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NPC SPPC

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of the Joint 2026 Natural Disaster Protection Plan Triennial Update.	Docket No. 26-02___

VOLUME 1 OF 2

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

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February 27, 2026

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

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

Dear Ms. Osborne:

Enclosed for filing with the Public Utilities Commission of Nevada ("Commission") please find the Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint 2026 Natural Disaster Protection Plan Triennial Update. Also enclosed is a draft notice of the Application pursuant to NAC § 703.162.

The Application contains a limited amount of confidential information. In accordance with the Commission's regulations governing confidential information (NAC §§ 703.527 to 703.5282), the public file contains redacted versions of the material. Unredacted versions of this information are being filed under seal.

The information set forth in Appendix G to the Joint 2026 Natural Disaster Protection Plan Triennial Update (Exhibit B to the Application) contains confidential information pursuant to Nevada's Homeland Security Act, codified in NRS §239C.210 and Federal Laws relating to Critical Energy Infrastructure Information and Controlled Unclassified Information. Specifically, Appendix G to the Plan is NV Energy's Emergency De-Energization Wildfire Policy. This policy document includes detailed information regarding NV Energy's infrastructure and its operational practices in certain emergency response situations.

Given the sensitive nature of this information, the Companies request permanent confidential treatment of the Emergency De-Energization Wildfire Policy, as other of the Companies' documents related to critical energy infrastructure and emergency response plans have received.

Should you have any questions regarding this filing, please contact me at (775) 834-5793 or Michael.Knox@nvenergy.com.

P.O. BOX 98910, LAS VEGAS, NEVADA 89151-0001 6226 WEST SAHARA AVENUE, LAS VEGAS, NEVADA 89146
P.O. BOX 10100, RENO, NEVADA 89520-0024 6100 NEIL ROAD, RENO, NEVADA 89511 **nvenergy.com**

Respectfully submitted,

/s/ Michael D. Knox
Michael D. Knox
Senior Attorney

Jordan Pinjuv
Eric Petrozino
Wilkinson Barker Knauer, LLP
2138 West 32nd Avenue Suite 300
Denver, CO 80211
Telephone: 916.671.0912
Telephone: 303.626.2356
jpinjuv@wbklaw.com
epetrozino@wbklaw.com

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

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Nevada Power Company
d/b/a NV Energy

and

Sierra Pacific Power Company
d/b/a NV Energy

Joint Natural Disaster Protection Plan
Triennial Update

Docket 26-020XX

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CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of **NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY** in Docket No. 26-020__ upon all parties of record in this proceeding by electronic service to the following:

Staff Counsel Division
Public Utilities Comm. of Nevada
9075 West Diablo Drive Suite 250
Las Vegas, NV 89148
pucn.sc@puc.nv.gov

Don Lomoljo
Public Utilities Comm. of Nevada
1150 E. William Street
Carson City, NV 89701-3109
dlomoljo@puc.nv.gov

Michael Saunders
Attorney General's Office
Bureau of Consumer Protection
8945 W. Russell Road, Suite 204
Las Vegas, NV 89148
bcpserv@ag.nv.gov
msaunders@ag.nv.gov

Attorney General's Office
Bureau of Consumer Protection
100 N. Carson St.
Carson City, NV 89701
bcpserv@ag.nv.gov

DATED this 27th day of February, 2026.

/s/ Caitlin Katzenbach
Caitlin Katzenbach
Paralegal
Nevada Power Company d/b/a NV Energy
Sierra Pacific Power Company d/b/a NV Energy

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 2026 Natural Disaster Protection Plan Triennial Update.

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 Joint 2026 Natural Disaster Protection Plan Triennial Update ("Plan"). The Application requests that the Public Utilities Commission of Nevada approve the Plan, which presents existing and proposed initiatives that are intended to mitigate natural disaster risks, including identification of areas at high-risk for natural disasters, implementation of protocols to inspect electrical infrastructure, implementation of protocols for vegetation management, preventative steps to mitigate disaster risks, provision of adequate natural disaster response, and establishment of 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

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.

(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.

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.

APPLICATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of the Joint 2026 Natural Disaster Protection Plan Triennial Update.	))))	Docket No. 26-02___

JOINT 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 Joint Application pursuant to Nevada Revised Statute ("NRS") § 704.7893 for approval by the Public Utilities Commission of Nevada ("Commission") of the Companies' Joint 2026 Natural Disaster Protection Plan Triennial Update ("NDPP" or "Plan"). NRS § 704.7983 establishes a requirement that NV Energy prepare and file with the Commission a Plan on or before June 1, 2020, and on or before June 1 of every third year thereafter. Furthermore, Section 5 of the approved regulations of the Commission in Docket No. 19-06009, Legislative Counsel Bureau File No. 181-24 ("NDPP Regulations"), requires that NV Energy file its NDPP on or before March 1, 2020, and every third year thereafter. Section 7 of the NDPP Regulations also requires the Commission to issue an order accepting or modifying the NDPP, or specifying any portions of the plan it deems to be inadequate, within 210 days after its filing. The statutory period within which this matter must be resolved therefore runs on September 25, 2026.

I.

SUMMARY AND INTRODUCTION

NRS § 704.7893 requires NV Energy to file an NDPP that contains information, procedures and protocols relating to the efforts of the electric utilities to prevent or respond to wildfires or other natural disasters. The NDPP Regulations define a natural disaster as "any

natural catastrophe, including, without limitation, wind, wildfire, storm, high water, earthquake, avalanche, landslide, mudslide or heat wave."

The Companies filed their inaugural NDPP on February 26, 2020, and the Commission issued its Second Modified Final Order approving the NDPP on December 22, 2020, in Docket No. 20-02031. The Companies also filed, and obtained the Commission's approval of, a first amendment to the NDPP in Docket No. 21-03040; and a second amendment to the NDPP in Docket No. 22-08001, which the Commission granted in part and denied in part. The Companies filed their Joint 2024-2026 Natural Disaster Protection Plan on March 1, 2023, in Docket No. 23-03003.

This Joint Application presents a comprehensive natural disaster protection plan for the 2027 through 2029 period. The Plan reflects NV Energy's lessons learned since filing the 2024-2026 plan and a deeper understanding of the connectedness of individual Plan elements.

The Plan begins with a focus on completing the wildfire risk mitigation work identified in the first two triennial plans. In this Plan, the Companies are operationalizing programs and projects identified in prior plans and amendments. The Plan includes the first system-wide review of wildfire Tier areas since the inaugural plan. As a result of this analysis, the Companies are requesting to modify the wildfire Tier areas, with relatively minor additions to the Tier 2 and Tier 1E areas and a more significant addition to the Tier 1 area. Despite these additions to the wildfire risk tier areas, the impact on the overall budget remains limited as the Companies plan to leverage technology and more targeted vegetation management to keep costs consistent with prior cycles.

The Plan provides a path to continue implementing operating practices that reduce the risk of wildfire ignitions. These include previously-approved programs like Public Safety Outage Management, fast-trip fire mode settings, and distribution automation. In general, the operating practices approved and implemented in prior plans will remain operational. Similarly, the Plan includes situational awareness programs such as weather stations, wildfire

cameras and the hazard awareness desk. The Commission approved these programs in prior plans and this Plan represents a continuation of prior activities.

Finally, the Plan advances system hardening efforts identified in prior plans. In this cycle, the Companies provide updates regarding the proposed microgrid installation at Mt. Charleston and a comprehensive plan to address overhead rebuilds, undergrounding, substation hardening, and other capital-intensive improvements in high-risk areas. The overall capital costs proposed in this Plan are consistent with those in the 2024-2026 planning cycle.

For the 2027-2029 period, the Companies propose $410,945,615 in total expenditures for the Plan. This includes $199,725,227 in operations, maintenance, administrative and general ("OMAG") expenses and $211,220,388 in capital investment. For comparison, for the 2024-2026 period the Companies requested $373,059,298 in total expenditures, with $201,961,191 in OMAG and $171,098,107 in capital investment.

Table 1 provides the breakdown of costs for inclusion in the authorized budget for this Plan by activity and service territory.

Table 1 – NDPP Capital and OMAG

Capital and OMAG Total	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Capital	81,641,463	23,673,600	32,200,169	25,767,694
OMAG	25,954,226	8,624,859	8,167,217	9,162,151
Nevada Power Total	**107,595,689**	**32,298,459**	**40,367,386**	**34,929,845**
Sierra Pacific Power				
Capital	129,578,925	47,964,118	42,984,172	38,630,635
OMAG	173,771,001	55,698,724	58,734,619	59,337,658
Sierra Pacific Power Total	**303,349,926**	**103,662,842**	**101,718,791**	**97,968,293**
Grand Total	**410,945,615**	**135,961,301**	**142,086,177**	**132,898,137**

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 the Companies as set forth below:

Michael Knox
Senior Attorney
6100 Neil Road
Reno, NV 89511
Telephone: 775.834.5793
Facsimile: 775.834.4098
michael.knox@nvenergy.com

Trevor Dillard
Director, Regulatory Services
6100 Neil Road
Reno, NV 89511
Telephone: 775.834.5823
regulatory@nvenergy.com

Jordan Pinjuv
Eric Petrozino
Wilkinson Barker Knauer, LLP
2138 West 32nd Avenue
Suite 300
Denver, CO 80211
Telephone: 303.626.2329
Telephone: 303.626.2336
jpinjuv@wbklaw.com
epetrozino@wbklaw.com

III.

APPLICATION EXHIBITS

NV Energy has included with this Joint 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 complete narrative version of the Natural Disaster Protection Plan entitled "2026 Natural Disaster Protection Plan Triennial Update."

IV.

SUPPORTING MATERIAL

The prepared direct testimony of the following witnesses supports the Companies' Plan.

Jesse Murray, Senior Vice President, Energy Delivery. Mr. Murray describes the policy objectives of the Companies' NDPP and the Companies' path to execute the Plan. In addition, Mr. Murray is sponsoring the Plan's Executive Summary and is responsible for ensuring this Plan complies with NRS 704.7983 and the approved regulation contained in LCB File No. R181-24 filed November 15, 2024, in Docket No. 19-06009.

Macy Campbell, Director of Natural Disaster Protection Compliance and Operations Support. Ms. Campbell sponsors the elements of the Companies' NDPP related to emergency operations, safety training, conditional awareness, system hardening, resource sufficiency, and the Mt. Charleston Rebuild.

John Donovan, Director of Natural Disaster Protection Project Execution. Mr. Donovan sponsors the element regarding Vegetation Management of the Companies' NDPP.

Francesco Zuniga, Natural Disaster Protection Senior Data Scientist. Mr. Zuniga presents the Companies' cost-benefit analysis for the Companies'

NDPP program elements, as required by the approved regulation contained in LCB File No. R181-24 filed November 15, 2024, in Docket No. 19-06009.

Alex Hoon, Natural Disaster Protection Principal Meteorologist. Mr. Hoon sponsors elements of the Companies' NDPP related to natural disaster threat identification, situational awareness, and operational practices. Mr. Hoon also addresses updates to the wildfire risk tier areas.

Haley Stewart, Regulatory Reporting Manager. Ms. Stewart supports the anticipated rate impact calculations for the Companies' NDPP for plan years 2027, 2028, and 2029 in compliance with the regulation in LCB File No. R181-24.

Chris Lautenberger, President & Chief Executive Officer, CloudFire, Inc. Mr. Lautenberger presents the updated wildfire risk assessment for the Companies' NDPP.

V.

CONFIDENTIALITY

Appendix G to the Plan (Exhibit B) contains confidential information pursuant to Nevada's Homeland Security Act, codified in NRS §239C.210 and Federal Laws relating to Critical Energy Infrastructure Information and Controlled Unclassified Information. Specifically, Appendix G to the Plan is NV Energy's Emergency De-Energization Wildfire Policy. This policy document includes detailed information regarding NV Energy's infrastructure and its operational practices in certain emergency response situations. As a result, NV Energy has designated this information confidential pursuant to NRS § 703.190 and NAC § 703.5274.

Pursuant to NAC § 703.5274(1), one unredacted copy of the confidential information will be filed with the Commission's Secretary in a separate envelope stamped "confidential." Redacted versions of confidential information will be submitted for processing and posting onto the Commission's public website.

Pursuant to NAC § 703.5274(2), the Companies hereby request that the above-described information not be disclosed to the public. The Companies request that this information remain confidential permanently. Confidential treatment of the above-described information will not impair the ability the Staff or the BCP to fully investigate the Companies' proposals. Pursuant to NAC § 703.527 and § 703.5274, Staff and BCP have already executed a protective agreement for this case and will be immediately provided unredacted copies of the filing.

VI.

REQUESTS FOR RELIEF

The Companies respectfully request that the Commission issue an order granting the following relief:

1. Approving the Plan as it is set forth in Exhibit B to this Joint Application;

2. Finding that this filing fully satisfies the reporting requirements of NRS § 704.7983 and the NDPP Regulations;

3. Approving NV Energy's updates to the wildfire risk areas;

4. Finding that NV Energy has complied with directive No. 4 from Docket No. 23-03003 requiring an update regarding the Companies' ground fuels substation policy.

5. Finding that NV Energy has complied with directive No. 6 in Docket No. 25-02032 requiring NV Energy to expand documentation of the verification of the reasonableness of the personnel hours and vehicle and equipment milage and usage hours charged by contractors for consistency with the work performed;

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

Dated and respectfully submitted this 27th day of February, 2026.

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

/s/Michael Knox
Michael Knox
Senior Attorney
6100 Neil Road
Reno, NV 89511
Telephone: 775.834.5793
Facsimile: 775.834.4098
michael.knox@nvenergy.com

Jordan Pinjuv
Eric Petrozino
Wilkinson Barker Knauer, LLP
2138 West 32nd Avenue Suite 300
Denver, CO 80211
Telephone: 303.626.2329
Telephone: 303.626.2336
jpinjuv@wbklaw.com
epetrozino@wbklaw.com
Attorneys for NV Energy

2026 NATURAL DISASTER PROTECTION PLAN TRIENNIAL UPDATE PART 1

2026 Natural Disaster Protection Plan Triennial Update

February 27, 2026

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EXECUTIVE SUMMARY

Nevada Power Company d/b/a NV Energy's ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy's (together "NV Energy" or the "Companies") joint Natural Disaster Protection Plan ("NDPP" or "Plan") promotes public safety and drives down risks from natural disasters in an efficient and cost-effective manner. In this third Triennial NDPP, the Companies provide their programs, projects, and initiatives for the 2027-2029 timeframe. The 2027-2029 Plan continues the value-driven prioritization of NDPP initiatives that reduce controllable risk for identified natural disasters. The Plan builds on previous Plans and related Amendments as the Companies have improved visualization tools, harmonized information, deployed advanced algorithms, and leveraged ongoing collaboration to identify and respond to risks.

The focus of the 2027-2029 NDPP is on operationalizing programs and projects identified in prior Plans and Amendments. The Companies have refreshed the fire risk Tiers system-wide using CloudFire[1] technology, which indicates updates to fire risk Tiers. This analysis represents the first system-wide assessment since the inaugural NDPP.

The Companies anticipate successful outcomes for certain advanced technology pilot programs, including AiDash, which supports vegetation management, and Foundry, which supports situational awareness and operational practices. NDPP cycle-based elements will leverage technology, where cost-effective, to include a condition-based component so work is not repeated where completed risk reduction measures are still effective. While wildfire mitigation remains a top priority, significant damage has been observed from extreme winds and storm-related conditions in Southern Nevada. The Circuit Resilience program for monsoon-prone areas in Southern Nevada remains an important part of the triennial Plan. Hardening along critical evacuation routes in natural disaster areas also remains an ongoing priority to promote public safety, protect infrastructure, and minimize outage impacts.

Priorities for the Plan are established based on risk analysis that is calibrated with field knowledge. Continued engagement with the Expert Working Group ("EWG") leverages the knowledge and capabilities of public safety partners for operations, emergency response, ruggedization and other initiatives. Ongoing outreach and engagement with communities and customers is also fundamental to the Plan's success.

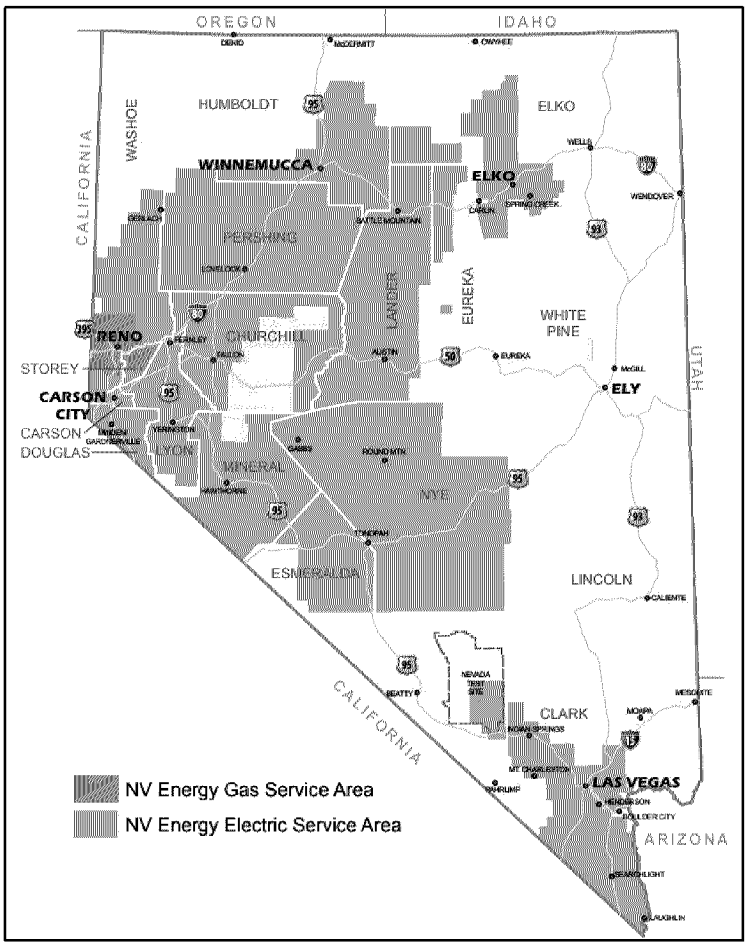
The Companies are pleased to provide this Triennial NDPP that reflects a value-driven approach to identifying and managing natural disaster risks to protect public safety and crucial infrastructure.

[1] Formerly REAX Engineering that provided targeted risk updates in the 2023 Second Triennial Filing, Docket No. 23-03003.

BACKGROUND

The Companies have served the citizens of Nevada for more than 150 years. Today, the service area covers nearly 46,000 square miles and some of the fastest growing populations in the U.S., including the communities of Las Vegas, Reno-Sparks, Henderson, and Elko. The Companies provide a wide range of energy services to nearly 1.3 million electric customers throughout the State and more than 50 million tourists annually. A map of the Companies' service territories are presented in Figure 1. The Companies take pride in providing reliable service and protecting public safety through the initiatives included in this 2027-2029 NDPP.[2]

Figure 1. The Companies' Service Territories



Source: NV Energy, 2014

[2] The Companies own electric infrastructure in California but does not serve any California retail customers.

The Companies' commitment to exceptional service, grid resilience, and public safety are incorporated through the elements of the Plan, filed in accordance with Nevada Revised Statutes ("NRS") 704.7983 and regulations adopted by the Commission in Docket No. 19-06009, LCB File No. R181-24 (the "Regulations").[3] The Plan reflects the Commission's related Orders beginning with the inaugural NDPP filing in Docket No. 20-02031 and the companion Regulatory Asset proceedings, beginning with Docket No. 20-02032. The Regulations define a natural disaster as "any natural catastrophe that includes wind, wildfire, storm, high water, earthquake, avalanche, landslide, mudslide, or heat wave." The Regulations require that the Plan be based on a risk-based approach and that elements of the Plan are prioritized based on lowering the likelihood and impact of natural disasters. Refreshed research and analysis from the Companies' meteorology and data science experts establishes the set of high likelihood and high impact natural disasters reflected in the Plan that could compromise public safety and reliable electric service.

The Triennial Plan update contains the following required elements:

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.

Situational Awareness – Involves the use of information about fire conditions and weather contributing to other natural disasters to help guide mitigation measures, including fuel mapping, and information from weather stations and cameras.

Operational Practices – Involves practices used to mitigate wildfire risk, including non-reclosing strategy, wildfire safety training, and implementation of applicable procedures.

Emergency Operations and Proactive De-Energization – Involves de-energization of pre-identified circuits, or sections of circuits, to mitigate against potential electric facility-caused ignitions.

Vegetation Management – Involves clearance distances, pole clearing, fuel breaks, and the removal of hazard trees to minimize the chances of vegetation striking lines.

Conditional Awareness: 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 resilience 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.

[3] https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2019-6/46693.pdf, updated in November 2024.

This Plan contains additional sections including advanced technologies, communications, financials, and metrics.

1. RISK-BASED APPROACH - NATURAL DISASTER RISK ANALYSIS AND DRIVERS

The Companies' NDPP focuses on geographic areas where the utilities' electrical infrastructure is situated in locations vulnerable to natural disaster threats.[4] The Companies conduct a comprehensive evaluation of natural disaster risks in its service territory every three years and concludes that the following natural disasters present sufficient risk to include in the Third Triennial Plan:

1.1. NATURAL DISASTER THREATS

The NDPP's objective is to reduce risk from natural disasters systematically and continually. Ongoing assessments consider frequency and impact of natural disasters based on the Companies' knowledge of the location and condition of energy infrastructure that is ratified in discussions with the EWG.[5] These inputs inform forecasting models that can predict impacts to populated areas and direct actions and investments to reduce risk exposure to natural disasters.

The Companies consider multiple local, state, and federal hazard rankings of natural disaster threats. Analyses of potential disasters and discussion of mitigating actions formed the basis for in-depth engagement with the EWG. Actual experience indicates the validity of previously identified natural catastrophes, so none were removed. The Companies' meteorologists have mapped the following natural disasters into Heightened Threat Areas ("HTAs") identified for this filing:

- Wildfires and rangeland fires that are reflected in Risk Tier Areas
- Wind occurrences, including high wind gusts
- Winter storms and blizzards with ice and snow accumulations
- Thunderstorms and microbursts
- Monsoons and flooding
- Earthquakes
- Landslides and avalanches

Heat waves are also listed in the Regulations and can reduce equipment life, cause extended outages, and exacerbate the frequency and impacts of many of the catastrophes listed above. Heat waves also impact the Companies' load profiles and supply resources. For the purposes of this

[4]According to the definition presented in the 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.

[5] The EWG is discussed further in the Outreach and Education section.

NDPP, resource-related questions are included in the Companies' Integrated Resource Plan filings.

1.2. RISK DRIVEN DECISION MAKING FRAMEWORK

The Companies' risk assessment process begins with a foundational understanding of areas and assets within the service territory that are vulnerable to natural disasters and catastrophes. Models and forecasts are compared with empirical evidence to understand the natural catastrophes that can impact the Companies' infrastructure. The Companies have a meteorology team that is responsible for identifying and analyzing natural disasters to gauge possible impacts to the Companies' infrastructure and communities. The Companies collaborate with industry experts and technology partners, including the National Weather Service ("NWS"), CloudFire, Inc., Technosylva Inc., and the University of Nevada, Reno's ("UNR") Department of Physics and Seismological Lab. The goal of the risk-based decision-making framework is to assess where high impact or high likelihood natural disasters could compromise public safety or result in power outages.

Climate change has also resulted in changes to weather patterns over Nevada, with increasing risk of natural disasters. Climate change brings shifting and heightened threats of catastrophic wildfires, winter storms, thunderstorms/microbursts, monsoons/flash flooding, as well as heatwaves/drought to all regions of Nevada.

The Companies use risk probability and likelihood obtained from information sources such as disaster reports, vulnerable asset locations, outage events, Major Event Days ("MEDs") and Catastrophic Event Days ("CEDs"), as well as corresponding incremental costs, to inform the underlying utility-specific assumptions and disaster risk maps.[6] These risk factors are analyzed and used to prioritize initiatives presented in this Plan. While maps are provided throughout the NDPP, Appendix A provides the compiled risk maps.

The overall aim of the NDPP focuses on both safety and preservation of Nevada's environmental and natural resources. The Companies track outage events and trends related to natural disasters where MEDs and CEDs are considered for each disaster type. Through advanced analytics, taking into account natural disasters that impact the grid, and combining with nearer-term situational and conditional awareness, the Companies focus on both short-term and long-term risk reduction activities to harden the grid and restore service as quickly and safely as possible.

1.2.1. WILDFIRE RISK PROFILES

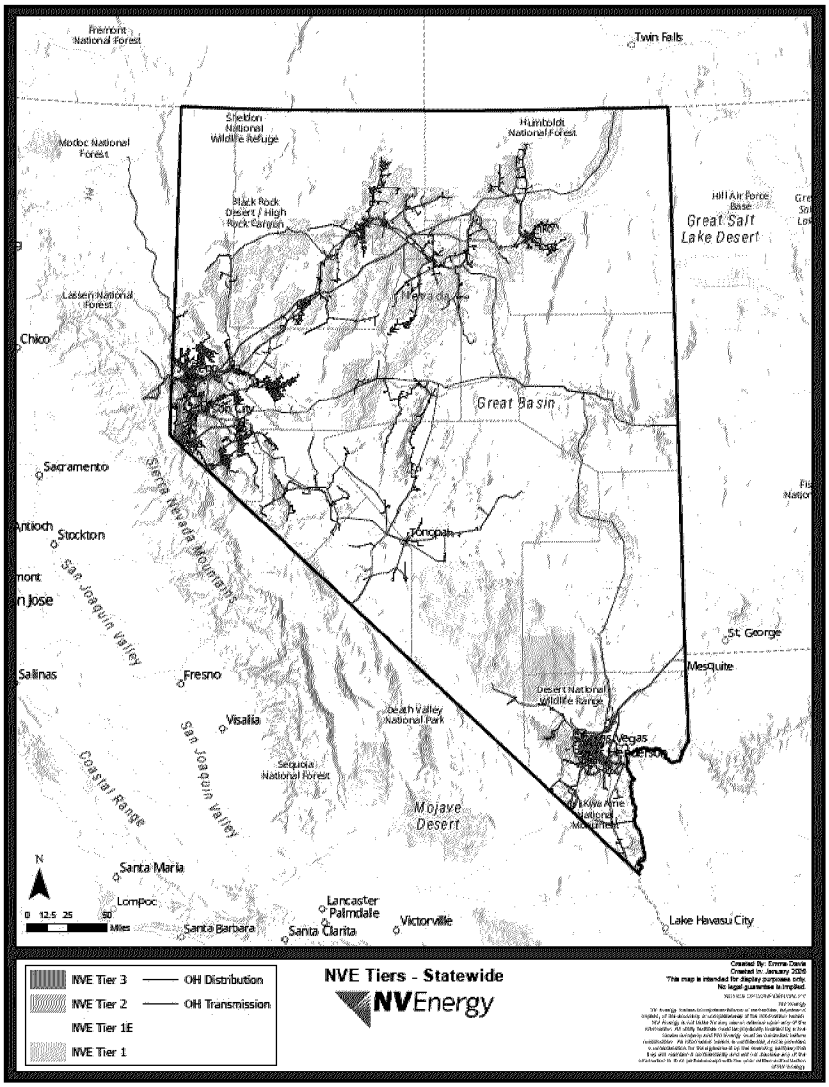
Wildfire risk is presented as Tier 3 (extreme), Tier 2 (high), Tier 1 – Elevated ("1E"), and Tier 1, based on prior Commission approval.[7] Tiers integrate several mapping layers to characterize

[6] Resource data includes NWS, National Oceanic and Atmospheric Administration ("NOAA"), the Federal Emergency Management Agency ("FEMA"), the United States Geological Survey ("USGS"), and UNR.

[7] Docket No. 24-12016.

heightened wildfire risk and potentially catastrophic wildfire risks across the Companies' distribution, telecommunication, and transmission assets in Nevada, and transmission assets in California.[8] The Tier definitions consider the distribution of extreme fire weather conditions, the historical distribution of wildfires, wildfire hazard potential, population centers, and other information about fuels and fire behavior. The risk is depicted through map layer combinations that indicate severity of ignition and fire spread potential. The map layers form important visualization tools that indicate the wildfire risk to specific infrastructure, population centers, and other risk-prone factors.

Figure 2. Wildfire Risk Tiers



[8] See Appendix A: Map 1 for the high and extreme designations of the developed fire hazard map.

Rangeland fires also pose a unique wildland threat due to the rapid rate of spread that can occur upon ignition. Sagebrush habitats, non-invasive annual grasses, and cheatgrass have been identified by regional fire agencies, the U.S. Wildland Fire Service, U.S. Forest Service, and the Bureau of Land Management ("BLM"),[9] as principal drivers in exacerbating rangeland fires. Several rangeland areas are included in Tier 2, Tier 1E, and Tier 1. Rangeland areas have experienced fires that damaged or destroyed buildings and infrastructure. The wildfire Tiers have been refined after assessing fine-scale landscape features and other factors that affect fire risk. The Companies continue to evaluate risk assessment methodologies and technologies and work with stakeholders to refine the wildfire Tiers. Regionally focused wildfire Tier maps are presented below reflecting the approved mapping changes in the First Amendment of the Second Triennial Plan.

[9] BLM. "Nevada Weeds and Invasives Program" https://www.blm.gov/programs/natural-resources/weeds-and-invasives/blm-control-strategies/nevada. https://www.blm.gov/programs/natural-resources/weeds-and-invasives/blm-control-strategies/nevada 2019.

Figure 3. Wildfire Risk Tiers: Washoe Region

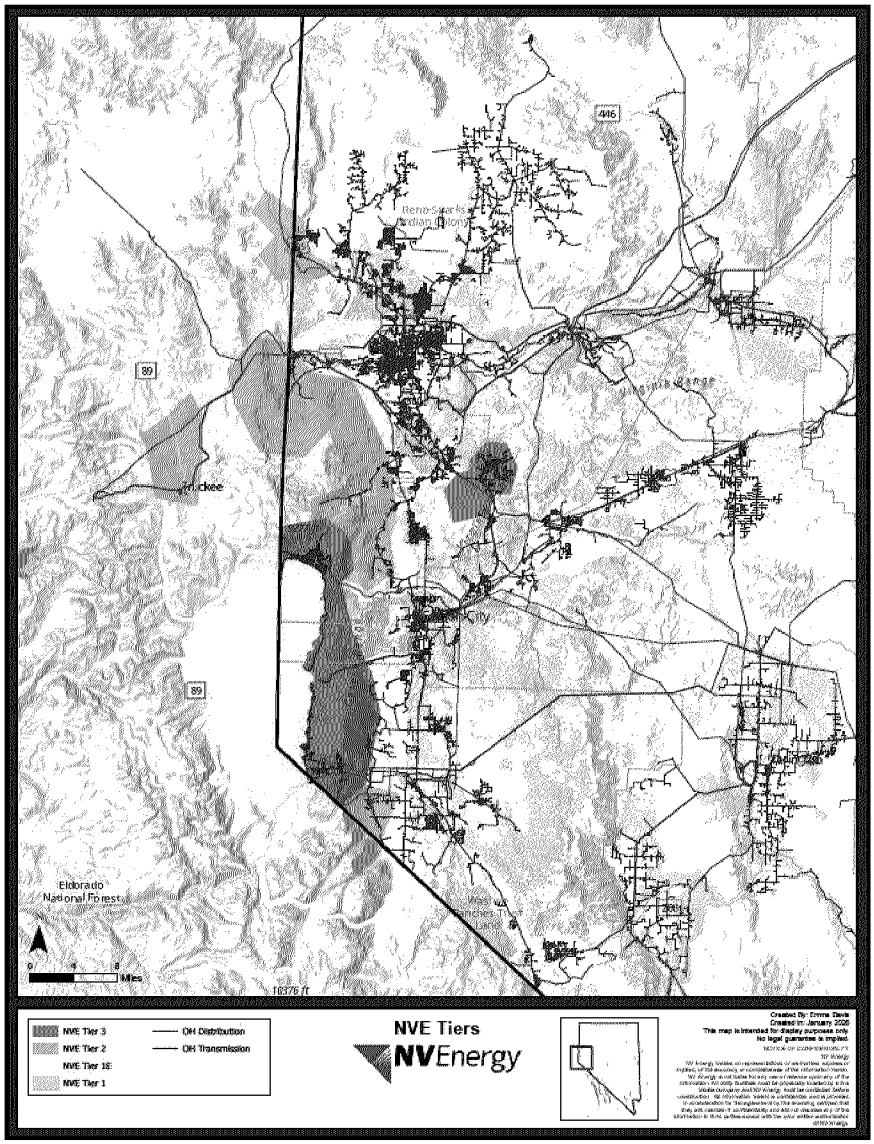


Figure 4. Wildfire Risk Tiers: Winnemucca - Elko Region

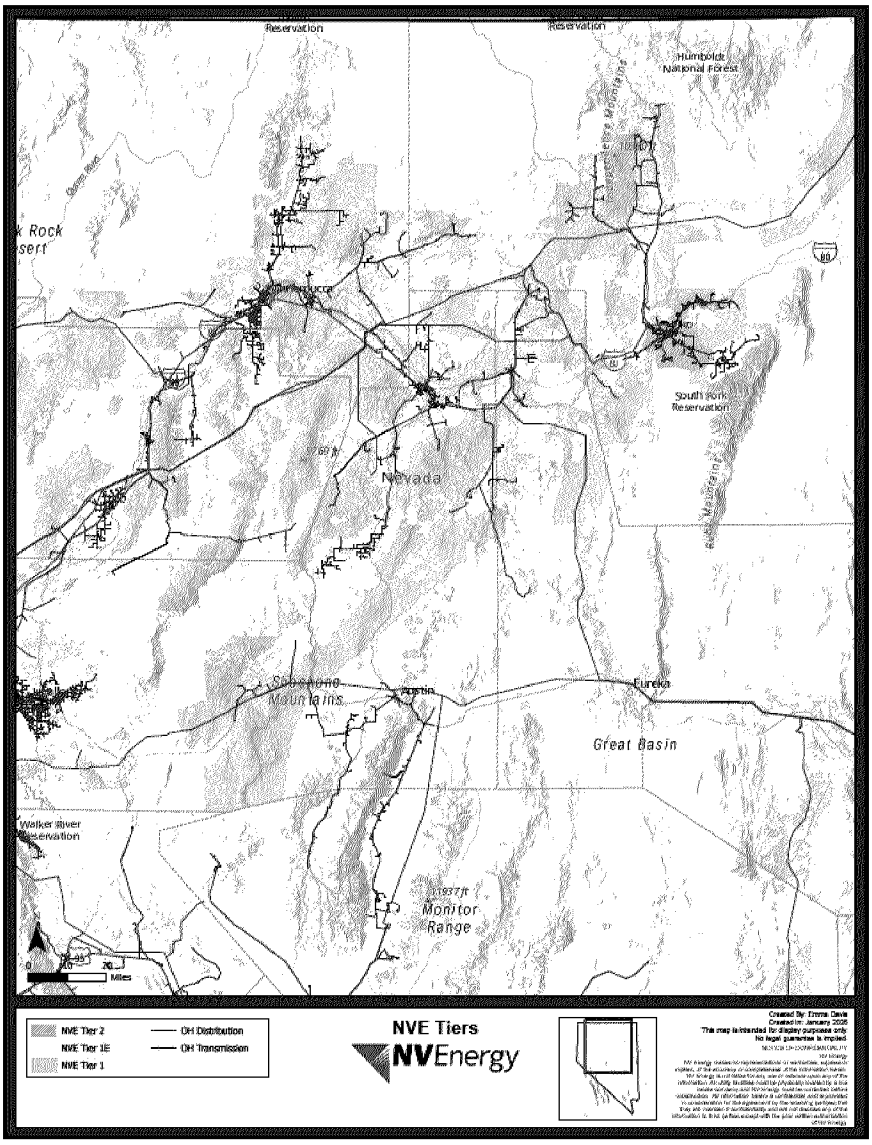


Figure 5. Wildfire Risk Tiers: Mt. Charleston Region



1.2.2. HIGH WIND EVENTS

High wind events are defined in this Plan as reaching NWS High Wind Warning criteria. NWS-warned high wind events are typically split into "non-convective" high wind and "convective" thunderstorm wind categories. "Non-convective" high wind events are addressed in this section, and "convective" thunderstorm wind events are addressed below in Thunderstorms and Microbursts.

Criteria for classification as a non-convective high wind event varies slightly based on local and regional definitions, but generally, sustained winds of 40 mph or greater lasting for at minimum one hour qualifies, as does any single gust (sustained or instantaneous) of 58 mph or greater, so

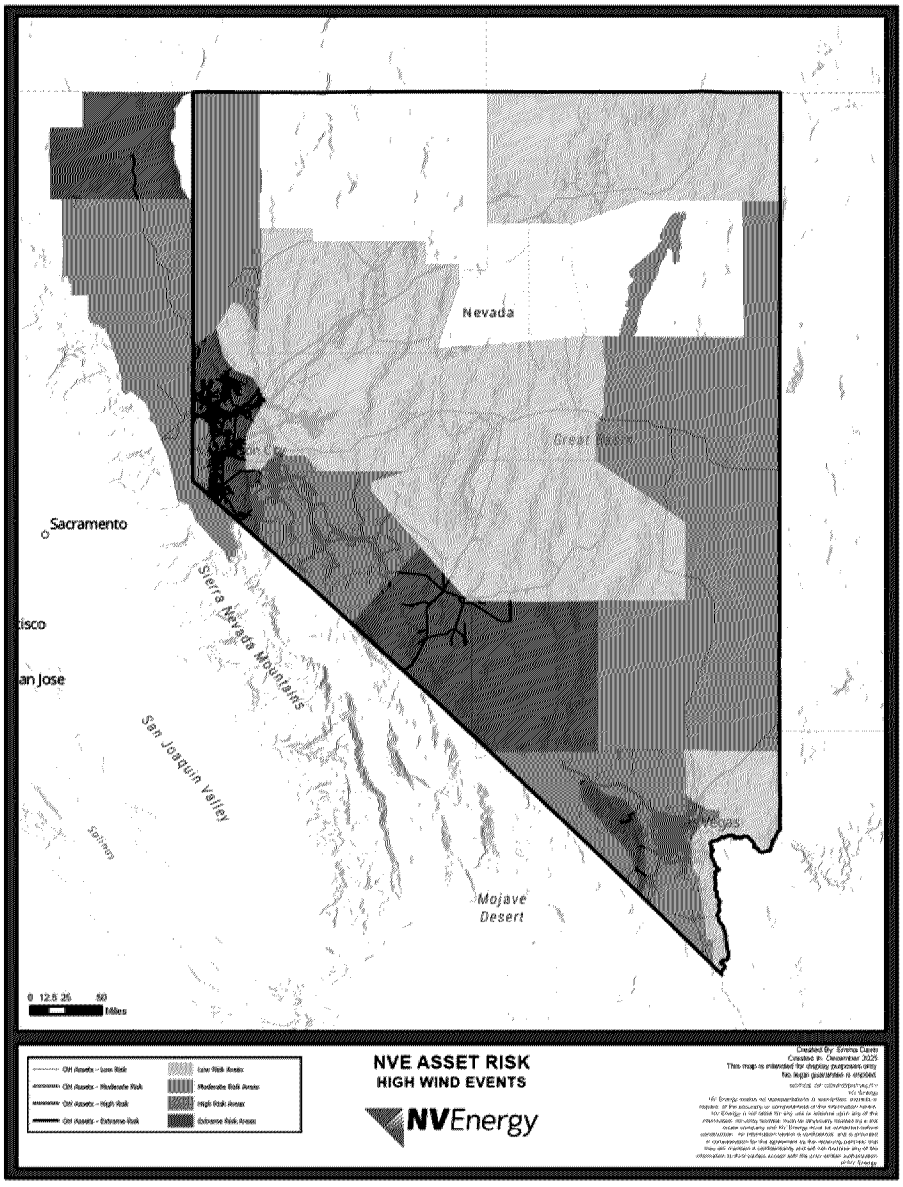
long as those measurements did not occur in conjunction with a thunderstorm. Size of area affected is not considered when classifying wind events in this manner. Because high wind events often coincide with severe winter weather and, in such cases, are conveyed through NWS winter weather products, this analysis includes Blizzard Warnings, representing the most severe co-occurrence of winds and winter weather, in the high wind assessment to capture these combined occurrences. 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, saturated soils, 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 danger indices are elevated. High wind risk is ubiquitous throughout the Companies' service territories, 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. For example, risk in urban areas may be either reduced by obstacles or elevated by artificial wind tunnels created by the built environment. Asset-level susceptibility to future wind events throughout the Companies' service territories must consider local currents and surrounding infrastructure or topography when evaluating system hardening needs. Damage from high wind or debris carried by a dust storm can be classified as a high wind incident.

To ensure consistency in high wind risk assessment across the service territories and minimize bias from population-driven storm reporting, this analysis relies on NWS warnings, which provide a comparatively population-independent measure of high wind events.

As shown in Figure 6, the current Plan adopts a more granular approach to wind risk representation than that adopted in prior years. Risk zones are now classified into five levels – Very Low (no color), Low, Moderate, High, and Extreme – rather than the previous four. This enhanced classification provides greater precision and supports a more data-driven assessment of wind-related risk.

Figure 6. High Wind Risk



1.2.3. WINTER STORMS

Winter weather is defined in this Plan as any snow event that either i) meets or exceeds defined 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.[10] According to 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 in Nevada have caused damage to infrastructure, resulting in customer outages lasting up to multiple days after the conclusion of snowfall 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.[11] 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.[12] 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 of 40 mph or higher, and are considered in this Plan to represent both a snow event and a wind event.

Extreme events may bury assets or lead to an increased risk of avalanche activity. Particularly heavy snow caused by a higher moisture content, colloquially known as "Sierra Cement," can weigh down lines and poles with relatively shallow accumulations. 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 Nevada's mountain ranges, including the Sierra Nevada, Ruby Mountains, and Spring Mountains, where snow loading is more prevalent due to the high propensity of winter weather.

NWS warnings for heavy snow, blizzards, and winter storms serve as the primary basis for representing winter weather risk across the Companies' service territories in this assessment.

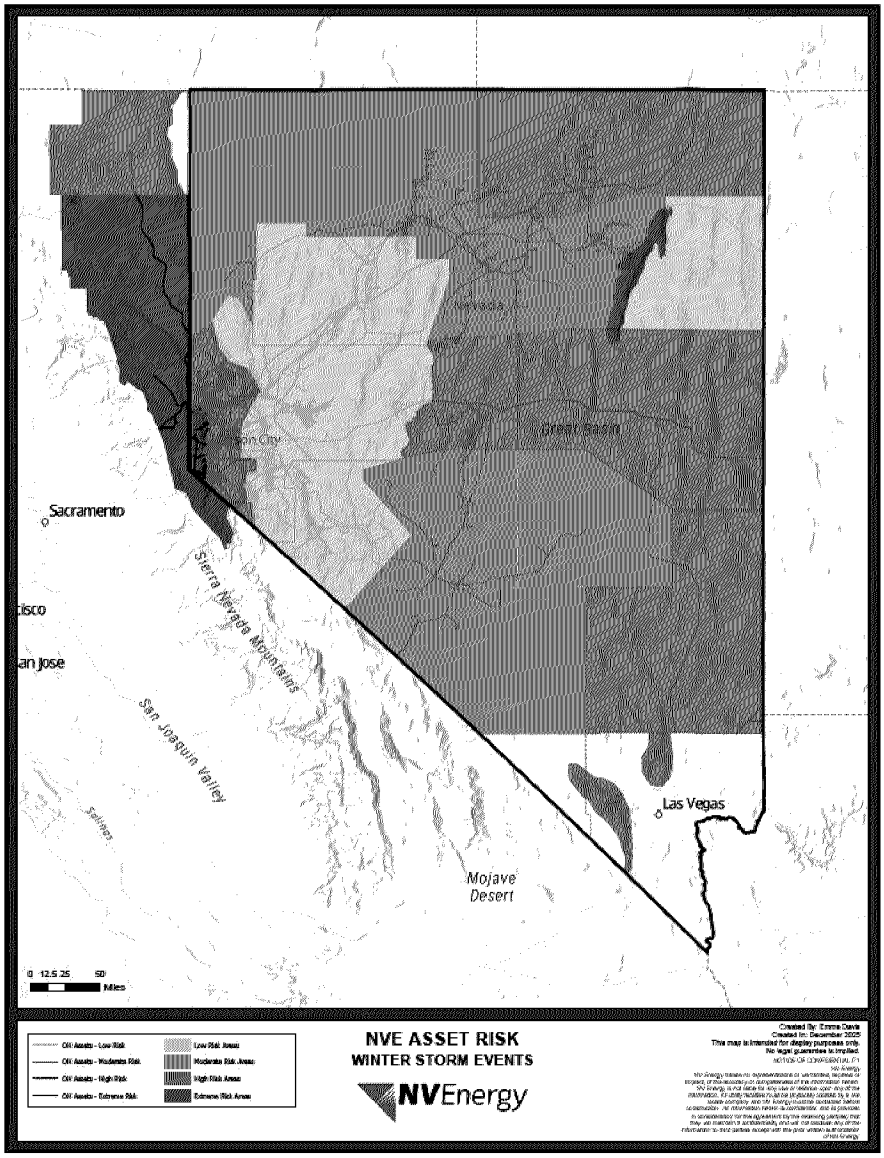
The current Plan adopts a more granular approach to winter storm risk representation than that adopted in prior years. As shown in Figure 7, risk zones are now classified into five levels – Very Low (no color), Low, Moderate, High, and Extreme – rather than the previous four. This enhanced classification provides greater precision and supports a more data-driven assessment of winter storm-related risk.

[10] NWS, NOAA, Department of Commerce. "Storm Data Preparation." https://www.ncdc.noaa.gov/stormevents/pd01016005curr.pdf. https://www.ncdc.noaa.gov/stormevents/pd01016005curr.pdf. March 23, 2016.

[11] *Id.*

[12] *Id.*

Figure 7. Winter Storm Risk



1.2.4. THUNDERSTORMS AND MICROBURSTS

Thunderstorms are transient and sometimes violent storms with thunder and lightning, often accompanied by heavy rain, strong wind, and hail. Thunderstorms are prevalent in Nevada during the summer season, especially when the southwestern monsoons are pushed into Nevada. Southern Nevada has the greatest exposure to severe thunderstorms, although they can occur throughout the state.

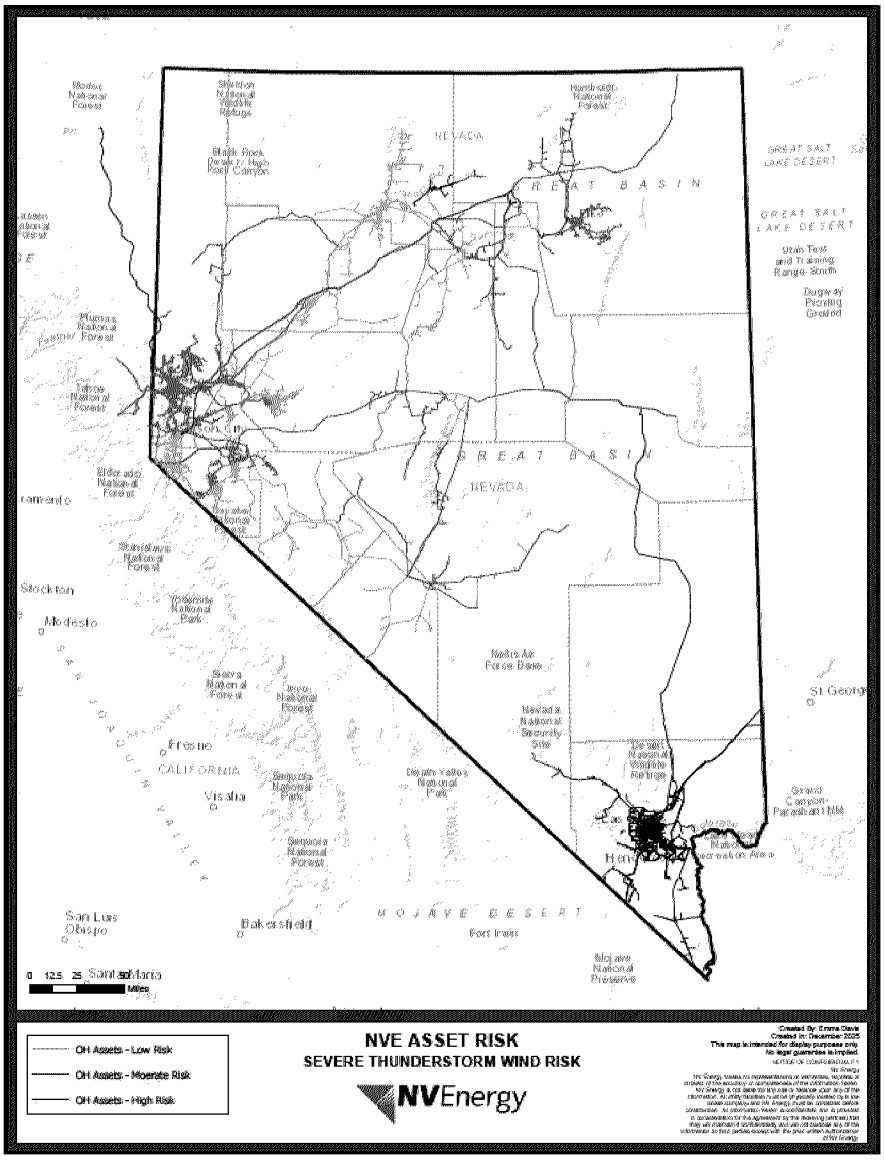
Winds occurring within 30 minutes of lightning being detected are classified as arising from convection, although these winds can also occur in the absence of lightning. Convective winds

above 58 mph and any other wind causing damage during a thunderstorm are jointly classified as severe thunderstorm wind events. Downbursts or microbursts, both dry and wet, are considered to be thunderstorm wind events. Thunderstorm winds, particularly during downbursts, may impact more localized areas than other high wind events due to their concentrated effects on the land area directly below or adjacent to a thunderstorm.

Some intense thunderstorms in Nevada are known to produce excessive cloud-to-ground lightning, nearly continuous, with twelve or more flashes per minute. This can add up to thousands of lightning strikes within a given thunderstorm event. Lightning presents a concern for grid reliability, as direct lightning strikes on electrical equipment have potential to cause surges and outages.

Since the 2023 NDPP Triennial Filing, the Companies have adopted new data sources that provide NWS storm-based Geographic Information System ("GIS") polygons for severe thunderstorm warnings. Previously, the assessment relied on storm damage reports, which were spatially biased toward high-population areas. The updated polygon-based approach, shown in Figure 8, offers a more accurate and normalized representation of thunderstorm risk across the service territory.

Figure 8. Thunderstorm Wind Risk



1.2.5. MONSOON AND FLOODING EVENTS

Areas of increased risk from natural catastrophes include Special Flood Hazard Areas ("SFHAs") as defined by FEMA.[13] 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

[13] FEMA. "Flood Zones." https://www.fema.gov/flood-zones. https://www.fema.gov/flood-zones. March 18, 2019.

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 the primary concern in the Las Vegas Valley due to varying cycles of annual precipitation, and surface cover that has little vegetative soil. Typically, the heaviest precipitation in southern Nevada is driven by summer monsoons, while winter atmospheric river storms bring the heaviest precipitation for northern Nevada.

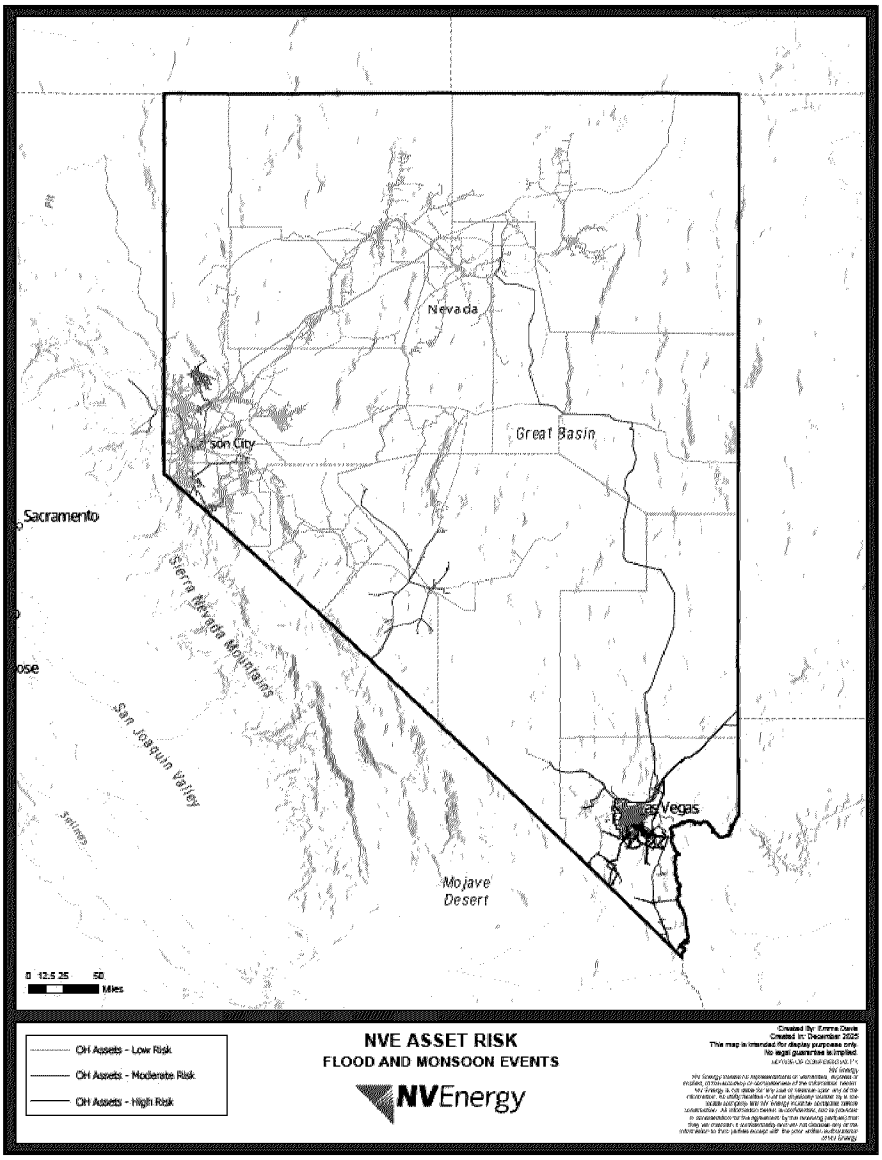
Flash floods are defined as any flooding event that occurs within six hours of a heavy rainfall event.[14] Damaging flash floods may occur both within and outside 100- and 500-year flood zones as the direct result of a downpour, often caused by severe thunderstorms. These floods often occur in urban areas, where physical infrastructure prevents the seeping of rainwater into the soil. Flash flooding is also tied to mudslides, debris flows, and landslides, especially in recently burned areas from wildfires. Flash floods may also occur due to dam, levee, or drainage systems failure. While this can occur at random due to standard wear over time, flash floods from infrastructure failure are often caused by other disasters like earthquakes and landslides. Historic flash flood events reported to NOAA have concentrated around population centers, including Carson City, Reno, and Las Vegas. Las Vegas has a history of flash flood events caused by summer 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. Monsoon events, combined flooding, and high wind events have resulted in significant outages, especially in the southern part of the Companies' service territory.

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. In contrast, flash flooding events, particularly those caused by infrastructure failure, may affect all types of neighboring assets (including susceptible poles) due to the force of rushing water.

Since the 2023 NDPP Triennial Filing, the Companies have incorporated new data sources that provide NWS storm-based GIS polygons for flash flood warnings. Previously, the assessment relied on storm damage reports, which were spatially biased toward high-population areas. The updated polygon-based approach, shown in Figure 9 offers a more accurate and normalized representation of flood risk across the service territory, reducing population-driven reporting bias, and improving the reliability of risk mapping.

[14] NWS, NOAA, U.S. Department of Commerce. "Flash Flooding Definition." https://www.weather.gov/phi/FlashFloodingDefinition.https://www.weather.gov/phi/FlashFloodingDefinition.

Figure 9. Flooding and Monsoon Risk



1.2.6. 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 major events are infrequent.[15] As seen most recently in Northern California, the aftermath of a major earthquake presents a great

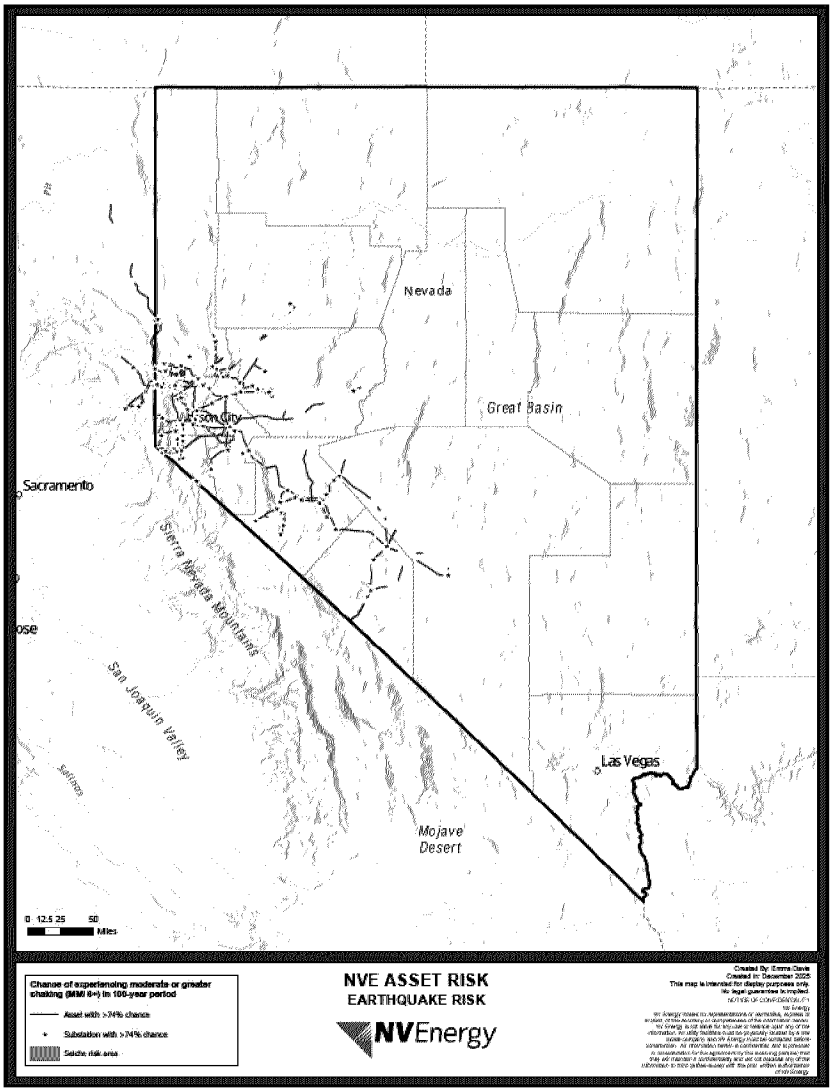
[15] UNR, NV Bureau of Mines & Geology. "2013 Nevada Enhanced Hazard Mitigation Plan." http://www.nbmg.unr.edu/nhmpc/State_of_Nevada_Enhanced_Multihazard_Mitigation_Plan/NV_plan_2013/Section_3_Hazards_Risk_Assessment_&_Profiles_9_Sept_2013.pdf. Pg.3-28. September 9, 2013.

risk consequence when lateral or vertical shaking can dislodge footings, sway poles and lines, and impact foundational pads in substations. For 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, is primarily caused by the energy release potential of the active faults, typically near the Lake Tahoe Basin ("Basin"). There is a lower seiche risk impact for Lake Las Vegas and Lake Mead in the southern portion of the State. The Basin has historically experienced high-magnitude earthquakes (magnitude 6.0+). Historical records illustrate seiches forming as high as 30 feet in the Basin, creating the potential for high, forceful water flow into the transmission and adjacent substation assets bordering California.

