>

### Table 13: Spacer Cable Costs

<table>
<thead>
<tr>
<th>Circuit</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kingsbury 2800- design &amp; permitting</td>
<td>$100,000</td>
<td>$200,000</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Kingsbury 2800 Construction</td>
<td>--</td>
<td>--</td>
<td>$212,500</td>
<td>$212,500</td>
</tr>
<tr>
<td>Roundhill 1503- design &amp; permitting</td>
<td>$100,000</td>
<td>$200,000</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Roundhill 1503- Construction</td>
<td>--</td>
<td>--</td>
<td>$212,500</td>
<td>$212,500</td>
</tr>
<tr>
<td>Spacer Cable Total ($)</td>
<td>200,000</td>
<td>400,000</td>
<td>425,000</td>
<td>425,000</td>
</tr>
</tbody>
</table>

### Table 14: Undergrounding Program

<table>
<thead>
<tr>
<th>Circuit</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Angel Peak 401 design and permits</td>
<td>$200,000</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Angel Peak 401 construction</td>
<td>--</td>
<td>$600,000</td>
<td>$750,000</td>
<td>$1,250,000</td>
</tr>
<tr>
<td>Angel Peak 402 design and permits</td>
<td>$200,000</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Angel Peak 402 construction</td>
<td>--</td>
<td>$600,000</td>
<td>$750,000</td>
<td>$250,000</td>
</tr>
<tr>
<td>Angel Peak 403 design and permits</td>
<td>$200,000</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Angel Peak 403 construction</td>
<td>--</td>
<td>$600,000</td>
<td>$750,000</td>
<td>$1,250,000</td>
</tr>
<tr>
<td>Incline 4100, Incline 4200, Incline 4300, Roundhill 1502, Roundhill 1504, Glenbrook 2302, Glenbrook 2505, and Glenbrook 2600</td>
<td>$200,000</td>
<td>$2,200,000</td>
<td>$6,000,000</td>
<td>$12,000,000</td>
</tr>
<tr>
<td>Undergrounding Total ($)</td>
<td>800,000</td>
<td>4,000,000</td>
<td>8,250,000</td>
<td>15,750,000</td>
</tr>
</tbody>
</table>
Angel Peak to Kyle Canyon Line:
The 34.5 kV circuit to Kyle Canyon from Angel Peak Substation ("AP3402") runs through an area that has been classified as having extreme fire threat. The Angel Peak 3402 circuit from Angel Peak feeds the Kyle Canyon 1201 at Kyle Canyon Substation. Around 445 customers are served by this circuit. This circuit is about 8.2 miles of which 7.7 miles is overhead and 0.5 mile is underground.

To address the fire threat risk and implement a long term fire mitigation solution, the preliminary analysis considered the following options:

- Upgrade of the current circuit including cables and structures to the spacer cable system. A description of this system is provided above in Section 4.3.5 in this document.
- New 19.2-mile distribution feeder to Kyle Canyon Substation from Northwest Substation ("NW1221"). Several scenarios have been run under this option for the 12 kV feeder including overhead, underground, and a combination of both. The preferred alternative at this time is further discussed below. This alternative will address the Tier 3 risk and may result in decommissioning or abandoning in place the current AP3402. This is not the final selected option as additional analysis will continue to be conducted prior to reaching a final recommendation. This Tier 3 area update is only included for informational purposes and the final construction approach, costs and schedule will be submitted during a subsequent filing.

Several simulations have been run under this option for the 12 kV feeder including overhead, underground and a combination of both. The route for this proposed feeder will follow the Nevada Department of Transportation ("NDOT") ROW from Northwest to Kyle Canyon substation (see Section 4.3.5 for additional details). This route will have the least impact on crossing the Red Rock Canyon National Conservation area and will also facilitate the installation and access for future maintenance and inspection of the line. Currently under study is the option of installing a new feeder that would address the Tier 3 wildfire risk, might result in decommissioning or abandoning in place the current Angel Peak-Kyle Canyon Substation 34.5 kV line and provide future capacity for the area.

Figure 22: New Distribution Feeder to Kyle Canyon Substation from Northwest Substation (NW1221)

Angel Peak AP3402 feeder with neighboring substations and NDOT ROW.
Underground single bundled cable will be run along 5.7 miles within the Tier 3 zone and the five miles across the Red Rock Canyon National Conservation area (shown in yellow) for a total of 11.7 miles underground and the remaining facilities installed overhead (shown in red).

Figure 23: Proposed 12 kV feeder with UG and OH options

(Red Rock Canyon National Conservation area shown in green)

4.3.5.2 Tree Attachment Removal Plan

Tree attachments are pieces of electrical infrastructure fastened to trees for infrastructural support. Because there are no approved standards for tree attachments, they inherently introduce system risk by being in direct proximity to vegetation. Tree attachment risks exist throughout the northern region of NV Energy’s distribution system, though an exact number of legacy attachments have not been determined at this time. NV Energy makes a consistent ongoing effort to eliminate these attachments as at-risk trees die, poles are inserted, and a new wiring configuration is made. Tree attachment replacement is an ongoing program to replace wires attached to trees. Tree attachments customarily include the service drop from a pole to a tree to a home. Sometimes this includes service drops for streetlight wires. Replacing tree attachments with poles requires permission from a property owner which is sometimes difficult to secure. When the trees die, the Companies replace the tree connection with a new pole.

Several challenges impede the elimination of tree attachments. Installations took place over many years and with limited locational documentation. Thus, to determine the location of tree attachments, NV Energy must leverage vegetation inspections, pole assessment inspection programs, and other capital improvement programs. As mentioned, NV Energy does not have an exact number of tree attachments identified, however, approximates that the number is in the thousands within the Lake Tahoe Basin. A formal identification or catalog process based on an electric system survey will have to be initiated for a comprehensive quantification.

Trees are inspected along the right of ways. Many tree attachments are also on private property, thereby requiring coordination with residents. As appropriate removal candidates (trees with electrical attachments nearing the end of their lives) will be located and mapped, NV Energy works to gain authorization from residents and/or local agencies and secure their removal and pole replacement.
In many cases, the elimination of tree attachments requires the installation one or more new poles. Current estimates (based on similar initiatives conducted by Liberty Utilities in the Basin) reflect costs of approximately $10,000 per tree attachment removal. Given that case by case evaluation is needed, NV Energy does not currently establish specific quantitative removal targets. The Companies do recognize that their elimination will further reduce wildfire risk, however, and is committed to cost-effective attachment removal. Considering the bundled cost estimates for this initiative, the Companies will re-evaluate the planned approach in future Plan updates and investigate adopting a deployment schedule if practical.

<table>
<thead>
<tr>
<th>Table 15: Tree Attachment Cost Estimates</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tree Attachment Removal (Total)</strong></td>
</tr>
<tr>
<td>North Lake Tahoe Estimate ($)</td>
</tr>
<tr>
<td>South Lake Tahoe Estimate ($)</td>
</tr>
</tbody>
</table>

4.3.6 Transmission Line Rebuilds & Ruggedization

Line rebuild and ruggedization is a part of system hardening that will strengthen the identified lines to withstand harsher conditions and improve grid resiliency. The rebuild and ruggedization plans will utilize alternative materials (steel, ductile iron, etc.) in lieu of wood to ruggedize specific transmission and distribution lines. All rebuilds and replacements will be made of alternative materials as a standard.

Various line rebuilds, such as the (Buckeye to Kingsbury 634) and (Voltaire Canyon to Glenbrook 624 lines,) have been included in the Plan specifically to address lines in high fire risk areas that are at risk of failure due to natural disasters such as high wind conditions. Other line rebuilds have been identified through inspection programs, such as the circuit rebuilds that are poor performing circuits. The scopes of these projects typically include 100 percent replacement of wood pole structures, re-engineered span lengths, increased conductor clearances, and grid hardening techniques such as metal pole construction.

Four lines identified in the high-risk Tier-3 wildfire areas are listed below and are included in the Plan for rebuild/ruggedization:

1. Brunswick to Incline (123 line)

The 123-transmission line is approximately 15.3 miles long and runs between Brunswick Substation in Carson City and Incline Substation in Incline Village. The line was constructed in 1974 and consists of wood pole H-frames and wood 3-pole guyed dead-end structures. Approximately 7.3 miles of the line runs along the small mountain range on the north side of Carson City in relatively sparse sagebrush and cheatgrass vegetation. The remaining eight miles of line climbs over the Carson Range and into the Lake Tahoe basin in moderate to heavily forested areas, peaking at just under 8,000’ of elevation. Due to the high elevation, steep terrain, and proximity to Lake Tahoe, this section of line experiences heavy loading during winter storms and high wind events.

The 123 line provides a radial transmission feed to the northeast area of Lake Tahoe (Tier 3 extreme fire risk area) and serves approximately 9,000 customers including the Incline Village General Improvement District. The peak load at Incline Substation is 14 MW. The Substation Reliability Taskforce also ranks the Incline Substation as the third least reliable substation in all of NV Energy’s system due to its age and design. This level of risk is also compounded due to the radial transmission line, single transformer, historical outages and limited backup capability to the distribution feeders. Additionally, some of the dead-end H-frame structures have experienced extreme wire loading events that have bent the cross arms. Due

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to the remoteness of the line and difficulty to obtain sustained outages for repairs, these damaged structures remain in place to this day. After 44 years of service and numerous emergency repairs, the line is also increasingly vulnerable to winter storm events.

The existing line is the worst performing transmission line in the Companies’ service territory with 143,772 customer outage hours over a two-year period; is constructed of wood pole structures and poses a wildfire risk. During the fall of 2018, the Companies found backup service through interconnection with Liberty Utilities at the Brockway Substation to be unreliable and contributed to extended outages in North Lake Tahoe. The 123 line is aged and scheduled for replacement; therefore, NV Energy is proposed its rebuild as part of this Plan.

Following figures show winter storm and pole fire-related damages to this line’s structures.

Figure 24: Damage during Winter Storm

![Image of damaged structure during winter storm]

Figure 25: Wood 3-Pole Structure Fire in Residential Backyard

![Image of wood 3-pole structure fire in residential backyard]
Proposed Mitigation

The project scope involves rebuilding of approximately 10 miles of the Brunswick-Incline 123-120 kV line with new fire-resistant steel or ductile iron poles and optical ground wire in accordance with the Companies’ current standards for resiliency, avian protection and wildfire risk mitigation.

The proposed effort will increase the resiliency of the sole source 15-mile transmission line. Critically damaged structures are vulnerable to weather, pose a significant safety hazard and can easily result in a sustained outage to the entire city. A single radial line already serves as a single contingency and in turn low reliability. As noted above, rebuilding this aged line in a Tier 3 area is an important mitigation step.

Proposed rebuild is recommended over the next two years to bring the #123 transmission line to an acceptable condition.

Table 16: 123 Line Rebuild Projected Costs

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>123 Line Rebuild</td>
<td>$1,150,000</td>
<td>$4,000,000</td>
<td>--</td>
<td>--</td>
</tr>
</tbody>
</table>

2. Glenbrook 624 line

Glenbrook-Voltaire Tap 624 Line between the Carson Valley and Lake Tahoe is located in a Tier 3 fire risk area. The purpose of this project is to replace the existing line from the 1940s with a modern design along the existing alignment corridor to provide safe and reliable electrical service and to improve fire safety, durability, and resiliency.
The existing radial 60 kV 624 line was constructed in or about 1941 and is the only transmission line to Glenbrook, Nevada. The 624 line is 9.5 miles long and the majority of the line is very difficult to patrol due to the rugged high mountainous terrain. The customers served by this line have experienced numerous outages associated with the age and deteriorated condition of the line structures. This line has suffered more than two times the overall average service interruptions experienced by other transmission lines in the Companies’ system. The Companies replaced several cross arms and insulators where the insulators had failed in the past. Failed insulators allow electricity to track through the insulator and can cause the cross arm to smolder. When this occurs, the insulator can detach from the cross arm allowing the conductor to float free of the structure. This situation poses a significant fire risk and also contributes to the number of outages experienced by the Companies’ customers. After almost 80 years of service and numerous emergency repairs, the line is also increasingly vulnerable to winter storm events. This line is also at high risk of failure outages due to old poles, cross arms and insulators, and additional problems caused by existing structure configuration which are convenient perches for hunting raptors.

The 624 line ranked 7th overall worst performing in customer outage hours and 10th overall worst performing in customers affected versus other transmission lines throughout the northern Nevada system over the past five years. The following photos below are representative of the condition of the line that require extensive replacements to improve the grid resiliency and service quality while mitigating fire and winter storm risk. In summary, the 624 line is aged and scheduled for replacement; therefore, NV Energy is proposed its rebuild as part of this Plan.

Figure 27: Wood Poles with Bent Insulator Pins, Porcelain Insulators, and Hardware Bonded
Figure 28: Wood Poles with Cross Arm Deterioration and Detached Hardware

Figure 29: Elevated Risk of Pole Fires: Aged Wood, Pole Splint, and Ground Line Deterioration

Proposed Mitigation

The proposed mitigation includes permitting and reconstruction of this 9.5 mile 624 line in the existing corridor. The design approach will be to replace the existing wood poles with light duty corten steel poles with 120 kV framing and 12 kV distribution on 12 foot fiberglass cross arms. The existing conductor will be replaced with 397.5 ACSR for 60 kV transmission. Telecommunications will consist of 48-count fiber upgrade in the shield wire position. Avian safety will be incorporated, which affects insulator size and phase spacing. It is proposed that the construction for some of the new structures and hardware will be by helicopter to minimize ground disturbance and new access roads to the ROW, thus reducing the surface disturbance in the forest and the cutting of new roads.
Figure 30: Proposed Tangent Structure

Designed by Transmission Engineering, this structure provides for an OPGW/Shield Wire, Raptor Safe construction and bonding of hardware.

This project has an estimated cost of $28,577,963 and an estimated in-service date of November 2022.

Table 17: 624 Line Rebuild Projected Costs

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
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<td>$14,085,986</td>
<td>$450,000</td>
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</table>
3. Chimney peak (201 line)

The Chimney Peak or Washoe #201 line, located in a Tier 2 zone, radially feeds the Chimney Peak radio site in Verdi, Nevada, which provides critical microwave and radio communications for the Companies, Liberty Utilities, Union Pacific Railroad, and the Nevada Shared Radio System for west Reno and the Interstate 80 corridor used by Nevada Highway Patrol, NDOT, and Washoe County. Located within the Humboldt Toiyabe National Forest, the line is approximately 60 years old and is a fire risk due to damaged and deteriorating poles, old insulators, lack of shield wire, and sagging wire. On average, there are also 8-10 outages during the winters that require emergency repairs. For example, two of the outages required contract helicopter services to fly in crews and equipment to repair the damage. Maintenance is difficult as much of the line is inaccessible due to steep terrain, dense forest growth, and restrictive access requirements on the USFS-managed lands. Other outage repairs require waiting for roads to clear and dry out. In summary, the 201 line is in a high fire risk area, aged and scheduled for replacement; therefore, NV Energy is proposing its rebuild as part of this Plan.

Proposed Mitigation

The proposed project scope includes permitting and rebuilding approximately 2.7 miles of the Washoe 201, 25 kV line with communications with modern design to provide safe and reliable electrical service and improve fire safety, durability, and resiliency. The full scope is being determined and the forecasted costs and schedule may be updated during a subsequent Plan filing.

<table>
<thead>
<tr>
<th>Table 18: Chimney Peak #201 Study Costs</th>
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<td>Study, Pre-design,</td>
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<tr>
<td>Alternative</td>
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<tr>
<td>Evaluation</td>
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<td>2019</td>
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<td>$15,000</td>
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4.3.7 Substation Design Hardening Investments

Substation Overview

NV Energy’s system has 412 substations which are spread throughout its 45,703 square mile service territory. The landscape across that service territory varies greatly from open rangeland, rural communities, urban communities, WUI and forested mountainous terrain. The varying landscapes that house the different substations introduce different risks and challenges as they pertain to wildfire danger.

NV Energy has identified six substations located in the Tier 3 extreme-risk wildfire area that require prioritized substation hardening investments.

Substation Hardening Investments

The six substations, located in the extreme-risk Tier 3 locations, have completed an assessment to determine the substation hardening investments that are needed to be performed to reduce the risk of causing an ignition and protect the substation from a wildfire.

Six specific substation hardening investments were determined to be appropriate for wildfire mitigation. They are:

**FR3 Transformer Oil** – Transformers have used mineral oils as insulating liquids since 1887. The oil performs multiple functions including dielectric insulating strength, heat transfer, diagnostic capabilities, and
protects the paper laminates in the transformer core. Traditional mineral oil has a 320°F (160°C) flash point but a new insulating oil, identified as FR3 oil, has a flash point of 680°F (360°C) while maintaining or improving the other characteristics required for transformer oils. The higher flash point reduces the likelihood the transformer oil can ignite or burn. See Figure 31 for transformer oil fire ignition comparisons.

![Figure 31: Transformer Oil Ignition Comparison](image)

**Replace Oil Filled Equipment** – Traditional reclosers and breakers are filled with mineral oil as the insulating material. The mineral oil has a flash point near 160-180°C with the possibility of igniting or spraying flaming oil during a catastrophic failure event. Modern reclosers and breakers use vacuum or sulfur hexafluoride gas (SF₆) as the insulating material. Modern reclosers and breakers will reduce the fire hazard at the substation by removing oil as an ignition source.

**Substation Grounding** – Substation equipment is installed with a grounding grid that bonds all metallic structures and equipment components to minimize voltage differentials between the various components that may come into contact with personnel. The bonding of certain equipment components also forms a low impedance fault current return path when unbalanced faults occur. The low-impedance return path maximizes the fault current flow thereby decreasing the time needed for the protection systems to detect a fault condition. Poorly-grounded substation equipment can slow fault clearing and introduce arcing at the ground connections if not well designed and properly bonded.

**Solid Fire Resistant Perimeter Barrier** – A solid fire resistant wall provides a barrier to help contain a fire within the substation or keep a fire outside from breaching the perimeter and damaging equipment. The solid fire resistant wall also minimizes the opportunity for vegetation seedlings to enter the substation creating additional fire fuels. See Figure 32 for Proposed Barrier Design.

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31 For example when gases in the oil are measured.
Weed Barrier and Crushed Rock Vegetation Control – Vegetation, especially when dry, can create a fire hazard when the grounding grid bonding arcs or equipment falls within the substation, among other potential ignition sources. The area inside the boundary should be clear of vegetation in order to eliminate those hazards. Vegetation can be better controlled through the use of geo-synthetic fabric below an adequate layer of type-two soil or surface rock. Areas also require periodic vegetation control treatment. See Figure 33 for Weed Barrier Materials.

Protection and Control Systems – NV Energy has partnered with UNR to study high impedance fault ("HIF") detection and traveling wave ("TW") protection design for the distribution and transmission systems, respectively. The HIF study will be complete May 2020 and the TW study May 2021. Replacing legacy
protection systems with modern systems will improve fire mitigation efforts. Replacing protection systems with relays and schemes as directed by the study will further minimize fire risk.

**Insulated Bus or Conductors for Distribution** – Traditional aluminum bus and conductors used in substation design do not have an outer insulation covering which subjects them to conductive debris or wildlife. Contact with the bare bus or conductor has the potential to generate an arcing fault or catastrophic failure of equipment. Custom-fitted insulation installed for substation equipment will greatly reduce the likelihood of debris or animal caused equipment failures inside of a substation, reducing the likelihood of arcing or catastrophic failure of equipment leading to a wildfire ignition. See Figure 34 Bus Covering Materials.

![Figure 34: Bus Covering Materials](image)

**Metal Clad Enclosed Switchgear** – Open air distribution equipment has traditionally been built with bare bus and conductors which is subject to wildlife or debris failures. Open air distribution equipment can be replaced with metal clad enclosed switchgear which provides a high degree of animal retardation with proper equipment sealing and guards. Several manufacturers also offer an arc resistant, Type 2A/2B gear which will contain any arcing to a faulted section, protecting both employees and reducing fire hazard. Replacing open air distribution equipment with Type 2A/2B switchgear will reduce fire risk.

**Substation Specific Investments**

**Kingsbury Substation**

Constructed in 1989, the Kingsbury Substation is located in the Tier 3 extreme-risk wildfire area in Stateline, Nevada (See Figure 35 of Kingsbury Substation). The substation is surrounded by national forest. The substation is on the east side of the Carson Mountain range in the Sierra Nevada mountain range near the Kingsbury summit. During fire season the winds are most often from the west with average wind speeds between 5.3-7.4 miles per hour but gusts are frequent because of its summit location. Because of this, should a fire ignite, there is an increased likelihood of causing a wildland fire.  

The substation is 60kV to 14.4kV with an 11 megavolt amperes (“MVA”) rating. There are four (including a spare) 4 MVA single phase transformer banks, two 0.645 MVA single phase regulators, and one oil-filled recloser. The substation is largely original design but the substation transformer and feeder relaying (recloser controller) were upgraded in 2008. The substation has a 10-foot chain-link fence with a snow gate.

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In May of 2018 a protection system study was initiated with the UNR as well as Sierra’s protection engineering department. The study is focused on identifying the best protection schemes and devices to mitigate fire risk. This study will conclude May of 2020 and the results will be utilized as a part of the upgrades that occur at the substation. Expansion of the existing ROW will be considered to mitigate the risk associated with adjacent vegetation.

**Detailed Substation Hardening Investments**

**FR3 Transformer and Regulator Oil:** Replacing the insulating transformer and regulator mineral oil with FR3 synthetic oil.

**Replace Oil Recloser:** Replace the #2800 (14.4kV) distribution oil recloser with a modern vacuum recloser.

**Weed Barrier and Crushed Rock Vegetation Control:** To minimize vegetation growth within the substation.

**Protection and Control Systems:** Install modern protection systems to include high impedance fault detection schemes.

**Insulated Bus:** and Conductors: Reduces the likelihood of arcing or catastrophic failure resulting in ignition of a wildfire.

**Substation Grounding:** Reduce arcing, an ignition source, during certain failure conditions.
Solid Fire Resistant Perimeter Barrier: To contain a fire within the substation or keep a fire outside. (See separate investment for schedule and cost).

Incremental Spending Justification:
NV Energy has not previously made financial arrangements for the upgrade of the substation. All spending for this substation would be incremental.

Resource (Labor) to support Program:
NV Energy proposes to use internal resources to support the installation of the substation investment. NV Energy will provide a labor resource update during a subsequent Plan update.

Incline Substation

Constructed in 1974, the Incline substation is located in the Tier 3 extreme-risk wildfire area in Incline Village, Nevada (See Figure 36 of Incline Substation). This substation is on the west side of the Carson Mountain range in the Sierra Nevada mountain range at the base of the range just east of Lake Tahoe. During fire season the winds are most often from the west with average wind speeds between 5.4-7.4 miles per hour.33 As this substation sits at the base of the mountains, should a fire ignite, it is likely that a combination of west to east winds plus the ascent of the mountain range, would increase the likelihood that a wildland fire would climb up the mountainside resulting in a large forest fire.

The substation is a 120kV to 14.4kV with a rating of 28 MVA. The substation is currently supplied by a single radial 120 kV feed from Brunswick Substation in Carson City, Nevada. The single transformer at the substation was replaced in 2018 with a transformer containing FR3 Oil.

Figure 36: Incline Substation

In May of 2018 a protection system study was initiated with the UNR as well as the NV Energy northern system protection engineering department. The study is focused on identifying the best protection schemes and devices to mitigate fire risk. This study will conclude May of 2020 and the results should be utilized as

a part of any upgrades that occur at Incline Substation. Expansion of the existing ROW will be considered to mitigate the risk associated with adjacent vegetation.

**Detailed Substation Hardening Investments**

**Replace Oil Breaker:** Replace the #123 (120kV) transmission oil breaker with a modern gas breaker.

**Weed Barrier and Crushed Rock Vegetation Control:** To minimize vegetation growth within the substation.

**Protection and Control Systems:** Install modern protection systems to include high impedance fault detection schemes.

**Insulated Bus and Conductors:** Reduces the likelihood of arcing or catastrophic failure resulting in ignition of a wildfire.

**Substation Grounding:** Reduce arcing, an ignition source, during certain failure conditions.

**Solid Fire Resistant Perimeter Barrier:** To contain a fire within the substation or keep a fire outside. (See separate investment for schedule and cost)

**Incremental Spending Justification:** NV Energy has not previously made financial arrangements for the upgrade of the substation. All spending for this substation would be incremental.

**Resource (Labor) to support Program:** NV Energy proposes to use internal resources to support the installation of the substation investment.

**Round Hill Substation**

The Round Hill Substation is located in the Tier 3 extreme-risk wildfire area in Stateline, Nevada (See Figure 37 of Round Hill Substation). The substation is located on the west side of the Carson Mountain range in the Sierra Nevada mountain range at the base of the range just east of Lake Tahoe. During fire season the winds are most often from the west with average wind speeds between 5.3-7.3 miles per hour.\(^34\) As this substation sits at the base of the mountains, should a fire ignite, it is likely that a combination of west to east winds plus the ascent of the mountain range, would increase the likelihood that a wildland fire would climb up the mountainside resulting in a large forest fire.

The substation is a 120kV to 14.4kV with a rating of 28 MVA. The substation is next to the local sewer plant and just southwest of a residential community. The substation interconnects with the Buckeye-Muller-Round Hill #112 (120kV) and the Round Hill-Stateline #160 (120kV) transmission lines via two gas transmission breakers. There is a single vacuum circuit switcher, 28MVA transformer, 2.8MVA three-phase regulator, three vacuum breakers and a control enclosure. The three 14.4kV feeders are local distribution feeders for the area.

---

The substation experienced a distribution equipment fire August 28, 2017 and was restored in two phases in 2017-2018. This restoration effort included replacement of the transformer, repair to the regulator, replacement of the distribution breakers, and replacement of the majority of the protection systems. At that time, the grounding grid was updated and the perimeter fencing was converted to a non-conductive material.

In May of 2018, a protection system study was initiated with the UNR and the NV Energy northern system protection engineering department. The study focused on identifying the best protection schemes and
devices to mitigate fire risk. This study will conclude in May 2020 and May 2021 regarding distribution and transmission, respectively, and the results will be utilized as a part of any upgrades that occur at Round Hill substation.

**Detailed Substation Hardening Investments**

**FR3 Transformer and Regulator Oil:** Replacing the transformer and regulator insulating mineral oil with FR3 synthetic oil.

**Protection and Control Systems:** Install modern protection systems to include high impedance fault detection schemes

**Insulated Bus and Conductors:** Reduces the likelihood of arcing or catastrophic failure resulting in ignition of a wildfire.

**Solid Fire Resistant Perimeter Barrier:** To contain a fire within the substation or keep a fire outside. (See separate investment for schedule and cost)

**Incremental Spending Justification:**
NV Energy has not previously made financial arrangements for the upgrade of the substation. All spending for this substation would be incremental.

**Resource (Labor) to support Program:**
NV Energy proposes to use internal resources to support the installation of the substation investment with the exception of the barrier wall which will be installed by contractors. NV Energy will provide a labor resource update during a subsequent filing.

**Glenbrook Substation**

The Glenbrook Substation is located in the Tier 3 extreme-risk wildfire area in Stateline, Nevada (See Figure 38 of Glenbrook Substation). This substation is located on the west side of the Carson Mountain range in the Sierra Nevada Mountains at the base of the range just east of Lake Tahoe. During fire season the winds are most often from the west with average wind speeds between 5.3-7.3 miles per hour. As this substation sits at the base of the mountains, should a fire ignite, it is likely that a combination of west to east winds plus the ascent of the mountain range, would increase the likelihood that a wildland fire would climb up the mountainside resulting in a large forest fire. The substation is surrounded by residents, tennis courts, and the Humboldt-Toiyabe National Forest.

Glenbrook Substation is a 60kV to 14.4kV with a rating of 5 MVA. There have been some feeder equipment control upgrades and two of the original oil breakers were replaced with newer oil breakers in the 1960s. Over time an oil recloser replaced a breaker and a third feeder was added via a recloser. The original transformer bank was changed out in 2008, replacing a 1953 vintage bank. The station service transformer is original from 1941. The control enclosure is antiquated and undersized. A sound resistant wall was installed in 2011 on the south side of the substation to reduce noise levels for the adjacent residents, but the homeowners association continues to request improvements. The other three sides utilize a six-foot chain-link fence. The station battery bank is 48V rather than today’s standard 125V and one of three feeders is still utilizing electromechanical protection equipment. The remaining equipment in the substation, including the transformer and regulator, are protected by a high-side fuse set. Partial telemetry is provided through a combination of the reclosers and solid-state meters.

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Figure 38: Glenbrook Substation

There are more than 2500 gallons of mineral oil in the equipment and the substation is less than one-third mile from Lake Tahoe’s waters. The telecommunications infrastructure is a leased four-wire service that raises; both support and dependability are concerns.

In May of 2018 a protection system study was initiated with the UNR and the NV Energy northern system protection engineering department. The study is focused on identifying the best protection schemes and devices to mitigate fire risk. This study will conclude May of 2020 and the results should be utilized as a part of any upgrades that occur at Glenbrook Substation.

Two mitigation solutions Considered: 1) Upgrade existing substation or 2) relocate the substation to a new location.

**Upgrade Existing Substation**
Upgrade certain equipment and install engineering controls to reduce fire risk. This would include upgrading the reclosers with vacuum type reclosers and installing modern microprocessor protection systems based on the results of the UNR’s study. These upgrades include: replacing the mineral oil in the transformer and regulator with FR3 synthetic oil; add custom bus and conductor cover up; rebuild the grounding grid and install synthetic weed barrier and new crushed rock; replace the control enclosure with a modern and properly sized enclosure; and upgrade the communications processor and remote terminal unit to today’s standard. Additionally, upgrades would consist of new telecommunications infrastructure for supervisory control and indication to provide dependable real-time status to system control; including a modern battery enclosure and consider upgrading the battery voltage to 125V; add oil containment to the regulator; and replace three sides of the perimeter fencing with a concrete masonry unit type wall and push the east wall outwards to create additional defensible space.

**Proposed Mitigation**

**Relocate the Substation**
Rebuild the substation to today’s standards at the new proposed location. Include options for a future second transmission feed (“AFH”), future fourth distribution feeder and future second transformer bank. Install a matching transformer bank to other Lake Tahoe basin transformers (28MVA with load tap changer) with FR3 synthetic oil. Include all modern flexibility to increase reliability for customers. Move the substation away from the customers and Lake Tahoe.
New Substation with Modern Standards Include:

- Metal Clad Enclosed Switchgear;
- FR3 Substation Transformer;
- Vacuum and Gas Circuit Breakers;
- Weed Barrier and Crushed Rock Vegetation Control;
- Modern Protection and Control Systems;
- Substation Grounding to Modern Standards; and
- Solid Fire Resistant Perimeter Barrier.

**Incremental Spending Justification**
NV Energy has not previously made financial arrangements for the new the substation. All spending for this substation would be incremental.

**Resource (Labor) to support Program**
NV Energy does not have internal resources to support the installation of the substation. NV Energy proposes to out-source the work using a contractor work force.

