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**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 their Joint Natural  
Disaster Protection Plan.

Docket No. 23-03 \_\_\_\_

**VOLUME 2 OF 2**

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

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<b>TESTIMONY</b>	
Jesse Murray	93
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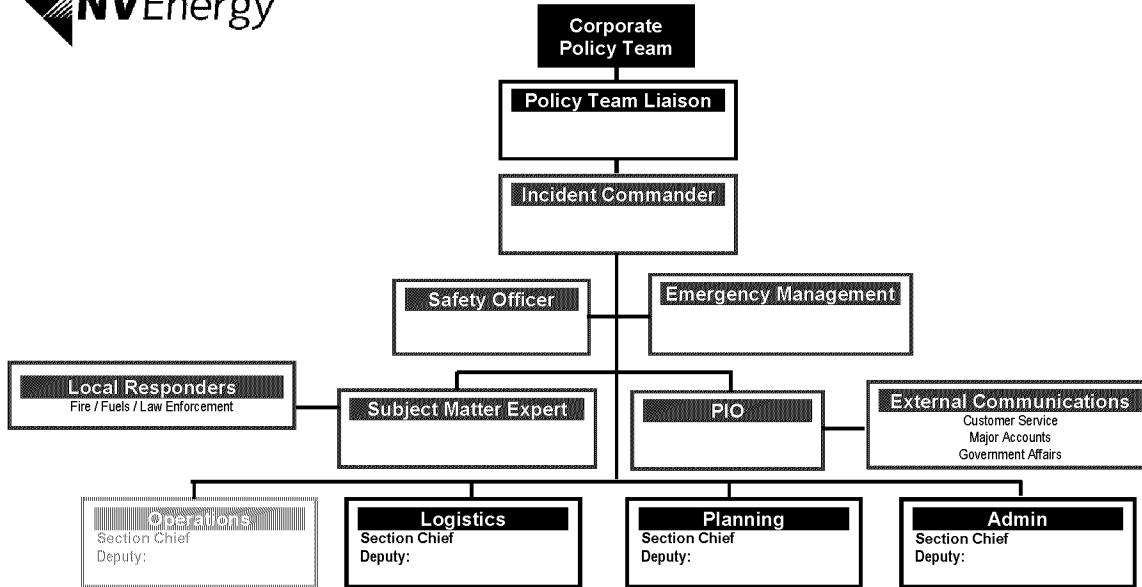
**EXHIBIT B**  
**THE PLAN PT. 2**

# APPENDIX C. PSOM PLAN

NV Energy's PSOM Plan is presented in this Appendix.



## NV Energy's Incident Command Structure





# PUBLIC SAFETY OUTAGE MANAGEMENT



Public Safety Outage Management  
(PSOM) Plan

Date: 2023

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**Purpose:**

This is intended to provide the **minimum** guidelines for a Public Safety Outage Management (PSOM) of energized facilities when the proactive de-energization criteria are met. A planned de-energization is a last resort measure to reduce public safety risk.

**Objective:**

Coordinate the response and restoration of a Public Safety Outage Management (PSOM) event to reduce any risk of energized facilities being involved in a public safety incident under extreme conditions.

**Scope:**

This plan is used by NVE incident management teams for the execution of PSOM events

**PRE-FIRE SEASON AND MICROGRID**

**Fire Season Mode**

Prior to fire season, identified circuits will be placed in to fire season mode with no circuit reclosing (one trip to lockout). The details of this are located in the Electric System Control Center NVE-DIS-005 Fire Season Operating Procedure.

**Communications**

Prior to fire season, Major Accounts will provide communications infrastructure providers (telecommunication companies affected by PSOM) with shapefile maps of each proactive de-energization zone.

**Microgrid**

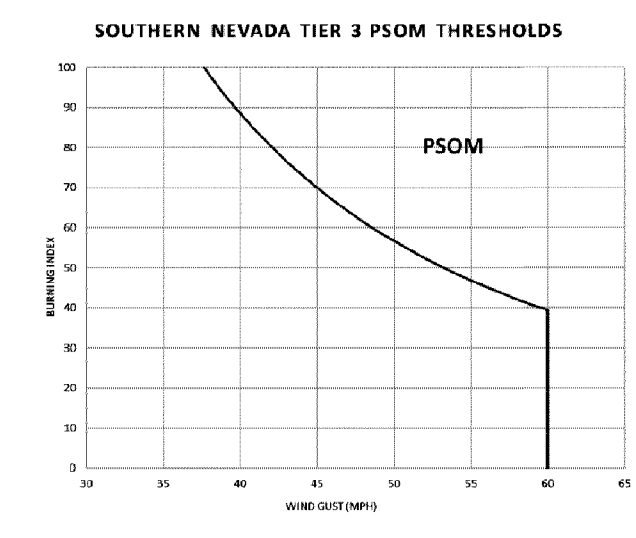
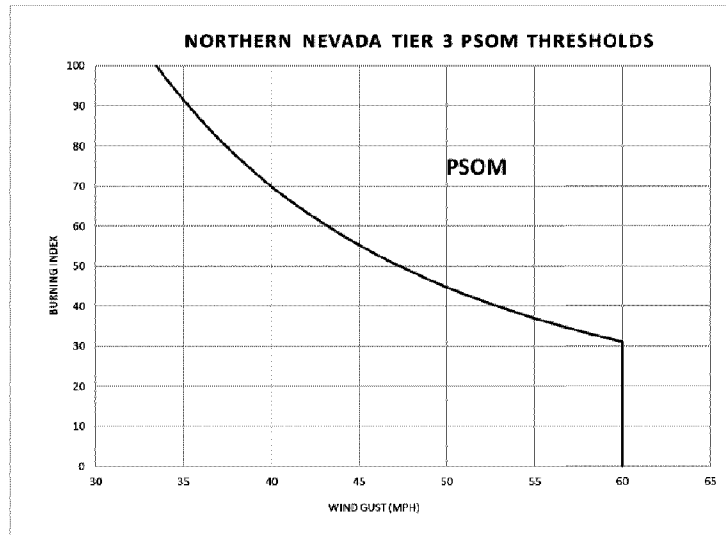
During a PSOM event that impacts Angel Peak PDZ but not Mt. Charleston PDZ there is an opportunity to deploy a microgrid to keep the Kyle Canyon circuit energized by powering the Kyle Canyon Substation via multiple generators. The microgrid operation requires coordination between NV Energy Lines Operations, Substations, System Control, and the generator company to set-up and maintain generators through duration of event. The microgrid deployment can occur prior to Angel Peak PDZ de-energization or following a de-energization event.

**PUBLIC SAFETY OUTAGE MANAGEMENT (PSOM)**

**Tier 3 Thresholds**

*Table 1. Tier 3 de-energization thresholds\**

Region	BI	Wind gust	Composite risk index ( $0.00256 \times V_g^2 \times B$ )
North PDZs (Greater Lake Tahoe)	> 70	> 40 mph (60 mph max)	> 287
South PDZs (Angel Peak and Mount Charleston)	> 70	> 45 mph (60 mph max)	> 363



**Tier 3 Mitigation Measures**

Table 2. Hierarchy of mitigation measures considered for the deployment based on composite risk index de-energization threshold.