The following Figure 10 shows earthquake risk for Nevada.

Figure 10. Earthquake Risk



1.2.7. 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.[16] 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 heavy rainfall, snowmelt, erosion from water or wind, earthquakes, and human disturbance. Landslide hazards exist throughout the State

[16] USGS. "What is a landslide and what causes one?" https://www.usgs.gov/faqs/what-a-landslide-and-what-causes-one?qt-news_science_products=0#qt-news_science_products.

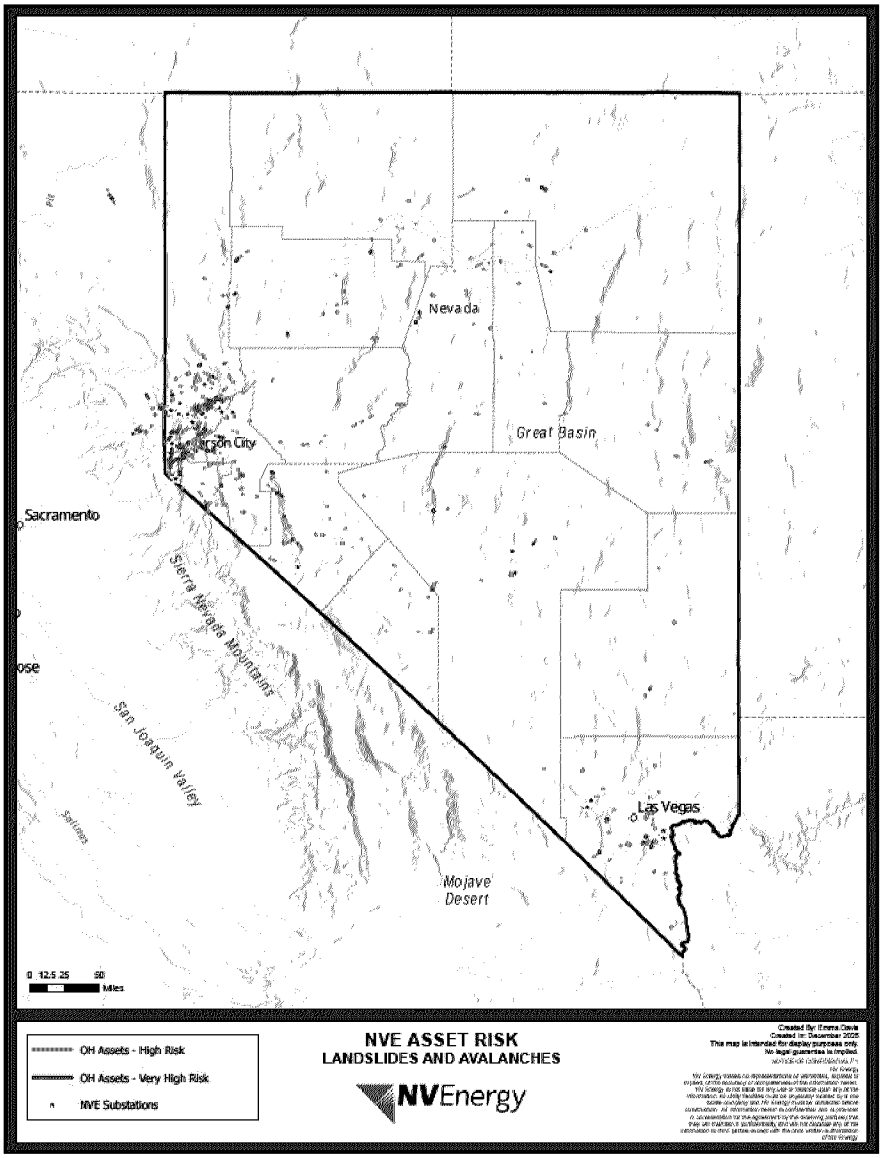
of Nevada but are largely concentrated in mountainous regions that are exposed more routinely to external factors like snow, rain, and earthquakes. Assets in California and in the hilly or mountainous areas surrounding Carson City and Reno are at the greatest risk. Minimal risk is identified for assets 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. In particular, landslides and debris flows are most prevalent in areas of previous severe wildfire activity.

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.[17] 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.

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 11 shows the map for Landslides and Avalanches as determined by the Sierra Avalanche Center information.

[17] Sierra Avalanche Center, https://www.sierraavalanchecenter.org/.

Figure 11. Landslide and Avalanche Risk

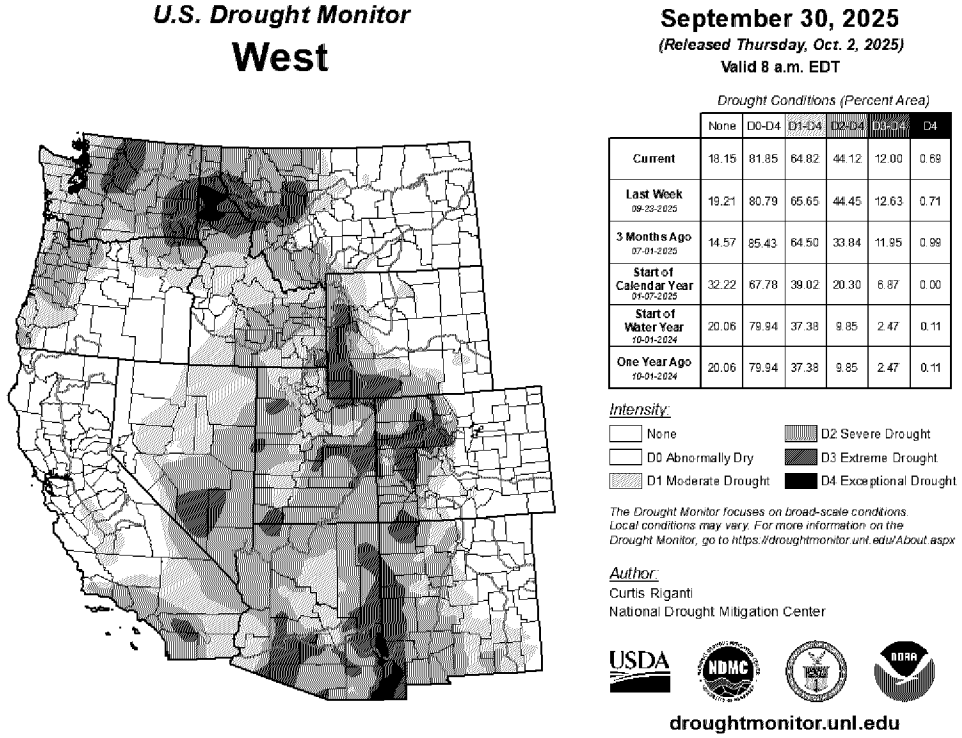


1.2.8. HEAT WAVES AND DROUGHT

As severe weather events continue to increase, the impacts of heat waves have continued to threaten reliable electricity supply to customers. Heat waves and extreme drought are common in the Companies' service territories and prolonged heat events can disrupt reliable power supply to customers when supplies or delivery routes are impacted. Wear and physical degradation from heat events will be integrated into conditional awareness to prioritize natural disaster threat remediation activities for future filings. Heat and drought conditions can exacerbate other natural disaster risk conditions, as noted by the EWG (e.g., wildfire risk). Droughts are another persisting condition potentially impacting hydroelectric generation and other water-intensive generating

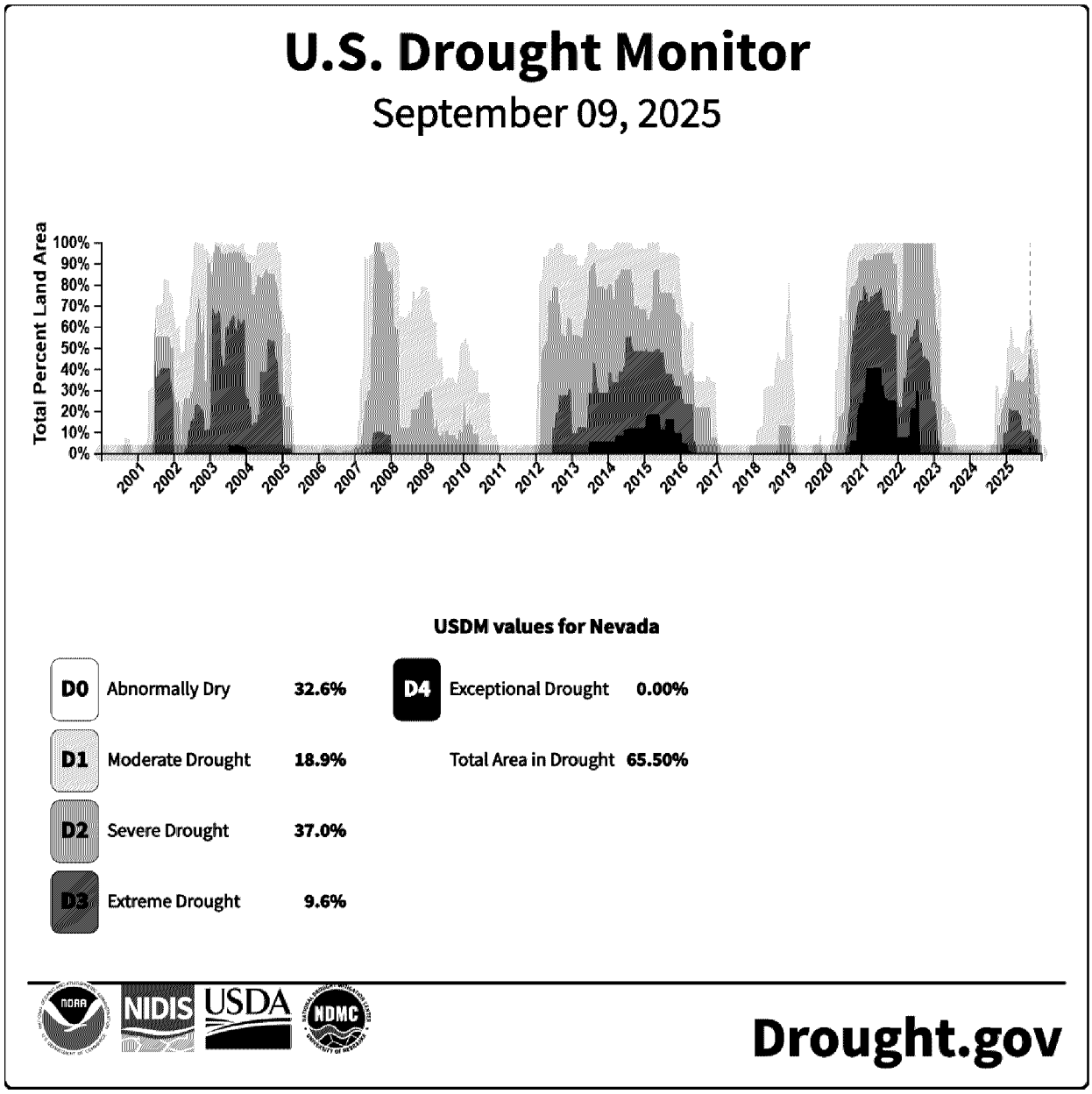
stations. As higher temperatures result in resource adequacy and power delivery issues in the Companies' service territories, mitigation measures would be harmonized with the Companies' Integrated Resource Plan and other regulatory filings, not within this plan.[18] These maps represent the recent drought conditions in September 2025. Recent rainstorms and snowstorms have temporarily relieved drought conditions as of February 2026.

Figure 12. Drought Risk Across the U.S.



[18] For additional information, please refer to the testimony of Alexander Hoon in Docket No. 23-03003.

Figure 13. Historical Drought in Nevada



2. NATURAL DISASTER PROTECTION STRATEGIES AND PROGRAMS

The following sections include the core aspects of the Companies' NDPP. The Companies harmonize activities across a portfolio of time windows to balance preparedness and hardening in advance of events with response and recovery for potential threats. As is common industry practice, the Plan is focused along multiple activity fronts. Each aspect supports one or more time horizon to ensure a comprehensive approach to protecting public safety and lowering the risk that the Companies' infrastructure would create or elevate natural disaster risk.

Figure 14. Portfolio Approach to Risk Assessment



2.1. SITUATIONAL AWARENESS

Situational awareness is a key aspect to understanding natural disaster risk. Conditional awareness is complementary to situational awareness and is addressed in later sections. The combination offers a picture of the natural disaster threats and the ability of infrastructure to withstand them. Awareness of what is happening on and around the power grid, especially in HTAs, is critical to good decision making.[19] Situational awareness provides insights into fire weather and other natural disasters. The Companies' programs include information sharing with expert agencies and other utilities along with obtaining accurate observations through weather stations and wildfire cameras. Field devices are increasingly equipped with data collection capabilities and artificial intelligence ("AI"). The Companies continue to expand the range and capabilities of devices to improve knowledge and accuracy of conditions. The Companies have also entered into important data and information sharing arrangements with the EWG and other organizations. Improved situational information is a key feature of risk evaluation for real-time operations and forecasting to prepare for potential natural disaster impacts on the power grid.

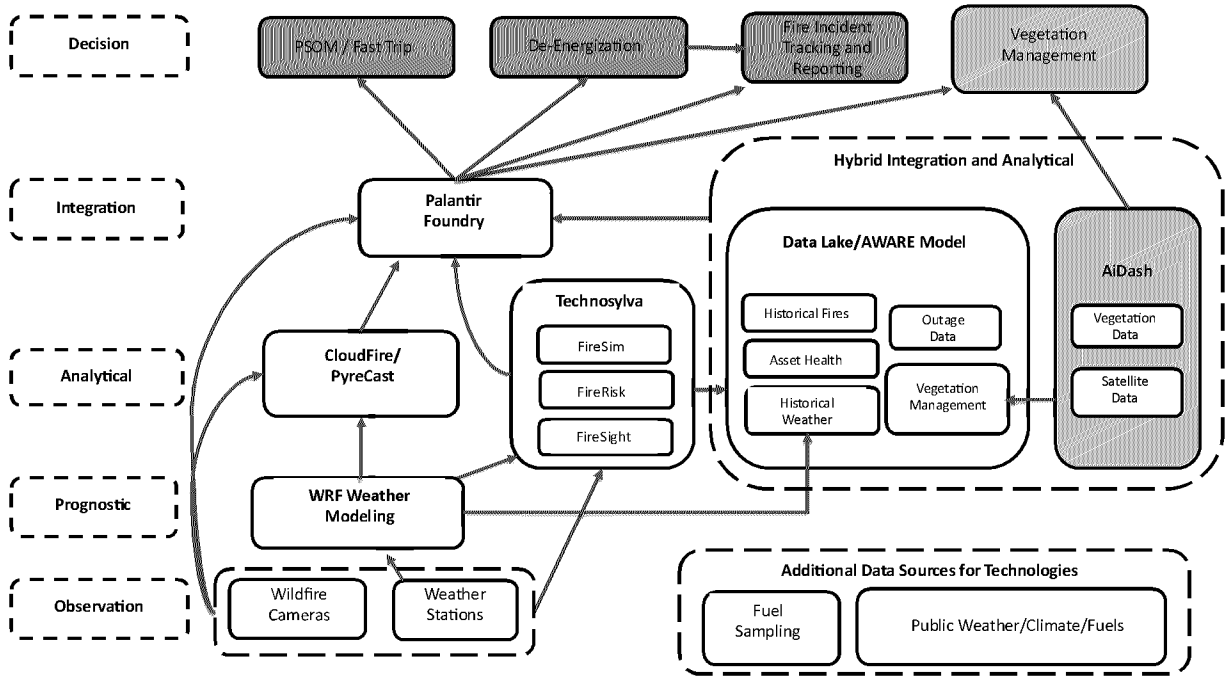
2.1.1. SITUATIONAL AWARENESS AND ANALYSIS

Situational awareness tools include internal and external sources. They are designed to support the Companies' observations, analyses, decisions, and forecasts and provide essential cross-validation as shown in Figure 15.[20]

[19] https://www.army.mil/article/238308/situational_awareness_make_safe_choices.

[20] Initially presented in Docket No. 24-12016.

Figure 15. Situational Awareness Data Map



2.1.1.1. CLOUDFIRE AND WILDFIRE RISK TIER REFRESH

Wildfire Tier are an important industry indicator of potential wildfire ignition risk from utility infrastructure. The Companies' wildfire Tier development is based on advanced modeling from CloudFire, Inc.[21] CloudFire's Planning Model provides a comprehensive look across the Companies' service territories and is used for developing wildfire risk Tiers and proactive de-energization zones. CloudFire's Operating Model is used for developing the Composite Risk Index ("CRI") and Severe Fire Danger Index ("SFDI") that informs seasonal and day-to-day operational decisions, including system protection settings and emergency procedures. A public-facing dashboard, located at nvfireweather.com provides a situational awareness platform that is available to the EWG, nearby utilities, communities, and customers. In this Triennial Plan, the Companies present an assessment of HTAs for wildfires that are indexed as Tier 3 (extreme), Tier 2 (high), Tier 1 – Elevated ("1E"), and Tier 1.

Wildfire Risk Tier Refresh

The Companies updated the Fire Risk Tiers to ensure the Plan reflects current conditions and to align mitigation activities with the best available data. CloudFire conducted a system-wide wildfire risk assessment for the 2027-2029 Triennial Plan, shown in Figure 16. This refreshes inputs and validates outputs consistent with the previously approved approach. The prior system-

[21] Formerly REAX Engineering.

wide assessment was conducted for the inaugural Triennial Plan in 2019. After experiencing some utility caused wildfires outside of the established Tiers, a system-wide wildfire risk assessment provides a full picture. The updates also address some map discontinuities based on the lack of granularity that was previously available. Updated maps are presented in this section, with a more detailed assessment included as Appendix B, Updated Wildfire Risk Assessment.

Assessment Summary

Risk Mapping Results are summarized in Table 1 and Table 2. The full assessment is presented in Appendix B.

- No Tier 3 changes are indicated in the updated assessment.
- Mapping corrections are suggested for Tier 2.
- Proposed changes to Tier 1E and 1 are presented with supporting mapping changes.

For Nevada Power, the CloudFire Wildfire Risk Assessment identifies 35 additional line miles of Tier 1E, and 529 miles of additional Tier 1.

Table 1. CloudFire Risk Assessment Summary Nevada Power

Tier	Current Line Miles	Proposed Line Miles	Line Miles Change	Percent Change
3	20	20	0	0 %
2	0	0	0	0 %
1E	0	35	35	–
1	291	820	529	181.8 %
Total	**311**	**875**	**564**	**181.3 %**

*No percent change was calculated for Tier 1E because there are currently zero Nevada Power Tier 1E line miles.

For Sierra, the CloudFire assessment identifies 50 additional miles of Tier 2; for Tier 1E, 249 additional miles, and 4,541 additional miles of Tier 1.

Table 2. CloudFire Risk Assessment Sierra

Tier	Current Line Miles	Proposed Line Miles	Line Miles Change	Percent Change
3	268	268	0	0 %
2	451	501	50	11.1 %
1E	1,430	1,679	249	17.4 %
1	2,064	6,605	4,541	220 %
Total	**4,213**	**9,053**	**4,840**	**114.9 %**

Figure 16. CloudFire Statewide Wildfire Risk Tier Assessment

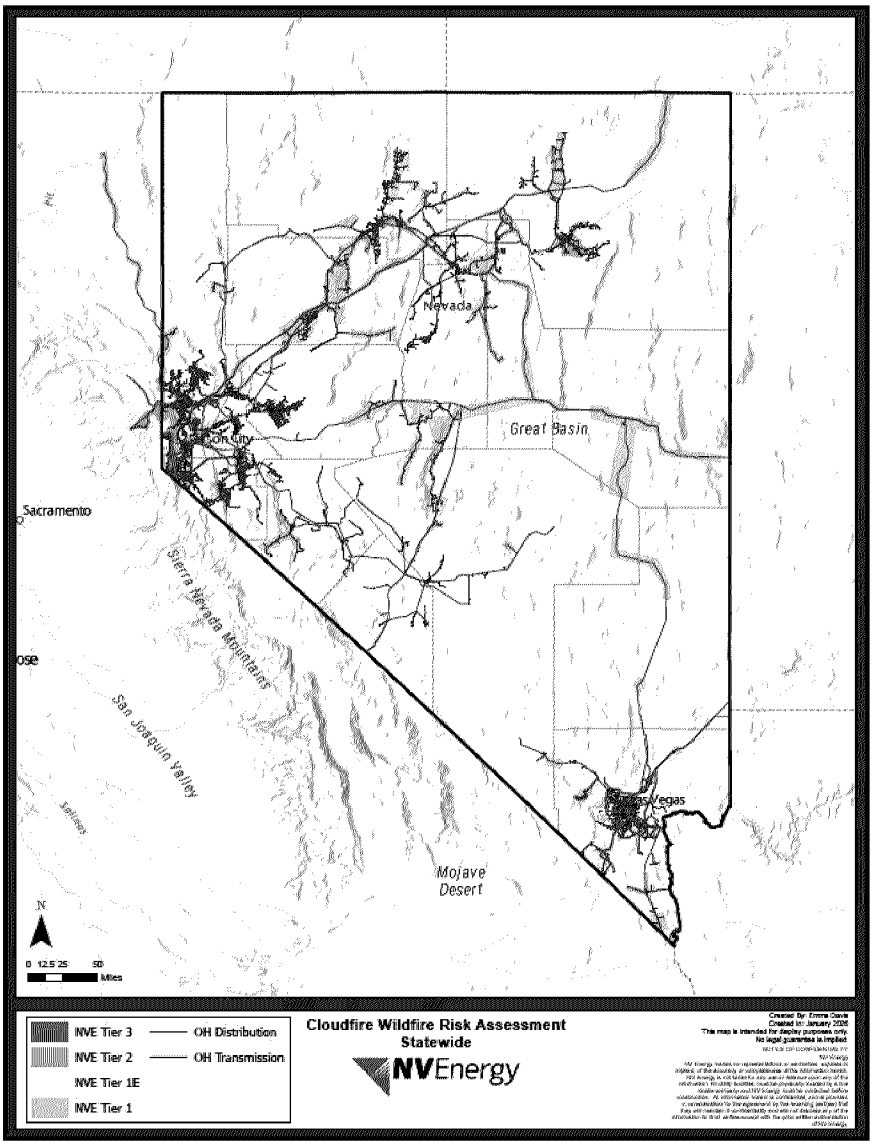


Figure 17. CloudFire Wildfire Risk Tier Assessment Northwest Area

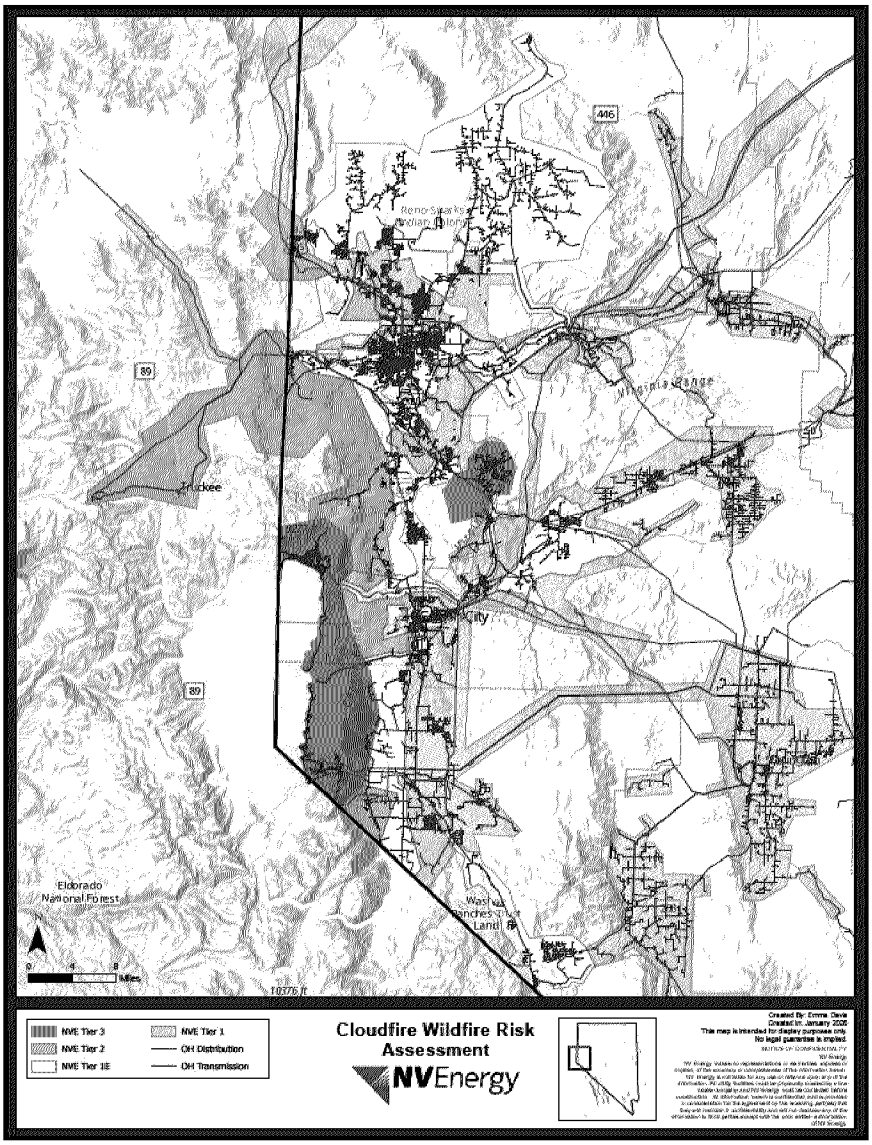


Figure 18. CloudFire Wildfire Tier Assessment Winnemucca - Elko Area

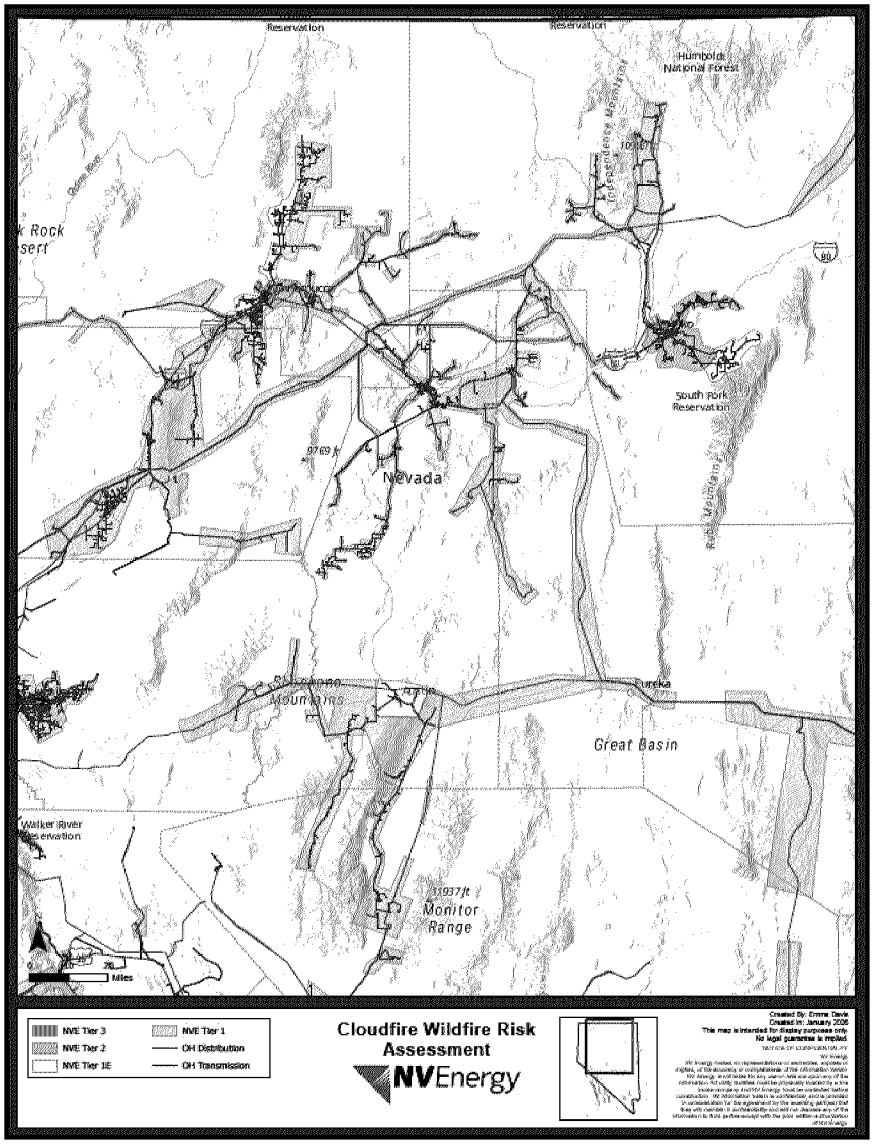
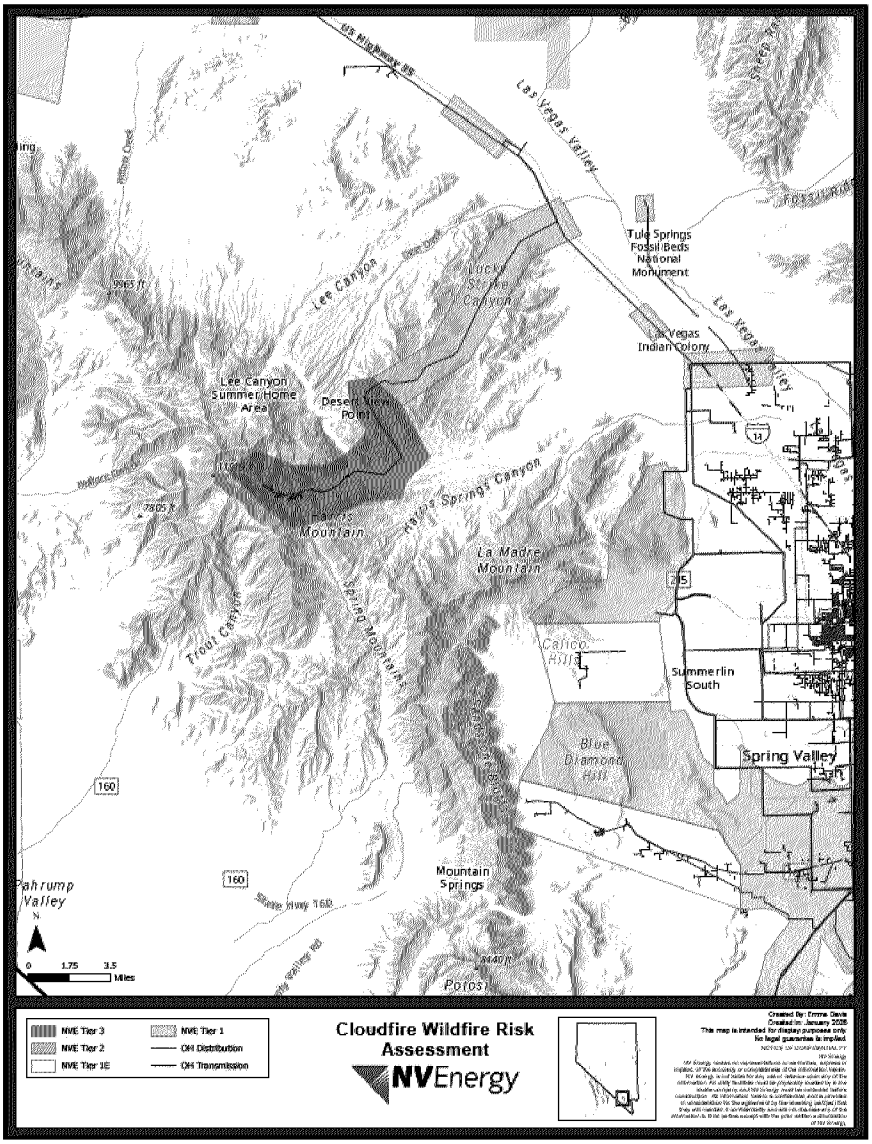


Figure 19. CloudFire Risk Tier Assessment Mt. Charleston Area



Potential Impacts:

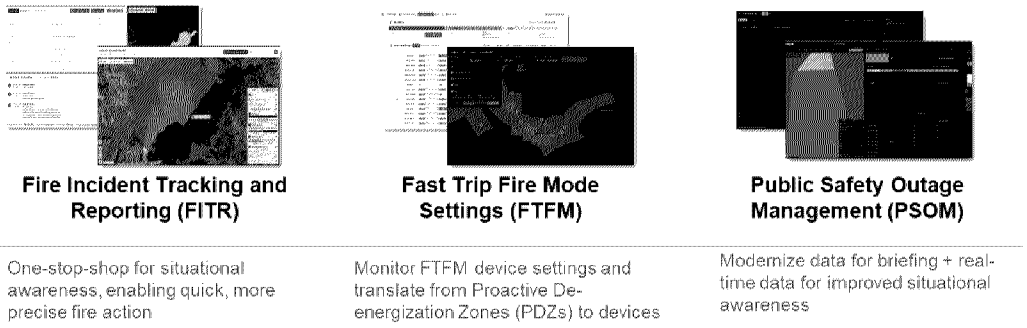
The proposed Tier changes have the potential to impact the vegetation management program, with the potential to extend the cycle completion past the original estimated dates. It also impacts the circuit patrols and detailed inspections program by increasing pole counts. This is discussed further in the respective sections.

2.1.1.2. FOUNDRY

Foundry is a wildfire data management platform for Public Safety Outage Management ("PSOM"), operational assessments,[22] and Fire Incident Tracking and Reporting ("FITR"). Foundry provides data integration, management and validation capabilities to reduce manual errors and processing delays for timely and accurate implementation of natural disaster mitigation operating programs.

Foundry systematically collects, curates, transfers and analyzes wildfire-related datasets for reporting, internal and external communications, and work tracking through dashboards and event management capabilities. The Companies propose three specific use cases for Foundry, resulting from the successful pilot program: FITR, FTFM, and PSOM.

Figure 20. Foundry Visualization and Reporting



Foundry benefits the Companies' customers in Nevada through its ability to automatically create customer notifications and data packages for sharing with the EWG partners, improving PSOM customer notifications, integrating existing databases, and eliminating the need for manual manipulation to improve the timeliness and accuracy of customer and EWG outreach. This reduces operational planning and implementation errors and data loss. Over the longer run, data-driven analyses support the prioritization of NDPP programs and projects.

As a result of the successful pilot program, the Companies request funding to continue with Foundry as a situational awareness, visualization, and reporting tool, shown in Table 3.

Table 3. Foundry OMAG Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Situational Awareness				
Situational Awareness and Analysis				
Foundry				
Nevada Power	$ 882,700	$ 280,000	$ 294,000	$ 308,700
Sierra Pacific Power	$ 11,727,300	$ 3,720,000	$ 3,906,000	$ 4,101,300
Foundry Total	$ 12,610,000	$ 4,000,000	$ 4,200,000	$ 4,410,000

[22] Informs operating decisions such as Fast Trip Fire Mode ("FTFM") and Emergency De-energization.

2.1.1.3. TECHNOSYLVA

Technosylva's outputs are used for grid hardening prioritization and cross-validation for operating decisions based on location-specific analysis. Technosylva provides risk ratings for infrastructure, individual equipment, and line segments to identify HTAs, assess field conditions, support mitigation activities, and analyze other infrastructure-related risk for wildfires. The Wildfire Analyst Enterprise fire spread prediction solutions, FireCast, FireSim and FireSight, are tailored to robustly support the requirements of the NDPP. Technosylva supports other initiatives in this Plan, such as conditional awareness based on inspections and patrols and vegetation programs to harmonize risk reduction actions.

FireCast – FireCast leverages high-resolution weather modeling and Technosylva's fire spread prediction systems to derive risk ratings for the Companies' assets that can be updated daily. Risk forecasts are produced daily using an 80-hour horizon through hundreds of millions of fire simulations for each forecast. Baseline risks are calculated for each individual distribution and transmission asset, considering population and structures impacted for each simulation. These daily risk forecasts, including fire behavior, fire size potential, and fire intensity help the Companies to:

1. Identify assets with the greatest probability of causing significant impacts should a fire occur;

2. Identify the assets with highest risk to be considered for proactive de-energization, PSOM, under extreme event conditions; and

3. Predict risk reduction potential achieved through a PSOM event.

FireSim – When fires occur, this predictive tool helps to quickly understand where the fire will likely go and what its impacts could be. FireSim provides an on-demand spread prediction containing detailed potential impacts. The impact analysis includes population density, structures, and infrastructure. This information is a key component for risk forecasting and mitigation response.

FireSight – FireSight consolidates modeling results into an operational tool that allows electric utility engineers to quantify risk reduction that will be achieved by planned system hardening projects and programs. Experts leverage this application to assess and prioritize projects based on risk reduction potential.

- To inform NDPP initiatives, FireSight integrates ignition spread predictions with infrastructure information to determine which assets are most likely to cause significant damage.

- Tools help experts design mitigation projects to maximize risk reduction by focusing on those assets with the highest expected risk.

- Detailed risk reduction reports inform planned hardening projects to gauge risk by individual asset, asset type, and at the circuit level.

Figure 21. Fire Spread Risk Analysis Example

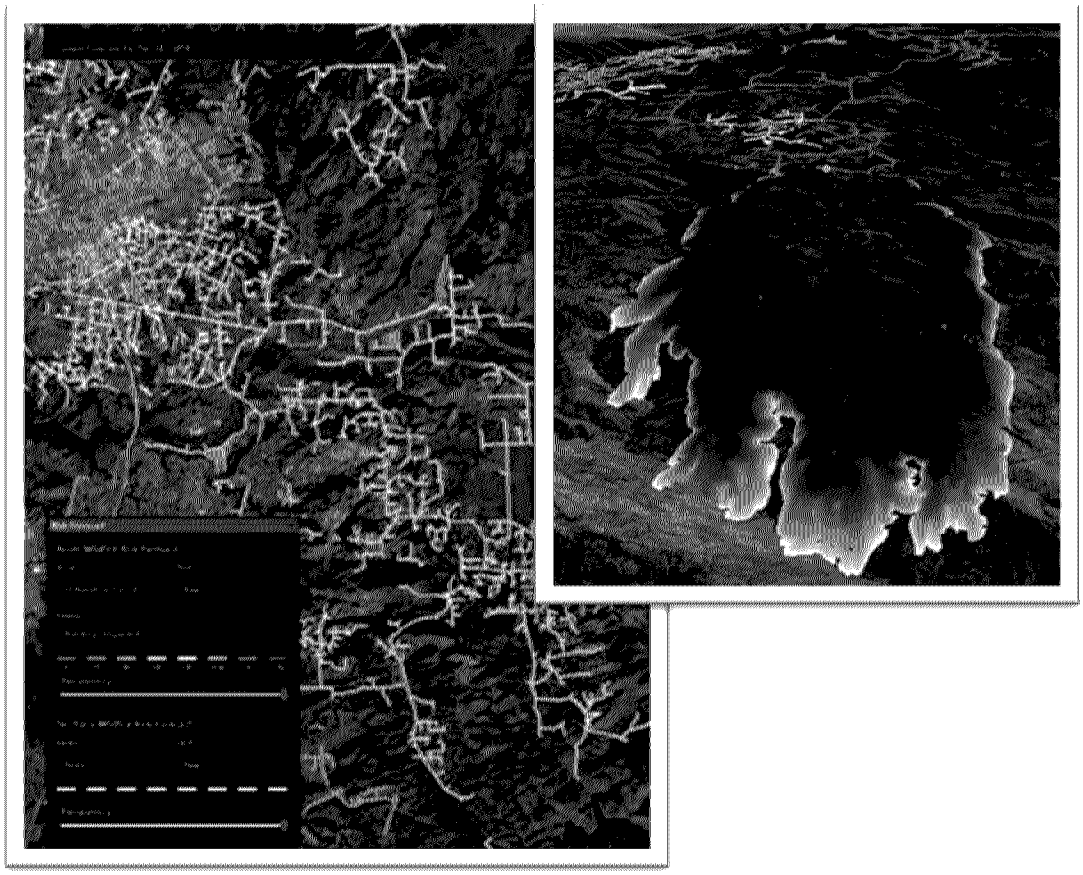


Table 4 below lists the situational awareness OMAG budget for Technosylva for this Triennial Plan.

Table 4. Technosylva OMAG Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Situational Awareness				
Situational Awareness and Analysis				
Technosylva				
Nevada Power	$ 472,700	$ 150,000	$ 157,500	$ 165,200
Sierra Pacific Power	$ 4,254,300	$ 1,350,000	$ 1,417,500	$ 1,486,800
Technosylva Total	$ 4,727,000	$ 1,500,000	$ 1,575,000	$ 1,652,000

2.1.2. WILDFIRE CAMERAS AND WEATHER STATIONS

The Companies will have 74 wildfire cameras—18 in the south, 56 in the north, and three long-range mobile units—deployed in their service territories by the end of 2026. These cameras are aligned to areas of wildfire risk based on Tier mapping. The Companies continue to collaborate on options for further deployment of cameras through partnerships with the BLM and other agencies. The Companies plan to add approximately ten additional cameras per year through partnerships with UNR, for a total of 30 new cameras deployed in the 2027-2029 time period.

The Companies will also have 115 weather stations by the end of 2026, with 19 in the south and 96 in the north. Weather is a key driver of operational mitigation efforts such as FTFM or PSOM. As knowledge is gained about weather patterns in the wildfire Tiers, it can inform other NDPP programs such as hardening initiatives, emergency response, and communications. These weather stations will improve situational awareness for remote and disadvantaged communities in Nevada. The Companies plan to add approximately ten additional weather stations per year for a total of 30 new weather stations deployed in the 2027-2029 time period.

Table 5 below lists the situational awareness OMAG budget for weather stations and wildfire cameras for this Triennial Plan. This budget covers ongoing service fees associated with communications to the existing and proposed devices, along with calibration costs for the weather stations. Table 6 below is the capital budget for the deployment of additional wildfire cameras for this Triennial Plan.

Table 5. Wildfire Cameras and Weather Stations OMAG Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Situational Awareness				
Nevada Power				
Wildfire Cameras	$ 756,158	$ 189,150	$ 242,708	$ 324,300
Weather Stations	$ 282,479	$ 79,501	$ 92,263	$ 110,715
Nevada Power Total	**$ 1,038,637**	**$ 268,651**	**$ 334,971**	**$ 435,015**
Sierra Pacific Power				
Wildfire Cameras	$ 2,351,206	$ 648,300	$ 750,015	$ 952,891
Weather Stations	$ 1,425,584	$ 401,688	$ 465,707	$ 558,189
Sierra Pacific Power Total	**$ 3,776,790**	**$ 1,049,988**	**$ 1,215,722**	**$ 1,511,080**
Situational Awareness Total	**$ 4,815,427**	**$ 1,318,639**	**$ 1,550,693**	**$ 1,946,095**

Table 6. Weather Stations and Wildfire Cameras Capital Budget Forecast

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Situational Awareness				
Nevada Power				
Wildfire Cameras	$ 724,458	$ 229,412	$ 241,486	$ 253,560
Weather Station	$ 148,956	$ 47,250	$ 49,613	$ 52,093
Nevada Power Total	**$ 873,414**	**$ 276,662**	**$ 291,099**	**$ 305,653**
Sierra Pacific Power				
Wildfire Cameras	$ 1,936,834	$ 614,437	$ 644,606	$ 677,791
Weather Station	$ 1,397,500	$ 443,000	$ 465,500	$ 489,000
Sierra Pacific Power Total	**$ 3,334,334**	**$ 1,057,437**	**$ 1,110,106**	**$ 1,166,791**
Situational Awareness Total	**$ 4,207,748**	**$ 1,334,099**	**$ 1,401,205**	**$ 1,472,444**

2.1.3. HAZARD AWARENESS DESK

The Companies are implementing the hazard awareness desk approved in Docket No. 24-12016 to identify risks across the service territories, pooling multiple sources of intelligence and communication. The Companies focus on awareness and analysis related to natural disaster impacts on grid operations. Five Hazard Awareness Analysts ensure 24-hour coverage to filter a wide range of intelligence from multiple sources to discern credible threats to the Companies' electric system and subsequently dispatch Fire Management Officers for emergency operations and coordinate with public safety incident commanders. Table 7 identifies the OMAG-related costs associated with the hazard awareness desk. There are no anticipated capital costs for this program.

Table 7. NDPP Hazard Awareness Desk Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Hazard Awareness				
Nevada Power	$ 336,642	$ 109,338	$ 112,185	$ 115,118
Sierra Pacific Power	$ 4,472,526	$ 1,452,632	$ 1,490,464	$ 1,529,430
Hazard Awareness Total	**$ 4,809,168**	**$ 1,561,970**	**$ 1,602,649**	**$ 1,644,549**

2.1.4. SITUATIONAL AWARENESS PROGRAM COSTS

Table 8. Situational Awareness Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Situational Awareness				
Nevada Power				
Hazard Awareness	$ 336,642	$ 109,338	$ 112,185	$ 115,118
Situational Awareness and Analysis	$ 1,458,676	$ 462,760	$ 485,898	$ 510,018
Weather Stations	$ 282,479	$ 79,501	$ 92,263	$ 110,715
Wildfire Cameras	$ 756,158	$ 189,150	$ 242,708	$ 324,300
Nevada Power Total	**$ 2,833,955**	**$ 840,749**	**$ 933,054**	**$ 1,060,151**
Sierra Pacific Power				
Hazard Awareness	$ 4,472,526	$ 1,452,632	$ 1,490,464	$ 1,529,430
Situational Awareness and Analysis	$ 16,275,539	$ 5,163,240	$ 5,421,402	$ 5,690,897
Weather Stations	$ 1,425,584	$ 401,688	$ 465,707	$ 558,189
Wildfire Cameras	$ 2,351,206	$ 648,300	$ 750,015	$ 952,891
Sierra Pacific Power Total	**$ 24,524,855**	**$ 7,665,860**	**$ 8,127,588**	**$ 8,731,407**
Situational Awareness Total	**$ 27,358,810**	**$ 8,506,609**	**$ 9,060,642**	**$ 9,791,559**
Grand Total	**$ 27,358,810**	**$ 8,506,609**	**$ 9,060,642**	**$ 9,791,559**

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Situational Awareness				
Nevada Power				
Wildfire Cameras	$ 724,458	$ 229,412	$ 241,486	$ 253,560
Weather Station	$ 148,956	$ 47,250	$ 49,613	$ 52,093
Nevada Power Total	**$ 873,414**	**$ 276,662**	**$ 291,099**	**$ 305,653**
Sierra Pacific Power				
Wildfire Cameras	$ 1,936,834	$ 614,437	$ 644,606	$ 677,791
Weather Station	$ 1,397,500	$ 443,000	$ 465,500	$ 489,000
Sierra Pacific Power Total	**$ 3,334,334**	**$ 1,057,437**	**$ 1,110,106**	**$ 1,166,791**
Situational Awareness Total	**$ 4,207,748**	**$ 1,334,099**	**$ 1,401,205**	**$ 1,472,444**

2.2. OPERATING PRACTICES

The Companies implement adaptive operating actions to protect public safety and manage infrastructure integrity. Grid automation incorporates protective devices into the system, enabling more precise timing and location of actions. Remotely operated field devices reduce the need for field crews and truck rolls through strategic deployment of technology. The Companies collaborate with members of the EWG in preparing for and implementing operational practices deployed for public safety. The Companies continue to utilize contracted fire resources for standby during critical fire weather or other hazardous conditions for rapid and coordinated response.

2.2.1. OPERATING MODES

The Companies have operationalized the Summer Readiness wildfire mitigation protocols initially identified in Docket No. 24-12016. Based on information from the meteorology and data science teams, the grid is configured to operate more conservatively to reduce wildfire risk during elevated fire weather conditions. Operating configurations are based on indices such as the CRI[23] and SFDI, respectively, shown in Figure 22. Indices are informational and there is always a "human in the loop" during the decision-making process.

Normal Operations: The power grid is typically configured to reclose should the system trip due to transient conditions such as animal contact or vegetation blowing through the area. This allows the temporary condition to clear and promptly return the system to normal operating conditions. There is a short time delay of a few seconds between detecting an anomalous condition and relay operation to ensure sequencing of all related protection relays.

Seasonal Fire Mode: Based on fire weather conditions and the SFDI, normal reclosing is disabled to avoid the possibility of creating a spark. The system is set to lock out until a patrol can confirm the conditions are safe to return the grid to service.

FTFM: The Companies have deployed protective devices that can be activated in 0.1 seconds, which is a shorter time than normal relay operations. This is deployed during extreme fire weather, based on the SFDI, in Tiers 3, 2, and 1E. The system will be patrolled prior to reclose if Fast Trip has activated. If no outages occur during elevated fire danger conditions, the system will be adjusted to Seasonal Fire Mode or normal operation when prevailing weather conditions permit. The Companies anticipate that the installation of FTFM-capable equipment for the Tier areas will be complete in 2026.

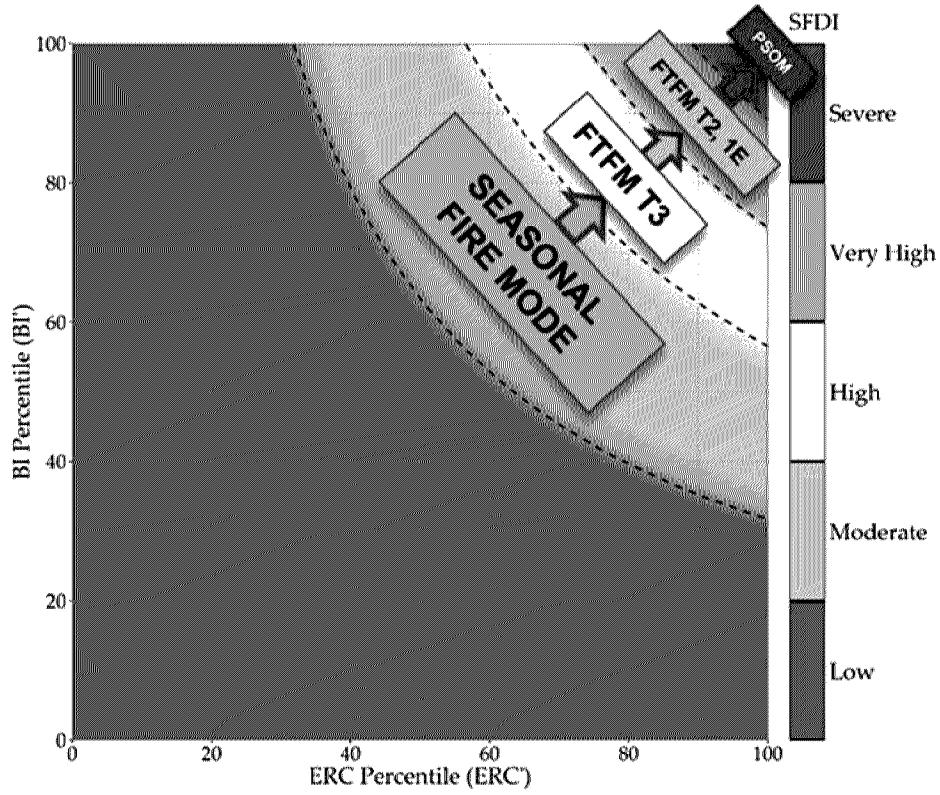
PSOM: Proactive de-energization is a system-wide practice for both the transmission and distribution systems, reserved for the extreme fire weather events. Informed by a combination of the CRI and inputs from meteorology, fire, and other subject matter experts, portions of the system may be de-energized to avoid the potential for the power grid to be a source of ignition. CRI criteria differ for Tiers 3, 2, and 1E (along with the balance of the service territory) and are used

[23] The CRI can be viewed at www.nvfireweather.com.

to guide decision makers about anticipated fire weather and the need for a PSOM event. The grid is patrolled prior to re-energization based on Tier-specific policies.

Emergency De-Energization: The Emergency De-Energization Policy is a system-wide practice to de-energize segments of the grid within the proximity of an active fire that is unpredictable and uncontrollable. Patrols are conducted where fire activity has occurred. The grid is re-energized incrementally based on prevailing conditions.

Figure 22. Operating Modes Based On SFDI



Source: NV Energy's NDPP Wildfire Season Operations Plan

2.2.2. PSOM

PSOM refers to a planned circuit outage that is activated by the Companies when conditions pose a significant safety threat to the Companies' customers, infrastructure, or the public. When conditions create an unacceptable level of risk of electric infrastructure becoming a source of a wildfire ignition, PSOM may be initiated. The CRI includes quantitative criteria that inform decisions about proactive de-energization. Fire weather conditions are tracked and communicated on the Companies' website www.nvfireweather.com. Fire Risk Tiers inform the criteria at which

PSOM may be activated.[24] Proactive De-energization Zone ("PDZ") maps are derived from the risk Tiers based on the location of controllable devices.[25] Customers and critical services are identified for each circuit as part of communications planning in fire Tiers. The Companies collaborate with the EWG representatives to include local information and considerations. A PSOM event is considered concluded once the restoration process is complete. This is after circuits are patrolled and, as needed, inspected and corrected, prior to re-energization. Appendix C contains the Companies' updated PSOM Plan.

2.2.3. MT. CHARLESTON MICROGRID OPERATIONS

The Companies are requesting annual operating and maintenance budget for ongoing operating costs for the duration of the 2027-2029 Triennial Plan, which includes preventive maintenance for the new backup generators, refueling generators, PV cleaning, battery maintenance, remote monitoring, daily monitoring, 24/7 phone support, automatic emails and phone calls for alerts and alarms, monthly reporting, visual inspections, vegetation management, thermal inspections, capacity testing, performance uptime guarantee, emergency maintenance support, annual permitting, and propane tank certification, shown in Table 9. The microgrid is moving from temporary diesel-generator sets to a 50 percent renewable fraction microgrid over the next few years. The microgrid OMAG costs are reflective of the transition from the seasonal microgrid to one that is operating year-round.

Table 9. Mt. Charleston Microgrid OMAG

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Operational Practices				
Emergency Response				
Mt. Charleston Microgrid	$ 1,680,000	$ 240,000	$ 480,000	$ 960,000

2.2.4. EMERGENCY DE-ENERGIZATION POLICY

Emergency De-Energization[26] refers to an unplanned circuit outage that is taken by the Companies when an active wildfire that is unpredictable and uncontrollable is approaching company infrastructure. The Emergency De-Energization Policy includes defined protocols that inform decisions about real time de-energization, presented in Appendix G. Active fire conditions are assessed through operational intelligence, field reports, and coordination with fire management and response agencies. Refinements in the Plan include situational awareness tools and the Hazard Awareness Desk. Analysts utilize real-time intelligence to inform the criteria at which Emergency De-Energization may be activated. Threatened circuits are identified through system mapping for distribution, transmission and generation assets. An Emergency De-

[24] De-energization criteria differ for Tier 3, Tier 2, and Tier 1E or lower.

[25] https://www.nvenergy.com/safety/psom.

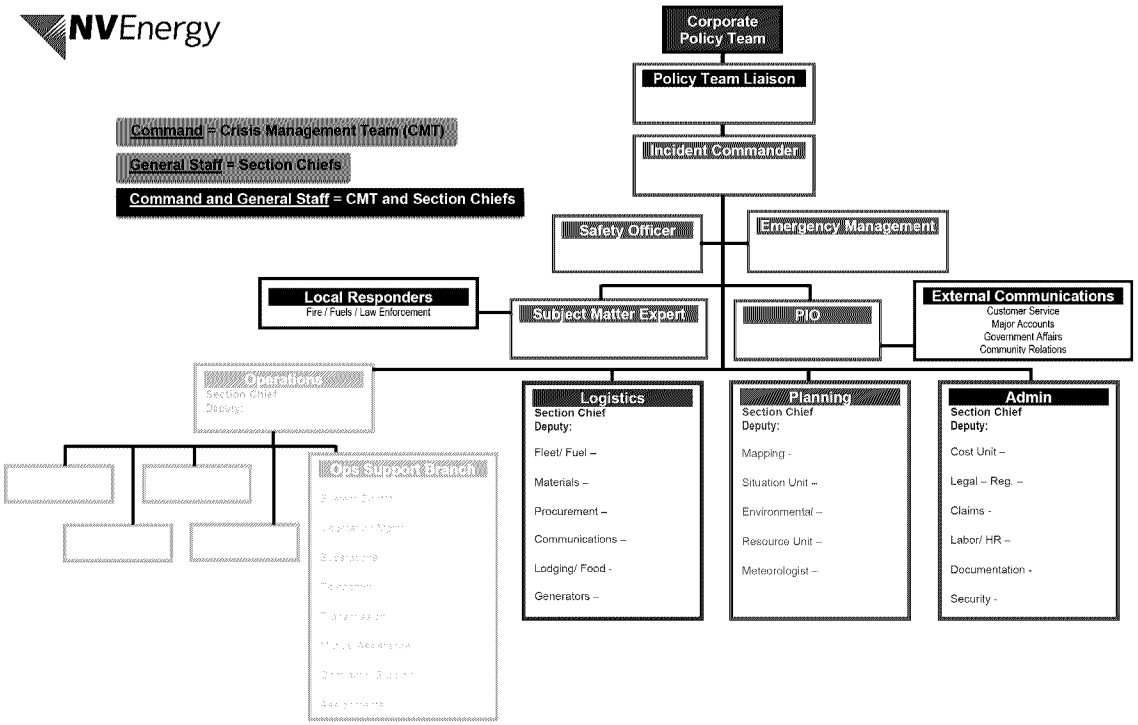
[26] Docket No. 24-12016.