**North Truckee Substation**

The North Truckee Substation is located in a Tier 3 extreme-risk area (See Figure 39) in Truckee, California. This substation is located on the east side of the Red Mountain in the Sierra Nevada mountain range at the base of Alder Hill. During fire season, the winds are most often from the west with average wind speeds between 4.8-5.7 miles per hour.\(^{36}\) As this substation sits at the base of the mountains, should a fire ignite, it is possible that a combination of any winds, plus surrounding forest, would increase the likelihood of a wildland fire to spread into a large forest fire.

The substation is a 120 kV to 60kV transmission substation and was significantly upgraded in 2016 with modern equipment including breakers and protection systems and includes a 75MVA transformer insulated with mineral oil and a station service transformer. There are eight lightning arrester sets including the 120kV line getaways, the 60kV line getaway, and on all three windings of the transformer. There are two controls enclosures, both of which consist of material unlikely to ignite or sustain fire.

**Figure 39: North Truckee Substation**

In May of 2018 a protection system study was initiated with the UNR as well as the NV Energy northern system protection engineering department. The study is focused on identifying the best transmission protection schemes and devices to mitigate fire risk. This study will conclude May of 2021 and the results should be utilized as a part of any upgrades that occur at Incline Substation.

**Detailed Substation Hardening Investments**

**FR3 Transformer Oil:** Replace the insulating transformer mineral oil with FR3 synthetic oil.

**Protection and Control Systems:** Install modern protection systems to include traveling wave detection schemes.

**Insulated Bus and Conductors:** Reduces the likelihood of arcing or catastrophic failure resulting in ignition of a wildfire.

**Solid Fire Resistant Perimeter Barrier:** To contain a fire within the substation or keep a fire outside. (See separate investment for schedule and cost)

**Incremental Spending Justification:**
NV Energy has not previously made financial arrangements for the upgrade of the substation. All spending for this substation would be incremental.

**Resource (Labor) to support Program:**
NV Energy proposes to use internal resources to support the installation of the substation investment with the exception of the barrier wall which will be installed by contractors. NV Energy proposes to out-source the work using a contractor work force.

**Truckee Substation**

The Truckee Substation is located in a Tier 3 extreme-risk area (See Figure 40) in Truckee, California. West of the substation is a lumber yard. The only surrounding vegetation is located at the north side of the property and is bordering Trout Creek, a small tributary of the Truckee River. As the limited vegetation is wet from the available water and not directly adjacent to wildland it is also unlikely that a wildland fire would ignite as this area is unlikely to kindle or sustain a fire. There are also three buildings on the property. One is the control enclosure. Another is a larger shop which houses a vacated office, bathroom, telecommunication room, and parts storage. The other is an older garage that no longer serves a purpose. While the garage is a wood structure with original wiring with some fire potential, it is very unlikely that a structure fire would ignite a wildland fire.

The substation is a 60kV to 14.4kV distribution substation. Portions of the substation have been upgraded over the years. The 14.4kV feeder reclosers and controllers have been upgraded. Several of the 60kV breakers and associated protection systems have been upgraded. The distribution regulators are also upgraded. Other 60kV breakers are original, including some of the metering equipment, station service and structures.
Figure 40: Truckee Substation
All of the breakers are relatively modern (gas or vacuum) and are expected to operate as intended except for the #650 (60kV) breaker which is an oil circuit breaker manufactured in 1956 with some risk for failure. This breaker sources the #650 (60kV) transmission circuit that runs from Truckee Substation through forested areas to Northstar Substation, owned by Liberty Utilities. The line is approximately eight miles long. The breaker has had two corrective maintenance work orders in the past eleven years to correct the tripping mechanism for failure to operate properly.

In May of 2018 a protection system study was initiated UNR as well as the NV Energy northern system protection engineering department. The study is focused on identifying the best protection schemes and devices to mitigate fire risk. This study will conclude May 2020 and May 2021 regarding distribution and transmission protection, respectively, and the results should be utilized as a part of any upgrades that occur at Truckee Substation.

**Detailed Substation Hardening Investments**

**Protection and Control Systems:** Install modern protection systems to include high impedance fault and traveling wave detection schemes for the distribution and transmission lines, respectively.

**Replace Oil Filled Breaker:** Replace the #650 (60kV) oil circuit breaker with a modern gas breaker to remove the elevated risk of this 63-year old breaker from failing to operate for a faulted line condition. By replacing this breaker with a modern breaker it is more likely that the modern breaker will operate as intended, when required to clear faulted conditions on the line thereby reducing the risk of igniting a wildland fire.

**Incremental Spending Justification:**
NV Energy has not previously made financial arrangements for the upgrade of the substation. All spending for this substation would be incremental.

**Resource (Labor) to support Program:**
NV Energy proposes to use internal resources to support the installation of the substation investments.
Figure 41: Extreme Wildfire Risk (Tier 3) Areas
Substation Fire Resistant Barrier Overview

There are five substations (Incline, Round Hill, Kingsbury, Glenbrook, and North Truckee) that are located in the Tier 3 extreme-risk wildfire areas that are adjacent to or surrounded by national forest in the Sierra Nevada mountain range. These substations are at risk of causing an ignition resulting in a wildfire or the substation could be severely damage in a wildfire. The installation of concrete masonry unit ("CMU") perimeter walls will reduce the risk by containing substation fires within the walls of the substations or preventing wildland fires from entering the substation.

The Incline, Round Hill and Glenbrook Substations are located on the west side of the Carson mountain range in the Sierra Nevada mountain range at the base of the range just east of Lake Tahoe. During fire season the winds are most often from the west with average wind speeds between 5.3-7.4 miles per hour.\(^{37}\) As these substations sit at the base of the mountains, should a fire ignite, it is likely that a combination of west to east winds plus the ascent of the mountain range, would increase the likelihood of a wildland fire to climb up the mountain side resulting in a large forest fire.

**Incline Substation** is located in a commercial area of Incline Village, Nevada, adjacent to the sewer plant, and surrounded by national forest. The substation has little defensible space (~15 feet) and utilizes a seven foot chain-link fence for perimeter security. Should a fire ignite within the substation it is likely that westward winds would push the fire towards the surrounding forest with little to prevent the spread. In the 1990’s the substation’s metalclad switchgear did experience an internal fault creating an arc blast and fire but the damage was contained within the switchgear. The walls of the enclosure are bowed from that blast. Metalclad switchgear provides additional fire mitigation over open air as the equipment (breakers) is located inside the switchgear and utilizes vacuum or air, rather than mineral oil, for dielectric properties.

**Round Hill Substation** is located near a residential area of Stateline, Nevada, adjacent to the sewer plant, and surrounded by national forest. The substation has little defensible space (~15 feet) and utilizes a ten foot porous fiber composite fence for perimeter security. Should a fire ignite within the substation it is likely that westward winds would push the fire towards the surrounding forest with little to prevent the spread. Round Hill Substation underwent some rebuild efforts in 2017-2018 after the substation experienced a catastrophic failure and fire in August of 2017, which did not spread external to the substation (winds were at low speeds, 0-10 mph), after an animal contact at one of the feeder breakers. Calm wind conditions likely prevented the spread of the fire to the surrounding forest.\(^{38}\)

Glenbrook Substation is located in a residential area of Glenbrook, Nevada, adjacent to homes, and surrounded by national forest. The substation has little defensible space (~10 feet) and utilizes a combination of seven foot chain-link, 12 foot wood, and 14 foot solid wall for perimeter security. The solid wall is located on the south side, plus two panels on the west side, of the substation and was installed for noise suppression for the neighboring home in 2010. It will need to be determined whether the existing solid wall provides any fire barrier benefit. The wood fence is located on the west side of the substation. Chain link encompasses the rest of the site. Should a fire ignite within the substation it is likely that westward or northern winds would push the fire towards the surrounding forest with little to prevent the spread.

Kingsbury Substation is located on the east side of the Carson mountain range adjacent to the Sierra Nevada mountain range near the summit. The substation has little defensible space (~12 feet) and utilizes a seven-foot chain-link fence for perimeter security. Should a fire ignite within the substation it is likely that summit winds would push the fire towards the surrounding forest with little to prevent the spread.


North Truckee Substation is located in Truckee, California adjacent to the Tahoe National Forest. The substation has some defensible space (>20 feet) and utilizes a seven-foot chain-link fence for perimeter security. Should a fire ignite within the substation it is likely that east-southeast winds would push the fire towards the surrounding forest with little to prevent the spread.

**Detailed Substation Hardening Investment**

**Fire Resistant Substation Barrier**

Install a fire resistant barrier around the five substations (Incline, Round Hill, Glenbrook, Kingsbury and North Truckee Substations). The wall should be designed per NV Energy standard SDS-04 with an emphasis to reduce fire risk. This includes containing substation fires within the walls of the substations, preventing wildland fires from entering the substation, and reducing the infiltration of vegetation seedlings from entering the substation to reduce the growth of potential fire fuels.\(^39\) Gate openings should be as wide as possible as to not restrict access and include accommodations for high snow pack. Because there are several substations proposed for this project the installation of controlling-and-monitoring units are being combined and contracted to both speed installation and bid down the cost.

**Incremental Spending Justification**

NV Energy has not previously made financial arrangements for the fire resistant substation barrier. All spending for this incremental.

### Table 19: Substation Hardening & Barrier Cost

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(*) NV Energy may provide a cost estimate update during a subsequent Plan update.

**Study - Fire Mitigation Protection System**

**Background**

In May of 2019 a protection system study was initiated with the UNR as well as the NV Energy northern system protection engineering department. The study is focused on identifying the best protection schemes and devices to mitigate fire risk. This study will conclude May 2021, and the results will be utilized as a part of the upgrades that occur at the substations.

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\(^39\) CN Utility Consulting. "Control of Weeds in Electrical Facilities such as Substations, Switchyards, Capacitor Stations, and Cable Termination Sites." West Des Moines, Iowa, U.S. May 2018.
Project Scope

In order to mitigate the risk of fire resulting from protection system failure to accurately identify and clear high impedance faults (“HIF”) in the Tahoe area, a modern HIF detection system must be designed and implemented in the Tahoe area. A sponsored collaborative study with UNR will assess state-of-the-art relay technologies in a simulated environment and produce a suite of new protection system options for the Tahoe area.

The collaboration and study is to be overseen by Dr. Mehrdad Majidi of NV Energy and conducted by Dr. Mehdi Etezadi-Amoli and a graduate student in electrical engineering at UNR. NV Energy’s cost for the project is $210,000 for two years. This includes $195,000 for the sponsorship (including use of the UNR laboratory, and graduate student time and effort) and $15,000 for one-time hardware purchases (to be owned by NV Energy). The duration of the sponsorship is to be two years.

Because the study is expected to provide new contributions in power delivery research field, it will be conducted using a plan and methodology which meets requirements to be submitted to academic and scholarly journals and conferences. As such, the study results will be universally applicable to any utility that utilizes legacy protection schemes in areas with high ground resistance. Details of the publication goals and requirements are included later in this document.

4.3.8 Tahoe Distribution System Background

NV Energy’s Tahoe distribution system serves approximately 24,700 customers from 10 feeders out of four substations. The communities served include Incline, Glenbrook, Round Hill, and South Lake Tahoe. Major customers include Heavenly Valley, Harrah’s, Harvey’s, Hyatt and the Incline Village General Improvement District. The design of the Tahoe distribution system is unique in that it is a 14.4 kV, uni-grounded wye system (a three wire distribution network which is solely grounded at the substation). Other than Round Hill Substation, which was rebuilt in 2017 due to a fire, the system is in excess of forty years old. Regardless of when built, the protection system utilizes a legacy residual ground sensitive earth fault (“SEF”) protection scheme which uses a definite time overcurrent trip with a low (~40 Amperes) pickup current, resulting in ground fault clearing times in excess of two seconds. The long time delayed trip is required in order to distinguish fault current from normal load unbalance, but it also introduces several operating risks, including increased risk of fire due to delayed or non-operation for a wire down or vegetation contact, increased safety risk to employees and the public, and increased risk of inadvertent tripping during switching. In the current utility environment, these risks are no longer acceptable. Therefore, protection system improvements are required to appropriately mitigate the risks. However, NV Energy’s current suite of protection system options are not capable of incorporating state of the art high impedance fault (“HIF”) detection. The purpose of the collaboration and study sponsorship with UNR is to assess state-of-the-art relay technologies in a simulated environment and develop a new suite of protection system options for the Tahoe area.

4.3.8.1 Study Plan

The study will recommend modifications to NV Energy’s Tahoe area distribution system that improve HIF detection and reduce known risk related to fire and human safety. In order to do this, the study will include:

1. Documentation and quantification of risk reduction due to various methods of HIF detection.
2. Investigation of the performance of HIF detection techniques using advanced off- the shelf-relays in a simulated network (called hardware in the loop simulations).
3. Exploration and economic analysis of system design alternatives which may facilitate improved HIF detection, including conversion from a uni-grounded wye system to an ungrounded wye or a multi-grounded wye, and telecom aided protection.
4.3.8.2 UNR Laboratory/Study Oversight

In order to investigate the performance of HIF detection techniques, it is necessary to simulate a power system network. As a result of this sponsorship, the Tahoe distribution network will be the case study. The Tahoe system will be studied in a power application software with an electromagnetic transient program (“EMTP”). The power system laboratory at UNR has a real-time digital simulator (“RTDS”) which is capable of conducting the EMTP simulations. Also, using RTDS and hardware-in-the-loop (“HIL”) simulation, NV Energy can assess the practical usefulness of the HIF detection functions embedded in commercially available relays, for the Tahoe network. HIL simulation is a technique that is used in the development and test of complex real-time embedded systems. HIL simulation provides an effective platform by adding the complexity of the plant under control to the test platform. In addition, this collaborative project between NV Energy and UNR will provide the protection engineers with an opportunity to become familiar with this state-of-the-art technology, in order to address other complex issues which exist in the NV Energy electric system.

The study will be co-led by NV Energy’s Dr. Mehrdad Majidi and UNR’s Dr. Mehdi Etezadi-Amoli and conducted by graduate students. The combined expertise and NV Energy specific experience of both doctors provides an opportunity to be leveraged—this study is in a new area of research where it is expected that re-direction on the fly may be necessary. While the study results are expected to provide a significant new protection design philosophy, the study will still be tailored to NV Energy’s Tahoe distribution system. Additionally, the proximity of the laboratory to NV Energy’s offices (both in Reno, Nevada) will make study oversight simple and effective.

Dr. Majidi holds a Ph.D. in electrical engineering from UNR and has conducted extensive published and peer reviewed power system studies. Dr. Etezadi-Amoli holds a Ph.D. in electrical engineering and has been a faculty member at UNR since 1983 where he is responsible for the power system program. In addition, he is a former electrical engineering department chair, and a former NV Energy employee during the summers of 1985-1998, conducting power system analysis, protection and protection and transient analysis. From 1979 to 1983, he was a Senior Protection Engineer with Arizona Public Service Company.

Final Study Result/Publication

UNR’s study goal is to generate research worthy of publication in peer reviewed Institute of Electrical and Electronics Engineers (“IEEE”) journals and conferences. Based on the IEEE paper formats, all papers must include an abstract, introduction to review the literature and the novelty of the presented work, proposed methodology, results and comparison, and conclusions. In addition, the proposed methodology must be universal for all networks (utilities) in order to provide new contributions in the research field. In the results and comparison section, any test case can be selected to verify the methodology. However, if funded by NV Energy, this research project will use the NV Energy Tahoe area network as the test case.

In order to meet UNR’s study goal, Dr. Etezadi-Amoli and Dr. Majidi will submit the results of the research project to the IEEE Transaction on Power Delivery. Although the reviewing process for IEEE Transaction journals is very tough, Dr. Etezadi-Amoli and Dr. Majidi believe that the results will be successfully peer reviewed and published. Dr. Majidi has already reviewed the existing scholarly literature on high impedance fault detection, which shows that the study plan and methodology present novel work.

Dr. Etezadi-Amoli is the author of many technical journal publications. He and Dr. Majidi are actively involved as reviewers for several reputable IEEE journals and conferences, including the IEEE Transactions on Power Delivery, whose aim and scope is to embrace innovations in electric delivery.40

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40 Recent publications for Dr. Majidi can be found at https://ieeexplore.ieee.org/xpl/RecentIssue.jsp?punumber=61.
4.3.9 Telecommunication Reinforcement

Telecom Prospectus

Of all critical infrastructure, the Telecommunication sector may be the most vulnerable. From the impact of extreme weather to the increasing risk of cyber-attack, this complex system runs the risk of significant disruption. This is extremely concerning, since communications are an integral component of NV Energy’s daily operations. The changes in the industry directly impact our internal telecommunication system. Between 60 to 80 percent of manufactured telecommunication infrastructure has been discontinued or is being phased out at an incredible speed. Lack of parts are creating a need to improve the communication infrastructure.

Telecommunication Infrastructure

The Telecommunications Network plays a significant role in monitoring and controlling aspects of the electric grid. Monitoring and control of the grid is not only vital for normal operations but is critical during natural disaster emergency events. As part of the overall Plan, the Companies will be installing or upgrading distribution equipment, such as pole-mounted reclosers, which will require reliable, high-speed communications for proper operations.

The overall plan is a strategic strike; the intent will be to replace all four wire configurations and T1 circuits with cellular modems. NVE has contracts for cellular service with both AT&T and Verizon, providing the Companies the flexibility to use the most optimal service for a particular area. The immediate result will be overall savings on leased services, and more reliable service provider support. By 2021, by working with internal teams for land and the BLM permitting, fiber backhaul installations will begin. NV Energy has adopted a new standard to include fiber on all line rebuilds. After a few years in, while other projects take effect, the plan will include adoption of a private LTE network. As part of this effort, we will provide an investigation in procurement of the 700 megahertz (“MHz”) spectrum. It is believed that the initial investment to procure the use of this frequency would be around $5 million (based on the cost of $0.75 per unit, assuming at this time that NV Energy would purchase the entire state of Nevada’s 700 MHz frequencies).

<table>
<thead>
<tr>
<th>Telecommunication Timeline: Infrastructure Strengthening</th>
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</thead>
<tbody>
<tr>
<td>2020</td>
</tr>
<tr>
<td>Cell Router Installations</td>
</tr>
</tbody>
</table>

Carson City to Tahoe Basin

Historically, communications into the Basin, which is primarily a Tier 3 wildfire risk, have been performed utilizing a leased four-wire line from local telephone companies. This equipment is considered to be older technology, using copper wire constructs, which makes it difficult to repair due to limited manufacturing availability for the unit. Since the current means of communication rely on a third-party service provider, reliability of the communications becomes a concern. During a natural disaster, such as a wildfire, reliability of the communications is critical to the Companies’ ability to respond to the event. The present four-wire technology being provided by the telephone company, is outdated, is becoming obsolete and will be phased out. In place of the four-wire technology, the Companies will be installing a fiber optics high-speed communication into the Basin in conjunction with a private radio network.

NV Energy, as part of the transmission line replacement projects, will be installing a new static-line, which will incorporate a fiber optical ground wire (“OPGW”) cable. The OPGW will serve a dual purpose by
providing lightning and grounding protection to the transmission line, while enabling high speed communications into the Incline Substation located in North Lake Tahoe.

Once the high-speed communications into Incline Substation are established, the Companies will be installing a new private radio communications network from the Incline Substation to the distribution field devices. The radio communications network will use 900 MHz and private cellular modem technology.

**Reno Metro Area**

The Reno area is exposed to high winds, and is settled in earthquake territory. The telecommunication’s core network for northern Nevada is Located in Reno. The Reno network is limited in fiber resources, and all fiber paths tend to overlap between Ohm and general office building, causing a situation that when one fiber lines goes out half of all communications for the state can be lost. By considering adding fiber to a few key lines within the Reno Metropolitan area, telecommunications could provide true redundancy for the entire northern territory. These lines include, but are not limited to, the following:

- 142 NVR to Reno;
- 114 California to Northwest;
- 141 Northwest to NVR;
- 128 Greg Street- Glendale (Stop at Ohm);
- 129 Glendale to Valley Road; and
- 180 Dove to Greg Street (Tap in at Canyon way).

**Elko, NV**

Like much of northern Nevada, Elko suffers from snow, and high winds. The Elko office has minimal network, and suffers on the operations side due to lack of telecommunication infrastructure. The 3428 line between Robinson to Valmy provides an opportunity to tie in resources in Elko Nevada, and help to provide fiber redundancy between highway (“HWY”) 50 and I-80. The State of Nevada owns fiber between Reno and Elko along 1-80, and NVE owns fiber along Hwy 50. Installing fiber along the 3428 line will give telecommunications the ability to tie both I-80 fiber and HWY 50 fiber, and give us high speed communications to critical service areas. Elko Service Center could become a powerful place of redundancy to provide a link between north and south, during any major weather events that affect both service areas.

**Fort Churchill to Utah**

The communication infrastructure from Reno to Las Vegas is dependent on the HWY 50 fiber route. NV Energy plans to have a Dense Wave Division Multiplexing (“DWDM”) optical transport system that provides a single point of failure. The Telecommunication infrastructure supports various microwave links connecting Fort Churchill to Tonopah. Many of the sites from Fort Churchill heading to Utah are utilizing a leased four-wire line from local telephone companies, or swapped service from other outside entities. By adding fiber to 638 Mason Valley to Fort Churchill, and a microwave shot to Bald Mountain, various T1 and four-wire circuits could be eliminated.

**Angel Peak**

Angel Peak in southern Nevada is located in Tier 3 wildfire extreme risk area. In 2016, telecommunications proposed a project to install fiber on existing 69kv line between Canyon Substation and Angel Peak Substation. Using existing conduit to install fiber between NV Energy Angel Peak Substation and U.S. Air Force (“USAF”) Angel Peak POP. The project required pole replacements that prompted a transmission study to be conducted. USAF had requested to install fiber on NV Energy-owned structures between Canyon Substation and Angel Peak.

This project included a great deal of coordination with the U.S. Department of Fish and Wildlife, the BLM, the Nevada Test Tactical Range (“NTTR”), the Nellis Air force Base, and the Creech Air Force Base. Due
to the organizations involved this will be a Buy America Project. NV Energy owns 31 of the 118 poles that would be involved in this project. A hardened pole line to steel or ductile iron study was completed. The project was never started due to the complexity and scope changes; many of the challenges included hot work in a forest area, and the fact it was the only line that supports Mount Charleston, and lack of clarity whether to build new line and fiber afterwards.

4.3.10 Copper Wire Replacement Program

Effective distribution and transmission facility upgrades are needed to ruggedize the electric system and mitigate the impact of natural disasters. One initiative used to ruggedize the electric system is the copper wire replacement program in all natural disaster risk areas.

The copper wire replacement program entails reconductoring or rebuilding distribution infrastructure that reduces the risk of a wire-down threat. This project is intended to address the inventory of approximately 47 miles of transmission and distribution lines in Tier 1, 2 or 3 areas in northern Nevada with small, annealed or otherwise degraded conductor which have been in service beyond their useful life and pose a wire-down risk. The Companies will also proactively replace approximately 35 miles of distribution and 12 miles of transmission small copper conductor in monsoon, thunderstorm, high wind and other natural disaster risk zones in southern Nevada.

The Companies typically experience over 200 live wire-down events in northern and southern Nevada per year. While rare, system protection devices may malfunction due to a high impedance fault or other issues which may result in energized conductors falling to the ground and posing a serious risk to persons and property. As described under the pole stopper and critical crossing programs, NV Energy has witnessed a degradation in electric service due to a number of factors, including aging infrastructure, changing climate conditions, extended drought, extreme weather events, extreme wind, etc. Small sized, copper wire tends to break during storms while large sized wire is more durable in high winds. Therefore, these wire down events pose a public safety risk in addition to wildfire risk in established risk tiers and this proactive program is prudent and reasonable.

The Companies have never performed similar proactive programmatic replacement; therefore, the program is incremental. The alternative to not replace will result in overhead conductor failures that may result in catastrophic events or public safety impacts. These impacts may be significantly more costly when compared to the program costs.

<table>
<thead>
<tr>
<th>Table 21: Copper Wire Replacement Program Costs</th>
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<tr>
<td></td>
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<tr>
<td>Total ($)</td>
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</tbody>
</table>

4.3.11 Lines Ruggedization – Natural Disaster Risk Zone (non-wildfire) Pole Replacements

The Companies’ proposed inspections methodology to identify impacted distribution circuits in southern Nevada (under non-wildfire natural disaster risk zones) in Section 4.2 above. As a result of these inspections, a proactive programmatic replacement of wood poles in high risk zones will be needed and the Companies have never performed similar replacements. Therefore, the program is incremental. The alternative to not perform this replacement will continue to result in overhead conductor failures that may result in catastrophic events or public safety impacts. These impacts may be significantly more costly when compared to the program costs.
Table 22: Pole Replacement Costs

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lines Ruggedization - Natural Disaster Risk Zone Pole Replacements (non-wildfire) (Capital)</td>
<td>$675,000</td>
<td>$2,754,000</td>
<td>$2,809,080</td>
<td>$2,865,262</td>
</tr>
</tbody>
</table>

Critical Road Crossings and Pole Stopper Investments

Between 2015 and 2018 Nevada Power Company witnessed a degradation in its electric service. The system average interruption duration index ("SAIDI") increased 25 percent from 35.01 minutes in 2015 to 43.8 minutes in 2018 and storm-related customer outage hours increased from 108,002 hours in 2015 to 1,041,499 hours in 2018 including major event days. This is due to a large number of factors, including but not limited to aging infrastructure, changing climate conditions, extended drought, extreme weather events, extreme wind, etc. A 2013 report by the President’s Council of Economic Advisers found that weather-related outages are estimated to have cost the U.S. economy an annual average $18 billion to $33 billion. In recent years the United States has experienced some of the costliest storms ever recorded including Hurricane Maria, Irma, Florence, Michael, etc.

In addition to degradation of electric service, facilitating access for first responders during an emergency along with the ability of the general public to evacuate from a disaster zone (wildfire, floods, monsoons, etc.) is critical for the safety of the general public. Major storms can damage the electric grid resulting in facilities, such as poles and equipment, to block major roads and evaluation routes. Equally important to keeping roads open is the ability to maintain service to critical facilities, and for NV Energy to restore power in an expedited manner should an outage occur. NV Energy has a significant number of locations where the power line cross over roads. When a natural disaster occurs, the poles on either side of the highway can break causing the power lines to come down across the road blocking all vehicle travel and presenting a public safety risk. Emergency responders cannot respond, and the general public cannot safely evacuate the area. During a natural disaster, extensive pole damage can also occur where one pole can cause a cascading effect bringing down multiple poles. Replacing multiple poles will significantly delay restoration of service to critical facilities.

In order to address these threats NV Energy has developed two specific targeted investments:

**Critical Crossings** - Replace wood poles adjacent to critical crossings, including highway, railroad, and other critical distribution and transmission lines with higher class steel or ductile iron structures to withstand and mitigate the impact of a cascade failure during a natural disaster.

**Pole Stoppers** - Replace every fifth to eighth wood tangent or suspension structure with higher class steel or ductile iron structures to increase the strength of the structures in order to withstand and mitigate the impact of a cascade failure during a natural disaster.

Table 23: Pole Stoppers and Critical Crossings Costs

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole Stoppers</td>
<td>-</td>
<td>$1,250,000</td>
<td>$1,275,000</td>
<td>$1,300,500</td>
</tr>
<tr>
<td>Critical Crossings</td>
<td>$2,330,778</td>
<td>$2,700,581</td>
<td>$2,754,593</td>
<td>$2,809,684</td>
</tr>
<tr>
<td>Total ($)</td>
<td>2,330,778</td>
<td>3,950,581</td>
<td>4,029,593</td>
<td>4,110,184</td>
</tr>
</tbody>
</table>

4.3.12 Lightning Arresters Replacement

Lightning arresters are used to protect the insulation and conductors of the electric distribution system from the damaging effects of lightning striking the line. The type of lightning arrester traditionally used on the
overhead distribution lines is known as “gap arresters.” If the lightning strike exceeds a specified voltage level, the electric current would jump the “gap” to ground. In some cases, the lightning strike was of such high voltage that the lightning arrester would fail, causing hot sparks. These hot sparks are a potential ignition source for a wildfire. Manufacturers now make an alternative metal-oxide varistor (“MOV”) arrester. The MOV is a solid-state device that can withstand higher levels of lightning. Although MOV arresters are better at reducing sparks, they utilize a “ground lead disconnector” that operates should the arrester fail, so sparking can still occur. Although better than a gap arrester, MOV arresters do not guarantee a complete removal of ignition risk.

NV Energy’s infrastructure replacement programs are based on inspections, outage data, and operational knowledge. These inform maintenance programs by identifying areas with aging hardware, outdated or missing equipment, including splices, conventional fuses, lightning arresters, and insulators. The equipment replacement programs help reduce the likelihood of ignition events, wildfire risks, and customer outages.

NV Energy proposes to perform an engineering review to determine the most effective approach to address lightning arrester failures. The review will determine where MOV arresters or engineering alternatives are suitable. Based on the analysis, the projected expenditures will be used for targeted lightning arrester failure mitigation. The Companies are only including expenses for conducting alternatives analysis and targeted replacement at this time. This would get updated in a subsequent plan update based on completion of the initial analysis.

<table>
<thead>
<tr>
<th>Table 24: Lightning Arresters - Initial Analysis Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total ($)</td>
</tr>
<tr>
<td>2020</td>
</tr>
<tr>
<td>-------</td>
</tr>
<tr>
<td>70,000</td>
</tr>
</tbody>
</table>

### 4.4 Vegetation Management

Section 1.3.2. (g) of SB 329 requires electric utilities to implement vegetation management procedures to minimize electric infrastructure-related wildfire risk. In order to comply with SB 329 and the Regulations, the Companies’ Plan accelerates and provides more frequent tree trimming cycles that will include more detailed transmission and distribution (“T&D”) vegetation risk inspections. In addition, these procedures will include removing vegetation line/ground clearance to comply with the above provisions and also to maintain integrity of overhead electric assets in the extreme risk areas defined as Tier 3, Tier 2, and Tier 1-elevated. The discussion below highlights the initiatives proposed to reduce ignition risk as well as meeting the state Fire Code requirements outside the Tier risk areas. The state Fire Code was passed and will be filed with the Secretary of State by April 1, 2020. IWUIJC Appendix A shall become the state’s minimum code.

#### 4.4.1 Vegetation Management Programs & Procedures

The objective of the vegetation management program is to identify and correct any vegetation-related problems on the electric system that could affect resiliency of the system, in order to reduce customer outages and reduce the risk of wildfire.

The Companies currently have field patrol programs designed for vegetation management as well as system inspection. However, these programs are not targeted or prioritized based on the risk classifications; moreover, specific circuits in the defined risk tiers may have a long lead time for patrols based on the program’s schedule. This Plan will assist with risk-based prioritization of vegetation management practices. The Companies currently use Asplundh Tree Experts (“ATE”), a vegetation clearance contractor which was selected through a competitively awarded contract bid in 2018 and CN Utility Consulting (“CNUC”), its current vegetation line inspector, which was selected through a competitively awarded contract bid in 2019. Each contract was awarded on three year terms. Upon expiration of these two existing contracts, the Companies intend to issue another request for proposal or extend the existing contracts.
The overall scope of work includes detailed accelerated application of line clearance specifications and protocols for maintaining vegetation growth within the ROWs of T&D lines to ensure mitigation of power outages, wildfires, and improved service reliability for Tier 3, Tier 2, and Tier 1-1 elevated defined areas, while meeting the IWUC Appendix A requirements. Total pole structure inspections and clearance in the defined Tier areas represent approximately 55,000 structures and associated conductor spans. This work scope includes a detailed inspection and itemized clearance work plan for each line circuit patrol performed by CNUC. The work plan is then executed by ATE, which consists of an inspection checklist including site location, tree species, and prescription. An overall plan will also be prepared to include safety, environmental, public access, quality assurance/control, and potential hazards.