Trigger as percent of composite risk index de-energization threshold	Fire mitigation measures
90% and/or National Weather Service issues Fire Watch	Conduct patrols and perform corrections
95% and/or National Weather Service issues Red Flag Warning	Conduct patrols and perform corrections and pre-stage fire resources
Exceed Composite Risk Index	Proactive de-energization

**Tier 2 and 1E Considerations**

No prescriptive thresholds but considers a wide variety of factors such as:

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

*Table 3. Tier 2 and Tier 1 elevated de-energization guidelines\**

Risk Tier	BI	Wind gust (mph)	Composite risk index
Tier 2	> 70	> 60 mph	> 645
Tier 1 Elevated	> 70	> 70 mph	> 878

**Tier 2 and 1E Mitigation Measures**

*Table 4. Hierarchy of mitigation measures considered for the deployment based on composite risk index de-energization threshold.*

Trigger as percent of composite risk index de-energization threshold	Fire mitigation measures
95% and/or National Weather Service issues Red Flag Warning	Conduct patrols and perform corrections and pre-stage fire resources
Exceed Composite Risk Index	Proactive de-energization

**Criteria Definitions\***

**Composite Risk Index**

The composite risk index is wind gust force (in units of psf) multiplied by BI, which is expressed mathematically as  $(0.00256 \times V_g^2 \times B)$


**Burning index**

A number which 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

*\*Thresholds and guidelines were determined by analysis from Reax Engineering and additional factors of safety as outlined in the NDPP first amendment filing.*

**PSOM STATUS TERMINOLOGY**

**Monitor** – This level is for internal notification only. At around 5 days if the CRI is 80% or above, enter this level and begin preliminary communications within the company and notifications of external first responders, other utility companies, and telecommunication companies.  
 - If at 2 to 3 days the CRI is below 90%, remain at this level.

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**Watch** – At 2 to 3 days if the CRI is above 90%, enter this level and begin external notifications of our customers and other stakeholders which is reflected in our media plan  
- If within 24 hours of de-energization the CRI is less than 100%, remain at this level

**Warning** – At 24 hours if the CRI is above 100%, enter the warning level and begin external notifications of our customers and other stakeholders which is reflected in our media plan

**MONITORING, NOTIFICATION, AND ACTIVATION TIMELINE – DAYS FROM EVENT**

**6-8 Days**

Key personnel in the NDP program monitor weather conditions from weather service provider throughout the fire season.

***Condition***

If Composite Risk Index (CRI) reaches the following criteria:

- Tier 3 > = 80% threshold
- Tier 2/1E > = 80% considerations
  - See criteria in section above

***Actions to take***

1. Notification to Incident Management Team (IMT)
  - IMT to consider resource availability (communications, contract fire resources, crews, etc.)
    - Incident Commander will request the Planning Section Chief to implement daily weather conditions monitoring
    - Provide daily weather reports to Emergency Response Organization (ERO) via email and/or Teams
    - PIO to ensure external notifications go to Communication Infrastructure Providers (CIP)

**4-5 Days (Monitor – Internal ONLY) –**

***Condition***

If Composite Risk Index (CRI) reaches the following criteria:

- Tier 3 > = 80% threshold
- Tier 2/1E > = 80% considerations
  - See criteria in section above
  - Enter **Monitor**



**Actions to take**

1. Notification and daily meetings scheduled with Incident Management Team
  - IMT to consider resource availability (communications, contract fire resources, crews, etc.)
    - Incident Commander will request the Planning Section Chief to implement daily weather conditions monitoring
    - Provide daily weather reports to Emergency Response Organization via email/Teams

**Condition**

If Composite Risk Index (CRI) reaches the following criteria:

- Tier 3  $\geq$  90% threshold
- Tier 2/1E  $\geq$  90% considerations
  - See criteria in section above

**Actions to take**

1. Notification and daily meetings scheduled with Incident Management Team
  - IMT to consider resource availability (communications, contract fire resources, crews, etc.)
    - Incident Commander will request the Planning Section Chief to implement daily weather conditions monitoring
    - Provide daily weather reports to Emergency Response Organization via email/Teams
    - Section chiefs will begin building and communicating with their sections as needed for the possible response.
  - Incident Management Team Goals/ Tasks
    - Activate and fill staff as necessary
    - Open the EOC
    - Notify external stakeholder and customers
      - Crisis Management Team (CMT) –
        - Notify external stakeholders about the possibility of the event
          - PIO – Follow media plan for PSOM event
            - Major Accounts rep will begin notifying critical facilities and telecommunications customers
          - Fire Liaison – Availability of fire resources
          - Emergency Management - A liaison will be established with Liberty, Plumas Sierra, and Truckee Donner Public Utility District (TDPUD) and the attached (Appendix B) communication timeline/ process will be followed
        - Planning – Schedule meetings, begin IAP creation
          - Create Situation Report (sitREP) and update daily
        - Admin – Create charge code for event
          - Follow Customer Resource Center Plan
          - Create area for event documentation to be stored
        - Logistics – Prepare for generators, Communication on Wheels (COW), and Customer Resource Center (CRC) deployment

- Identify staging areas for crews – internal, external, and equipment
- Operations – prepare for generator deployment, as necessary
  - Discuss mutual assistance needs and initiate Western Region Mutual Assistance Group. (WRMAG), Berkshire Hathaway Energy (BHE), non-impacted NVE territory, or contract crew. If needed, emergency management will coordinate conference calls/evaluations
  - Begin requesting switching orders and putting Playbooks together

**2-3 Days (Monitor or Watch) – Condition**

- If CRI is below 90% - refer to mitigation efforts based off CRI threshold in previous section and consider and if needed begin planning for those.
- Remain in **Monitor**

If Composite Risk Index (CRI) reaches the following criteria:

- Tier 3  $\geq$  90% threshold
- Tier 2/1E  $\geq$  90% considerations
  - See criteria in section above
  - Move to **Watch**

**Actions to take**

1. Notification and daily meetings scheduled with Incident Management Team
  - IMT to consider resource availability (communications, contract fire resources, crews, etc.)
    - Incident Commander will request the Planning Section Chief to implement daily weather conditions monitoring
    - Provide daily weather reports to Emergency Response Organization via email/Teams
  - Incident Management Team Goals/ Tasks
    - *Verify actions from 4-5 day timeline have been completed*
    - Schedule ERO Calls – Set schedule
    - Update Policy Team
    - Begin Mutual Assistance coordination, as necessary
      - Crisis Management Team (CMT) –
        - Notify external stakeholders about the possibility of the event
          - PIO – Follow media plan for PSOM event
            - Increase needed resources to notify customers at the 72- and 48-hour mark
            - Customer Care will make calls to critical facilities, medium sized customers, and Green Cross Customers
            - Provide notification to CIP