Energization event is considered concluded once the fire threat has passed and the restoration process is complete. The restoration process includes patrolling identified circuits and, as needed, conduct a detailed inspection as needed and complete identified corrections, prior to re-energization.

2.2.5. EMERGENCY OPERATIONS

The Companies respond to emergencies using Incident Command Structure ("ICS") and in accordance with the Corporate Emergency Response Plan. When significant emergencies arise, such as PSOMs, earthquakes, and other severe weather events, the Companies' Incident Management Teams ("IMTs") are activated. Staffing is tailored to each incident, according to ICS protocols. In collaboration with the public safety partners and the broader EWG, the Companies have harmonized their emergency management and operations with a broadened collaborative ICS. The Companies have a standing IMT whose members rotate through on-call duty. There is a reserve pool of employees that support these teams.

Figure 23. Incident Management Team Chart



Emergency response also includes communications resources. FirstNet, the nationwide public safety broadband network, is used for continuous internal and external cellular phone and iPad communication. The Companies own 13 Communication on Wheels ("COWs") for deployment during emergencies to facilitate communications and reliable internet when normal communication infrastructure is compromised. Over time, the Companies intend to supplement communications with Starlink satellite communications. Portable Wi-Fi devices help to provide

internet capability in the field. The Companies intend to incorporate Amateur Radio Emergency Services ("ARES"), using its own trained employees, as a backup for all disasters and will ensure the necessary equipment is situated in the north and south Emergency Operations Centers ("EOCs"). Handheld field radios are also available for deployment.

As part of emergency operations, the Companies may open one or more customer resources centers ("CRCs") for drive through or walk-up services. The Companies may use private facilities to serve the dual purpose of supporting impacted PSOM customers and serving as an alternate Incident Command Post. Additional support for Green Cross Customers supplements services to the broader community.

The Companies contract with a vendor to support CRCs, including CRC set-up such as providing a tent for customers or mobile workspace for staff, directional signage, and other services as directed by the Companies' IMT.

Table 10 below lists the Emergency Response budget forecast for this Triennial Plan.

Table 10. Emergency Response Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Operational Practices				
Emergency Response				
Nevada Power	$ 2,365,062	$ 466,202	$ 708,326	$ 1,190,534
Sierra Pacific Power	$ 2,493,613	$ 814,388	$ 831,032	$ 848,194
Emergency Response Total	**$ 4,858,676**	**$ 1,280,590**	**$ 1,539,358**	**$ 2,038,728**

2.2.6. SPECIALIZED SAFETY TRAINING

At least on an annual basis, personnel are trained in wildfire safe work practices and emergency procedures. Those involved with the IMT receive training in emergency operations and the Companies' ICS approach. Members of these teams are pursuing or have completed the Federal Emergency Management Agency Incident Command System courses 100, 200, 300, 700, and 800. The teams are responsible for creation and implementation of incident action plans for managing complex or expanded emergencies. The IMTs have been activated for PSOM events and participate in multiple event preparation training exercises.

During fire season, the Companies take special safety measures, including federal decision memos and permits, and the Wildland Urban Interface ("WUI") Code, to ensure that work activities do not cause a wildfire ignition. In addition to minimizing hot work during fire season, preventive protocols include keeping incipient firefighting equipment in an accessible location, having fire personnel and fire engines on standby when conditions warrant, providing fire watch 1-3 hours after hot work is completed, assuring non-combustible areas around the work site, erecting barriers to contain sparks, avoiding driving on dirt roads, wetting the work area, monitoring weather hourly, and monitoring fire risk daily. Partnerships with fire agencies provide

access to engines and fire suppression support that remain on standby and fire watch as part of vegetation management and prioritizing system hardening projects. Partner programs also provide fire and Emergency Management Services ("EMS") standby during PSOM events and on Extreme Weather Warning days.

2.2.7. DISTRIBUTION AUTOMATION

The Commission approved a dedicated Distribution Automation ("DA") group within the NDPP responsible for coordination and proper operation of new protective devices such as reclosers, TripSavers, and fuses.[27] The DA group will refresh outmoded protection on distribution circuits and add new intelligent devices to remotely control the system and reduce the duration and number of customers impacted by NDPP-related outages. Performing coordination studies on higher risk distribution circuits potentially reduces fault clearing times that lower wildfire risk, improve the safety of field personnel, and significantly improve reliability. DA personnel will identify, program, and monitor field devices, such as reclosers and smart fuses, to sectionalize circuit segments. The DA team will perform engineering studies and system analysis to assess the impact of potential proactive de-energization, identifying where system outages can be reduced both geographically and temporally. Engineers will use intelligent automation to enable remote operation and sectionalization during high-risk conditions that limit or eliminate the need for multiple truck rolls and delays associated with manual operation of system devices. This also makes the system more robust against other severe natural disasters, like heavy snowstorms with wet snow taking down sections of distribution network.

NDPP DA staffing began in 2026, including a leader and engineer to perform and complete studies and facilitate installations, including communications. The Companies plan to onboard the additional technical resources as outlined in Docket No. 24-12016 by the third quarter of 2027. In 2027, the Companies anticipate the DA team will complete a comprehensive strategic plan and feeder-level coordination studies that standardize settings and communications architecture across wildfire risk Tiers. In 2028 and 2029, the Companies will perform and complete studies, integration, and field installations for up to 15 initial devices (TripSavers and/or line reclosers)

[27] Docket No. 24-12016.

targeted per year, inclusive of communications. Table 11 and Table 12 show the proposed OMAG and capital budgets for DA group within NDPP.

Table 11. NDPP Distribution Automation OMAG Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Operational Practices				
Distribution Automation				
Nevada Power	$ 154,878	$ 90,999	$ 31,467	$ 32,411
Sierra Pacific Power	$ 1,896,231	$ 549,272	$ 663,526	$ 683,432
Distribution Automation Total	**$ 2,051,109**	**$ 640,272**	**$ 694,993**	**$ 715,843**

Table 12. NDPP Distribution Automation Capital Budget Forecast

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Operating Practices				
Distribution Automation				
Nevada Power	$ 321,157	$ 30,261	$ 133,965	$ 156,931
Sierra Pacific Power	$ 6,225,190	$ 905,565	$ 2,496,508	$ 2,823,117
Distribution Automation Total	**$ 6,546,347**	**$ 935,826**	**$ 2,630,473**	**$ 2,980,048**
Operating Practices Total	**$ 6,546,347**	**$ 935,826**	**$ 2,630,473**	**$ 2,980,048**

2.2.8. OPERATIONAL PRACTICES BUDGET FORECAST

Table 13. Operational Practices Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Operational Practices				
Nevada Power				
Distribution Automation	$ 154,878	$ 90,999	$ 31,467	$ 32,411
Emergency Response	$ 2,365,062	$ 466,202	$ 708,326	$ 1,190,534
PSOM	$ 1,394,766	$ 451,570	$ 464,703	$ 478,493
Nevada Power Total	**$ 3,914,705**	**$ 1,008,772**	**$ 1,204,496**	**$ 1,701,437**
Sierra Pacific Power				
Distribution Automation	$ 1,896,231	$ 549,272	$ 663,526	$ 683,432
Emergency Response	$ 2,493,613	$ 814,388	$ 831,032	$ 848,194
PSOM	$ 2,063,987	$ 670,655	$ 687,040	$ 706,291
Sierra Pacific Power Total	**$ 6,453,831**	**$ 2,034,316**	**$ 2,181,598**	**$ 2,237,917**
Operational Practices Total	**$ 10,368,536**	**$ 3,043,087**	**$ 3,386,094**	**$ 3,939,355**

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Operating Practices				
Nevada Power	**$ 321,157**	**$ 30,261**	**$ 133,965**	**$ 156,931**
Distribution Automation	$ 321,157	$ 30,261	$ 133,965	$ 156,931
Sierra Pacific Power	**$ 6,225,190**	**$ 905,565**	**$ 2,496,508**	**$ 2,823,117**
Distribution Automation	$ 6,225,190	$ 905,565	$ 2,496,508	$ 2,823,117
Operating Practices Total	**$ 6,546,347**	**$ 935,826**	**$ 2,630,473**	**$ 2,980,048**

2.3. VEGETATION MANAGEMENT

Vegetation mitigation is an essential element of natural disaster risk reduction. The Companies' vegetation management, including patrols along utility rights-of-way ("ROW"), tree pruning, vegetation removal, clearing space around poles, in combination with vegetative fuels mapping is an ongoing program. Dedicated vegetation management experts have operationalized industry-standard utility vegetation management ("UVM") practices, which continue to evolve. The Companies' vegetation management now leverages technology and expertise to prioritize patrols and conduct strategic vegetation clearing work across all HTAs, while longer-term maintenance activities continue.

The Companies have modified practices such as strategic herbicide application following mowing and mastication along ROW to deter invasive species and reduce ongoing cycle-based maintenance. However, not every authority having jurisdiction ("AHJ") allows the use of herbicide without some level of National Environmental Policy Act ("NEPA") study and only one AHJ has approved resilient corridor clearances. Modifications to the ground fuels program continue to focus on reducing risk. Clearing vegetation around utility facilities, conducting hazard tree patrols, and creating fuel breaks without invasive species are all part of a successful integrated vegetation management ("IVM") program. This plan includes a policy regarding enhanced clearances around substations, included in Appendix E.

The Companies' vegetation management objectives remain unchanged, focusing on minimizing the likelihood of vegetation contacting electric conductors and reducing ground fuels that could ignite and contribute to fire spread near facilities. The program continues to comply with the International Wildland Urban Interface Code ("IWUIC"), meets all permitting requirements from the AHJs, and aligns with Community Wildfire Protection Plans ("CWPP"). NDPP funding targets incremental vegetation management for identified HTAs only. General Rate Case funding is used for vegetation management treatments outside of HTAs.

2.3.1. PATROLLING AND TREE PRUNING

The Companies have protocols for patrolling and tree pruning, requiring a certified arborist or similarly qualified person to conduct patrols and evaluate conditions prior to implementing mitigation work. Patrols identify hazard trees and potential vegetation encroachment to develop prescribed treatments. The Companies have performed extensive annual patrols and removed thousands of hazard trees to protect electric infrastructure. This Triennial Plan reflects the transition from initial treatments and clearance work to ongoing maintenance treatments.

Competitively awarded contracted resources perform tree pruning to maintain safe distances between conductors and vegetation. This includes both prescheduled cyclical pruning and reactive tree pruning based on conditions in the field. Tree work can include canopy pruning and total tree removals using cranes and helicopters for logging. Working near power lines may require planned outages for safety. Where possible, tree pruning work coordinates with pole and ROW clearing to increase efficiency in managing debris removal and project completion.

With the proposed expansion of the wildfire Tiers, the Companies will establish 2032 target completion dates incremental treatments in Tiers 2 and 1E. Leveraging satellite imagery and the condition-based approach, the proposed budget will fund the required work, with a focused effort in high-risk areas during 2027-2029. Any impacts that require further adjustments will be reflected in future updates.

2.3.2. GROUND FUELS MANAGEMENT

To evaluate the effectiveness of pole and ROW clearing, the program is moving to condition-based cycles rather than calendar-based cycles. Clearing poles and ROW includes the strategic removal of ground vegetation adjacent to the Companies' facilities. Where authorized by the AHJ, herbicide application has proven successful around poles and within the ROW to reduce invasive species. Herbicide treatment has the potential to reduce annual ROW maintenance by minimizing incompatible species and limiting brush density for several years. Herbicide application requires AHJ approval, special permits, and cannot be used in protected or sensitive areas.

At distribution voltage levels, the IWUIC requires a minimum radial clearance of 10 feet for poles with facilities. For transmission voltages clearances are often set through mandatory transmission clearance standards, in some cases, up to 30 feet.[28] The Companies' ground fuels mitigation considers fuel type, herbicide approval, and equipment on poles for the needed enhanced clearing. All debris must be removed, and the Companies aim to complete the removals as quickly as possible, in most cases within two weeks. Continued collaboration with the local, state, and federal agencies affords the opportunity to implement best practices and treatment methods tailored to the environment and terrain. Updates to Master Special Use Permits ("MSUP") helps expedite ROW clearing, reducing delays through other special permitting requirements. All AHJ's must approve of enhanced pole and ROW clearance requiring stewardship agreements or revised grants of easement.

The Companies utilize science-based UVM practices to thin vegetation to slow wildfire spread and decrease flame length. ROWs can serve as anchor points to fuel breaks within HTA where the AHJ and private landowners have approved such work. Vegetative fuel removal includes physical disposal, mastication, chipping, and prescribed pile burning. In steep remote terrain where vegetation cannot be hauled away or chipped, vegetative material is gathered and piled, then burned in the winter under special permits. With AHJ approval and where terrain allows, vegetation debris may be chipped and broadcast onsite to reduce erosion. Where chip trucks have access, chipped debris can be donated to state and city parks and to citizens upon their request. Vegetative debris could also be made available for bioenergy fuel if available.

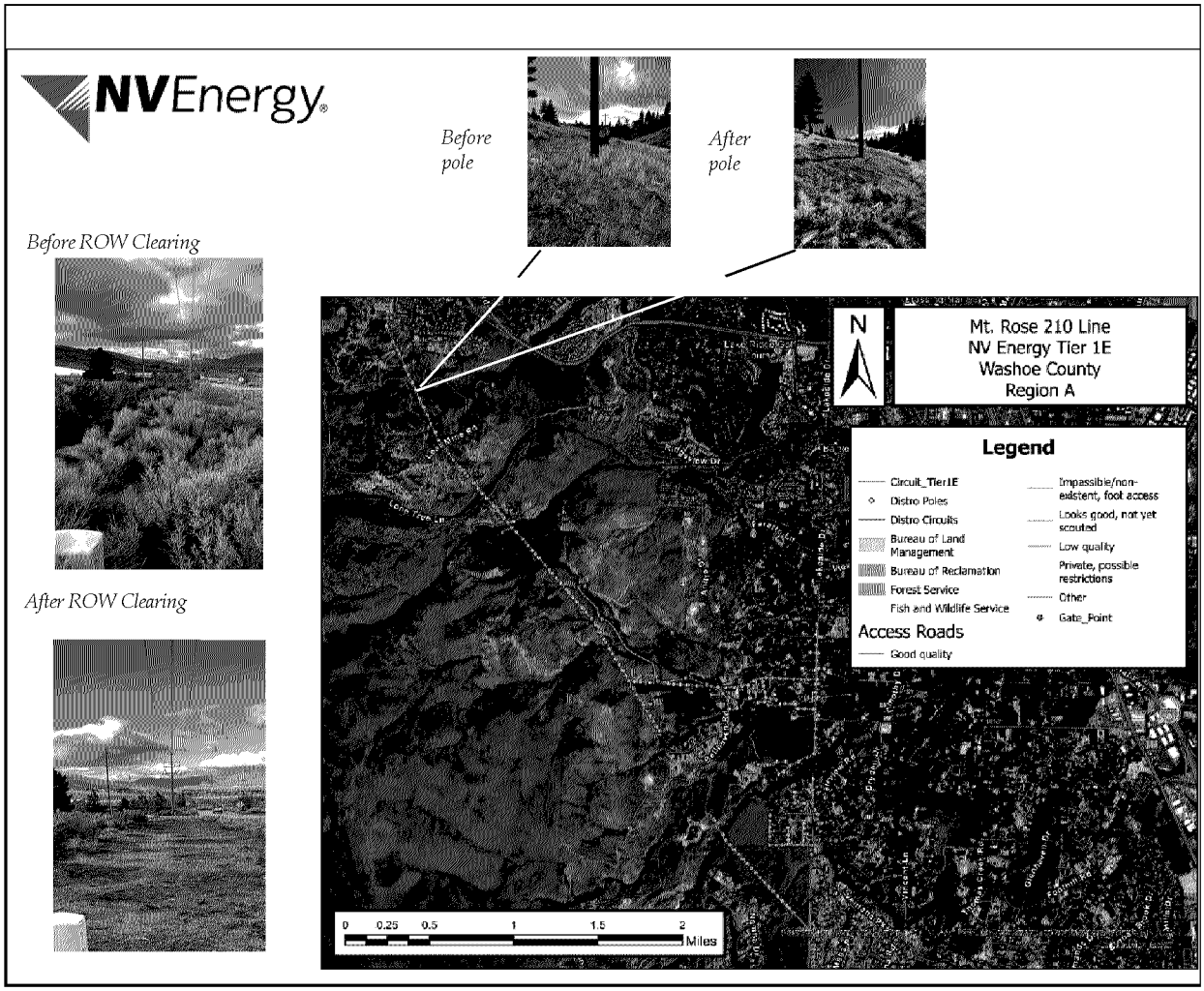
The Companies intend to perform ROW fuels mitigation work utilizing third party contractors based on least cost, including contractual partnerships with local fire agencies. Local fire agency crews are qualified by the National Wildfire Coordinating Group to perform debris pile burning and fire overwatch during high-risk weather conditions. Their qualifications help facilitate the accomplishment of fire mitigation efforts.

[28] FAC-003-5 of the North American Electric Reliability Corporation ("NERC").

A strategic approach under consideration is utilizing local fire agencies, within their own districts, to monitor and perform fuels reduction maintenance in residential communities alongside existing defensible space programs.

Figure 24 below shows the before and after results of a project in the Mount Rose and Overland circuits of northern Nevada.

Figure 24. Rights of Way Clearing Examples



2.3.3. SATELLITE IMAGING

The Companies will complete the satellite imaging and analysis pilot program in 2026. Based on the successful conclusion of the pilot program, the Companies anticipate conducting a competitive solicitation for ongoing satellite imaging services, incorporated into the vegetation management program. Satellite imagery raw data obtained through satellite flyovers helps to

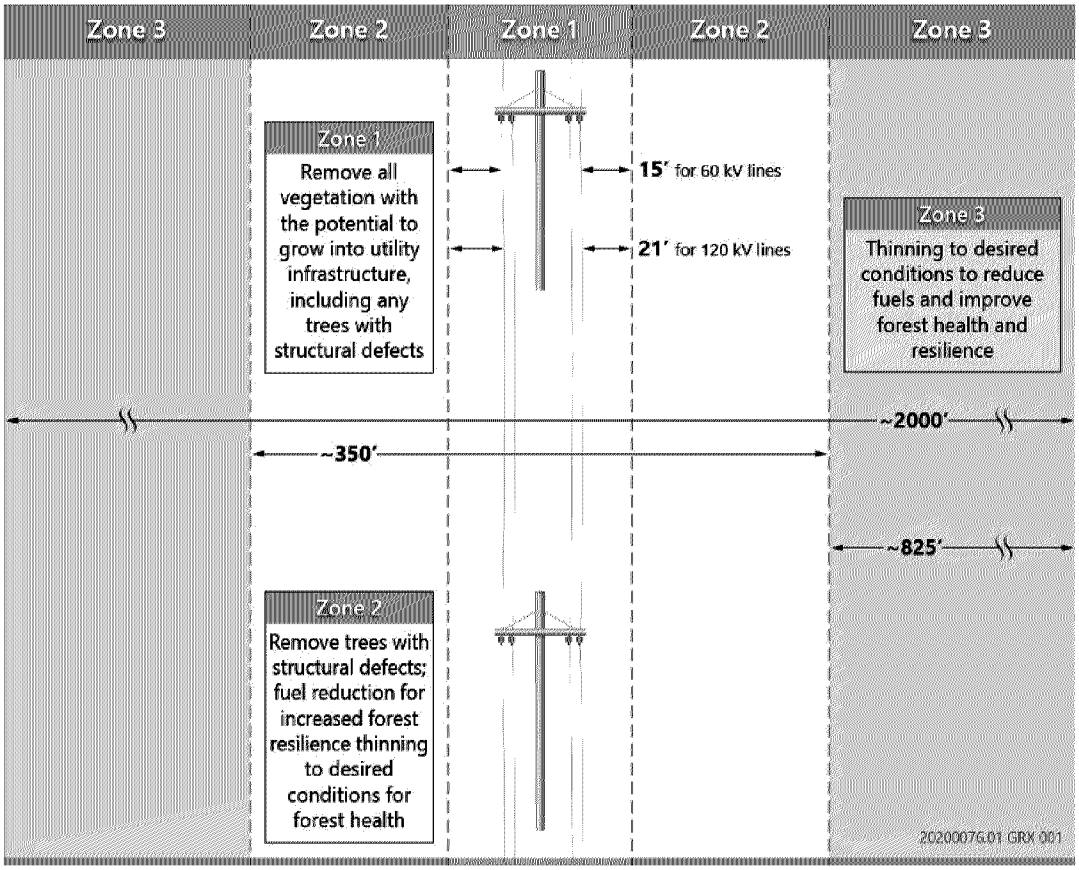
strategically prioritize risk mitigation projects within budget parameters. With PSOM and Emergency De-Energization system-wide, this is a critical component to prioritizing risk and minimizing outage impacts to customers.

2.3.4. RESILIENT CORRIDORS

Despite the known benefits of reducing adverse impacts during natural disaster events, only the Lake Tahoe Basin Management Unit ("LTBMU") has implemented resilient corridor project ("RCP") clearances through Stewardship Agreements. RCP treatments were completed and are transitioning to maintenance. Grants of easement and other restrictions, including the need for additional NEPA studies and updated MSUPs, limit expanded RCP implementation.

While the Companies are limited in the ability to independently create resilient corridors, the concept remains a possibility within HTAs, if allowed by the property owner or AHJ. RCP specifies three clearance zones for ROWs, as shown in Figure 25. Vegetation clearance tolerances vary by operating voltages and consider the local topography and previous fuel treatments. The Companies continue to participate in regular coordination meetings with the United States Forest Service ("USFS"), BLM, State Lands and the Interdisciplinary Team ("IDT") to resolve issues and address schedule constraints with the overarching goal of expanding RCP implementation where accepted and Stewardship Agreements are possible.

Figure 25. Resilient Corridors Clearance Example



In addition to the single Resilient Corridor Program agreement with LTBMU, there are other collaborative vegetation management programs. Table 14 below lists current and pending vegetation management agreements with the AHJs.

Table 14. Vegetation Management Agreements

Authority Having Jurisdiction	Location/Area	Agreement Type	Agreement Status
USFS	Lake Tahoe Basin Management Unit	Shared Stewardship Agreement	In effect
USFS	Humboldt-Toiyabe Mount Charleston Spring Mountains	Master Special Use Permit	In effect
Tahoe Regional Planning Agency	Lake Tahoe	Memo	In effect
Nevada Division of State Lands	Lake Tahoe State Park	Fuel Reduction and Mitigation License	Under review
Nevada Division of State Lands	Washoe Lake State Park	Fuel Reduction and Mitigation License	In progress
USFS	Humboldt-Toiyabe Carson Ranger District	Master Special Use Permit	Under review

2.3.5. VEGETATION MANAGEMENT SCHEDULE

The Companies' updated vegetation patrols and management work cycles are presented in Table 15, reflecting a more feasible completion cycle for pole and ROW clearing. The vegetation management program is transitioning to a condition-based approach, consistent with prevailing industry practices. Improved imagery and more detailed in-the-field information afford the ability to determine vegetation management schedules for each circuit.

Table 15. Proposed Vegetation Management Schedule

Program	Tier 3	Tier 2 and 1E	Tier 1	Non-NDPP
Patrolling	Annual	2-Years	4-Years	8+ Years
Tree Pruning	4-Years	4-Years	4-Years	8+ Years
Pole/ROW Clearing (with or without herbicide)	3-Years	6-Years	8-Years	N/A

Fuels mitigation and treatment work reduces vegetation growth and related risk on a sustained basis when applied scientifically and based on conditions in the Companies' ROWs. The refinement of using a condition-based approach informed by satellite imaging is expected to narrow the scope of work, although that will differ across the Tiers. Vegetation type and density are given more weight in the evaluation to determine what work is necessary. Tiers 2 and 3 have moved from initial clearing into maintenance mode, focused on managing regeneration rather than intensive initial clearing. Generally, there is less work in Tiers 1E and 1, which consist mainly of brush that can be effectively treated through defensible space around wooden poles and leveraging community and county CWPP. Ground fuels will update circuit schedules of poles and ROW clearing annually across all Tiers based on vegetation type and fuel density. This approach will enable the Companies to strategically address the additional Tier areas identified in this Plan while maintaining budgets consistent with prior years. This will be achieved by deploying work more efficiently across Tiers. The Companies will continue to foster collaborative relationships with State and Federal agencies, fire agencies, and private property owners.[29]

Minor impacts are anticipated from the CloudFire risk assessment that adds mileage to the wildfire Tier circuits. The increase in line miles may extend the end date of cycle clearing approved in Docket No. 23-03003.[30] However, the efficiencies gained by the transition to condition-based clearing, informed by satellite imaging, are expected to minimize the impact of the increased Tier area line miles on the vegetation management budget.

[29] https://eip.laketahoeinfo.org/Project/FundingRequestSheet/02.01.02.0016

[30] Originally estimated completion for Tier 2 and 1E is 2027 and Tier 1 is 2032.

2.3.6. VEGETATION MANAGEMENT BUDGET

Table 16 below shows the proposed vegetation management budget. Some of the funding will support match funding from Nevada's Governor's Office of Energy for the contiguous ROW clearing for disadvantaged communities.

Table 16. Vegetation Management Triennial Budget

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Vegetation Management				
Nevada Power	$ 15,714,000	$ 5,918,000	$ 5,078,000	$ 4,718,000
Sierra Pacific Power	$ 103,866,600	$ 34,172,200	$ 34,622,200	$ 35,072,200
Vegetation Management Total	**$ 119,580,600**	**$ 40,090,200**	**$ 39,700,200**	**$ 39,790,200**

2.4. CONDITIONAL AWARENESS: CIRCUIT PATROLS, DETAILED INSPECTIONS AND CORRECTIONS

The 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 or other natural disasters. Circuit patrols and detailed inspection of overhead electrical facilities provide the conditional awareness required to maintain a resilient system. These programs are performed by qualified electric line personnel and are designed to identify conditions that could result in potential fault scenarios, including situations in which the infrastructure may no longer be able to operate as designed, and may become susceptible to weather conditions and natural disasters. Circuit patrols are brief visual inspections performed by viewing each facility from a clear vantage point to identify obvious damage or defects to the transmission or distribution system. Patrols are typically performed by vehicle but can be performed on foot, from aircraft, or using Unmanned Aerial Vehicles ("UAVs"). Detailed inspections are careful visual inspections of each transmission or distribution structure, and spans between structures. The inspections program identifies anomalies for correction and may include the use of high-definition cameras and unmanned aerial devices or drones. Patrols are typically conducted more frequently than detailed inspections. The Companies have transitioned to a levelized work plan so a tranche of work is completed annually for each category. The Companies propose to utilize drone inspections in conjunction with the ground inspections to acquire a 360° view of all poles and pole connections within the Tier boundaries. This additional information will ensure that all conditions are identified and corrected prior to their becoming further risks to the system. The Companies intend to competitively award a new three-year contract for the inspections and patrols programs. The successful contractor will quality check provided drone video and pictures provided by the Companies. Inspection results are reviewed by certified linemen to capture any repairs discovered from an aerial view.

There are two competitively awarded patrols and inspections programs, the first is the wildfire Tier Program that applies to circuits in both Sierra and Nevada Power. The Wildfire Tier Program targets wildfires and rangeland fires in Tiers 3, 2, 1E, and 1, shown in Table 17.

Table 17. Patrol and Inspection Frequency - Wildfire Tiers

Heightened Fire Risk Areas Circuit Patrol and Detailed Inspection Frequency				
Overhead Transformers, Switching/Protective Devices, Regulators / Capacitors, Conductor and Cables, Wood Poles and Other Overhead Assets	Circuit Patrols		Detailed Inspections	
	Tiers 3, 2, 1E	Tier 1	Tiers 3, 2, 1E	Tier 1
	Annual	Every 4 years	Every 5 years except Every 3 years for Tier 3	Every 10 years

The second program, the Circuit Resilience Program, applies only to Nevada Power and is based on circuit performance. The Circuit Resilience Program identifies the 20 worst performing

distribution circuits in Southern Nevada's HTAs, based on the past five years of nature-caused outages, shown in Table 18. Circuit performance is an early indicator of potential risk.

Table 18. Patrol and Inspection Frequency - Circuit Resilience in Natural Disaster Areas Based on Circuit Performance

Circuit Resilience Circuit Patrol and Detailed Inspection Frequency			
Overhead Transformers, Switching/Protective Devices, Regulators / Capacitors, Conductor and Cables, Wood Poles and Other Overhead Assets	Nevada Power Top 20 Worst Performing Circuits	Circuit Patrol	Detailed Inspection
		1 thru 20	1 thru 10
		Annual, except where detailed inspection is scheduled for the same year	Every 4 Years

Wildfire Tiers

Patrols and inspections are performed by qualified electric line personnel and are designed to identify conditions that could result in potential fault scenarios, including situations in which the infrastructure may no longer be able to operate as designed, and may become susceptible to external factors, such as weather conditions that create a potential for an equipment caused natural disaster. The Companies conduct a proportional tranche of cycle work for a levelized schedule. More frequent patrols or inspections may be necessary for safe operation of the electric system. When patrols and inspections are scheduled for the same cycle year, only detailed inspections are performed. Corrective action or corrections are defined as maintenance, repair, or replacement of utility equipment and structures so that they function properly and safely.

Table 19. Sierra Wildfire Tier Patrols and Inspections Pole Counts

Sierra Pacific Power	**2027-2029 Forecast**	**2027**	**2028**	**2029**
Inspections	**60,385**	15,467	24,562	20,356
Patrols	**171,196**	60,116	52,549	58,531
Total	**231,581**	**75,583**	**77,111**	**78,887**

Table 20. Sierra Wildfire Tier Patrols and Inspections Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Sierra Pacific Power				
Inspections	$ 8,405,592	$ 2,153,006	$ 3,419,030	$ 2,833,555
Patrols	$ 2,299,162	$ 807,358	$ 705,733	$ 786,071
Sierra Pacific Power Total	**$ 10,704,754**	**$ 2,960,364**	**$ 4,124,763**	**$ 3,619,627**

Table 21. Nevada Power Wildfire Tier Patrols and Inspections Pole Counts

Nevada Power	2027-2029 Forecast	2027	2028	2029
Inspections	**3,582**	849	1,402	1,331
Patrols	**7,736**	2,683	2,249	2,804
Totals	**11,318**	**3,532**	**3,651**	**4,135**

Table 22. Nevada Power Inspections and Patrols Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Inspections	$ 498,614	$ 118,181	$ 195,158	$ 185,275
Patrols	$ 103,894	$ 36,033	$ 30,204	$ 37,658
Nevada Power Total	**$ 602,509**	**$ 154,213**	**$ 225,362**	**$ 222,933**

Corrections are estimated for each Tier based on a percentage of corrective actions experienced in the prior year, 2025.

Table 23. Sierra Corrections Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Sierra Pacific Power				
Corrections	$ 5,699,235	$ 1,428,389	$ 2,256,551	$ 2,014,295
Sierra Pacific Power Total	**$ 5,699,235**	**$ 1,428,389**	**$ 2,256,551**	**$ 2,014,295**

Table 24. Nevada Power Corrections Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Corrections	$ 664,119	$ 203,526	$ 214,502	$ 246,091
Nevada Power Total	**$ 664,119**	**$ 203,526**	**$ 214,502**	**$ 246,091**

The Companies use codes to designate priorities for any identified corrections. These priority designations are detailed in this section.

Priority Correction Codes used in the patrols and inspections program for conditions requiring correction are:

Priority A - presents imminent risk to safety;

Priority B – presents no immediate risk but requires attention at first opportunity as worsening of the issue could cause an increase in risk level; goes through the normal design and permitting process; and

Priority C – presents a near-term risk and indicates the need for an expedited solution that cannot be accommodated by Priority B design and permitting timelines.

The Companies also perform a broader assessment to identify where the accumulation of repairs may indicate a need for rebuild or replacement in the system hardening programs.

Performing inspections and patrols with prioritized corrections lowers damage that may occur during a natural disaster. Priority A pole replacements are completed immediately based on a "failure" status and are exempt from standard design and permitting long lead times to construct. Priority B pole replacements typically require formal design and permitting subject to jurisdictional requirements and lead times. Priority C corrections are expedited and bypass the longer design and permitting requirements. In all cases, the Companies assess pole replacement projects to coordinate the most expedient means for replacement. Pole replacements are assessed to identify any overlaps with other NDPP projects to determine if pole corrections can be coordinated with other NDPP projects.

The Companies have established Master Permits that allow flexibility to replace poles and undertake modifications within guidelines and parameters. For example, the Companies streamlined many single pole replacements around Lake Tahoe, a sensitive environmental zone with work restrictions, through collaborative efforts with the Tahoe Regional Planning Authority ("TRPA").[31]

The tables below forecast wildfire Tier pole replacements for 2027-2029.

[31] https://naldc.nal.usda.gov/download/CAT10310193/PDF.

Table 25. Nevada Power Wildfire Tier Pole Replacement Counts

Pole Replacements – Wildfire Tiers	2027-2029 Forecast	2027	2028	2029
Actual Backlog	36	12	12	12
Forecast	84	28	28	28
Total	**120**	**40**	**40**	**40**

Table 26. Sierra Wildfire Tier Pole Replacement Counts

Pole Replacement – Wildfire Tiers	2027-2029 Forecast	2027	2028	2029
Actual Backlog	690	245	230	215
Forecast	330	135	100	95
Total	**1,020**	**380**	**330**	**310**

Circuit Resilience

For 2027-2029, the Companies plan to perform detailed inspections and patrols in the circuit resilience corridor areas in Southern Nevada. Approximately 16,500 poles are scheduled for inspection or patrol.

Table 27. Nevada Power Circuit Resilience Patrols and Inspections Pole Counts

Nevada Power	2027-2029 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Circuits 1-10	8,250	2,750	2,750	2,750
Circuits 11-20	8,250	2,750	2,750	2,750
Total	**16,500**	**5,500**	**5,500**	**5,500**

Table 28. Nevada Power Circuit Resilience Patrols and Inspections Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Circuit Resiliency				
Inspections	$ 382,800	$ -	$ -	$ 382,800
Patrols	$ 184,663	$ 73,865	$ 73,865	$ 36,933
Circuit Resiliency Total	**$ 567,463**	**$ 73,865**	**$ 73,865**	**$ 419,733**

Table 28 shows anticipated Circuit Resilience OMAG repairs forecasted for 2027-2029. Forecasted corrections are estimated using past patrols and inspections historical run rate. Estimates include immediate completion of Priority 0 corrections. Projections for Priority 1 OMAG corrections anticipate 33 percent will be completed within twelve months and 66 percent will be completed within 24 months. The Circuit Resilience Program is an additional program

that addresses poles in Nevada Power based on circuit performance. Table 29 shows the NPC forecasted Priority 0 and Priority 1 pole replacements for 2027-2029. Pole replacements are forecasted using a historical run rate of past pole replacements.

Table 29. Nevada Power Circuit Resilience Corrections Pole Replacement Forecast Counts

Nevada Power	2027-2029 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Circuits 1-10	463	17	17	429
Circuits 11-20	41	18	18	5
Total	**504**	**35**	**35**	**434**

Corrections are separate from pole replacements. Based on inspection information, equipment will be replaced as a correction. However, if the condition of the pole is sufficiently deteriorated, the entire pole will be replaced.

Table 30. Nevada Power Circuit Resilience Pole Replacement Counts

Pole Replacements for-Circuit Resilience	2027-2029 Forecast	2027	2028	2029
Actual Backlog	45	20	15	10
Forecasted	75	30	25	20
Total	**120**	**50**	**40**	**30**

Table 31. Nevada Power Circuit Resilience Corrections Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Circuit Resiliency				
Corrections	$ 435,415	$ 30,612	$ 30,612	$ 374,190
Circuit Resiliency Total	**$ 435,415**	**$ 30,612**	**$ 30,612**	**$ 374,190**

Pole replacements in the wildfire Tiers are separate from pole replacements associated with the Circuit Resilience program, which is specific to Nevada Power. Based on inspection information, equipment on a pole will be replaced as a correction. However, if the condition of the pole is sufficiently deteriorated, the entire pole will be replaced.

Priority A pole replacements are completed immediately based on a "failure" status and are exempt from long lead time design and permitting requirements. Priority B poles are assessed to determine the most expedient replacement based on AHJ permitting requirements. Pole replacements are further assessed to determine overlaps with other NDPP projects to coordinate

with other overlapping NDPP projects whenever possible. Pole replacements are recovered in GRC.

2.5. GRID RESILIENCE AND SYSTEM HARDENING

System hardening programs represent the greatest long-term mitigation opportunity, prioritized to focus on locations that present the greatest risk. NDPP system hardening programs target a combination of projects and programs in the HTAs, using a combination of situational, conditional, and structural awareness. For northern Nevada, many of the same areas threatened by wildfire ignition and spread are also threatened by extreme winter storms. For Southern Nevada, system hardening programs reduce risks in HTAs threatened by extreme wind, flooding events, and monsoons.

System hardening initiatives focus on infrastructure improvements to mitigate operational risks associated with natural disasters. No single system hardening program mitigates all natural disaster risks. Individual programs address different conditional factors, different circumstances, and different geographic areas. Programs and initiatives share the common objective of reducing overall natural disaster risk through a combination of improved design standards and ruggedized equipment.

2.5.1. SYSTEM HARDENING STRATEGY

The Companies use a programmatic approach for the System Hardening Program, where project scopes are set in motion two to three years in advance. Preparing a portfolio of "shovel ready" projects, coordinated with critical external stakeholders and communities, reflects an industry best practice. Implementing the program across HTAs allows risk mitigation work to continue in areas with less complex permitting in a continuous workflow. Specifically, risk mitigation activities could alternate among Tier 3, Tier 2, and Tier 1E circuits, including those identified for rebuild. Narrow work windows for seasonal construction are typical in the Lake Tahoe Basin and other regions such as Mt. Charleston. Based on an accumulation of identified corrections from the inspections program, if enough pole replacements are identified on a circuit, the Companies will consider a full rebuild instead.

The Companies have implemented the work levelizing strategy to realize the full potential of the NDPP's risk reduction efforts year round. The ability to efficiently coordinate work on targeted circuits to address accumulated corrections, fuse replacements, and remove bare wire from other high risk fire zones using holistic planning and engineering to accommodate hardened poles and wires greatly improves efficiency and effectiveness.

Undergrounding efforts will continue as approved. The total undergrounding proposal for 2027 – 2029 addresses 13 of the 32 circuit segments identified through collaboration with fire agencies in the NDPP Selective Underground Prioritization Plan. Most of these undergrounding efforts will extend beyond 2029. Within this Triennial Plan, excavation and installation of conduit systems will be the dominant phase of undergrounding projects. Of the remaining segments, 14

have already been mitigated, 13 segments will be in progress. Based on the prioritization, 5 segments will be addressed in the next Triennial Plan.

Table 32 below lists the system hardening capital budget for this Triennial Plan.

Table 32. System Hardening Capital Budget Forecast

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Nevada Power				
Copper Wire Replacement	$ 6,305,315	$ 2,000,100	$ 2,100,105	$ 2,205,110
Grid Ruggedization - Critical Crossings	$ 6,590,000	$ 2,090,000	$ 2,200,000	$ 2,300,000
Grid Ruggedization - Pole Stoppers	$ 7,875,000	$ 2,500,000	$ 2,625,000	$ 2,750,000
Line Rebuilds - Mt Charleston	$ 58,450,000	$ 15,550,000	$ 24,850,000	$ 18,050,000
Nevada Power Total	**$ 79,220,315**	**$ 22,140,100**	**$ 31,775,105**	**$ 25,305,110**
Sierra Pacific Power				
Copper Wire Replacement	$ 5,090,850	$ 401,530	$ 2,120,620	$ 2,568,700
Line Rebuilds - Curry 1280	$ 2,677,600	$ 1,128,400	$ 168,000	$ 1,381,200
Line Rebuilds - Incline 4100	$ 4,685,100	$ 2,101,000	$ 1,249,700	$ 1,334,400
Line Rebuilds - Muller 1295	$ 4,803,600	$ 1,480,160	$ 1,239,980	$ 2,083,460
Line Rebuilds - North East District	$ 3,375,000	$ 1,125,000	$ 1,125,000	$ 1,125,000
Non-Expulsion Fuses	$ 17,600,000	$ 6,300,000	$ 5,650,000	$ 5,650,000
Substation Hardening - Barrier Walls	$ 1,250,288	$ 1,250,288	$ -	$ -
Substation Hardening - Glenbrook Substation	$ 4,677,304	$ 1,294,783	$ 1,133,581	$ 2,248,940
Substation Hardening - Interior	$ 2,804,845	$ 2,688,238	$ 116,607	$ -
Tree Attachments	$ 6,960,000	$ 2,250,000	$ 2,320,000	$ 2,390,000
Undergrounding - Cost Share Zephyr Cove	$ 3,612,804	$ -	$ 3,602,974	$ 9,830
Undergrounding - Cost Share Glenbrook	$ 100,000	$ 100,000	$ -	$ -
Undergrounding - Cost Share TTD Bike Path	$ 8,808,567	$ 2,759,810	$ 2,935,298	$ 3,113,459
Undergrounding - Heybourne 1288, incline 4100/4200/4300,Muller 1295, Zephyr Cove	$ -	$ -	$ -	$ -
Undergrounding - Sierra Phase 1	$ 7,445,000	$ 6,695,000	$ 750,000	$ -
Undergrounding - Sierra Phase 2	$ 10,977,353	$ 8,079,937	$ 2,897,416	$ -
Undergrounding - Sierra Phase 3	$ 26,812,142	$ 4,457,926	$ 10,023,030	$ 12,331,186
Sierra Pacific Power Total	**$ 111,680,453**	**$ 42,112,072**	**$ 35,332,206**	**$ 34,236,175**
System Hardening Total	**$ 190,900,768**	**$ 64,252,172**	**$ 67,107,311**	**$ 59,541,285**

2.5.2. DESIGN AND CONSTRUCTION STANDARDS

The Companies developed the *Application Standard - NDPP Distribution Line Construction* for construction in areas of identified fire risk. The risk reduction program prioritizes facilities located in HTAs with known legacy equipment and designs that are more susceptible to fault or failure under severe weather conditions. Standards reflect specifications for covered conductor and fire mesh application. For example, resilient overhead distribution standards prohibit installation of bare wire, expulsion fuses, and wood poles without fire mesh wrap in the highest wildfire risk areas.

Covered conductor "tree wire" has been established as the standard for overhead construction in HTAs. Tree wire is the preferred technology for resilient overhead rebuild projects. Ductile iron poles are the standard for hardening where installation is possible. When installation of non-wood poles is not feasible, fire mesh pole wrap has been added for standard new wood pole installations in Tier 3. Installation of covered conductor, non-expulsion fuses, and non-wood poles where possible are now required for Tier 3 applications. A collaborative meeting of internal stakeholders is required as part of the predesign process to determine adequate fire mitigation in the design and scope for certain HTAs. Tier 2 and Tier 1E locations along the eastern front of the Sierra Nevada mountain range require resilient fire mitigation design. Southern Nevada's high risk monsoon areas are hardened with pole stoppers and structural ruggedization at critical crossings.

2.5.3. SIERRA UNDERGROUNDING

The NDPP undergrounding initiatives mitigate risks associated with the Companies' overhead distribution system in HTAs. Undergrounding is frequently the most effective design to reduce the risk of equipment-related ignition or infrastructure impacts from other natural disaster events. The cost and operational constraints of underground construction make it difficult to apply on a widespread basis. Undergrounding circuits also does not completely eliminate the possibility of ignition, primarily because of above ground junctions. Therefore, undergrounding is evaluated carefully and reserved for the highest risk areas.

The Companies identified approximately 78 total miles for undergrounding. This consists of 69 miles in Tier 3, four miles in Tier 2, and five miles of Tier 1E underground circuits. Lead times for undergrounding projects are long, compounded by additional permit requirements, extensive excavation, and conduit system installation before actual relocation of the overhead lines. Risk is still present during the relocation of high risk sections. During the construction period, controllable risk is managed through operating practices, patrols, inspections, corrections, and vegetation management as part of the risk reduction portfolio.

Undergrounding project estimates are based on current market conditions with added contingency factors. Estimates are refined as geological assessments and subsurface surveys reveal conditions for the various recommended undergrounding locations such as Lake Tahoe, situated on a composition of dense granite. NDPP undergrounding projects are presented by milestone with recommended activities. Generally, project status milestones are referenced as:

- Design/Permit
- Civil/Substructure
- Lines Construction

Segments proposed for this Plan are grouped into four tables based on the sequence from prior NDPP approvals and project interdependencies. Reference to specific dockets and the respective approval of work is noted in each table.

Each Sierra grouping is referred to as a "Phase" of the NDPP undergrounding program.[32] Three phases are represented for Sierra. Each circuit segment within a phase is noted with its corresponding priority ranking from the NDPP Selective Undergrounding Prioritization Plan. Cost Sharing segments are grouped separately.

Each grouping includes the scope of work recommended for 2027 through 2029, although completion is contingent on permitting, labor, and material resources. The extensive number of surveys, civil plans, profiles and other civil factors required to be completed as part of the underground permitting process extend the timeline for the various segments.

Group 1: Sierra Phase 1 Undergrounding

Priority Rank 1, 2, 10, 12, 17

Table 33. Sierra Phase 1 Undergrounding Projects

NDPP Phase	Priroity Rank	Service Terriroty	Title	Length in miles	Map Reference	Prior Docket No.	Prior Approval	2027-2029 Recommendation	Cost Recovery NDPP	Cost Recovery NDPP-GRC	Scope Extends Beyond 2029*
PH 1 2 and 4 Miles	1	SPPC	Curry 1280	0.5	F1	20-02031/ 20-02032, 22-08001 and 23-03003	Continue Civil Construction and start Lines Construction	Continue Civil Construction and start Lines Construction	NDPP	No	No
	2	SPPC	Downs 1285	1.8	F2						No
	10	SPPC	Roundhill 1504	0.53	F3						No
	12	SPPC	Incline 4200 Phase 3	0.7	F4						No
	17	SPPC	Incline 4300 Phase 3	2	F5						No
Total Miles				**5.53**		*timeline based on permits, material and labor availability					

Sierra Phase 1 is the first phase of undergrounding in Sierra's service territory. Sierra's Phase 1 totals 5.53 miles with the projects divided among south shore and north shore Lake Tahoe and along the eastern front of the Sierra Mountain Range near Carson Valley. 2.83 miles of Sierra Phase 1 will be completed and another 1.7 miles of civil construction will be completed in 2026. Curry 1280 (1), Round Hill 1504 (12) and Downs 1282 are expected to be complete in 2026. Incline 4200 Phase 3 (17) civil construction will be complete in 2026, with lines construction and removals completed in 2027. Incline 4300 Phase 3 civil construction will continue into 2027. Lines construction will begin in 2027 and continue into 2028 along with the removal of overhead assets. Table 34 represents estimated costs for the 2027 through 2029 work in Sierra Phase 1.[33]

[32] The program continues the Selective Undergrounding Prioritization Plan presented in Docket No. 23-03003.

[33] See Docket No. 23–03003 for selective undergrounding details.

Table 34. Sierra Phase 1 Undergrounding Budget Forecast

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Undergrounding - Selective 2 and 4 miles	$ 7,445,000	$ 6,695,000	$ 750,000	$ -

Group 2: Sierra Phase 2 Undergrounding

Priority Rank 4, 5, 6

Table 35. Sierra Phase 2 Undergrounding Projects

NDPP Phase	Priroity Rank	Service Terriroty	Title	Length in miles	Map Reference	Prior Docket No.	Prior Approval	2027-2029 Recommendation	Cost Recovery NDPP	Cost Recovery NDPP-GRC	Scope Extends Beyond 2029*
PH 2 Next 3 Segments	4	SPPC	Incline 4300 Phase 1	1.72	F6	22-08001 and 23-03003	(start) Civil/Substructure	(continue) Civil/Substructure	NDPP	No	No
	5	SPPC	Incline 4300 Phase 4	0.47	F7						No
	6	SPPC	Heybourne 1288	3.74	F8						No
			Total Miles	**5.93**			*timeline based on permits, material and labor availability				

Sierra Phase 2 undergrounding is comprised of the line segments that received Priority Rank 4, 5, and 6. These segments represent approximately 5.93 miles of undergrounding divided between north shore and south shore Lake Tahoe, and along the eastern front of the Sierra Mountain Range near Carson Valley. Incline 4300 Phase 1 (4) civil construction is scheduled to start in 2027 and be completed in 2028. Incline 4300 Phase 4 (5) civil construction will be completed in 2026 with lines construction and removal in 2027. Heybourne 1288 (6) is scheduled for construction starting in Q4 2026 and will continue into 2027. The Companies are currently pursuing permitting and easement acquisition for this project.

Group 3: Sierra Phase 3 Undergrounding

Priority Rank: 7, 8, 9, 14, 16

Table 36. Sierra Phase 3 Undergrounding Projects

NDPP Phase	Priroity Rank	Service Terriroty	Title	Length in miles	Map Reference	Prior Docket No.	Prior Approval	2027-2029 Recommendation	Cost Recovery NDPP	Cost Recovery NDPP-GRC	Scope Extends Beyond 2029*
PH 3 Next 5 Segments	7	SPPC	Muller 1295	10.8	F9	23-03003	Design/Permit	(continue) Design/Permit and (start) Civil/Substructure w/Amendment	NDPP	No	Yes
	8	SPPC	Incline 4200 Phase 1	4.84	F10						Yes
	9	SPPC	Incline 4200 Phase 2	2.38	F11						Yes
	14	SPPC	Incline 4100 Phase 2	1.73	F12						Yes
	16	SPPC	Incline 4200 Phase 4	0.91	F13						Yes
			Total Miles	**20.66**			*timeline based on permits, material and labor availability				

Sierra Phase 3 Undergrounding projects were approved by the Commission in the previous Plan for design and permitting costs only on the 20.66 miles identified in Priority Rank 7, 8, 9, 14, & 16. Designs and permitting have begun on all five segments and are expected to continue into 2027-2029. An estimate of civil construction costs is included in the table below.

Table 37 represents estimated costs for 2027-2029 work on Phase 2 and Phase 3.

Table 37. Sierra Phase 2 and Phase 3 Undergrounding Funding

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Undergrounding - Sierra Phase 3	$ 26,812,142	$ 4,457,926	$ 10,023,030	$ 12,331,186
Undergrounding - Sierra Phase 2	$ 10,977,353	$ 8,079,937	$ 2,897,416	$ -
Sierra Pacific Power Total	**$ 37,789,495**	**$ 12,537,863**	**$ 12,920,446**	**$ 12,331,186**

Group 4: Sierra Cost Sharing Undergrounding

Priority Rank: 19, 17, 26, 30, 32

Table 38. Sierra Undergrounding Phase 3 Cost Sharing Projects

NDPP Phase	Priroity Rank	Service Terriroty	Title	Length in miles	Map Reference	Prior Docket No.	Prior Approval	2027-2029 Recommendation	Cost Recovery NDPP	Cost Recovery NDPP-GRC	Scope Extends Beyond 2029*
Cost Sharing	19	SPPC	Incline 4100 Phase 3	1.1	F14	20-02031/ 20-02032 and 23-03003	Fund Lines Construction	Fund Lines Construction	NDPP	No	Yes
	17	SPPC	Glenbrook 2302 Ph 1	3.4	F15	22-08001 and 23-03003	Adjust Credit	Complete			No
	26	SPPC	Glenbrook 2302 Ph 4	0.75	F16	23-03003	Fund Lines Construction	Fund Lines Construction			No
	30	SPPC	Glenbrook 2505 Ph 1	1.14	F17	22-08001 and 23-03003	Adjust Credit	Complete			No
	32	SPPC	Glenbrook 2505 Ph 2	0.74	F18	22-08001 and 23-03003	Fund Credit	Move to Copper Wire Rebuild			No
			Total Miles	**7.13**			*timeline based on permits, material and labor availability				

Cost sharing projects are funded through a collaborative relationship between the Companies and the project partner, following the Rule 9 Line Extension Agreement ("LEA") process.

Glenbrook Undergrounding Incorporated

Priority Rank: 17, 30, and 32

The first of three phases of the work undergrounding in the Glenbrook community are complete, a total of 2.67 miles that included a portion of the Glenbrook 2302 Phase 1 (17), all of the Glenbrook 2600 (29), and Glenbrook 2505 Phase 1 (30) segments. The final phase of the cost sharing partnership is a portion of the Glenbrook 2505 Phase 2 (32) segment and is currently in permitting and easement acquisition. This work may be completed in 2026 but overruns into 2027 are possible.

Table 39. Glenbrook Undergrounding Budget Forecast

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Undergrounding - Cost Share Glenbrook	$ 100,000	$ 100,000	$ -	$ -

Tahoe Transportation District ("TTD")

Priority Rank: 19

The Incline 4100 Phase 3 Bike Path Project is moving forward from Thunderbird Lodge to the Secret Cove Parking Lot. Currently, funding has been delayed to 2027. The Companies have started designing and TTD will help with permitting.

Table 40 represents costs to perform design, civil construction, substructure installation, and lines construction for this segment.

Table 40. TTD Cost Sharing Budget Forecast

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Undergrounding - Cost Share TTD Bike Path	$ 8,808,567	$ 2,759,810	$ 2,935,298	$ 3,113,459

LTBMU – Zephyr Cove Undergrounding

Priority Rank: 26

The LTBMU expressed interest in participating in a cost sharing partnership to underground sections of Glenbrook 2302 and Round Hill 1504 distribution circuits located at Zephyr Cove Resort located at Lake Tahoe's south shore. The section is comprised of roughly one mile. Three-quarters of a mile was previously identified by the Tahoe Douglas Fire District as high risk and recommended for undergrounding within the NDPP Selective Underground Prioritization Plan. This segment is represented as Priority Rank 26. The partnership assigns responsibility to the Forest Service for civil design, permitting assistance for USFS permits, civil excavation, purchase and installation of substructure, and pavement restoration where necessary. The Companies' responsibility includes performance of all construction for the lines. This delineation of responsibilities is like the partnership between the Companies and TTD's east shore bike path cost sharing partnership. Existing survey and civil design information has been shared among the partners and electrical designs are in progress. Construction is planned to begin in 2027 and run

through 2028 in conjunction with the Forest Service's existing expansion plans. Table 41 represents costs to perform the work for this segment.

Table 41. Zephyr Cove Resort Underground Cost Sharing Budget Request

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Undergrounding - Cost Share Zephyr Cove	$ 3,612,804	$ -	$ 3,602,974	$ 9,830

A summary of the undergrounding program budget request is shown in Table 42.

Table 42. Undergrounding Program Budget Request Summary

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Undergrounding - Sierra Phase 1	$ 7,445,000	$ 6,695,000	$ 750,000	$ -
Undergrounding - Sierra Phase 2	$ 10,977,353	$ 8,079,937	$ 2,897,416	$ -
Undergrounding - Sierra Phase 3	$ 26,812,142	$ 4,457,926	$ 10,023,030	$ 12,331,186
Undergrounding - Cost Share TTD Bike Path	$ 8,808,567	$ 2,759,810	$ 2,935,298	$ 3,113,459
Undergrounding - Cost Share Zephyr Cove	$ 3,612,804	$ -	$ 3,602,974	$ 9,830
Undergrounding - Cost Share Glenbrook	$ 100,000	$ 100,000	$ -	$ -
Sierra Pacific Power Total	**$ 57,755,866**	**$ 22,092,673**	**$ 20,208,718**	**$ 15,454,475**
System Hardening Total	**$ 57,755,866**	**$ 22,092,673**	**$ 20,208,718**	**$ 15,454,475**

2.5.4. SIERRA OVERHEAD REBUILDS

Modernizing the electric system with ruggedized design against natural disasters is a multi-year initiative that extends across multiple Triennial Plans. The program is based on the risk reduction prioritization developed in collaboration with the fire agencies. The levelized work approach targets high risk Tier 3 circuits in North Lake Tahoe, South Lake Tahoe, and Mt. Charleston, and also addresses Tier 2 and Tier 1E circuit segments to continue progress. Permitting constraints, customer reliability impacts, and a short seasonal construction window compound the complexity. Grid hardening programs set a project scope in motion with two to three years of advance design. The Companies have operationalized a portfolio of "shovel ready" projects and coordinated with external stakeholders and communities to create a steady flow of construction. Tier 3 projects

continue to remain highest priority. Line rebuild projects are segmented according to permit requirements. Segments requiring simple permits are prioritized for construction. Permitting agencies typically request project submittals two years in advance.

For the 2027-2029 period, the Companies propose to continue design, permitting and construction for 6 miles of previously approved circuits in wildfire Tiers, shown in Table 43.[34] For the projects that continue past 2029, the Companies have included a funding request to continue design and permitting only.