NV Energy has already begun inspections and corrective actions in Tier 3, 2 and 1 (elevated) areas. Corrective actions requiring immediate attention are being executed promptly upon discovery. Additional steps highlighted in this section are expected to begin promptly after the vegetation management plan is approved and execution of the desired trimming cycle in the currently mapped high risk tier areas will be targeted for completion in 2026. To meet Appendix A of the IWUC and applicable requirements, areas outside of the defined wildfire risk tiers will be addressed by 2028 with yearly maintenance in all areas. The companies will also execute a pilot program to study fuel loading. Mitigation of fuel loading, or reducing available fuel, will greatly increase the resiliency of the grid by reducing potential for wildfire ignition. The objective of this program will be to understand fuel loading, fuel changes, seeking to identify ROW infringement and along corridors with thermal, color, and multi-modal LIDAR data and derivation of management zones for fuel mitigation. Additional details are included in Section 4.5.3 below. The companies’ staff will also assist with relevant safety training and contractor onboarding for additional inspectors and line clearance crews during the onboarding process.

For vegetation management, the International Society of Arboriculture has established a certification program that credentials professional arborists who have a minimum of three years full-time experience working in the professional tree care industry and have passed an examination covering facets of arboriculture. The standard to be met is the American National Standards Institute (“ANSI”) A300, which establishes standards for pruning and trimming operations. This standard was developed by the Tree Care Industry Association and discusses areas such as Pruning and Integrated Vegetation Management and is a voluntary standard based on industry consensus prudent practice. The companies’ vegetation management contractors meet these requirements. Consistent with the requirements of SB 329, inspection crews will include (at a minimum) a qualified arborist certified by the International Society of Arboriculture. Tree trimming crew work will be performed under the general guidance of a certified arborist.

Work will be performed per the relevant collective bargaining agreements for all areas. The procedures, protocols and measures set out in the Plan comply with all applicable requirements of the IWUC. Per the applicable requirements, each ground clearance fuels crew will consist of a crew supervisor and personnel who will meet the National Wildfire Coordinating Group ("NWCG") and the National Fire Protection Association ("NFPA") certification requirements for their specific position for the pole grubbing and ground clearance activities. Each member will be fire line red-carded as a firefighter. There will be a crew supervisor for every 20 personnel and one squad boss for every 10 personnel. A crew of five will have one Captain or Single Resource Boss and an assigned forester. Every project will have all safety requirements in place as outlined in the scope of work. General work performed by NVE within its ROW outside of this initial initiative would not require a qualified firefighter cardholder on site.

4.4.1.1 Pole Grubbing

Pole grubbing includes the removal of trees, shrubs, stumps, roots, cheatgrass, sagebrush, and other fine fuels in proximity to a pole or other susceptible assets to create a combustible-free space. The companies’ vegetation management procedures include reducing fuel loads along the T&D line ROWs through pole grubbing and ground clearing. Pole grubbing has not previously been implemented by the companies’ personnel within service territory as part of routine, system-wide vegetation management to meet the requirements of SB 329 and the IWUC. Pole grubbing will be performed annually in the high fire threat
areas once initial fuels treatment has been completed. The Companies will use best practices during pole grubbing and ground clearing to prevent introduction of noxious weeds into areas that currently do not have a noxious weed problems and will address any other environmental concerns. Also, the Companies will work with land managers and fire districts implementing the appropriate and most effective maintenance treatment to prevent the growth of cheatgrass in the ROWs. Some of these treatments may include the use of pre-emergent herbicides, seeding with fire resilient grasses, soil bacteria which works like a pre-emergent herbicides, yearly mowing or livestock grazing. These efforts will facilitate the creation of a combustible-free space as stipulated by the IWUIC.

4.4.1.2 Four-Year Cycle Maintenance Program

The Companies are accelerating existing tree trimming cycles to support detailed transmission and distribution circuit inspection and remove vegetation to maintain integrity of overhead assets in extreme risk areas, defined as Tier 3, Tier 2, and Tier 1-elevated wildfire ignition risk zones. The Companies use skilled and specially trained contractors to meet requirements given by the Occupational Safety and Health Administration and ANSI Z 133.1-200, as well as good utility practices, to maintain vegetation around lines, which minimizes both customer outages and potential for wildfire ignition.

The Companies’ current vegetation management inspections are performed on an eight to nine-year cycle in northern Nevada with a four to five-year cycle in southern Nevada. Annual grassland inspections will also be conducted as part of pole grubbing and ground clearing activities. These inspections utilize the USFS exclusion zones. These ROWs are currently spaced at 30 feet from the center pole line. A proposed ROW of up to 350 feet from centerline has been established by the USFS in Lake Tahoe for Liberty Utilities and would not require a full National Environmental Policy Act evaluation or Environmental Impact Study. Electric utilities are not required to solely manage this expanded ROW but would collaborate with USFS and other entities. NV Energy is working with the USFS in Lake Tahoe to establish similar exclusion zones and potentially explore that in southern Nevada as well.

All T&D line assets considered for vegetation-related wildfire mitigation include northern California (for NV Energy-owned transmission assets), Lake Tahoe, Truckee, and Mt. Charleston (Tier 3 extreme fire risk) areas; the Cold Springs, Elko, Minden, Virginia City, Galena, Verdi, areas of Carson City, Douglas County, and Winnemucca (Tier 2 elevated fire risk) areas; and the Battle Mountain and Dayton (Tier 1 elevated high fire risk within the WUI and prior fire history) areas that are currently on an approximate eight to nine-year cycle for patrol and maintenance tree trimming. The vegetation management department’s proposed standard is to shorten that cycle to four years for these three tiered wildfire risk areas. Vegetation management scope also includes reducing fuel loading along the T&D line ROWs through pole grubbing and ground clearing for the stated Tier areas. This proactive trimming cycle reduction work has never been conducted by the Companies along with pole grubbing; therefore, this work scope is incremental in nature. As mentioned, pole grubbing and ROW vegetation clearance will be on a yearly maintenance cycle pending completion of the initial treatment. This practices will help protect NV Energy’s infrastructure in the event that a fire starts outside the ROW. Additionally, this activity increases healthy forest treatments. This increased inspection frequency aligns well with good utility practice for vegetation management strategies and is prudent in the fire threat zones.

4.4.1.3 Creation of Exclusion Zones with the USFS

The Companies along with the USFS will create exclusion zones, which include the area immediately under and adjacent to wire supporting structures, whether those structures are lattice tower or steel poles. The creation of these exclusion zones ensures access for maintenance and repair as well as minimizing fire hazard. These exclusion zones protect structures from fires that start in the vicinity of the ROW. All woody vegetation will be removed to create the exclusion zone. Some low-lying shrubs and grasses may be allowed, provided they do not impede access to the structure. These exclusion zones are generally for transmission level structures, however, they may also be applied to designated distribution level circuits.
4.4.1.4 Resiliency Corridor

The Companies are proposing the implementation of a resiliency corridor. As noted above, the resiliency corridor concept was recently adopted in an executed agreement between Liberty Utilities, USFS, the Lake Tahoe Basin Management Unit, and the counties of El Dorado and Placer in CA and Washoe County in Nevada. This proposed project area crosses over the Basin into the Tahoe National Forest. The USFS and Liberty Utilities have built upon existing partnerships toward a long-term commitment to reduce vegetation risk along power lines. The Companies’ proposed resiliency corridor, subject to the USFS’ approval, is based off of this agreement.

A resiliency corridor creates three zones, with varying degrees of vegetation management, from the center line of distribution lines. Zone 1 will have all vegetation removed from 15 feet from the center line, spanning a total distance of 30 feet. Low-lying, slow-growth shrubs and grasses will be allowed to remain within the zone. Zone 2 will have all trees with structural defects removed from 175 feet of the center line. Fuel reduction for increased resilience and thinning for forest health will also occur in Zone 2. Zone 3 will be thinned to reduce fuels and improve forest health and resilience. Zone 3 spans 1,000 feet from the center line on each side. Transmission lines will have a greater clearance measurement, which will be agreed upon between the Companies and the USFS. The Companies will abide by the IWUIC to move towards a combustible-free zone around poles. This would include the Tier 3 areas surrounding the Basin, along the Sierra Nevada mountain range, the Humboldt-Toiyabe National Forest, and the Mt. Charleston area. Expansion of healthy forest treatments is anticipated to result in an overall healthier forest, reducing the risk of ignition over time.

The Companies will continue to work with the USFS to implement this resiliency corridor in the Tier 3 areas, based upon the Zone requirements shown in the graphic above to significantly reduce the wildfire risk. This is neither a FERC requirement, nor a Commission requirement. With the significant risk that the Basin, Mt. Charleston, and the Sierra Nevada mountain range front face, the proposed measures will significantly reduce the instances of ignition due to vegetation contact.

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4.4.1.5 Collaborative Fuel Management with Fire Districts

The Companies will be required to undertake necessary fire protection measures to reduce the threat of wildfire in WUI areas and improve the capability of controlling such fires to comply with not only SB 329, but also adopted wildland fire codes. The Companies will also have to comply with AHJ CWPPs. The Companies are working with local, state, and federal fire protection districts and fuel management officers to develop the required vegetation management for each of these AHJ. For activities related to ground clearing, the Companies are working with AHJs to establish appropriate treatment plans relative to their stipulations, goals, and environmental concerns. This will also help align initiatives with CWPPs as collaborative discussions on fuels mitigation continue.

For example, Central Lyon County Fire Protection District ("CLCFPD") enacted a resolution adopting the 2018 edition of the IWUIC, including Appendix A, as published by the International Code Council ("ICC"), for which the 2018 IWUIC is poised to become the minimum standard in the state. These regulations are known as the Wildland-Urban Interface Code of CLCFPD. The Companies are working collaboratively with CLCFPD, the Nevada Division of Forestry, and other partners to reduce the threat of wildland fire and help protect residents, their property and businesses, and the infrastructure that serves the communities. One element of the partnership is overlapping the required vegetation management for the Companies with current fuels mitigation projects and projected future projects of CLCFPD.

The Companies contracted with CLCFPD and Nevada Division of Forestry to provide fuels reduction crews that will perform the vegetation thinning and clearing required for pole grubbing and ROW clearances. All pole grubbing and ROW easement clearing will comply with the requirements set forth in the IWUIC, and Central Lyon Counties CWPP. Based on the scope of work and estimates developed with the fire protection districts and fuel management officers, the CLCFPD cost is approximately $2.3 million over next five years and the Companies have estimated an additional $250,000 will be required to perform program management and oversight tasks. These are estimates and actual costs may vary based on field conditions.

The cost of this project is lower because the work is being performed in conjunction with other fuels mitigation projects that have already been started and will continue for the next five years in the Dayton, Mound House, Stagecoach, and Silver Springs areas. The partnership approach with state, local and federal fire agencies will reduce costs due to joint grant funding, prior fuels mitigation projects in the area and projects that have prior approval. Also, these agencies are not-for-profit; therefore, all project work is done at true cost. This fuels mitigation work will include various types of fuel removal techniques, from mechanical to hand-removal. ROWs will be left clear of all combustible materials and when approved, treated with herbicides or other techniques deemed appropriate by the forester and/or AHJ (to align with CWPP initiatives in the future), to neutralize the soil, preventing the future growth of combustible vegetation. This will prevent the growth of cheatgrass and sagebrush in the ROWs. Areas that cannot be treated by herbicides will need to have vegetation re-treatment every year. Areas treated by herbicides will require monitoring and evaluation for re-treatment.
All required permits for projects will be obtained by each fire district prior to performing the work. When possible, all projects will be incorporated into the Central Lyon County's cross-hatching fuels projects to create linear fuel breaks throughout their community. The Companies’ field personnel will work on a daily basis with fire agencies, enhancing the working relationships and communications during any emergency incident and recovery throughout the state of Nevada. Each fuels crew will consist of a crew supervisor and personnel who will meet the NWCG and NFPA certification requirements for their specific position. Also, each member shall be fire line red-carded as a firefighter.

Another benefit of this partnership is that the Companies will have the ability to have crews perform firestand-by while working under a hot work permit or during times of high fire danger. Should a wildfire start, the contracted crews will help suppress wildland fires faster, which will help protect the Companies infrastructure, reducing repair cost while maintaining power. Fire agencies will also provide the required wildland training to all field personnel. This eliminates the Companies’ need to contract for training. A stronger relationship is created when those training the personnel are the same individuals responding to disaster incidents.

All local, state and federal agencies are in the process of adopting IWUIIC, and the Nevada State Fire Marshal also just adopted the 2018 IWUIIC, including Appendix A. The BLM recently issued the Nevada Instruction Memorandum ("IM") 2020-009, “to facilitate and expedite O&M activities necessary to reduce the risk of wildfires.” Per 2020-009 IM, it is the Companies’ responsibility to carry out O&M activities to prevent wildfires within Nevada’s BLM ROWs. Using the model already implemented with CLCFPD and Nevada Division of Forestry, similar compliance work will need to be conducted across the state of Nevada. NV Energy will continue to develop similar contacts and relationships with other local, state, and federal fire agencies in order to continue the momentum and collaborative effort to remediate critical threats in the near term. Other discussions with the USFS, the BLM, the Nevada Division of Forestry, and other fire agencies resulted in considered efforts to map future projects. The Companies will provide updates into the development of a future collaboration to reduce fuels adjacent to Tier 3 areas in its subsequent updates to the Plan.

4.4.2 Meeting & Exceeding Requirements

The additional ROW clearances along with the increased inspection frequency will exceed the standard and existing state and Commission requirements for vegetation management. Further, these initiatives are poised to exceed those industry standards that align with stringent clearance and vegetation management requirements in neighboring states such as General Order ("GO") 95 Rule 35, issued by the CPUC, as well as California Public Resources Code 4293. 42

While equivalent requirements are not mandated in the state of Nevada or by the Commission, the Companies aspire to maintain best practices through visibility into similar electric utility vegetation management operations and operate under prudent vegetation management practices in compliance with approved internal protocols, the NERC standards, the FERC mandates, the ICC IWUIIC Appendix A, CWPPs, and requirements set forth in ANSI A133.1-2000.

4.4.2.1 Requirements for Tree Trimming Contractors

Per SB 329, the Commission may authorize a person who is not employed by an electric utility to perform tree trimming related to line clearance. Tree trimming by an authorized person who is not an employee of an electric utility must be performed under the direction of an arborist certified by the International Society of Arboriculture. Any applicant (company) for authorization by the Commission must complete an application including:

42 CPUC GO 95 Rule 35
The name of the applicant.

The current telephone number, mailing address, electronic mailing address, and a physical street address of the applicant.

A copy of each business license and certificate issued by this State and any local government within this State authorizing the applicant to conduct business in this State.

Documentation demonstrating that tree trimming will be performed under the direction of an arborist certified by the International Society of Arboriculture.

Pursuant to this requirement, the Companies’ Inspection crews will each include at least one qualified arborist certified by the International Society of Arboriculture. Consistent with SB 329 Section 14.1 requirements, the Companies will coordinate efforts to maintain records confirming that contractors not employed by the Companies have been authorized to perform tree trimming by the Commission and that the person performs the tree trimming under the direction of an arborist certified by the International Society of Arboriculture. For implementation of this Plan, the Companies will utilize the current vegetation clearance contractor, ATE and its current vegetation line inspector, CNUC.

<table>
<thead>
<tr>
<th>Table 25: Vegetation Management Program Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vegetation Management Total ($)</td>
</tr>
</tbody>
</table>

4.5 Emerging Technologies & Strategies

The Companies have established study or pilot programs to study emerging technologies and strategies that will be aimed at reducing the natural disaster impacts by proactive condition assessment, enabling automation or using technology for reducing response time. These initiatives are poised to address controllable threats to the system.

4.5.1 Cable Rehabilitation Study

With aging cable infrastructure and a high cost to re-cable lines, the Companies are investigating extending the useful life of cables within the Companies’ electric system. This work might assist in avoiding the replacement of entire cables that have reached the manufacturer’s specified end-of-life of the asset.

NV Energy will initiate a pilot program to investigate the feasibility of increasing the life of underground cables. The Companies will use Partial Discharge Testing to discover potential problems with the cables. If problems are found, a cable injection inspection will be performed to determine the remaining service life of said cable. NV Energy has used this type of testing on a spot check basis, but has never prioritized targeted natural disaster risk zones at a programmatic level. This pilot is expected to be done in a flood-prone area. A brief overview of this pilot program is to look back at outages over a three-year period to determine whether cables in flood-prone areas are more susceptible to failure than cables outside flood-prone areas. For the calendar year 2020, the Companies will monitor cables to determine which flood-prone cables failed and test a sample of these cables in 2021.

NV Energy has identified data that shows a comparable utility saved an estimated $1.2M utilizing this technique for locating potential failures, with approximately 2.15 times the cable mileage assessed with life extensions versus wholesale replacement of cables. This amounted to a 54 percent reduction of total unit cost per foot of cable. This proactive technology allows will allow for greater cable coverage at a lower cost per foot of cable.
This program has five steps, listed below.

1. Initiation
   a. Identify Purpose and Need
   b. Identify Sponsors
   c. Identify Preliminary Locations, Targets, and Duration

2. Planning
   a. Identify Preliminary Costs
   b. Accounting to Confirm whether Capital or O&M
   c. Present Costs to Steering Committee, if needed

3. Schedule
   a. Identify and Engage Stakeholders
   b. Identify Available Resources
   c. Request for Proposals

4. Execute
   a. Execute Based on Available Resources and/or Need
   b. Find Efficiencies and Modify Processes
   c. Track Monthly, Quarterly, and Annual Targets or Milestones

5. Closeout
   a. Lessons Learned
   b. Cost Analysis/Return on Investment
   c. Pilot Status Evaluated and Additional Areas Shortlisted

4.5.2 Use of Unmanned Aerial Vehicles for Line Patrol and Perform Image Analytics

NV Energy has started to explore the integration of drone technology into the inspection process. The biggest challenge with integration of drones for condition assessment of the electric infrastructure is efficient analysis of large volumes of data that is collected from these surveys. NV Energy plans to conduct a proof of concept for using image analytics (using artificial intelligence or machine learning platforms) for finding vegetation contact and overhead asset issues on NV Energy’s lines. This effort will assist in exploring the use of drones and image analytics to identify the current state of overhead assets along with vegetation in extreme wildfire risk areas to conduct proactive replacement and vegetation management. Machine learning will be explored to assist with image analytics and NV Energy will share the proof of concept output and next steps in subsequent filings.

4.5.3 Fuel Inventory Mapping

The Companies have a pilot program to study fuel loading. Mitigation of fuel loading, or reducing available fuel, will greatly increase the resiliency of the grid by reducing potential for wildfire ignition. The objective of this program is to understand fuel loading, fuel changes, seeking to identify ROW infringement and along corridors with thermal, color, and multi-modal LiDAR data and derivation of management zones for fuel mitigation. NV Energy has been investigating platforms, tools, and third-party resources that may complement existing conditional awareness and inspection activities to provide visibility into the density of vegetation and at-risk trees within its service territory. Additionally, the Companies will be issuing a RFP targeting vendors that provide fuel and fire behavior modeling to supplement internal monitoring activities.

BLM shared recommendations through the EWG meetings for the Companies to explore web-based platforms utilized in the lands management industry. These suggestions provide informational sources for active fire weather and meteorological condition monitoring. In addition to the U.S. National Fire Danger Rating System (“NFDRS”) fuels modeling tool, discussed in detail in Section 5.1, as well as future meteorological data provided by the Companies’ weather station deployments, the following simulation and modeling resources will be considered as this pilot continues.
4.5.4 Falling Conductor Pilot Program

Anticipating falling conductors may increase grid resiliency and minimize wildfire ignition events caused by the Companies’ equipment. The falling conductor detection method uses patterns of changes in voltage synchro-phasors to detect a falling conductor in the milliseconds following the break. In most instances, it takes an energized conductor one to two seconds from the time it breaks to touch the ground.

San Diego Gas & Electric (“SDG&E”) has filed a patent describing the method of detecting fallen conductors. SDG&E completed this work with assistance from Quanta and Schweitzer Engineering Laboratories to develop protection schemes that are able to detect a broken conductor before it hits the ground. Field tests yielded a 100 percent correct operation success rate.

Installation of these schemes will provide the Companies’ system with greater resiliency with substantially less risk of ignition of wildfire. These broken wire detections schemes sense and isolate in less than 0.7 seconds, which is less time than it takes for the wire to fall to the ground.

4.5.5 High Impedance Fault Detection

As noted in Section 4.3.7 above, NV Energy has partnered with UNR to study high impedance fault detection as well as traveling wave protection schemes for the distribution and transmission systems, respectively. Relevant details are included above and study costs are included in the summary table below.

4.5.6 Cost Estimates

Following table includes the cost estimates for the above study and pilot programs:

<table>
<thead>
<tr>
<th>Table 26: Emerging Technologies &amp; Strategies Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emerging Technologies and Strategies</td>
</tr>
<tr>
<td>2020 2021 2022 2023</td>
</tr>
<tr>
<td>$986,483 $1,264,513 $1,277,803 $1,291,359</td>
</tr>
</tbody>
</table>

4.6 Situational Awareness

Situational awareness provides insight into fire weather and other natural disaster impacts on the electric grid and the electric grid’s behavior during these events. This awareness may help in natural disaster risk mitigation and grid resiliency improvement. Information from equipment, such as weather stations and wildfire cameras, can provide valuable information that may assist the Companies before, during, and after natural disaster events. As noted in Section 5 below, fuel sampling can also provide valuable information regarding fuel conditions and provide a key indication of flammability. Weather stations and wildfire cameras may also help in situational awareness during trouble response and help in improving response time.

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43 USDA, USFS. “FlamMap.” [https://www.firelab.org/project/flammap](https://www.firelab.org/project/flammap).
4.6.1 Weather Station Deployment

NV Energy plans to install 30 weather stations on transmission and distribution poles or stand-alone structures in the identified natural disaster risk areas. The weather stations will provide readings on temperature, relative humidity, wind speed, wind gusts, wind direction, precipitation, fuel moisture, and other parameters that will be integrated into NV Energy’s operations. After this integration is completed, the collected data will be used for better weather forecasts, analyzing the fire risk potential and evaluating the PSOM criteria as noted in Section 5 below. The Companies’ weather station deployment will be accomplished by Western Weather Associates (“Western”) and will be initiated in 2020, with completion expected by the end of 2021. Western will monitor the data and package the data so that it is available in the public domain. NV Energy has never installed weather stations in specific risk areas and all program costs are incremental. Estimated costs for these weather stations are included in Table 27 and Table 28. Preliminary northern Nevada weather station locations are also included in the figure below. These locations will continue to be refined based on both internal and external (e.g., NWS) input and southern Nevada locations will also be included.

Figure 44: Preliminary Weather Station Locations

4.6.2 Wildfire Cameras Deployment

NV Energy has been working with the Nevada System of Higher Education (“NSHE”), specifically the UNR’s Nevada Seismological Lab (“NSL”) to deploy and operate a network of cameras for wildfire risk reduction, early detection and situational awareness. An added benefit will be the ability to view local facilities for security, preventative maintenance and failure assessment (all of these aspects have been demonstrated in regular use). This deployment will complement a growing network of fire cameras throughout the western United States. Nevada cameras have been primarily supported by the BLM. NV Energy will have remote
access control permissions on installed cameras, as well as view-only permission on other cameras in Nevada in coordinating best practices for wildfire monitoring with other agencies. The fire-hazard specific distributed internet protocol network (ALERTWildfire) will help isolate fire ignition confirmation and provide continuous situational awareness during fire incidents (near-Infrared bands provide visual fire monitoring during night-time hours). This is a proven system (confirming/monitoring 600+ fires in the past two years) and is currently used by fire managers at the BLM, the USFS, the CA Department of Forestry and Fire Protection, SDG&E, Pacific Gas & Electric, several California counties and many local fire protection districts. Non-critical infrastructure views from the NV Energy owned cameras will also be available in the public domain for broader monitoring and faster response. As noted in Section 3 above, the UNR also supported NV Energy with development of a state map of fire prone areas that can be used a reference in NV Energy’s mapping system that supports operational usage, decision making and new business decisions for minimum service requirements for new customers, and system improvements/enhancements to improve reliability.

The Companies’ wildfire cameras will complement the existing ALERTWildfire camera network. View-sheds, both at potential NV Energy sites and existing NSL locations, were computed using an on-line communications tool that provides assessment at an elevation of 50’ above a site location for evaluating actual visual coverage within the network. These view-sheds also provide a quick visual understanding of what important areas can be viewed and covered and illustrate qualitative limits of any one site’s contribution. NV Energy’s target in selecting sites for the camera installation has been maximum possible coverage of the identified wildfire risk tier areas. Site control status and targeted operational date are included for site selection and prioritization. For example, an NV Energy-owned substation where a camera can be installed without any additional permitting is prioritized. The Companies’ cameras may also provide redundant coverage for existing wildfire cameras where needed.

The Companies have focused on critical areas with population near the WUI. As these critical area installations are implemented, the Companies will evaluate additional coverage needed in remote areas. The Companies’ site control, Tier 3 coverage and prompt execution are desired attributes that are used to shortlist the initial locations specified in the map below.
Figure 45: Preliminary Wildfire Camera Locations

4.6.3 Situational Awareness Program Costs

The costs for camera and weather station deployments are summarized in Table 27 below.

Table 27: Situational Awareness Capital Forecast

<table>
<thead>
<tr>
<th>Situational Awareness Capital Costs</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weather Stations</td>
<td>$600,000</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Wildfire Cameras</td>
<td>$530,000</td>
<td>$530,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total ($)</td>
<td>1,130,000</td>
<td>530,000</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 28: Situational Awareness OMAG Forecast

<table>
<thead>
<tr>
<th>Situational Awareness OMAG Costs</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weather Stations</td>
<td>$60,000</td>
<td>$61,200</td>
<td>$62,424</td>
<td>$63,672</td>
</tr>
<tr>
<td>Wildfire Cameras</td>
<td>$60,000</td>
<td>$61,000</td>
<td>$62,424</td>
<td>$63,672</td>
</tr>
<tr>
<td>Total ($)</td>
<td>120,000</td>
<td>122,400</td>
<td>124,848</td>
<td>127,345</td>
</tr>
</tbody>
</table>
5 PROACTIVE DE-ENERGIZATION (PUBLIC SAFETY OUTAGE MANAGEMENT)

PSOM refers to a planned circuit outage triggered by conditions that pose a significant safety threat to the Companies’ customers, infrastructure or the public. PSOM is a measure of last resort to prevent or mitigate the potential catastrophic impacts caused by wildfire. PSOM events may be initiated when the Companies’ obligation to operate the system safely is jeopardized by natural conditions. PSOM procedures are enacted typically during official declared fire season, which may be extended based on prevailing weather conditions in a particular year. A series of quantitative and qualitative criteria must be met before de-energization occurs, which will then be followed by continued weather condition tracking and communication with vested stakeholders. The Companies have designated specific zones, only within the Tier 3 fire threat area, that will be subject to fire-related PSOM events. There may, however, be related impacts outside these zones if the de-energized circuits impact customers outside the established proactive de-energization zones ("PDZ"). The details are described below.

5.1 PSOM Criteria

As mentioned in Section 3, the Companies mapped several attributes that collectively present a potential for fire threat conditions. A variety of factors go into determining whether to employ a PSOM in a given area of the Companies’ service territory. These factors may include, and are not limited to:

- Weather conditions;
- Vegetation/fuel conditions;
- Field observations;
- Information from first responders;
- Flying debris;
- Meteorology;
- Expected duration of conditions;
- Information from a Fire Behavior Analyst ("FBAN"); and
- Location of any existing fires.

Based on these factors and the Companies’ operational experience, the decision on how to manage risk to communities affected will be made by NV Energy. Three key quantitative inputs, largely informed by factors listed above, are used as the primary metrics for determining if, when, and where a PSOM event may be necessary to reduce risk to the public. The baseline proactive de-energization thresholds established during the 2019 fire season demonstrated a zero risk level and provided a starting point for developing area specific reasonable risk de-energization thresholds that are discussed in these comments. Historical weather station observations were analyzed to quantify how frequently various de-energization thresholds have been exceeded in the past. However, actual observations during the 2019 fire season resulted in significantly higher number (i.e., at least once weekly) of potential PSOM events. Therefore, it was concluded that the initial thresholds (i.e., Energy Release Component ("ERC") > 60th percentile, wind gusts > 30 mph, and Fosberg Fire Weather Index ("FFWI") > 50) established unreasonably low risk levels and would result in unnecessary service interruptions. Given that proactive de-energization or PSOM is a last resort measure for fire prevention, PSOM thresholds must be sufficiently high to prevent unnecessary and/or frequent service interruptions. Additionally, it was determined that slightly different wind gust and FFWI is required for northern and southern Nevada Tier 3 regions. Finally, a qualitative assessment was determined to be necessary along with the criteria-based quantitative assessment prior to triggering a PSOM event.

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Through an iterative process, the quantitative thresholds shown in Table 29 have been established and were tested against historical weather station observations and archived weather forecast data to assess historical threshold exceedance frequencies.

**Table 29: Updated Quantitative Thresholds**

<table>
<thead>
<tr>
<th>Region</th>
<th>ERC</th>
<th>Wind Gust (mph)*</th>
<th>FFWI*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lake Tahoe / Truckee Transmission</td>
<td>&gt;92nd percentile</td>
<td>&gt;40 mph</td>
<td>&gt;50</td>
</tr>
<tr>
<td>Kyle Canyon / Angel Peak</td>
<td>&gt;92nd percentile</td>
<td>&gt;45 mph</td>
<td>&gt;60</td>
</tr>
</tbody>
</table>

*Six-hour average

The three quantitative metric definitions are:

1. **FFWI:** Quantifies the effect of short-term variations in meteorological conditions including temperature, humidity, and wind speed to determine the potential for wind-driven fire spread. This metric relies on factors that influence instantaneous fire weather conditions but does not consider other factors that may affect fire spread, including topography, fuel type, fuel moisture, and historic precipitation.

2. **NFDRS ERC:** Value proportional to energy per unit area that may be released within a fire’s flaming front. ERC may vary daily due to changes in the moisture content of fuels. In turn, these factors are dependent on recent precipitation, relative humidity, and temperature. This metric typically peaks during summer months in the western U.S., reducing after the return of rainfall and reduced temperatures. As ERC depends on fuel loading, it is commonly referred to in terms of percentiles instead of an absolute value. The National Wildfire Coordinating Group issued a directive for all jurisdictional fire entities or agencies to transition to the new 2016 NFRDS by January 2021. This update may affect the Companies’ PSOM procedures through the ERC calculation. Per discussions with REAX Engineering, the recommendation for the 2020 fire season directs the Companies to continue using the ERC calculation on Fuel Model G for operational purposes. Moreover, the Companies will continue to perform fuel sampling to estimate the ERC in the PDZs and report that data to relevant agencies on an as needed basis. The Companies also plan to collaborate with these agencies to ensure that consistent sampling and measurement methods are used.