- Fire Liaison – Verify availability of fire resources and begin handing out radios and weather stations to field crews.
- Emergency Management - A liaison will be established with Liberty, Plumas Sierra, and Truckee Donner Public Utility District (TDPUD) and the attached (Appendix B) communication timeline/ process will be followed
  - Communicate with local emergency managers (emails, phone calls, texts, and/or WebEOC)
  - Planning – Continue IAP and sitREP update and meeting schedule
  - Admin – Continue current tasks
  - Logistics – Schedule generators, COW, and CRC deployment
  - Operations – Prepare for generator deployment, as necessary
    - Review Playbooks and switching orders

**Within 24 hours to De-energization (Watch or Warning Phase) –**

***Condition***

- If CRI is below 90% - Consider executing mitigation efforts (patrols, corrections, and fire resources)

***Condition***

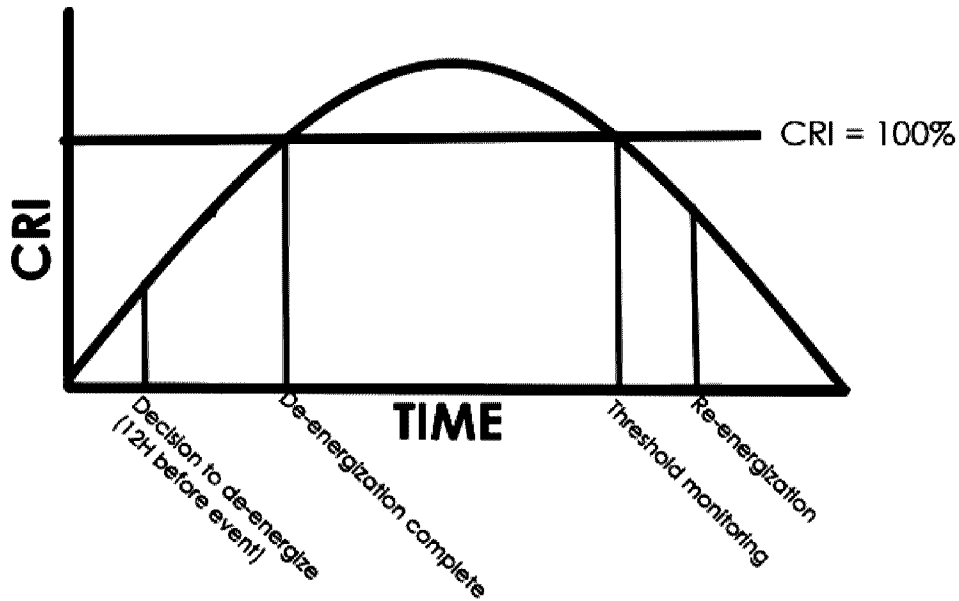
If Composite Risk Index (CRI) reaches the following criteria:

- Tier 3 = 90% - 100% threshold
- Tier 2/1E = 90% - 100% considerations
  - Execute mitigation efforts
  - Remain in **Watch**

***Condition***

If Composite Risk Index (CRI) reaches the following criteria:

- Tier 3 > = 100% threshold
- Tier 2/1E > = 100% considerations
  - De-Energize PDZ(s)
  - Move to **Warning**



*\*\*Graph depicts decision and monitoring timeline for a PSOM event within 24 hours*

**Actions to take**

- Incident Management Team Goals/ Tasks
  - Determine time of exceedance (CRI)
  - Decision to de-energize should be established within 12 hours of the threshold exceedance
    - Considerations: Wind speeds (forecasted and actual), fuel moistures, relative humidity, time to de-energize, and resources
  - Event summary with backup information will be given to the Policy Team Liaison to share with the Policy Team, this summary will include analytics from REAX and/or the NVE Meteorologist, and the PSOM Scorecard(s)
  - Continue threshold monitoring
  - Determine time of re-energization and communicate
  - Based on circuits/PDZ(s) actual conditions and meeting thresholds, determine areas requiring full patrolling and communicate to Operations.
    - Crisis Management Team – Continue tasks
    - Planning – IAP completed and shared
      - Creation and completion of the PSOM scorecard for each affected transmission line and/or PDZ(s)
    - Admin – Continue tasks
    - Logistics – Continue tasks

- Operations – Plan for de-energization
  - Share IAP with crews
  - Review playbooks
  - Stage resources
  - Verify switching orders

**Patrolling – Restoration –**

***Actions to take***

- Incident Management Team Goals/ Tasks
  - The CRC, operations, and EOC will remain in constant contact during this time
  - The EOC will de-activate once all customers have been restored to power, crews are demobilized, and the CRC is shut down
    - Operations –
      - Conduct patrols on all Tier 3 de-energized circuits meeting threshold
        - Consider patrols on Tier 2/1E circuits as necessary
      - Internal and external resources will check in and check out with the Incident Command Post (ICP)
      - Share status of PDZ restoration with EOC via Section Chief

**+ 24 hours**

***Actions to take***

- Legal submits a copy of the final external stakeholder notification form to PUCN which gets shared to internal and external stakeholders at the time of complete restoration of customers.
- Incident Commander will send request to ERO to submit needed documentation to complete report for PUCN

**+ 14 days**

***Actions to take***

- Emergency Management completes After Action Report for the event for fully executed PSOM events

**30 days**

***Actions to take***

- Incident Commander or designee will prepare a full report and submit to Legal to review and submit to PUCN.

**DE-ENERGIZATION COMMUNICATION PLAN**

After time to de-energize is established:

1. Share PDZ(s) affected and timeframes with IMT to be shared with their personnel
2. IMT will be advised of the de-energization and communications and updates will be distributed as outlines in the communication timeline/ media plan.

3. IC will request a confirmation of orders from the following groups over the Command radio channel which will be outlined in the Incident Action Plan (IAP).
  - a. Operations Section Chief
    - i. System Control Lead
    - ii. Lines Department Lead(s)
  - b. Fire Mitigation Liaison

### **RE-ENERGIZATION COMMUNICATION PLAN**

After CRI is below threshold

1. Incident Commander (IC) will put an announcement over the Command radio channel authorizing start of re-energization process. IC will request a confirmation of orders from the following groups:
 

*\*\* Command channel will be identified in the IAP*


  - a. Operations Section Chief
    - i. System Control Lead
    - ii. Impacted Lines Department Lead(s)
  - b. Fire Mitigation Liaison
2. IMT will be advised of the de-energization and communications and updates will be distributed as outlines in the communication timeline.
3. Status of the line restoration will be input by the Operations Section, but it will be tracked and shared by the Planning Section in the Situation Report
  - a. Tracking form will be updated every 30min - 1hr
4. Operations Section Chief will put an announcement over the Command radio channel informing that the lines in impacted PDZ have all been re-energized and all customers should be back in power.
5. IMT will be advised of the re-energization and communications and updates will be distributed as outlines in the communication timeline/ media plan.

### **DEMOBILIZATION**

When the event has slowed, more customers power has been restored, and the need for extensive coordination has decrease the Incident Commander can scale the response to meet the needs of the event.

Demobilization of resources will be decided at the operational level. The Operations team will notify the planning section when any resource has been activated or de-activated, so it can be tracked on the ICS form and IAP.