Table 43. Overhead Rebuilds Continuation Projects

NDPP Ref	Circuit	Tier	Service Territory	Total Miles	Length Completed through 2026	Prior Docket #	Length in 2027-2029	2027-2029 Recommendation	Cost Recovery NDPP-Miles	Scope Extends Beyond 2029*
OH Rebuilds	INC4100	3	Sierra	25	4.5	23-03003	3	Design/Permitting/Construction	3	Yes
	Curry 1280	3/1E		4	3		1	Design/Permitting/Construction	1	No
	Muller 1295	3/2/1E		31	5		2	Design/Permitting/Construction	2	Yes

Curry 1280 Rebuild

Curry 1280 is a 16-mile, 12.47 kV distribution circuit with 0.33 miles of line located in Tier 3, 1.11 miles in Tier 1, and 7.64 miles in Tier 1E. The circuit runs into the Clear Creek Canyon up the eastern slope of the High Sierra Mountain Range to a neighborhood with minimal emergency access so an ignition on this circuit poses a risk to nearby communities. The Companies propose to continue circuit mitigation in Tiered areas. Roughly 3 miles of the 4 miles identified for overhead rebuild will be completed in 2026. Construction of the remaining 1 mile is scheduled to be completed before 2029.[35]

Incline 4100

Incline 4100 has 25 miles of overhead distribution line located in Tier 3 of North Lake Tahoe. Approximately 9.8 miles of Incline 4100 was identified by the North Lake Tahoe Fire Protection District as high risk for fire ignition and spread resulting in a catastrophic event due to environmental conditions, lack of evacuation routes, and impact to community water sources. This mileage has been identified for mitigation under both underground and overhead rebuild efforts. At the end of 2026, 4.5 miles will have been completed.

The Companies request to continue design and permitting, while completing roughly 3 miles of construction during the 2027-2029 Triennial Plan. The remaining miles of line extends into future Triennial Plans.

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[34] Docket No. 23-03003.

[35] Although CUR1280 is a 16-mile circuit with nine miles identified in a Tiered Area, 0.5 Miles has been identified for undergrounding and the remainder was ruggedized with non-expulsion and hardened equipment prior to the NDPP.

Muller 1295 Rebuild

Muller 1295 is a 31-mile distribution line located in Tiers 3, 2, and 1E within the Carson Region. This circuit has unique conditions where the area receives extreme runoff from spring snow melt on the eastern slope of the Sierras, creating flooding conditions that cause rapid underbrush growth. Once the runoff evaporates, the area is left with highly flammable underbrush in an area that experiences extreme wind events. Roughly 5 miles will be rebuilt in 2026. The Companies plan to rebuild the remainder of this circuit in phases through 2054. The Companies request to continue design and permitting, while completing approximately 2 miles of construction during the 2027-2029.

The funding requests for these NDPP distribution line rebuild projects is shown in Table 44.

Table 44. Distribution Line Rebuilds Summary

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Line Rebuilds - Curry 1280	$ 2,677,600	$ 1,128,400	$ 168,000	$ 1,381,200
Line Rebuilds - Incline 4100	$ 4,685,100	$ 2,101,000	$ 1,249,700	$ 1,334,400
Line Rebuilds - Muller 1295	$ 4,803,600	$ 1,480,160	$ 1,239,980	$ 2,083,460
Sierra Pacific Power Total	**$ 12,166,300**	**$ 4,709,560**	**$ 2,657,680**	**$ 4,799,060**

Northeast Operating Region (NDPP) Design and Permitting

The risk analysis indicates that ruggedization is needed in the Northeast Region based on wildfire risk identified by both Technosylva and CloudFire models. Circuits that have been identified for overhead rebuilds in Tier areas are Dutch Flat 208, Dutch Flat 209, Dutch Flat 210, Grass Valley 2517, and Grass Valley 2518. These circuits feed remote rural areas in Tier 1E and 1 in northeast Nevada. The Companies request funding for design and permitting a total of approximately 15 miles on these lines. Construction for these lines will be identified in future requests for funding.

The Companies plan on undertaking rebuilds on the circuit segments in 2027-2029 in the Northeast District, shown in Table 45.

Table 45. Sierra Overhead Rebuilds Part 2

NDPP Ref	Circuit	Tier	Service Territory	Total Miles	Length Completed through 2026	Length in 2027-2029	2027-2029 Recommendation	Cost Recovery NDPP-Miles	Scope Extends Beyond 2029
OH Rebuild	DUTCH FLAT 208	1/1E	Sierra	70	0	3	Design/Permitting	3	Yes
	DUTCH FLAT 209	1/1E		10	0	3	Design/Permitting	3	Yes
	DUTCH FLAT 210	1/1E		2.8	0	2.8	Design/Permitting	2.8	Yes
	GRASS VALLEY 2517	1/1E		36	0	3	Design/Permitting	3	Yes
	GRASS VALLEY 2518	1/1E		41	0	3	Design/Permitting	3	Yes

Table 46. System Hardening New Projects

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Line Rebuilds - North East District				
DUTCH FLAT 208	$ 675,000	$ 225,000	$ 225,000	$ 225,000
DUTCH FLAT 209	$ 675,000	$ 225,000	$ 225,000	$ 225,000
DUTCH FLAT 210	$ 675,000	$ 225,000	$ 225,000	$ 225,000
GRASS VALLEY 2517	$ 675,000	$ 225,000	$ 225,000	$ 225,000
GRASS VALLEY 2518	$ 675,000	$ 225,000	$ 225,000	$ 225,000
Line Rebuilds - North East District Total	$ 3,375,000	$ 1,125,000	$ 1,125,000	$ 1,125,000

The Companies present the following NDPP-GRC status updates:

Round Hill 1502

The Round Hill 1502 is a 21-mile distribution circuit located entirely in Tier 3 of South Lake Tahoe. This circuit has been and will continue to be addressed as overhead rebuild projects. The Companies plan to continue design and permitting, while completing approximately 6 miles of overhead rebuild construction during the 2027-2029 Triennial Plan.

Steamboat 212

The Steamboat 212 is a 39-mile distribution circuit located in Tiers 3 and 2. 12 miles will be mitigated as an overhead rebuild by the end of 2026. For the 2027 to 2029 plan, an additional 19 miles are scheduled to be mitigated as overhead rebuilds. The balance of 8 miles will extend beyond this Triennial Plan.

Steamboat 213

The Steamboat 213 is a 47 mile distribution circuit located in Tiers 3 and 2 and some non-tiered areas. By the end of 2026, 13 miles will be mitigated with overhead rebuilds. The 2027 to 2029 Plan requests to mitigate an additional 23 miles, while the balance of 11 miles will extend beyond this Triennial Plan.

Mount Rose 242

The Mount Rose 242 is a 9 mile distribution circuit located in Tier 1E and 1 and non-tiered areas. In Spring 2024, a small brush fire indicated an immediate need for mitigation. By the end of 2026, 1 mile will have been rebuilt in the non-tiered area. For the 2027 to 2029 plan, it is anticipated to mitigate 1 mile in overhead rebuilds, which will complete mitigation in the Tier areas on this circuit.

2.5.5. NON-EXPULSION EQUIPMENT

The Companies are systematically replacing equipment that can release hot particles and gases, which can be an ignition source leading to a wildfire. This program focuses on fuses that protect sensitive equipment from fault currents in HTAs. Replacement devices include electronic fuses, "Trip Savers," and current limiting "Fault Tamers." As new devices are installed, technical coordination studies inform proper operation settings. Should the need for additional devices be identified through the patrols and inspections program, they are identified for replacement in wildfire Tiers 3, 2, and 1E. Lightning Arrestor replacements have been subsumed into the non-expulsion equipment program and are replaced when identified in the field. Cost for this work breaks down to approximately 49 percent Capital and 51 percent OMAG, based on work to be completed in 2027-2029, shown in Table 47. The Companies have completed the replacement of all non-expulsion equipment for Tier 3 and anticipate that all non-expulsion equipment replacements in Tiers 2 will be completed in 2026, including any expanded Tier 2. Tier 1E is scheduled for completion in 2029, that factors in the expanded Tier 1E.

Table 47. Non-Expulsion Equipment OMAG Budget Forecast

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Expulsion Fuses				
Sierra Pacific Power	$ 17,200,000	$ 5,750,000	$ 5,650,000	$ 5,800,000
Expulsion Fuses Total	**$ 17,200,000**	**$ 5,750,000**	**$ 5,650,000**	**$ 5,800,000**
System Hardening Total	**$ 17,200,000**	**$ 5,750,000**	**$ 5,650,000**	**$ 5,800,000**

Table 48. Expulsion Device Replacement Capital

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Non-Expulsion Fuses	$ 17,600,000	$ 6,300,000	$ 5,650,000	$ 5,650,000

2.5.6. TREE ATTACHMENT REMOVAL

Tree attachments are pieces of electrical infrastructure fastened to trees for structural support. Because there are no approved standards for tree attachments, they inherently introduce system risk from this electrical equipment being in close proximity to vegetation. Tree attachment risks exist throughout the northern region of the Sierra's distribution system. Based on mapping records and field surveys, 988 tree attachments remain in Tier 3 of the Tahoe Basin.

Each tree attachment requires a case-by-case evaluation to determine how to eliminate the tree attachment. The Commission previously approved the Companies' tree attachment removal plan that includes identifying tree attachments, customer communications, permitting, design, and the tree attachment removal.[36] Removal requires a third-party easement from the property owner in order to replace the tree attachment with a new pole. Each removal includes a written plan, customer outreach, and progressive communication. Dedicated NDPP resources support and track customer outreach for improved program acceptance and efficiency.

Proposed Triennial Budget

The Companies proposes to remove 80 tree attachments per year. Based on present budget estimates, the Companies request funding of $ 6,960,000 for 2027-2029 as indicated in Table 49 below.

Table 49. Tree Attachment Removal Budget Forecast

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Tree Attachments	$ 6,960,000	$ 2,250,000	$ 2,320,000	$ 2,390,000

2.5.7. COPPER WIRE REPLACEMENT PROGRAM

The copper wire replacement program replaces bare, aged copper wire that has become brittle and annealed over time. The replacement program entails reconductoring or rebuilding distribution infrastructure to reduce the risk of a wire-down event from compromised copper wire.

[36] Dockets Nos. 20-02031, 20-02032, 22-08001, and 23-03003.

The Companies typically experiences over 200 live wire-down events in Nevada each year. The small sized copper wire is more likely to break during severe events, compared to large sized wire that is more durable. For fire HTA's, the Companies are replacing copper wires with a covered conductor solution.

Sierra

The NDPP targets approximately 47 baseline miles of copper wire across fire Tiers in northern Nevada. The first grouping, known as Sierra's Baseline copper wire, delineates this from additional copper wire identified through the patrols and inspections program. Sierra's copper wire is replaced with covered conductor.

For 2027-2029 the Companies request funding to continue replacement of approximately 16 miles of copper conductor. Table 50 shows the breakdown of this work by Tier and scope. Scopes include either a) design, permitting and construction or b) design and permitting where construction will follow in the next triennial Plan. There is significant design and permitting costs in 2027 that leads to construction in 2028 and 2029.

Table 50. Sierra Copper Wire Replacement Program

Tier	Miles	Plan	Scope of Work	Cost Recovery NDPP-Miles	Cost Recovery NDPP-GRC Miles
3	1.70	2027-2029	Design, Permit and Construct	0.50	1.20
2	1.05			0.76	0.29
1E	3.63				3.63
3	5.45		Design and Permitting	5.45	
2	0.45				0.45
1E	3.91				3.91

Table 51. Sierra Copper Wire Replacement Plan Budget

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Copper Wire Replacement	$ 5,090,850	$ 401,530	$ 2,120,620	$ 2,568,700
Sierra Pacific Power Total	**$ 5,090,850**	**$ 401,530**	**$ 2,120,620**	**$ 2,568,700**
System Hardening Total	**$ 5,090,850**	**$ 401,530**	**$ 2,120,620**	**$ 2,568,700**

Nevada Power

The approved scope for the Copper Wire Replacement Program in Southern Nevada is 35 miles of distribution lines in monsoon, thunderstorm, high wind, and other natural disaster risk zones.

Table 52. Nevada Power Copper Wire Replacement Plan

Type	Miles	Plan	Scope of Work	Recovery NDPP	Recovery GRC
Monsoon	13	2027-2029	Design, Permit and Construct	13	0

Through 2026, the Companies will have completed 22 of the 35 approved miles, representing 63 percent of the approved miles. For 2027-2029 the Companies request funding to continue replacing copper wire in all natural disaster risk areas in Southern Nevada, including wildfire Tiers. Table 53 represents costs to perform the work for this project.

Table 53. Nevada Power Copper Wire Replacement

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Nevada Power				
Copper Wire Replacement	$ 6,305,315	$ 2,000,100	$ 2,100,105	$ 2,205,110

2.5.8. SUBSTATION HARDENING

Substation Hardening investments involve installation of new equipment or modifications of existing equipment to reduce the risk of a fire originating inside a substation and spreading outwards, resulting in a wildfire. The measures include solid fireproof perimeter walls, weed barrier and crushed rock vegetation control, insulated bus, and conductors, synthetic transformer oil, replacement of oil-filled equipment, installation of metal clad enclosed switchgear, and improved substation grounding. Solid fireproof perimeter walls will also reduce the risk of a wildfire that started outside the substation causing damage to equipment located inside a substation.

Beginning with the 2020 NDPP, the Companies prioritized five substations located in Tier 3 for hardening investments to mitigate wildfire risk: Kingsbury, Round Hill, Incline, Glenbrook, and North Truckee. The Companies have systematically addressed ruggedization including:

1) **Solid Fire-Resistant Perimeter Walls** – A solid fire-resistant perimeter 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. Since there are five substations proposed for this hardening, the installation of barrier walls is being combined and bid-out as one project to reduce cost and installation time.
2) **Transformer Oil Replacement (FR3 Transformer Oil)** – Substation Transformers have used mineral oils as insulating liquids since 1887. The oil performs multiple functions, including dielectric insulating strength, heat transfer, diagnostic capabilities, and protecting 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 Transformer 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 of FR3 Transformer Oil reduces the likelihood the transformer oil can ignite or burn.
3) **Breaker and Recloser Oil-Filled Equipment Replacement** – Legacy substation breakers and reclosers and are filled with mineral oil as the insulating material. The

mineral oil has a flash point near 320°F with the possibility of igniting or spraying flaming oil during a catastrophic failure event. Modern breakers and reclosers use vacuum or sulfur hexafluoride gas (SF_6) as the insulating material. The replacement of legacy breakers and reclosers with modern equipment will reduce the fire hazard at the substation by removing oil as an ignition source.

4) **Substation Grounding** – Substation equipment is connected to a substation grounding grid that bonds all metallic structures and equipment together. An improvement of the bonding of equipment to the substation grounding grid will improve the return path of certain low impedance faults. An improved grounding grid will enable faster fault clearing time, reducing the duration of arcing, a source of ignition, which could result in a wildfire.

5) **Weed Barrier and Crushed Rock Vegetation Control** – Vegetation, especially when dry, can create a fire hazard when arcing occurs within the substation or when substation equipment fails in service. The area inside the boundary should be clear of vegetation to eliminate those hazards. Vegetation can be better controlled with the installation of geo-synthetic fabric below an adequate layer of type-two soil or surface rock.

6) **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 vegetation, wildlife, and other debris contact. 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 vegetation, animal, or debris contact that could cause equipment failures inside of a substation. This will reduce the likelihood of arcing or catastrophic failure of equipment leading to a wildfire ignition.

Weed and vegetation control are complete for all substations. Insulated bus or conductors are partially complete. Table 54 below continues the Substation Hardening previously approved for these substations.

Table 54. Long-Term Substation Hardening Investments

Substation	FR3 Transformer Oil	Replace Oil Filled Equipment	Insulated Bus or Conductors	Weed and Vegetation Control	Substation Grounding	Perimeter Wall
Kingsbury	✓	✓	X	X	✓	✓
Incline	-	✓	✓	X	✓	✓
Round Hill	✓	-	X	X	-	✓
Glenbrook	✓	-	✓	X	✓	✓
North Truckee	✓	-	X	X	-	✓

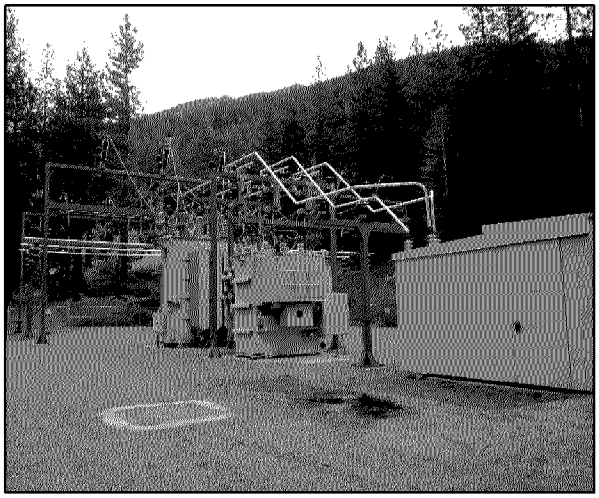
✓ = work continues X = work complete - = not indicated

Substation Descriptions

Incline

The Incline Substation is located in Tier 3 of Incline Village, Nevada, adjacent to the sewer plant, and surrounded by national forest. See Figure 26 for a picture of the Incline Substation. The substation has limited distance between vegetation and substation equipment (~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 toward the surrounding forest with little to prevent the spread. In the 1990's the substation's metal-clad switchgear experienced an internal fault creating an arc blast and fire, but the damage was contained within the switchgear.

Figure 26. Incline Substation



Round Hill

The Round Hill Substation_is located in Tier 3 near a residential area of Stateline, Nevada, adjacent to the sewer plant, and surrounded by national forest. Figure 27 shows a picture of the Round Hill Substation. The substation has limited distance between vegetation and substation equipment (~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 toward the surrounding forest with little to prevent the spread. The 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, after an animal

contact at one of the feeder breakers. Calm wind conditions likely prevented the spread of the fire to the surrounding forest.[37]

Figure 27. Round Hill Substation

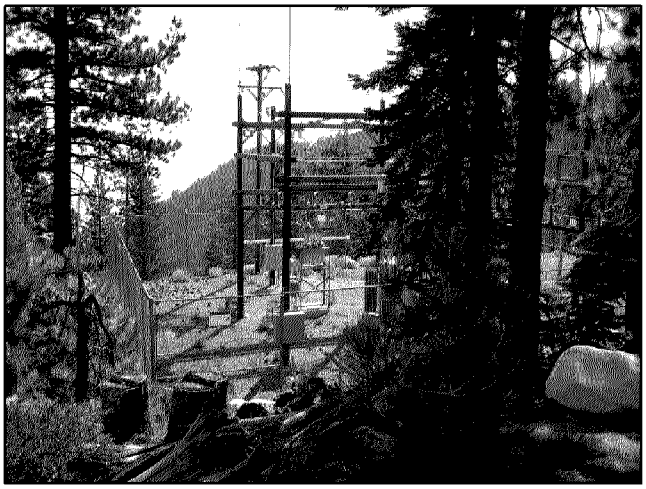


Kingsbury

The Kingsbury Substation is located in Tier 3 on the east side of the Carson mountain range adjacent to the Sierra Nevada mountain range near the summit. See Figure 28 for a picture of the Kingsbury Substation. The substation has limited distance between vegetation and substation equipment (~15 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 toward the surrounding forest with little to prevent the spread.

[37] "Past Weather in South Lake Tahoe, California, USA." https://www.timeanddate.com/weather/usa/south-lake-tahoe/historic?month=8&year=2017. https://www.timeanddate.com/weather/usa/south-lake-tahoe/historic?month=8&year=2017. August 2017.

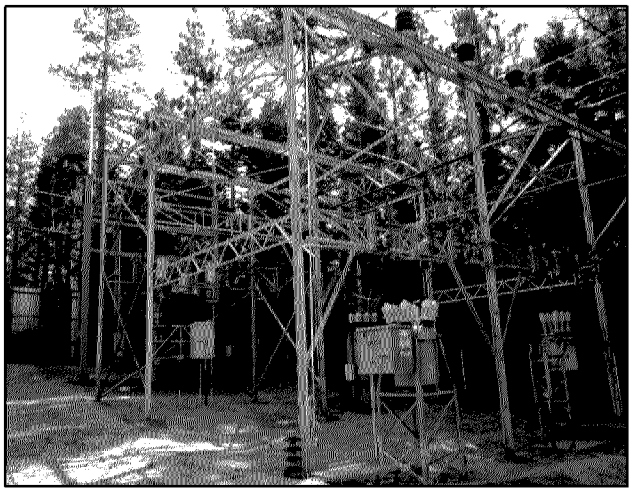
Figure 28. Kingsbury Substation



Glenbrook

The Glenbrook Substation in Tier 3 is in a residential area of Glenbrook, Nevada, adjacent to homes, and surrounded by national forest. See Figure 29 for a picture of the Glenbrook Substation. The substation has limited distance between vegetation and substation equipment (~15 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. 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 toward the surrounding forest with little to prevent the spread.

Figure 29. Glenbrook Substation



North Truckee

The North Truckee Substation is in Tier 2 in Truckee, California adjacent to the Tahoe National Forest. See Figure 30 for a picture of the North Truckee Substation. The substation has some distance between vegetation and substation equipment (>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 toward the surrounding forest with little to prevent the spread.

Figure 30. North Truckee Substation



The Companies request funding to continue the substation hardening investments that began under the 2020 NDPP. Table 55 summarizes the 2027-2029 funding request for the five substations.

Table 55. Substation Hardening Budget

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Sierra Pacific Power				
Substation Hardening - Barrier Walls	$ 1,250,288	$ 1,250,288	$ -	$ -
Substation Hardening - Interior	$ 2,804,845	$ 2,688,238	$ 116,607	$ -
Substation Hardening - Glenbrook Substation	$ 4,677,304	$ 1,294,783	$ 1,133,581	$ 2,248,940
Sierra Pacific Power Total	**$ 8,732,437**	**$ 5,233,309**	**$ 1,250,188**	**$ 2,248,940**

2.5.9. FIRE MESH POLE WRAP

The Companies are proposing to continue to deploy a fire-resistant fire mesh pole wrap and pole coating. Fire mesh is designed to protect wood structures from burning or scorching, by forming a barrier that expands at temperatures greater than 300°F. The coating on the mesh expands to

prevent ignition and reduce burning on the pole. Fire mesh is now installed on new wood poles in the Wildfire HTAs where installation of a non-wood pole is not feasible.

Table 56 shows the requested funding for the Plan period for installation of the fire wrap/pole coating on existing poles in the wildfire Tier 3, 2, 1E, and 1, where no immediate pole replacement projects are planned. Fire mesh/pole coating installation will begin along critical evacuation routes, critical circuits, and higher fire ignition areas in Tier 2, Tier 1E, and Tier 1. New poles in the Tier 3 will have the fire mesh/pole coating installed to the standards. The Companies will collaborate with EWG fire agencies, will consider evacuation routes and fire risk maps to assure priority areas are addressed. The Tier expansions will not affect the budget as this program utilizes a dollar budget rather than a per pole cost.

Table 56. Fire Mesh Program Budget

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Pole Coatings				
Nevada Power	$ 928,125	$ 300,000	$ 309,375	$ 318,750
Sierra Pacific Power	$ 1,608,654	$ 485,998	$ 534,598	$ 588,058
Pole Coatings Total	**$ 2,536,779**	**$ 785,998**	**$ 843,973**	**$ 906,808**

2.5.10. NEVADA POWER LINES RUGGEDIZATION PROGRAMS

The Lines Ruggedization Program includes a portfolio of programs to guard against widespread outages and other impacts from all natural disasters, such as downed wires or poles. During an emergency, it is critical that any electric grid infrastructure not impede first responders or compromise the general public's ability to evacuate from a natural disaster. The Companies must have access to restore power in an expedited manner should an outage occur. Pole damage can quickly cascade, bringing down multiple poles with compounding impacts. Replacing multiple poles further delays service restoration to critical facilities. To address these threats, the Companies have specific targeted investments with pole stoppers and hardening around critical crossing.

Pole Stoppers – The Pole Stoppers program ruggedizes the transmission infrastructure by replacing every fifth to eighth wood tangent or suspension structure with higher class steel or ductile iron structures and transmission guyed wood dead-end structure to better withstand the impact of a cascade failure. Table 57 shows the status, including structures, which comprise the pole stopper program. The Companies recommend continuing the design, permitting, and construction for identified pole stopper guyed wood dead-end structures. Timelines may be impacted based on permits, materials, and labor availability.

Table 57. Nevada Power Pole Stopper Program

NDPP Reference	Service Territory NPC	Total Structures	Total Complete Through 2026	Total Remaining	Docket No.	Prior Approval	2027-2029 Recommendation
Pole Stoppers	Tiers 3, 2, & 1E	34	34	0	20-02031/ 20-02032	Design Permit Construction	(continue) Design Permit Construction
	Phase 1: Tier 1	7	2	5			
	Phase 2: Monsoon	14	0	14			

Critical Crossings – The Critical Crossings program replaces specific wood poles adjacent to critical crossings, including highways, railroads, and at critical distribution and transmission lines, with higher class steel or ductile iron structures to better withstand and mitigate the impact of poles and wire coming down across the critical crossings during a natural disaster. This project to guard ingress and egress routes minimizes the number of customers impacted by a PSOM event by adding load break isolation devices on the lines near the transition point between non-Tiered and Tiered areas. Table 58 shows the status of the critical crossings program. The Companies recommend continuing design/engineering, permitting and construction to ruggedize the remaining 16 critical crossing structures, and future identified critical crossings. Timelines may be impacted based on permits, materials, and labor availability.

Table 58. Nevada Power Critical Crossing Program

NDPP Reference	Service Territory NPC	Total Structures	Total Complete Through 2026	Total Remaining	Docket No.	Prior Approval	2027-2029 Recommendation	Extends Beyond 2029
Critical Crossings	Distribution	34	30	4	20-02031/ 20-02032	Design Permit Construction	(continue) Design Permit Construction	
	Transmission	45	33	12				

Proposed Triennial Budget

The Companies seek authorization to continue the design, permitting, and construction for identified pole stopper wood guyed dead-end structures, the 16 remaining critical crossing structures, and future identified critical crossings. Table 59 shows the funding requested for the pole stoppers and critical crossing lines ruggedization.

Table 59. Lines Ruggedization Budget Forecast

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Nevada Power				
Grid Ruggedization - Pole Stoppers	$ 7,875,000	$ 2,500,000	$ 2,625,000	$ 2,750,000
Grid Ruggedization - Critical Crossings	$ 6,590,000	$ 2,090,000	$ 2,200,000	$ 2,300,000
Nevada Power Total	**$ 14,465,000**	**$ 4,590,000**	**$ 4,825,000**	**$ 5,050,000**

2.5.11. MT. CHARLESTON REBUILD

The first phase of the Mt. Charleston rebuild was approved in Docket No. 24-12016. The complete project was presented as a four-phase project. The Companies are requesting to update the Mt. Charleston request as a three-phase project due to the need to accelerate the work on the Angel Peak 3402 (phase 3) and Canyon 3401 (phase 4) lines due to extreme deterioration identified through the Inspections Program. Cost recovery of the projects required to bring these two lines up to Tier 3 ruggedized standards using tree wire covered conductor will be sought under NDPP-GRC.

The Department of Energy ("DOE") recently requested modifications for the Mt. Charleston clean energy microgrid grant. Although the Companies received a conditional grant award under DOE's Grid Resilience and Innovation Partnership ("GRIP") Round 2, more recent discussions indicate modifications are needed to qualify for funding. The Companies will continue discussions to adapt the design for the microgrid and surrounding Mt. Charleston infrastructure if feasible. Recently, permitting delays have been experienced by multiple companies seeking to locate solar generation on federal land. The Companies will continue to provide updates as they become available.

Phase 1 - Develop and Install a Clean Energy Microgrid

The Commission approved Phase 1 funding of $19,075,000 million through 2026.[38] This represents the amount needed to procure and implement a permanent microgrid using a combination of solar photovoltaic ("PV") generation, a battery energy storage system ("BESS"), and propane generation resulting in a 50 percent renewable profile. The microgrid can be activated during a natural disaster event, to fully island Kyle Canyon 1201 and Angel Peak 3402. Based on anticipated permitting delays most of the previously-approved budget has been reallocated for 2027-2029.

The Companies are in the process of adapting the microgrid design in anticipation of awarding a comprehensive engineering, procurement, and construction ("EPC") project. The microgrid, sized to provide uninterrupted power to supply both winter and summer peak power was conceived as a clean energy microgrid. The minimum microgrid requirements consist of a combination of the

[38] Docket No. 24-12016.

solar PV generation, the BESS, and propane generation to deliver a minimum 50 percent renewable profile, in addition to a control system capable of integrating with onsite electrical equipment and the Companies' grid operations control center. Winter peak loading is estimated to be 2 MW and summer peak loading is estimated to be 1.85 MW. The winter and summer peak loadings include the new Mt. Charleston Lodge peak demand. The microgrid will provide uninterrupted power for the duration of a PSOM event, typically up to 24 hours with varying energy demand; however, the energy required from the microgrid should be able to meet the peak load for 24 hours. To maximize energy savings, the microgrid will be grid-connected when able to provide additional energy and be capable of fully islanding when needed to serve the customers on Kyle Canyon 1201 and Angel Peak 3402 circuits.

The Companies have incorporated permitting delays into the proposed funding request shown below to accommodate additional discussions with federal agencies. Discussions include both the need to eliminate PV to qualify for DOE grant funding and whether PV can be permitted on federal land for the microgrid. The funding request for Phase 1 design, permitting and construction is shown below in Table 60.

Table 60. Mt. Charleston Microgrid Phase 1

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Nevada Power				
Phase One - Mt Charleston Microgrid	$ 35,700,000	$ 5,500,000	$ 13,400,000	$ 16,800,000
Nevada Power Total	**$ 35,700,000**	**$ 5,500,000**	**$ 13,400,000**	**$ 16,800,000**
System Hardening Total	**$ 35,700,000**	**$ 5,500,000**	**$ 13,400,000**	**$ 16,800,000**

Phase 2 Ruggedize the Kyle Canyon 1201 Feeder

The Companies propose to bring the Kyle Canyon 1201 feeder up to wildfire ruggedized Tier 3 standards. The circuit will be rebuilt using tree wire covered conductor. The Companies require ruggedized structures for any overhead poles that are built within Tier 3. Poles in less accessible areas will be constructed using fire-wrapped wood poles. In this plan, The Companies are moving from design and permitting into construction. The Commission previously approved $250,000 for design and permitting through 2026. The budget request for this project is $7.5M for 2027 and $3.5M for 2028.

The funding request for Phase 2 design, permitting and construction through completion is shown below in Table 61.

Table 61. Mt. Charleston Rebuild Phase 2

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Nevada Power				
Phase Two - Kyle Canyon 1201 Feeder	$ 11,250,000	$ 7,500,000	$ 3,500,000	$ 250,000

Phase 3 Ruggedize the Kyle Canyon Substation

The Companies request funding to bring the Kyle Canyon substation up to Tier 3 ruggedized standards. The Companies will provide necessary civil site improvements for proper drainage, retaining walls, and natural disaster resilience improvements. Repairs to deteriorating substation equipment include transformers, switching devices, and foundations to ensure the longevity and useful life of the microgrid. The Commission previously approved $250K for design and permitting through 2026. The budget request for phase 3 is $2M in 2027, $7.5M in 2028 and $750,000 for 2029 to complete the Phase 3 Kyle Canyon substation rebuild.

The funding request for Phase 3 design, permitting and construction is shown below in Table 62.

Table 62. Mt. Charleston Phase 3

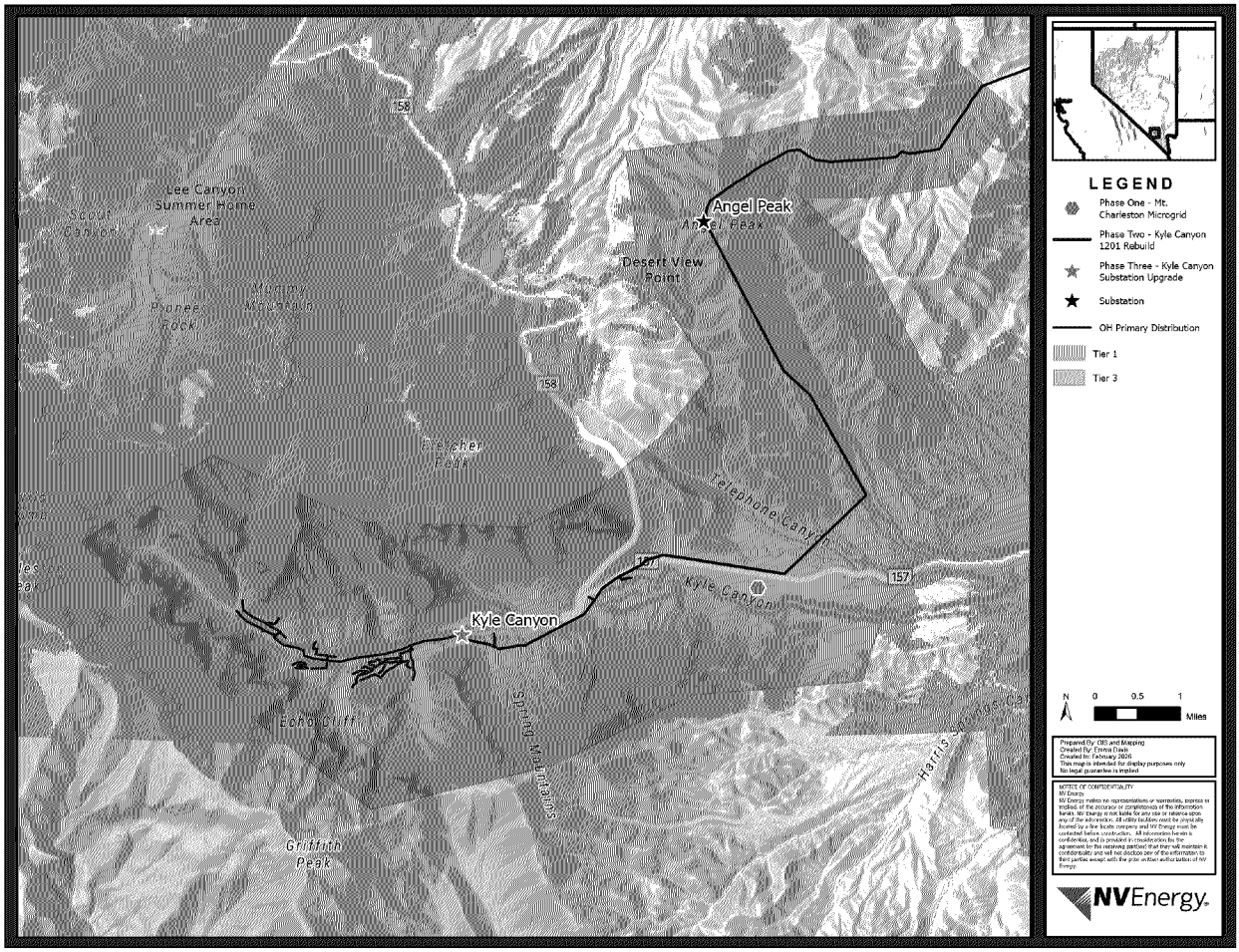
Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Nevada Power				
Phase Three - Kyle Canyon Sub	$ 10,250,000	$ 2,000,000	$ 7,500,000	$ 750,000

A summary of the Mt. Charleston Rebuild funding request is shown in Table 63.

Table 63. Mt. Charleston Rebuild

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
System Hardening				
Nevada Power				
Phase One - Mt Charleston Microgrid	$ 35,700,000	$ 5,500,000	$ 13,400,000	$ 16,800,000
Phase Two - Kyle Canyon 1201 Feeder	$ 11,250,000	$ 7,500,000	$ 3,500,000	$ 250,000
Phase Three - Kyle Canyon Sub	$ 10,250,000	$ 2,000,000	$ 7,500,000	$ 750,000
Mt Charleston Land Rights	$ 1,250,000	$ 550,000	$ 450,000	$ 250,000
Nevada Power Total	**$ 58,450,000**	**$ 15,550,000**	**$ 24,850,000**	**$ 18,050,000**
System Hardening Total	**$ 58,450,000**	**$ 15,550,000**	**$ 24,850,000**	**$ 18,050,000**

Figure 31. Mt. Charleston Rebuild Project



At the time of this filing, the detailed design of the microgrid is not yet available due to the pending issuance of the RFP award. Once the detailed design is available, the Companies will submit an informational update with the information.

2.5.12. ADVANCED TECHNOLOGIES

Through various industry organizations, such as the International Wildfire Risk Mitigation Consortium ("IWRMC"), and industry research organizations, such as the Electric Power Research Institute and the national laboratories, The Companies remain current on industry practices and in the field experiences. Select technologies that address specific challenges are recommended for inclusion in the NDPP that have demonstrated technical readiness, usually a Technology Readiness Level ("TRL") of 8 or greater.

In this Plan, the Companies have identified an advanced technology, Gridware,[39] that is being implemented by many utilities in conjunction with covered conductor. In some instances, hard to detect high impedance faults have been associated with covered conductor. While rare, system protection devices may malfunction due to a high impedance or other faults that can result in energized conductor falling to the ground posing a serious risk to people and property. High impedance faults ("HIF") are not unique to covered conductor and occur when an energized conductor makes contact with a poorly conductive surface, such as dry soil, asphalt, concrete, or vegetation. Unlike typical faults that generate high current and are easily detected by protective relays, HIF produce low fault currents that do not trigger conventional protection systems. While covered conductor lowers ignition risk, should an HIF develop and remain on the line or a line remains on the ground, the risk of ignition increases over time. The Companies are requesting a pilot program with Gridware to support detection and alerts of HIF.

Gridware provides pole-mounted devices that are designed to provide alerts when an overhead line has an unusual condition. Gridware devices are placed on alternating poles that report to System Control via wireless communications when normal conditions are violated. Wireless reporting to System Control allows for field personnel to be dispatched to investigate and report on the unusual conditions and to call in reinforcements if necessary to make repairs. Gridware's Gridscopes detect both electrical and mechanical disturbances and can easily detect HIF on covered conductor and bare wire. In addition to being able to detect anomalies involving electric infrastructure that could lead to a wildfire ignition, Gridscopes are equipped with volatile organic compound ("VOC") sensors which can detect smoke around the devices. These VOC sensors can indicate a fire on electric infrastructure.

Additional benefits of Gridscopes include critical asset health updates, such as pole tilt or a broken guy wire, to allow for corrections before fire weather conditions are present. During fire weather conditions, Gridscopes can indicate anomalies and inconsistencies at their location for immediate investigation and determination of the cause such as a downed wire, a limb laying on the line, poles leaning out of plumb, vibrations in the system, etc. Gridscopes can decrease response time and potentially reduce spread wildfire and equipment damage.

The Companies request funding for an initial program of 350 Gridscopes for Nevada Power Company and 1,425 Gridscopes for Sierra Pacific Power. If successful, the Companies request a budget for 2028 and 2029 to add 1,425 Gridscope units each year in Sierra's service territory.

[39] Gridware | Protecting the Grid Today, Preparing the Grid for Tomorrow www.gridware.io.

Gridware counts per circuit and requested budget are shown in Table 64.

Table 64. Gridware Advanced Technology Pilot Program Budget Forecast

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Risk Based Approach				
Gridware				
Nevada Power	$ 1,226,577	$ 1,226,577	$ -	$ -
Sierra Pacific Power	$ 8,338,948	$ 3,889,044	$ 4,045,352	$ 404,552
Gridware Total	**$ 9,565,525**	**$ 5,115,621**	**$ 4,045,352**	**$ 404,552**

2.6. NDPP COST BENEFIT CALCULATOR

The NDPP Cost Benefit Calculator provides a benefit-to-cost ratio ("BCR") for each program element consistent with the regulations adopted in Docket No. 19-06009. In this section, the Companies describe the NDPP Cost Benefit Calculator framework and the initial results presented in this Triennial Plan. The Companies intend to continue refining the NDPP Cost Benefit Calculator to provide results that are more specific to the Companies' service territories and their proposed NDPP mitigation efforts. The analysis presented for this Triennial Plan shows that each wildfire-related NDPP element provides benefits that exceed program costs on a probability-based risk reduction basis. The Companies note that the NDPP Cost Benefit Calculator primarily quantifies potential benefits associated avoiding catastrophic wildfire events and it does not currently quantify other benefits such as improved reliability and resilience or more generalized public safety benefits.

Table 65. Initial Cost Benefit Analysis

A	B	C	D	E	F	G	H	I	J	K	L
Program	Triennial Program OMAG	Triennial Program Capital	Total Triennial Program Cost	Risk Reduction - Low	Risk Reduction - High	Annual Risk	Triennial Risk	$ Loss Reduction (Low)	$ Loss Reduction (High)	BCR (Low)	BCR (High)
Vegetation Management	119,580,600	0	119,580,600	0.5	0.6	92,000,000	276,000,000	138,000,000	165,600,000	1.15	1.38
Situational Awareness											
Weather Stations	1,708,063	1,546,456	3,254,519	0.1	0.2	92,000,000	276,000,000	27,600,000	55,200,000	8.48	16.96
Wildfire Cameras	3,107,364	2,661,292	5,768,656	0.2	0.35	92,000,000	276,000,000	55,200,000	96,600,000	9.57	16.75
Operational Practices											
FTFM, PSOM, Emergency Operations, plus Distribution Automation	10,368,536	6,546,347	16,914,883	0.4	0.6	92,000,000	276,000,000	110,400,000	165,600,000	6.53	9.79
Circuit Patrols, Detailed Inspections and Corrections	18,673,494	0	18,673,494	0.2	0.35	92,000,000	276,000,000	55,200,000	96,600,000	2.96	5.17
Pole Replacements (GRC-only)	0	30,850,000	30,850,000	0.4	0.55	92,000,000	276,000,000	110,400,000	151,800,000	3.58	4.92
System Hardening											
Undergrounding Program	0	57,755,866	57,755,866	0.85	0.95	92,000,000	276,000,000	234,600,000	262,200,000	4.06	4.54
Overhead Rebuild+Copper Wire Replacement	0	85,387,465	85,387,465	0.35	0.55	92,000,000	276,000,000	96,600,000	151,800,000	1.13	1.78
Tree Attachment Program	0	6,960,000	6,960,000	0.1	0.2	92,000,000	276,000,000	27,600,000	55,200,000	3.97	7.93
Expulsion Fuse Replacement Program	17,200,000	17,600,000	34,800,000	0.15	0.35	92,000,000	276,000,000	41,400,000	96,600,000	1.19	2.78
*Substation Hardening	0	8,732,437	8,732,437								
*Pole Coatings	2,536,779	0	2,536,779								
**Critical Crossings Program	0	6,590,000	6,590,000								
**Pole Stoppers	0	7,875,000	7,875,000								
Risk Based Approach											
Gridware Pilot Program	0	9,565,525	9,565,525	0.25	0.4	92,000,000	276,000,000	69,000,000	110,400,000	7.21	11.54
***Resource Sufficiency	4,007,007	0	4,007,007								

Footnotes

*Substations and Pole Coatings-- The Companies' are still working on quantifying the estimated wildfire risk reduction for these.

**Critical Crossings and Pole Stoppers -- The Companie's are still working on quantifying the natural disaster risk reduction for these. (not wildfire related)

***Resource Sufficiency enables each of the programs listed above, though it does not yield an independent risk reduction metric. Rather, this spending serves as a catalyst that enhances other programs' performance.

The BCR estimates whether potential program potential benefits exceed potential costs. This analysis presents two scenarios: a high versus low cost and associated risk. This analysis shows the difference between performing a given job for the program in a remote area, difficult to access, with adverse territory conditions and a higher wildfire risk versus a job performed in lower wildfire risk area. In Table 65, Column A presents NDPP program elements. Columns B, C, and D present the Companies' proposed Triennial Program OMAG, capital and total spending as included in the plan, respectively. The values in column D present the Estimated Project Cost which represents the total cost required to execute the mitigation activity during the triennial period. This total cost value is the denominator for the BCR calculation.

Columns E and F present low and high risk reduction values for each program element. These represent estimated risk reduction associated with the NDPP element as the programs are currently designed. Risk reduction is calibrated based on the current NDPP program design, meaning that this level of risk reduction will not be achieved if the NDPP program element is scaled back or eliminated. The risk reduction numbers provide a high and low range of risk reduction to account for treatments in different areas with different risk profiles. These values represent absolute risk related to a single given job, associated with a single program; not relative risk associated with two given jobs from two programs combined. The risk reduction values for each Program used in this initial cost-benefit analysis are derived from the Companies' comprehensive literature review of mitigation strategies implemented by other utilities operating under comparable conditions, challenges, and system characteristics. The Companies provide more details regarding this risk reduction literature review in Appendix D to the Plan. This approach ensures alignment with industry practices and provides a benchmark for evaluating the relative effectiveness of each program over time.

To adjust these externally sourced estimates to Nevada's unique wildfire-risk profile, the Companies applied a conservative safety factor that scales risk reduction values downward. This precautionary adjustment is intended to avoid overstating expected benefits and to support a more robust and reliable cost-benefit assessment, which will be progressively refined as empirical data from the Companies' internal modeling becomes available.

Columns G and H in Table 1, present "Annual Risk" and "Triennial Risk" in dollar terms. The annual risk value is based on the wildfire-related financial exposure associated with a potential catastrophic event for the Companies. Expert Witness Nathan Pollak calculated the annualized wildfire-related financial exposure in Docket No. 25-01018.[40] His analysis estimated that the Companies' expected annual loss associated with wildfire to be approximately $92 million.[41] Using this estimate from Mr. Pollak's testimony, the Companies assumed an annual risk value of $92 million. This also informs the triennial risk metric, which multiplies the annual risk estimate by three to reflect a three-year NDPP planning horizon. Both metrics are constant across all observations because the analysis assumes that each Program is evaluated as an independent mitigation action, and that each job or intervention within the Program is capable of preventing a potential catastrophic wildfire event on its own. Consequently, these values are not cumulative,

[40] See Docket No. 25-01018, Prepared Direct Testimony of Nathan Pollak at pages 27-28.

[41] Id. At page 27, lines 10-11.

as Programs are not modeled to interact or compound risk reductions within this specific framework.

This approach intentionally incorporates assumptions to ensure that the resulting cost-benefit assessment is robust and does not understate the Companies' potential financial exposure or overstate expected program benefits. Mathematically, this approach distributes the expected cost of a high-impact, low-frequency wildfire event over its assumed recurrence interval, which in this case is ten years. While this method appropriately incorporates the probability of a catastrophic event into the analysis, it does not imply that an eventual extreme wildfire would result in a loss of only $276 million. In reality, if such an event were to occur, the financial impact would likely be closer to the approximately $1 billion loss identified in Mr. Pollak's assessment. However, directly applying the full $1 billion loss as the annualized or triennial expected cost would introduce significant upward bias into the BCR calculations, overstating the apparent effectiveness of mitigation programs. The current method therefore uses a probability-weighted, interval-adjusted estimate to maintain analytic rigor and prevent overvaluation of program benefits.

Columns I and J in Table 1, present low and high loss reduction values in dollar terms. These represent potential avoided losses from catastrophic wildfire events (i.e., the benefits of NDPP elements) in dollar terms. The Companies computed these values by multiplying the risk reduction probabilities by the Triennial Risk estimate. The resulting figures represent the minimum and maximum expected loss reduction benefits achievable on a given circuit from performing a specific job within the NDPP element evaluated.

These two values define a credible range of potential financial benefits for each Program. For purposes of calculating the BCR, they serve as the numerator in the BCR (Low) and BCR (High) formulations, providing lower- and upper-bound estimates of program effectiveness.

Columns K and L present the Benefit-Cost Ratio (Low) and Benefit-Cost Ratio (High), the metrics developed to evaluate the relative effectiveness of each Program. Each BCR is computed as the ratio of the estimated loss-reduction benefit to the associated program cost and therefore yields a value strictly greater than zero.

A BCR less than 1.0 indicates that the program's projected costs exceed its expected loss-reduction benefits, implying limited cost-effectiveness. Conversely, a BCR greater than 1.0 signifies that the anticipated benefits in avoided losses exceed the program costs, indicating that the program provides a net economic benefit.

Please see below for a guided step-by-step example for the Vegetation Management Program with numbers, conclusions and a final analysis of the BCR metric for this program.

Example:

This example describes the step-by-step method used to calculate the Total Triennial Program Cost, the Triennial Risk, the Loss Reduction ($) values, and the resulting BCRs for the Vegetation

Management Program. Each step identifies which input value is used, what operation is performed, and why that calculation is needed. No advanced mathematical knowledge is required.

1. Calculating the Total Triennial Program Cost

Two types of program costs are provided:

- Triennial Program OMAG = $119,580,600
  (Operations, Maintenance, and Administrative Costs over three years)
- Triennial Program Capital = $0
  (Capital investment over the same three-year period)

Purpose of this step:
To determine the *full* cost of implementing the program over the three-year timeline.

Process
We add these two values:

$$\text{Total Triennial Program Cost} = \text{Triennial Program OMAG} + \text{Triennial Program Capital}$$
$$= 119{,}580{,}600 + 0$$
$$= \$119{,}580{,}600$$

This combined value becomes the program's total financial investment for the three-year period.

2. Converting Annual Risk into Triennial Risk

The dataset provides:

- Annual Risk = $92,000,000
  (The estimated monetary loss expected per year due to wildfire-related impacts)

However, our cost and benefit calculations are based on a three-year program cycle. Therefore, the annual risk must be scaled to represent the same time span.

Process
To find the risk over three years, we multiply the annual risk by 3:

$$\text{Triennial Risk} = \text{Annual Risk} \times 3$$
$$= \$276{,}000{,}000$$

This gives the total expected loss over the same three-year period for which program costs are measured.

3. Calculating the Dollar Value of Loss Reduction

The program has two estimated levels of wildfire risk reduction [derived from the Companies' comprehensive literature review and application of the safety factor]:

- Risk Reduction – Low = 0.5

- Risk Reduction – High = 0.6

Each represents the fraction of wildfire risk expected to be removed by the program (for example, 0.5 = 50%).

Purpose of this step
To convert those percentage-based reductions into actual monetary benefits (i.e., dollars saved).

3.1. Calculating $ Loss Reduction (Low)
We multiply the Low risk reduction percentage by the Triennial Risk value:

$$\begin{aligned}\text{\$ Loss Reduction (Low)} &= \text{Risk Reduction (Low)} \times \text{Triennial Risk} \\ &= 0.5 \times 276{,}000{,}000 \\ &= \$138{,}000{,}000\end{aligned}$$

This value represents the estimated dollars saved assuming the lower-bound effectiveness.

3.2. Calculating $ Loss Reduction (High)

We perform the same operation using the High risk-reduction estimate:

$$\begin{aligned}\text{\$Loss Reduction (High)} &= \text{Risk Reduction (High)} \times \text{Triennial Risk} \\ &= 0.6 \times 276{,}000{,}000 \\ &= \$165{,}600{,}000\end{aligned}$$

This value represents the estimated dollars saved assuming the higher-bound effectiveness.

4. Calculating the BCR

The BCR compares:

- Benefits = monetary value of risk reduction
- Costs = Total Triennial Program Cost

The BCR shows how many dollars of benefit are returned for every dollar invested.

4.1. BCR (Low)

$$\begin{aligned}\text{BCR (Low)} &= \frac{\text{\$ Loss Reduction (Low)}}{\text{Total Triennial Program Cost}} \\ &= \frac{138{,}000{,}000}{119{,}580{,}600} \\ &= 1.15\end{aligned}$$

This ratio uses the lower-bound estimate of program effectiveness.

4.2. BCR (High)

$$\text{BCR (High)} = \frac{\text{\$ Loss Reduction (High)}}{\text{Total Triennial Program Cost}}$$

$$= \frac{165{,}600{,}000}{119{,}580{,}600}$$
$$= 1.38$$

This ratio uses the higher-bound estimate of program effectiveness.

Conclusion:

A BCR below 1.0 indicates that the program's expected financial benefits are smaller than its costs, meaning the investment does not fully "pay for itself," whereas a BCR greater than 1.0 means the program is expected to deliver more financial benefit than it costs, representing a net positive return on investment. In this example, both the BCRs are expected to deliver more financial benefit than the actual cost. The lower-bound estimate of program effectiveness implies that every dollar spent on the program produces $1.15 in benefit, and the higher-bound estimate implies that every dollar spent on the program produces $1.38 in benefit.

3. PROGRAM ANALYSES

In the Appendix, the Companies present the overall approach to value-driven risk reduction that informs this Plan. This includes a cost-benefit analysis in response to the Regulations,[42] as updated in 2024. Cost-benefit analyses are presented for the specific Plan element and are included in Appendix D.

[42] Section 4. (b) The projected costs, including, without limitation supporting documentation and analysis, of any element of the natural disaster protection plan that is incremental to the normal course of business.

4. COMMUNICATIONS AND OUTREACH

The Companies foster communication and outreach efforts to build awareness, preparedness, and leverage local knowledge related to heightened natural disaster threats. The Companies use a multi-pronged approach that includes engagement with the EWG, community and customer outreach, and project-focused communication. A rebranding of the Companies' NDPP efforts under the Power Safe NV https://www.nvenergy.com/safety/wildfire was a result of community feedback to improve effectiveness.

4.1. EWG ENGAGEMENT

The Companies convened two focused NDPP discussion sessions with the EWG to review programs, projects, and initiatives on January 22 and January 27, 2026. The EWG sessions provide an opportunity to engage with collaborating organizations in advance of the Plan submittal and prepare for the broader community outreach initiative after the NDPP has been filed at the Commission. Local subgroups of the EWG will continue to meet for ongoing alignment. In addition to discussions in the NDPP sessions, participants can also provide feedback and request clarifications at any time through the dedicated email box NDPP@nvenergy.com. The 2026 sessions did not indicate concerns with the proposed direction and content of the Plan.

4.2. CUSTOMER COMMUNICATION

The Companies encourage customers to stay informed through community engagement efforts and their webpages where the public can obtain updates on the Plan's development and implementation. Additionally, the Companies have targeted communications initiatives that include special notifications through email and direct mail, social media, public meeting sessions, emergency notifications, and other channels. Events are covered by local news media and provide an opportunity to share information on the Companies' NDPP projects, programs, and initiatives.

Corporate Communications prepares messages and talking points used by the customer service teams throughout the lifecycle of NDPP activities. The Companies apply focused attention on Green Cross Customers to gauge what extra support might be needed during natural disaster events, as those customers can be particularly impacted by grid disturbances. The Companies review their list of critical services customers regularly to supplement outreach for essential services such as hospitals.

5. METRICS PERFORMANCE AND MONITORING

The Commission directed the Companies to report the metrics that appear in this Section,[43] some by service territory and, when available, on a Wildfire Tier basis. The Companies track and present metrics in as granular a representation as possible using available information. Table 65 identifies the required metrics and includes partial data through the middle of 2025. The Companies will provide refreshed data for all of 2025 in a future filing.

[43] The Commission approved the metrics in the Second Modified Order in Docket No. 20-02031, paragraphs 317-319.