3. **Wind gust speed:** Wind gusts that reach an approximate 35 to 45 mph threshold lead to a statistically significant increase in outage occurrence, which may be viewed here as a proxy for ignition occurrence. While wind speed is factored into the FFWI metric above, live observations of elevated winds must be considered as a stand-alone metric due to the risk high winds pose to above-ground assets.

Conditions that satisfy the thresholds set by these three metrics (FFWI, ERC, and wind gust speeds) may be cause for a PSOM event. Qualitative factors, as listed below, will also be used when making the final determination. Figure 46 summarizes the thresholds and the decision stream. The Companies will perform robust analysis and discussion around each potential event before making a final decision on whether to implement a PSOM event.

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Public Safety Outage Management

De-Energization Threshold Criteria

<table>
<thead>
<tr>
<th>Is the Energy Release Component (ERC) &gt; 92nd Percentile?</th>
<th>Are Wind Gust Forecasted to Exceed PDZ Threshold?</th>
<th>Is the Fosberg Fire Weather Index (FFWI) Forecasted to exceed PDZ Thresholds?</th>
<th>Do Local Qualitative Assessments warrant a PSOM?*</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO</td>
<td>YES</td>
<td>YES</td>
<td>Updated: July 9, 2019</td>
</tr>
</tbody>
</table>

Updated: July 9, 2019

**PSOM** – Public Safety Outage Management: Circuit De-Energization as a last resort option to mitigate extreme wild fire risk areas (PDZ – Planned De-energization Zones) and conditions. Safety is our top priority and PSOM reflect the best utility safety practices.

**ERC** (Energy Release Component) - Are seasonal conditions associated with intermediate to long term drying (e.g., live fuel moisture content) such that rapidly spreading fires are possible? The National Fire Danger Rating System’s ERC is proportional to energy per unit area that can be released within a fire’s flaming front. ERC varies daily due to changes in moisture content of both live and dead fuels, which are in turn dependent on antecedent precipitation, relative humidity, and temperature.

**Wind Gusts** - Are forecasted 6 hour rolling average wind gust speeds high enough to increase the probability of powerline-associated fire ignition?

**FFWI** (Fosberg Fire Weather Index) – Are 6 hour rolling average forecasted fire weather conditions (including temperature & relative humidity) conducive to rapidly spreading fires? The FFWI is a widely-used index that quantifies the effect of short-term variations in meteorological conditions (temperature, relative humidity, and wind speed) on the potential for wind-driven fire spread. FFWI is based on instantaneous fire weather considerations so it does not consider other factors that may affect fire spread potential such as fuel type, topography, live fuel moisture, and recent precipitation. Generally, Fosberg indices above 50 are considered conducive to rapid wind-driven fire spread.

*Perform community, environmental and infrastructure assessment in de-energization zones considering (Day 7-8):
  A. Area Specific impacts (Major Accounts)
  B. Specific vegetation management input (Delivery Support)
  C. Specific input from patrols (Lines)
  D. Specific view on construction type (Design Resilience)
  E. Specific fire professional and first responders view of conditions (Emergency Management)
  F. Specific meteorological view of conditions (Grid Operations)
  G. Critical Infrastructure Readiness (Telecom, Water / Sewage, Comfort Center, etc)
In addition to the weather station observations, three years (2016 through 2018) of archived weather forecast data were analyzed using the highest resolution forecast model to determine how frequently the revised thresholds were forecast to be exceeded. Based on historical weather station observations for several years of reviewed data, one potential exceedance in the Lake Tahoe basin, three exceedances in the Truckee (northern California) territory and no exceedances in the Mt. Charleston territory were identified. Based on archived weather forecast data for last three years, the de-energization thresholds were exceeded for one hour per year for Angel Peak (Mt. Charleston) and 0.7 hours per year for Carson/Minden (Lake Tahoe basin). Based on initial de-energization thresholds, at least one de-energization event per fire season was expected in each of the above areas. Based on updated thresholds, some areas may not experience any PSOM event in a non-drought year like 2019. It is worthwhile to note that actual frequency and duration of these events may vary due to variability in weather conditions from one year to another especially during drought years. In summary, NV Energy is currently managing the PSOM process based on the above thresholds in Figure 46 as they balance a reasonable risk profile of last resort mitigation measure with customer service interruptions.

Upon further evaluation and as noted in Figure 46 above, NV Energy also established a qualitative criteria that will be utilized if the quantitative criteria is met. An objective process is developed for this qualitative assessment and consists of several factors that enable the Companies to perform a community, environmental and infrastructure assessment. Once the quantitative criteria is triggered in one of the eight proactive de-energization zones, NV Energy Grid Operations will seek input from several team members on the following parameters and individual and total scores (zero to 10 with 10 being no concerns or highest confidence and zero being extremely high concerns or lowest confidence-if specific items cannot be scored for an event, they may be assigned a “go/no go” decision) will be assigned as part of this assessment:

- **Vegetation Management:** Based on the last vegetation management cycle completed, the NV Energy Delivery Support team will complete this assessment.

- **Patrol/Detailed Inspection:** Based on the last patrol or inspection completed, the NV Energy Delivery Operations or Lines team managing the affected area will complete this assessment.

- **Local Fire District Input:** NV Energy Fire Mitigation Specialist- Fire Chief and/or Emergency Management will seek input from the local fire district on their assessment of field conditions and necessity for a PSOM event. Also, may seek input from a FBAN on developing possible fire behavior information, predicting fire growth, and interpreting possible fire characteristics if a fire started during the weather event.

- **Large Event/Visitor Status:** NV Energy Major Accounts will provide input based on if a significant event is projected during the potential PSOM event duration.

- **Water/Sewage Readiness:** NV Energy Major Accounts, Customer Operations and/or Emergency Management will provide input on whether any critical water or sewage treatment facilities will have any issues. Three business units are listed, but the respective business unit who owns the customer relationship will provide input.

- **Telecommunications Readiness:** NV Energy Major Accounts will provide input on whether any critical telecommunications facilities will have any issues. Three business units are listed, but the respective business unit who owns the customer relationship will provide input.

- **Infrastructure Design:** NV Energy Distribution Design and Transmission Engineering will provide input based on the base design of overhead infrastructure and its expected resiliency. The

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47 Lake Tahoe basin is divided into five proactive de-energization zones: Incline, Glenbrook, Carson/Minden, Roundhill and Kingsbury. Therefore, there are a total of eight proactive de-energization zones also including Truckee, Angel Peak and Kyle Canyon.
Companies’ revised designs would have higher scores while older designs and aged systems would get lower scores.

- **Customer Resource Centers:** NV Energy Community Relations will provide input based on the readiness levels for the customer resource centers.

- **Restoration Readiness:** NV Energy Grid Operations will provide input based on the restoration readiness for the affected circuits.

- **Local Emergency Management Input:** NV Energy Emergency Management and/or Fire Mitigation Specialist- Fire Chief will seek input from the local emergency management contacts on their assessment of field conditions and necessity for a PSOM event.

NV Energy Grid Operations will recommend a PSOM event to NV Energy’s Senior Vice President of Operations and Vice President of Transmission if the total score of the above qualitative assessment is lower than 50 out of 100 (maximum) or three or more individual category scores are lower than three or one or more of the category scores is extreme or unacceptable. Specific categories with a “go or no-go” decision may also impact the final decision and it is possible that a single category score or evaluation may impact the final decision. The final decision would be made by either NV Energy’s Senior Vice President of Operations or Vice President of Transmission based on the above quantitative and qualitative assessments.

NV Energy believes that the combination of above quantitative and qualitative assessments will enable a prudent decision making process that will only bring forward the absolutely necessary PSOM events.

### 5.2 Emergency Operations Center & Command Structure

The Emergency Operation Center ("EOC") may be activated in response to an emergency event or a combination of emergencies that pose a significant threat to the Companies’ assets or public safety and requires coordination across multiple departments. A designated Crisis Management Team ("CMT"), comprised of the Executive in Charge, Corporate Communications, Safety, Government Affairs, Customer Operations, Emergency Management, Fire Mitigation Specialist and the impacted department of the Companies will lead the response to any event. One or more of six response sections may be activated following the establishment of an EOC to support the CMT. During events the nationally recognized Incident Command System ("ICS") will be followed, and if needed, Unified Command maybe implemented with outside agencies. These six sections are as follows:

- **Operations** – responsible for management of all operations directly related to the utility, including damage assessment, identification of operational strategies to achieve incident objectives, and determination of estimated restoration timeline in the case of a PSOM event.

- **Logistics** – coordinates requests for resources; monitors resource levels; provides ongoing situational reports; and ensures adequate food, water, and housing for all crews involved in incident response, facilities, transportation, communications, supplies, equipment maintenance and fueling, medical services (for responders), all off-incident resources; and provides logistical input to the Incident Action Plan ("IAP").

- **Planning** – provides support in developing incident objectives and the IAP; conducts planning meetings with all activated sections, and supports Operations and Logistics in the identification of current resources and needed next steps; collects and manages all incident-relevant operational data; provides input to the incident commander ("IC") and Operations in preparing the IAP; incorporates Traffic, Medical, and Communications Plans and other supporting materials into the IAP; conducts and facilitates planning meetings; reassigns personnel within the ICS organization; compiles and displays incident status information; establishes information requirements and reporting schedules for units (e.g., Resources and Situation Units); determines need for specialized
resources, assembles and disassembles Task Forces and Strike Teams (or law enforcement resource teams) not assigned to Operations; establishes specialized data collection systems as necessary (e.g., weather) assembles information on alternative strategies; provides periodic predictions on incident potential; reports significant changes in incident status; and oversees preparation of the Demobilization Plan.

- **Support** – contributes periodic status reports on regulatory issues; ensures effective coordination of legal issues; and provides guidance for personnel issues that may arise. Major accounts to be liaison officers as needed. Communications staff to work with telecom stakeholders to ensure adequate communications.

- **Safety** - identifies and mitigates hazardous situations; ensures safety messages and briefings are made; exercises emergency authority to stop and prevent unsafe acts; reviews the IAP for safety implications; assigns assistants qualified to evaluate special hazards; initiates preliminary investigation of accidents within the incident area; reviews and approves the medical plan; and participates in planning meetings.

- **Public Information**- determines, according to direction from the IC, any limits on information release(s); develops accurate, accessible, and timely information for use in press/media briefings; obtains IC’s approval of news releases; conducts periodic media briefings; arranges for tours and other interviews or briefings that may be required; monitors and forwards media information that may be useful to incident planning; maintains current information, summaries, and/or displays on the incident; makes information about the incident available to incident personnel; and participates in planning meetings.

Each section is comprised of one Section Chief leading supporting departments and functional groups that provide resources, information, and support in the event of an emergency. Depending on the scale and progression of an event, all six sections may be activated.

### 5.3 Public Safety Partner Engagement

The Companies attribute great value to established relationships with first/emergency responders, Public Safety Answering Points (PSAPS 911 dispatch centers) and public safety partners within the service territory and maintain robust contact lists, which they update regularly, for these stakeholders. The Companies have taken the steps below to confirm the identity of these partners and to continue to grow these relationships.

### 5.4 Critical Infrastructure & Public Safety Considerations

The Companies will provide public safety partners, critical infrastructure partners and telecommunication partners, at the time of the first notification of the event, information regarding the upcoming PSOM event, including estimated start time of the event, what PDZs will be affected, estimated duration of the event, and estimated time to full restoration of service. This form will be sent out daily during the event and will be updated with relevant information. The notification form that was finalized based on the input received during the EWG meetings is included in Appendix C.

### 5.5 Pre and Post PSOM Event Patrols & Inspections

After a PSOM event it is critical to patrol the lines for any vegetation or debris that must be removed before re-energization. Although these patrols are not full inspections, but rather are being completed to ensure public safety and minimize risk of wildfire ignition after the PSOM event, patrol crews will still note any electrical equipment that needs attention in the Companies’ System Management system.
5.6 Re-Energization Procedures

Upon the subsidence of weather conditions sufficient to trigger a PSOM event, de-energized circuits will be re-energized following an evaluation and correction of any damage to the Companies’ equipment. This will take place once the Companies’ Grid Operations determines that wind speeds have decreased, and forecasts indicate that winds will not re-accelerate above dangerous levels. All de-energized lines are inspected for damage before being eligible for re-energization. This process is outlined in Section 5.6.1 below. Once a line is patrolled and needed repairs are identified, re-energization may begin in segments, utilizing available sectionalizing devices to safely expedite the process.

5.6.1 PSOM Restoration Protocols

Safety is of utmost concern when re-energizing the power grid after an outage event. Prior to re-energization of a de-energized circuit, each foot of overhead line and other company assets in a de-energized zone must be checked by a re-energization patrol. These patrols may be conducted on foot, by vehicle, or by air via helicopter. Future patrols may use technology-based inspection solutions, including drone flyovers. In the interest of public safety, only qualified, certified personnel are eligible for use during the inspection phase.

Once hazardous conditions are cleared, field personnel will expeditiously patrol de-energized circuits and identify critical equipment and vegetation hazards. Timeline for re-energization will in part be defined by obstacles preventing crews from assessing the Companies’ equipment on a given circuit. These obstacles are referred to as Notable Access issues. Notable Access issues include, but are not limited to:

- Densely forested terrain;
- Steep or treacherous terrain;
- Private residencies and other properties requiring special permission to access;
- Roadway congestion, traffic, or parking; and
- Communications difficulties in remote localities.

In addition to notable access issues, restoration timelines will be influenced by the length of the circuit de-energized, the number of customers affected, and prevailing weather conditions. For the safety of the Companies’ employees, contractors, and the general public, patrols will only be conducted during daylight hours between daybreak and sunset. Patrol crews must seek approval to re-energize the lines after confirmation that restoration activities have been completed. Once lines have been re-energized, the Companies will update first responders, government officials, communications providers, critical facilities, neighboring utilities, and other stakeholders.

5.7 Public Outreach & Safety

The Companies will continue to work with relevant public safety and community partners to ensure the establishment of effective implementation and communication protocols. To ensure protocols are effective the Companies will conduct yearly training exercises with first/emergency responders and public safety partners. The Companies will participate in disaster training exercises that are being conducted in the service areas by NV Energy’s public safety partners. To ensure communication to the public is continuous during a PSOM event, the Companies have agreements with the Washoe County, Douglas County, and Clark County Emergency Management to utilize its emergency alert systems. If additional emergency messaging is needed during the PSOM, the same agreement would allow for the utilization of the Wireless Emergency Alert ("WEA"). The WEA is an alerting network in the U.S. designed to disseminate emergency alerts to mobile devices such as cell phones and tablets. The Companies will also be contracting with FirstNet for continuous internal and exterior cell communication. FirstNet is the nationwide public safety broadband network that is dedicated to first responders. The use of FirstNet is important for a few main
reasons: FirstNet provides all of the first responders and other public safety personnel with a harmonized platform that allows them all to communicate with each other during a disaster; and, FirstNet will deploy additional communication on wheels ("COWs") and satellite communicate equipment in the PSOM area to help enhance and maintain cellular in the area. The Companies will also activate the Verizon’s Crisis Response Team that will also deploy additional COWs and satellite communicate equipment in the PSOM area to help enhance and maintain cellular in the area. In the stakeholder meeting, telecommunication companies agreed with early notification they would be able to boost cell towers in the affected area and provide generation at sites, this would amplify cellular coverage in the area. Detailed PDZ maps were provide to the telecommunication companies during the stakeholder meetings so they could develop a pre-plan. A pre-fire season meeting with telecommunication companies will be conducted yearly to keep the plan update. The Companies will also incorporate Amateur Radio Emergency Service ("ARES") as a back-up for all disasters. The Companies will have the necessary radio equipment in both EOCs, Back-up EOCs, and Controls Centers and will have field radios in the EOCs available for deployment. Utilization of current employees trained as amateur radio operators and the ARES volunteer amateur radio operator would be used to support the system. ARES will support back-up communications companies and statewide with EOCs across the state during a disaster.

5.7.1 Portable Generator & Distribution Interconnection Equipment, Lease & Services

The Companies plan to provide emergency generator equipment, electric distribution equipment and comprehensive services to restore and maintain electric service to critical facilities (e.g., first responders, healthcare, water and sewage treatment, telecommunications, etc.) identified during a PSOM event. The Companies’ representatives reached out to these facilities during the 2019 fire season to confirm the need for the emergency generator support and will continue to refine these communications along with contingency plan execution during the 2020 and future fire seasons.

NV Energy will ask green cross customers to utilize the Companies’ Customer Resource Centers ("CRC") during a PSOM event. Green cross customers will receive an advance notice that can help them plan for the event. Providing customers with alternate lodging accommodations during a PSOM event will also be considered. In addition, NV Energy will encourage green cross customers to find other accommodations. NV Energy procured and will provide a limited number of portable generators to those customers who reside in Tier 3 wildfire threat areas and are certified by a licensed physician that they require immediate response from emergency personnel with life supporting equipment to sustain life or are confined to their home due to their medical condition, as certified by a licensed physician. NV Energy may install transfer switches for these customers during the PSOM event initial notification window to ensure continuity of service.

5.7.2 Corporate Communications Plan, Marketing & External Stakeholder Outreach for PSOM

Communication is of utmost importance when protecting against natural disasters. NV Energy has stress-tested and improved its customer call center capabilities to deal with the additional volume anticipated during a natural disaster event. One of the goals by making the improvements to the customer call center was to help with the possible overload to the Public Safety Answering Points (PSAPS 911 dispatch centers) during a PSOM event. NV Energy has collaborated with telecommunications companies, emergency responders, and government agencies to assure communications responsibilities are clear and coordinated. NV Energy plans to use an Incident Command Structure so a common language and approach is taken by the partner agencies. For example, emergency communications has a public-facing aspect for which NV Energy has assigned specific personnel based on working relationships. Collaboration among critical services providers includes Customer Resource Centers, temporary enhancement of communication capacity, and mutual aid programs.

Customers received email notifications on or around January 21, 2020 describing the Companies’ development of the NDPP pursuant to SB 329 as well as details for the public open forums, discussed
further in Section 7.1. NV Energy encouraged customers to stay informed through its webpage, nvenergy.com/ndpp, to obtain updates on the Plan’s development and community engagement efforts. Additionally, customers can follow www.nvenergy.com/wildfiresafety for current notifications on potential PSOM events or wildfire emergencies, in addition to the landing page. NV Energy’s objective is to communicate as far ahead as possible to support public safety and collaborate across responders to leverage resources, channels, and media to aid in delivering the most up-to-date information to the surrounding communities. NV Energy gives focused attention on the “Green Cross” customers who are particularly impacted by grid disturbances. Additional elements of the outreach include bill inserts, media outreach, social media, public meeting sessions, emergency notifications, and other channels.

Prepare: NVE has developed an extensive communication plan related to natural disaster preparedness with the goal of ensuring the public is ready for, and safe during, a disaster-related outage event – including PSOM. Elements of the plan include traditional media, social media, website and blog, collateral development, direct customer communication and collaboration with preparedness partners, such as “Living with Fire.” Customers are encouraged to take small but specific steps, such as charging cell phones, filling vehicle gas tanks, and having cash on hand as preventative measures. To enhance preparedness, NV Energy is available to conduct community meetings for specific agencies and the public.

Mitigate: The Companies’ previous actions and this NDPP devote significant focus and resources to mitigate against the impacts of natural disasters. Those mitigating actions include: grid resiliency and hardening; using a risk-based approach to evaluate and prioritize mitigation activities in high threat areas; leveraging community and agency mutual aid resources to maximize community awareness and participation in mitigation efforts; and taking measures aimed at reducing the likelihood of public impacts from potential failure of NV Energy equipment during a natural disaster.

Respond: The inevitable reality is that natural disasters will occur. NV Energy intends to communicate with and issue notifications to critical facilities, public safety partners, and customers in a timely and sequenced manner to ensure an accurate flow of information delivery and response mobilization for restoration efforts. The Companies will also conduct drill response simulations to create ‘muscle memory’ and improve from lessons learned in a simulated environment. Applied learnings include providing Customer Resource Centers as a haven during response events. NV Energy has planned for additional connectivity and communications for the customers through COWs and collaborating with the telecommunications companies so they can also remedy any of their network insufficiencies. Every action is based on harmonizing emergency response plans to be efficient and effective in the response activities, minimizing public impact wherever possible. Additional communications are directed at public safety, including the danger of damaged utility equipment such as downed power lines and how to be safe around these assets. The Emergency Operations Center is equipped to quickly mobilize to support continued communication in the event of a natural disaster.

Recover: NV Energy’s goal is to be prepared to assist the public in being and staying safe after emergency conditions have passed. The power grid cannot be re-energized without a purposeful and careful inspection. NV Energy will communicate the actions to impacted customers, including restoration status, as soon as it is known. Safety inspectors will be deployed as quickly as possible. Follow-up communications to vulnerable customers will be supported by the customer care professionals, including account representatives. With the first priority of public safety, NV Energy will collaborate with the community partners to communicate the return to normal and safe operating conditions.

The Companies’ PSOM communications plan, which aligns with the larger campaign to communicate efforts to mitigate wildfire risk and extreme weather conditions in Nevada, contains three phases and reflects best practices utilized by other utilities that employ PSOM for safety.

- Phase One creates awareness among key audiences of this new safety protocol.

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Phase Two addresses customer and stakeholder communication during a PSOM event. Phase Three focuses on restoration.

The communications plan was developed for the 2019 fire season and will be the basis for all communications planning moving forward. Although the Companies did not experience a PSOM event in 2019, Phase One was executed and the other phases were in place. Specific outreach timelines are also included in sections below.

Broadly, the key stakeholders include the following:
- NV Energy customers;
- Green Cross customers;
- NV Energy Major Accounts in high-impact areas;
- Public Utilities Commission of Nevada;
- Bureau of Consumer Protection;
- NV Energy employees;
- Visitors to high-fire risk areas;
- Government agencies/elected officials;
- Fire Departments/First Responders;
- Local Chambers of Commerce, businesses;
- Media; and
- Local economic development agencies and planning groups.

**Phase One: Educate Customers and Stakeholders about the PSOM Process**

**Objectives**
- To educate all audiences about wildfire and extreme weather safety efforts that reduce wildfire risks, with focus on PSOM and emergency preparedness.
- Develop strategic third-party partnerships to serve as ambassadors for PSOM.
- Encourage customers in high-fire risk areas to sign up for MyAccount alerts.
- To broaden customer education regarding outage preparedness:
  - Create an outage kit that can also be used for any disaster;
  - Generator safety; and
  - Sign up for outage alerts.

**Strategy and Tactics**

NV Energy will reach the PSOM communication objectives by executing an integrated marketing communications strategy that disseminates consistent messaging through the following channels:

**Direct Outreach:** Stakeholder meetings were held between key contacts and NV Energy relationship owners, stakeholder feedback was incorporated into the outreach plan. Specific tactics related to direct outreach also include, but are not limited to, the following:

**Executed in 2019**
- Create list of stakeholders and owners to track outreach and feedback.
- Host Open House-style meetings in high-risk areas in partnership with local fire and emergency officials.

**Ongoing Effort (but also executed in 2019)**
• NV Energy Major Account representatives to have one-on-one meetings with major customers in impacted areas to explain PSOM and seek input on how NV Energy can lessen any impacts.
• Work with NV Energy Operations and Customer Operations to ensure that customers who may not be key accounts, but could be negatively impacted by PSOM, are contacted.
• NV Energy Government Affairs team to have one-on-one meetings with relevant public officials and elected officials regarding PSOM.
• NV Energy Emergency Management team to have regular, ongoing meetings with emergency organizations (fire, police, emergency managers for local jurisdictions, National Weather Service) in impacted areas regarding PSOM.
• Target social media posts to these areas to raise awareness of PSOM and encourage them to sign up for alerts (if they have not already.)

**Upon Plan Approval or In Preparation for a PSOM Event**

• NV Energy Corporate Communications to hold a weekly meeting with stakeholder owners to discuss outreach efforts.
• NV Energy Regulatory to provide an overview of PSOM to the Commission, Staff and Bureau of Consumer Protection.
• NV Energy Corporate Communications to communicate with Public Information Officers for impacted areas, tourism organizations, Chambers of Commerce and emergency groups regarding PSOM.
• NV Energy Community Relations to communicate with their contacts at nonprofits who provide emergency assistance, Chambers of Commerce, local economic development agencies and planning groups etc.
• Distribute letter via mail and email to customers in the high-risk areas to explain PSOM. This will be followed up by a phone call from customer service.
• Present at currently scheduled public meetings in high-risk areas.
• Send MyAccount email to all customers.
• Develop content for My Energy Snapshot promo.
• Include information in quarterly customer newsletter.
• Create a bill ad for impacted customers.
• Provide materials (Frequently Asked Questions (“FAQ”), talking points, etc.) to NV Energy Customer Operations to assist with customer representative training.

**Media Outreach (executed in 2019 but will also continue in 2020 and beyond):**

• Hold deskside meetings with television station assignment managers and local print reporters to explain PSOM.
• Distribute press release to print and television media from NV Energy to explain and set the stage for possible PSOM events and encourage outage preparedness.
  o Target weather reporters.
  o Include tourist publications that target Mt. Charleston and Lake Tahoe.
  o Send to Chambers of Commerce and tourism groups for inclusion in their newsletters and on social media.
• Seek opportunities to promote wildfire safety and PSOM with partner organizations.
  o Wildfire Preparedness Month.
• Develop pitch on the importance of creating an outage preparedness kit.
• Create FAQs on PSOM for media and nvenergy.com.
• Distribute alerts to communicate PSOM event status.
• NV Energy Corporate Communications will develop scripts and alert templates for use by Customer Operations regarding PSOM events.
Social Media:
- Develop video content explaining PSOM – process, notification and restoration.
  - What conditions are monitored?
  - Get fire officials to explain the importance of doing this/share on their channels.
- Create videos to highlight the importance of outage preparedness.
  - What should be included in an outage kit?
  - Demonstrate how to open a garage door without power.
  - Explain the kinds of alerts will be sent.
- Create preparation checklist infographics.
- Share posts by National Weather Service with weather information and local fire jurisdiction safety and fire danger alerts.
- Share posts from partner organizations regarding wildfire safety and preparedness.
- Provide outage status warnings and subsequent updates.

Website:
- Create page dedicated to explaining PSOM. Content will include:
  - What NV Energy is monitoring.
  - Explanation Videos.
    - What is PSOM?
    - Be Prepared for an Outage.
  - PSOM FAQs.
  - Maps of Tier 3 areas.
  - Outage Preparedness.
    - What’s in Your Outage Kit?
    - Generator Safety.
  - Link to sign up for MyAccount alerts and Green Cross.
  - Up-to-date information with PSOM warnings and status updates.
- Ensure the outage map has PSOM available as an outage cause.
  - Add a “key” to explain outage map causes.

Grass Roots:
- Create flyer with information on PSOM and outage preparedness information, including links to other resources.
- Distribute Nevada Fire Marshall Homeowners’ Checklist.
- Provide training to employees who volunteer at events to answer questions regarding PSOM.
- Distribute PSOM flyer at community events staffed by Community Relations, PowerShift and Business Solutions Center.
- Purchase branded giveaways that link to website.
  - Flashlights.
  - External cell phone chargers.
- Collateral Development:
  - Flyer.
  - Placard to be placed in rental cabins, hotels to explain PSOM, outage safety and where to get more info.
  - Direct mail postcard.
- Attend Chamber of Commerce meetings to distribute information and collateral.

Visitor Outreach:
- Provide PSOM training/information to employees of Tier 3 casinos and visitor centers.
- Place flyer/table tent with PSOM and evacuation/safety information in vacation rentals.
Research possibility of including flyer/table tent in permit packet for vacation rentals in Washoe and Douglas County.
- Utilize county emergency alert system to notify visitors of pending PSOM event in Tier 3 areas.
- Utilize NDOT signage to provide PSOM information.

**Paid Media and Sponsorships**: to align with overall Wildfire Risk Management Outreach.
- Direct mail campaign to impacted customers.
- Radio spots.
- Digital.
- Outdoor.
- Social Media.
- Sponsorships with nonprofit agencies who promote fire safety and preparedness.

The Companies conducted extensive personal outreach with key stakeholders in the areas impacted by PSOM. Talking points, informational flyers, dedicated website and presentations that focused on ongoing efforts were developed to assist with this outreach, which included: meetings with fire personnel, including fire chiefs; federal, state and local elected officials; county emergency managers; large customers; chambers of commerce; tourism groups; and others. The Companies’ fire mitigation specialist also participated in several of these meetings. The goal of the outreach is to make these stakeholders aware of this new safety protocol, and to better understand their needs before and during a PSOM event in order to mitigate its impact on their respective agencies and communities. Direct stakeholder outreach was conducted, and the outreach team met weekly to discuss progress and next steps.

The Companies also distributed a letter via U.S. mail to all residential and business customers in the impacted areas. The letter explained why the Companies are implementing PSOM, encouraged customers to be prepared for a possible outage, to sign up for outage alerts via MyAccount and to enroll in Green Cross, if appropriate. The PSOM flyer was mailed with the letter to residential customers. These letters were also followed up with a phone call from the customer service team to ensure they are aware of the possibility of a PSOM event and the process to communicate; and to encourage them to sign up for email and/or text outage alerts and to address and note their concerns regarding PSOM.

Broader customer communication was also conducted with the distribution of a PSOM press release to northern and southern Nevada media, resulting in coverage in both broadcast and print media. The Companies also participated in the Wildfire Safety Expo in South Tahoe on June 15, 2019. Public open house events to provide customers with information on PSOM and answer their questions were conducted in northern Nevada on June 26, 2019, in Stateline, Nevada; on July 8, 2019, in Douglas County, Nevada and on July 17, 2019, in Incline Village, Nevada. An open house event in Mt. Charleston, Nevada was also conducted on July 16, 2019. An article on PSOM was also included in the summer quarterly customer newsletter, which was distributed with customer bills starting in July. Paid media outreach to raise awareness of PSOM was also conducted starting on July 1, 2019.

Employees are the best ambassadors for helping customers understand new programs and initiatives, like PSOM. The Companies provided an overview of PSOM at an employee presentation, and held employee “lunch and learn” events in both northern and southern Nevada.

NV Energy also held a series of meetings with the EWG, whose members included telecommunications companies and emergency management professionals. This was enhanced by additional outreach to the public with support of participating experts. The results of these outreach efforts helped inform the PSOM communications plan and telecommunications plan, which will be refined throughout continued conversations with telecommunication stakeholders in 2020. NV Energy intends to continue meeting with experts as an ongoing effort to enhance communications and leverage infrastructure and new technologies, including an expansion of a higher frequency radio system. Communications to the public are handled by special-purpose departments and enhanced by NV Energy’s direct relationships with organizations and customers. There is a self-identification process for customers requesting special assistance, such as
'Green Cross' customers. NV Energy does an annual structured refresh in addition to on an as-requested basis.

The Companies have coordinated this plan with federal, state, and local entities to ensure maximum awareness of the Plan and to solicit input. This also includes both local and regional fire departments, as well as local and federal forestry divisions to ensure coordination for vegetation management and public safety. Communication of this plan to first responders ensures that the Companies’ infrastructure, that may be a public safety issue, such as a downed line, are communicated to NV Energy for de-energization in the shortest time possible to minimize impact to public safety, whether from electrocution or fire ignition. As noted above, the Companies will also continue to work with the Nevada Department of Public Safety, Division of Emergency Management and emergency managers for various counties, communities within the Tahoe and Mt. Charleston areas along with city jurisdictions. This coordination also included tribal governments that may be affected.