All these efforts will be documented and tracked in the IAP completed by the Planning Section.

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## **DOCUMENTATION REQUIREMENTS**

The following information needs to be documented and tracked for reporting and compliance purposes:

1. Forecast information before and during the event
2. Notes from meetings that determined if it was a go/no go
3. The notification that was provided to telecommunication/Greencross customers
4. Number of customers involved
5. Time for reenergization – any issues that occurred (if we have any information on any debris in the lines that will be helpful)
6. Information on CRCS – how many people used them (if we have it)
7. Information on the public safety/partner engagement
8. What infrastructure we used/brought to the site – and cost (if that’s available)
9. Our overall budget/cost for the PSOM
10. Lessons learned or issues we encountered.

## **CONTACTS**

Verizon Crisis Response Team  
1(800) 981-9558 24/7 Line

Verizon Area Manager  
1(415) 385-6015 mobile  
1(925) 279-6119 office

AT&T/First Net Emergency Number - 1(800) 574-7000

NV Energy FirstNet Specialist Local Contact 1(858) 200-5496

**APPENDIX A: INCIDENT COMMAND POST (ICP) AND STAGING AREA LOCATIONS**

- Pre-Planning Meeting area (24 hours before event and can accommodate 50-70 people)
  - Incline FPD Fuels Building- 71 Carry Way Mound House, NV 89706
  - Carson office for smaller events
  - Ohm for Reno area
  - Elko Office for Elko
  - Winnemucca Office for Winnemucca
- Incline Village
  - Tahoe Biltmore
  - Diamond Peak Ski
- Tahoe Douglas
  - Hard Rock Hotel
  - Carson Fuji Park
- Mt Charleston
  - Staging Area - Spring Mountain Visitor Center
  - ICP – The Retreat at Mt Charleston

**APPENDIX B: PUBLIC SAFETY OUTAGE MANAGEMENT (PSOM) EVENT TEMPLATES**

**NV Energy's External Notification Form**

	<b>NV Energy Public Safety Outage Management (PSOM) Notification Form</b>	
	Report Date	Report Time

Report Number	<b>PSOM- YYYY - N/S - Event # - Report #</b>
---------------	--

Notification Type			
-------------------	--	--	--

De-Energization Potential	<input type="checkbox"/>	De-Energization Initiated	<input type="checkbox"/>
Initiated Assessment to Re-Energize (Patrols)	<input type="checkbox"/>	All Lines Re-Energized	<input type="checkbox"/>
	<input type="checkbox"/>	De-Energization Event Cancelled	<input type="checkbox"/>

Is this an update notification?	Yes <input type="checkbox"/>	No <input type="checkbox"/>	Initial <input type="checkbox"/>
If "yes", provide an update number:			

Maps of impacted areas:	<a href="https://www.nvenergy.com/safety/psom">https://www.nvenergy.com/safety/psom</a>
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**Potential Impact**

County	Zone	# Of Customers/ GCC	Estimated De-energization Time	Actual Time of De-energization	Estimated Time of Re-energization
Total Number of Customers:					
Number of Green Cross Customers (GCC):					

<b>List of impacted Critical Infrastructure:</b> (including, but not limited to, hospitals, fire stations, police stations, water treatment facilities, schools, communications facilities etc.)		
<b>Zone</b>	<b>Description of Infrastructure</b>	<b>Estimated Time of Restoration</b>

**Public/ Customer Notification Information and Report**

<b>Method of Public Notification</b> (Check All That Apply)		
<b>Recipient/ Type of Notification or Update</b>	<b>Est. Completion of notification (Time)</b>	
Local Stakeholders/ First Responders	<input type="checkbox"/>	
Major Accounts	<input type="checkbox"/>	
Public Information Officers (PIO)	<input type="checkbox"/>	
Green Cross Customers	<input type="checkbox"/>	
Customers (Text, Call, and/ or Email)	<input type="checkbox"/>	
Social Media/ Media Outreach	<input type="checkbox"/>	
Website Updated	<input type="checkbox"/>	

**Disclaimer**

*This document and the data included herein are intended for the sole use of the intended recipient(s). The above data is based on an assessment in wildfire risk tiers in NV Energy's service territory. NV Energy is not responsible for any missing data. Supporting data is collected by NV Energy personnel and its agents using several different data sources. Notwithstanding that, NV Energy makes no representations or warranties, express or implied, of the accuracy or completeness of the information herein. NV Energy is not liable for any use or reliance upon any of the information.*

**NV Energy’s Qualitative Criteria PSOM Event Evaluation**

County	Location	Circuit	# of Customers	Estimated De-energization Time	Estimated Time of Re-energization
Total Number of Customers:					
Number of Green Cross Customers:					
Projected end date of event:					

Based on the forecasted conditions for the above circuit(s), a qualitative score for each individual parameter can be seen below.

The scores range from zero to 10 with 10 being highest confidence and zero being low confidence. A “go” or “no go” can be given to an area where a number cannot be assigned

**EXPLANATION:**

“How confident are we that an ignition event will not be caused by our infrastructure”

10 – High confidence our infrastructure will fare well without de-energization

0 – Our infrastructure is not ready and could cause an ignition event.

Go – Stakeholder is ready and prepared to go through a PSOM event

No-Go – Stakeholder is not ready or prepared - ***\*\*Must provide reasoning behind this***

	Score
<b>1. Vegetation Management:</b> Based on the last <b>tree</b> vegetation management cycle completed <u>Responsible owner:</u> Operations (Vegetation Management)  Received input from:	0-10
<b>2. Patrol/Detailed Inspection:</b> Based on the last patrol or inspection completed <u>Responsible owner:</u> Operations (Lines)  Received input from:	0-10
<b>3. Local Fire District Input and Fire Resources:</b> Available fire resources in the area and response capability, give detailed response if needed. <u>Responsible owner:</u> Fire Management	0-10

Received input from:	
<p><b>4. Fuels Mitigation Work:</b> Assessment of field conditions near impacted infrastructure, last time <b>ground fuels</b> management was completed  <u>Responsible owner:</u> Fuels/ Fire Management</p> <p>Received input from:</p> <p>Did a FBAN develop possible fire behavior information: Yes / No</p>	
<p><b>5. Large Event/Visitor Status:</b> If a significant event is projected during the potential PSOM event duration  <u>Responsible owner:</u> PIO (Major Accounts)</p> <p>Received input from:</p>	GO or NO-GO
<p><b>6. Utility Infrastructure Readiness:</b> Any critical water or sewage treatment facilities will have any issues  <u>Responsible owner:</u> PIO (Major Accounts)</p> <p>Received input from:</p>	GO or NO-GO
<p><b>7. Communication Infrastructure Provider Readiness:</b> to include "any company that provides Broadband Internet Access Service (BIAS), Personal Communications Service ("PCS"), local exchange service, or Voice over Internet Protocol service, or is a Telephone Company.  <u>Responsible owner:</u> PIO (Major Accounts)</p> <p>Received input from:</p>	GO or NO-GO
<p><b>8. Radio Communications:</b> Any radio communication concerns regarding the 800MHz radio system  <u>Responsible owner:</u> Logistics (Telecommunications)</p> <p>Received input from:</p>	GO or NO-GO
<p><b>9. Infrastructure Design – Distribution:</b> Input based on the base design of overhead infrastructure and its expected resiliency  <u>Responsible owner:</u> Planning (Distribution Design)</p> <p>Received input from:</p>	0-10
<p><b>10. Infrastructure Design – Transmission:</b> Input based on the base design of overhead infrastructure and its expected resiliency  <u>Responsible owner:</u> Planning (Distribution Design)</p>	0-10