Table 66. Reported Plan Metrics

ID	Metric	Metric Definition / Detail	CY 2023	CY 2024	First Half 2025	Measurements (Units)	Comments
M1	Number of Electric Infrastructure Caused Ignition Events and/or Fires that occur within the Vicinity of Utility Electrical Equipment	Number of ignition events: electric infrastructure caused or within the vicinity of electrical equipment **(total)**	26	46	9	# of all ignitions (Total)	
		Sierra: Number of ignition events: electric infrastructure caused or within the vicinity of electrical equipment	26	43	8	# of all ignitions (in Sierra)	
		Nevada Power: Number of ignition events: electric infrastructure caused or within the vicinity of electrical equipment	0	3	1	# of all ignitions (in Nevada Power)	*These ignition events are less than an acre, if not quickly suppressed in a confined space (e.g., 2'x2' area).*
M2	Number of Vegetation Contacts with Lines in Wildfire Risk Tiers	Number of vegetation contact incidents **(total)**	73	197	86	# of vegetation contacts that caused a power outage (Total)	*Vegetation contacts show contacts that resulted in an outage.* *Unavoidable tree outages are tree contacts that were from outside the maintenance zone including fall ins, broken limbs fall in, windblown vegetation, etc.*
		Sierra: Number of vegetation contact incidents	50	136	63	# of vegetation contacts that caused a power outage (in Sierra)	
		***Non-Tier**: Number of vegetation contact incidents*	33	46	13	# of vegetation contacts that caused a power outage (Sierra Non-Tier)	
		***Tier 1E**: Number of vegetation contact incidents*	9	35	14	# of vegetation contacts that caused a power outage (Sierra Tier 1E)	
		***Tier 2**: Number of vegetation contact incidents*	5	2	2	# of vegetation contacts that caused a power outage (Sierra Tier 2)	
		***Tier 3**: Number of vegetation contact incidents*	3	15	10	# of vegetation contacts that caused a power outage (Sierra Tier 3)	
		Nevada Power: Number of vegetation contact incidents	23	60	23	# of vegetation contacts that caused a power outage (in Nevada Power)	
		***Non-Tier**: Number of vegetation contact incidents*	23	60	23	# of vegetation contacts that caused a power outage (Nevada Power Non-Tier)	
		***Tier 1E**: Number of vegetation contact incidents*	N/A	N/A	N/A	# of vegetation contacts that caused a power outage (Nevada Power Tier 1E)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*
		***Tier 2**: Number of vegetation contact incidents*	N/A	N/A	N/A	# of vegetation contacts that caused a power outage (Nevada Power Tier 2)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*
		***Tier 3**: Number of vegetation contact incidents*	0	0	0	# of vegetation contacts that caused a power outage (Nevada Power Tier 3)	*0 Unavoidable*

ID	Metric	Metric Definition / Detail	CY 2023	CY 2024	First Half 2025	Measurements (Units)	Comments
M3	Number of Overhead Equipment Failures in Wildfire Risk Tiers	Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures) **(total)**	1679	1488	418	# of overhead equipment failures (Total)	*Findings determined through outage data reports of incident causation.*
		Sierra: *Number of overhead equipment failures resulting in an outage* (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)	932	790	202	# of overhead equipment failures (Sierra)	*Findings determined through outage data reports of incident causation.*
		***Non-Tier**: Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)*	518	99	21	# of overhead equipment failures (Sierra Non-Tier)	*Findings determined through outage data reports of incident causation.*
		***Tier 1E**: Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)*	261	224	78	# of overhead equipment failures (Sierra Tier 1E)	*Findings determined through outage data reports of incident causation.*
		***Tier 2**: Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)*	109	72	29	# of overhead equipment failures (Sierra Tier 2)	*Findings determined through outage data reports of incident causation.*
		***Tier 3**: Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)*	44	77	13	# of overhead equipment failures (Sierra Tier 3)	*Findings determined through outage data reports of incident causation.*
		Nevada Power: Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)	747	698	216	# of overhead equipment failures (Nevada Power)	*Findings determined through outage data reports of incident causation.*
		***Non-Tier**: Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)*	739	642	187	# of overhead equipment failures (Nevada Power Non-Tier)	*Findings determined through outage data reports of incident causation.*
		***Tier 1E**: Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)*	N/A	N/A	N/A	# of overhead equipment failures (Nevada Power Tier 1E)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*
		***Tier 2**: Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)*	N/A	N/A	N/A	# of overhead equipment failures (Nevada Power Tier 2)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*
		***Tier 3**: Number of overhead equipment failures resulting in an outage (e.g., wire-down events, pole, overhead transformer, and overhead insulator failures)*	8	N/A	N/A	# of overhead equipment failures (Nevada Power Tier 3)	*Findings determined through outage data reports of incident causation.*

ID	Metric	Metric Definition / Detail	CY 2023	CY 2024	First Half 2025	Measurements (Units)	Comments
M4	Average Time for Vegetation Clearance Permissions from Local Agencies	Average permitting time for local agency approval for performing clearance work across the service territory (**total)**	12	4	4	Average Permitting time in Business Days (Total Annual represented)	*Average permitting time for local agencies has not been tracked as there has not been extended delays with local agencies. Processing times seem to be in line with the requirements. Federal agencies, especially the USFS, have extremely long processing/approval times which can and have exceeded 18 months to receive approval of work submitted.*
		Sierra: Average permitting time for local agency approval for performing clearance work across the service territory	12	4	4	Average Permitting time in Business Days (Total Annual represented) in Sierra	*Average permitting time for local agencies has not been tracked there have not been extended delays with local agencies. Processing times seem to be in line with the requirements. Federal agencies, especially USFS, have extremely long processing/approval times which can and have exceeded 18 months to receive approval of work submitted.*
		Nevada Power: Average permitting time for local agency approval for performing clearance work across the service territory	12	4	4	Average Permitting time in Business Days (Total Annual represented) in Nevada Power	*Average permitting time for local agencies has not been tracked as there have not been extended delays with local agencies. Processing times seem to be in line with the requirements. Federal agencies, especially USFS, have extremely long processing/approval times which can and have exceeded 18 months to receive approval of work submitted.*
M5	Number of PSOM Events	Number of initiated PSOM events (**total)**	2	8	4	# of Events (Total)	
		Sierra: Number of initiated PSOM events	1	3	3	# of Events (Sierra)	
		Nevada Power: Number of initiated PSOM events	1	5	1	# of Events (Nevada Power)	
M6	Acreage burned by ignition events	Acreage burned by utility-involved ignition events (total)	160.5	350.1	344.65	Acreage burned (Total)	
		Sierra: Acreage burned by utility-involved ignition events	160.5	350	344.45	Acreage burned (Sierra)	
		Nevada Power: Acreage burned by utility-involved ignition events	0	0.1	0.2	Acreage burned (Nevada Power)	

ID	Metric	Metric Definition / Detail	CY 2023	CY 2024	First Half 2025	Measurements (Units)	Comments
M7	Value of mitigation assets destroyed by ignition events	Recorded costs of mitigation assets destroyed by ignition events **(total)**	1,200	1,861,679	-31,052 (accounting correction)	($) Cost of destroyed NDPP mitigation assets (Total)	
		Sierra: Recorded costs of mitigation assets destroyed by ignition events	1,200	1,867,679	-31,052 (accounting correction)	($) Cost of destroyed NDPP mitigation assets (Sierra)	
		Nevada Power: Recorded costs of mitigation assets destroyed by ignition events	0	0	0	($) Cost of destroyed NDPP mitigation assets (Nevada Power)	
M8	Value of all assets and structures destroyed by ignition events	Recorded costs of all other assets and structures destroyed by ignition events **(total)**	32,371	2,113,534	-11,322 (accounting correction)	($) Cost of other Assets and Structures (Total)	
		Sierra: Recorded costs of all other assets and structures destroyed by ignition events (total)	32,371	2,113,534	-11,322 (accounting correction)	($) Cost of other Assets and Structure (Sierra)	
		Nevada Power: Recorded costs of all other assets and structures destroyed by ignition events (total)	0	0	0	($) Cost of other Assets and Structure (Nevada Power)	
M9	Duration of power outage during PSOM events in minutes/hours;	Duration (minutes/hours) of PSOM events **(total)**	6 hours 1 minute	145 hours 43 minutes	63 hours 5 minutes	# (duration) time of PSOM event (Total)	
		Sierra: Duration (minutes/hours) of PSOM events	6 hours 1 minute	67 hours 32 minutes	23 hours 44 minutes	# (duration) time of PSOM event (Sierra)	
		Nevada Power: Duration (minutes/hours) of PSOM events	0	78 hours 11 minutes	39 hours 21 minutes	# (duration) time of PSOM event (Nevada Powers)	*Single event within Tier 3 in Nevada Power*
M10	Number of minutes/hours to re-energize after hazardous conditions are cleared during a PSOM event	Duration (minutes/hours) to re-energize after "all clear" noticed received during PSOM events **(total)**	1 hour 55 minutes	26 hours 19 minutes	17 hours 54 minutes	# in time for Duration to re-energize after PSOM activation/circuit shutoff (Total)	*Duration accounts for the time to patrol the affected lines and then to safely re-energize.*
		Sierra: Duration (minutes/hours) to re-energize after "all clear" noticed received during PSOM quarterly	1 hour 55 minutes	12 hours 36 minutes	3 hours 1 minute	# in time for Duration to re-energize after PSOM activation/circuit shutoff (Sierra)	
		Nevada Power: Duration (minutes/hours) to re-energize after "all clear" noticed received during PSOM quarterly	0	13 hours 43 minutes	14 hours 53 minutes	# in time for Duration to re-energize after PSOM activation/circuit shutoff (Nevada Power)	*Duration accounts for the time to patrol the affected lines and then to safely re-energize.*
M11	Number of unplanned outages outside	Number of unplanned outages (excluding momentaries) that are not PSOM events **(total)**	6,046	4,974	1,462	# of Unplanned Outages (Total)	

ID	Metric	Metric Definition / Detail	CY 2023	CY 2024	First Half 2025	Measurements (Units)	Comments
	of PSOM events;	**Sierra:** Number of unplanned outages (excluding momentaries) that are not PSOM events	3,288	2,299	753	# of Unplanned Outages (Sierra)	
		Nevada Power: Number of unplanned outages (excluding momentaries) that are not PSOM events	2,758	2,675	709	# of Unplanned Outages (Nevada Power)	
M12	Duration of unplanned outages in minutes/hours outside PSOM events	Duration (minutes) of unplanned outages (excluding momentaries) that are not PSOM events **(total)**	1,131,040	864,985	254,378	# (duration) time for Unplanned Outage (Total)	
		Sierra: Duration (minutes/hours) of unplanned outages (excluding momentaries) that are not PSOM events	644559	381756	119693	# (duration) time for Unplanned Outage (Sierra)	
		Nevada Power: Duration (minutes/hours) of unplanned outages (excluding momentaries) that are not PSOM events	486482	465229	135686	# (duration) time for Unplanned Outage (Nevada Power)	
M13	Number of community emergency evacuations	Number of (utility-owned infrastructure involved in fire incidents) wildfire evacuations **(total)**	0	2	4	# of wildfire-related evacuations (Total)	*Q2 2021 - Jacks Valley Fire (Gardnerville), Petrilla Fire (Reno), Elko Fire (Elko)*
		Sierra: Number of (utility-owned infrastructure involved in fire incidents) wildfire evacuations	0	2	3	# of wildfire-related evacuations (Sierra)	
		Nevada Power: Number of (utility-owned infrastructure involved in fire incidents) wildfire evacuations	0	0	1	# of wildfire-related evacuations (Nevada Power)	
M14	Total increased cost incurred per customer due to wildfire mitigation and ignition events	Additional costs incurred divided by total customer count due to both NDPP mitigation activities and utility-involved ignition events **(total)**	47.19330527	51.01753	12.20568	$/Total NVE customer count in that calendar year (Total)	
		Sierra: Additional costs incurred divided by total customer count due to both NDPP mitigation activities and utility-involved ignition events (total)	35.11358097	40.96419	9.20798	$/Total NVE customer count in that calendar year (Sierra)	
		Nevada Power: Additional costs incurred divided by customer total count due to both NDPP mitigation activities and utility-involved ignition events (total)	12.0797243	10.05334	2.9977	$/Total NVE customer count in that calendar year (Nevada Power)	
M15	Increased cost per customer due to wildfire mitigation	Additional costs incurred divided by total customer count due to all NDPP mitigation activities **(total)**	46.76206564	49.52253	12.21358	$/Total NVE customer count in that calendar year (Total)	
		Sierra: Additional costs incurred divided by total customer count due to all NDPP mitigation activities (total)	34.68234135	39.46919	9.21588	$/Total NVE customer count in that calendar year (Sierra)	

ID	Metric	Metric Definition / Detail	CY 2023	CY 2024	First Half 2025	Measurements (Units)	Comments
		Nevada Power: Additional costs incurred divided by total customer count due to all NDPP mitigation activities (total)	12.0797243	10.05334	2.9977	$/Total NVE customer count in that calendar year (Nevada Power)	
M16	Increased cost per customer due to ignition events	Additional costs (outside of NDPP) incurred by reportable, significant ignition events, divided by total customer count **(total)**	0.431239622	1.495	-0.0079	$/Total NVE customer count in that calendar year (Total)	*Ignition events only caused by NVE facilities (costs associated with that damage/loss)*
		Sierra: Additional costs (outside of NDPP) incurred by reportable, significant ignition events, divided by total customer count (total)	0.431239622	1.495	-0.0079	$/Total NVE customer count in that calendar year (Sierra)	
		Nevada Power: Additional costs (outside of NDPP) incurred by reportable, significant ignition events, divided by total customer count (total)	0	0	0	$/Total NVE customer count in that calendar year (Nevada Power)	
M17	Total increased cost per risk area customer due to wildfire mitigation and ignition event	Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to ignition and NDPP mitigation activities **(total)**	47.19330527	50.60351	11.90536	$/Total NVE customer count in that calendar year (Total)	
		Sierra Non-Tier: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to ignition and NDPP mitigation activities*	6.022074243	9.35753	0.7063	$ in Sierra Non-Tier Spend divided by Total NVE customer count in that calendar year (total)	*Non-Tier may consider work nonspecific to Tiered areas or general costs not categorized*
		Sierra Tier 1E: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to ignition and NDPP mitigation activities*	6.545713009	7.65979	3.11294	$ in Sierra Tier 1E Spend divided by Total NVE customer count in that calendar year (total)	
		Sierra Tier 2: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to ignition and NDPP mitigation activities*	6.288896996	6.83355	1.15352	$ in Sierra Tier 2 Spend divided by Total NVE customer count in that calendar year (total)	
		Sierra Tier 3: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to ignition and NDPP mitigation activities*	16.25689672	7.82787	1.13192	$ in Sierra Tier 3 Spend divided by Total NVE customer count in that calendar year (total)	
		Nevada Power Non-Tier: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to ignition and NDPP mitigation activities*	10.53884624	5.93479	2.12933	$ in Nevada Power Non-Tier Spend divided by Total NVE customer count in that calendar year (total)	*Non-Tier may consider work nonspecific to Tiered areas or general costs not categorized*
		Nevada Power Tier 1E: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to ignition and NDPP mitigation activities*	N/A	N/A	N/A	$ in Nevada Power Tier 1E Spend divided by Total NVE customer count in that calendar year (total)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*
		Nevada Power Tier 2: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to ignition and NDPP mitigation activities*	N/A	N/A	N/A	$ in Nevada Power Tier 2 Spend divided by Total NVE customer count in that calendar year (total)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*

ID	Metric	Metric Definition / Detail	CY 2023	CY 2024	First Half 2025	Measurements (Units)	Comments
		Nevada Power Tier 3: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to ignition and NDPP mitigation activities*	1.540878055	3.70453	0.56805	$ in Nevada Power Tier 3 Spend divided by Total NVE customer count in that calendar year (total)	
M18	Increased cost per risk area customer due to wildfire mitigation	Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to NDPP mitigation activities **(total)**	46.76206564	49.52253	12.21358	$/Total NVE customer count in that calendar year within all Wildfire Tiers (Total)	
		Sierra Non-Tier: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to NDPP mitigation activities*	5.700146078	9.17938	0.69254	$ in Sierra Non-Tier Spend divided by Total NVE customer count in that calendar year (total)	
		Sierra Tier 1E: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to NDPP mitigation activities*	6.521563203	7.58109	3.10984	$ in Sierra Tier 1E Spend divided by Total NVE customer count in that calendar year (total)	
		Sierra Tier 2: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to NDPP mitigation activities*	6.203735345	6.5551	1.09314	$ in Sierra Tier 2 Spend divided by Total NVE customer count in that calendar year (total)	
		Sierra Tier 3: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to NDPP mitigation activities*	16.25689672	7.82787	1.13192	$ in Sierra Tier 3 Spend divided by Total NVE customer count in that calendar year (total)	
		Nevada Power Non-Tier: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to NDPP mitigation activities*	10.53884624	5.93479	2.12933	$ in Nevada Power Non-Tier Spend divided by Total NVE customer count in that calendar year (total)	
		Nevada Power Tier 1E: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to NDPP mitigation activities*	N/A	N/A	N/A	$ in Nevada Power Tier 1E Spend divided by Total NVE customer count in that calendar year (total)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*
		Nevada Power Tier 2: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to NDPP mitigation activities*	N/A	N/A	N/A	$ in Nevada Power Tier 2 Spend divided by Total NVE customer count in that calendar year (total)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*
		Nevada Power Tier 3: *Total increased cost per risk area (Wildfire Tiers and Non-Tiered areas) customer due to NDPP mitigation activities*	1.540878055	3.70453	0.56805	$ in Nevada Power Tier 3 Spend divided by Total NVE customer count in that calendar year (total)	
M19	Increased cost per risk area customer due to ignition events	Total additional/increased cost per risk area (Wildfire Tiers) customer due to ignition events **(total)**	0.431239622	1.495	-0.0079	$/Total NVE customer count in that calendar year within all Wildfire Tiers (Total)	
		Sierra Non-Tier: *Total additional/increased cost per risk area (Wildfire Tiers) customer due to ignition events*	0.321928165	0.17815	0.01376	$ in Sierra Non-Tier Spend divided by Total NVE customer count in that calendar year (total)	*Non-Tier may consider work nonspecific to Tiered areas or general costs not categorized*
		Sierra Tier 1E: *Total additional/increased cost per risk area (Wildfire Tiers) customer due to ignition events*	0.024149806	0.0787	0.0031	$ in Sierra Tier 1E Spend divided by Total NVE customer count in that calendar year (total)	

ID	Metric	Metric Definition / Detail	CY 2023	CY 2024	First Half 2025	Measurements (Units)	Comments
		***Sierra Tier 2**: Total additional/increased cost per risk area (Wildfire Tiers) customer due to ignition events*	0.085161651	0.27845	0.06038	$ in Sierra Tier 2 Spend divided by Total NVE customer count in that calendar year (total)	
		***Sierra Tier 3**: Total additional/increased cost per risk area (Wildfire Tiers) customer due to ignition events*	0	0	0	$ in Sierra Tier 3 Spend divided by Total NVE customer count in that calendar year (total)	
		***Nevada Power Non-Tier**: Total additional/increased cost per risk area (Wildfire Tiers) customer due to ignition events*	0	0	0	$ in Nevada Power Non-Tier Spend divided by Total NVE customer count in that calendar year (total)	*Non-Tier may consider work nonspecific to Tiered areas or general costs not categorized*
		***Nevada Power Tier 1E**: Total additional/increased cost per risk area (Wildfire Tiers) customer due to ignition events*	N/A	N/A	N/A	$ in Nevada Power Tier 1E Spend divided by Total NVE customer count in that calendar year (total)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*
		***Nevada Power Tier 2**: Total additional/increased cost per risk area (Wildfire Tiers) customer due to ignition events*	N/A	N/A	N/A	$ in Nevada Power Tier 2 Spend divided by Total NVE customer count in that calendar year (total)	*N/A - Currently, no area is mapped as Tier 1E or Tier 2 within Nevada Power*
		***Nevada Power Tier 3**: Total additional/increased cost per risk area (Wildfire Tiers) customer due to ignition events*	0	0	0	$ in Nevada Power Tier 3 Spend divided by Total NVE customer count in that calendar year (total)	
M20	Customer survey feedback on awareness prior to an event and information given at the conclusion of a PSOM or emergency community evacuation event;	Collected feedback from surveys issued prior to the wildfire season as well as concluding an emergency evacuation or PSOM event **(total)**	N/A	N/A	N/A	# of Feedback collected from Surveys (Total)	
		Sierra: Collected feedback from surveys issued prior to the wildfire season as well as concluding an emergency evacuation or PSOM event (total)	N/A	N/A	N/A	# of Feedback collected from Surveys (Sierra)	
		Nevada Power: Collected feedback from surveys issued prior to the wildfire season as well as concluding an emergency evacuation or PSOM event (total)	N/A	N/A	N/A	# of Feedback collected from Surveys (Nevada Power)	
M21	Number of customer complaints following a PSOM or emergency community evacuation event	Number of recorded customer complaints following a PSOM or emergency evacuation event **(total)**	N/A	58	0	# of Customer complaints (due to utility-equipment involved wildfire incident evacuations) (Total)	
		Sierra: Number of recorded customer complaints following a PSOM or emergency evacuation event (total)	N/A	58	0	# of Customer complaints (due to utility-equipment involved wildfire incident evacuations) (Sierra)	
		Nevada Power: Number of recorded customer complaints following a PSOM or emergency evacuation event (total)	N/A	0	0	# of Customer complaints (due to utility-equipment involved wildfire incident evacuations) (Nevada Power)	

6. RESOURCE SUFFICIENCY

The resource sufficiency category identifies resources of sufficient types and amounts to successfully support and implement the Plan. Resource sufficiency includes fully dedicated NDPP personnel labor charges (when not specifically supporting other programs), technology, and program support. There is funding for a corporate communications specialist for the NDPP with responsibility for projects, programs, and potential outages related to system hardening, and emergency response. The Companies also include technical writers, a contracted GIS analyst, project directors, customer care, and other contracted labor. Items also include supporting the COWs, radios, mobile devices, iPads, and the amateur radio emergency services associated with the NDPP.

This category includes costs associated with materials and supplies, PPE, telecommunications equipment, travel expenses, and the contracted resources to assist with NDPP-related grants management. Costs for participation in the International Wildfire Risk Mitigation Consortium ("IWRMC"), an industry-sponsored collaborative organization designed to facilitate the sharing of wildfire risk mitigation insights and discovery of innovative and unique utility wildfire practices, is included.

The majority of the costs are identified as OMAG with some capital costs for equipment for NDPP personnel to view mapping, weather, work management access, PSOMs, and remote connectivity to network systems.

6.1. RESOURCE SUFFICIENCY BUDGET FORECAST

Table 67 below lists the resource sufficiency budget for this Triennial Plan.

Table 67. Resource Sufficiency Triennial Budget Forecast OMAG

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Resource Sufficiency				
Nevada Power	$ 293,936	$ 95,121	$ 97,949	$ 100,865
Sierra Pacific Power	$ 3,713,071	$ 1,201,597	$ 1,237,321	$ 1,274,153
Resource Sufficiency Total	**$ 4,007,007**	**$ 1,296,718**	**$ 1,335,271**	**$ 1,375,018**

7. FINANCIALS

This Section contains financials specific to projects, programs, and initiatives.

7.1. PLAN IMPLEMENTATION COSTS 2027-2029

Table 68. OMAG Budget Request Forecast Summary

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Inspections and Corrections	$ 2,269,505	$ 462,217	$ 544,342	$ 1,262,947
Operational Practices	$ 3,914,705	$ 1,008,772	$ 1,204,496	$ 1,701,437
Risk Based Approach	$ 293,936	$ 95,121	$ 97,949	$ 100,865
Situational Awareness	$ 2,833,955	$ 840,749	$ 933,054	$ 1,060,151
System Hardening	$ 928,125	$ 300,000	$ 309,375	$ 318,750
Vegetation Management	$ 15,714,000	$ 5,918,000	$ 5,078,000	$ 4,718,000
Nevada Power Total	**$ 25,954,226**	**$ 8,624,859**	**$ 8,167,217**	**$ 9,162,151**
Sierra Pacific Power				
Inspections and Corrections	$ 16,403,989	$ 4,388,753	$ 6,381,314	$ 5,633,922
Operational Practices	$ 6,453,831	$ 2,034,316	$ 2,181,598	$ 2,237,917
Risk Based Approach	$ 3,713,071	$ 1,201,597	$ 1,237,321	$ 1,274,153
Situational Awareness	$ 24,524,855	$ 7,665,860	$ 8,127,588	$ 8,731,407
System Hardening	$ 18,808,654	$ 6,235,998	$ 6,184,598	$ 6,388,058
Vegetation Management	$ 103,866,600	$ 34,172,200	$ 34,622,200	$ 35,072,200
Sierra Pacific Power Total	**$ 173,771,001**	**$ 55,698,724**	**$ 58,734,619**	**$ 59,337,658**
Grand Total	**$ 199,725,227**	**$ 64,323,583**	**$ 66,901,836**	**$ 68,499,808**

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Inspections and Corrections				
Circuit Resiliency	$ 1,002,877	$ 104,477	$ 104,477	$ 793,922
Inspections and Corrections	$ 1,266,628	$ 357,740	$ 439,864	$ 469,024
Inspections and Corrections Total	**$ 2,269,505**	**$ 462,217**	**$ 544,342**	**$ 1,262,947**
Operational Practices				
Distribution Automation	$ 154,878	$ 90,999	$ 31,467	$ 32,411
Emergency Response	$ 2,365,062	$ 466,202	$ 708,326	$ 1,190,534
PSOM	$ 1,394,766	$ 451,570	$ 464,703	$ 478,493
Operational Practices Total	**$ 3,914,705**	**$ 1,008,772**	**$ 1,204,496**	**$ 1,701,437**
Risk Based Approach				
Resource Sufficiency	$ 293,936	$ 95,121	$ 97,949	$ 100,865
Risk Based Approach Total	**$ 293,936**	**$ 95,121**	**$ 97,949**	**$ 100,865**
Situational Awareness				
Hazard Awareness	$ 336,642	$ 109,338	$ 112,185	$ 115,118
Situational Awareness and Analysis	$ 1,458,676	$ 462,760	$ 485,898	$ 510,018
Weather Stations	$ 282,479	$ 79,501	$ 92,263	$ 110,715
Wildfire Cameras	$ 756,158	$ 189,150	$ 242,708	$ 324,300
Situational Awareness Total	**$ 2,833,955**	**$ 840,749**	**$ 933,054**	**$ 1,060,151**
System Hardening				
Fire Mesh	$ 928,125	$ 300,000	$ 309,375	$ 318,750
System Hardening Total	**$ 928,125**	**$ 300,000**	**$ 309,375**	**$ 318,750**
Vegetation Management				
Vegetation Management	$ 15,714,000	$ 5,918,000	$ 5,078,000	$ 4,718,000
Vegetation Management Total	**$ 15,714,000**	**$ 5,918,000**	**$ 5,078,000**	**$ 4,718,000**
Nevada Power Total	**$ 25,954,226**	**$ 8,624,859**	**$ 8,167,217**	**$ 9,162,151**

OMAG	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Sierra Pacific Power				
Inspections and Corrections				
Inspections and Corrections	$ 16,403,989	$ 4,388,753	$ 6,381,314	$ 5,633,922
Inspections and Corrections Total	**$ 16,403,989**	**$ 4,388,753**	**$ 6,381,314**	**$ 5,633,922**
Operational Practices				
Distribution Automation	$ 1,896,231	$ 549,272	$ 663,526	$ 683,432
Emergency Response	$ 2,493,613	$ 814,388	$ 831,032	$ 848,194
PSOM	$ 2,063,987	$ 670,655	$ 687,040	$ 706,291
Operational Practices Total	**$ 6,453,831**	**$ 2,034,316**	**$ 2,181,598**	**$ 2,237,917**
Risk Based Approach				
Resource Sufficiency	$ 3,713,071	$ 1,201,597	$ 1,237,321	$ 1,274,153
Risk Based Approach Total	**$ 3,713,071**	**$ 1,201,597**	**$ 1,237,321**	**$ 1,274,153**
Situational Awareness				
Hazard Awareness	$ 4,472,526	$ 1,452,632	$ 1,490,464	$ 1,529,430
Situational Awareness and Analysis	$ 16,275,539	$ 5,163,240	$ 5,421,402	$ 5,690,897
Weather Stations	$ 1,425,584	$ 401,688	$ 465,707	$ 558,189
Wildfire Cameras	$ 2,351,206	$ 648,300	$ 750,015	$ 952,891
Situational Awareness Total	**$ 24,524,855**	**$ 7,665,860**	**$ 8,127,588**	**$ 8,731,407**
System Hardening				
Expulsion Fuses	$ 17,200,000	$ 5,750,000	$ 5,650,000	$ 5,800,000
Fire Mesh	$ 1,608,654	$ 485,998	$ 534,598	$ 588,058
System Hardening Total	**$ 18,808,654**	**$ 6,235,998**	**$ 6,184,598**	**$ 6,388,058**
Vegetation Management				
Vegetation Management	$ 103,866,600	$ 34,172,200	$ 34,622,200	$ 35,072,200
Vegetation Management Total	**$ 103,866,600**	**$ 34,172,200**	**$ 34,622,200**	**$ 35,072,200**
Sierra Pacific Power Total	**$ 173,771,001**	**$ 55,698,724**	**$ 58,734,619**	**$ 59,337,658**
Grand Total	**$ 199,725,227**	**$ 64,323,583**	**$ 66,901,836**	**$ 68,499,808**

Table 69. Capital Budget Forecast Request Summary

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Distribution Automation	$ 321,157	$ 30,261	$ 133,965	$ 156,931
Risk Based Approach	$ 1,226,577	$ 1,226,577	$ -	$ -
Situational Awareness	$ 873,414	$ 276,662	$ 291,099	$ 305,653
System Hardening	$ 79,220,315	$ 22,140,100	$ 31,775,105	$ 25,305,110
Nevada Power Total	**$ 81,641,463**	**$ 23,673,600**	**$ 32,200,169**	**$ 25,767,694**
Sierra Pacific Power				
Distribution Automation	$ 6,225,190	$ 905,565	$ 2,496,508	$ 2,823,117
Risk Based Approach	$ 8,338,948	$ 3,889,044	$ 4,045,352	$ 404,552
Situational Awareness	$ 3,334,334	$ 1,057,437	$ 1,110,106	$ 1,166,791
System Hardening	$ 111,680,453	$ 42,112,072	$ 35,332,206	$ 34,236,175
Sierra Pacific Power Total	**$ 129,578,925**	**$ 47,964,118**	**$ 42,984,172**	**$ 38,630,635**
Grand Total	**$ 211,220,388**	**$ 71,637,718**	**$ 75,184,341**	**$ 64,398,329**

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Nevada Power				
Distribution Automation				
Distribution Automation	$ 321,157	$ 30,261	$ 133,965	$ 156,931
Distribution Automation Total	**$ 321,157**	**$ 30,261**	**$ 133,965**	**$ 156,931**
Risk Based Approach				
Gridware	$ 1,226,577	$ 1,226,577	$ -	$ -
Risk Based Approach Total	**$ 1,226,577**	**$ 1,226,577**	**$ -**	**$ -**
Situational Awareness				
Weather Station	$ 148,956	$ 47,250	$ 49,613	$ 52,093
Wildfire Cameras	$ 724,458	$ 229,412	$ 241,486	$ 253,560
Situational Awareness Total	**$ 873,414**	**$ 276,662**	**$ 291,099**	**$ 305,653**
System Hardening				
Copper Wire Replacement	$ 6,305,315	$ 2,000,100	$ 2,100,105	$ 2,205,110
Grid Ruggedization - Critical Crossings	$ 6,590,000	$ 2,090,000	$ 2,200,000	$ 2,300,000
Grid Ruggedization - Pole Stoppers	$ 7,875,000	$ 2,500,000	$ 2,625,000	$ 2,750,000
Line Rebuilds - Mt Charleston	$ 58,450,000	$ 15,550,000	$ 24,850,000	$ 18,050,000
System Hardening Total	**$ 79,220,315**	**$ 22,140,100**	**$ 31,775,105**	**$ 25,305,110**
Nevada Power Total	**$ 81,641,463**	**$ 23,673,600**	**$ 32,200,169**	**$ 25,767,694**

Capital	2027-2029 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Sierra Pacific Power				
Distribution Automation				
Distribution Automation	$ 6,225,190	$ 905,565	$ 2,496,508	$ 2,823,117
Distribution Automation Total	**$ 6,225,190**	**$ 905,565**	**$ 2,496,508**	**$ 2,823,117**
Risk Based Approach				
Gridware	$ 8,338,948	$ 3,889,044	$ 4,045,352	$ 404,552
Risk Based Approach Total	**$ 8,338,948**	**$ 3,889,044**	**$ 4,045,352**	**$ 404,552**
Situational Awareness				
Weather Station	$ 1,397,500	$ 443,000	$ 465,500	$ 489,000
Wildfire Cameras	$ 1,936,834	$ 614,437	$ 644,606	$ 677,791
Situational Awareness Total	**$ 3,334,334**	**$ 1,057,437**	**$ 1,110,106**	**$ 1,166,791**
System Hardening				
Copper Wire Replacement	$ 5,090,850	$ 401,530	$ 2,120,620	$ 2,568,700
Line Rebuilds - Curry 1280	$ 2,677,600	$ 1,128,400	$ 168,000	$ 1,381,200
Line Rebuilds - Incline 4100	$ 4,685,100	$ 2,101,000	$ 1,249,700	$ 1,334,400
Line Rebuilds - Muller 1295	$ 4,803,600	$ 1,480,160	$ 1,239,980	$ 2,083,460
Line Rebuilds - North East District	$ 3,375,000	$ 1,125,000	$ 1,125,000	$ 1,125,000
Non-Expulsion Fuses	$ 17,600,000	$ 6,300,000	$ 5,650,000	$ 5,650,000
Substation Hardening - Barrier Walls	$ 1,250,288	$ 1,250,288	$ -	$ -
Substation Hardening - Glenbrook Substation	$ 4,677,304	$ 1,294,783	$ 1,133,581	$ 2,248,940
Substation Hardening - Interior	$ 2,804,845	$ 2,688,238	$ 116,607	$ -
Tree Attachments	$ 6,960,000	$ 2,250,000	$ 2,320,000	$ 2,390,000
Undergrounding - Cost Share Zephyr Cove	$ 3,612,804	$ -	$ 3,602,974	$ 9,830
Undergrounding - Cost Share Glenbrook	$ 100,000	$ 100,000	$ -	$ -
Undergrounding - Cost Share TTD Bike Path	$ 8,808,567	$ 2,759,810	$ 2,935,298	$ 3,113,459
Undergrounding - Sierra Phase 1	$ 7,445,000	$ 6,695,000	$ 750,000	$ -
Undergrounding - Sierra Phase 2	$ 10,977,353	$ 8,079,937	$ 2,897,416	$ -
Undergrounding - Sierra Phase 3	$ 26,812,142	$ 4,457,926	$ 10,023,030	$ 12,331,186
System Hardening Total	**$ 111,680,453**	**$ 42,112,072**	**$ 35,332,206**	**$ 34,236,175**
Sierra Pacific Power Total	**$ 129,578,925**	**$ 47,964,118**	**$ 42,984,172**	**$ 38,630,635**
Grand Total	**$ 211,220,388**	**$ 71,637,718**	**$ 75,184,341**	**$ 64,398,329**

APPENDIX

This Section contains maps, reports, responses to directives, analyses, and other information related to the NDPP:

Appendix A: Natural Disaster Heightened Risk Area Maps

Appendix B: Updated Wildfire Risk Assessment

Appendix C: PSOM Plan

Appendix D: Value Analysis – Directive

Appendix E: Clearing Around Substations

Appendix F: Fire Agencies

Appendix G: Emergency De-Energization Protocols

APPENDIX A. NATURAL DISASTER HEIGHTENED THREAT AREA MAPS

Maps for heightened threat risk are presented in this Appendix:

1. Wildfire
2. Wind Occurrences
3. Winter Storms
4. Thunderstorms and Microbursts
5. Monsoons and Flooding
6. Heat Waves and Drought
7. Earthquakes
8. Landslides and Avalanches