NV Energy has created a new section of the website (www.nvenergy.com/wildfiresafety) that outlines the efforts to mitigate risk of wildfire and extreme weather, including PSOM. The front page of nvenergy.com highlights PSOM during wildfire season and links directly to the PSOM section. NV Energy will continue to augment the website with new content including videos and infographics to help further engender understanding of PSOM and the importance of being prepared for a possible outage. A PSOM flyer has also been designed for use at community events, and can be downloaded from the website.

Phase Two: Communicate with Customers and Stakeholders during a PSOM Event

Objectives
- To provide advance notice to impacted customers of a possible event.
- To communicate with customers during a PSOM event.

Strategy and Tactics
NV Energy will reach these goals by executing an integrated marketing communications strategy that disseminates consistent messaging through the following channels. A timeline of when these will be utilized may be found below. During a PSOM event, appropriate communications protocols will be followed.

Direct Communication
- Customer Operations will contact impacted residential and small business customers via automated calls in advance of an event.
- Green Cross customers will be contacted in person by a customer service representative.
- Alerts will be distributed to customers who have signed up for them via automated phone call, text, and email.
- Major Accounts will call impacted customer accounts and work with the Operations team to provide pre-determined assistance.
- NV Energy Government Affairs, Emergency Management, Corporate Communications and Regulatory teams will inform relevant stakeholders regarding a possible and pending event.
- NV Energy Corporate Communications will develop scripts and alert templates for use by NV Energy Customer Operations regarding PSOM events.
- Use county phone alert system to notify customers in impacted areas.

Media Outreach
- Distribute media alert to television and print publications in impacted areas.
- Provide on-camera interviews as requested to further explain PSOM and encourage outage preparedness.
- Hold press conference if needed to distribute updates on restoration status.

Social Media
- Post PSOM "watch" and "warning" posts to Facebook and Twitter per timeline below.
• Provide restoration updates as needed.
• Create videos to share prior to and during the event to explain current conditions and why NV Energy may have de-energized (Facebook Live and Periscope).
• Use social media video channels to broadcast press conference.
• Show photos of any damage to lines caused by weather conditions.
• Post photos of crews walking the line prior to re-energization.

Website
• Utilize website alert/notification feature to post PSOM “watch” and “warning” messages.
• Update PSOM web page with current information regarding PSOM status.
• Create banner on nvenergy.com during an event that links to PSOM page with updates.

Internal
• Post “watch” and “warning” updates on MyNVE.
• Send broadcast to employees when a PSOM event is activated and re-energized.

Paid Media – to align with overall Wildfire Risk Management Outreach
• Direct mail campaign to impacted customers;
• Radio spots;
• Digital;
• Outdoor; and
• Social Media.

Customer Notification Timeline
NV Energy will receive refreshed PSOM threshold notifications from the external weather analytics expert, REAX Engineering, at the 8-day, 3.5-day and 1.5-day mark prior to the PSOM trigger with expected duration of the event. Based on these notifications, NV Energy will follow the following notification timelines:

8 Days Prior (Or when NV Energy is made aware that an event is possible):
• NV Energy Emergency Management, Government Affairs, Regulatory and Major Accounts will contact their stakeholders as requested regarding timing.
• NV Energy Operations will notify affected local utilities as needed.

3.5 Days Prior:
• NV Energy customer operations will reach out to Green Cross customers with an in-person call.
• NV Energy Corporate Communications will post information on PSOM website and will include an alert message on the homepage of nvenergy.com.
• NV Energy Corporate Communications will issue media alert.
• NV Energy Corporate Communications will post information on social media – targeting impacted areas.
• NV Energy Major Accounts will alert their customers and work with Operations team to implement any assistance.
• NV Energy Emergency Management, Government Affairs, Regulatory, Community Relations and Corporate Communications will contact their stakeholders.

48 hours Prior:
• NV Energy Customer Operations will engage in outage alerts to reach impacted customers (automatic call-outs, text and email).
• NV Energy Corporate Communications will update information on nvenergy.com, the alert message and PSOM webpage.
Natural Disaster Protection Plan

- NV Energy Corporate Communications will send media alerts and will post updates on social media – targeting impacted areas.
- NV Energy Major Accounts will maintain communications with their customers.
- NV Energy Emergency Management, Government Affairs, Regulatory, Community Relations and Corporate Communications will maintain contact with their stakeholders.
- NV Energy Emergency Management, Fire Mitigation Specialist will work with County Emergency Managers on alert messaging from the county’s alert system.

2 Hours Prior:
- NV Energy Customer Operations will engage in outage alerts to reach impacted customers.
- NV Energy Corporate Communications will update information on nvenergy.com.
- NV Energy Corporate Communications will post updates on social media – target impacted areas.
- NV Energy Major Accounts will alert their customers.

1 Hour Prior:
- NV Energy Customer Operations will engage in outage alerts to reach impacted customers.
- NV Energy Corporate Communications will update information on nvenergy.com.
- NV Energy Corporate Communications will post on social media – target impacted areas.
- NV Energy Corporate Communications will send media alert.
- NV Energy Major Accounts will alert their customers.
- NV Energy Emergency Management, Government Affairs, Regulatory, Community Relations and Corporate Communications will maintain contact with their stakeholders.

During the Event:
- Provide information/scripts to customer operations as needed.
  - Estimated Time of Restoration ("ETR") Status.
- When the Companies experience extended outage durations in general, CRCs serve as a response support activity for customers needing power. In general, these CRCs are intended to support short-duration outages, but NV Energy will extend hours of support where viable or appropriate, and will alert customers that CRCs are being made available (during an extended outage, but may also be enabled earlier under specific circumstances).

- Keep update information on nvenergy.com.
  - Home Page.
  - PSOM webpage.
  - Outage map reflects correct outage cause.
- Provide updates on social media accounts – target impacted areas.
  - Monitor questions and assist, as needed, with customer responses.

Phase Three: Restoration – communicate with affected customers and key stakeholders on step restoration process and ETR for specific areas

- NV Energy Customer Operations will engage outage alerts to reach impacted customers.
- NV Energy Corporate Communications will update information on nvenergy.com.
- NV Energy Corporate Communications will post updates on social media.
- NV Energy Corporate Communications will send media alerts.
- NV Energy Major Accounts will alert their customers.
- NV Energy Emergency Management, Government Affairs, Regulatory, Community Relations and Corporate Communications will alert their stakeholders.
The Companies’ Fire Mitigation Specialist will also be involved in responding to a PSOM event and will leverage our corporate EOC for maximum benefit. As identified by the Companies, confirmed in the expert working group, and public outreach, telecommunications is an essential component of protection from natural disasters. Additional actions will include the opportunity for telecommunication providers to harden their systems in the areas of the identified CRCs. In practice drills, it was apparent that customers’ needs during an outage could overwhelm existing telecommunications networks. Some options considered to mitigate this issue include additional COWs or satellite communication systems to provide temporary support in vulnerable locations.

5.8 Customer Resource Centers

The following four locations will serve as CRCs during a PSOM event:

Southern Nevada Customer Resource Center
The Retreat on Charleston Peak
2755 Kyle Canyon Road
Mt. Charleston, NV 89124

Northern Nevada Customer Resource Center 1
Kahle Community Center
Rubicon Room
236 Kingsbury Grade
Stateline, NV 89449

Northern Nevada Customer Resource Center 2
Douglas County Community Center
1329 Waterloo Ln
Gardnerville, NV 89410

Northern Nevada Customer Resource Center 3
Diamond Peak Ski Resort
1210 Ski Way, Incline Village, NV 89451
Main Lodge Cafeteria

NV Energy is in the process of executing back-up generation contingency plans for all the above CRCs. The Companies will follow the established protocols that local emergency, police and fire officials determine at the time of a required community emergency evacuation. As noted above, the CRC’s will be activated during extended PSOM events in the affected areas. CRC’s will be powered using a portable back-up generator connected through a manual transfer switch. Once activated, the CRC will operate in roughly 10 hour shifts from 8:00 a.m. through 6:00 p.m. daily, until power to the affected community has been restored. NV Energy subject matter experts will collaborate with volunteer staff at an activated CRC to provide, to the extent possible, updates and real-time information directly to the community impacted. NV Energy will also partner with other volunteer organizations to provide bottled water and light snacks to provide temporary relief to residents in the area. The Companies may establish more CRCs should the need arise.

5.9 Incident Reporting to the Commission

The Companies will track and report information related to risk reduction effectiveness, ignition events, utility equipment damage, and power outages in accordance with the regulations established by the Commission. Reporting requirements are discussed in further detail in Section 9 of this Plan.
5.10 Cost Benefit Analysis

The cost of PSOM event can be quantified directly by the loss of revenue and indirectly by loss of reputation and impact on economy. The benefit is avoidance of a catastrophic event that can potentially lead to loss of property and life. After a wildfire, the potential costs include firefighting, emergency response, infrastructure damage, agricultural damage, environmental damage, human injury, and loss of life. Below is some of the examples of damage caused by wildfires in the recent history:

- In 2007, the Angora wildfire started due to an illegal campfire in Lake Tahoe which cost approximately $11 million to fight and resulted in destruction of over 3,000 acres and over 300 residential and commercial structures.\(^{49}\)

- The costliest natural disaster of 2018, Camp Fire in Paradise, California, caused damage of approximately $16 billion.\(^{50}\) The wildfire was ignited by a faulty transmission line and fueled by persistent drought conditions and high winds. It also led to death of 85 civilians and injuries to many other civilians and firefighters.

Nevada may not have had similar catastrophic wildfire events; however, it is beneficial to have a PSOM protocol as a last resort measure to mitigate the risk for similar catastrophic events.

5.11 Cost Estimates

Table 31 includes the cost estimates for the different components to execute the PSOM plan:

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weather Analytics and Fuel Sampling</td>
<td>$300,000</td>
<td>$306,000</td>
<td>$312,120</td>
<td>$318,362</td>
</tr>
<tr>
<td>Restoration Patrols and Inspections</td>
<td>$100,000</td>
<td>$102,000</td>
<td>$104,040</td>
<td>$106,121</td>
</tr>
<tr>
<td>Customer Resource Centers</td>
<td>$50,000</td>
<td>$51,000</td>
<td>$52,020</td>
<td>$53,060</td>
</tr>
<tr>
<td>PSOM Communications</td>
<td>$100,000</td>
<td>$102,000</td>
<td>$104,040</td>
<td>$106,121</td>
</tr>
<tr>
<td>Grid Operations Support</td>
<td>$100,000</td>
<td>$102,000</td>
<td>$104,040</td>
<td>$106,121</td>
</tr>
<tr>
<td>Back-up Generation</td>
<td>$1,340,000</td>
<td>$1,366,800</td>
<td>$1,394,136</td>
<td>$1,422,019</td>
</tr>
<tr>
<td>Total ($)</td>
<td>1,990,000</td>
<td>2,029,800</td>
<td>2,070,396</td>
<td>2,111,804</td>
</tr>
</tbody>
</table>


6 EMERGENCY RESPONSE AND RESTORATION

6.1 Emergency Response Plan

The Companies released revisions to the internal Corporate Emergency Response Plan (“CERP”) in March 2018. This plan outlines the Emergency Response Organization and methodologies used to support operational response while helping to provide effective coordination and communication both within the company and between the Companies and state agencies, local jurisdictions, and customers served by the Companies. The CERP identifies how the Companies would respond to emergency situations down to the department or divisional level. It also serves to provide methodology to support coordination between department and division-level emergency response plans that may be in place throughout the organization. Objectives of the CERP include the identification of the Emergency Response Organization (“ERO”) and the provision of clear guidance on how emergencies should be managed.

Generally, the CERP outlines and defines four phases of emergency response functions labelled as Mitigation, Preparedness, Response, and Recovery. These four phases are defined as follows:

1. **Mitigation** entails identifying risks and hazards to substantially either reduce or eliminate the impact of an incident, usually through structural measures. Mitigation activities often have a long-term or sustained effect. Mitigation activities can occur in the recovery stage of a major disaster.

2. **Preparedness** focuses on eliminating or reducing risks. The general focus of preparedness is to enhance the response capacity to an incident by implementing steps to ensure personnel and entities are capable of responding to a wide range of potential incidents.

3. **Response** activities are comprised of the immediate actions to save lives, protect property and the environment. Response involves executing emergency plans and other related actions.

4. **Recovery** activities are intended to restore essential services and repair damages caused by the event. Recovery activities may include mitigation of potential hazards.

Initial activation of the emergency response organization most often begins in the event of an abnormal occurrence or emergency, including wildfires, earthquakes, snowstorms, explosions, or any other event that significantly disrupts operating systems, business systems, or utility services. In other cases, an event may start in response to a previously normal, routine, or non-threatening situation growing to a point where additional resources and coordination across multiple departments is required.

The CERP further outlines company and corporate support structures to coordinate response to various levels of activation, which are determined in accordance with the severity of the event and the risk posed to the Companies’ infrastructure and public safety. Reviews and updates to the CERP occur annually, while tests evaluating the Plan’s effectiveness may occur intermittently. Nevada Revised Statute (NRS 239C) requires utilities to submit annual updates on the CERP to the Nevada State Division of Emergency Management.

6.1.1 Plan Alignment

Emergency response measures outlined in this Plan are intended to align with NV Energy’s CERP.

Utilities deal with emergencies as part of daily operation. When events occur (or the risk of an event is forecasted to occur) that will exceed normal response capabilities, the Companies’ ERO will be activated. Any internal stakeholder can request the activation of the ERO in response to an abnormal event or emergency such as an earthquake, snowstorm, explosion, or other event that significantly disrupts...
operating systems, business systems, or utility services. The ERO is the overarching organizational structure that can provide additional emergency support in response to an emergency. ERO consists of single or multiple operating departments and emergency leadership, including the executive in charge, policy team, crisis management team, and supporting department, and can increase or decrease levels of support as required by an incident. NV Energy will pursue the integration of the ICS framework into natural disaster event response protocols to align with standardized terminology and response efforts similar to emergency managers, first responders, and fire districts. This section outlines the duties and responsibilities on the Companies’ staff with respect to implementation of the Plan.

6.1.2 Emergency Response Organizational Chart

All operations and activities are controlled by the department or departments most affected by the emergency event. The CMT or EOC does not take over operational control if an ERO is initiated. Instead, the CMT and EOC work in conjunction with the department or departments affected to provide support. Departmental priorities include safety, assessment of the situation, management of resources, communication and coordination with internal and external stakeholders, and restoration of services.

Source: NV ENERGY Corporate Emergency Response Plan

The Corporate Policy Team ("CPT") is comprised of the CEO and/or President and some, or all, corporate officers available at the time of an event. CPT members are distinct from those included in the CMT, but communication between these groups is critical in any emergency. A CMT is led by the Executive in Charge ("EIC"), and otherwise consists of representatives from Corporate Communications, Government Affairs, and Customer Operations in addition to leadership from departments affected by an event. Specific roles of select CPT and CMT employees are described in the Companies’ CERP.
An EOC activates in response to an emergency event or a combination of emergencies that pose significant risk to the Companies’ assets or the public and require coordinated response across multiple departments within the Companies. Activation of the EOC is designated as a Level Three activation of the Companies’ CERP, the highest level of coordinated response to an emergency. One or more of four response sections, defined as Operations, Logistics, Planning, and Support, may be activated. Depending on the scale and progression of an event, all four sections may be activated.

WebEOC: NV Energy has approved the migration into a centralized emergency response network service. WebEOC will allow the Companies to integrate emergency response notifications with county-level emergency management such as Washoe and Clark counties (both of which have communicated the recommendation for NV Energy to adopt this platform). This collaborative management network is poised to communicate incidents as they occur to governmental entities and has the modularity to integrate with auxiliary industries such as healthcare and private corporations. Incidents will be logged and updated by trained moderators within the Emergency Management Division. NV Energy will be performing quarterly trainings on how to operate the platform and will hold drills as the ICS is adopted and integrated into emergency management operations. Training will also occur externally through hired consultants to help facilitate advanced system management controls and through table top exercises to test operational efficiency. The Companies anticipate aligning several PMS to initially ramp up and manage the network as internal training activities are carried out. Initial costs include training and implementation, resulting in a cost of $665,470 (2019 – 2020). Year two and year three project $161,893 and $160,533, respectively. NV Energy forecasts approximately $160k for 2023 and on.

FirstNet: NV Energy will be initiating an agreement with AT&T to deploy FirstNet, a response and communication network dedicated to public safety. FirstNet is the nationwide public safety broadband network solution providing a homogenous platform for ease of communications during an emergency, which allows them all to communicate with each other during a disaster. COWs and satellite boxes will be deployed in the proactive de-energization zones to ensure cellular resiliency in those targeted regions. Cost estimates approximate $30k in 2020 and $61.2k in 2021.51

Verizon Community Response Team: Additionally, NV Energy is investigating opportunities with Verizon Wireless to utilize the Verizon Crisis Response Team (“VCRT”) during emergencies to help the utility stay connected with customers in the case telecommunication networks fail. The VCRT will respond to an event of any size and provide the community with COWs, satellite boxes, repeaters, cellular phones, and WiFi. The Companies anticipate internal presentations and further discussions after filing this Plan. Estimated costs at this time include data and cell phone usage as well as equipment rental costs during a PSOM event. Current cost estimates approximate $30k in 2020 and $61.2k in 2021.52

Capstone: NV Energy has contracted with Capstone to provide advanced firefighting support in wildland settings, crisis management response, and daily attendance in the field to support tailboard meetings and communicate compliance and fire concerns during the later months of fire season. Capstone Fire & Safety Crews will create daily reports to summarize and identify unusual weather conditions, inspection findings, create hot work permits, and post-correction reports. Capstone’s Fire & Safety personnel meet NFPA, ANSI, NWCG and OSHA standards. Onsite support materials will include a wildland fire engine, 385-gallon water storage tank to quickly suppress small fires, several hoses, foam or gel retardants, and a crew of two to five personnel. Capstone will provide a Type-6 fire engine staffed with two personnel, a captain, and a firefighter on a Monday through Friday basis. Costs include onsite personnel at $100,160 for this upcoming season with a lodging expense of $6k for the operational period. Additional costs include over time, double time, holiday rates, and as-needed support during Red Flag Warning days outside of the contracted timeline.

51 Based on a two percent escalation rate.
52 Id.
The table below aggregates the anticipated spend for emergency management operational enhancements.

<table>
<thead>
<tr>
<th>WebEOC, FirstNet, Verizon Community Response Team, and Capstone Fire Support</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$831,630</td>
<td>$390,453</td>
<td>$389,093</td>
<td>$388,560</td>
</tr>
</tbody>
</table>

Table 31: Emergency Management Operations Cost Estimate

These operational enhancements exceed existing requirements and enable a more collaborative approach for NV Energy and its public safety partners. The alternative in using antiquated systems and methods would delay response efforts and mustering of first responders and resources, thus putting the public and surrounding communities at risk. These investments are considered to be industry-accepted and are supported by emergency management entities as communicated during the EWG meetings. These initiatives are incremental to normal operations in an effort to bolster communication and response capabilities within NV Energy and align with network platforms commonly used throughout the state.
7 COMMUNITY OUTREACH

Robust stakeholder engagement was a central element of the Companies’ Plan development. Before drafting plan materials, the Companies convened and solicited input from a range of community partners and SMEs to form the EWG. This approach afforded the ability to set a common language and explore synergies of existing Companies’ programs such as PSOM, leverage partner programs such as CWPPs, and set future plans for collaboration. As noted in Section 2.2, the three expert working group sessions averaged approximately 40-50 participants each, including representatives from key partners identified in SB 329 and the Regulations. These participants included:

- Local and regional fire agencies and fire districts;
- Local Emergency Managers;
- The Bureau of Land Management;
- The U.S. Forest Service;
- State and local law enforcement and military agencies;
- The Nevada Division of Emergency Management;
- The Nevada Division of Forestry;
- The Nevada Division of Lands;
- The Nevada Division of State Parks;
- The Nevada Department of Conservation & Natural Resources Management; and
- Telecommunication Companies.

Meetings took place at the Companies’ hosted sites in Las Vegas, Reno, and Elko, and were supplemented with remote participation capability, on January 7th, 13th, and 21st, 2020.

7.1 Stakeholder Workshops & Outreach

The Companies believe that the Plan and its implementation will be most effective when all parties are aligned in the Plan’s objectives and components. Outreach will continue with the expert partners and the public to enhance community understanding and preparedness and to assure an actionable plan for future coordination and communication. The Companies provide information for citizens and communities to prepare against future natural disasters. Through combining information and actions that begin with the Companies and with the communities themselves, alignment in understanding, developing a common language for communications and response, and refining action plans through tabletop exercises and practice drills, all parties will be better prepared against impacts from natural disasters. In addition to these EWG workshops, NV Energy has engaged and will continue discussions with agencies such as SNOPS, NNFC, county-level emergency managers, federal and state lands and forestry agencies, and local fire districts.

7.1.1 Stakeholder Workshop Summary

After drafting Plan materials drawing on the expert input described above, the Companies convened a series of seven stakeholder engagement sessions for the general public – six in-person meetings and one meeting streamed and published via Facebook Live for remote participants. These public meetings provided a forum for the open exchange of ideas surrounding the Companies’ plan. They also served to enhance community understanding and preparedness, identify questions that have emerged during Plan development, and satisfy SB 329 outreach and review requirements. These open public sessions helped guide the emergence of an actionable plan for future coordination and communication. The Companies held stakeholder engagement sessions in Reno, Elko, South Tahoe, North Tahoe, Mount Charleston, and Las Vegas. Sessions took place between January 27, 2020 and February 6, 2020.
Following the presentation portion of each stakeholder engagement meeting, key Company staff and expert working group representatives were available to speak with customers regarding the various focused elements of the plan. Additionally, the Companies provided attendees with printed materials and informed attendees that they could also send feedback at any time before February 11, 2020, to ndpp@nvenergy.com, a mailbox established for the Plan feedback process.

7.1.2 Local & State Agency Engagement

As noted above, a number of local and state agencies contributed time and resources to help ensure the creation of a thoughtful and robust Plan. The following local and state organizations were among those that provided their expert input to the Plan draft:

- The Nevada Fire Chiefs Association;
- The North Lake Tahoe Fire Protection District;
- The Central Lyon Fire District;
- The Tahoe Douglas Fire Protection District;
- The Mount Charleston Fire Protection District;
- The Southern Nevada Operations Group;
- Nevada Division of Emergency Management;
- Washoe County Emergency Management;
- Clark County Emergency Management;
- Douglas County Emergency Management;
- The Nevada Division of Forestry;
- The Nevada Division of State Lands;
- The Nevada State Parks; and
- The Nevada Department of Conservation & Natural Resources Management.

7.2 Stakeholder Input on Plan Elements

The Companies solicited, tracked, and considered stakeholder input on all elements of the Plan. Comments considered during this process include expert opinions in collaboration sessions, public comments from outreach sessions, questions directed to the Companies’ staff, and submitted questions to the Companies’ electronic mailbox. Figure 47 below depicts a breakdown of stakeholder comments by category.
The Companies discussed CWPPs with applicable local and regional jurisdictions while compiling this Plan. Given the range of CWPPs that may be relevant in the Companies’ service territory and the knowledge that these plans are being updated, the Companies appreciate the need to continue coordination with community response partners and to consider new and updated CWPPs as appropriate. The Companies’ expert working group sessions and the regular Plan update process provide a means to harmonize with new CWPP developments, coordinate resources, and prevent the emergence of conflicting policies, plans, and procedures.

Stakeholder comments largely focused on expanding Plan details, decisions related to proactive de-energization, and the natural disaster categories. A significant share of comments also discussed vegetation management-related plans and activities.

Emergency Response: Comments centered around support for vulnerable populations, such as the elderly, and evacuation routes during emergencies. Additional information about NV Energy’s emergency response plans and programs is located in Section 6 of the Plan. System hardening projects and programs are also discussed in Section 4.3 of the Plan to improve resiliency around major evacuation routes.
External Assistance Offered: NV Energy received offers of assistance based on stakeholder-specific expertise. NV Energy will continue to participate in ongoing meetings (similar to EWG meetings) and will seek additional expertise as needed to inform the next iteration of its Plan.

Stakeholder Engagement: NV Energy received comments on its Stakeholder Engagement process, including meeting locations and additional Plan details. The regulatory review process affords a 180-day review period where stakeholders can review and comment on the Plan details. Suggestions for additional community session locations were accommodated through a Facebook Live presentation where customers that could not attend an in-person session could get additional information about the Plan. NV Energy also established an email inbox (ndpp@nvenergy.com) for anyone to provide input through February 11, 2020.

Operational Practices: Comments related to operating assets in vulnerable areas, including sources of supply. As explained in Section 3, NV Energy will periodically refresh high-likelihood and high-threat natural disasters to consider for future plans.

Proactive de-energization: NV Energy considers PSOM a last-resort measure when public safety is at risk. NV Energy would prefer to keep the power grid energized to support community and first responder needs during a natural disaster. Plans to reduce the likelihood of needing PSOM to keep the public safe are explained in detail in Section 5 of the NDPP.

Risk Based Approach: Comments were directed toward the types of natural disasters considered and the related weather maps. NV Energy carefully researched the most likely and largest impact natural disasters. These were vetted with the EWG collaboration sessions. As noted in Section 3, additional review and research was undertaken based on comments received. The risk-based approach is also discussed in detail beginning with Section 3.2 of the NDPP.

Situational Awareness: Comments included how people and technology will support utility personnel and community awareness to detect natural disaster conditions. Section 4.6 describes situational awareness programs (e.g., wildfire cameras and weather stations for which the data will be available in the public domain upon implementation).

System Hardening: Comments and questions were received related to program and project details. Section 4.3 provides details of high-priority system hardening projects, directed to extreme risk areas. These include, but are not limited to, replacing overhead assets, line and substation rebuilds, undergrounding sections of cable, and pole replacements.

Vegetation Management: Comments contained questions related to location, timing and frequency of vegetation management activities. In extreme threat areas, NV Energy plans to reduce the trimming cycles as noted in Section 4.4 of the Plan. NV Energy will use certified foresters and arborists; the EWG confirmed the capabilities and willingness of partner organizations such as the BLM and the USFS there are benefits from sharing data and information, and coordinating vegetation management programs. The following figure lists all working group and community sessions that were conducted prior to the Plan filing:
Expert Working Group Meetings took place at NV Energy in Las Vegas, Reno and Elko with a dial-in for remote participants. Each meeting takes a deeper look at the plan, with ongoing participation.

**Occurred on:**
- January 7th
- January 13th
- January 21st

Public Stakeholder Meetings will be in the form of an open forum to engage public on the Plan’s progress and consider feedback while educating on key areas such as PSOM.

**Locations:**
1. Reno
2. Elko
3. North Lake Tahoe
4. Mt. Charleston
5. Las Vegas
6. South Lake Tahoe
8 METRICS, PERFORMANCE MONITORING & PLAN ACCOUNTABILITY

The following section describes the activities surrounding metric and Plan implementation tracking, recording-keeping, and responsible parties for ensuring effective risk reduction through ongoing monitoring.

8.1 Description of Metrics

Metrics are used to track the Companies’ progress toward activity targets held within this Plan to reduce risk of natural disaster-related impacts, fire ignitions, and PSOM events. NV Energy has been tracking the WMP progress of the California IOUs. Using a similar approach, the Companies propose progress-based metrics for the first version of the Plan, to track actions that reduce disaster risk and outline utility progress toward specific targets. Future filings will include additional metrics after the baseline is established to assess the efficacy of risk reduction measures.

The Companies will monitor industry practices and assess feedback from Plan implementers, public safety partners, and EWG members to capture lessons learned for more effective Plan updates and future plans. Investigation into best practices for metric setting and tracking will continue as NV Energy monitors neighboring states’ risk indicators and progress tracking.

In this Plan, the Companies focus on measurable progress and programmatic targets. As this Plan evolves, future metrics will follow industry practices and those directed by the Commission. Currently, effective metrics applicable to natural disasters are described in proceedings in front of the CPUC.53

1. Metrics should present a comprehensive view into the Companies’ contribution to risk reduction and how the Companies’ efforts fit within the state’s long-term objectives.
2. A valuable metric should track information that can be used to inform action and Plan updates.
3. Metrics should consider both lagging indicators to help understand past events and prevent recurrence and leading indicators to avoid future incidents.
4. Data analysis of records should determine which metrics best predict or reflect disaster risk and should be used to update or identify new metrics accordingly.
5. Metrics should rely on consistent units of measurement to ensure comparability across the service territory and in differing conditions.
6. Underlying data for metrics should be auditable so they can be independently verified for the success or failure in reducing risk of natural disaster impact or causation.

Robust metrics play a critical role in evaluating the success of the Plan. The Companies rely on metrics to inform disaster mitigation and preparedness progress and identify existing and potential gaps that may arise as conditions change. Upon Plan approval, the Companies will create metrics tracking templates, and periodically refresh for updates or upon direction of the Commission. Table 32 below describes the identified metrics for the initial Plan.

53 On December 16, 2019, the CPUC issued a Ruling under Rulemaking 18-10-007 establishing 2020 WMP templates and related materials directed to California IOUs. Included in the materials package was the attachment for WMP Metrics, from which NV Energy reviewed to further its understanding of the industry at large. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M322/K232/322232145.PDF.
Table 32: Proposed Plan Metrics

<table>
<thead>
<tr>
<th>Metric</th>
<th>Rationale</th>
<th>Risk Reduction Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Electric Infrastructure Caused Ignition Events and/or Fires</td>
<td>Determination of the Plan’s overall effectiveness with respect to fire-related natural disasters that are caused or exacerbated by electrical equipment.</td>
<td>Fire frequency will reduce by maintaining a hardened system and committing to these operational practices. This metric will serve as the foundational baseline for controls efficacy that the Companies maintain to prevent ignition or spread of fires.</td>
</tr>
<tr>
<td>that occur within the Vicinity of Utility Electrical Equipment</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of Vegetation Contacts with Lines in Wildfire Risk Areas</td>
<td>Measuring effectiveness of vegetation inspections and remediation procedures to ensure forest and vegetative health and clearance in proximity to electrical lines.</td>
<td>With shortened inspection cycle times and collaborative efforts for fuel mitigation activities, it is expected that vegetation contact incidents will reduce over time, greatly abating likelihood of ignition or spark events.</td>
</tr>
<tr>
<td>Number of Overhead Equipment Failures in Wildfire Risk Tiers</td>
<td>Assess if the initiatives within system hardening and electrical equipment inspections have effectively reduced risk over time.</td>
<td>In executing system hardening efforts, NV Energy anticipates the frequency of overhead equipment failures to decrease. Accounting for faults and outage incidents will, over time, lead to a reduction pattern in recorded incidents.</td>
</tr>
<tr>
<td>Average Time for Vegetation Clearance Permissions from Local Agencies</td>
<td>Track processing and groundbreaking timelines as strategies are implemented to help the Companies assess mitigation initiative constraints and timelines for future execution efforts.</td>
<td>Exploring opportunities to work and streamline efforts with authorities having jurisdiction as it relates to permitting and environmental studies.</td>
</tr>
<tr>
<td>Number of PSOM Events</td>
<td>Monitor the number of PSOM events over time as an indicator of changing climatic and weather patterns as well as grid resiliency efforts implemented through this Plan.</td>
<td>The Companies will only proactively de-energize circuits as a matter of last resort. This metric will aid in determining the effectiveness of procedures and strategies to mitigate the need for PSOM events.</td>
</tr>
</tbody>
</table>

8.1.1 Supporting Data & Assumptions

NV Energy will utilize internal recordkeeping described throughout this Plan such as inspection and corrections reports, and progress status updates, to determine whether the Plan’s components effectively reduce risk of natural disaster impact over time. Additional data includes outage and MED data, incident tracking, along with project implementation progress. NV Energy will work with stakeholders to share data and resources that supplement situational awareness.