Received input from:	
<b>11. Customer Resource Centers:</b> Readiness levels for the customer resource centers <u>Responsible owner:</u> Admin (Community Relations) Received input from:	GO or NO-GO
<b>12. Restoration Readiness – Distribution:</b> Based on the restoration readiness for the affected circuits <u>Responsible owner:</u> Operations (Lines, Substations, and System Control) Received input from:	0-10
<b>13. Restoration Readiness – Transmission:</b> Based on the restoration readiness for the affected circuits <u>Responsible owner:</u> Operations (Lines, Substations, and System Control) Received input from:	0-10
<b>14. Local Emergency Management Input:</b> Their assessment of field conditions and necessity for a PSOM event <u>Responsible owner:</u> Emergency Management Received input from:	GO or NO-GO
<b>15. Customer/ Public Communications:</b> Resource/ timeline readiness to get information out to customers <u>Responsible owner:</u> PIO (Corporate Communication) Received input from:	GO or NO-GO
<b>16. OTHER:</b> Include any other topics or concerns to be considered for the event – <i>there will be no score associated with this section. (Example: Air Quality Index, Extreme heat, Extreme cold, or other weather conditions)</i>  <u>Responsible owner:</u> All Section Chiefs	N/A
<b>Total</b>	

Initiate a PSOM event if the total score of the above qualitative assessment includes any of the following:

- Lower than 40 out of 80 (maximum), **or**
- Three or more individual category scores are lower than three (0, 1, or 2) **or**
- One or more of the category scores is extreme or unacceptable

The final decision to initiate a PSOM event would be made by either the Incident Commander or Policy Team Liaison for the event. If there are any "go or no-go" scores, they will need to be considered on a case-by-case basis.

**Recommendation to Initiate PSOM Event: YES / NO**

Score Card completed on:	
Reasoning behind recommendation:	
Summary of any changes from previous score card:	
Brief summary of additional mitigation efforts being implemented for the event:	

**Recommendation/ Additional Mitigation Approved by:**

\_\_\_\_\_  
Incident Commander

\_\_\_\_\_  
Policy Team Liaison

**Utility Communication Plan**

*Purpose:* To outline a communication and coordination timeline between NVE, RC West Truckee Donner Public Utility (TDPUD), Plumas Sierra Utility, and Liberty during a possible PSOM event that would impact TDPUD and Liberty’s electric distribution grid.

<b>Impacted lines by Utilities</b>
------------------------------------

TDPUD – North Truckee 101 Transmission line (Verdi PDZ), Summit Metering Stations 102 Transmission line (Verdi PDZ), and Truckee Summit Metering Station 607 Transmission  
Liberty - North Truckee 101 Transmission line (Verdi PDZ), Summit Metering Stations 102 Transmission line (Verdi PDZ), Truckee Summit Metering Station 607 Transmission, Buckeye-Meyers 111, Incline Village PDZ, Stateline PDZ, California 204, Muller 1296, and Topaz 1261, 112 Buckeye to Roundhill, Kingsbury 2800 (Heavenly PDZ)  
Plumas Sierra – 619 Transmission Line  
RC West – All transmission outages

<b>Notification Timeline</b>
------------------------------

- 4-6 Days out from event:
  - An email notification with an external stakeholder form from NV Energy will be sent to TDPUD/ Liberty/ Plumas Sierra contacts.
  - RC West will be communicated with through ESCC via established protocols
  
- 2-3 Days out from event:
  - An email notification with an external stakeholder form from NV Energy will be sent to TDPUD/ Liberty/ Plumas Sierra contacts.  
*\*\* Information will be added to the email about additional communication to be held within 48 hours of the event.*
  - TDPUD/ Liberty/ Plumas Sierra representative is invited to NV Energy’s Emergency Response Organization (ERO) calls or called to be told about the incoming weather.
  - *\*\* TDPUD/Liberty will ensure the other is informed and will be available and on the update call*
  
- 0-2 Days out from event:
  - A daily call from an NV Energy POC to TDPUD/ Liberty/ Plumas Sierra contacts to discuss the event and give the below information (as available).
    - Agenda
      - Estimated de-energized time and duration
      - Probability
      - Impacted area or lines
        - See above listed possible impacted lines for each utility
      - TDPUD/ Liberty/ Plumas Sierra to identify a single POC for NVE to communicate directly with through the remaining steps of the event.



*\*\* Set standard time for daily update calls  
\*\* CANNOT have call between 1600-1700 due to Liberty restrictions*

- De-energization – at time of actual de-energization
  - NVE will make a phone call directly to TDPUD/ Liberty/ Plumas Sierra POC that has been pre-established
  
- Weather decreased notification
  - NVE will make a phone call directly to TDPUD/ Liberty/ Plumas Sierra POC that has been pre-established
    - NVE will let TDPUD/ Liberty/ Plumas Sierra know that the weather decreased around the transmission line and NVE is preparing to patrol
  
- Patrols
  - NVE will make a phone call directly to TDPUD/ Liberty/ Plumas Sierra POC that has been pre-established to let them know NVE has begun patrols of the transmission line
  
- Ready to re-energize
  - NVE will make a phone call directly to TDPUD/ Liberty/ Plumas Sierra POC that has been pre-established to let them know NVE has finished patrols and are ready to re-energize the transmission line.

# APPENDIX D. USFS RESILIENCE CORRIDORS PROJECT DECISION MEMO

## NV Energy Resilience Corridors Project



### Decision Memo



U.S. Forest Service  
Lake Tahoe Basin Management  
Unit and  
Humboldt-Toiyabe National Forest, Carson Ranger  
District Carson City and Douglas and Washoe  
Counties, Nevada

### DECISION

I have decided to implement the proposed action, which includes treatment and maintenance of vegetation adjacent to NV Energy electrical infrastructure and power line corridors (see project overview map). These treatments will create safe clearance between vegetation and infrastructure, improve wildlife habitat, reduce fuel loads, promote tree growth, and improve forest health. Treatment activities include:

- Implementing vegetation management activities in Zone 1 consistent with the International Wildland Urban Interface Code
- Pole grubbing on each power pole (removing all combustible vegetation within a 20-foot radius around the pole)
- Removing hazard trees that could directly strike power lines if they fall consistent with Forest Plan direction
- Mechanical thinning on slopes less than 50 percent and hand thinning where needed to protect natural resources (often on slopes ranging from 30-50 percent)
- Removing and managing biomass by piling, mastication, broadcast chipping, or mechanical means
- Using helicopter support operations
- Prescribing understory burning as a primary or follow-up treatment option in all areas to reduce natural fuel build-up and improve plant vigor, depending on fuel and post-treatment conditions
- Pile burning
- Vegetation treatments, roads, and prescribed fire activities are described below.