Figure 1. Wildfire Risk Tiers

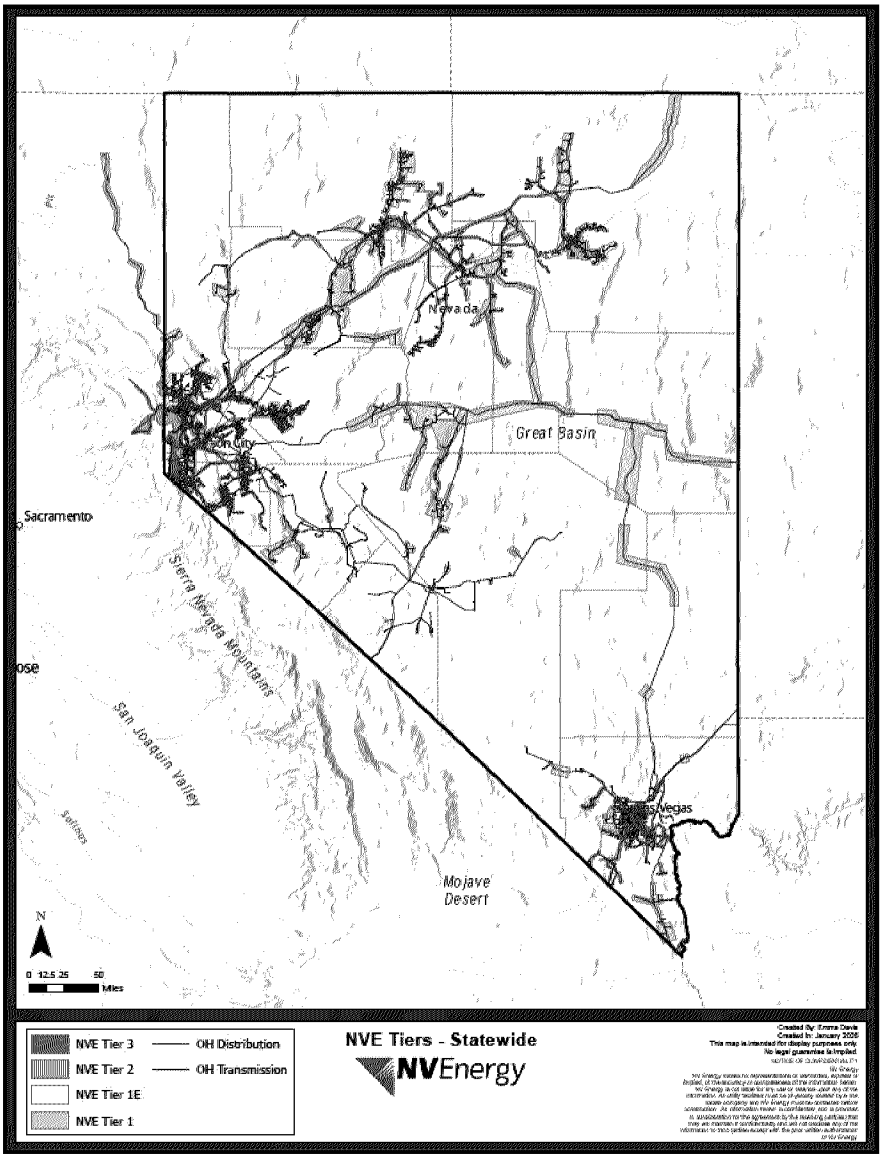


Figure 2. Wildfire Tiers Map Washoe Region

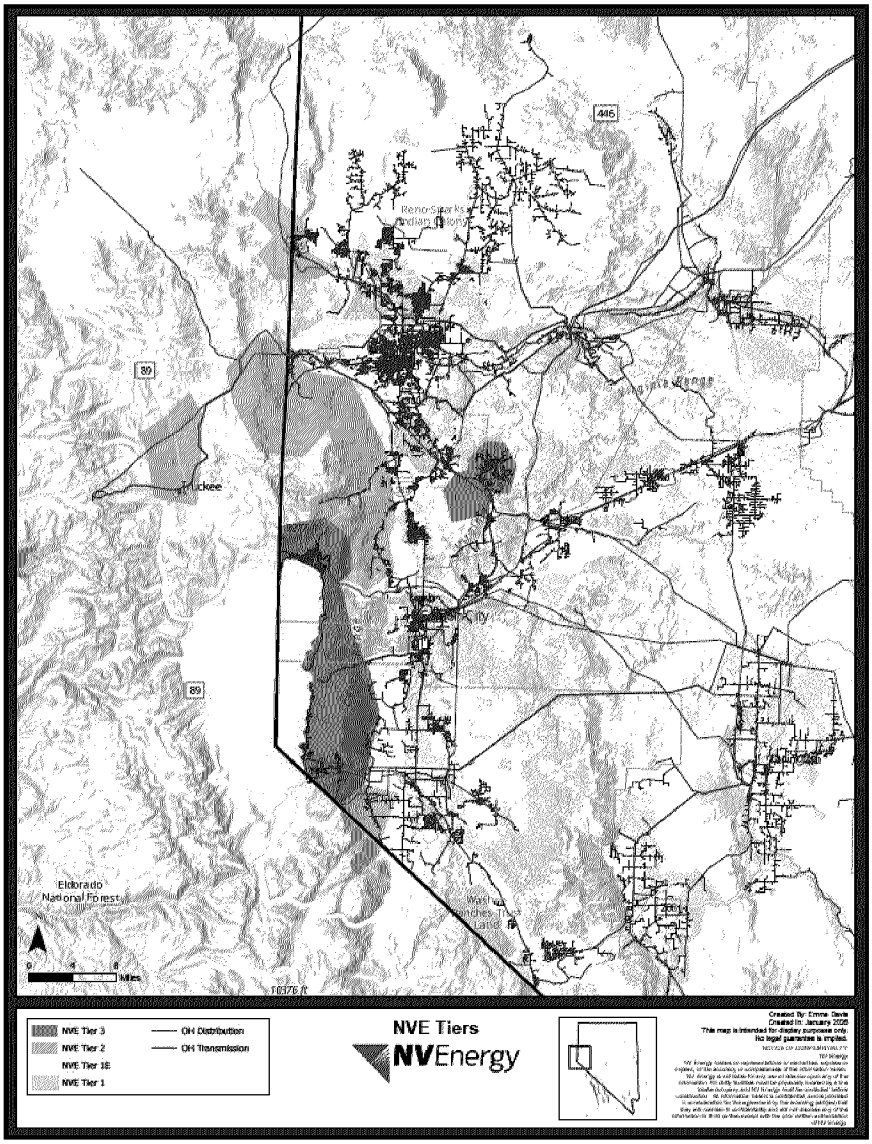


Figure 3. Wildfire Risk Tiers Winnemucca - Elko Region

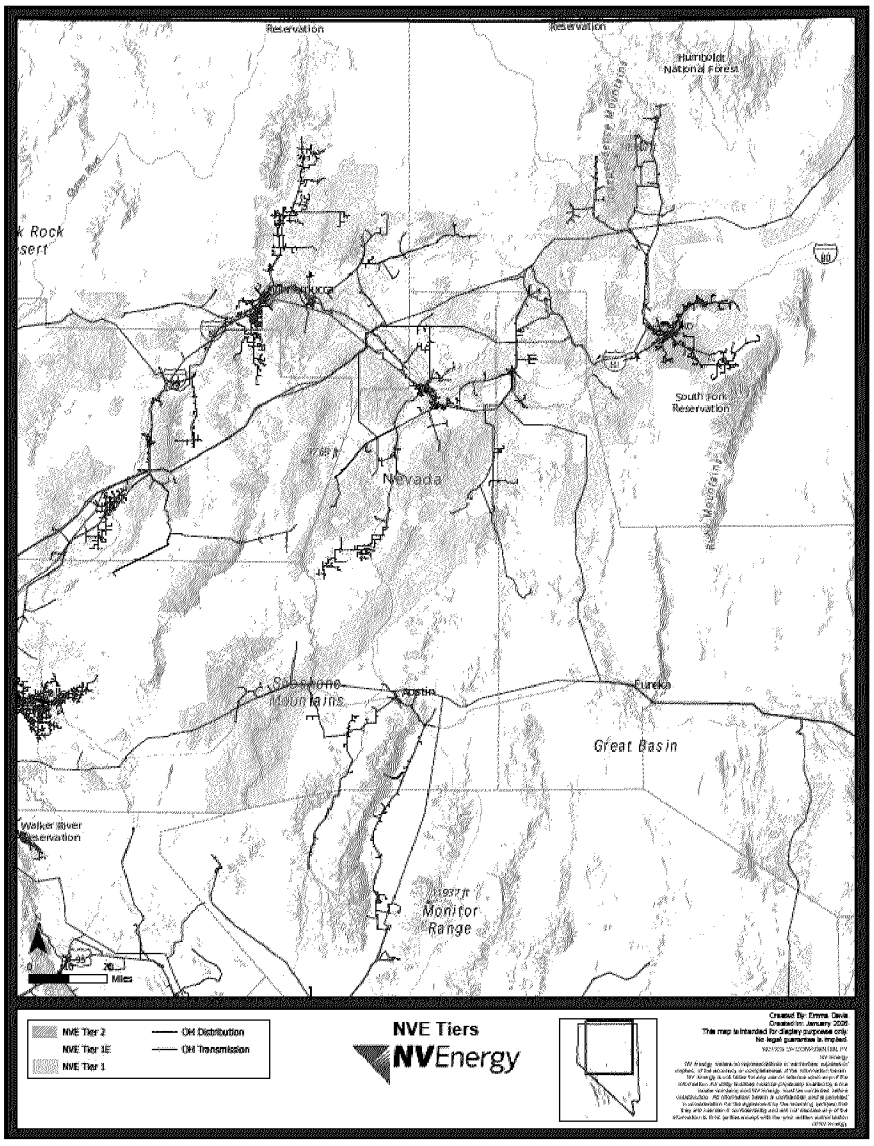


Figure 4. Wildfire Risk Tiers Mt. Charleston Region



Figure 5. High Wind Risk

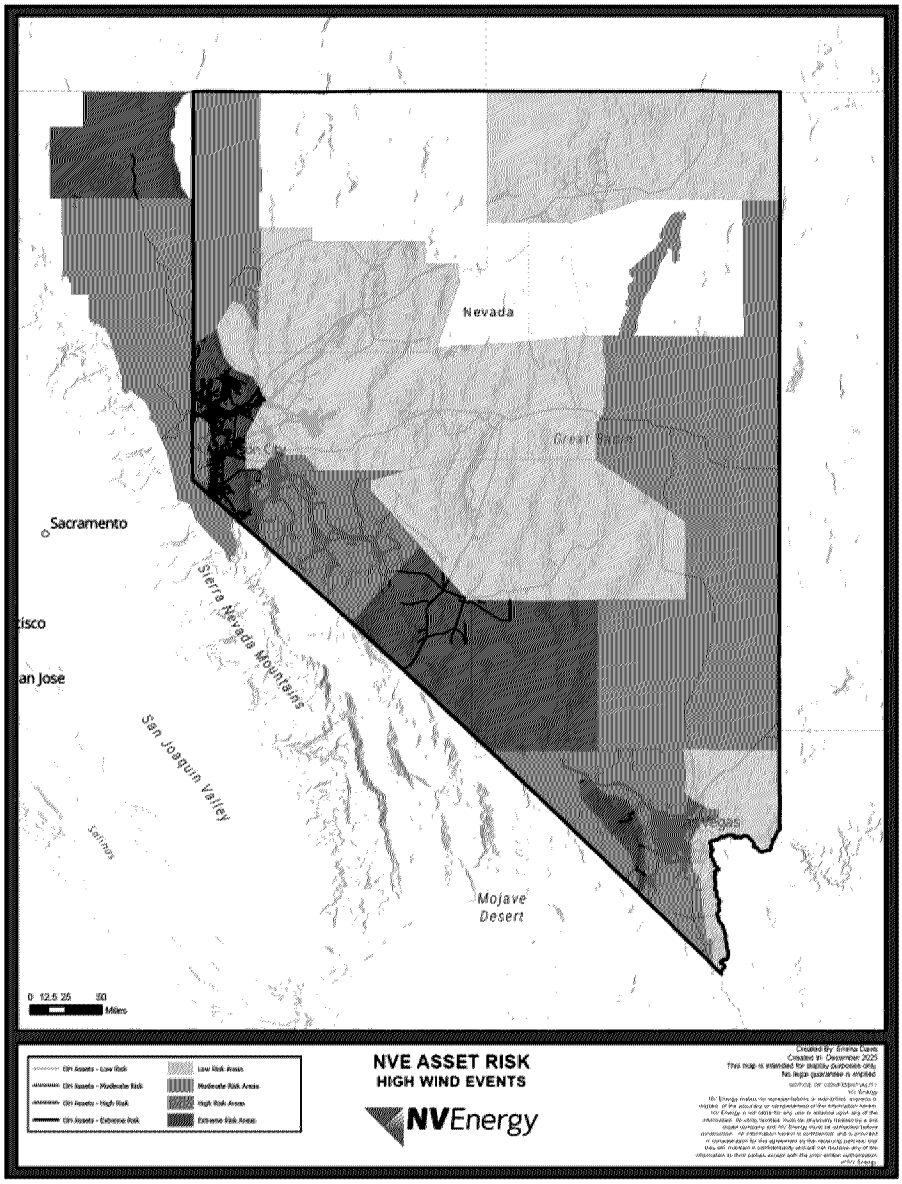


Figure 6. Winter Storm Risk

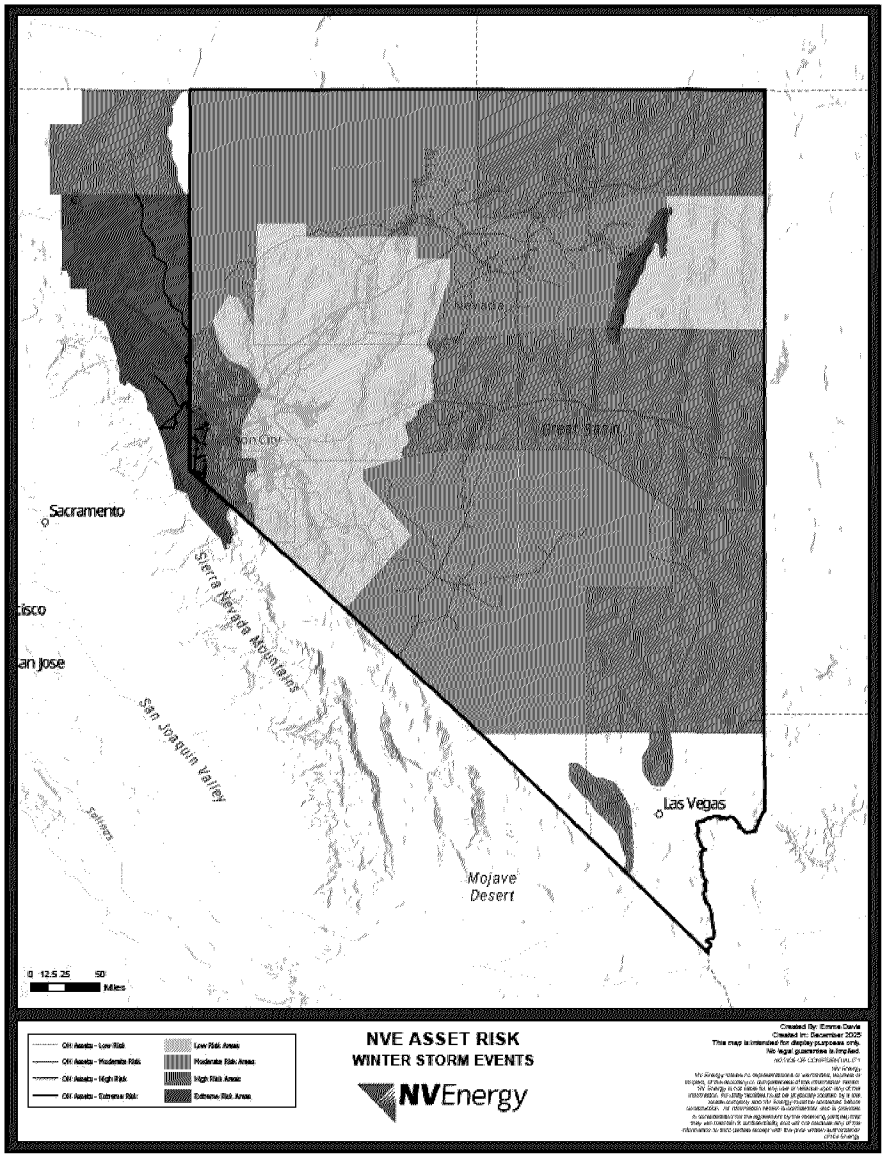


Figure 7. Thunderstorm Wind Risk

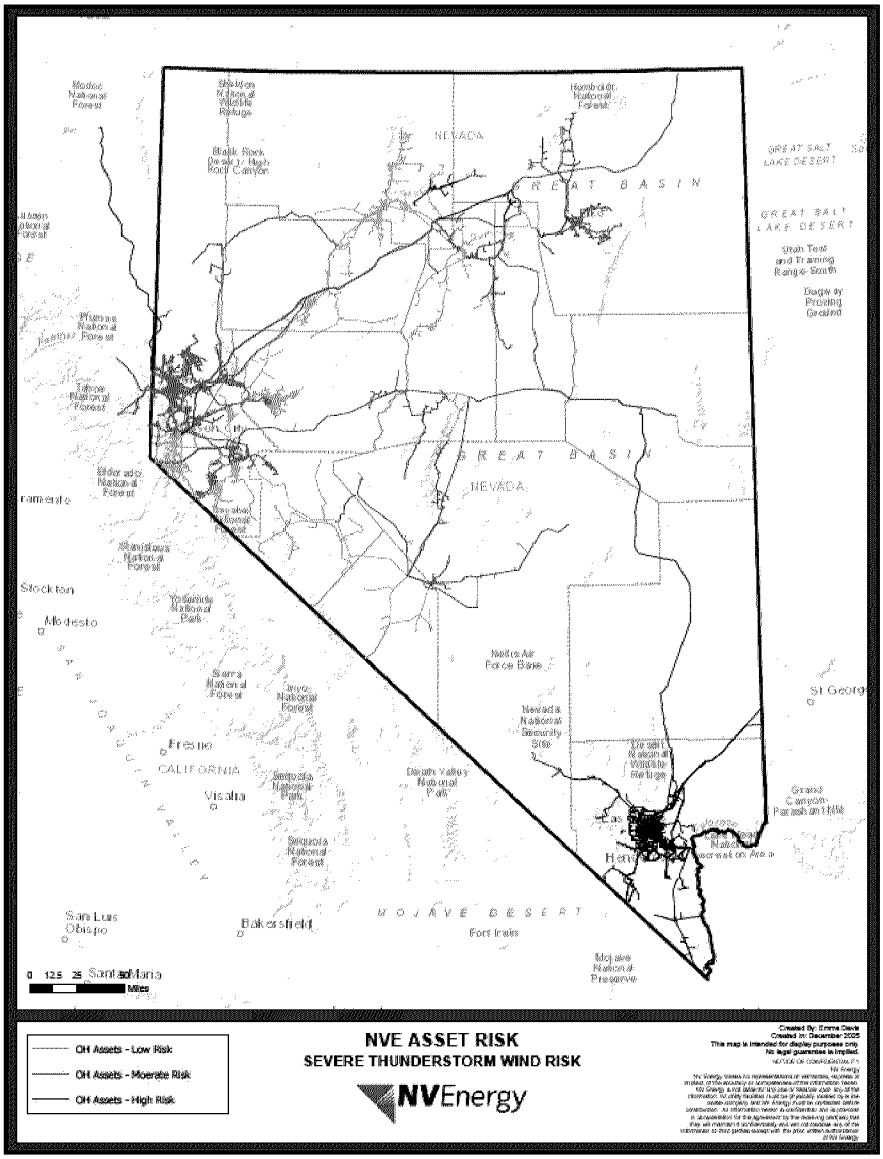


Figure 8. Flooding and Monsoon Risk

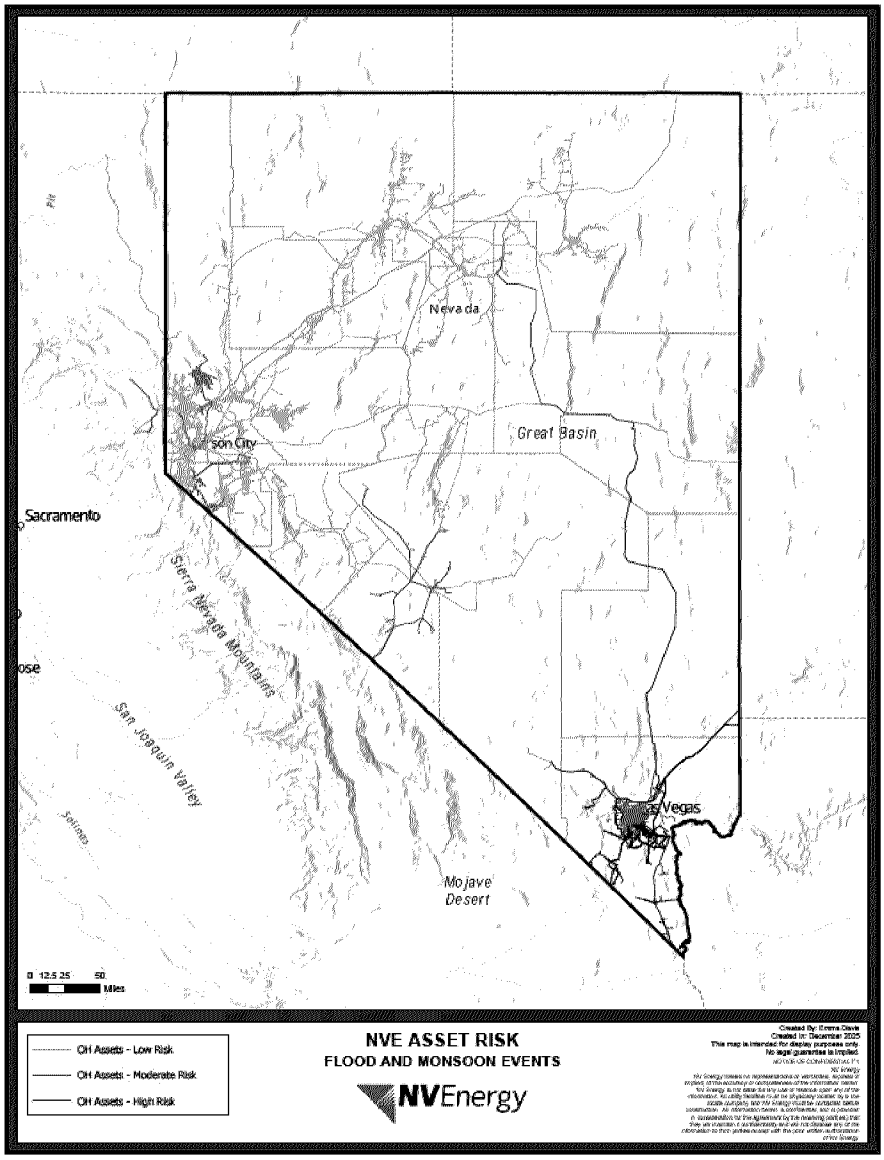


Figure 9. Earthquake Risk

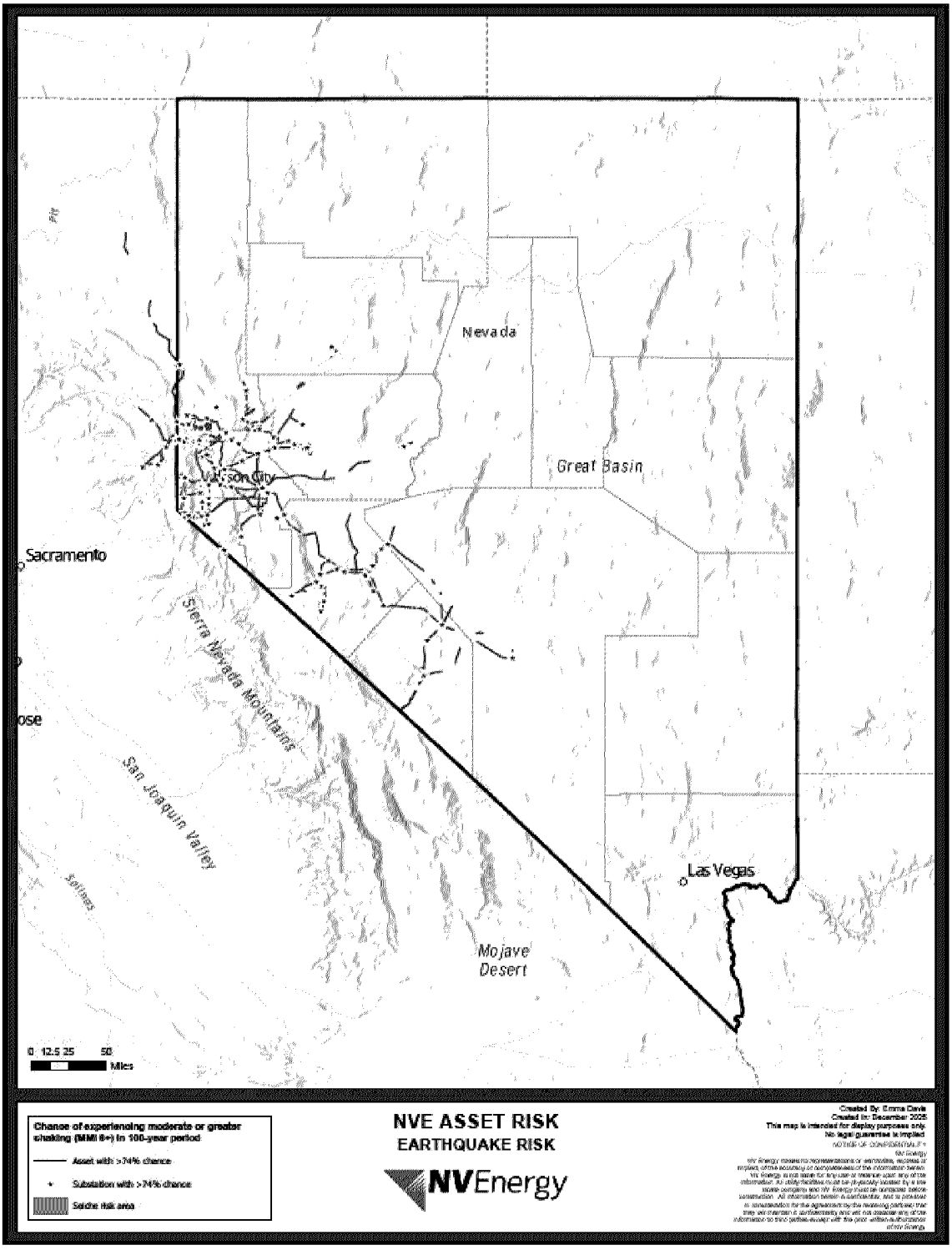


Figure 10. Landslides and Avalanches

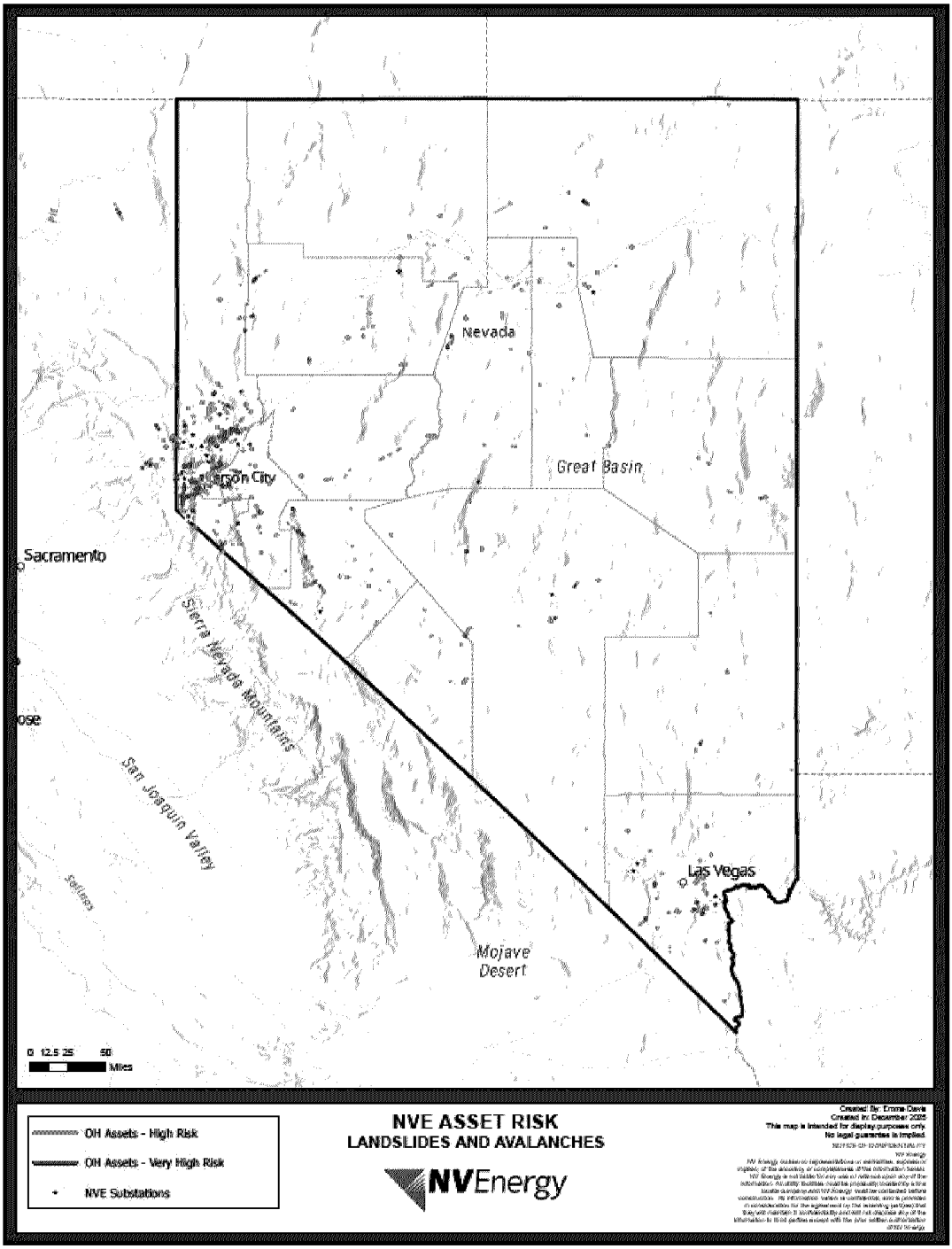


Figure 11. CloudFire Statewide Wildfire Risk Tier Assessment

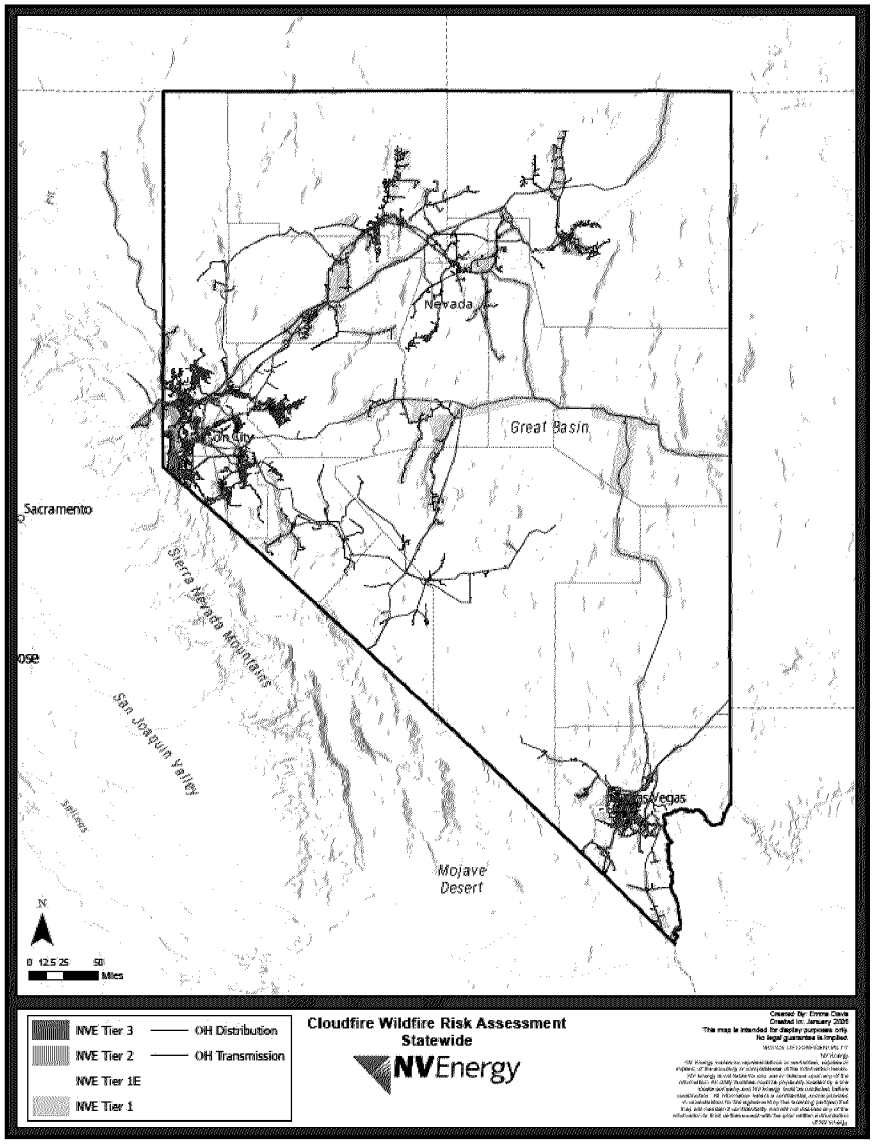


Figure 12. CloudFire Wildfire Tier Assessment Northwest Area

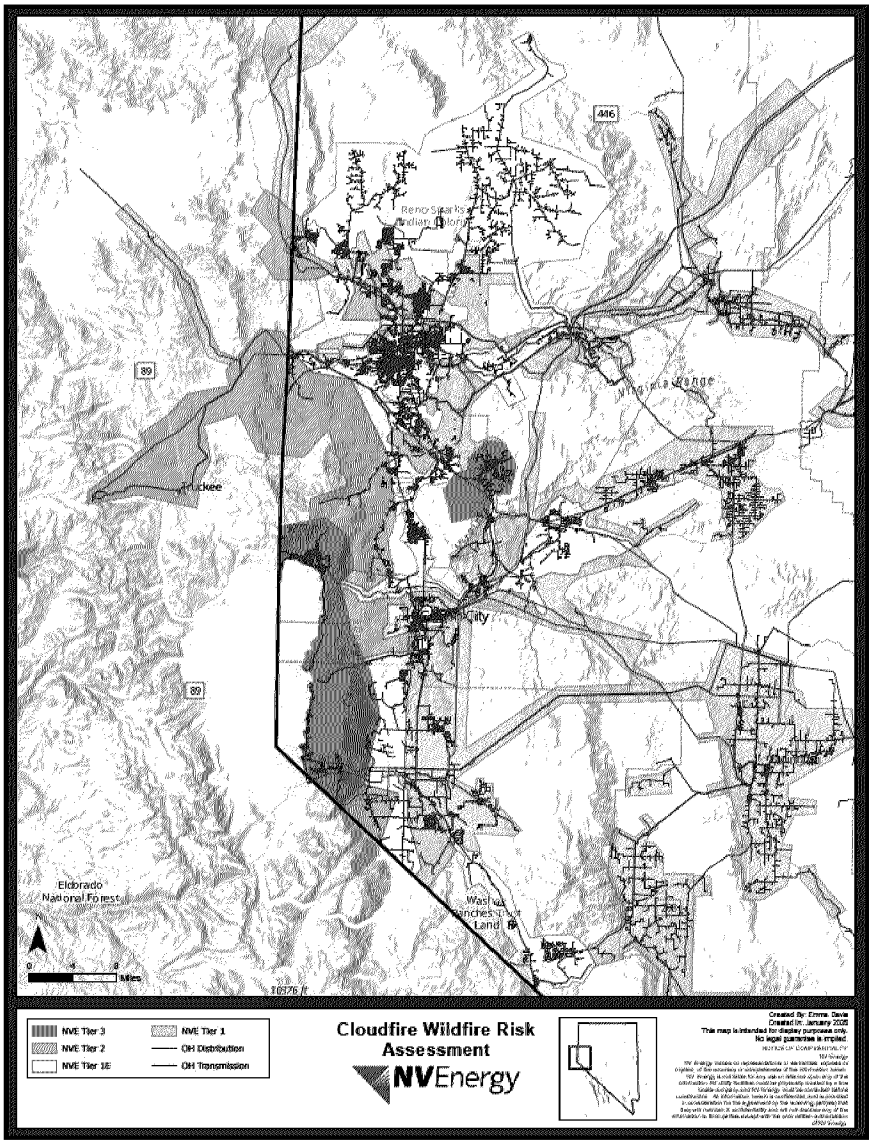


Figure 13. CloudFire Wildfire Tier Assessment Winnemucca - Elko Area

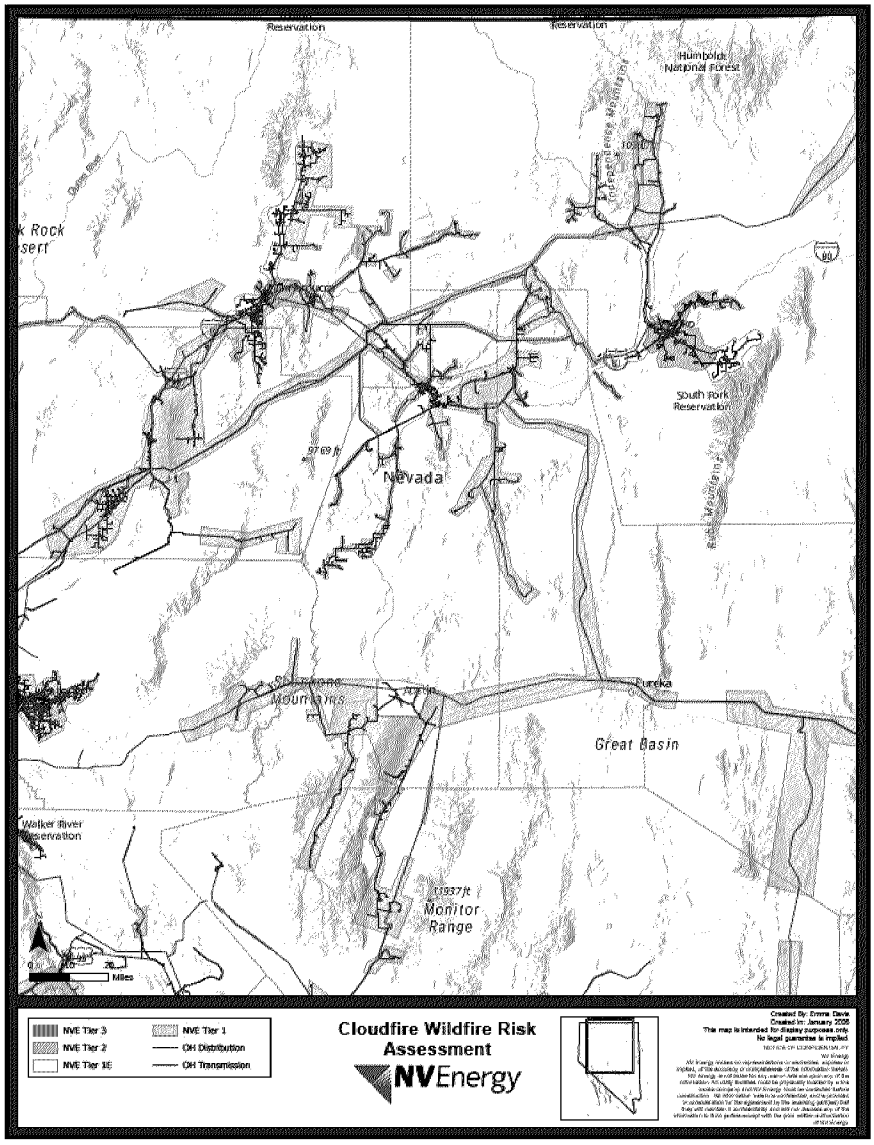
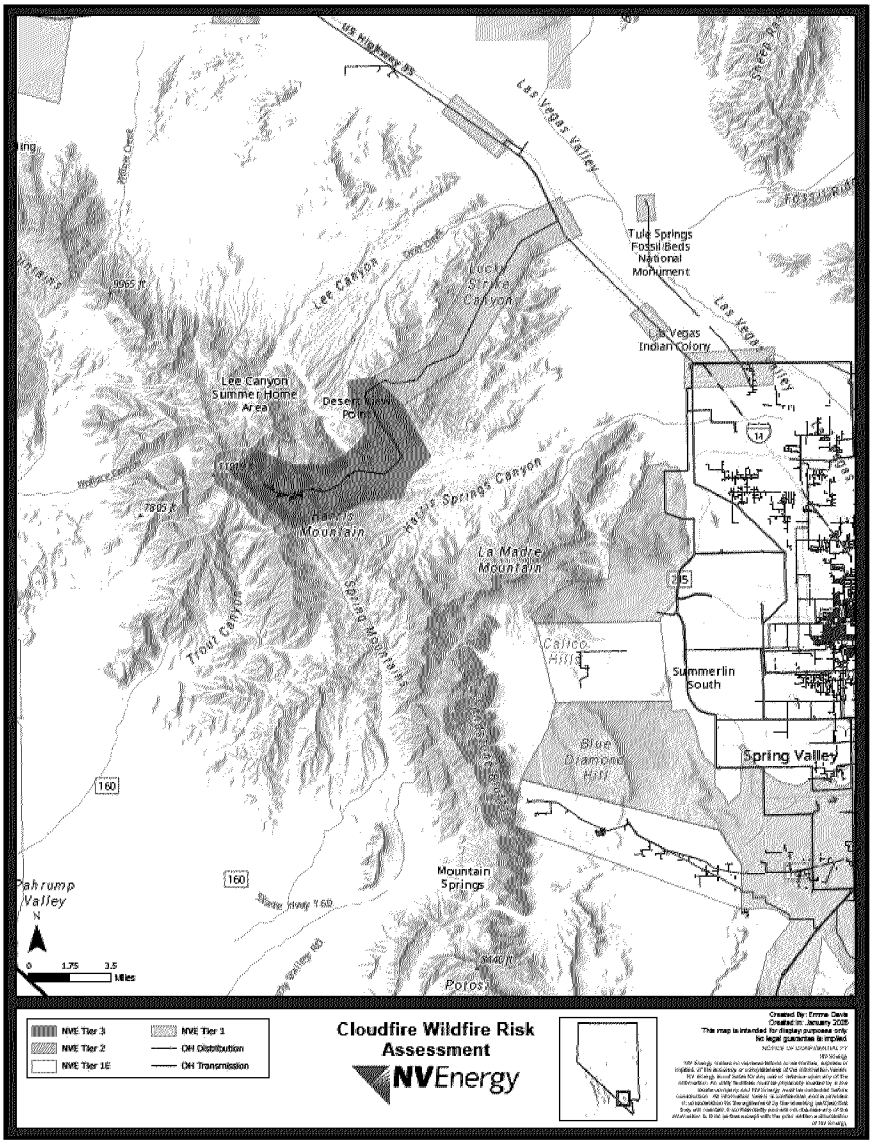


Figure 14. CloudFire Risk Tier Assessment Mt. Charleston Area



APPENDIX B. UPDATED WILDFIRE RISK ASSESSMENT

This Section includes an updated Wildfire Risk Assessment Report developed by CloudFire.

CloudFire Inc.
1111 High Street, Suite B
Auburn, CA 95603
530-202-9057

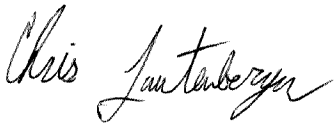
NV Energy System Wide Fire Tier Refinement Recommendations

February 11, 2026

Prepared by:

Kasra Shamsaei, PhD
Chris Lautenberger, PhD, PE(CA)

Approved by:



Chris Lautenberger, PhD, PE(CA)

Summary

In 2025, CloudFire Inc. was engaged to propose recommendations to its wildfire risk tier designations. The proposed refinements are based primarily on utility fire risk/consequence modeling, expert judgment, and other factors such as fire history, meteorological conditions, and configuration of the Wildland Urban Interface (WUI). Additionally, simplification and consolidation of existing Tier 1, Tier 1E, and Tier 2 polygons was proposed to streamline fire tier maps for deploying appropriate fire mitigations. No Tier 3 modifications were identified as part of this work.

Tier-specific changes in overhead line miles for Nevada Power Company (Nevada Power), located in southern Nevada, are shown in Table 1. Changes for Sierra Pacific Power Company (Sierra) in northern Nevada are shown in Table 2.

Table 1. Summary of Line Miles Change Nevada Power*

Tier	Current Line Miles	Proposed Line Miles	Line Miles Change	Percent Change
3	20	20	0	0 %
2	0	0	0	0 %
1E	0	35	35	–
1	291	820	529	181.8 %
Total	**311**	**875**	**564**	**181.3 %**

*No percent change was calculated for Tier 1E because there are currently zero Nevada Power Tier 1E line miles.

Table 2. Summary of Line Miles Change Sierra

Tier	Current Line Miles	Proposed Line Miles	Line Miles Change	Percent Change
3	268	268	0	0 %
2	451	501	50	11.1 %
1E	1,430	1,679	249	17.4 %
1	2,064	6,605	4,541	220 %
Total	**4,213**	**9,053**	**4,840**	**114.9 %**

Methodology Overview

A comprehensive wildfire analysis was last conducted (by others) prior to the inaugural 2020 Natural Disaster Protection Plan. This wildfire assessment conducted by CloudFire reflects improvements in utility fire risk modeling since that time. The current analysis includes all circuits owned and operated by the Companies.

Consequence from utility-caused fires was quantified by modeling the spread of millions of virtual fires ignited in proximity to overhead lines under historical wind/weather conditions using the fire spread model ELMFIRE.[44,45] Inputs to this analysis include:

1) Distribution & transmission lines GIS data, overhead only.
2) Forced outage records, 2014-2024.
3) Historical wind/weather conditions from the Real Time Mesoscale Analysis (RTMA) dataset[46] which provides hourly estimates of sensible weather variables on a 2.5 km grid for the Continental US. Period of record is ~15 years, 2011-current.
4) Topography, surface fuel, and canopy fuel layers at 30 m resolution from 2025-capable LANDFIRE data.[47]
5) Timber mask developed from the LANDFIRE surface and canopy fuel layers.
6) Structure (building) footprints from 2025 FEMA data[48] and population estimates from the National Structure Inventory (NSI).[49]

The analysis proceeds by igniting virtual fires in proximity to overhead electrical assets under historical wind and weather conditions and modeling their spread for 8 hours. For each ignition location and time of ignition, the resultant fire size, acres of timber consumed, and population within the modeled fire perimeter are recorded. This is repeated for millions of ignitions across the service territory under the full range of historical wind/weather conditions.

Outputs from the fire spread modeling are post-processed to quantify asset-level fire consequence for 200 m spans. A statistical procedure is used to translate raw model outputs to percentiles, with 0 being lowest consequence and 100 being highest consequence. A composite percentile is also calculated by assigning 50% weight to population impacts, 25% to timber, and 25% to fire size.

The primary output of this analysis is a GIS map of asset-level fire consequence, a sample of which is shown in **Figure 1**. Fire risk tiers were overlaid on this asset-level data to facilitate identification of areas where refinements may be appropriate or additional analyses may be required. Composite percentile is the primary fire modeling output that is used for this purpose.

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[44] https://elmfire.io

[45] http://dx.doi.org/10.1016/j.firesaf.2013.08.014

[46] https://www.nco.ncep.noaa.gov/pmb/products/rtma/

[47] https://landfire.gov/data

[48] https://fema.maps.arcgis.com/home/item.html?id=0ec8512ad21e4bb987d7e848d14e7e24#overview

[49] https://www.hec.usace.army.mil/confluence/nsi

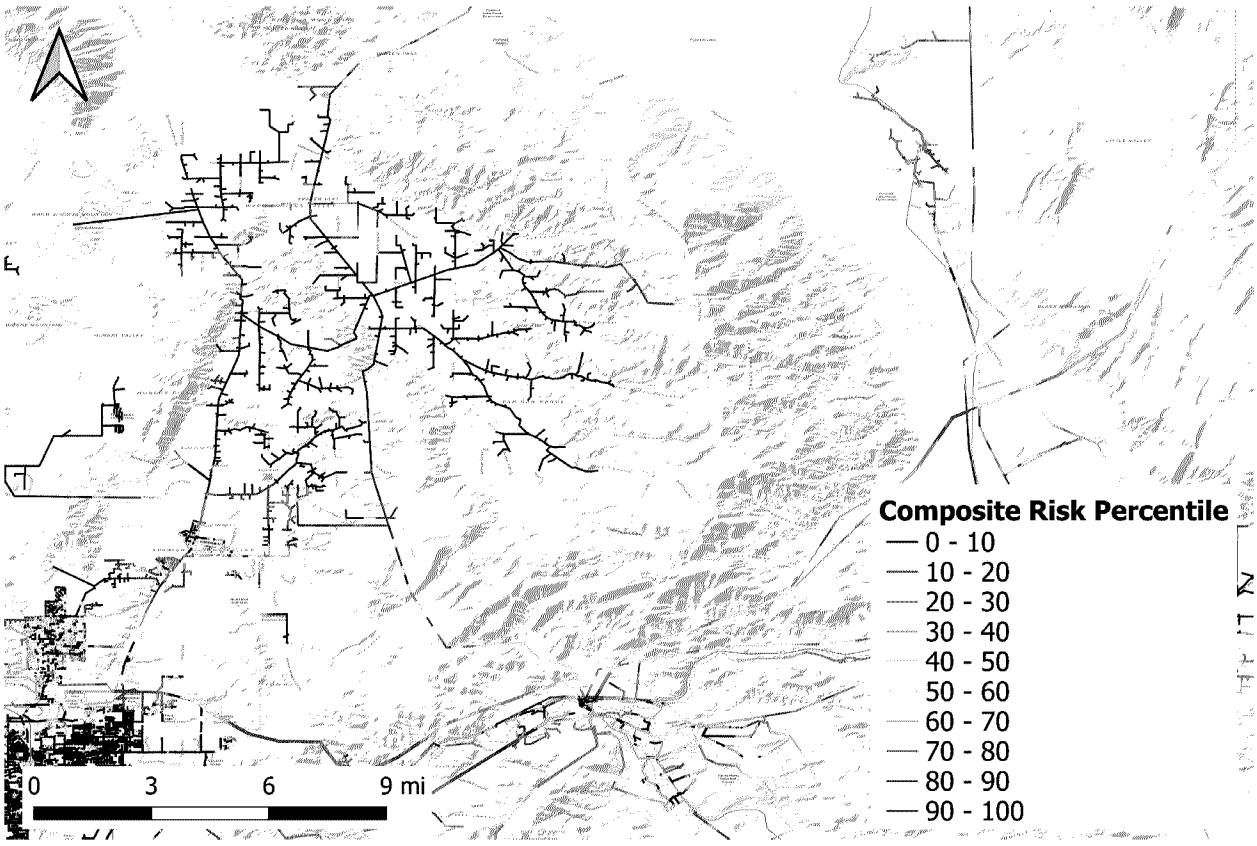


Figure 32. Sample of asset-level fire consequence data.

Proposed tier refinements from this process are grouped into six separate groups:

1. Proposed Tier 2 Addition to the California Transmission Zone
2. Proposed Tier 1E Promotion of the Arrowcreek and Steamboat Area in Reno
3. Proposed Tier 1E Promotion of the West Las Vegas Area
4. Proposed Tier 1E Promotion of the Washoe Valley Area
5. Proposed Tier 1 Refresh
6. Proposed Mapping Correction for Tier 1E and Tier 2

Each of these groups of proposed tier refinements is explained separately in the following sections.

Analysis 1: Proposed Tier 2 Addition to the California Transmission Zone

This analysis focuses on fire risk considerations in the Companies' California Transmission fire risk zone / Proactive De-energization Zone (PDZ). Although parts of the transmission line in this zone are currently classified as non-Tier, these lines/areas are more appropriately classified as Tier 2 as described below.

Overview

The existing Tier 2 designations and the proposed Tier 2 additions in the California Transmission zone are shown in **Figure 2**. Currently, the east area of the Stampede Reservoir as well as between Prosser Creek Reservoir are designated as Tier 2. However, as will be described, the remaining segments of the transmission line, which are currently non-Tier, pose the same wildfire risk as the current Tier 2 segments. Thus, it is proposed to designate the current, non-Tier segments as Tier 2.

Risk Assessment

Utilizing CloudFire's wildfire risk assessment result for the Companies' overhead facilities, the composite and population risk percentiles for the California Transmission zone are shown in **Figure 3** and **Figure 4**, respectively. As can be seen, the transmission line segments in the proposed Tier 2 addition pose similar risk as the segments currently designated as Tier 2, reaching 80^{th} to 100^{th} percentile composite risk and 50^{th} to 100^{th} percentile population risk. These risk percentiles show that an ignition in these areas can have severe consequences on land and structures, and that there is high chance of large wildfires in the area.

Fire History

To understand how fire has historically impacted the California Transmission area, fire history records were analyzed. Such analysis of past fire history provides context for historical fire sizes, locations, and frequency at which fires occur. To this end, historic fire perimeters from the CAL FIRE's Fire and Resource Assessment Program (FRAP) database are utilized.[50] **Figure 5** presents a map of the historic fire perimeters in the vicinity of the California Transmission area, which shows that multiple fires with varying sizes have occurred in the area. An anecdotal historic fire in the area is the 1960 Donner Ridge Fire, which burned around 43,300 acres in a matter of days under extreme winds.

[50] https://www.fire.ca.gov/what-we-do/fire-resource-assessment-program/fire-perimeters

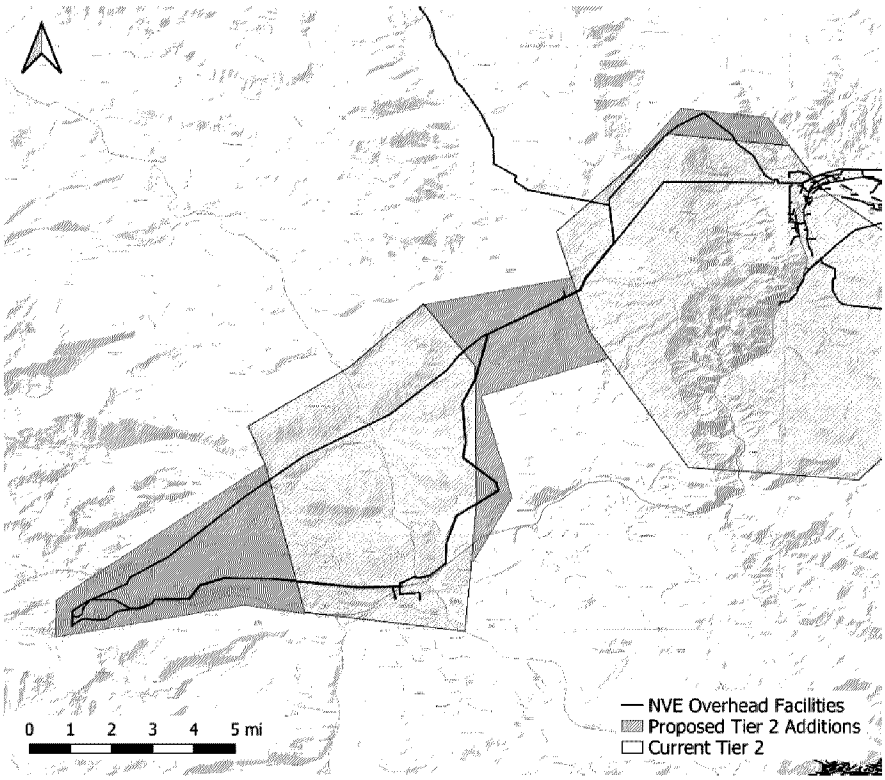


Figure 33. Proposed Tier 2 Additions in the California Transmission Zone

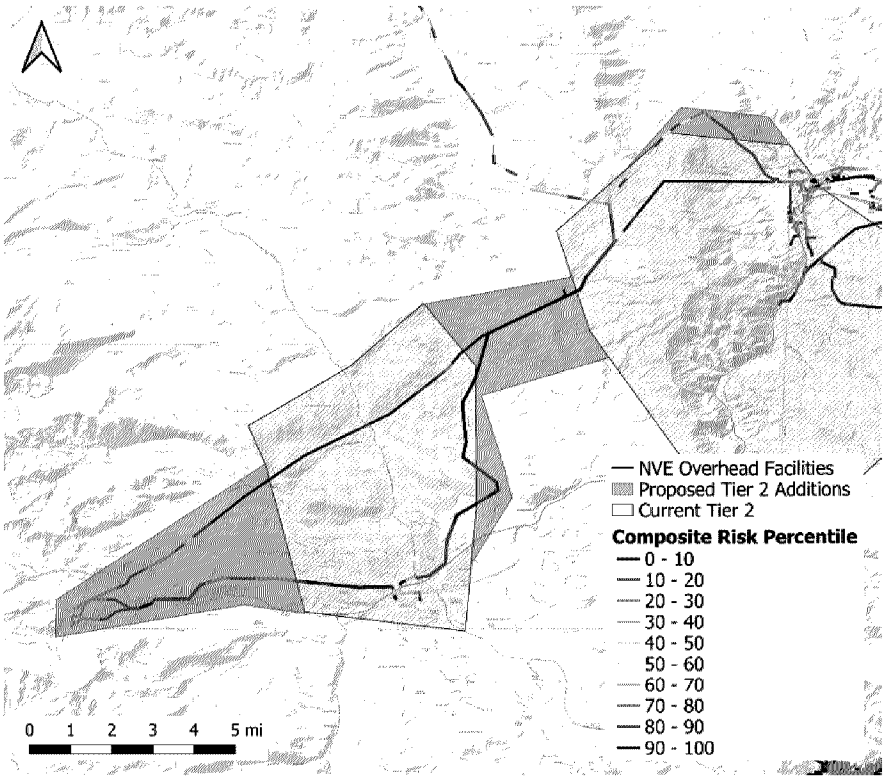


Figure 34. Composite Risk Percentiles for the California Transmission Zone

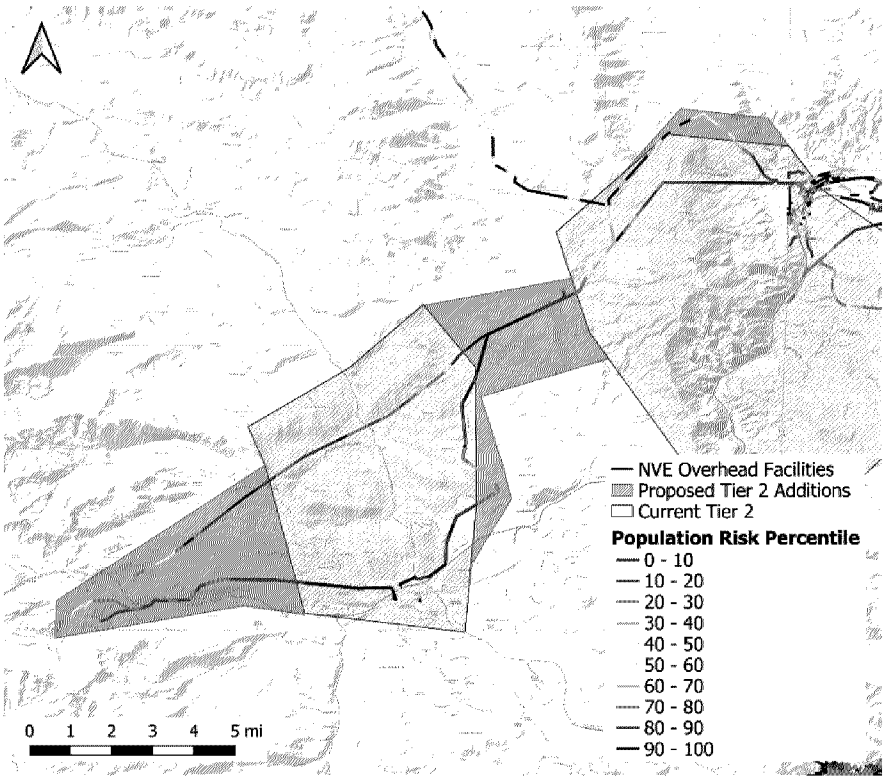


Figure 35. Population Risk Percentiles for the California Transmission Zone

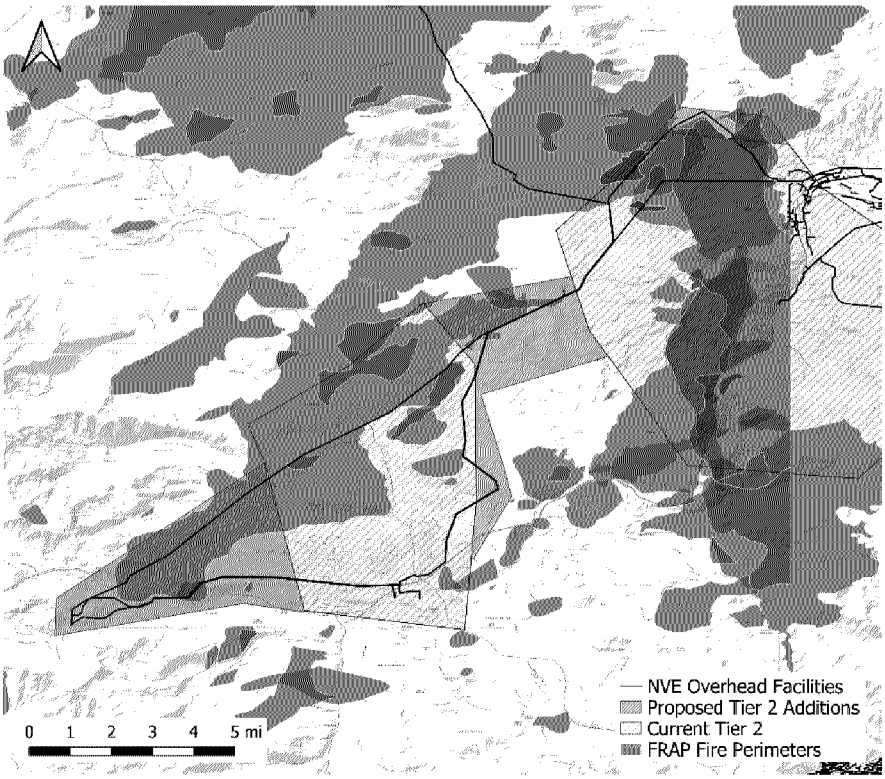


Figure 36. Historic Fire Perimeters in the California Transmission Zone Based on FRAP

Structure Density and Wildland Urban Interface

According to SILVIS labs Wildland Urban Interface dataset,[51] the proposed Tier 2 zones are in the vicinity of low to medium density intermix and medium density interface areas as shown in **Figure 6**. Additionally, **Figure 7** presents the building footprints in the western area proposed to be designated as Tier 2 based on the Microsoft building footprint dataset.[52] This figure shows the sparse, interspersed nature of structures within the wildland fuels. Structure losses are more likely in low- and medium-density housing than in high-density housing,[53] and the intermix areas have the highest structure losses probability.[54]

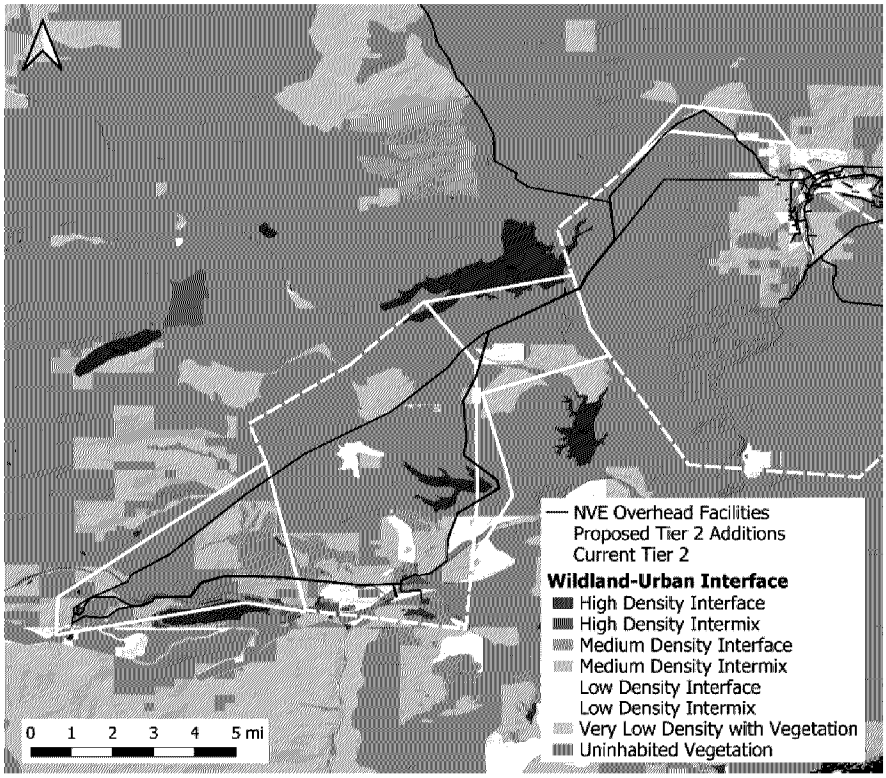


Figure 37. Wildland Urban Interface Area in the California Transmission Zone

[51] http://silvis.forest.wisc.edu/data/wui-change-2020/

[52] https://github.com/microsoft/USBuildingFootprints

[53] Syphard, A.D., Rustigian-Romsos, H., Mann, M., Conlisk, E., Moritz, M.A., Ackerly, D., "The relative influence of climate and housing development on current and projected future fire patterns and structure loss across three California landscapes," Global Environmental Change, **56** pg. 41-55 (2019).

[54] Caggiano, M. D., T. J. Hawbaker, B. M. Gannon, Hoffman C. M., "Building Loss in WUI Disasters: Evaluating the Core Components of the Wildland Urban Interface Definition." Fire, 3 (4)(73). (2020).

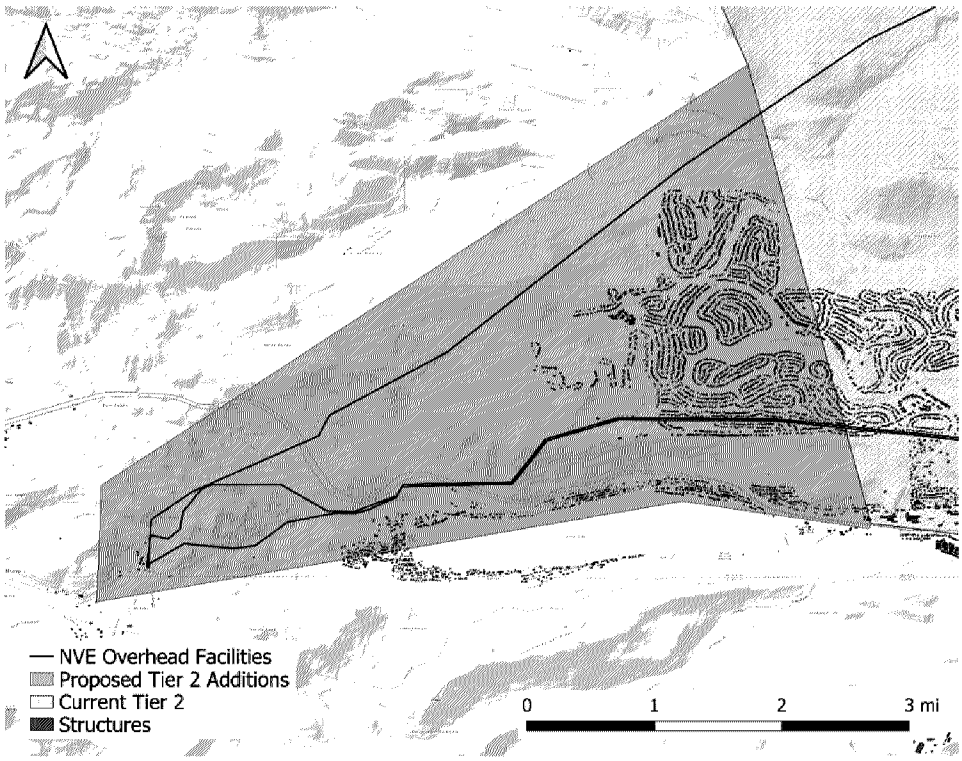


Figure 38. Structures in the West Portion Proposed for Tier 2 Designation

Wind Condition

A primary fire weather concern in the California Transmission line area is strong winds. To study the wind speed and direction pattern in the area, wind observations from the Tahoe-Donner and Stampede Remote Automatic Weather Stations (RAWS) are utilized. **Figure 8** presents the relative frequency of wind speeds and directions at the Tahoe-Donner RAWS, highlighting dominant south-southwest to southwest sustained winds often in the 10 – 20+ mph range. Furthermore, **Figure 9** illustrates the climatology of daily maximum wind gust speed at the same RAWS, which highlights gusts reaching 60-80 mph in fall and winter times and 40 mph in summer times can be expected.

Similar to the Tahoe-Donner RAWS, **Figure 10** and **Figure 11** present the relative frequency of wind speeds and directions and daily maximum wind gust climatology at Stampede RAWS, respectively. At this station, winds are predominantly from south with speed often in 7-20 mph range. Additionally, wind gusts reaching 30-40 mph is expected throughout the year.

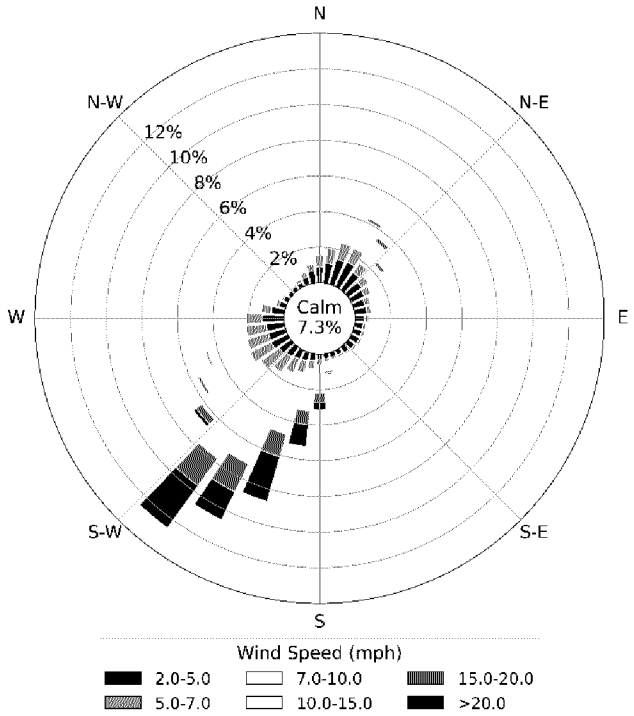


Figure 39. Sustained Wind Speeds at Tahoe-Donner RAWS

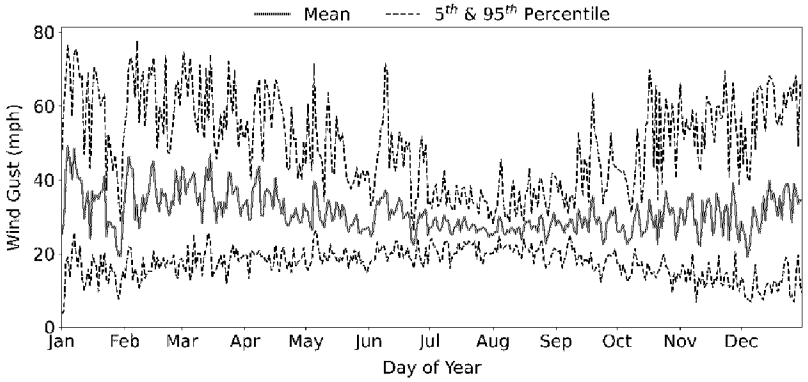


Figure 40. Climatology of Daily Maximum Wind Gust at Tahoe-Donner RAWS

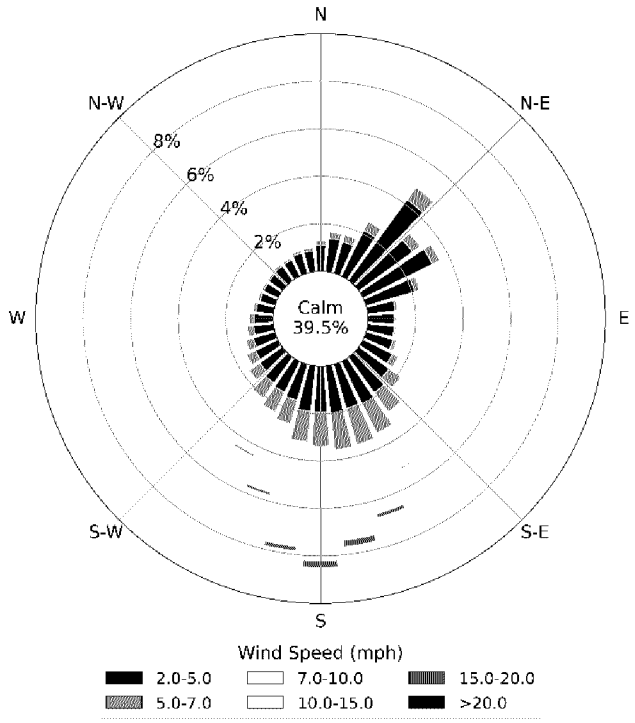


Figure 41. Sustained wind speeds at Tahoe-Donner RAWS

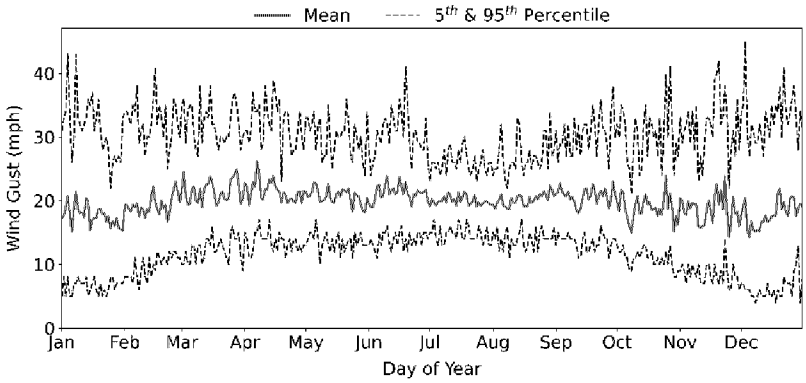


Figure 42. Climatology of Daily Maximum Wind Gust at Tahoe-Donner RAWS

Summary and Conclusions

The conditions that exist within the segments of the California Transmission line zone currently designated as non-Tier not only pose a similar wildfire risk as the current Tier 2 areas, but, in general, it presents a notable risk to the community in the event of a wildfire. The area has experienced multiple historic fires including a large fire with rapid rate of spread, consists mostly of low- to medium-density Wildland Urban Interface (WUI) interface and intermix, and strong winds are likely. These factors all contribute to the proposal that the current non-Tier segments be designated as Tier 2.

Analysis 2: Proposed Tier 1E Promotion of the Arrowcreek and Steamboat Area in Reno

This analysis focuses on fire risk considerations in the Arrowcreek and Steamboat areas in Reno. Although these areas are currently classified as Tier 1, they are more appropriately classified as Tier 1E as described herein.

Overview

The existing Tier 1E designations and the proposed Tier 1E promotions in the Arrowcreek and Steamboat areas in Reno are shown in **Figure 2**. Currently, the areas to the west of Arrowcreek and south of the Steamboat relative to the proposed promotion zones are designated as Tier 1E. However, as will be described, the proposed promotion zones, which are currently in Tier 1, pose similar, and even higher wildfire risk than the current Tier 1E areas. Thus, it is proposed to promote the current Tier 1 areas to Tier 1E.

Risk Assessment

Utilizing CloudFire's wildfire risk assessment result for the Companies' overhead facilities, the composite and population risk percentiles for the Arrowcreek and Steamboat areas in Reno are shown in **Figure 3** and **Figure 4**, respectively. As can be seen, the overhead lines in the Arrowcreek area pose similar and even higher risk than the current Tier 1E areas, reaching 80th to 90th percentile composite risk and 90th to 100th percentile population risk. Similarly, the composite and population risks reach 90th to 100th percentile for the Steamboat area. These risk percentiles show that ignition in these areas can have severe consequences on structures and communities and can potentially lead to large wildfires.

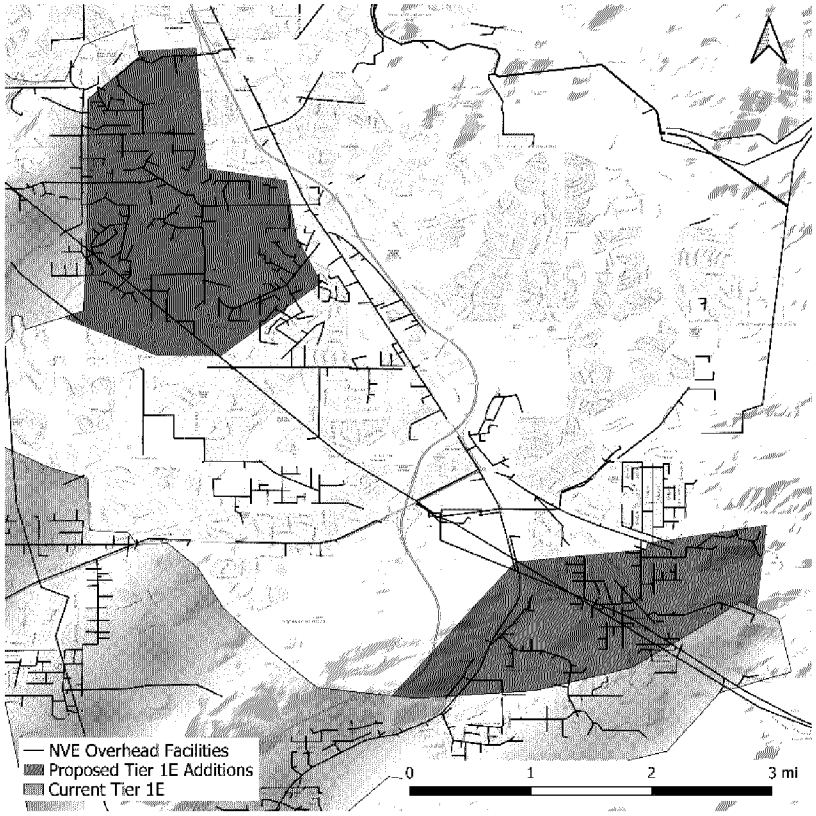


Figure 43. Proposed Tier 1E Additions in the Arrowcreek and Steamboat Areas in Reno

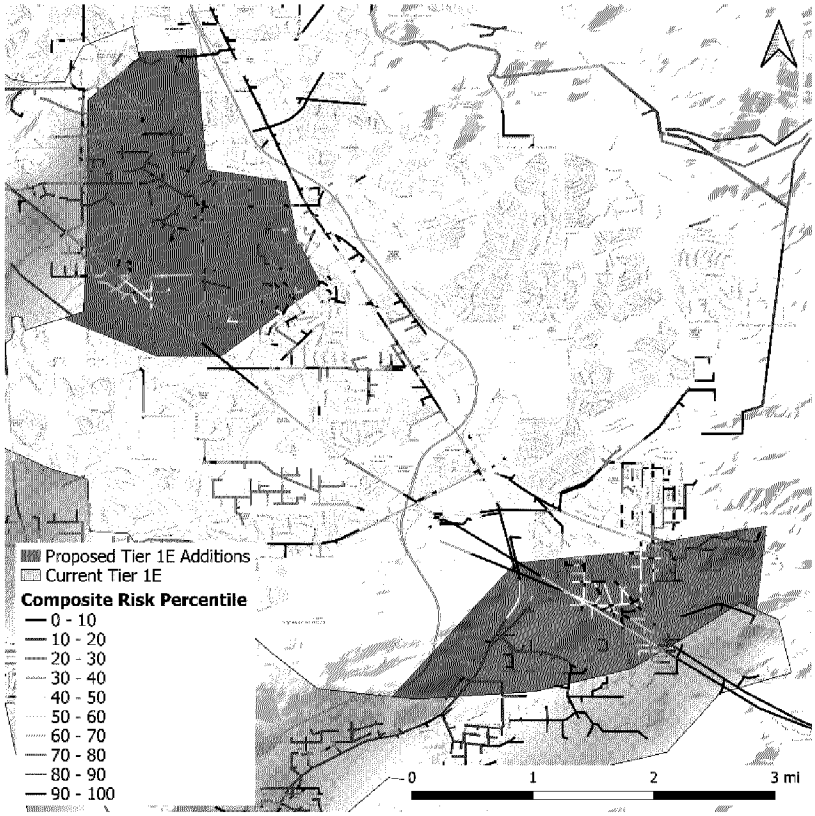


Figure 44. Composite Risk Percentiles for the Arrowcreek and Steamboat Areas in Reno

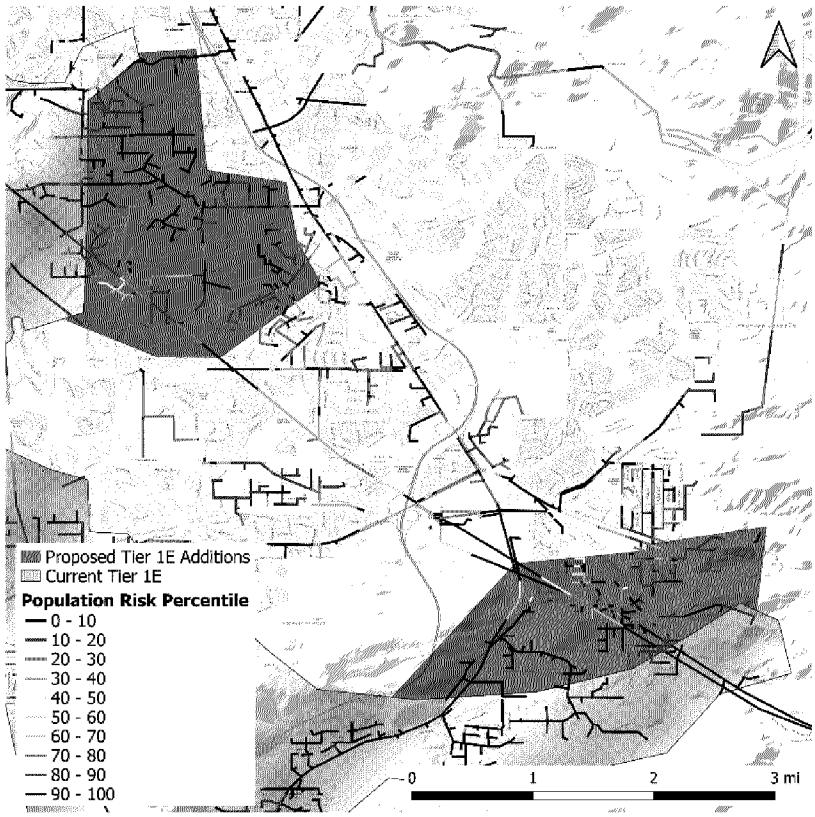


Figure 45. Population Risk Percentiles for the Arrowcreek and Steamboat Areas in Reno

Structure Density and Wildland Urban Interface

According to SILVIS labs Wildland Urban Interface dataset,[55] the proposed Tier 1E promotion zones are in the vicinity of very low to low and medium density intermix and medium density interface areas in both Arrowcreek and Steamboat areas as shown in **Figure 6**. During a wildfire event, structure losses are more likely in low- and medium-density housing than in high-density housing,[56] and the intermix areas have the highest structure losses probability.[57]

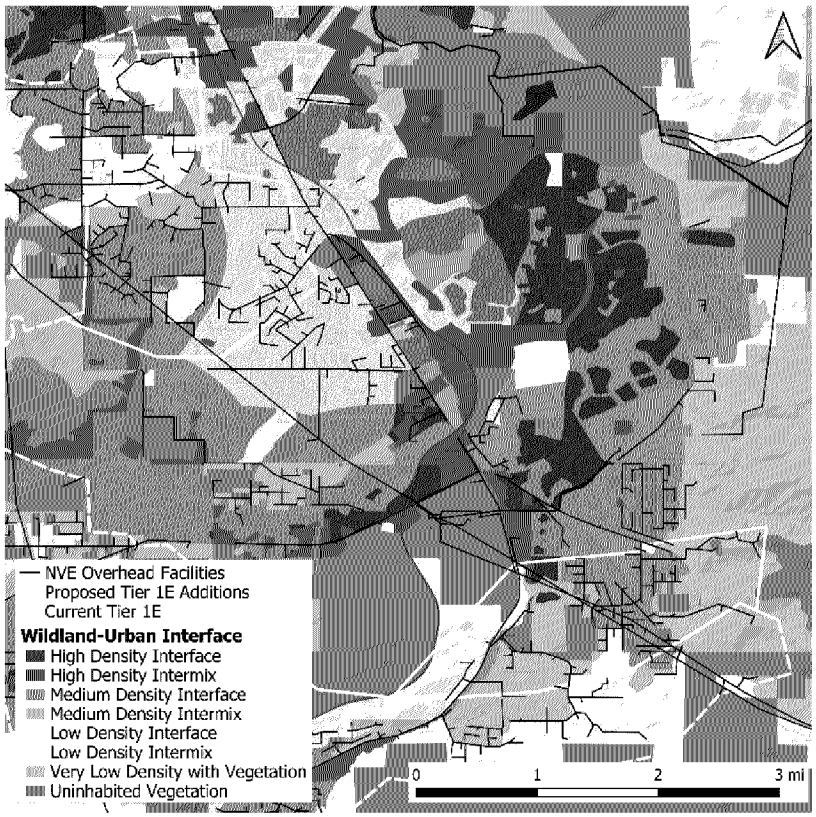


Figure 46. Wildland Urban Interface Area for the Arrowcreek and Steamboat Areas in Reno

Summary and Conclusions

The conditions that exist within the proposed promotion zones in Arrowcreek and Steamboat areas in Reno, currently designated as Tier 1, not only pose a similar wildfire risk as the current Tier 1E areas in the vicinity of them, but, in general, they present a notable risk to the community in the event of a wildfire. The area presents high population and composite risk percentiles, consisting mostly of low- to medium-density WUI interface and intermix. These factors all contribute to the proposal that the current Tier 1 areas should be promoted to Tier 1E.