8.2 Metrics Tracking & Comparison

The Companies will track metrics as material occurrences arise (e.g. including outage reports, tree clearing notifications, weather conditions from deployed weather stations, etc.) and produce periodic internal updates. Formal reports will aggregate metrics for review by the Companies’ leadership on a semi-annual
schedule to align with the Commission’s Plan approval period. Reports will document whether the Companies are meeting, exceeding, or falling below Plan metrics. The Companies will periodically review metrics to determine whether revisions are required to accurately capture progress toward risk reduction goals. NV Energy will also consider metrics being tracked by California utilities for risk reduction. Upon Plan approval, the Companies will begin tracking the proposed metrics listed in Table 32.

8.3 Accountability of the Plan

Accountability for this plan resides with the Senior Vice President of Operations. This executive oversees the implementation of the Plan’s components. The Senior Vice President also oversees emergency operations, which are foundational to natural disaster response and recovery, aligned with overall accountability.

8.3.1 Plan Implementation Roles & Responsibilities

The table below identifies accountable parties related to the execution of the Plan’s initiatives.

<table>
<thead>
<tr>
<th>Category</th>
<th>Project or Program Description</th>
<th>Area/Owner(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>System Hardening</td>
<td>Small copper wire line rebuilds</td>
<td>Engineering and Project Management</td>
</tr>
<tr>
<td>Inspections &amp; Corrections</td>
<td>Pole Replacements and additional capital work - wildfire mitigation</td>
<td>Lines North/South</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Grey wire replacement</td>
<td>Lines North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Lines Ruggedization - Natural Disaster Risk Zone Pole Replacements (non-wildfire)</td>
<td>Lines South</td>
</tr>
<tr>
<td>System Hardening</td>
<td>123 Line Rebuild</td>
<td>Lines North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Chimney Peak #201 Line Rebuild</td>
<td>Lines North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Glenbrook Tap (624) Rebuild</td>
<td>Lines North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Incline Substation Rebuild</td>
<td>Substations North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Round Hill Substation Rebuild</td>
<td>Substations North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Kingsbury Substation Rebuild</td>
<td>Substations North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>North Truckee Substation Rebuild</td>
<td>Substations North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Truckee Substation Rebuild</td>
<td>Substations North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Glenbrook Substation Rebuild</td>
<td>Substations North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Tree Attachment Removals</td>
<td>Lines North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Covered conductor - portions of Cal 204, Incline 4100 and Incline 4200 (pilot only)</td>
<td>Lines North</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Spacer Cable - portions of Kingsbury 2800 and Roundhill 1503 (pilot only)</td>
<td>Lines North</td>
</tr>
<tr>
<td>Category</td>
<td>Project or Program Description</td>
<td>Area/Owner(s)</td>
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<tr>
<td>-------------------------</td>
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<td>System Hardening</td>
<td>Undergrounding - portions of Incline 4100, Incline 4200, Incline 4300, Roundhill 1502, Roundhill 1504, Glenbrook 2302, Glenbrook 2505, and Glenbrook 2600</td>
<td>Lines North</td>
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<tr>
<td>System Hardening</td>
<td>Undergrounding - portions of Angel Peak 401, 402 and 403</td>
<td>Lines South</td>
</tr>
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<td>System Hardening</td>
<td>653 line rebuild</td>
<td>EPM/Trans/Civil Engineering</td>
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<td>620 line rebuild</td>
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<td>Grid Operations</td>
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<td>Wildfire Cameras</td>
<td>Risk Management</td>
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<td>System Hardening</td>
<td>Pole Stoppers</td>
<td>EPM</td>
</tr>
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<td>System Hardening</td>
<td>Critical Crossings</td>
<td>EPM</td>
</tr>
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<td>Inspections &amp; Corrections</td>
<td>Circuit Resiliency Patrols and Inspections-Natural Disaster Risk Zones (non-wildfire)</td>
<td>Lines South</td>
</tr>
<tr>
<td>Inspections &amp; Corrections</td>
<td>Wildfire Patrols and Inspections</td>
<td>Lines North/South</td>
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<tr>
<td>Vegetation Management</td>
<td>Tree trimming, pole grubbing and fuel inventory mapping</td>
<td>Delivery Support</td>
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<td>System Hardening</td>
<td>Lightning Arresters</td>
<td>Lines North/South</td>
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<tr>
<td>System Hardening</td>
<td>Non-expulsion Fuses</td>
<td>Lines North/South</td>
</tr>
<tr>
<td>Risk Based Approach</td>
<td>Resource Sufficiency- additional positions</td>
<td>Several</td>
</tr>
<tr>
<td>Risk Based Approach</td>
<td>Proactive Technology Assessment and Asset Management (Underground rehabilitation study, image analytics, fuel inventory mapping, falling conductor protection study and high impedance fault detection study)</td>
<td>Several</td>
</tr>
<tr>
<td>PSOM</td>
<td>Public Safety Outage Management (Weather analytics, fuel sampling, restoration patrols, customer resource centers, communications, grid operations support and back-up generation)</td>
<td>Several</td>
</tr>
<tr>
<td>Risk Based Approach</td>
<td>Emergency Response (Fire Management services, FirstNet, WebEOC and Verizon support)</td>
<td>Emergency Management</td>
</tr>
</tbody>
</table>

### 8.4 Auditing & Monitoring the Plan

The Companies will monitor progress toward Plan objectives and produce reports, supported by data collection such as vegetation and equipment inspection results. Work order progress will be tracked for
executed initiatives. This information is evaluated for the purpose of disaster mitigation planning. Plan's progress reports to support program management will be developed and circulated to promote collaborative discussion among NV Energy team members and assess changes to approved strategies on a periodic basis. Collected reports, progress and work order statuses, and related data collected will undergo a quality check by ensuring all data points are tracked through a master template. Data assurance through self-audit practices include internal quality checks, backup documentation, project justification, and senior management approvals.

8.4.1 Monitoring Procedures & Responsibilities

The Companies will assign a Project Manager ("PM") to monitor progress of the Plan. The PM will monitor progress of identified projects, as well as assigned costs for each section of the Plan. The PM may be assisted by the various SMEs for each section. Cost monitoring will also be done by the Accounting Department. Risk Management will also provide oversight and input to the monitoring process to ensure risk is minimized.

Achieving a robust, all-encompassing Plan to mitigate natural disaster risk from the Companies is the primary objective of this document. Staff responsible for assigned mitigation areas have the role of vetting current procedures and recommending changes or enhancements to the Plan. Whether due to unforeseen circumstances, regulatory changes, emerging technologies, or other rationales, any potential deficiencies within the Plan will be sought out and reported to the Commission in the form of an updated Plan. The Fire Mitigation Specialist, Risk Management Director, or their designees, will be responsible for spearheading discussions on including potential enhancements when updating the Plan for subsequent filings.

8.4.1.1 Recordkeeping Practices for Plan Execution

Procedures for tracking Plan implementation and associated costs are reflected in the Companies’ internal NDPP project approval and journal entry processes. The purpose of this defined process is to properly account for capital and OMAG expenses to ensure accurate and efficient reporting. Projects will be reviewed on a monthly basis by the business analyst of each organizational area of the Plan’s initiatives. In addition to providing Journal Entries, business analysts will also share with NV Energy’s accounting team supporting documentation for review and approval. The package shall include:

1. The project justification memo, which references supplemental key decision reports or authorization for expenditures;

2. Journal summary, which intends to expand upon financial line items;

3. Journal detail providing the initiative’s granularity including vendor updates, invoices, and materials;

4. PMs’ (from applicable business units) confirmation of expenses to be transferred to the regulatory asset budget ID or OMAG; and

5. Additional documentation pertinent to execution.

8.4.2 Audit of Plan Implementation

To comply with NV Energy’s internal control over the Plan’s spend, the Companies implemented approval guidelines and procedures to validate and justify incremental spending for projects and programs in the interim regulatory asset account until the Plan’s approval.
To validate the Companies are accurately monitoring its SB 329 costs as incremental and provide justification in the Plan, the following procedures were implemented. Going forward, projects will be started by a PM, who reaches out to the Electric Delivery assurance, risk management, accounting, regulatory, legal and assigned business analyst with a completed project justification, cost forecast, incremental spend justification and other relevant details for relevant approvals. Case by case exceptions can be made for emergency projects also approved by business unit leader, risk management, electric delivery assurance, accounting, regulatory, and legal team.

Additionally, the Companies will use a project approval process that establishes a standard of minimum documentation with senior leadership approvals to ensure Plan expenses are prudently recorded as stipulated by SB 329 and the Regulations. This policy provides adequate back up documentation for the transfer of expenses to the regulatory asset account via the journal entry process described in the section above.

8.4.2.1 Procedures for Plan Enhancements

For projects and programs requiring enhancements or changes, the manager responsible for that program will determine the scope change or enhancement, decide on corrective action, and observe results to determine if the enhancements have the desired effect. Corresponding journal entry updates will also be made to the established accounting budget code as needed following the internal standard process.

8.5 Resource Sufficiency

The projects and programs in the Plan reflect the need for additional resources to address the potential effects of natural disasters on the electric system as contemplated by SB 329. The Companies’ efforts to accelerate its ability to protect against disasters, such as wildfires, as required by the newly enacted legislation and the accompanying Regulations, began as soon as threats and mitigating practices were identified. This Plan expands efforts to include high-frequency and high-impact natural disasters, to prepare, mitigate, respond, and recover from these threats. NV Energy will continue to partner with organizations, such as emergency responders, resource land managers, and fire fighters, to maximize the impact of the Companies’ investments in people, projects, and programs. In order to protect against natural disasters beyond wildfires and actions beyond mitigation, resources will need to be refocused and enhanced for successful implementation. NV Energy added a Fire Mitigation Specialist (Fire Chief) position in 2019 to support continued collaboration with external communities. In addition, specific skillsets that may require multi-business unit coordination and handling confidential data and systems may be needed as part of NV Energy’s workforce for long term execution of the Plan. The Companies will also need to work with some contractors where their expertise is needed on an immediate basis. For example, Navigant Consulting or a similar firm’s continued support for Plan development, project management, Plan oversight and structure development, updates to the Plan, subsequent regulatory filings etc. Finally, the Companies will also add labor, tools and materials as needed to execute on the different Plan elements. This support will also be included at the project level as noted in the respective sections above. Table 34 includes the cost estimates for additional labor and contractor support that will support the overall execution of the Plan:

<table>
<thead>
<tr>
<th>Table 34: Additional Labor and Contractor Support Cost Estimates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>Total Costs ($)</td>
</tr>
</tbody>
</table>
9 REPORTING & FILING TIMELINES

9.1 Plan Filing & Update Cycle

The Regulations require electric utilities to file a Plan every three years on or before March 1st and require annual progress reports be filed on September 1st, during the first two years after the initial filing. This Plan is submitted in compliance with this requirement. The Commission shall review and approve the Plan or require subsequent modifications within 180 days of filing.

9.1.1 Monthly Reporting Requirements

The Regulations establish monthly reporting requirements related to ignition events in extreme fire risk areas or high fire risk areas, proactive de-energization and outage events, and wildfires caused by utility infrastructure that burn more than one acre of land. NV Energy has been conducting training and collaboration with fire investigators to define the reporting structure per the Regulations and this Plan. NV Energy is targeting to complete this training by May 31, 2020. Therefore, the first monthly report will be submitted upon completion of this process while the 24-hour reports will be filed upon occurrence of any ignition events within the vicinity of the Companies’ electric infrastructure.

9.1.2 Cost Recovery Filing Timeline

The Regulations establish an annual cost recovery process for all prudent and reasonable expenditures made by the electric utility to develop and implement the Plan. The Companies will file an application to recover the costs held in the regulatory asset account, for the prior year, on or before March 1st.

Similar to the Energy Efficiency Program Cost tracking, costs will be period specific (i.e. 2019 costs = Period 1; 2020 costs = Period 2, etc.) but remain tracked within the same regulatory asset FERC Account 182.3 to ease tracking historical cost and rate recovery.

Rates will go into effect on October 1st for twelve months, with other annually filed rates, such as Energy Efficiency Program Rate (“EEPR”), until the next annual rate application.

9.1.3 Establishment of a Natural Disaster Protection Regulatory Asset Account

Senate Bill 329 requires the expenditures incurred by an electric utility for its natural disaster protection plan be recorded as a separate monthly rate charged to all customer of the electric utility. In order to follow the ruling, the Companies proposed to the PUCN, which was approved in Docket No. 19-07014, to establish a regulatory asset account for tracking applicable costs incurred for the Plan’s execution. Recovery of the regulatory asset will be filed on an annual basis per the Regulations. The account will contain incremental costs relating to operating and maintenance as well as capital costs incurred for the Plan. All costs incurred will be reviewed by the project manager and documented for justification.

All capital work orders will be tracked through a class code in PowerPlan. The class code will be uniquely identified in the system to indicate the capital assets that are incurred for the Plan. It will be the responsibility of the project owner to supply the work order numbers to Plant Accounting. The business unit incurring costs will perform a detailed monthly analysis of these work orders. A dedicated business analyst will support this monthly review process for capital work orders. Plant Accounting will track the plant-in-service and provision via the class code. Depreciation expenses will be tracked and recorded through PowerPlan but the depreciation related to capital assets will be deferred into the regulatory asset and not part of the general rate cases. For capital improvements, the regulatory asset will include depreciation and a return on
capital (using the allowed rate from the territory in which the assets reside), including the effects of tax. In addition, the amounts in the regulatory asset will be subject to carry costs.

It is anticipated that NV Energy will record Plan related capital improvements in the service territory where the project is located, which will determine which utility records these assets on their jurisdictional books. For both utilities, Plan related assets will not be part of either company’s rate base, revenue requirement, or base tariff general rates.

Operating and maintenance work orders will be tracked through unique Natural Disaster Mitigation or Protection budget IDs. It will be the responsibility of the project owner to map these work orders in applicable work management systems for proper tracking. The business unit incurring costs will perform a detailed monthly analysis of these work orders and a dedicated business analyst will support the monthly review process for these work orders.

There will be one rate for customers in southern Nevada and northern Nevada. In order to calculate one rate for all customers, the costs will be split between Nevada Power and Sierra based on their billing determinants from the prior year, i.e. based on each utilities’ prior year total unit sales as a percent of total consolidated sales, for all customers. This percentage will then be used to allocate the charges in the following year when incurred between Nevada Power and Sierra. The costs will then be trued-up between the Companies’ allocations through an intercompany payable/receivable and the appropriate cash will be exchanged based on this methodology.

Similar to the EEPR, NV Energy will track the costs in different projects based on the recovery period in which the costs are incurred and the revenue collected from the Plan rate will be offset in the regulatory asset for that period. The costs will be tracked on a calendar year basis for the twelve months ending December 31st, and then filed in the annual filing for rates to be effective October 1st of the preceding year. Any over or under collection in a calendar year will then be rolled into the following year’s filing.

For more details on the recovery strategy and the accounting related to the recovery of the Plan costs, please see the NDPP recovery filing, filed simultaneously with the Plan.
10 PLAN IMPLEMENTATION COST IMPLICATIONS

Pursuant to SB 329, NV Energy has prepared this Plan that includes cost estimates for the three-year execution timeline. For this first Plan submission, the Companies have included a budget through 2023 for Plan’s approval in 2020.

The information provided below intends to inform the Commission on anticipated level of expenditures and provide further justification that the Companies have employed cost-effective initiatives that result in significant natural disaster risk reduction. Capital and OMAG determinations specified in this Plan are based on the best information available at the time and will continue to be reviewed during the specific programs’ implementation.

The Companies intend to work with stakeholders and the Commission in order to have the smallest financial impact possible to our customers across the state, while also providing the greatest possible protection of critical geographical areas that add value for all Nevadans and visitors alike, and provide state-wide benefits.

10.1 3-Year Projected Costs for Plan Execution

Overview

The Companies’ Plan has been formulated to reduce controllable risks primarily through program expenses (patrol/inspect/repair/vegetation management), reduce uncontrollable risk primarily through capital investment (replacement/infrastructure additions) and reduce public safety risk through program expenses and investment.

Summary Table 35 and Table 36 below aggregate the Plan’s cost forecasts for program expense (OMAG) and investment expense (capital) for 2020 through 2023. These costs are detailed within the respective sections of this Plan. The estimated financial impact of the Plan may be modified during the project implementation phases and additional details will be included in the subsequent Plan updates and triennial filings. Table 37 provides a summary of program expenses and investment expense for 2020 through 2023.

As demonstrated below, the majority of the costs are in maintenance programs - vegetation management, inspections and repairs, followed by investment in system hardening (e.g., line and substation rebuilds, undergrounding, small copper replacement, pole replacements, etc.).

Different investment scopes in the Plan may have more favorable outcomes (for example resources may be more readily available and/or permitting timelines may meet the quick turnaround anticipated in the Plan) and others will have less favorable outcomes versus what is presented in this Plan. The Companies will move investment from work scopes that are lagging (or failing to reduce uncontrollable risk) to work scopes than can be accelerated in order to maximize the reduction of uncontrollable risk.

It is important to note, that actual maintenance programs and investments might decrease upon completion of the initial inspection and correction cycle, achievement of the desired vegetation management trimming cycles, and completion of the proposed system hardening projects over the first few years.

In order to be transparent on a range of outcomes associated with program costs in this Plan, Table 38 provides one potential outcome as to how the actual costs may differ from those outlined within the Plan. The difference in outcomes could be driven by technology that reduces vegetation management costs or the costs for compliance with the IWUIC Appendix A among other things.

Similarly, for investment capital included in the Plan, Table 38 provides one potential outcome as to how the actual costs may differ from those outlined within the Plan. With virtually no initial engineering or
permitted having yet been completed, the Companies have provided a snapshot of one potential outcome using annual discounts to its portfolio in order to reflect the range of outcomes for capital investment.

**Controllable Risk**

Controllable risk is risk associated with failures of the Companies’ infrastructure or vegetation contacts with the Companies’ infrastructure. Either of these occurrences could lead to an ignition event or a wire-down event. Climate change has increased the chances of these outcomes and the Plan addresses programs necessary to combat that increased risk.

Incremental controllable risk reduction can be realized quickly through maintenance programs. The Plan includes descriptions and cost estimates for those programs. The Companies’ view is that annual maintenance program expenses will drop over time (beyond 2023) as far more acute risk assessment technology is developed to support the utility industry’s challenge with increased wildfire risk. Various technology improvements were discussed earlier in the Plan and successful implementation of any of these technologies could result in lower overall program expense within the three year period covered by the Plan. The Companies will pursue technology in order to reduce Plan expenses as a core principle.

Many of the patrol, inspect, repair, weather analytics, vegetation management, and PSOM expense programs have already been started to reduce controllable and some uncontrollable ignition risk as soon as possible. Other expenses designed to further address controllable risk (and described within this Plan) will commence upon approval of this Plan.

The cost for maintenance programs in the Plan reflects a higher cost than originally contemplated by the Companies and reflects the adoption, by our state, of laws to further reduce the risks associated with devastating wildfires. Since NV Energy’s comments in Docket No. 19-06009 (June 26, 2019), where estimated program expenses were thought to be on the order of $25m annually, the state of Nevada has passed laws requiring the Companies to come into compliance with IWUIC Appendix A (as documented earlier in the Plan). The costs associated with compliance with IWUIC Appendix A in this Plan reflect aggressive compliance with this new state law. Actual costs could be lower based on adoption plans of various agencies and the deployment of technology that addresses risk more acutely.

**Uncontrollable risk**

Uncontrollable risk is risk associated with having energized, bare conductor in the air (overhead construction). The introduction of contacts via animals, dead fuel from outside the right-of-way, extreme and frequent weather anomalies or other debris entering the lines presents an uncontrollable risk of ignition or wire-down events. No level of program maintenance reduces the risk of these occurrences.

The greatest reduction in ignition risk and public safety risk will be realized with capital investment, but capital investment also has the greatest challenges for timely deployment as the capital investment requires intense and detailed public and governmental planning.

Very limited capital investment has been initiated outside of this Plan to address uncontrollable risk. The majority of the capital investment projects in the Plan will commence following approval of the Plan.

The estimates for expense and capital investment included within the Plan are based on reasonable experience performing related work, historical costs and the assumption that external resources (e.g. lines personnel and vegetation management personnel) are available. Further, it assumes optimistic views on permitting and stakeholder approval processes based on a shared sense of urgency to complete capital investment that reduces uncontrollable risk and materially enhances public safety.

The Companies are aware of the demands on resources associated with wildfire mitigation in other western states and expect that resource availability may impact the Companies’ ability to execute on all work scopes.
included in this Plan whether those scopes are related to expenses for controllable risk reduction or investment for uncontrollable risk reduction. Scarcity of resources may also affect the projected costs associated with implementation of the Plan.

The Companies will endeavor to complete all the work outlined within this Plan, and any work not completed will be addressed in PSOM risk assessment as described earlier in the Plan. In other words, the actual status of work scopes for this Plan will be factored into any decision to have a PSOM event. As the scope of work is completed – especially for the capital investment to reduce uncontrollable risk – there is less risk of a PSOM event. The Companies continue to view PSOM as a last resort and it will only be used when the uncontrollable risk of ignition starting from overhead infrastructure is too high to allow energized operations.

<table>
<thead>
<tr>
<th>Category</th>
<th>Project or Program Description</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
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</thead>
<tbody>
<tr>
<td>System Hardening</td>
<td>Small copper wire line rebuilds</td>
<td>$200,000</td>
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<td>$8,220,142</td>
<td>$10,260,142</td>
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<td>System Hardening</td>
<td>Pole Replacements and additional capital work - wildfire mitigation</td>
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<td>$6,607,895</td>
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<td>System Hardening</td>
<td>Fire Mesh Pole Wrap</td>
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<td>$6,200,000</td>
<td>$11,500,000</td>
<td>$12,300,000</td>
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<td>System Hardening</td>
<td>Pole Top Reclosers</td>
<td>$160,000</td>
<td>-</td>
<td>-</td>
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<td>System Hardening</td>
<td>Grey Wire Replacement</td>
<td>$2,500,000</td>
<td>$2,000,000</td>
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<td>-</td>
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<td>System Hardening</td>
<td>Lines Ruggedization - Natural Disaster Risk Zone Pole Replacements (non-wildfire)</td>
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<td>$2,809,080</td>
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<td>System Hardening</td>
<td>Brunswick-Incline (123 Line) Rebuild</td>
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<td>System Hardening</td>
<td>Glenbrook Tap #624 Line Rebuild</td>
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<td>Incline Substation Rebuild</td>
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<td>$340,000</td>
<td>$360,000</td>
<td>$2,337,000</td>
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<td>System Hardening</td>
<td>Round Hill Substation Rebuild</td>
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<td>System Hardening</td>
<td>Glenbrook Substation Rebuild</td>
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<td>$2,000,000</td>
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<td>System Hardening</td>
<td>Tree Attachment Removals</td>
<td>$100,000</td>
<td>$500,000</td>
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<td>$520,200</td>
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### Natural Disaster Protection Plan

<table>
<thead>
<tr>
<th>Category</th>
<th>Project or Program Description</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>System Hardening</td>
<td>Covered conductor - portions of Cal 204, Incline 4100 and Incline 4200 (pilot only)</td>
<td>$300,000</td>
<td>$600,000</td>
<td>$637,500</td>
<td>$637,500</td>
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<tr>
<td>System Hardening</td>
<td>Spacer Cable - portions of Kingsbury 2800 and Roundhill 1503 (pilot only)</td>
<td>$200,000</td>
<td>$400,000</td>
<td>$425,000</td>
<td>$425,000</td>
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<tr>
<td>System Hardening</td>
<td>Undergrounding - portions of Incline 4100, Incline 4200, Incline 4300, Roundhill 1502, Roundhill 1504, Glenbrook 2302, Glenbrook 2505, and Glenbrook 2600</td>
<td>$200,000</td>
<td>$2,200,000</td>
<td>$6,000,000</td>
<td>$12,000,000</td>
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<tr>
<td>System Hardening</td>
<td>Undergrounding - portions of Angel Peak 401, 402 and 403</td>
<td>$600,000</td>
<td>$1,800,000</td>
<td>$2,250,000</td>
<td>$3,750,000</td>
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<td>Situational Awareness</td>
<td>Weather Stations</td>
<td>$600,000</td>
<td>$1,250,000</td>
<td>$1,275,000</td>
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<td>Situational Awareness</td>
<td>Wildfire Cameras</td>
<td>$530,000</td>
<td>$530,000</td>
<td>$530,000</td>
<td>$530,000</td>
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<td>System Hardening</td>
<td>Pole Stoppers</td>
<td>$530,000</td>
<td>$530,000</td>
<td>$530,000</td>
<td>$530,000</td>
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<tr>
<td>System Hardening</td>
<td>Critical Crossings</td>
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<td><strong>Total Capital Program Costs ($)</strong></td>
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<td>52,044,524</td>
<td>63,891,195</td>
<td>67,373,788</td>
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</table>

**Table 36: Natural Disaster Protection Plan Program Expense Cost Implications: 2020 – 2023**

<table>
<thead>
<tr>
<th>Category</th>
<th>Project or Program Description</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
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<tbody>
<tr>
<td>Inspections &amp; Corrections</td>
<td>Circuit Resiliency Patrols and Inspections- Natural Disaster Risk Zones (non-wildfire)</td>
<td>$1,666,732</td>
<td>$1,700,067</td>
<td>$1,734,068</td>
<td>$1,768,749</td>
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<tr>
<td>Inspections &amp; Corrections</td>
<td>Wildfire Patrols and Inspections</td>
<td>$10,861,111</td>
<td>$5,563,553</td>
<td>$4,172,665</td>
<td>$8,524,427</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Lightning Arresters</td>
<td>$70,000</td>
<td>$71,400</td>
<td>$72,828</td>
<td>$74,285</td>
</tr>
<tr>
<td>System Hardening</td>
<td>Non-expulsion Fuses</td>
<td>$550,000</td>
<td>$2,000,000</td>
<td>$3,000,000</td>
<td>$3,000,000</td>
</tr>
<tr>
<td>Risk Based Approach</td>
<td>Resource Sufficiency</td>
<td>$503,750</td>
<td>$1,419,000</td>
<td>$1,447,380</td>
<td>$1,476,328</td>
</tr>
<tr>
<td>Category</td>
<td>Project or Program Description</td>
<td>2020</td>
<td>2021</td>
<td>2022</td>
<td>2023</td>
</tr>
<tr>
<td>-------------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>---------</td>
<td>---------</td>
<td>---------</td>
<td>---------</td>
</tr>
<tr>
<td>Risk Based Approach</td>
<td>Proactive Technology Assessment and Asset Management (Underground rehabilitation study, image analytics, fuel inventory mapping, falling conductor protection study and high impedance fault detection study)</td>
<td>$986,483</td>
<td>$1,264,513</td>
<td>$1,277,803</td>
<td>$1,291,359</td>
</tr>
<tr>
<td>PSOM</td>
<td>Public Safety Outage Management (Weather analytics, fuel sampling, restoration patrols, customer resource centers, communications, grid operations support and back-up generation)</td>
<td>$1,990,000</td>
<td>$2,029,800</td>
<td>$2,070,396</td>
<td>$2,111,804</td>
</tr>
<tr>
<td>Situational Awareness</td>
<td>Weather Stations</td>
<td>$60,000</td>
<td>$61,200</td>
<td>$62,424</td>
<td>$63,672</td>
</tr>
<tr>
<td>Situational Awareness</td>
<td>Wildfire Cameras</td>
<td>$60,000</td>
<td>$61,200</td>
<td>$62,424</td>
<td>$63,672</td>
</tr>
<tr>
<td>Risk Based Approach</td>
<td>Emergency Response (Fire Management services, FirstNet, WebEOC and Verizon support)</td>
<td>$831,630</td>
<td>$390,453</td>
<td>$389,093</td>
<td>$388,560</td>
</tr>
<tr>
<td>Total OMAG Program Costs ($)</td>
<td></td>
<td>29,857,957</td>
<td>37,712,686</td>
<td>37,740,582</td>
<td>42,214,358</td>
</tr>
</tbody>
</table>

Table 37 summarizes the annual capital and OMAG program costs for the above projects and programs:

**Table 37: Natural Disaster Protection Plan Cost Summary: 2020 – 2023**

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital ($)</td>
<td>15,489,752</td>
<td>52,044,524</td>
<td>63,891,195</td>
<td>67,373,788</td>
<td>198,799,259</td>
</tr>
<tr>
<td>OMAG ($)</td>
<td>29,857,957</td>
<td>37,712,686</td>
<td>37,740,582</td>
<td>42,214,358</td>
<td>147,525,583</td>
</tr>
<tr>
<td>Total ($)</td>
<td>45,347,709</td>
<td>89,757,210</td>
<td>101,631,777</td>
<td>110,618,146</td>
<td>346,324,842</td>
</tr>
</tbody>
</table>

As noted above, Table 38 provides one potential outcome as to how the actual costs may differ from those outlined within the Plan; Table 38 is derived by discounting the numbers in Table 37.

**Table 38: Natural Disaster Protection Plan Portfolio Discounted Cost Summary: 2020 – 2023**

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital ($)</td>
<td>4,646,926</td>
<td>26,022,262</td>
<td>38,334,717</td>
<td>50,530,341</td>
<td>119,534,246</td>
</tr>
<tr>
<td>OMAG ($)</td>
<td>23,886,366</td>
<td>30,170,149</td>
<td>30,192,465</td>
<td>33,771,486</td>
<td>118,020,467</td>
</tr>
<tr>
<td>Total ($)</td>
<td>28,533,291</td>
<td>56,192,411</td>
<td>68,527,183</td>
<td>84,301,827</td>
<td>237,554,712</td>
</tr>
</tbody>
</table>
APPENDIX A: NATURAL DISASTER THREAT MAPS

Map 1. NV Energy Wildfire Threat
Map 2. NV Energy Asset Risk: Earthquakes
Map 3. NV Energy Asset Risk: Landslides/Avalanches
Map 4. NV Energy Asset Risk: High Wind Events
Map 5. NV Energy Asset Risk: Flooding
Map 6. NV Energy Asset Risk: Winter Weather
APPENDIX B: PROACTIVE DE-ENERGIZATION ZONE MAPS

PDZ Map: Incline Village
PDZ Map: Glenbrook
PDZ Map: California Transmission
PDZ Map: Carson/Minden
APPENDIX C: PSOM NOTIFICATION FORM

Report Date | Report Time
--- | ---

Report Number | PSOM - YYYY - N/S - Event # - Report #

<table>
<thead>
<tr>
<th>Notification Type</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>De-Energization Potential (192 hours)</td>
<td>De-Energization Potential (96 Hours)</td>
</tr>
<tr>
<td>Decision to De-Energize (48 hours)</td>
<td>De-Energization Initiated</td>
</tr>
<tr>
<td>Initiated Assessment to Re-Energize</td>
<td>All Lines Re-Energized</td>
</tr>
<tr>
<td>De-Energization Event <strong>Cancelled</strong></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Is this an update notification?</th>
<th>Yes</th>
<th>No</th>
</tr>
</thead>
<tbody>
<tr>
<td>If “yes”, provide an update number:</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Potential Impact

<table>
<thead>
<tr>
<th>County</th>
<th>Location</th>
<th>Zone</th>
<th># of Customers</th>
<th>Estimated De-energization Time</th>
<th>Actual Time of De-energization</th>
<th>Estimated Time of Re-energization</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Total Number of Customers:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Green Cross Customers:</td>
<td></td>
</tr>
<tr>
<td>Projected end date of event:</td>
<td></td>
</tr>
</tbody>
</table>

**List of impacted Critical Infrastructure:** (including, but not limited to, hospitals, fire stations, police stations, water treatment facilities, schools, communications facilities etc.)