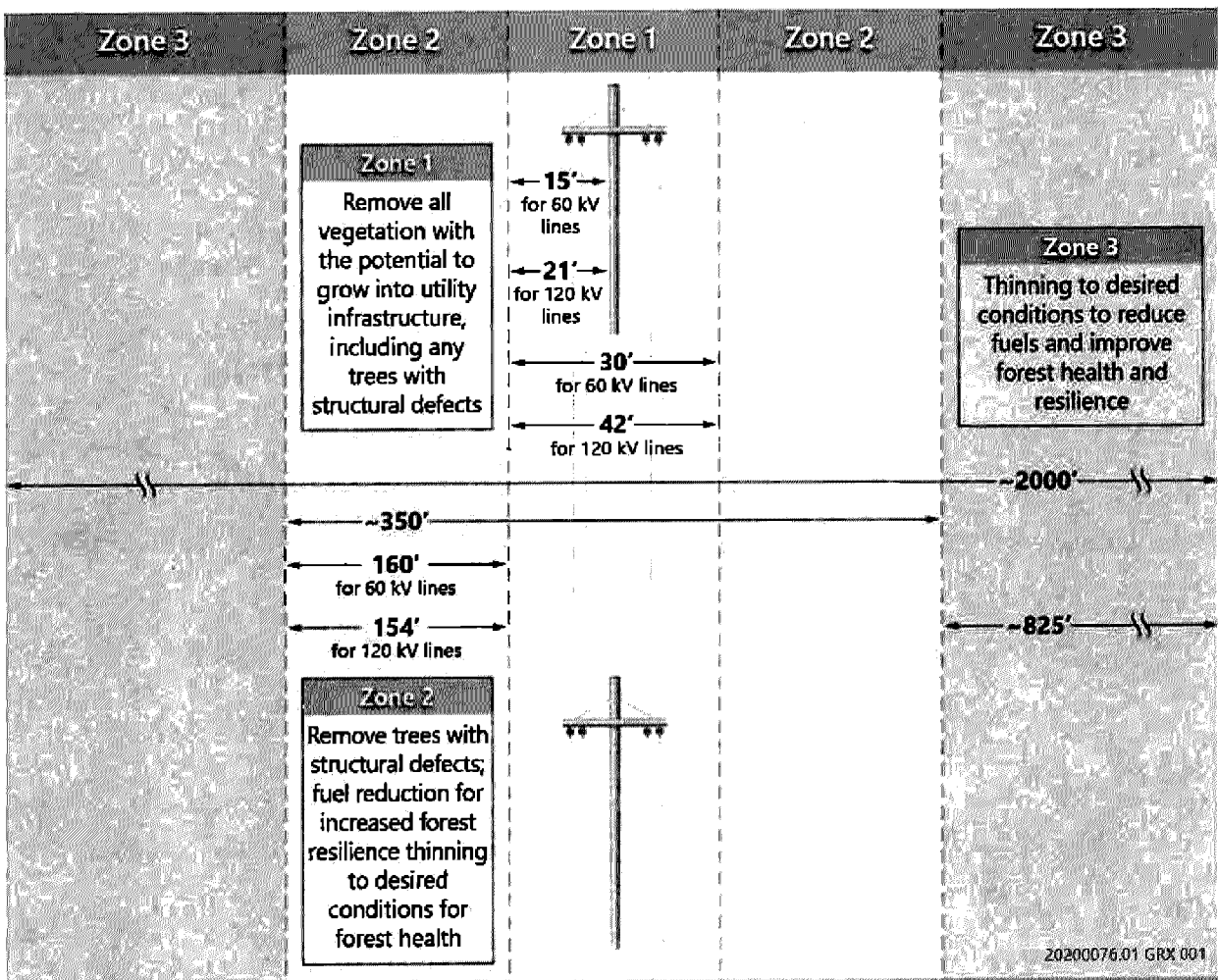
### Forest thinning

Forest thinning treatment activities will occur primarily from May to October but can be conducted throughout the year except when a limited operating period (LOP) is implemented to protect sensitive resources.

All treatment activities will use best management practices (BMPs) and resource protection measures (RPMs) to avoid, eliminate, or reduce unintended and undesirable effects of the activities. The BMPs and RPMs are included as Attachment 1.

Treatments will generally take place within approximately 1,000 feet of existing power lines, in three linear zones defined below and shown in the following Figure.

- **Zone 1** (up to 15 feet on each side of power lines up to 60 kV and up to 21 feet for 120 kV lines): Remove all vegetation (see exceptions below), including all trees, within the specified distance {15 or 21 feet) from power poles and create a noncontiguous fuel pattern consistent with the International Wildland Urban Interface Code and NV Energy's Natural Disaster Prevention and Protection Plan.
- **Zone 2** (between 15 and 175 feet on each side of the power lines for 60 kV lines, and between 21 and 175 feet for 120 kV lines): Remove trees with structural defects that have the potential to strike utility infrastructure, reduce fuels, and thin to desired conditions.
- **Zone 3** (between 175 and approximately 1,000 feet on each side of the power line): Reduce fuel loads and thin the forest to desired conditions.



Source: NV Energy 2021

Riparian fuels, including mature aspen trees, will be removed only if they have the potential to grow into the utility infrastructure. Trees showing signs of insect infestation, diseases, or symptoms of poor health

will be selected for removal first. Intermediate (crowns are generally narrow or one-sided and below the general level of the canopy) and co-dominant (crown extends into canopy and receives direct sunlight from above but limited sunlight from the sides) trees will also be removed first. Buffers will be used near perennial and intermittent streams, lakes, riparian corridors, stream environment zones (SEZs), and federally designated wetlands or waters of the United States to protect riparian vegetation.

The general prescription for thinning treatments would be to remove trees up to 30 inches diameter-at-breast-height (DBH) to meet desired conditions for stand density. Trees larger than 30 inches DBH may be removed if reviewed by a Forest Service wildlife biologist and if the tree presents a safety hazard, prevents equipment operability, or is infested by insects or disease with the potential to spread to adjacent trees. In hand treatments, where material would be piled or scattered and not removed, thinning would generally be limited to trees under 20 inches DBH. Sugar pine, Jeffrey pine, incense cedar would be favored for retention at mid-elevations and whitebark pine, Jeffrey pine, western white pine, incense cedar and red fir will be favored for retention at higher elevations.

Protected activity centers (PACs) for northern goshawk, spotted owl, and flammulated owl and home range core areas (HRCAs) for spotted owl that overlap the power line corridors will be treated to reduce fuels and remove hazard trees in these sensitive areas. Within PACs, Zone 1 will be treated in the same manner as Zone 1 treatments outside of PACs to protect power line infrastructure. Zone 2 treatments will include removing hazard trees that could strike power infrastructure. Thinning treatments within Zone 2 and 3 will be designed to retain habitat requirements for northern goshawks, spotted owls, and flammulated owls in accordance with the LTBMU and HTNE Forest Plans and RPMs intended to protect these sensitive species.