[55] http://silvis.forest.wisc.edu/data/wui-change-2020/

[56] Syphard, A.D., Rustigian-Romsos, H., Mann, M., Conlisk, E., Moritz, M.A., Ackerly, D., "The relative influence of climate and housing development on current and projected future fire patterns and structure loss across three California landscapes," Global Environmental Change, **56** pg. 41-55 (2019).

[57] Caggiano, M. D., T. J. Hawbaker, B. M. Gannon, Hoffman C. M., "Building Loss in WUI Disasters: Evaluating the Core Components of the Wildland Urban Interface Definition." Fire, 3 (4)(73). (2020).

Analysis 3: Proposed Tier 1E Promotion of the West Las Vegas Area

This document analyzes fire risk considerations in the west Las Vegas area. Although this area is currently classified as Tier 1, they are more appropriately classified as Tier 1E as described herein.

Overview

The proposed Tier 1E promotions areas in west Las Vegas are shown in **Figure 2**. Currently, these zones are classified as Tier 1. However, as will be described, the proposed promotion zones pose similar wildfire risk characteristics as other Tier 1E areas in Nevada Power's service territory. Thus, it is proposed to promote these zones from Tier 1 to Tier 1E.

Risk Assessment

Utilizing CloudFire's wildfire risk assessment result for Nevada Power's overhead facilities, the composite and population risk percentiles for the west Las Vegas are shown in **Figure 3** and **Figure 4**, respectively. As can be seen, the overhead lines in west Las Vegas pose 50th to 100th percentile composite risk and even higher 70th to 100th percentile population risk. These risk percentiles show that ignition in these areas can have severe consequences on structures and communities.

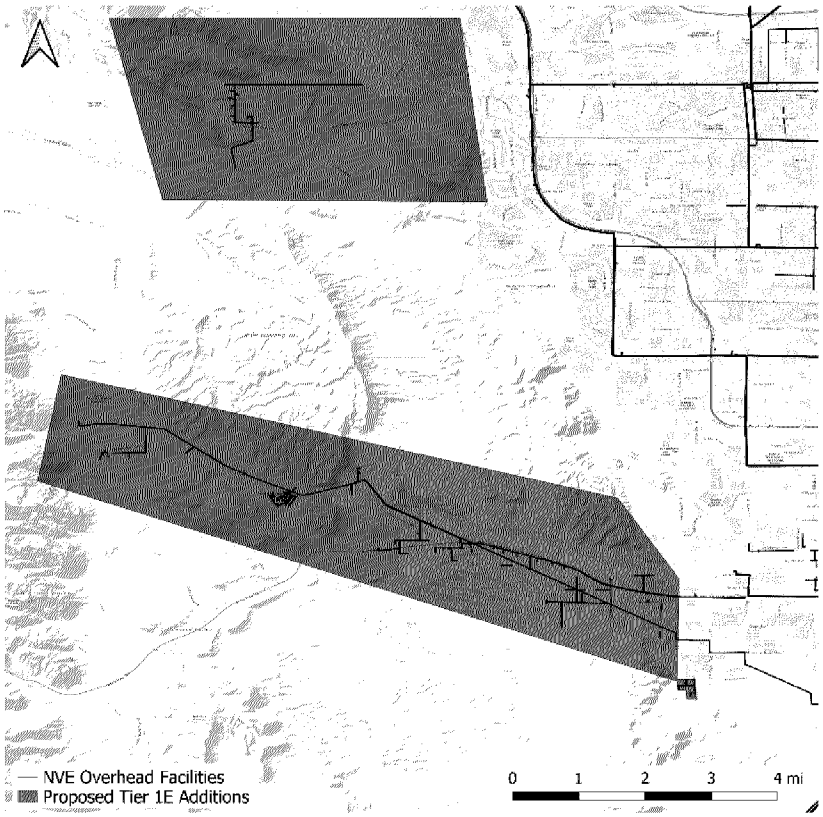


Figure 47. Proposed Tier 1E Additions in West Las Vegas

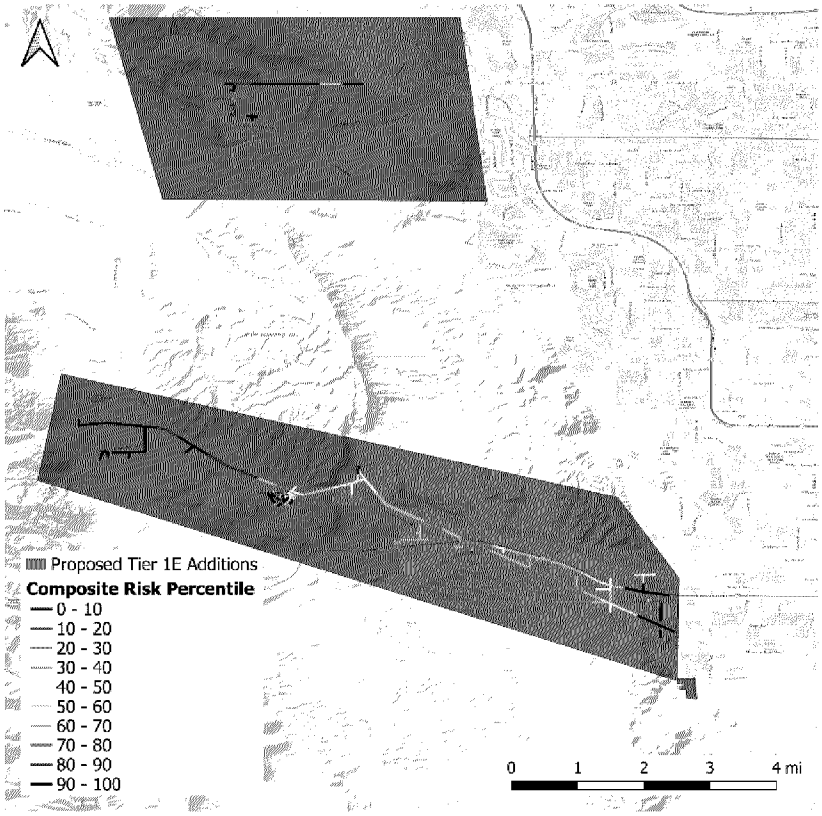


Figure 48. Composite Risk Percentiles for West Las Vegas

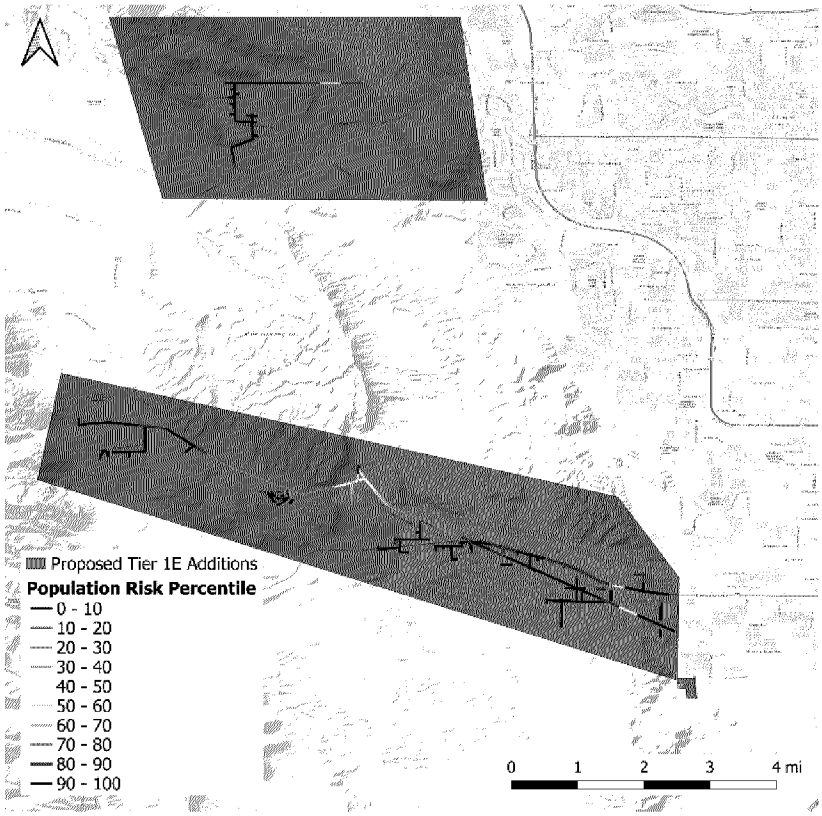


Figure 49. Population Risk Percentiles for West Las Vegas

Structure Density and Wildland Urban Interface

According to SILVIS labs Wildland Urban Interface dataset,[58] the overhead lines in the proposed Tier 1E promotion zones are in the vicinity of very low to low and medium density intermix areas as shown in **Figure 6**. During a wildfire event, structure losses are more likely in low- and medium-density housing than in high-density housing,[59] and the intermix areas have the highest structure losses probability.[60]

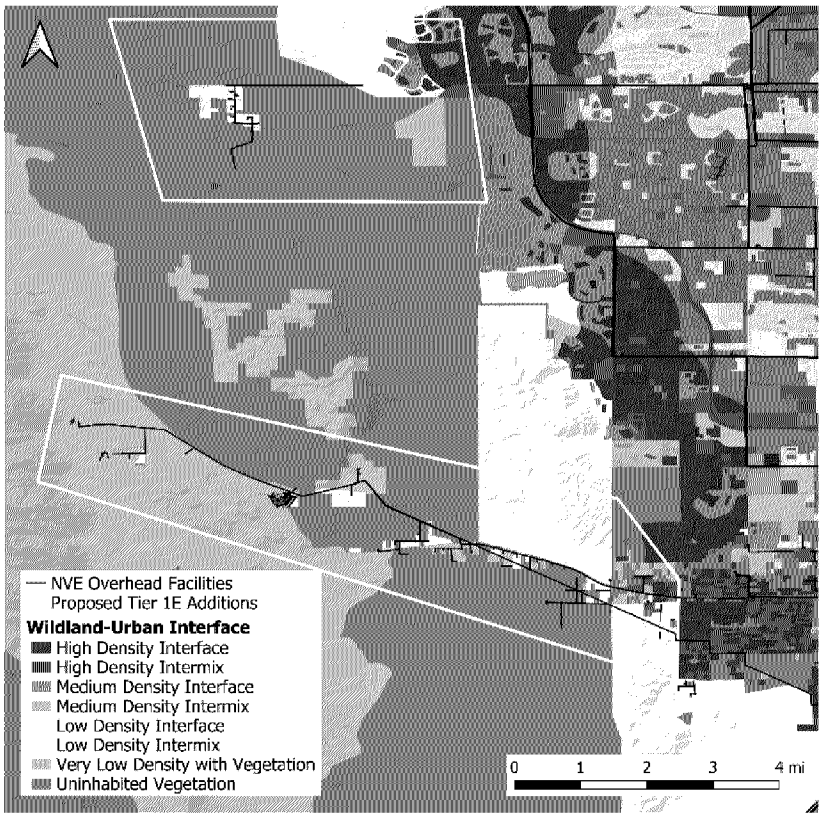


Figure 50. Wildland Urban Interface Area for West Las Vegas

Summary and Conclusions

The conditions that exist within the proposed promotion zones in west Las Vegas, currently designated as Tier 1, not only pose a similar wildfire risk as the current Tier 1E areas in the rest of the Companies' service territory, but, in general, they present a notable risk to the community in the event of a wildfire. The area presents high population and composite risk percentiles, consisting mostly of low- to medium-density WUI interface and intermix. These factors all contribute to the proposal that the current Tier 1 areas should be promoted to Tier 1E.

[58] http://silvis.forest.wisc.edu/data/wui-change-2020/

[59] Syphard, A.D., Rustigian-Romsos, H., Mann, M., Conlisk, E., Moritz, M.A., Ackerly, D., "The relative influence of climate and housing development on current and projected future fire patterns and structure loss across three California landscapes," Global Environmental Change, **56** pg. 41-55 (2019).

[60] Caggiano, M. D., T. J. Hawbaker, B. M. Gannon, Hoffman C. M., "Building Loss in WUI Disasters: Evaluating the Core Components of the Wildland Urban Interface Definition." Fire, 3 (4)(73). (2020).

Analysis 4: Proposed Tier 1E Promotion of the Washoe Valley Area

This document analyzes fire risk considerations in the Washoe Valley area. Although this area is currently classified as Tier 1, they are more appropriately classified as Tier 1E as described herein.

Overview

The existing Tier 1E designations and the proposed Tier 1E additions in the Washoe Valley area are shown in **Figure 2**. Currently, the areas north, and south of the New Washoe City are designated as Tier 1E. However, as will be described, the New Washoe City area, which are currently in Tier 1, pose the same wildfire risk as the current Tier 1E areas. Thus, it is proposed to promote the current Tier 1 areas to Tier 1E.

Risk Assessment

Utilizing CloudFire's wildfire risk assessment result for the Companies' overhead facilities, the composite and population risk percentiles for the New Washoe City are shown in **Figure 3** and **Figure 4**, respectively. As can be seen, the overhead lines in the New Washoe City pose similar and even higher risk than the current Tier 1E areas, reaching 50th to 100th percentile composite risk and 90th to 100th percentile population risk. These risk percentiles show that ignition in these areas can have severe consequences on structures and communities.

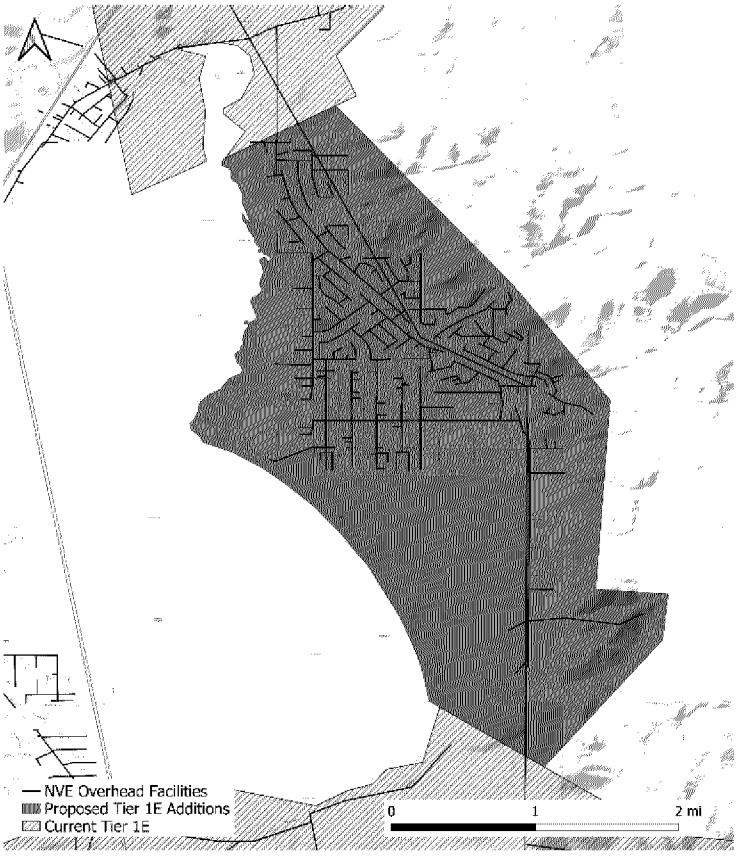


Figure 51. Proposed Tier 1E Additions in the Washoe Valley Area

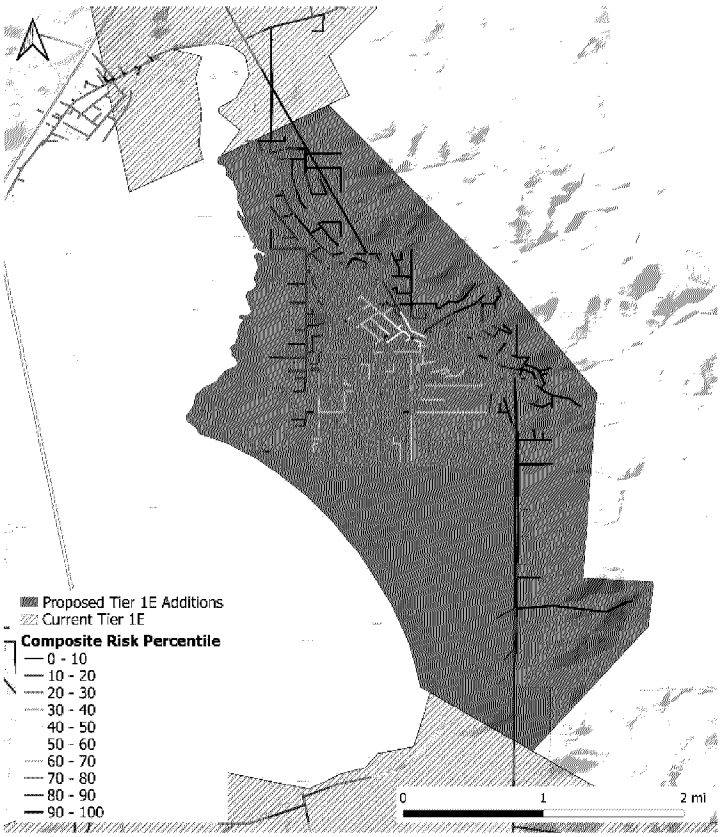


Figure 52. Composite Risk Percentiles for the New Washoe City Area

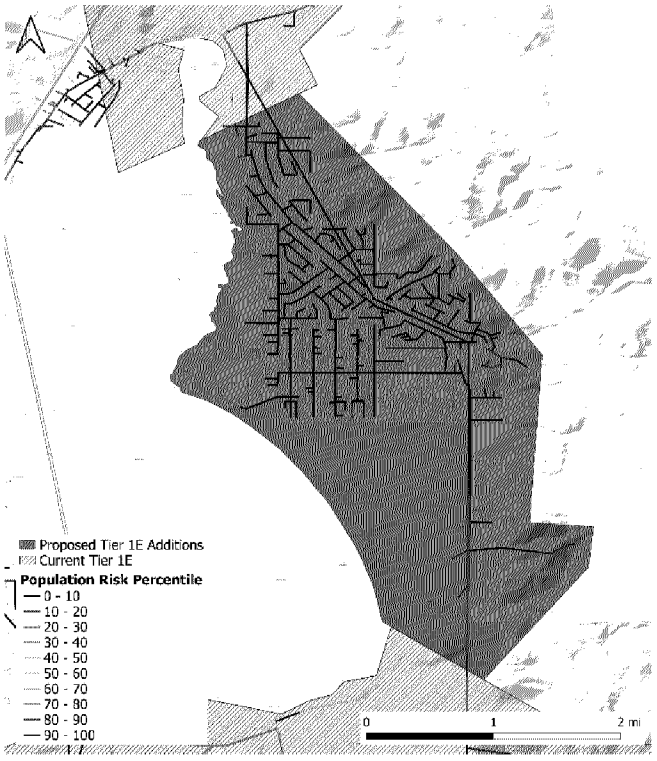


Figure 53. Population Risk Percentiles for the New Washoe City Area

Structure Density and Wildland Urban Interface

According to SILVIS labs Wildland Urban Interface dataset,[61] the proposed Tier 1E promotion zones are in the vicinity of very low to low and medium density intermix and medium density interface areas as shown in **Figure 6**. During a wildfire event, structure losses are more likely in low- and medium-density housing than in high-density housing,[62] and the intermix areas have the highest structure losses probability.[63]

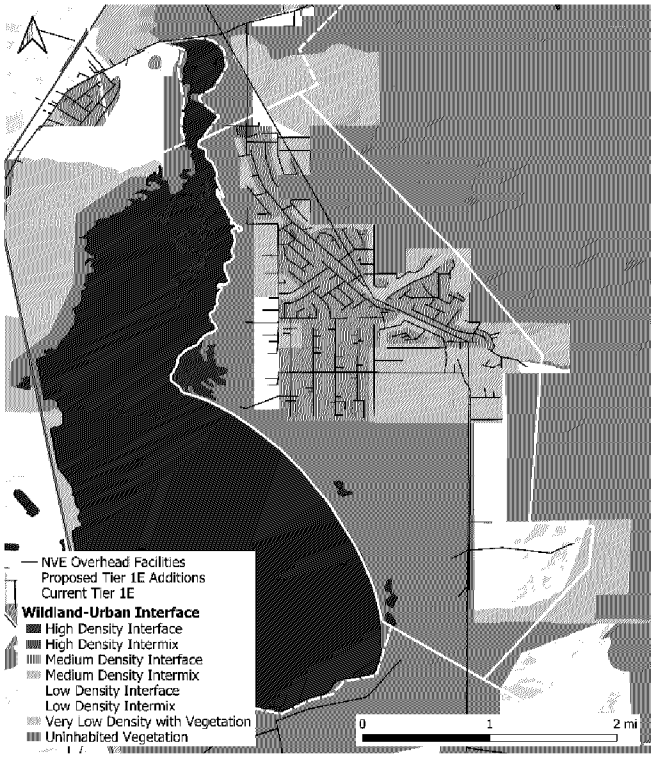


Figure 54. Wildland Urban Interface Area in the California Transmission Zone

Wind Condition

A primary fire weather concern in the New Washoe City area is strong winds. To study the wind speed and direction pattern in the area, wind observations from the Companies' NV005 weather station are utilized. **Figure 8** presents the relative frequency of wind speeds and directions at the NV005 station. As can be seen, winds are predominantly southwesterly and northeasterly with sustained winds often in the 7–20+ mph range for the southwest winds and in 2-15 mph range for the northeast winds. Furthermore, **Figure 9** illustrates the climatology of daily maximum wind gust speed at the same station, which highlights gusts reaching 40-50 mph in fall and winter times and 30 mph in summer times can be expected.

[61] http://silvis.forest.wisc.edu/data/wui-change-2020/

[62] Syphard, A.D., Rustigian-Romsos, H., Mann, M., Conlisk, E., Moritz, M.A., Ackerly, D., "The relative influence of climate and housing development on current and projected future fire patterns and structure loss across three California landscapes," Global Environmental Change, **56** pg. 41-55 (2019).

[63] Caggiano, M. D., T. J. Hawbaker, B. M. Gannon, Hoffman C. M., "Building Loss in WUI Disasters: Evaluating the Core Components of the Wildland Urban Interface Definition." Fire, 3 (4)(73). (2020).

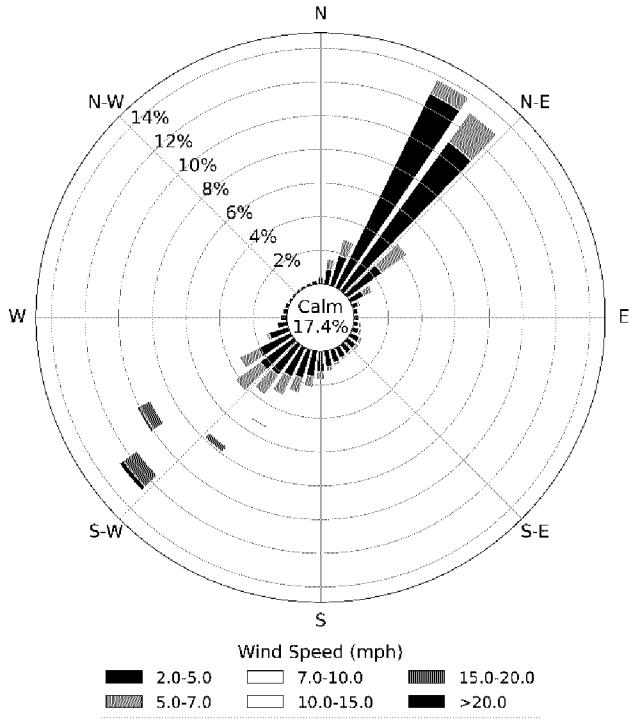


Figure 55. Sustained Wind Speeds at NV005 Weather Station

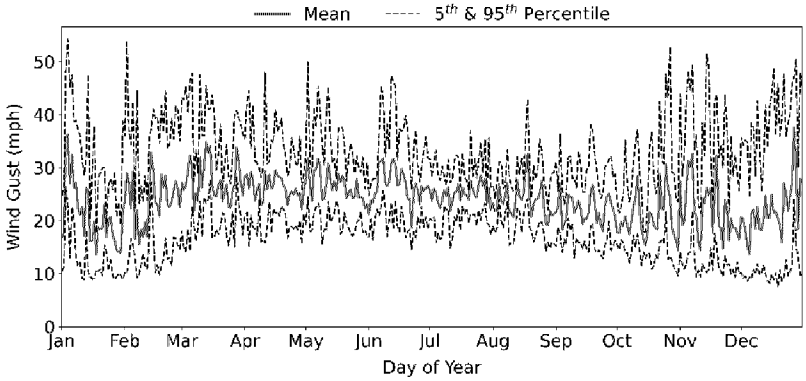


Figure 56. Climatology of Daily Maximum Wind Gust at NV005 Weather Station

Summary and Conclusions

The conditions that exist within the New Washoe City area, currently designated as Tier 1E, not only pose a similar wildfire risk as the current Tier 1E areas in the vicinity of the New Washoe City, but, in general, it presents a notable risk to the community in the event of a wildfire. The area presents high population and composite risk percentiles, consisting mostly of low- to medium-density WUI interface and intermix with the high likelihood of strong winds. These factors all contribute to the proposal that the current Tier 1 areas should be promoted to Tier 1E.

Analysis 5: Proposed Tier 1E Promotion of the Austin Area

This document analyzes fire risk considerations in the Austin area. Although this area is currently classified as Tier 1, they are more appropriately classified as Tier 1E as described herein.

Overview

The proposed Tier 1E promotions in the Austin are shown in Figure 26. Currently, this area is designated as Tier 1. However, as will be described, the proposed promotion poses a similar risk as other Tier 1E areas based on risk assessment as well as expert and local knowledge. Thus, it is proposed to promote the current Tier 1 area to Tier 1E.

Risk Assessment

Utilizing CloudFire's wildfire risk assessment result for the Companies' overhead facilities, the composite and population risk percentiles for the Austin area are shown in **Figure 27** and **Figure 28**, respectively. As can be seen, the overhead lines in the Austin area pose significant risk, reaching 60th to 100th percentile composite risk and 40th to 80th percentile population risk. These risk percentiles show that ignition in these areas can have severe consequences on structures and communities, and can potentially lead to large wildfires.

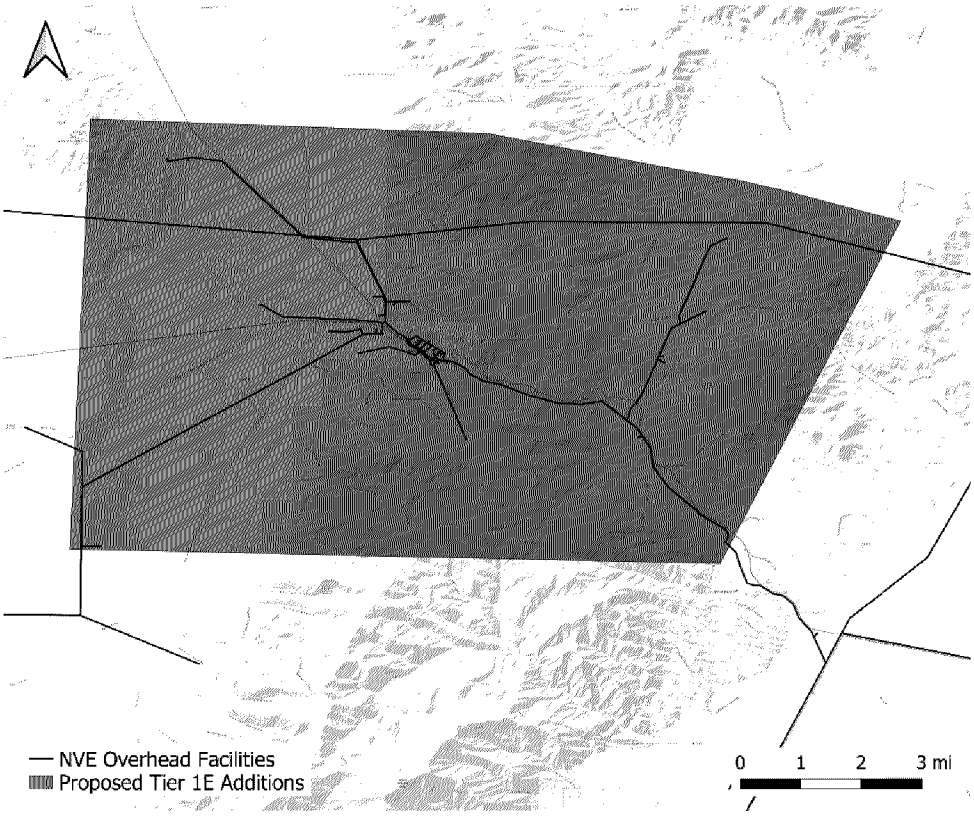


Figure 57. Map depicting proposed Tier 1E additions in the Austin area

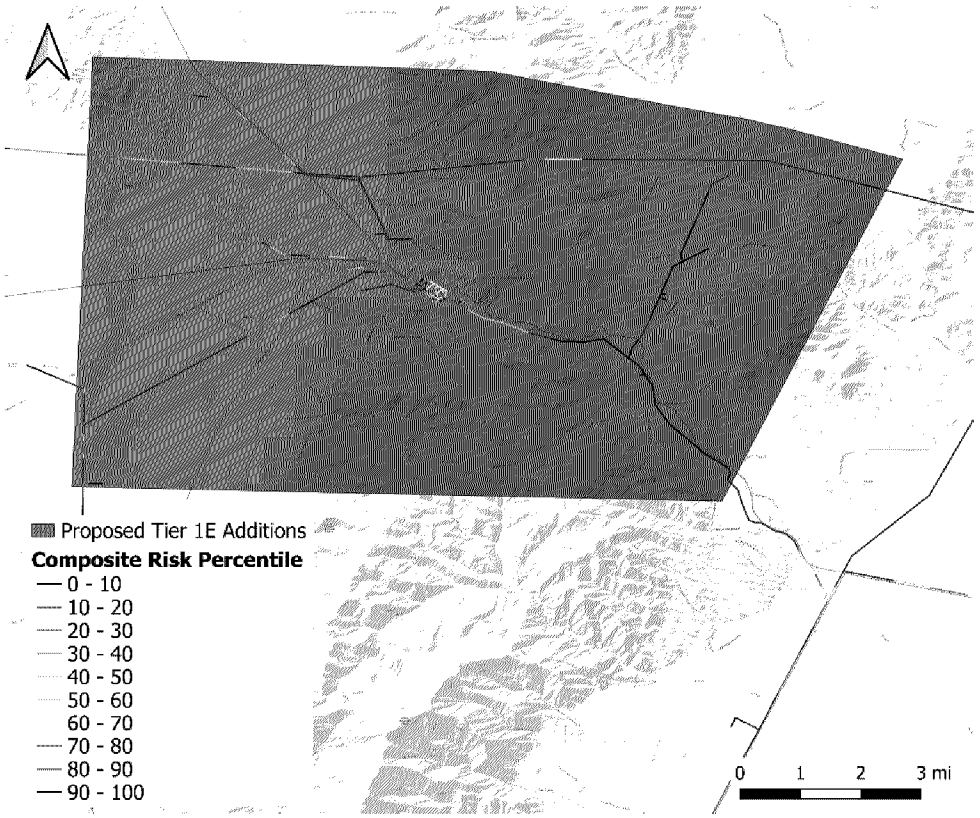


Figure 58. Composite risk percentiles for the Austin area

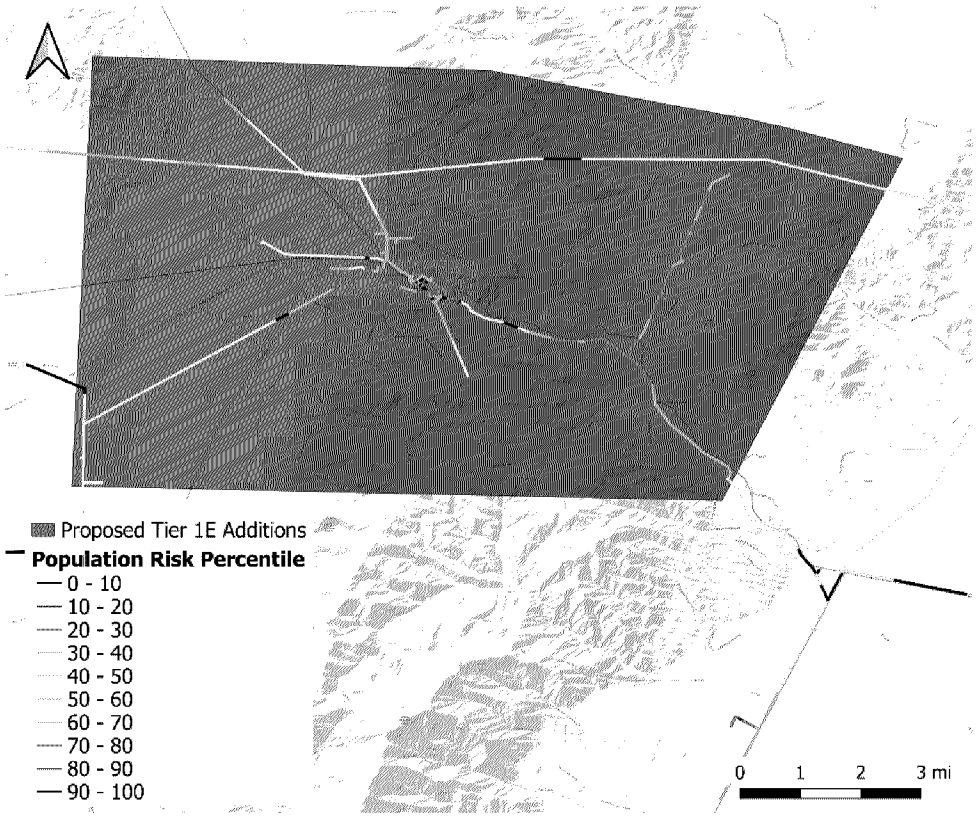


Figure 59. Population risk percentiles for the Austin area

Structure Density and Wildland Urban Interface

According to SILVIS labs Wildland-Urban Interface dataset,[64] the proposed Tier 1E promotion zone is in the vicinity of very low to low and medium density intermix and medium density interface areas, together with uninhabited vegetation areas, as shown in **Figure 29**. During a wildfire event, structure losses are more likely in low- and medium-density housing than in high-density housing,[65] and the intermix areas have the highest structure losses probability.[66] Additionally, an ignition in the uninhabited vegetation can lead to large or fast spreading fires, that can pose a significant threat to communities.

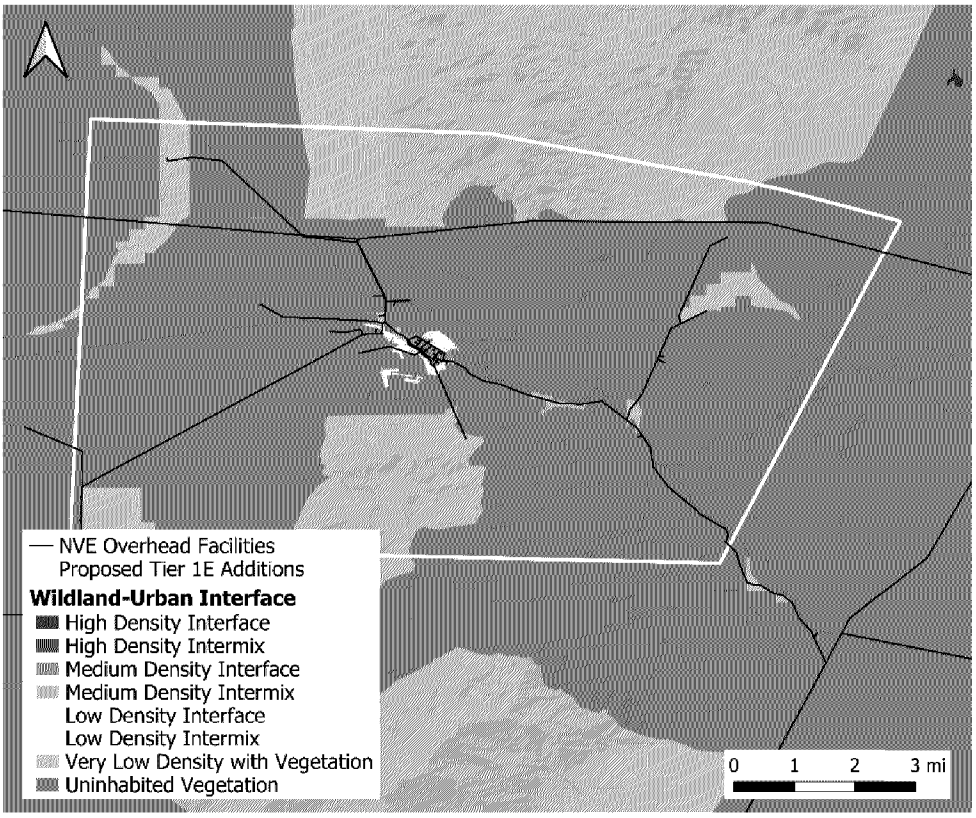


Figure 60. Wildland-Urban Interface area for the Austin area

Summary and Conclusions

The conditions that exist within the proposed promotion zone in the Austin area, currently designated as Tier 1, present a notable risk to the community in the event of a wildfire. The area presents high population and composite risk percentiles, consisting mostly of low- to medium-density WUI interface and intermix and uninhabited vegetation. These factors all contribute towards the proposal that the current Tier 1 areas should be promoted to Tier 1E.

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[64] http://silvis.forest.wisc.edu/data/wui-change-2020/

[65] Syphard, A.D., Rustigian-Romsos, H., Mann, M., Conlisk, E., Moritz, M.A., Ackerly, D., "The relative influence of climate and housing development on current and projected future fire patterns and structure loss across three California landscapes," Global Environmental Change, **56** pg. 41-55 (2019).

[66] Caggiano, M. D., T. J. Hawbaker, B. M. Gannon, Hoffman C. M., "Building Loss in WUI Disasters: Evaluating the Core Components of the Wildland–Urban Interface Definition." Fire, 3 (4)(73). (2020).

Analysis 6: Proposed Tier 1E Promotion of the West and Southwest Reno Areas

This document analyzes fire risk considerations in the west and southwest Reno area. Although this area is currently classified as non-tier, it is more appropriately classified as Tier 1E as described herein.

Overview

The existing Tier 1E designations and the proposed Tier 1E additions in the west and southwest Reno area are shown in **Figure 30**. Currently, areas to the north, south, and southwest of the proposed Tier 1E areas are classified as Tier 1E. As will be described, the proposed Tier 1E areas pose the same wildfire risk as the current Tier 1E areas.

Risk Assessment

Utilizing CloudFire's wildfire risk assessment result for the Companies' overhead facilities, the composite and population risk percentiles for the west and southwest Reno are shown in **Figure 31** and **Figure 32**, respectively. As can be seen, the overhead lines in the proposed areas to be classified as Tier 1E pose similar and even higher risk than the current Tier 1E areas, reaching 70th to 80th percentile composite risk and even higher 80th to 90th percentile population risk. These risk percentiles show that ignition in these areas can have severe consequences on structures and communities surrounding the overhead lines.

Structure Density and Wildland Urban Interface

According to SILVIS labs Wildland-Urban Interface dataset,[67] the proposed Tier 1E promotion zones are in the vicinity of low and medium density interface areas as shown in **Figure 33**. During a wildfire event, structure losses are more likely in low- and medium-density housing than in high-density housing,[68] posing a high risk to the structures and communities.

[67] http://silvis.forest.wisc.edu/data/wui-change-2020/

[68] Syphard, A.D., Rustigian-Romsos, H., Mann, M., Conlisk, E., Moritz, M.A., Ackerly, D., "The relative influence of climate and housing development on current and projected future fire patterns and structure loss across three California landscapes," Global Environmental Change, **56** pg. 41-55 (2019).

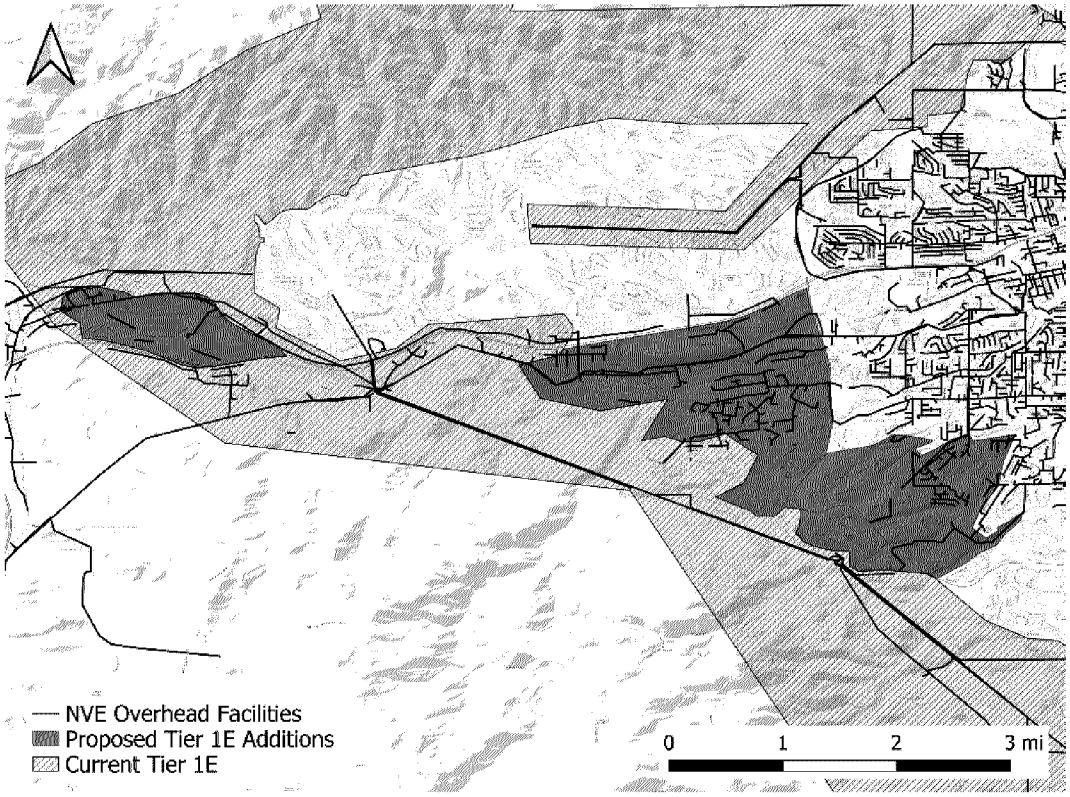


Figure 61. Map depicting proposed Tier 1E additions in the West and Southwest Reno

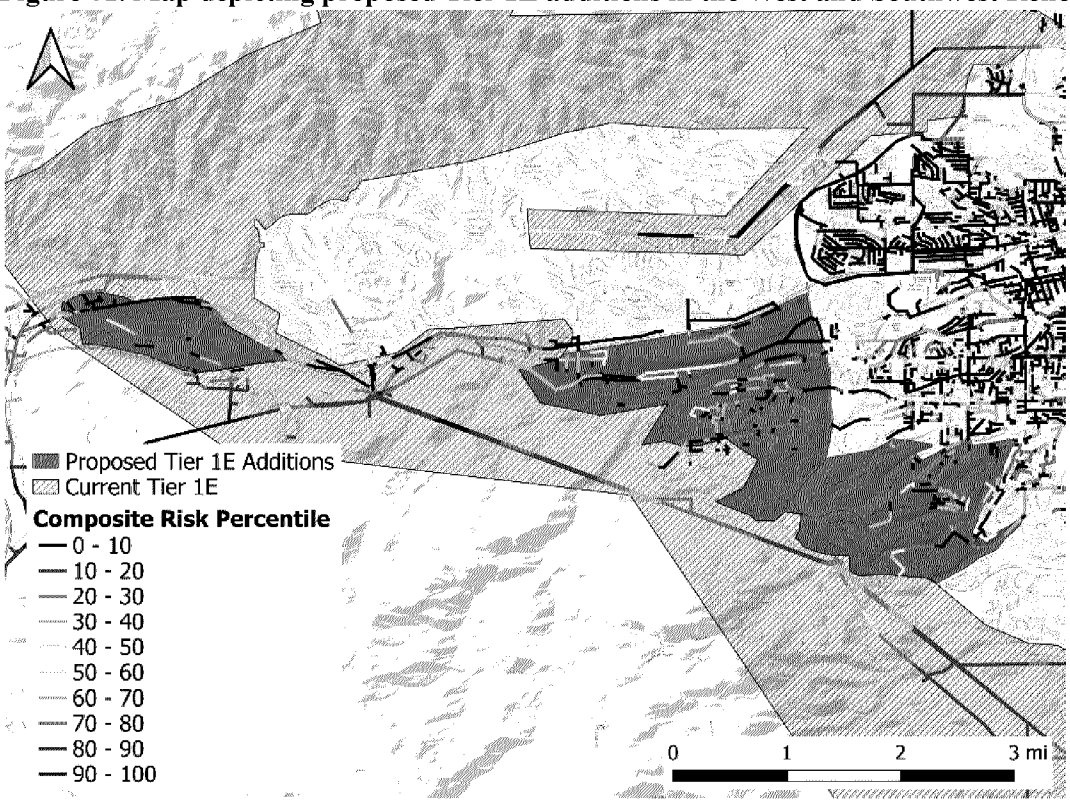


Figure 62. Composite risk percentiles for the West and Southwest Reno

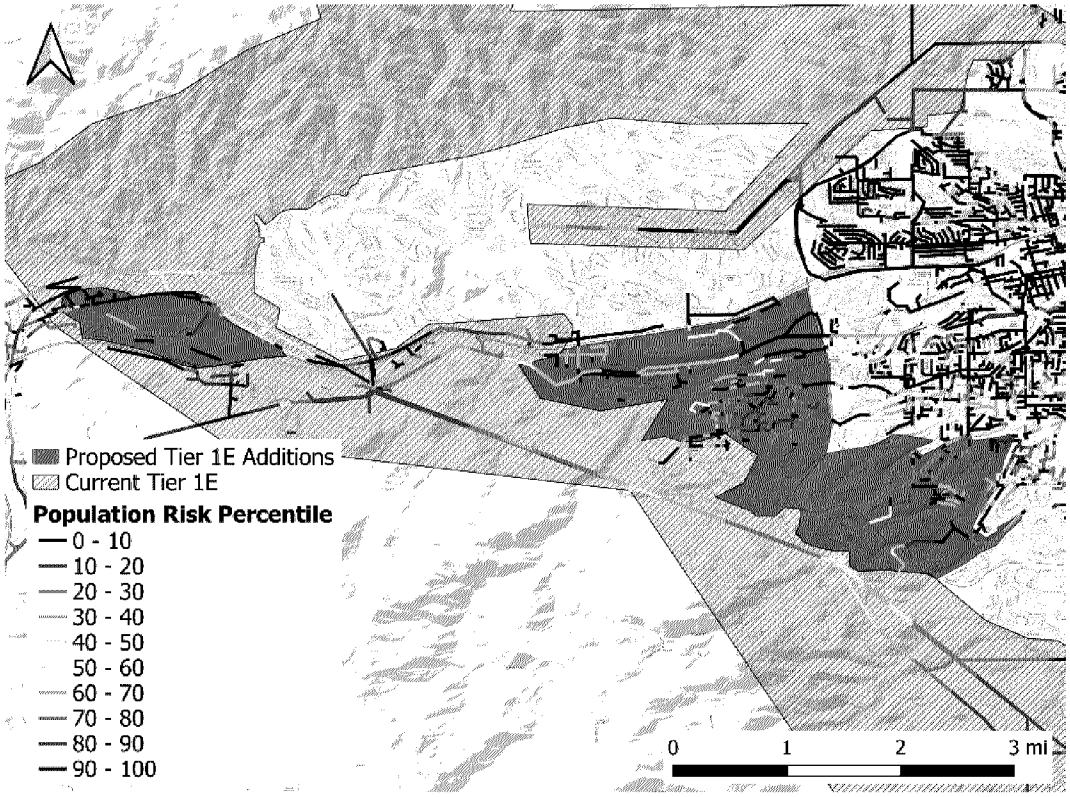


Figure 63. Population risk percentiles for the West and Southwest Reno

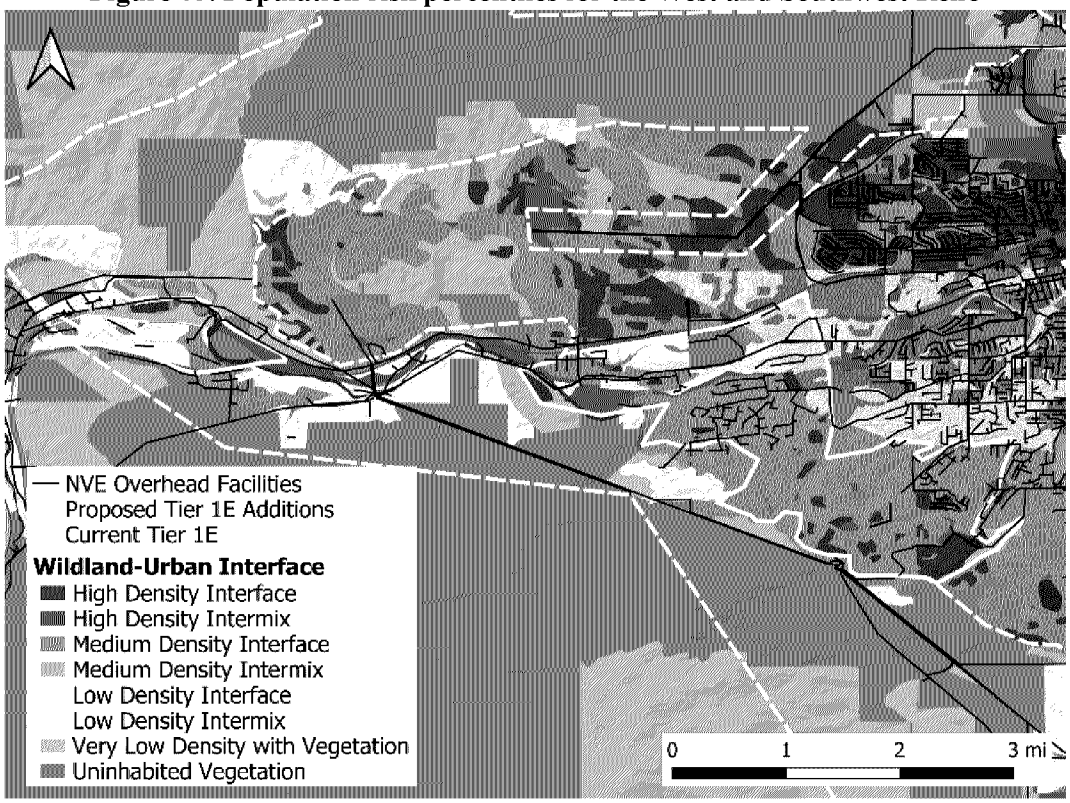


Figure 64. Wildland-Urban Interface area in the West and Southwest Reno

Summary and Conclusions

The conditions that exist within the west and southwest Reno, currently designated as non-tier, not only pose a similar wildfire risk as the current Tier 1E areas in their vicinity, but, in general, it presents a notable risk to the community in the event of a wildfire. The area presents high population and composite risk percentiles, consisting mostly of low- to medium-density WUI interface. These factors all contribute towards the proposal that the current non-tier areas should be promoted to Tier 1E.

Analysis 7: Proposed Tier 1 Refresh

This analysis refreshes the existing Tier 1 designations in The Companies' service territory. The primary motivations for this refresh are to better capture areas with heightened fire risk in the vicinity of The Companies' assets and overcome the shortcomings of the current Tier 1 designations.

Background

The current The Companies' Tier 1 areas are identified mainly based on Nevada Division of Forestry (NDF) fire risk map, which provides statewide risk classifications. Additionally, the current Tier 1 designations capture areas with heightened fire risk associated with potential impacts to assets at risk beyond structures, including grazing, ranching, habitat, drinking water, and timber. However, these designations may not encompass the full risk posed by The Companies' assets (i.e., overhead lines) as the NDF risk map is not tailored to The Companies' assets and data. Moreover, due to the rasterized (gridded) nature of NDF risk maps and its conversion to risk Tier polygons, segments of The Companies' lines with similar risk and operational characteristics to Tier 1 segments may not be classified as Tier 1 as shown below.

Proposed Tier 1 Refresh

Composite risk percentiles described in the "Methodology Overview" section are the primary basis of the proposed Tier 1 refinements. To the extent possible, assets that scored as more than 50^{th} percentile composite risk, that are currently not in other tiers, are classified as Tier 1. Additionally, current segments classified as Tier 1 that have smaller than 50^{th} percentile in the risk assessment are kept as Tier 1, rather than being demoted to non-Tier.

Figure 34 presents a zoomed in sample of the proposed Tier 1 refresh in the areas east of Lake Tahoe. As can be seen, current Tier 1 areas contain many small, disjointed, and non-homogeneous polygons between which small gaps are present. Such polygons fail to fully encompass overhead lines segments with similar risk characteristics and result in small gaps between current Tier 1 areas. Conversely, the proposed Tier 1 refresh not only encompasses all overhead line segments with similar characteristics, derived from more robust risk assessment tailored to The Companies' assets and data, but it also provides a uniform, homogenous polygon for Tier 1 classification.