<table>
<thead>
<tr>
<th>County</th>
<th>Location(s) / Description of Infrastructure</th>
<th>Estimated Time of Restoration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

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### Public/ Customer Notification Information and Report

#### Proposed Public Notification Language (List by Customer Type)

<table>
<thead>
<tr>
<th>Customer Type</th>
<th>Notification Language</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Method of Public Notification (Check All That Apply)

<table>
<thead>
<tr>
<th>Method</th>
<th>Other – Please Specify:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Automated Notification System: SMS/ Text Message</td>
<td></td>
</tr>
<tr>
<td>Automated Notification System: E-mail</td>
<td></td>
</tr>
<tr>
<td>Media Outreach</td>
<td></td>
</tr>
<tr>
<td>Stakeholder Coordination:</td>
<td></td>
</tr>
<tr>
<td>Personnel Phone Call</td>
<td></td>
</tr>
<tr>
<td>Social Media</td>
<td></td>
</tr>
<tr>
<td>Local Government Coordination</td>
<td></td>
</tr>
</tbody>
</table>

#### Entities to be Notified – including Key Customers and Stakeholders

<table>
<thead>
<tr>
<th>Entity</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
</tbody>
</table>

### Disclaimer

This document and the data included herein are intended for the sole use of the intended recipient(s). The above data is based on an assessment in wildfire risk tiers in NV Energy’s service territory. NV Energy is not responsible for any missing data. Supporting data is collected by NV Energy personnel and its agents using several different data sources. Notwithstanding that, NV Energy makes no representations or warranties, express or implied, of the accuracy or completeness of the information herein. NV Energy is not liable for any use or reliance upon any of the information.
APPENDIX D: MT. CHARLESTON, SOUTH LAKE TAHOE AND INCLINE VILLAGE/NORTH LAKE TAHOE PROJECT/PROGRAM IMPLICATIONS

Tier 3 Extreme Wildfire Risk Supplement

Stakeholder outreach to extreme wildfire high-threat Tier 3 areas where natural disasters are most likely to impact customers includes South Lake Tahoe, North Lake Tahoe / Incline Village, and the Mount Charleston area near Las Vegas. NV Energy has targeted action plans for these regions. The action plans, milestones, and other information about these projects appears in this Appendix.

Common projects and programs for these Tier 3 areas include:
Blocking reclosers during fire season (Section 4.3.4) – to avoid the risk of ignition from vegetation and debris coming into contact with infrastructure. NV Energy will prohibit automatic reclosing so that when a line that has tripped it will not accidentally reclose into ignitable material on the power line. The automatic reclosing feature will be disabled during fire season and during high-threat conditions. Improved automation will continue to support enhanced protection and awareness programs.
Adequate vegetation management and inspection cycles (Sections 4.4 and 4.2) – the Companies will also collaborate with relevant regulatory agencies and other external stakeholders to perform adequate vegetation management and overhead asset inspections. NV Energy also plans to clear vegetation around the base of poles so the cleared area does not contain any ignitable materials.

Mt. Charleston
The Mount Charleston area (including Angel Peak and Mary Jane Falls) is in a remote area vulnerable to multiple disaster types. It is limited in evacuation options with a single route of entry and egress. Mt. Charleston represents the only Tier 3 fire zone in the southern Nevada service territory. High wind events of strong enough force to affect infrastructure are common, a factor considered in this Tier 3 designation. Flash flooding has also been reported in the event of heavy precipitation. Despite negligible seismic risk, much of the area surrounding Mt. Charleston is classified as having very high landslide susceptibility due largely to the combination of topography and fire risk.

Grid hardening efforts include reconductoring and working with local telecommunications providers, first responders, and local agencies for a cohesive support plan. The Lodge at Mt. Charleston has been declared a Customer Resource Center for emergencies and additional preparedness around these centers will continue. PSOM practice sessions in the Mt. Charleston area have already resulted in investments to the customer call center capabilities and local emergency responder meetings.

Pole Wrapping (Section 4.3.2)
Fire mesh is designed to protect wood structures from burning or scorching, which significantly weakens the poles. The fire mesh forms a barrier by expanding at temperatures greater than 300°F that will shield the wooden pole structure from radiant heat and fire. The coating on the mesh expands to prevent ignition and will not contribute to the burning of the pole. The schedule is based on Plan approval, lead time for labor and material for execution. NV Energy intends to install fire mesh in all Tier 3 areas with efforts starting in 2020.

Fuses: Non-Expulsion Fuse Standardization (Section 4.3.3)
Conventional fuses, when operated, expel hot particles and gases, which can be an ignition source to start a wildfire. In contrast, current limiting fuses, that traditionally were used for protecting “sensitive equipment” expel no materials, limits the available fault current, and in many cases can reduce the duration of faults. NV Energy has approximately 3,200 Fuses in the Tier 3 area. Investments in the Mt. Charleston area will begin in 2020 and continue through 2023.

Covered Conductor / Selective Undergrounding (Section 4.3.5)
Predicated on a successful pilot project, the covered conductor replacement program will target the extreme-risk Tier 3 areas. Several factors drive the ability to begin reconductoring. These factors include: (1) Receipt of the construction permit by regulatory authorizes, (2) availability of materials, (3) resources to perform the work, (4) line clearance (maintaining reliability) and (5) planning and permitting approvals. Undergrounding and planned reconductoring with covered conductors in the Mt. Charleston Tier 3 area:

**Angel Peak Circuit 401**
Approximately one mile replacement of existing underground cable and conduit in the Mount Charleston area of Nevada. This area is presently undergrounded with an existing 4kV underground cable that has deteriorated with resulting outages. During heavy rain and water ponding, the cable might also fail. It is also expected that following a proactive de-energization event, during a high wildfire risk period, when re-energizing the line, the inrush current of turning the power back on might result in the obsolete 4kV cable failing. This might result in an extremely long duration power failure. Therefore, the existing cable should be replaced with modern 12kV cable that can support the NDPP. Permitting will begin in 2020 and take 18 months to complete. Construction would be in completed 2023.

**Angel Peak Circuit 402**
Similar to Angel Peak Circuit 401, approximately one mile of existing underground cable and conduit on the Angel Peak Circuit 402 is also targeted for replacement. This area is presently undergrounded with an existing 4kV underground cable that has deteriorated with resulting outages. During heavy rain and water ponding, the cable might also fail. It is also expected that following a proactive de-energization of power, during a high wildfire risk period, when re-energizing the line, the inrush current of turning the power back on might result in the obsolete 4kV cable failing. This might result in an extremely long duration power failure. Therefore, the existing cable should be replaced with modern 12kV cable that can support the natural disaster plan. Permitting will begin in 2020 and take 18 months to complete. Construction is expected to be completed by 2023.

**Angel Peak Circuit 403**
Undergrounding the existing half mile overhead 4 kV line. The above ground conductor spans present a wildfire risk and most of the issues noted for aging 4 kV infrastructure are applicable for this circuit. The existing cable should be replaced with modern 12kV cable that can support the NDPP by reducing risk of ignition events and service reliability. Permitting will begin in 2020 and take 18 months to complete. Construction is expected to be completed by 2023.

**Angel Peak to Kyle Canyon Line**
The 34.5 kV circuit to Kyle Canyon from Angel Peak Substation runs through an area that has been classified as having extreme fire threat. The AP3402 circuit from Angel Peak feeds the KC1201 at Kyle Canyon Substation. Around 445 customers are served by this circuit. This circuit is about 8.2 miles of which 7.7 miles is overhead and 0.5 mile is underground.

To address the fire threat risk and implement a long term fire mitigation solution, the analysis considered the following options:

- **Upgrade of the current circuit including cables and structures to the Spacer Cable system.** A description of this system is provided in Section 4.3.5 in this document.

- **New 19.2-mile distribution feeder to Kyle Canyon Substation from Northwest Substation (NW1221).** Several scenarios have been run under this option for the 12 kV feeder including overhead, underground, and a combination of both. The preferred alternative at this time is further discussed below. This alternative will address the Tier 3 risk and may result in decommissioning or abandoning in place the current AP3402. This is not the final selected option as additional analysis will continue to be conducted prior to reaching a final recommendation.
Several simulations have been run under this option for the 12 kV feeder including overhead, underground and a combination of both. The route for this proposed feeder will follow the NDOT ROW from Northwest to Kyle Canyon substation (see Section 4.3.5 for additional details). This route will have the least impact on crossing the Red Rock Canyon National Conservation area and will also facilitate the installation and access for future maintenance and inspection of the line. Currently under study is the option of installing a new feeder that would address the Tier 3 wildfire risk, might result in decommissioning or abandoning in place the current Angel Peak-Kyle Canyon Substation 34.5 kV line (AP3402) and provide future capacity for the area.

Tree Attachments (Section 4.3.5.3)
In many cases, the elimination of tree attachments requires the installation one or more new poles. NV Energy does not currently establish specific quantitative removal targets, however, existing tree attachments in this selected region will be evaluated and considered for removal. NV Energy approximates thousands of tree attachments in the Lake Tahoe Basin, anticipating the need for a potential cataloging method for a more accurate account of the total targeted for replacement.

Vegetation Management (Section 4.4.1)
Vegetation management process begins with an evaluation of a qualified forester to identify dying and distressed trees and other potential vegetation problems. A priority number is assigned to each tree or situation to assure the most urgent conditions are remedied by certified vegetation management professionals, such as arborists. Vegetation management will be targeted to occur on a four-year cycle, reduced from the current nine-year cycle. NV Energy expects significant resources and attention will be paid to Tier 3 vegetation management.

Situational Awareness (Section 4.6)
NV Energy intends to install additional high-definition cameras to enhance the existing network and improve situational awareness. The camera images are available to the public and camera controls, such as ‘pan’ and ‘zoom’ are enabled for utility operators and emergency personnel. Initially, there will be one or two cameras placed in the Mt. Charleston area to evaluate their efficacy. NV Energy will also supplement weather awareness by adding approximately four weather stations in the southern Nevada region (including Mt. Charleston) to supplement the National Weather Service systems.

Public Safety Outage Management PSOM (Section 5)
NV Energy has an extensive preparedness plan that continues to be refined. PSOM plans include customer outreach, improving customer call center capability, and reinforcing Customer Resource Centers. Additional awareness and communications programs are underway. NV Energy is collaborating with telecommunication providers, emergency responders, and local government agencies to assure that, as a last resort, all actions are taken to minimize impacts of proactive de-energization on the public.

Southern Nevada Customer Resource Center
The Retreat on Charleston Peak
2755 Kyle Canyon Road
Mt. Charleston, NV 89124

From 2020-2023, NV Energy estimates to investment approximately $12 million in the above targeted areas of risk mitigation and improvement.
South Lake Tahoe
South Lake Tahoe has substantial risk of incidence of several natural disaster types. The entirety of service territory adjacent to Lake Tahoe, including communities in South Lake Tahoe, is encompassed by a Tier 3 wildfire risk zone. Seismic risk is elevated in general, and communities on the eastern shoreline of Lake Tahoe below 30 meters elevation over the water line are included in an identified seiche risk (Lake Tsunami) area. Winter weather events are common, and flooding from extreme precipitation and flash floods have also been reported. Due to steep slopes, heavy precipitation, seismic activity, and deforestation risk due to wildfires, many areas are also identified as having “high” or “very high” landslide and avalanche susceptibility.

Grey Wire Replacement Program (Section 4.3.1)
The grey wire program replaces specific obsolete service wire and secondaries that have deteriorated to the point where the wire is a risk of becoming an ignition source for a wildfire. The grey wire used a type of rubber insulation material to cover the wire which over-time has aged to the point where it is no longer insulating the wire. Grey wire replacement is a generally accepted investment to reduce ignition sources that can cause a wildfire. NV Energy intends to replace grey wire over a two year period and targeted completion is by end of 2021.

Pole Wrapping (Section 4.3.2)
Fire mesh is designed to protect wood structures from burning or scorching, which significantly weakens the poles. The fire mesh forms a barrier by expanding at temperatures greater than 300°F that will shield the wooden pole structure from radiant heat and fire. The coating on the mesh expands to prevent ignition and will not contribute to the burning of the pole. The schedule is based on Plan approval, lead time for labor and material for execution. NV Energy intends to install fire mesh in all Tier 3 areas with efforts starting in 2020.

Fuses: Non-Expulsion Fuse Standardization (Section 4.3.3)
Conventional fuses, when operated, expel hot particles and gases, which can be an ignition source to start a wildfire. In contrast, current limiting fuses that traditionally were used for protecting “sensitive equipment,” expel no materials, limits the available fault current, and in many cases can reduce the duration of faults. NV Energy has approximately 3,200 fuses in the Tier 3 area. Investments in the Tier 3 areas will begin in 2020 that continues through 2023.

Covered Conductor / Selective Undergrounding (Section 4.3.5)
Covered conductor achieves many of the same ignition mitigation benefits as converting overhead wire to underground cable, but at a much lower cost. It also has similar public safety benefits but does not suffer from the troubleshooting and restoration delays associated with underground systems, affording faster repairs and shorter outage times for customers.  Additional limitations of underground systems include that they i) cannot be visually inspected, ii) could require service interruptions to perform certain maintenance, iii) are difficult to upgrade and often require excavation, and iv) are difficult to troubleshoot during emergencies, resulting in longer outages. The Companies’ goal is to minimize ignition potential and optimize PSOM restoration timelines as part of its wildfire mitigation strategy. While covered conductor provides protection from vegetation ignition, it can be more prone to damage due to lighting strikes and other overhead contact risks. As noted above, NV Energy plans to take a balanced approach towards overhead and underground rebuild.

Predicated on a successful pilot project, the covered conductor replacement program will target the extreme-risk Tier 3 areas. Several factors drive the ability to begin reconductoring. These factors include: (1) Receipt of the construction permit by regulatory authorizes, (2) availability of materials, (3) resources to perform the work, (4) line clearance (maintaining reliability) and (5) planning and permitting approvals. Undergrounding and planned reconductoring with covered conductors in the South Lake Tahoe Tier 3 area:

Roundhill Circuit 1502 - approximate total circuit length in Tier 3 is approximately 21 miles.
Portions of the circuits may have selected undergrounding.
Roundhill Circuit 1504 - approximate total circuit length in Tier 3 is approximately 11 miles. Portions of the circuits may have selected undergrounding.

Glenbrook Circuit 2302 - approximate total circuit length in Tier 3 is approximately 12 miles. Portions of the circuits may have selected undergrounding.

Glenbrook Circuit 2505 - approximate total circuit length in Tier 3 is approximately six miles. Portions of the circuits may have selected undergrounding.

Glenbrook Circuit 2600 - approximate total circuit length in Tier 3 is approximately four miles. Portions of the circuits may have selected undergrounding.

Kingsbury Circuit 2800 - approximate total circuit length in Tier 3 is approximately three miles. Portions of the circuits may have selected undergrounding.

NV Energy is proposing a spacer cable pilot on the Kingsbury 2800 (reconductor 2900 feet in the circuit) and Roundhill 1503 circuits (approximately 1200 feet of the circuit) and Roundhill 1502, Roundhill 1504, Glenbrook 2302, Glenbrook 2505, and Glenbrook 2600 circuits are also shortlisted for undergrounding. Pilot completion is targeted for completion by 2023. Approximately two miles of undergrounding is targeted for completion by 2022 and another four miles by 2023. Additional details on the undergrounding (e.g., updated costs, schedule etc.) will be included in a subsequent Plan filing.

Transmission Line Rebuilds & Ruggedization [Glenbrook #624 Line]
This line rebuild project, located in a Tier 3 zone, is a part of the Companies’ Plan. The purpose of this project is to replace the existing line from the 1940s with a modern design along the existing alignment corridor to provide safe and reliable electrical service and to improve fire safety and durability.

The existing radial 60 kV 624 line was constructed in or about 1941 and is the only transmission line to Glenbrook, Nevada. The customers served by this line have experienced numerous outages associated with the age and deteriorated condition of the line structures. This line has suffered more than two times the overall average service interruptions experienced by other transmission lines in the Companies’ system. In 2014, the Companies replaced six cross arms and insulators where the insulator had failed. Failed insulators allow electricity to track through the insulator and can cause the cross arm to smolder. When this occurs, the insulator can detach from the cross arm allowing the conductor to float free of the structure. This situation poses a significant fire risk and contributes to the number of outages experienced by the Companies’ customers. Additional details are also included in Section 4.3.5.

Substation Investments (Section 4.3.7)
Substation hardening investments for South Tahoe include:

Kingsbury: Replace transformer oil, replace oil recloser, crate weed barrier in the substation, modernize automated protection systems, insulate bus and conductor, improve substation grounding, erect fire resistant barrier.

Round Hill: Replace transformer oil, upgrade protection systems, insulate bus and conductor, erect fire resistant barrier.

Glenbrook: Install a new, relocated substation

Tree Attachments (Section 4.3.5.3)
In many cases, the elimination of tree attachments requires the installation one or more new poles. NV Energy does not currently establish specific quantitative removal targets, however, existing tree attachments in this selected region will be evaluated and considered for removal. NV Energy approximates thousands of tree attachments in the Lake Tahoe Basin, anticipating the need for a potential cataloging method for a more accurate account of the total targeted for replacement.

Vegetation Management (Section 4.4)
Vegetation management process begins with an evaluation of a qualified forester to identify dying and distressed trees and other potential vegetation problems. A priority number is assigned to each tree or situation to assure the most urgent conditions are remedied by certified vegetation management professionals, such as arborists. Vegetation management will be targeted to occur on a four-year cycle,
reduced from the current nine-year cycle. NV Energy expects significant resources and attention will be paid to Tier 3 vegetation management.

**Situational Awareness (Section 4.6)**
NV Energy intends to install additional high-definition cameras to enhance the existing network and improve situational awareness. The camera images are available to the public and camera controls, such as ‘pan’ and ‘zoom’ are enabled for utility operators and emergency personnel. Initially, there will be approximately eight cameras placed in the northern Nevada region to evaluate their efficacy. NV Energy will also supplement weather awareness by adding approximately 26 weather stations in the northern Nevada region (including South Tahoe) to supplement the National Weather Service systems.

**Automated Reclosers (Section 4.3.4)**
It is proposed that two circuits, located in the Tier 3 high risk wildfire area of South Lake, have two pole-mounted modern automatic reclosers installed. Additional locations will continue to be evaluated for recloser installations.

**Public Safety Outage Management PSOM (Section 5)**
NV Energy has an extensive preparedness plan that continues to be refined. PSOM plans include customer outreach, improving customer call center capability, and reinforcing Customer Resource Centers. Additional awareness and communications programs are underway. NV Energy is collaborating with telecommunication providers, emergency responders, and local government agencies to assure that, as a last resort, all actions are taken to minimize impacts of proactive de-energization on the public.

**Northern Nevada Customer Resource Center 1**
Kahle Community Center
Rubicon Room
236 Kingsbury Grade
Stateline, NV 89449

**Northern Nevada Customer Resource Center 2**
Douglas County Community Center
1329 Waterloo Ln
Gardnerville, NV 89410

From 2020-2023, NV Energy estimates to invest approximately $72 million in the above targeted areas of risk mitigation and improvement.

**North Lake Tahoe / Incline Village**
North Lake Tahoe and Incline Village maintain a similar risk profile to South Lake Tahoe. Incline and surrounding areas are included in the Lake Tahoe Tier 3 fire zone. Seismic risk is elevated, as is threat to shoreline communities from seiche events. The entirety of lower Incline Village sits within 30 meters in elevation from Lake Tahoe. Heavy snow and other winter weather events occur regularly. Heavy flooding and flash flooding events are less frequently reported in the North Lake Tahoe area, perhaps biased by a smaller permanent population. High winds that may damage infrastructure (58+ miles per hour) are rarely reported. As with South Lake Tahoe, the confluence of steep slopes, precipitation, seismic activity, and fire risk results in a high or very high landslide susceptibility designation.

Specific investment plans are captured below.

**Grey Wire Replacement Program (Section 4.3.1)**
The grey wire program replaces specific obsolete service wire and secondaries that have deteriorated to the point where the wire is a risk of becoming an ignition source for a wildfire. The grey wire used a type of
rubber insulation material to cover the wire which over-time has aged to the point where it is no longer insulating the wire. Grey wire replacement is a generally accepted investment to reduce ignition sources that can cause a wildfire. NV Energy intends to replace grey wire over a two-year period and targeted completion is by end of 2021.

**Pole Wrapping (Section 4.3.2)**
Fire mesh is designed to protect wood structures from burning or scorching, which significantly weakens the poles. The fire mesh forms a barrier by expanding at temperatures greater than 300°F that will shield the wooden pole structure from radiant heat and fire. The coating on the mesh expands to prevent ignition and will not contribute to the burning of the pole. The schedule is based on Plan approval, lead time for labor and material for execution. NV Energy intends to install Fire Mesh in all Tier 3 areas with efforts starting in 2020.

**Fuses: Non-Expulsion Fuse Standardization (Section 4.3.3)**
Conventional fuses, when operated, expel hot particles and gases, which can be an ignition source to start a wildfire. In contrast, current limiting fuses, that traditionally were used for protecting “sensitive equipment” expel no materials, limits the available fault current, and in many cases can reduce the duration of faults. NV Energy has approximately 3,200 fuses in the Tier 3 area. Investments in the Tier 3 areas will begin in 2020 that continues through 2023.

**Covered Conductor / Selective Undergrounding (4.3.5)**
Predicated on a successful pilot project, the covered conductor replacement program will target the extreme-risk Tier 3 areas. Several factors drive the ability to begin reconductoring. These factors include: (1) Receipt of the construction permit by regulatory authorizes, (2) availability of materials, (3) resources to perform the work, (4) line clearance (maintaining reliability) and (5) planning and permitting approvals. Undergrounding and planned reconductoring with covered conductors in the Incline Tier 3 area:

**Incline Circuit 4100** - approximate total circuit length is 26 miles. Portions of the circuit will be undergrounded. All circuits listed in this section are Tier 3 circuits and undergrounding will support the Plan by reducing risk of ignition events.

- Design and permitting years 2020 and 2021
- Construction of one mile in year 2022
- Construction of one mile in year 2023

Based on initial design, NV Energy plans to underground portions of Lakeshore Boulevard and locations near the east shore bike path. NV Energy is also currently working with the Tahoe Transportation District to assess feasibility of undergrounding along the next phase of the bike path development.

**Incline Circuit 4200** - approximate total circuit length is 27 miles. Portions of the circuits may have selected undergrounding.

- Design and permitting years 2020 and 2021
- Construction of one mile in year 2022
- Construction of one mile in year 2023

**Incline Circuit 4300** - approximate total circuit length is five miles. Portions of the circuits may have selected undergrounding.

**Transmission Line Rebuilds & Ruggedization [123 Line]**
The 123-transmission line is approximately 15.3 miles long and runs between Brunswick Substation in Carson City and Incline Substation in Incline Village. The line was constructed in 1974 and consists of wood pole H-frames and wood 3-pole guyed dead-end structures. Approximately 7.3 miles of the line runs along the small mountain range on the north side of Carson City in relatively sparse sagebrush and cheatgrass vegetation. The remaining eight miles of line climbs over the Carson Range and into the Lake Tahoe basin in moderate to heavily forested areas, peaking at just under 8,000’ of elevation. Due to the high elevation,
steep terrain, and proximity to Lake Tahoe, this section of line experiences heavy loading during winter storms and high wind events. The 123 line provides a radial transmission feed to the north-east area of Lake Tahoe and serves approximately 9,000 customers including the Incline Village area. The peak load at Incline Substation is 14 MW. The Substation Reliability Taskforce ranks Incline Substation as the third highest risk substation in all of NV Energy’s system and it has a very poor reliability performance. This level of risk is due to the radial transmission line, single transformer, historical outages and limited backup capability to the distribution feeders. This situation poses a significant fire risk and contributes to the number of outages experienced by the Companies’ customers. Additional details are also included in Section 4.3.5.

Substation Investments (Section 4.3.7)
Substation investments for North Lake Tahoe include:
Incline Substation: Replace oil breaker, install weed barrier and crushed rock, modernize protection systems, install insulated bus and conductors, improve substation grounding and erect fire resistant perimeter.
North Truckee Substation: Replace transformer oil, upgrade protection systems, insulate bus and conductors, erect fire resistant barrier.
Truckee Substation: Upgrade protection and control system, replace oil-filled breaker.

Vegetation Management (Section 4.4)
Vegetation management process begins with an evaluation of a qualified forester to identify dying and distressed trees and other potential vegetation problems. A priority number is assigned to each tree or situation to assure the most urgent conditions are remedied by certified vegetation management professionals, such as arborists. Vegetation management will be targeted to occur on a four-year cycle, reduced from the current nine-year cycle. NV Energy expects significant resources and attention will be paid to Tier 3 vegetation management.

Situational Awareness (Section 4.6)
NV Energy intends to install additional high-definition cameras to enhance the existing network and improve situational awareness. The camera images are available to the public and camera controls, such as ‘pan’ and ‘zoom’ are enabled for utility operators and emergency personnel. Initially, there will be approximately eight cameras placed in the northern Nevada region to evaluate their efficacy. NV Energy will also supplement weather awareness by adding approximately 26 weather stations in the northern Nevada region (including North Tahoe) to supplement the National Weather Service systems.

Tree Attachments (Section 4.3.5.3)
In many cases, the elimination of tree attachments requires the installation one or more new poles. NV Energy does not currently establish specific quantitative removal targets, however, existing tree attachments in this selected region will be evaluated and considered for removal. NV Energy approximates thousands of tree attachments in the Lake Tahoe Basin, anticipating the need for a potential cataloging method for a more accurate account of the total targeted for replacement.

Public Safety Outage Management PSOM (Section 5)
NV Energy has an extensive preparedness plan that continues to be refined. PSOM plans include customer outreach, improving customer call center capability, and reinforcing Customer Resource Centers. Additional awareness and communications programs are underway. NV Energy is collaborating with telecommunication providers, emergency responders, and local government agencies to assure that, as a last resort, all actions are taken to minimize impacts of proactive de-energization on the public.

Northern Nevada Customer Resource Center 3
Diamond Peak Ski Resort
1210 Ski Way, Incline Village, NV 89451
Main Lodge Cafeteria
From 2020-2023, NV Energy estimates to investment approximately $50 million in the above targeted areas of risk mitigation and improvement.
DISCLAIMER

This Plan is developed in accordance with SB 329 and NRS § 704.7983. In Docket No. 19-06009, the Commission adopted consensus regulations that the electric utilities are required to follow in the development of this Plan. Navigant’s approach in supporting the development of this Plan included, but was not limited to, the following:

- Data Review: Navigant reviewed available data for inclusion in this Plan.
- Team Discussions: Initial kick-off and periodic team meetings were conducted to determine specific actions and strategies to be included.
- Plan Development: Navigant developed a Plan based on the direction and information provided to Navigant by the Companies.
- Review of the Plan: The Companies reviewed and approved this Plan.
KEVIN C. GERAGHTY
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
2020 Natural Disaster Protection Plan

Prepared Direct Testimony of

Kevin C. Geraghty

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

A. My name is Kevin Geraghty. My current position is Senior Vice President of
Operations 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, “NV Energy”). My business address is 6226 West Sahara Avenue,
Las Vegas, Nevada. I am filing testimony on behalf of NV Energy.

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

A. I hold a Bachelor of Science Degree in Electrical Engineering (December 1987)
from the University of Pittsburgh in Pittsburgh, Pennsylvania. Before joining NV
Energy, I was employed by Allegheny Energy in various director-level positions,
where I managed all aspects of the operations of six coal plants, seven small hydro
plants, and several combustion turbine sites. While at Allegheny I managed the
siting and development of a 1,080 MW combined cycle facility in La Paz County,
Arizona, and several of Allegheny’s other energy projects and/or contracts in
Nevada, Arizona and California. I am currently responsible for managing all of NV
Energy’s operating business units – Generation, Gas Delivery, Transmission,
Electric Delivery and Resource Operations. More details regarding my professional
background and experience are set forth in Exhibit Geraghty-Direct-1.
3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT OF OPERATIONS.
   A. As Senior Vice President of Operations, my responsibilities include operations, maintenance, construction, new business, strategic planning, project development, power purchase agreements, capital management and financial functions.

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. My most recent appearance was in Sierra and Nevada Power’s 2018 joint integrated resource plan, Docket No. 18-06003.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
   A. The purpose of my testimony is to describe NV Energy’s Natural Disaster Protection Plan (“Plan”) and how it meets the requirements of SB 329 and associated regulations.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?
   A. Yes. I am sponsoring the following Exhibits:

   Exhibit Geraghty-Direct-1 Statement of Qualifications
   Exhibit D Natural Disaster Protection Plan

7. Q. PLEASE DESCRIBE NV ENERGY’S SERVICE TERRITORY AND CUSTOMER BASE.
   A. NV Energy has served the citizens of southern Nevada since 1906 and northern Nevada for more than 150 years. NV Energy’s service area covers nearly 46,000 square miles and about 90 percent of the state’s population. NV Energy is
comprised of Nevada Power in Southern Nevada and Sierra in Northern Nevada. NV Energy serves more than 1.4 million customers and a state tourist population of nearly 50 million annually. NV Energy’s infrastructure includes over 1.29 million miles of electric infrastructure and 168,000 miles of gas pipeline. NV Energy employs more than 2,470 employees statewide.

8. **Q. WHAT ARE THE PRIMARY GOALS OF NV ENERGY RELATIVE TO SB 329?**

A. SB 329 (protection from natural disasters), passed by the 2019 Nevada Legislature, codified as NRS § 704.7983, aims to protect the safety of the public from threats related to the electric grid during natural disasters. It requires a utility to conduct a focused assessment of the electric grid and identify areas that are subject to a heightened threat of a fire or other natural disaster. It also requires a utility to propose an approach for the mitigation of potential fires or other threats. NV Energy’s Plan encompasses the projects and programs that will be and/or continue to be implemented to minimize the risk of electric infrastructure causing a fire or other harm, improve grid resiliency during natural disaster impact and provide adequate natural disaster response.