Vegetation treatments may create openings to restore forest structure, ranging in size from less than 1 acre to 3 acres. Openings may retain trees and clumps to produce spatial and structural variability, increasing forest resiliency. The location of openings will be influenced by: (1) areas of heavy tree mortality, insect infestation, or disease; (2) proximity to PACs and HRCAs and detections of late- and mid-seral associated species; (3) existing connectivity of habitat for species within or adjacent to project area; (4) proximity to developed recreation sites, scenic resources, and heritage resources; (5) proximity to open water and SEZs; (6) proximity to communities; (7) surrounding seral stages; and (8) spread of invasive species.

The type of thinning operation selected will be based on soil type and slope of treatment stands. Mechanical thinning may occur on slopes less than 50 percent and hand thinning may occur where needed to protect natural resources (often on slopes ranging from 30-50 percent). Cable yarding or helicopter systems for biomass removal could take place in areas where soils are too sensitive for ground-based mechanized equipment or otherwise needed to protect natural resources. Cable yarding generally has a limitation of occurring within about 1,500 feet of roads.

In mechanical units, treatment may be completed by whole tree skidding or low impact methods such as cut-to-length forwarding. Follow-up treatments to reduce or redistribute residual fuel could include lop and scatter, mastication, chipping or grapple piling, and pile burning.

Existing downed logs and fuels may be reduced by removal through ground-based mechanical methods. Material not removed could be chipped or masticated, piled, and burned within the units or at landings, or consumed during planned understory burning.

Conifers will be thinned from SEZs, including riparian areas, meadows, and aspen stands. All conifers that are competing with riparian vegetation, overtopping aspen, or encroaching upon meadows will be considered for removal.

Landings will primarily be in areas previously used as landings and in other exist in g openings, though some may need to be constructed. They will be strategically placed to create openings to restore forest

heterogeneity. Landings will be large enough to safely facilitate the handling and removal of biomass material and will range from less than 1 acre to 3 acres to meet forest structure objectives.

Temporary stream crossings may occur in ephemeral, intermittent, and perennial drainages. The Forest sale administrator, hydrologist, and aquatic biologist will agree on temporary locations and designs prior to construction. The number of crossings will be kept to the minimum required for access and will be as perpendicular to stream course as possible.

Within 300 feet of developed areas (homes and other infrastructure), brush, snags, and down logs may be removed to meet defensible space objectives.

Seeds or plugs will be planted in areas where increased size, age, and species diversity are desired. Reforestation may be used as a post-thinning treatment to increase the diversity of seral stage, species, and size class in forest stands, and prescriptions will incorporate species mix, stocking density, and the use of white pine blister rust resistant seedlings. Examples of where reforestation may be used include, but are not limited to, areas that are cleared for landings and openings from thinning dead or dying trees. Areas will be chosen based on the need for diversity in species and size composition in that area.

### **Prescribed fire**

Prescribed fire may be used to remove slash piles, when off-hauling of cut material is not feasible, and to reduce surface and ladder fuels. Prescribed fire may also be used to promote pockets of tree mortality where it is not feasible for thinning treatments to meet these objectives {e.g., too many trees that are too large for hand piling, or current stand densities will result in too many piles) and to increase available snags and down woody debris for wildlife habitat.

Prescribed fire could occur within Zones 2 and 3 but will not be conducted in Zone 1. The creation of snags and coarse woody debris using prescribed fire will only occur more than 300 feet from private property and outside of Zone 1. Fuel treatments using prescribed fire may occur as the primary treatment, or within 2 to 5 years following hand or mechanical treatment. Existing roads and trails will be utilized as fire lines to minimize new ground disturbance, though additional fire lines may be constructed with hand tools.

### **Roads**

Temporary road construction will be required to facilitate thinning treatments. Where possible, temporary roads will be constructed on top of a non-historic, relic road prism {i.e., previously decommissioned). The need for temporary roads will be determined as the silvicultural prescriptions for individual treatment units are developed. Construction needs may include installation of drainage structures to prevent surface water runoff, road widening for vehicle access (including removal of trees and brush), and road surface stabilization. The proximity and crossing of recreation corridors (such as trails) will be considered during the planning of the temporary road system and avoided whenever possible.

Forest system roads will be maintained commensurate with use. Native surface roads will be watered to abate dust during project implementation. Upgrades to roads will not be undertaken to accomplish substantial improvements in road standard to raise the maintenance level. Damage to any bituminous, chip seal, or asphaltic surfaced type will be repaired.

Construction of temporary roads will be limited to no more than 1 mile on land managed by HTNF in accordance with the category of exclusion for this activity.

### **CATEGORICAL EXCLUSIONS**

The action is categorically excluded from documentation in an environmental impact statement (EIS) or an environmental assessment (EA). The applicable categories of actions are as follows:

For the LTBMU, the proposed action meets the criteria outlined in the Water Infrastructure Improvement for the Nation Act of 2016 (Public Law 114-322):

*A forest management activity conducted in the Lake Tahoe Basin Management Unit for the purpose of reducing forest fuels is categorically excluded from the requirements of the National Environmental Policy Act, if the forest management activity:*

*(A) does not exceed 10,000 acres, including not more than 3,000 acres of mechanical thinning;*

*(B) is developed in coordination with impacted parties, specifically including representatives of local governments, such as county supervisors or county commissioners and in consultation with other interested parties; and,*

*(C) is consistent with the Lake Tahoe Basin Management Unit land and resource management plan.*

For the HTNF, the proposed action meets the criteria outlined in the additional category (36 CFR 220.6(e)(6)):

*Timber stand and/or wildlife habitat improvement activities that do not include the use of herbicides or do not require more than one mile of low standard road construction.*

Because recent destructive fires demonstrate the urgent need to reduce forest fuel loads, I am using the category specifically created by Congress for this purpose on the LTBMU portion of the project. Because one of the examples given under the (e)(6) category specifically states thinning or brush control may be used to improve growth or reduce fire hazard, I am using that category for the HTNF portion of the project. These categories are the best fit for the project actions.

I considered the following resource conditions based on information and analysis in the specialist reports available in the project record and find there are no extraordinary circumstances warranting further analysis and documentation in an EA or EIS.

**Federally listed threatened or endangered species or designated critical habitat, species proposed for federal listing or proposed critical habitat, or forest service sensitive species**

Federally Listed Botanical and Animal Species

No botanical species listed as threatened or endangered under the federal Endangered Species Act (ESA) are present in the project area. Whitebark pine (*Pinus albicaulis*) is proposed for federal listing as threatened and is present in the project area. As described in the project Biological Assessment (BA) and the Biological Evaluation (BE), with incorporation of applicable RPMs, the proposed action may affect but is not likely to adversely affect whitebark pine.