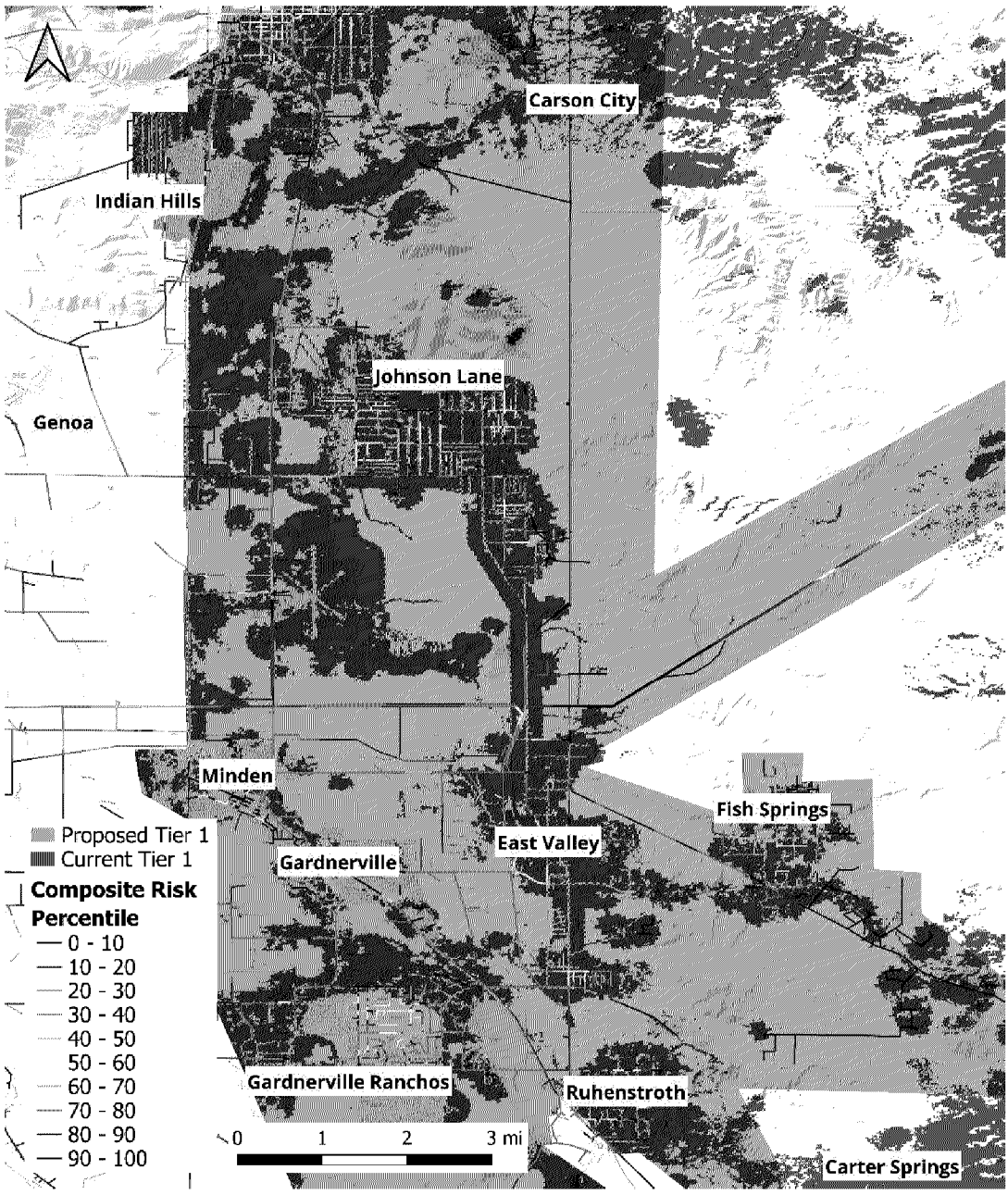


Figure 65. Detailed Sample of Proposed Tier 1 Refresh in the Carson Valley Area

Tier 1 Refresh Maps

Maps designating the proposed Tier 1 refresh zones, together with current Tier 1 and CloudFire's composite risk percentiles for The Companies' overhead lines are presented in **Figure 35** through **Figure 40**. These maps are organized as follows:

- Figure 35. Proposed Tier 1 Refresh **and Current Tier 1 in North to Northwest Nevada**
- Figure 36. Proposed Tier 1 Refresh **and Current Tier 1 in Northwest to West Nevada**
- Figure 37. Proposed Tier 1 Refresh **and Current Tier 1 in North to Northeast Nevada**
- Figure 38. Proposed Tier 1 Refresh **and Current Tier 1 in Northeast to East Nevada**
- Figure 39. Proposed Tier 1 Refresh **and Current Tier 1 in Central Nevada**

- Figure 40. Proposed Tier 1 Refresh **and Current Tier 1 in Southern Nevada**

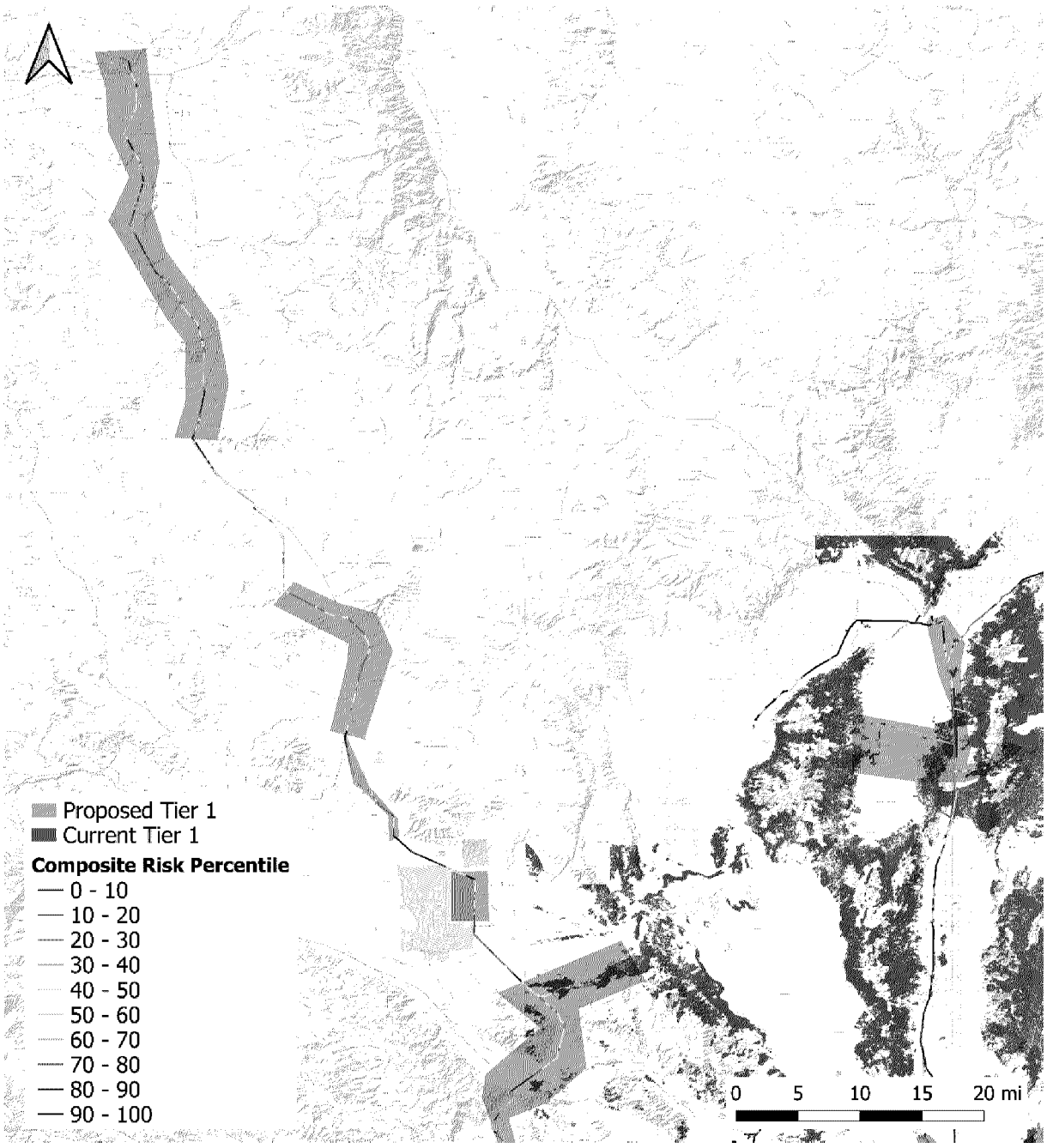


Figure 66. Proposed Tier 1 Refresh and Current Tier 1 in North to Northwest Nevada and East of California near State Line

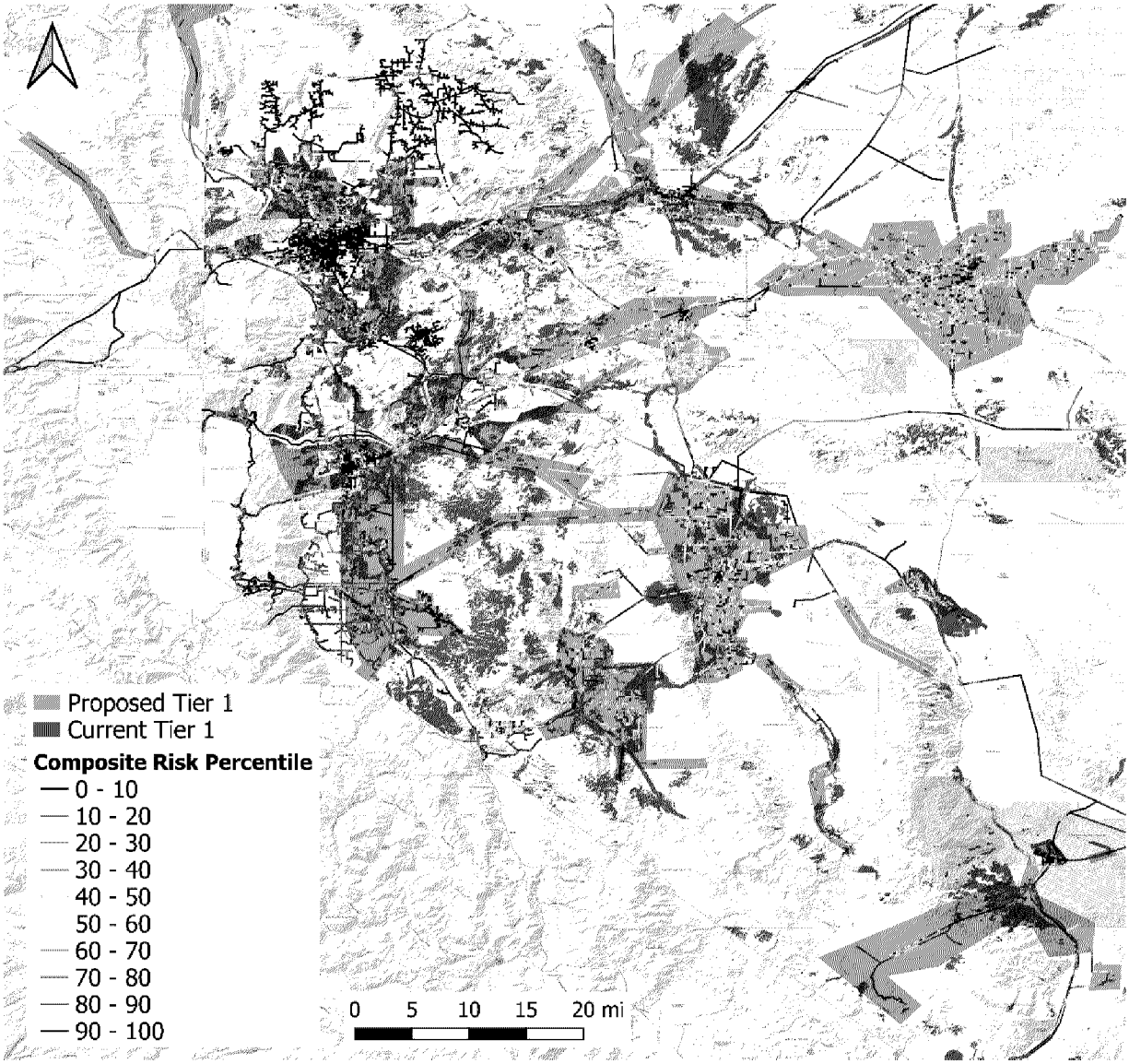


Figure 67. Proposed Tier 1 Refresh and Current Tier 1 in Northwest to West Nevada

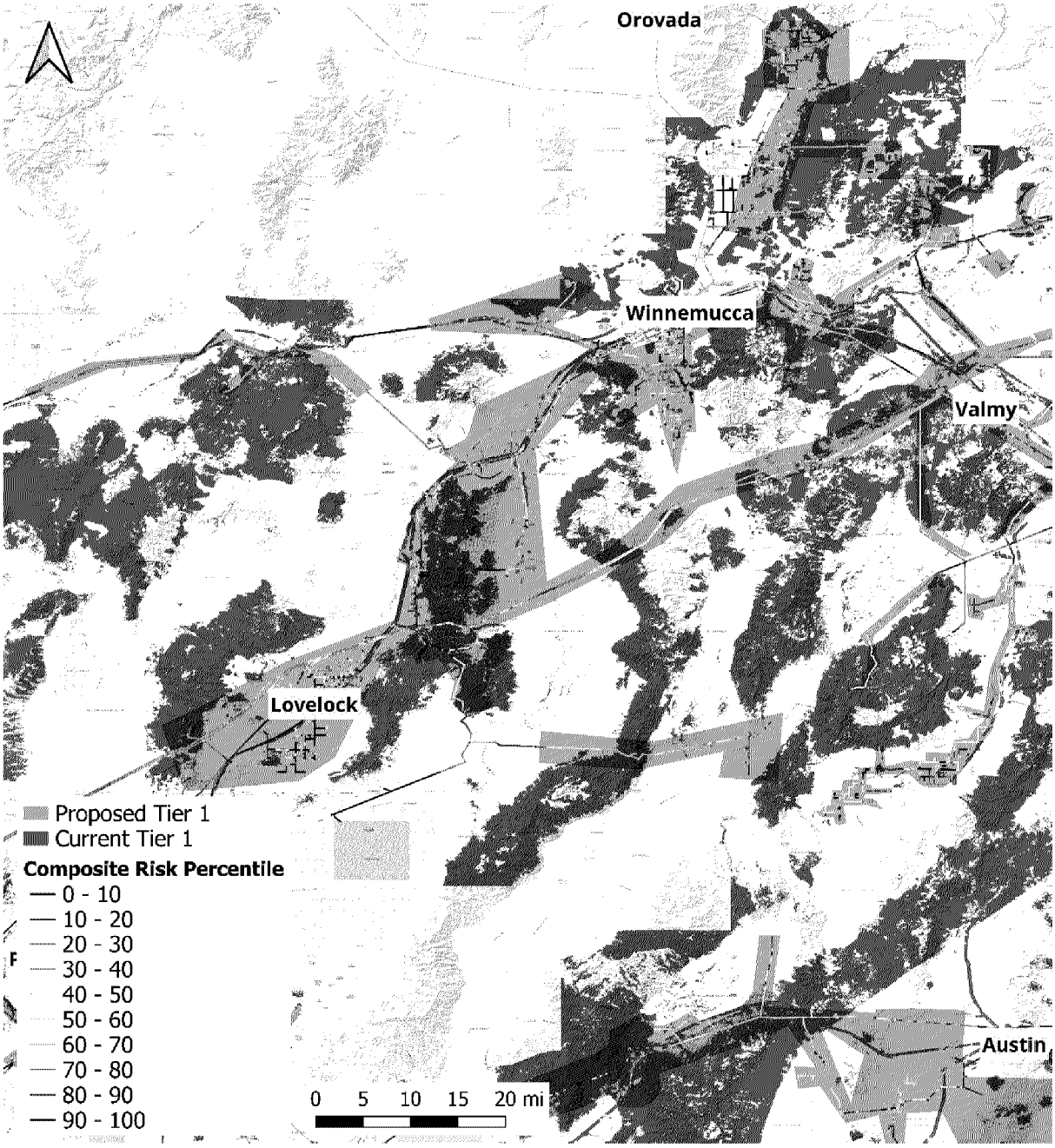


Figure 68. Proposed Tier 1 Refresh and Current Tier 1 in North to Northeast Nevada

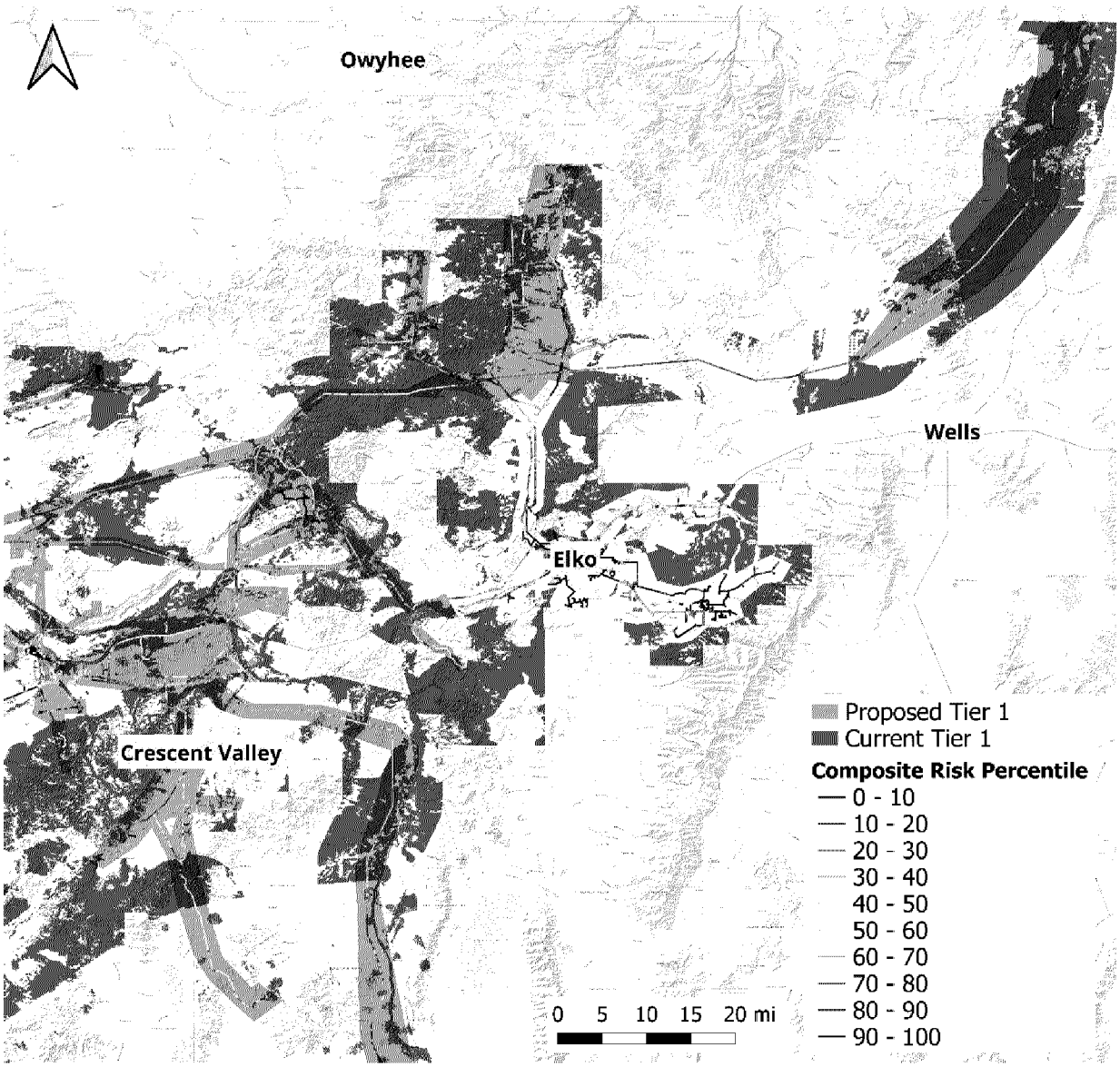


Figure 69. Proposed Tier 1 Refresh and Current Tier 1 in Northeast to East Nevada

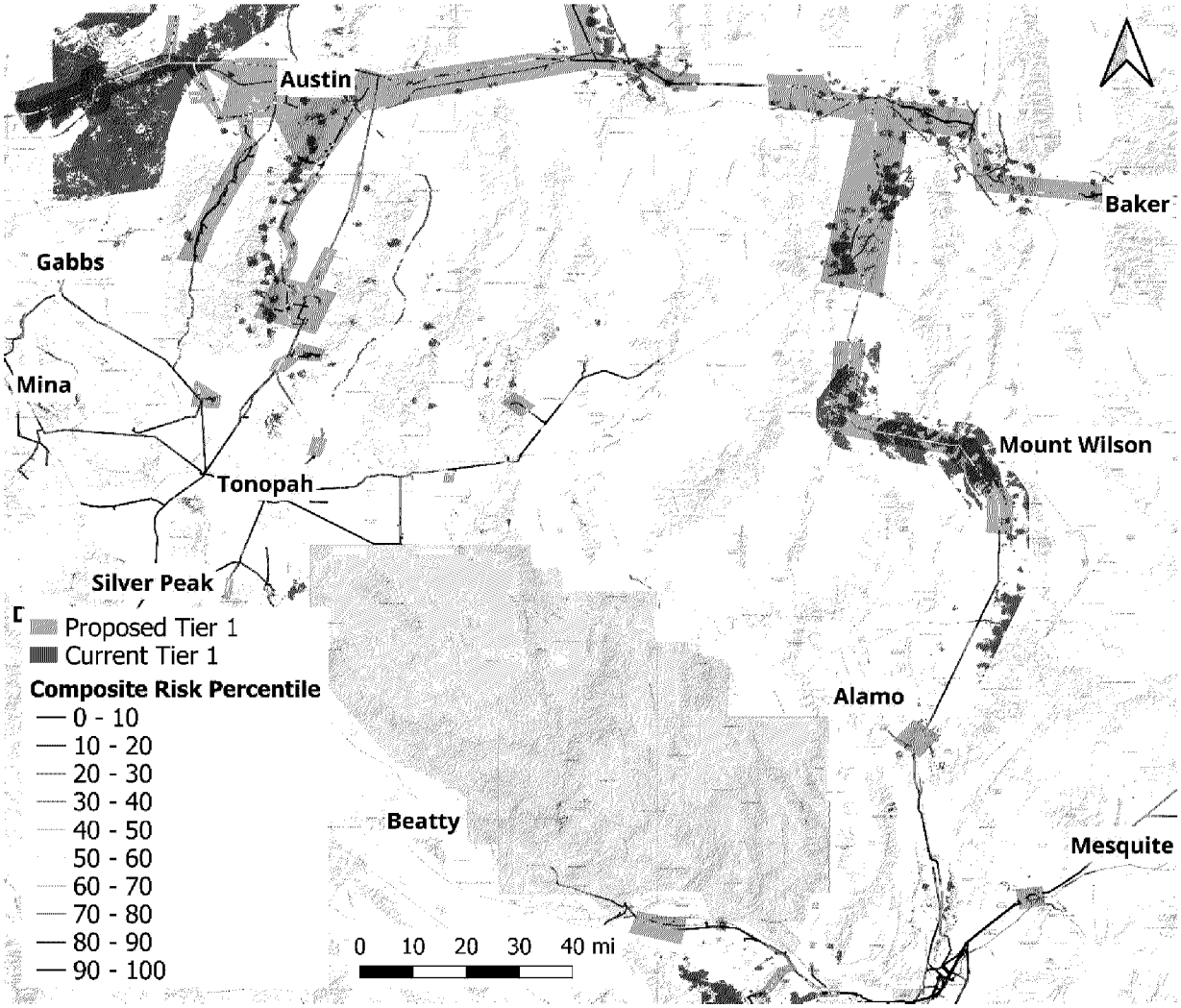


Figure 70. Proposed Tier 1 Refresh and Current Tier 1 in Central Nevada

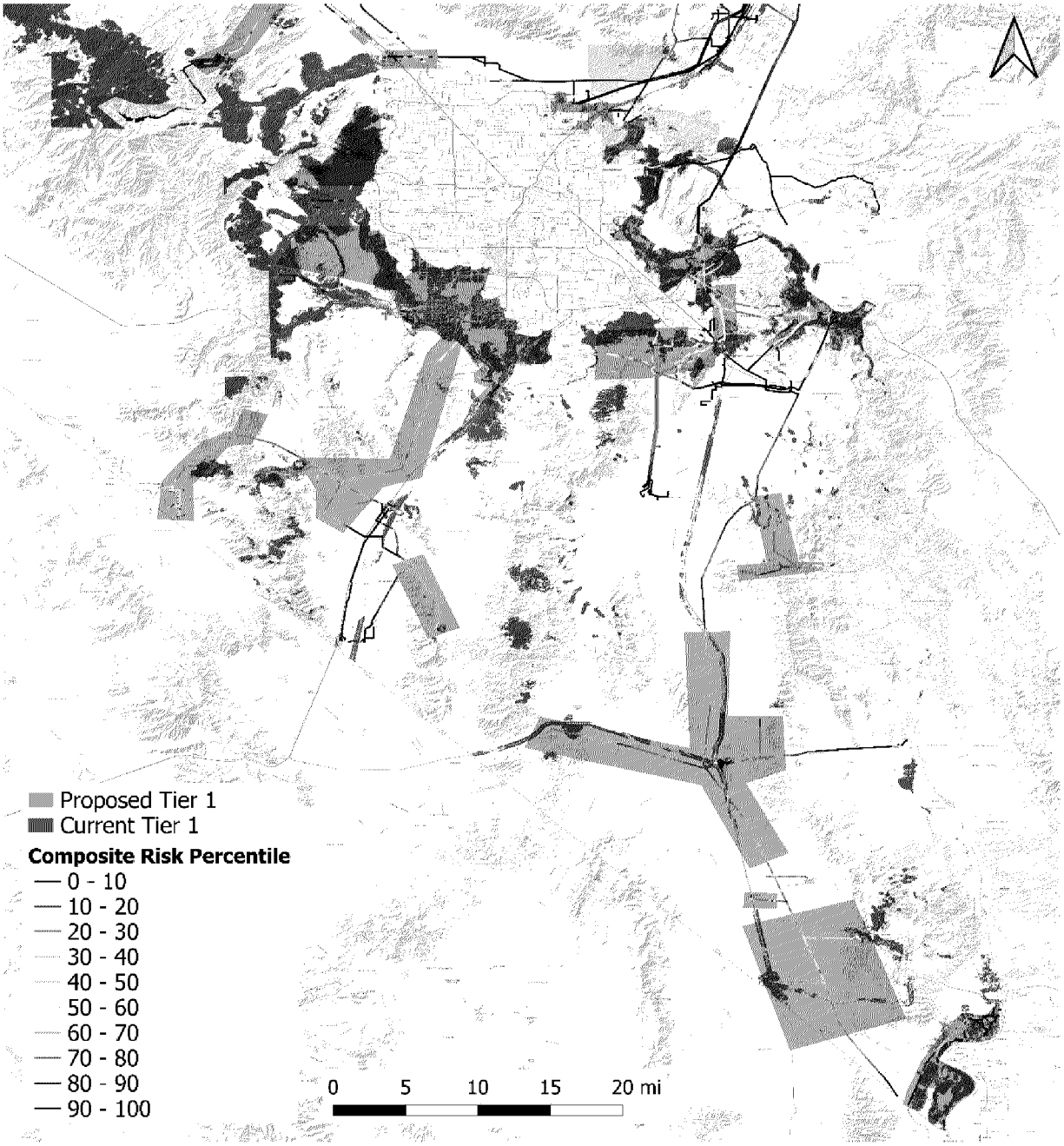


Figure 71. Proposed Tier 1 Refresh and Current Tier 1 in Southern Nevada

Analysis 8: Proposed Mapping Correction for Tier 1E and Tier 2

This document identifies mapping correction in several areas of Tier 1E and Tier 2. Although adjacent to Tier 1E or Tier 2 classifications, these areas are currently classified as non-Tier. However, they share similar wildfire risk and operational characteristics as their adjacent Tier classifications. Therefore, the mapping correction areas are more appropriately classified as Tier 1E or Tier 2 based on their adjacent Tier classification. The mapping correction areas, together with the current Tier areas and CloudFire's composite risk assessment are presented in **Figure 41** through **Figure 45**, which are organized as follows:

- Figure 41. Tier 2 Mapping Correction Near Elko
- Figure 42. Tier 1E Mapping Correction Near Sun Valley
- Figure 43. Tier 1E Mapping Correction Near Pyramid Lake
- Figure 44. Tier 1E Mapping Correction Near Carson City and Dayton
- Figure 45. Tier 1E mapping correction near Winnemucca

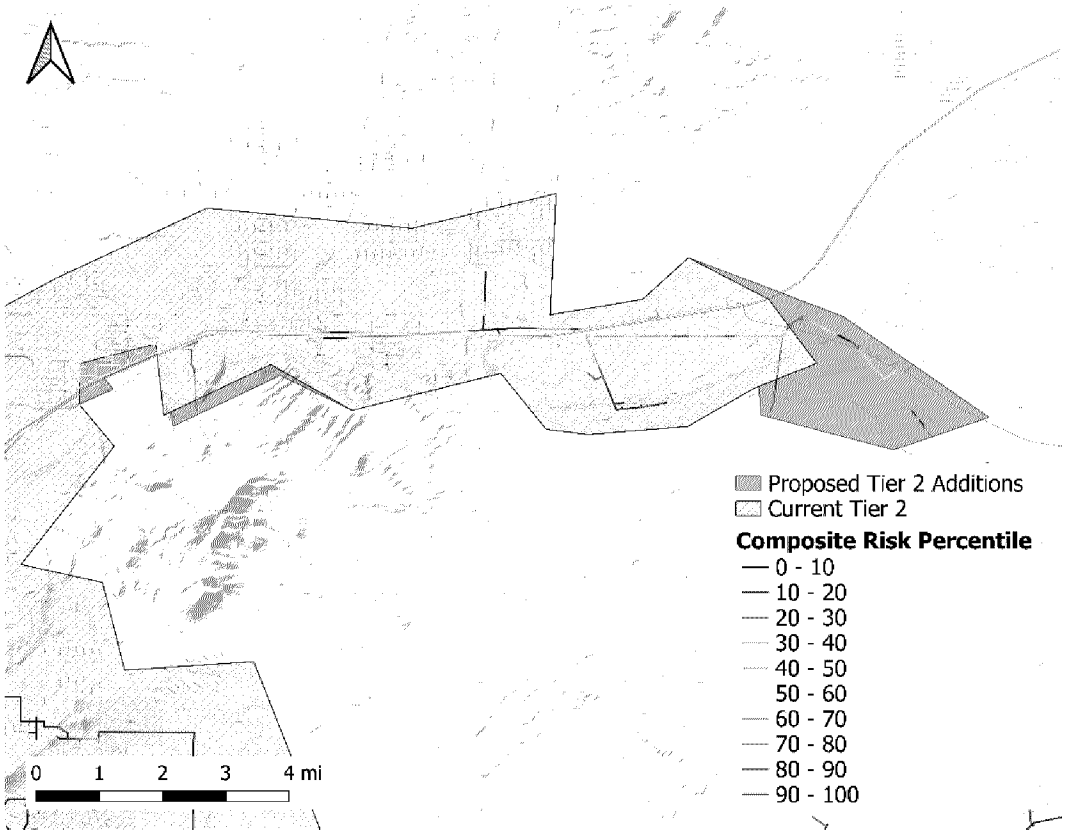


Figure 72. Tier 2 Mapping Correction Near Elko

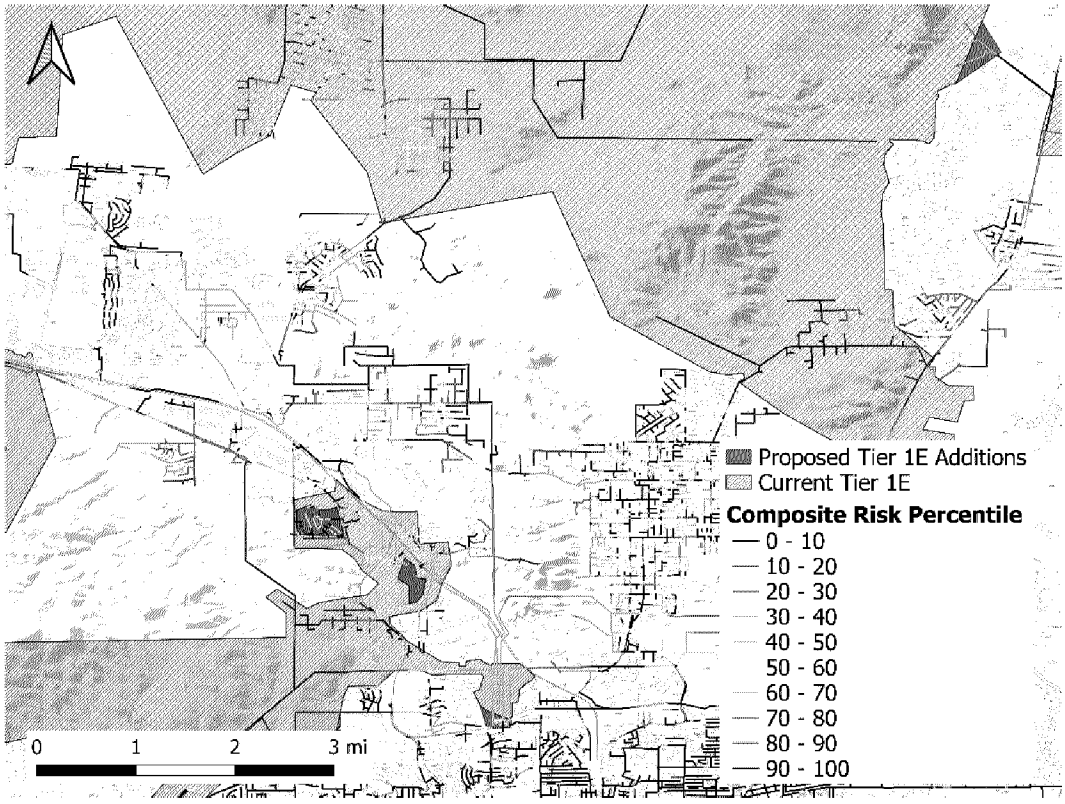


Figure 73. Tier 1E Mapping Correction Near Sun Valley

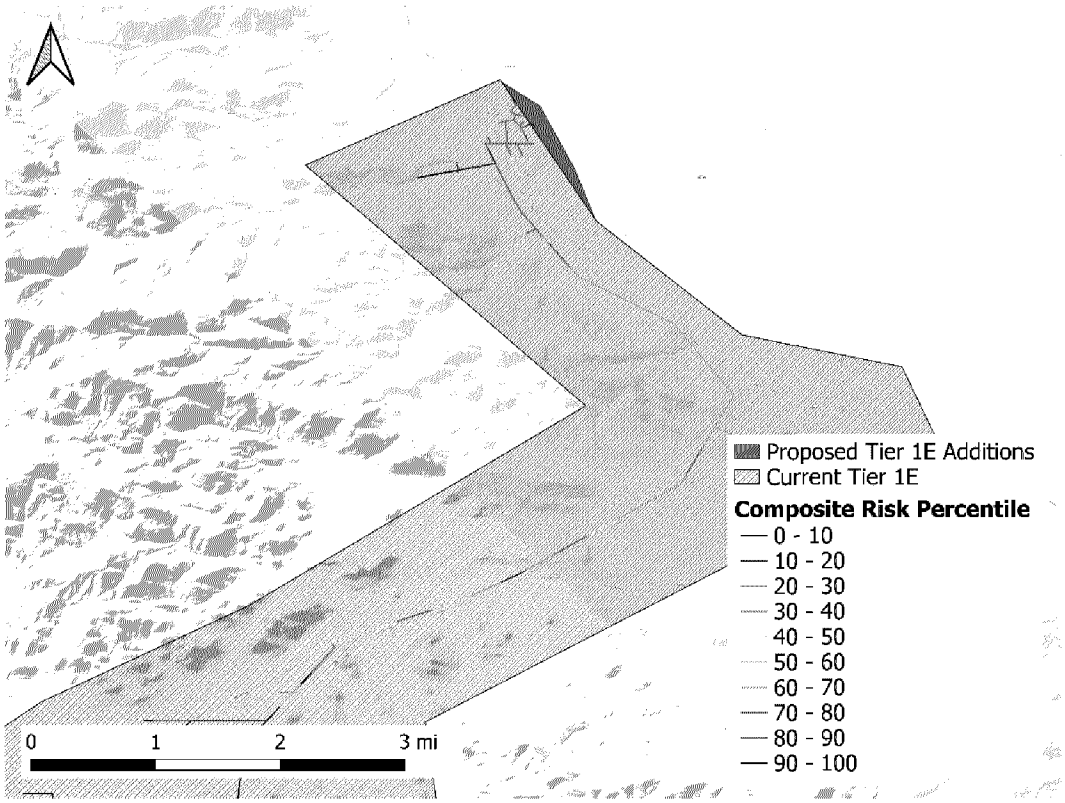


Figure 74. Tier 1E Mapping Correction Near Pyramid Lake

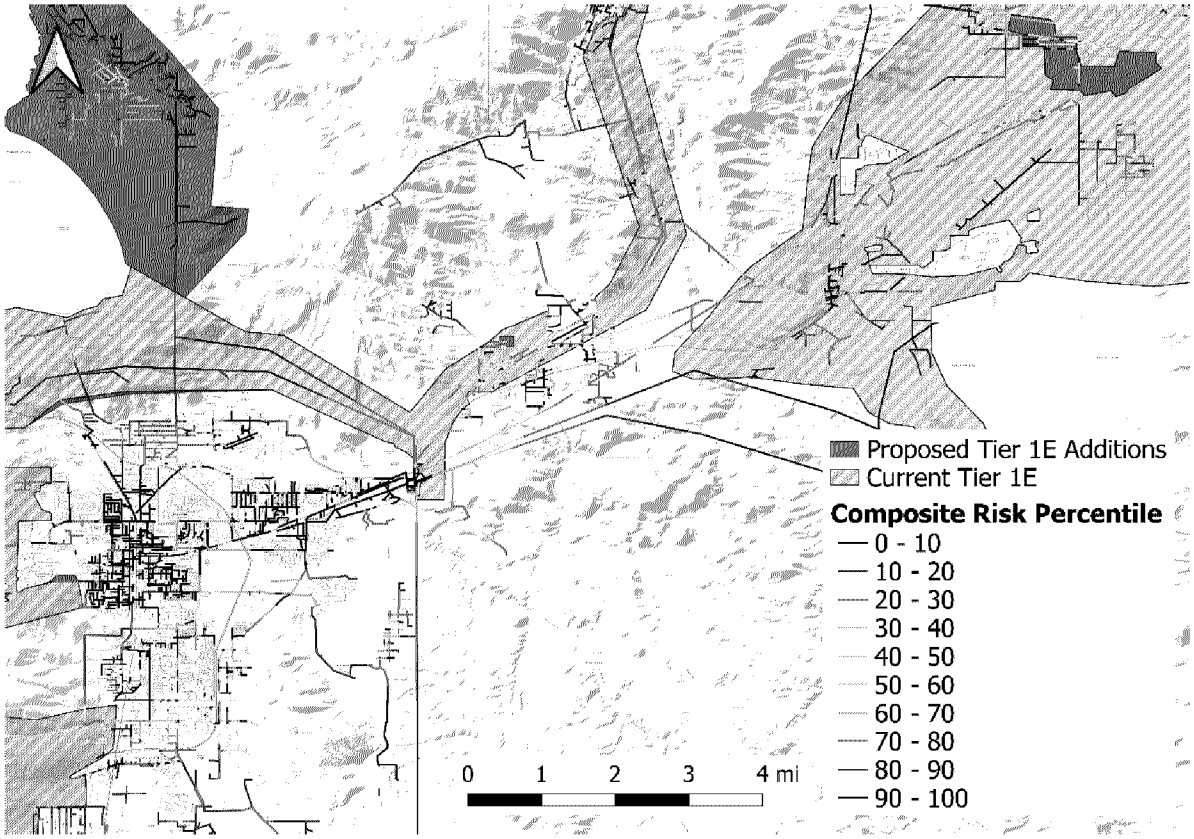


Figure 75. Tier 1E Mapping Correction Near Carson City and Dayton

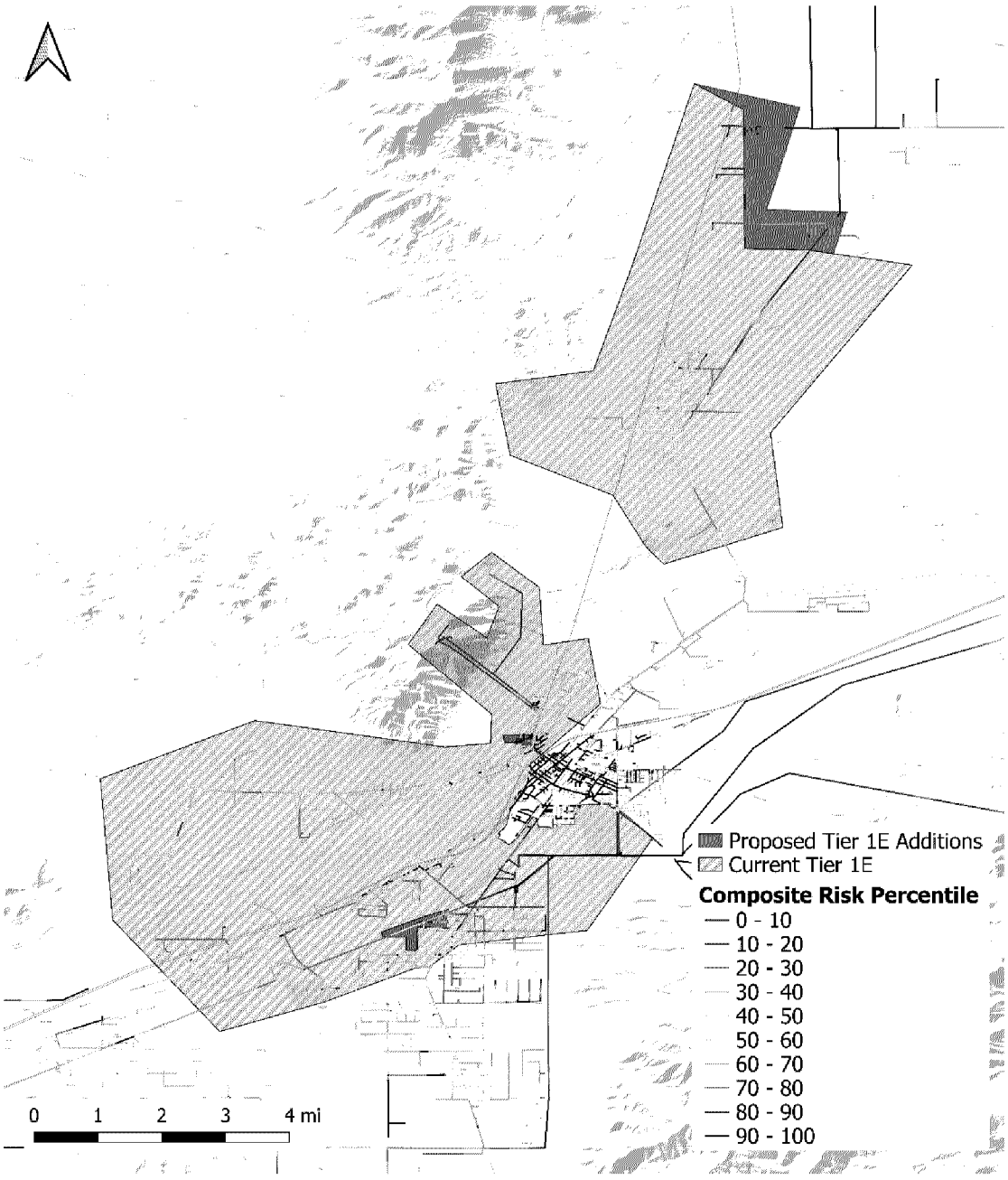


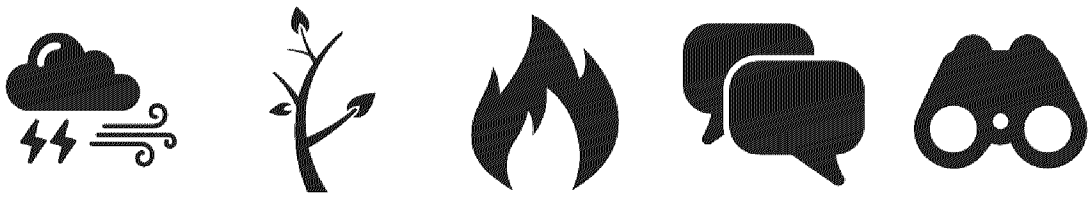
Figure 76. Tier 1E mapping correction near Winnemucca

APPENDIX C. PSOM PLAN

The Companies' 2026 PSOM Plan is presented in this Appendix.

NVEnergy®

PUBLIC SAFETY OUTAGE MANAGEMENT



Public Safety Outage Management ("PSOM") Plan

Date: February 2026

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PURPOSE:

The Companies (also "NV Energy") are committed to public safety and the risk of wildfires is a top priority. Public Safety Outage Management ("PSOM") is a proactive de-energization program that the Companies use to help protect communities from the risk of wildfires. During a PSOM, The Companies may shut off power when certain fire weather conditions exist to help prevent equipment or debris from starting or contributing to a wildfire. This document contains the minimum guidelines for proactive de-energization of facilities when the risk of keeping the system energized is greater than impact of de-energizing the grid.

Objective:

Communicate the criteria, processes, and methods the Companies use for PSOM. Coordinate the response and restoration of a PSOM to reduce the risk of energized facilities being involved in a public safety incident under extreme weather conditions.

Scope:

This plan is used by the Companies' Incident Management Teams ("IMT")[1] and leadership for implementing PSOM. Proactive de-energization may be used as a risk mitigation practice across the Companies' service territories.

FIRE SEASON PREPARATION

Incident Management Team

The Companies use an Incident Command System ("ICS"),[2] a standardized approach for responding to incidents, established by the Federal Emergency Management Agency ("FEMA"). This affords the ability to use a standardized scalable approach and common terminology for PSOM. PSOM events are managed and coordinated through NVE's IMT. The IMT is also responsible for developing an Incident Action Plan ("IAP") document that lists objectives and resources necessary to implement PSOM events.

Preparing for Fire Season Mode

Every year, prior to Fire Season, circuits at risk will be identified for special operational settings under fire weather conditions. Identified circuits will be placed into Fire Season Mode, which means there will be no automatic circuit reclosing, resulting in a single fault locking out the circuit. This reduces the likelihood that sparks could result from re-energizing the line should field conditions causing the fault to remain. Certain circuits may also be set to Fast Trip Fire Mode ("FTFM"), where trip sensitivity will be higher during certain wildfire risk conditions.

Communications Infrastructure Providers Informed of Proactive De-energization Zones

Annually and prior to Fire Season, telecommunication companies that could be impacted by PSOM will be provided with shapefile maps of each Proactive De-energization Zone ("PDZ") by the Companies.

Entering Fire Season Mode

The Companies monitor and identify conditions to enter Fire Season Mode. Factors considered include fuel moisture conditions, Severe Fire Danger Index ("SFDI"), and the Energy Release Component percentile.[3]

Microgrid Deployment at Angel Peak

During a PSOM event that impacts the Angel Peak PDZ but not the Kyle Canyon PDZ there may be an opportunity to deploy a microgrid to keep the Kyle Canyon circuit energized. The microgrid is activated by powering the Kyle Canyon Substation using special-purpose generators. The microgrid operation requires coordination between the Companies' Lines Operations, Substations, System Control, and the generator company to set up and maintain the generators for the duration of an event. The Angel Peak PDZ microgrid can be activated prior to de-energization or after a PSOM.

PSOM PROCEDURES

PSOM procedures are implemented according to the level of risk that has been determined through advanced analytics and modeling. Unique criteria apply for Tier 3 "Extreme Risk," Tier 2 "Severe Risk," and for the balance

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[1] Per the Companies' Corporate Emergency Response Plan

[2] https://training.fema.gov/emi.aspx

[3] Per the Companies' Wildfire Season Operations Plan

of the Companies' service territory that includes Tier 1 Elevated ("1E") and Tier 1. The Composite Risk Index ("CRI") has been developed as a decisional guideline to mitigate wildfire risk using proactive de-energization based on a variety of factors.

Tier 3 Extreme Risk Procedures

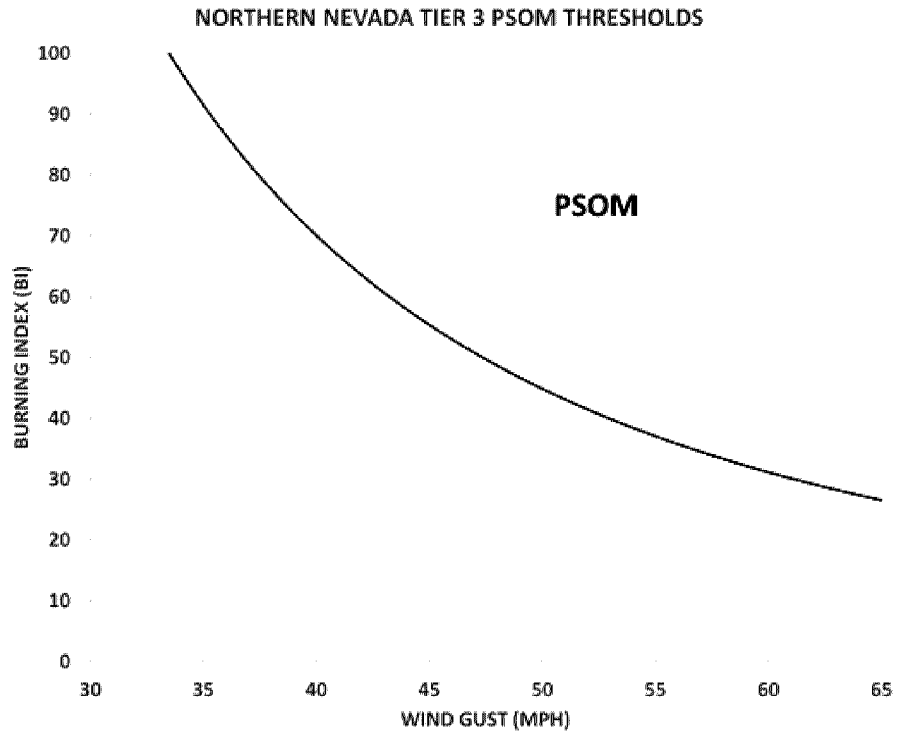
This section outlines criteria and procedures for Extreme Risk Tier 3.

Tier 3 Thresholds

Table 1. Tier 3 De-Energization Thresholds[4]

Region	**Burning Index ("BI")[5]**	**Wind Gust ("V_g")**	**Composite Risk Index ("CRI")[6] ($0.00256 \times V_g^2 \times$ BI)**
North PDZs (Greater Lake Tahoe)	> 70	> 40 mph (60 mph max) [7]	> 287
South PDZs (Angel Peak and Kyle Canyon)	> 70	> 45 mph (60 mph max)[8]	> 363

Figure 77. Northern Nevada Tier 3 PSOM Thresholds



[4] Thresholds and guidelines were determined by analysis from fire risk models. The results of these models are included with the Natural Disaster Protection Plan filings and are refreshed periodically.

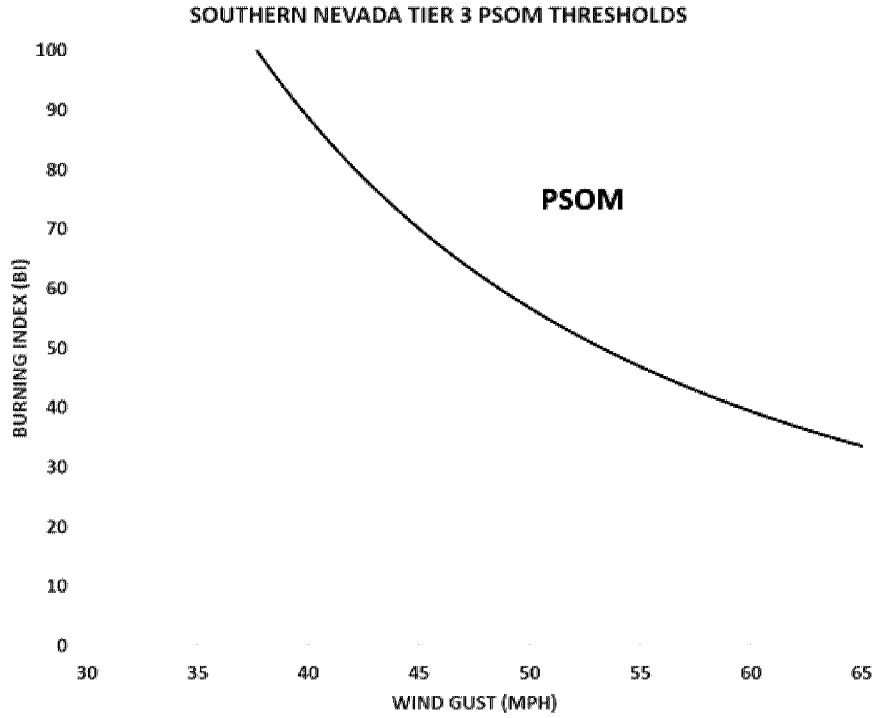
[5] Burning Index ("BI"): A value that is determined from the moisture content of a forest, wind speed, and other factors that affect burning conditions and from which ease of ignition and behavior of a forest fire may be estimated.

[6] Composite Risk Index ("CRI"): The CRI is wind gust force (in units of psf) multiplied by the BI, which is expressed mathematically as ($0.00256 \times V^2_g \times BI$).

[7] PSOM criteria, wind gusts greater than 60 mph with Red Flag Warning issued by National Weather Service.

[8] PSOM criteria, wind gusts greater than 60 mph with Red Flag Warning issued by National Weather Service.

Figure 78. Southern Nevada Tier 3 PSOM Thresholds



Tier 3 Mitigation Measures

This section describes mitigation measures that are taken in accordance with the CRI.

Table 2. Hierarchy of Mitigation Measures Considered for the Deployment Based on CRI De-Energization Thresholds

Trigger as Percent of CRI De-energization Threshold	Fire Mitigation Measures
90% and/or National Weather Service issues Fire Watch	Consider conducting patrols and perform corrections
95% and/or National Weather Service issues Red Flag Warning	Consider conducting patrols and perform corrections and pre-stage fire resources
Forecast to exceed or exceeds the Composite Risk Index	Proactive de-energization

Tier 2 Severe Risk Procedures

This section outlines criteria and procedures for Severe Risk Tier 2.

Tier 2 Thresholds

Tier 2 has prescriptive thresholds but considers a wide variety of factors such as:

- Weather Conditions;
  - National Weather Service Red Flag Warnings;
  - Available public weather data from existing Remote Automated Weather Stations ("RAWS");
- Field observations and vegetation conditions;
- Information from Expert Working Group ("EWG") members;[9] and

[9] Expert Working Group members include those defined by LCB File R181 – 24 and enabling regulation in Docket No. 19-06009.

- Wildfire activity and location of any existing fires affecting state resource availability.

Table 3. Tier 2 De-Energization Guidelines

Risk Tier	BI	Wind Gust (mph)	CRI
Tier 2	> 70	> 60 mph	> 645

Tier 2 Mitigation Measures

Table 4. Hierarchy of Mitigation Measures Considered for Deployment Based on CRI De-Energization Thresholds

Trigger as Percent of CRI De-energization Threshold	Fire Mitigation Measures
95% and/or National Weather Service issues Red Flag Warning	Consider conducting patrols and perform corrections and pre-stage fire resources
Forecasted to exceed or exceeds the Composite Risk Index	Proactive de-energization

Balance of Service Territory Procedures

This section outlines criteria and procedures for the balance of the Companies' service territory, including Tier 1E and Tier 1.

Balance of Service Territory Thresholds

The balance of the service territory has prescriptive thresholds but considers a wide variety of factors such as:

- Weather Conditions;
  - National Weather Service Red Flag Warnings;
  - Available public weather data from existing Remote Automated Weather Stations ("RAWS");
- Field observations and vegetation conditions;
- Information from EWG members; and
- Wildfire activity and location of any existing fires affecting state resource availability.

Table 5. Balance of Service Territory De-Energization Guidelines

Risk Tier	BI	Wind Gust (mph)	CRI
Balance of Territory including Tier 1E, Tier 1, and all wildland areas	> 70	> 70 mph	> 878

Balance of Service Territory Mitigation Measures

Table 6. Hierarchy of Mitigation Measures Based on CRI De-Energization Thresholds

Trigger as Percent of CRI De-energization Threshold	Fire Mitigation Measures
95% and/or National Weather Service issues Red Flag Warning	Consider conducting patrols and perform corrections and pre-stage fire resources
Forecasted to exceed or exceeds the Composite Risk Index	Proactive de-energization

DEFINITIONS

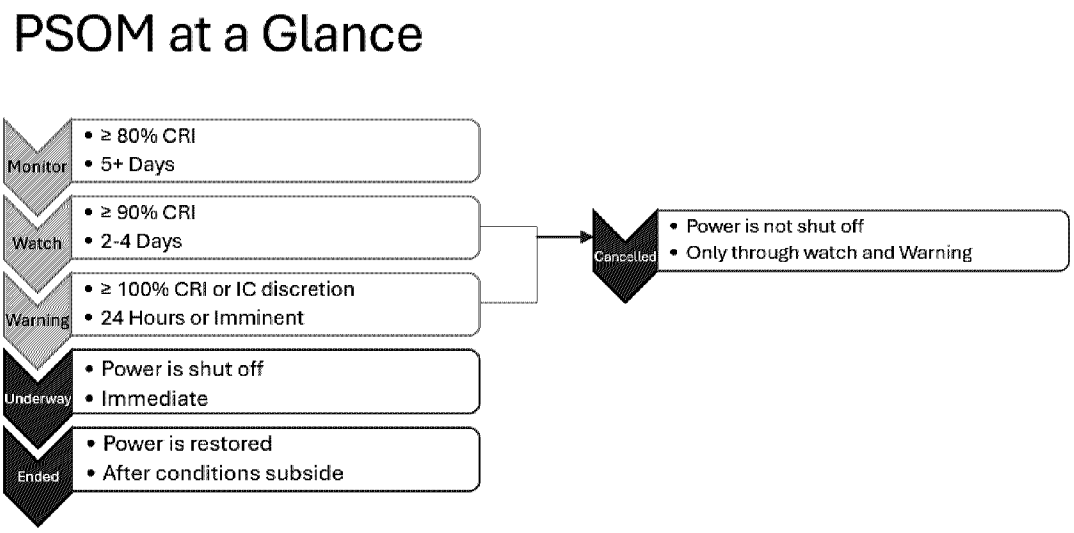
- ***Burning Index ("BI")***
- Burning Index is a value determined from the moisture content of vegetative fuels, wind speed, and other factors that affect burning conditions and the contribution of fire behavior to the effort of containing a fire. The BI "difficulty of controlling the fire" is derived from a combination of Spread Component - how rapidly a fire will spread - and the Energy Release Component - how much energy will be produced.

Composite Risk Index ("CRI")
The CRI is wind gust force (in units of psf) multiplied by the BI, which is expressed mathematically as $(0.00256 \times V_g^2 \times \mathbf{BI})$[10]

PSOM STAGES

This section describes the PSOM Stages.

Figure 79. PSOM Stages



MonitorThis stage is for internal notification only. When weather forecasts permit, approximately 5 days if the CRI is 80% or above, enter this stage, and begin preliminary communications within the company
- If at 2 to 3 days the CRI is below 90%, remain at this stage.

Watch When weather forecasts permit, at 2 to 3 days if the CRI is above 90%, enter this stage, and begin external notifications of NVE customers and external stakeholders which is reflected in the PSOM Communication Plan and Utility to Utility Communication Plan
- If within 24 hours of de-energization the CRI is less than 100%, the Incident Commander ("IC") will decide on whether to move into Warning or stay in Watch. If there is a high confidence the event will occur the IC should move to Warning to allow for adequate messaging

Warning When the weather forecast permits, at 24 hours if the CRI is above 100%, or with IC discretion, enter the Warning stage and begin external notifications of customers and external stakeholders

Canceled Should conditions subside, a PSOM may be canceled by the Companies' Incident Commander at any time prior to de-energization

Underway Immediate if the CRI is above 100%, upon direction of the Incident Commander, begin de-energization of at-risk circuits

Ended When the CRI is below 80%, re-energize circuits as safe conditions are met

[10] CRI weather forecasting is located at https://nvfireweather.com/forecast/