9. **Q. BEFORE SB 329 WHAT PLANS DID NV ENERGY HAVE IN PLACE TO PROTECT PUBLIC SAFETY?**

A. NV Energy has been and continues to be vigilant in considering the safety of its customers, visitors, and businesses. The Companies have been applying common utility practices regarding inspections, patrols, repairs and lifespan replacement. Its designs have changed over time to improve resiliency, but historical designs and even modern designs are not able to provide the protection and resilience in light
of significantly changing climate conditions impacting utilities in general and in particular wildfire risk for western utilities. The Plan explains NV Energy’s future focus in light of the requirements of SB 329; however, NV Energy had already taken a forward looking approach and was actively engaged in wildfire protection and mitigation programs in Lake Tahoe and other high fire risk areas that were consistent with the requirements of the Plan.

10. Q. PLEASE DESCRIBE THE NECESsITY AND STRUCTURE OF NV ENERGY’S NATURAL DISASTER PROTECTION PLAN.

A. NV Energy is required to submit the Plan per SB 329 and Section 7.2 of the associated regulations, which were codified by the Legislative Counsel Bureau ("LCB") in LCB File No. R085-19 on February 26, 2020. Historically, NV Energy’s infrastructure has not started catastrophic wildfire events. However, overhead electric infrastructure in general as well as NV Energy’s overhead infrastructure has had both failure and weather-related ignitions. The primary changes that have resulted in the natural disaster risk evolution are:

Aging electric infrastructure: NV Energy’s overhead and underground electric transmission and distribution and assets (e.g., wooden poles, overhead conductors, substations, etc.) have aged and need upgrades or replacements for safety purposes. This Plan includes infrastructure assessment, replacement, and improvement programs. These programs will help mitigate natural disaster risks as required by SB 329 by improving electric grid resiliency.

Fuel risk and human land use practices: Human land use practices and fuel risk have increased the frequency of large wildfires several-fold. In drier forested
ecosystems, fire exclusion over many years has resulted in unnatural fuel buildups that are now leading to fires of uncharacteristic size and severity. Average fire season lengths have increased by at least a couple of months owing to earlier springs and later winters in mountainous regions. Finally, human populations continue to spread into flammable ecosystems, increasing the danger to personal and real property as well as people.

**Climate:** Within the 21st century, United States ("U.S.") is witnessing a large number of 100, 500 and 1,000-year weather events. The National Weather Service reported that eight 500-year flood events occurred in the U.S. between August 2015 and August 2016 alone. Hotter and drier summers have led to historic wildfires. During October 2017, there were 21 major wildfires in northern California. These massive impacts have motivated government and regulatory entities to require grid hardening initiatives. For example, the New Jersey Board of Public Utilities approved 103 measures for the state’s electric utilities to undertake to improve preparedness and responses to severe storm leading to $1.2 billion in investments to strengthen electric and gas systems against severe weather events. Similarly, one Florida utility invested $3 billion to harden its facilities. Slowly but surely, utilities, regulators, and customers are beginning to realize that long standing maintenance and repair processes and schedules that simply restore the grid to its previous state are inadequate to ensure greater resilience in the face of these worsening conditions.

Natural disaster risk to the electric infrastructure has increased significantly and must be mitigated through combination of operations, maintenance, system hardening, public safety preparation, and prevention programs that exceed the standards previously maintained by NV Energy. Keeping this mind, the Nevada
legislature enacted SB 329 to allow for execution of these programs and the Plan is an essential component of SB 329.

NV Energy’s Plan includes a comprehensive assessment of natural disasters (Section 3) and an evaluation of potential mitigation measures. The Plan considers public safety in four steps: prepare in advance; mitigate potential harm using a risk-based assessment; respond in a coordinated and structured manner; and recover using safe inspection and restoration practices. The Plan protects the public safety most effectively when all four steps related to natural disaster actions are considered and implemented. Ongoing public outreach from NV Energy and its collaboration partners, that include first responders, government agencies, and other entities identified by SB 329 and the related regulations, are coordinated for effectiveness. The Plan also leverages existing plans and programs to improve their effectiveness and aligns actions and options that reach across vulnerable communities to ensure coordinated preparation for, and responses to, natural disasters.

NV Energy’s electric infrastructure faces two types of natural disaster related risks: controllable and uncontrollable (i.e., within and outside NV Energy’s control). The controllable natural disaster risks are presented in NV Energy’s electric infrastructure right of way (“ROW”) and uncontrollable risks are presented by debris, vegetation, birds, animals, other foreign materials, and extreme weather outside the ROW that may impact the electric infrastructure to cause failures and ignitions. Therefore, it is necessary to have a risk mitigation strategy for both controllable and uncontrollable risks. In order to mitigate controllable natural
disaster risks and infrastructure failures, NV Energy has examined its operations and maintenance practices and are proposing changes to reduce the risk of ignition and other natural disaster impacts caused by electric infrastructure failure and vegetation management issues (Sections 4.1, 4.2 and 4.4). For mitigating uncontrollable natural disaster risks, NV Energy has examined their designs to be applied to aging systems assessments, replacements and improvements (Sections 4.3). It’s also important to explore emerging technologies (Section 4.5) and understand evolving climate and electric grid behavior (Section 4.6) to manage the uncontrollable portion of the risk. Finally, for mitigating the greatest possible public impacts from uncontrollable ignition risks, NV Energy has examined their operating and public safety practices and propose changes, including Public Safety Outage Management (“PSOM”) as a last resort option to avoid potential wildfire ignition when unmitigated risk is too high (Section 5).

11. Q. PER SB 329, ARE THERE SPECIFIC FOCUS AREAS IN NV ENERGY’S PLAN?

A. Per Section NRS § 704.7983 and Section 7.2 of the final regulations,¹ NV Energy’s Plan is divided into seven areas:

- RISK-BASED APPROACH
- OPERATIONAL PRACTICES
- INSPECTIONS AND CORRECTIONS
- SYSTEM HARDENING
- VEGETATION MANAGEMENT

¹ LCB File No. R085-19.
• SITUATIONAL AWARENESS
• PSOM OR PROACTIVE DE-ENERGIZATION

SB 329 and the Commission’s regulations established this structure for the Plan, which is also a best practice based on NV Energy’s analysis and review of other utilities’ wildfire mitigation plans. Some important aspects of the Plan are collaborative emergency operations management with first responders, fuel management with input from the State of Nevada and fire districts and creation of resiliency corridors or exclusion zones with regulatory agencies. NV Energy will continue to leverage the expertise of community partners, such as firefighters and emergency responders, and identified areas of common actions, creating synergies with community needs through the sharing of action and response plans. As noted above, areas for immediate collaboration included fuels or vegetation management, situational awareness, communications – including telecommunications – and aligning to a uniform approach to emergency response across agencies and service providers.

12. Q. PLEASE ELABORATE IF THE PLAN IS FINAL OR THERE WILL BE POTENTIAL FOR ANY FUTURE REVISIONS.

A. The submitted Plan represents NV Energy’s inaugural approach to meet the requirements of SB 329. NV Energy will continue community outreach based on the success of our collaboration efforts with the community to hone the plan. NV Energy’s intention is to update the Plan when necessary and provide triennial filings of the Plan including new projects and programs to mitigate natural disaster risk as well as progress updates on specified projects and programs.
13. Q. WILL NV ENERGY’S PLAN MITIGATE THE NATURAL DISASTER RISK FOR ALL NEVADA COMMUNITIES?

A. No. Per SB329, the focus of the Plan is electric assets and grid that are owned and operated by NV Energy. The goals are to mitigate ignition risk from NV Energy’s electric assets while minimizing PSOM occurrences, improve grid resiliency during natural disasters and provide adequate response related to electric assets during natural disasters. During the Plan’s implementation, NV Energy will continue to work with the community to align with other agency plans as needed.

14. Q. DESCRIBE THE PUBLIC OUTREACH PROCESS THAT NV ENERGY FOLLOWED FOR THE PLAN PREPARATION.

A. NV Energy hosted a series of expert working groups where input was collected from SB 329 ‘identified entities’ including, but not limited to, the following:
   
   • Local and Regional Fire Districts
   • Nevada Department of Public Safety, Divisions of Emergency Management, Counties and other authorities (Washoe, Douglas, Tahoe, Mt. Charleston areas, and Tribal Governments)
   • Nevada Division of Forestry
   • Telecommunication Companies (AT&T, Century Link, Sprint/Nextel, T-Mobile, and Verizon Wireless)
   • Nevada Division of Lands and State Parks
   • Nevada Department of Conservation and Natural Resources

NV Energy invited over 150 organizations and individuals to inform the initial draft of the Plan, to consider gaps and explore synergies among the entities. Several presentations were made at specific agency meetings (e.g., Southern Nevada Operations Meeting, Northern Nevada Fire Chiefs Meeting, Nevada Emergency
Managers Meetings, etc.) and three formalized working group meetings, with on-site and remote participation, were conducted. Topics included all seven areas that are included in the Plan along with protocols for de-energizing sections of the power grid as a last resort with emergency managers, fire protection agencies, and telecommunications companies.

Once the initial Plan was drafted and included input from subject matter experts, NV Energy identified locations where a natural disaster could pose significant threat to life or property (e.g., Lake Tahoe, Mt. Charleston, and various areas of Las Vegas,). NV Energy’s team, alongside first responders and other community-facing organizations, engaged with the customers in these regions to explain the Plan, gain public input, and answer key questions. Six public outreach and community sessions were held, focused on NV Energy’s territory most susceptible to natural disasters. These sessions were advertised using social media, news broadcasts, print postcards and targeted messaging to specific customers and organizations. These sessions also included representation from local experts to demonstrate the understanding and support for NV Energy’s Plan and approach. A Facebook live session was also conducted for those who could not attend in person. Feedback received during the specific meetings, working groups and community sessions is included in Section 7 of the Plan. NV Energy’s Plan seeks to minimize adverse impacts on public safety and support the needs of its community partners during a natural disaster event.
15. **Q.** PLEASE DESCRIBE BENEFITS TO THE PLAN DEVELOPMENT THAT RESULTED FROM THIS OUTREACH.

   **A.** The community outreach described above assisted NV Energy in building customer awareness and having continued communications with community partners. Both working groups and community sessions also supported collaboration with telecommunication providers, who can provide customer resources such as assuring networks are powered in customer resource centers during a natural disaster or during a public safety outage management event. NV Energy sought input and shared the relevant notification form and wildfire risk maps with the telecommunication providers. NV Energy will continue to improve its communications networks and methods, including communication system upgrades. NV Energy’s partner outreach also resulted in plans for future communications and collaboration sessions to enhance customer support during natural disasters—for example, temporarily enhancing data and calling services at customer resource centers. NV Energy will continue to refine its communications plan with telecommunication companies in a series of focused upcoming meetings. NV Energy also plans to enhance its corporate emergency response program to harmonize with the incident command structure used by first responders. NV Energy also used planned equipment outage events as a real-world simulation of emergencies to underpin continuous improvement.

16. **Q.** WHAT IS THE IMPORTANCE OF A RISK BASED ASSESSMENT APPROACH?

   **A.** NV Energy identified natural disasters that could impact its electric grid and customers, including the risk of electric infrastructure causing a fire. NV Energy identified a series of actions, projects and programs and used a risk-based
assessment that affords a prioritized approach and ability to leverage resources so they are directed toward the most important issues. As a last resort, NV Energy will proactively de-energize certain electric circuits in high wildfire risk areas to minimize the likelihood of electric infrastructure causing a fire.

As identified in the following figure, NV Energy’s primary focus is on public safety. The rings represent additional layers, prioritized as resiliency, minimizing short term impacts, and finally minimizing long term impacts that drive the economic health of the state.
17. Q. PLEASE ELABORATE ON OPTIONS FOR NATURAL DISASTER PROTECTION THAT WERE EXPLORED.

A. Options included Prepare, Mitigate, Respond, and Recover. Not every natural disaster identified had an apparent mitigation plan. For example, earthquake locations are not precisely known. Although some preparation would be possible, it is also likely that respond and recover would also be necessary actions.

![Diagram of Mitigate, Prepare, Respond, Recover]

18. Q. PLEASE DESCRIBE PROGRAMS AND PROJECTS FOR VEGETATION MANAGEMENT?

A. NV Energy has an extensive vegetation management plan that considers the impacts of vegetation according to the different characteristics of the specific type of vegetation. Described in detail in Section 4.4 of the Plan, NV Energy has widened and deepened its projects and programs to include creative collaboration and increased rigor.

In the Plan, NV Energy is filing for approval of specific vegetation management cycles and actions, focused in specific wildfire risk tiers and additional areas required per Appendix A of the International Wildland Urban Interface Code
IWUIC Appendix A compliance is a new compliance requirement per SB 329, Section 1.3.3. The cost for maintenance programs in the Plan reflects a higher cost than originally contemplated by the Companies and reflects the adoption, by our state, laws to further reduce the risks associated with devastating wildfires. Since NV Energy’s comments in Docket No. 19-06009 (June 26, 2019), where estimated program expenses were thought to be on the order of $25m annually, the state of Nevada has passed laws requiring the Companies to come into compliance with IWUIC Appendix A. The costs associated with compliance with IWUIC Appendix A in this Plan reflect aggressive compliance with this new state law. Actual costs could be lower based on adoption plans of various agencies and the deployment of technology that addresses risk more acutely.

NV Energy will continue work in all established wildfire risk tiers to achieve a four year trimming cycle that is reduced from the current nine year cycle. NV Energy will also employ pole grubbing, which includes removing plants and brush from around a pole’s base and creating a clear space surrounding the utility pole, as an additional vegetation control measure and work towards maintaining adequate clearance from the transmission and distribution lines.

As part of NV Energy’s outreach to experts, NV Energy identified partnership opportunities with the United States Forest Service (“USFS”), Bureau of Land Management (“BLM”), and Nevada Division of Forestry, among others, to share knowledge and resources to manage Nevada’s diverse vegetation. Requirements and impacts of fires in rangelands and grasslands differ from those in dense forests with tall trees. Fuel mitigation is an area of attention that will continuously improve inside NV Energy’s service territory through these partnerships, beginning with
identified risk zones. NV Energy will continue to cooperate with local, state, and federal agencies to align vegetation management and develop a state-wide system of fuel breaks using existing grid and roadway infrastructure. These partnerships will also be used to assess health of range lands, forests, and identify fuel tonnage per acre through mapping programs encompassing all service territory.

19. Q. PLEASE DESCRIBE PROGRAMS AND PROJECTS FOR OPERATIONAL PRACTICES.

A. Specific Northern Nevada circuits (extreme and high risk areas) are set for fire season operational mode. Automatic reclosers are disabled during high-threat seasons or conditions and any trip, including on the transmission grid, requires patrol before reclosing. In southern Nevada, Mount Charleston is also identified as an extreme-threat area so the same approach is used. NV Energy will continue with seasonal settings in 2020 and beyond, as outlined in Section 4.1 of the Plan. Where possible, NV Energy plans to increase cooperation with Liberty Utilities in the Lake Tahoe area.

20. Q. PLEASE DESCRIBE PROGRAMS AND PROJECTS FOR INSPECTIONS AND CORRECTIONS.

A. NV Energy will continue to build upon the wildfire safety inspections completed in 2019. NV Energy will follow-up on priority repairs, identified as part of the inspections, to achieve compliance with inspection requirements proposed in the Plan Section 4.2. NV Energy also proposed specific inspection cycles in the Plan for the Commission’s approval. NV Energy’s goal will be to conduct detailed inspections of overhead electric assets on a four year cycle in defined wildfire risk
areas. Advanced technologies being considered will include drone fly-overs and advanced in-line sensing technologies.

21. Q. PLEASE DESCRIBE PROGRAMS AND PROJECTS FOR SYSTEM HARDENING.

A. Plans, programs, and projects identified for hardening the electric grid are detailed in Section 4.3 of the Plan. A hardened and resilient grid is the first line of defense to protect against impacts from a natural disaster. The risk assessment is intended to direct efforts to address the highest risks and obtain the greatest benefits. NV Energy will continually assess and prioritize projects based on conditions and situations, aging infrastructure with older design criteria, or equipment that is no longer suited for natural disasters such as expulsion fuses that could cause sparks.

System hardening programs will also include introducing more isolation and sectionalizing points so vulnerable parts of the system can be efficiently isolated without impacting large regions. NV Energy will be submitting plans and obtaining approval to modify infrastructure in the defined risk areas. These include a combination of ruggedized overhead equipment, covered wire aerial systems, and increased undergrounding. NV Energy will continue to evaluate technologies to ruggedize and de-risk regions from NV Energy’s existing infrastructure through programs that include, but not limited to, expulsion fuse replacement, substation upgrades, establishing fire-proof barriers, and using sturdier, non-flammable poles and towers.
22. Q. PLEASE DESCRIBE PROGRAMS AND PROJECTS FOR SITUATIONAL AWARENESS.

A. Situational awareness is crucial to disaster preparedness, protection and mitigation. As outlined in Section 4.6, NV Energy is seeking approval for additional meteorological stations to supplement and enhance the National Weather Service capabilities in the service territory. NV Energy will also continue and expand its partnership with UNR through new investments in wildfire camera systems that is open to the community and affords viewing for community safety partners. NV Energy’s Emergency Management responsibilities have been harmonized with the Plan and moved to the Operations group. NV Energy also plans to integrate fire specialist and meteorologist expert’s input into the real-time environment.

23. Q. PLEASE DESCRIBE THE PROCESS FOR PROACTIVE DE-ENERGIZATION TO PROTECT THE PUBLIC.

A. As a last resort, NV Energy may find it necessary to proactively de-energize sections of the power grid when the safety of the public is in question related to energized equipment and nearby fuel conditions. This process is described in detail in Section 5. Any decision to proactively de-energize the grid will be weighed against the impacts on energy-reliant community partners and our customers. This topic was discussed at length during the Expert Working Group and community sessions. The initial step in deciding whether to communicate a Public Safety Outage Management event is based on the confluence of a number of factors that include evaluation of dry vegetation, high winds and fire weather, indicating conditions where a simple spark could cause a massive wildfire. PSOM would be
used as a last resort and communicated as far in advance as possible. As indicated in the following figure, there are three phases to a PSOM event:

**Communicate and Prepare**
- Situational Awareness
- Emergency Preparedness

**Act**
- Incident Command Structure
- Operations
- Customer Support

** Recover**
- Inspections Prior to Re-energization

Prepare – using situational awareness tools and partnerships, assess conduciveness of a natural disaster to cause the power grid to negatively impact the public. These conditions are sometimes known up to a week in advance but more likely a day or two ahead of time. Continue communications with telecommunications companies, emergency and first responders, and other community partners. Data and information will be shared and compared as far ahead as possible.

Act – as a last resort and after communicating with partners and the public, de-energize the smallest section of the grid possible to avert potential impacts from a disaster. At this time, an incident command structure will be enacted, Operations will continue to monitor, and customer support services, such as Customer Resource Centers and care for Green Cross customers will launch.

Recover – because the high voltages on the electric grid are dangerous, the de-energized assets will be inspected by qualified personnel prior to returning these assets to service. Even if the natural disaster has passed, care must be taken during this step to avoid any further negative public impacts.
NV Energy has ongoing efforts to improve a coordinated response. NV Energy will continue to implement programs and projects that minimize the impacts of proactive power shutoffs, including qualitative assessments, community engagement, additional grid sectionalizing and discrete isolation capabilities that has been shown to be a best practice.

24. **Q. DESCRIBE NV ENERGY’S ABILITY TO IMPLEMENT THE PLAN.**

A. The programs and projects contained in the Plan are the result of extensive outreach and engagement. NV Energy has conducted this extensive outreach to assure its programs, projects, and approach are aligned with the needs and desires of the communities it serves. These programs and projects also represent the immediate actions the Companies will take. The investment projects have very little engineering other than conceptual. There are risks associated with having resources to implement these projects due to the demand in the western United States. The projects also have permit and planning risks as these projects impact communities and public participation in permitting is essential and is not a schedule the Companies control. The Companies plan to start and pursue every program and investment project and as projects lag or advance, the Companies will re-allocate resources and funds to create the greatest reduction in risk. Emerging technology may impact costs favorably in inspections and vegetation management – the Companies are exploring all opportunities to increase real-time situational awareness versus traditional and increased inspection cycles.

NV Energy will continue to work with the Commission and all stakeholders to reduce the risk associated with natural disasters and also to mitigate the costs associated with compliance with SB329 to the greatest extent possible.
Q. DID NV ENERGY INVEST IN NATURAL DISASTER PROTECTION EXPENSES IN 2019 AND 2020? IF SO, PLEASE DESCRIBE WHY THESE PROJECTS AND PROGRAMS WERE INITIATED PRIOR TO THE NATURAL DISASTER PROTECTION PLAN (“PLAN”) EFFECTIVE PERIOD. PLEASE ALSO SUMMARIZE ANY PROJECTS AND PROGRAMS THAT WILL BE INITIATED ONLY UPON THE COMMISSION’S APPROVAL.

A. Yes. In light of the frequency with which catastrophic wildfires are occurring in California, coupled with the extraordinarily destructive impacts of these wildfires, they have been identified as one of the greatest weather-related risks to NV Energy operations. Because of the known wildfire risk and the potential impacts on operations, and its customers, NV Energy executed several projects in 2019 and will continue to execute on them in 2020 to adapt to the changing climate conditions across its service territory. These projects included identification of locations at greatest risk for wildfires within the service territory, performing inspections, corrections and vegetation management in high risk areas, conducting weather analytics and executing on the public safety outage management protocol, and preparation of the Plan. These projects assisted NV Energy and will continue to minimize the risk of catastrophic wildfire posed by overhead electric lines and equipment during extreme fire-weather events. NV Energy’s commitment to fire safety, prevention, mitigation, control, and recovery is a priority. Therefore, NV Energy continues to take a leadership role in addressing fire threats in the communities it serves and shares its personnel, resources, information, communications facilities, and/or fire-defense assets to enhance the capabilities of the local communities to defend against any catastrophic wildfire events. The only project costs that are included in the regulatory asset are from February 1, 2019,
onwards based on the timing of the introduction of draft SB329. Moreover, the
above projects align with the requirements specified in Section 1.3.2 of SB 329 and
Section 7.2 of the final regulations.

The Companies are also proposing several system hardening (e.g., line and
substation rebuilds, undergrounding, small copper replacement, pole replacements,
etc.) programs in the Plan; however, any significant investment on these capital
investment intensive programs will only be incurred at the direction of the
Commission.

26. WHAT IS NV ENERGY’S PROJECTED COSTS FROM 2020-20203 FOR
THE PLAN?

A. Table 1 below aggregates the Plan’s cost forecasts for program expense
(Operations, Maintenance, Administrative and General (“OMAG”)) and
investment expense (Capital) from 2020 through 2023. This estimated financial
impact of the Plan may be modified during the project implementation phases and
those details will be included in the subsequent Plan updates and triennial filings.

As noted in the Plan, the majority of the spend is in maintenance programs -
vegetation management, inspections and repairs, followed by investment in system
hardening (e.g., line and substation rebuilds, undergrounding, small copper
replacement, pole replacements, etc.).
**Table 1: Natural Disaster Protection Plan Cost Summary: 2020 – 2023**

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital ($)</td>
<td>15,489,75</td>
<td>52,044,5</td>
<td>63,891,19</td>
<td>67,373,78</td>
<td>198,799,2</td>
</tr>
<tr>
<td>OMAG ($)</td>
<td>29,857,95</td>
<td>37,712,6</td>
<td>37,740,58</td>
<td>42,214,35</td>
<td>147,525,5</td>
</tr>
<tr>
<td>Total ($)</td>
<td>45,347,70</td>
<td>89,757,2</td>
<td>101,631,7</td>
<td>109,588,1</td>
<td>346,324,8</td>
</tr>
</tbody>
</table>

It is important to note, that actual maintenance programs and investments might decrease upon completion of the initial inspection and correction cycle, achievement of the desired vegetation management trimming cycles, and completion of the proposed system hardening projects over the first few years. The estimates for expense and capital investment included within the Plan and in Table 1 are based on reasonable experience performing related work, historical costs and the assumption that external resources (e.g. lines personnel and vegetation management personnel) are available. Further, it assumes optimistic views on permitting and stakeholder approval processes based on a shared sense of urgency to complete capital investment that reduces uncontrollable risk and materially enhances public safety. There is inherent uncertainty related to permitting, labor and materials procurement, community support and feedback, and other project or program execution steps. Therefore, these project execution risks are factored in to develop the Plan portfolio discounted cash flows. NV Energy’s goal will be to execute on all projects and programs included in this Plan with their costs summarized in this section; however, it is prudent to establish some realistic expectations based on the practical constraints outside NV Energy’s control. Table
Table 2: Natural Disaster Protection Plan Portfolio Discounted Cost Summary: 2020 – 2023

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital</td>
<td>4,646,926</td>
<td>26,022,2</td>
<td>38,334,7</td>
<td>50,530,3</td>
<td>119,534,2</td>
</tr>
<tr>
<td>($)</td>
<td>62</td>
<td>17</td>
<td>41</td>
<td>46</td>
<td></td>
</tr>
<tr>
<td>OMAG</td>
<td>23,886,36</td>
<td>30,170,1</td>
<td>30,192,4</td>
<td>33,771,4</td>
<td>118,020,4</td>
</tr>
<tr>
<td>($)</td>
<td>6</td>
<td>49</td>
<td>65</td>
<td>86</td>
<td>67</td>
</tr>
<tr>
<td>Total ($)</td>
<td>28,533,29</td>
<td>56,192,4</td>
<td>68,527,1</td>
<td>84,301,8</td>
<td>237,554,7</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>11</td>
<td>83</td>
<td>27</td>
<td>12</td>
</tr>
</tbody>
</table>

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

A. Yes.
KEVIN C. GERAGHTY
SVP, Energy Supply
NV Energy, Inc
6226 West Sahara Avenue
Las Vegas, NV 89146
(702) 402-5662

Mr. Geraghty joined NV Energy, Inc (“NVE”) in June 2008 as Executive, Power Generation and currently serves as the company’s Senior Vice President for Energy Supply. He has 30 years of experience in power generation with extensive knowledge of operations, maintenance, construction and management of coal, gas and hydro facilities. Mr. Geraghty has prepared and/or directed the preparation of various reports and analyses for submission to multiple state jurisdictions, EPA, NERC and FERC. Mr. Geraghty has also sponsored testimony before the Arizona Corporation Commission.

EMPLOYMENT HISTORY

NV Energy, Inc.
6/08 to Present

SVP, Energy Supply
Responsible for managing all of NV Energy’s power generation assets, interests in jointly-owned assets, resource optimization and the gas local distribution company in northern Nevada. Responsibilities include resource optimization, coal procurement, operations, maintenance, construction, strategic planning, capital management and financial functions associated with gas operations, power production and procurement.

Allegheny Energy
12/87 to 6/08

Director Level Assignments:
Smith, Western, Fort Martin and Harrison Regions
5/99 to 12/07

Managed all aspects of six (6) coal plants, seven (7) small hydro plants and multiple peaking combustion turbine sites. Managed the development and siting of a 1,080 MW combined cycle facility in La Paz County, Arizona. Managed the company’s interest in several other energy projects and/or contracts in Nevada, Arizona and California.

Manager Level Assignments:
Operations, Maintenance and Engineering –
Hatfield’s Ferry and Harrison Power Stations
4/93 to 5/99

Managed all departmental-specific functions at two (2) large, coal-fired facilities; each facility had three (3) large (555-665) supercritical units.
Engineering Level Assignments:
Plant (Hatfield’s Ferry) and Construction
12/87 to 4/93
Performed plant engineering assignments in support of production, reliability and performance at the 1,665 MW coal-fired Hatfield’s Ferry Power Station. Performed construction engineering assignments in support of large O&M and CAPEX projects at every facility in the fleet (including coal, gas, hydro and oil facilities).

EDUCATION

University of Pittsburgh, Pittsburgh, PA
Bachelor of Science in Electrical Engineering

ASSOCIATIONS AND MEMBERSHIPS

- Board Member, Las Vegas Natural History Museum
- Board Member, FIRST Nevada
AFFIRMATION

STATE OF NEVADA )
COUNTY OF CLARK ) ss.

I, KEVIN C. GERAGHTY, 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.

KEVIN C. GERAGHTY

Subscribed and sworn to before me this 18th day of February, 2020.

NOTARY PUBLIC

S. MANNISUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023
DRAFT NOTICE
Draft Notice Application for Applications, Petitions and Complaints

The Commission requires a draft notice be included with all applications, petitions and complaints. See Nevada Administrative Code 703.162. Please include one copy of this form with all the above filings.

I. Include a title that describes the relief requested, or proceeding scheduled pursuant to Nevada Administrative Code ("NAC") 703.160 (5)(a).

Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint Natural Disaster Protection Plan.

II. Include the name of the applicant, complainant, petitioner, or the name of the agent for same pursuant to NAC 703.160 (5)(b).

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

III. Include a paragraph with a brief description of the purpose of the filing or proceeding with an introductory statement in plain English understandable to a person of average knowledge and intelligence, that summarizes the relief requested or proceeding scheduled, AND its impact upon consumers, pursuant to NAC 704.160 (5)(c).

Nevada Power Company and Sierra Pacific Power Company are seeking approval of their first joint Natural Disaster Protection Plan. The Application requests that the Public Utilities Commission of Nevada approve the Plan, which identifies areas at high-risk for natural disasters, implements protocols to inspect electrical infrastructure, performs vegetation management, proposes preventative steps to mitigate disaster risks, provides adequate natural disaster response, and establishes proactive de-energization protocols for the utilities’ electric assets in the event of fire weather conditions or related natural disasters.

IV. A declaration by the applicant, petitioner, or complainant whether a consumer session is required by Nevada Revised Statute ("NRS") 704.069 (1). NAC 703.162 (2)\(^1\)

\(^1\) NRS 704.069 Commission required to conduct consumer session for certain rate cases; Commission required to conduct general consumer session annually in certain counties.

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.
A consumer session is not required pursuant to NRS 704.069.

V. 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.

2. In addition to the case-specific consumer sessions required by subsection 1, the Commission shall, during each calendar year, conduct at least one general consumer session in the county with the largest population in this state and at least one general consumer session in the county with the second largest population in this state. At each general consumer session, the Commission shall solicit comments from the public on issues concerning public utilities. Not later than 60 days after each general consumer session, the Commission shall submit the record from the general consumer session to the Legislative Commission.
CERTIFICATE OF SERVICE
CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of NV ENERGY in Docket No. 20-020 upon the persons listed below by electronic mail:

David Noble  
Staff Counsel Division  
Public Utilities Comm. of Nevada  
Public Utilities Comm. of Nevada  
1150 E. William Street  
9075 West Diablo, Suite 250  
Carson City, NV 89701-3109  
Las Vegas, NV 89148  
dnoble@puc.nv.gov  
pucn.sc@puc.nv.gov

Attorney General’s Office  
Michael Saunders  
Bureau of Consumer Protection  
Attorney General’s Office  
100 N. Carson St.  
Bureau of Consumer Protection  
Carson City, NV 89701  
8945 W. Russell Road, Suite 204  
bcpserv@ag.nv.gov  
Las Vegas, NV 89148  
msaunders@ag.nv.gov

DATED this 28th day of February, 2020.

/s/ Lori Petersen  
Lori Petersen  
Senior Legal Administrative Assistant  
NV Energy