No federally listed animal species are expected to occur in the project area; however, potential habitat for the threatened Lahontan cutthroat trout (*Oncorhynchus clarkii henshawi*) and endangered Sierra Nevada yellow-legged frog (*Rana sierrae*) may be present. Because the proposed action includes RPMs designed to reduce and avoid potential project-related effects on these species, the species are not expected to occur in the project area, and any potential residual effects would be minor, the proposed action may affect but is not likely to adversely affect Lahontan cutthroat trout or Sierra Nevada yellow-legged frog. Critical habitat for Lahontan cutthroat trout has not been designated by the U.S. Fish and Wildlife Service within the project area. The nearest designated critical habitat for Sierra Nevada yellow-legged frog is approximately 10 miles west of the project area and would not be affected by the proposed action.

Forest Service Sensitive Botanical and Animal Species

Determinations for Forest Service Sensitive botanical and animal species are as follows, based on the detailed analyses and determinations provided in the BE available in the project record. The proposed action may affect but is not likely to result in a trend toward federal listing or loss of viability for any Forest Service Sensitive botanical and animal species.

**Floodplains, wetlands, or municipal watersheds**

The project area includes floodplains and wetlands. Floodplains will receive both mechanical and hand thinning treatments. Due to soil moisture restrictions, mechanical treatments would not occur within wetlands. Hand thinning treatments will improve wetland conditions by removing encroaching conifers with material piled for later burning or removal by cable yarding or helicopter systems. The project will have no effect on municipal watersheds.

**Congressionally designated areas**

There are no congressionally designated areas within the project area.

**Inventoried Roadless Areas or potential wilderness areas**

IRAs are located within the project area (Rose, Lincoln, and Jobs Peak roadless areas), but no roads would be constructed within them. Some trees may be harvested for commercial purposes if access is available. The Roadless Rule allows the cutting, sale, or removal of timber if needed "to maintain or restore the characteristics of ecosystem composition and structure, such as to reduce the risk of uncharacteristic wildfire effects, within the range of variability that would be expected to occur under natural disturbance regimes of the current climatic period" (36 CFR 294.13(b)).

The Pacific Southwest Regional Forester has reviewed the proposed activities and determined this project is consistent with the 2001 Roadless Area Conservation Rule. The Intermountain Regional Forester delegated review and compliance determination for portions of the 2001 Roadless Area Conservation Rule to forest supervisors. The HTNF Forest Supervisor concurred on the activities described above consistent with the 2001 Roadless Area Conservation Rule. Roadless area characteristics will be protected.

**Research natural areas**

There are no research natural areas within the project area.

**American Indians religious or cultural sites**

The proposed action would not adversely affect known American Indian religious or traditional heritage resource sites within the project area. Consultation with the Washoe Tribe of Nevada and California was initiated on November 20, 2020, and no concerns were expressed.

**Archaeological sites, or historic properties or areas**

A comprehensive inventory consistent with the *Programmatic Agreement Among the USDA Forest Service Southwest Region (Region 5), California State Historic Preservation Officer, Nevada State Historic Preservation Officer, and the Advisory Council on Historic Preservation Regarding the Processes for Compliance with Section 106 of the National Historic Preservation Act for Management of Historic Properties by the National Forests of the Pacific Southwest Region (2018)* (R5 PA) has been completed for the project's Area of Potential Effects (APE) that includes HTNF and LTMBU managed lands (*Cultural Resources Inventory Report for the Nevada Energy Resilience Corridors Project, USDA USFS Lake Tahoe Basin Management Unit, South Lake Tahoe, CA and Humboldt-Toiyabe National Forest, Carson Ranger District, Carson City, NV*, prepared by Natural Investigations Company in 2022 [LTBMU Report No. R2022051900001; HTNF Report No. R2021041702965]). By agreement with the Nevada State Historic Preservation Officer, the R5 PA is being applied across the entire project area, including HTNF managed lands (SHPO UT 2022-7096; 29110, March 31, 2022). Historic properties identified within the APE will be protected through implementation of R5 PA Standard Protection Measures, ensuring that the project will have no adverse effect on historic properties.

The proposed action complies with the National Historic Preservation Act of 1966, as amended (54 USC 306108) and implementing regulations at 36 CFR 800 in accordance with the provisions and stipulations of the R5 PA.

## **PUBLIC INVOLVEMENT**

The action was first listed as a proposal on the LTBMU Schedule of Proposed Actions (SOPA) on July 1, 2020, and the HTNF SOPA on October 1, 2020. On November 20, 2020, the project was posted for a 30-day scoping period on the LTBMU Forest Projects webpage and SOPA and in press releases to surrounding media outlets. On the same day, the proposed action and cover letter were emailed to multiple state, county, and local entities as well as to other potentially interested stakeholders from both forest units. Consistent with the Water Infrastructure for Improvements to the Nation Act, notices were also sent to the following local officials: Douglas County Commissioners Wes Rice, Barry Penzel, and John Engels; Washoe County Commissioners Bob Lucey and Marsha Berkgigler; Mayor Hilary Shieve and Council Member Naomi Duerr of Reno; and City Manager Nancy Pulson and Supervisor John Barrette of Carson City. The scoping period concluded on December 21, 2020.

During the scoping period, six comment letters were received. Comment letters are contained in the project record and have been addressed either within this document, by resource specialists' analyses, or by other information in the project record.

## **FINDINGS REQUIRED BY OTHER LAWS AND REGULATIONS**

This project is consistent with the standards and guidelines contained in the LTBMU and HTNF Forest Plans. The project will implement BMPs and RPMs that are compliant with any permit or waiver issued by the Nevada Division of Water Resources. This portions of this project within the Lake Tahoe Basin fall under the *Memorandum of Understanding* between TRPA and Forest Service Region 5 regarding Fuels Reduction and Forest Health Projects. LTBMU staff will coordinate closely with TRPA during project planning to ensure that the project components within TRPA jurisdiction are consistent with TRPA's environmental thresholds. Coordination may include completing a TRPA environmental checklist and environmental threshold findings.

## **ADMINISTRATIVE REVIEW**

This decision is not subject to appeal or objection, pursuant to Section 431 of the Consolidated Appropriations Act of 2014.

## **IMPLEMENTATION DATE**

Implementation may begin immediately in areas where pre-implementation survey requirements and any associated documentation have been completed. NV Energy and the Forest Service will coordinate the required survey work to gain clearance for implementation prior to completing vegetation treatments.

Interdisciplinary coordination during project development, design, and implementation is mandated in the LTBMU and HTNF Forest Plans and is based on the Forest Service's multiple use land management mandate. The project Interdisciplinary Team ("IDT") will continue to work as a group throughout the implementation of this project. The IDT consists of resource specialists from planning, timber, silviculture, terrestrial and aquatic wildlife, botany, hydrology, fuels, recreation, and engineering. Treatments for this project will be fitted to as-observed assessments and current resource information at the time of implementation. The IDT will continue to gather information throughout implementation to ensure appropriate RPMs are applied while the needs of this project are met.

CONTACT

For additional information concerning this decision or project, please contact Victor Lyon, Vegetation Management Staff Officer, at either 530-543-2625 or [victor.lyon@usda.gov](mailto:victor.lyon@usda.gov).



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ERICK J. WALKER

4/28/2022  
Date

Forest Supervisor

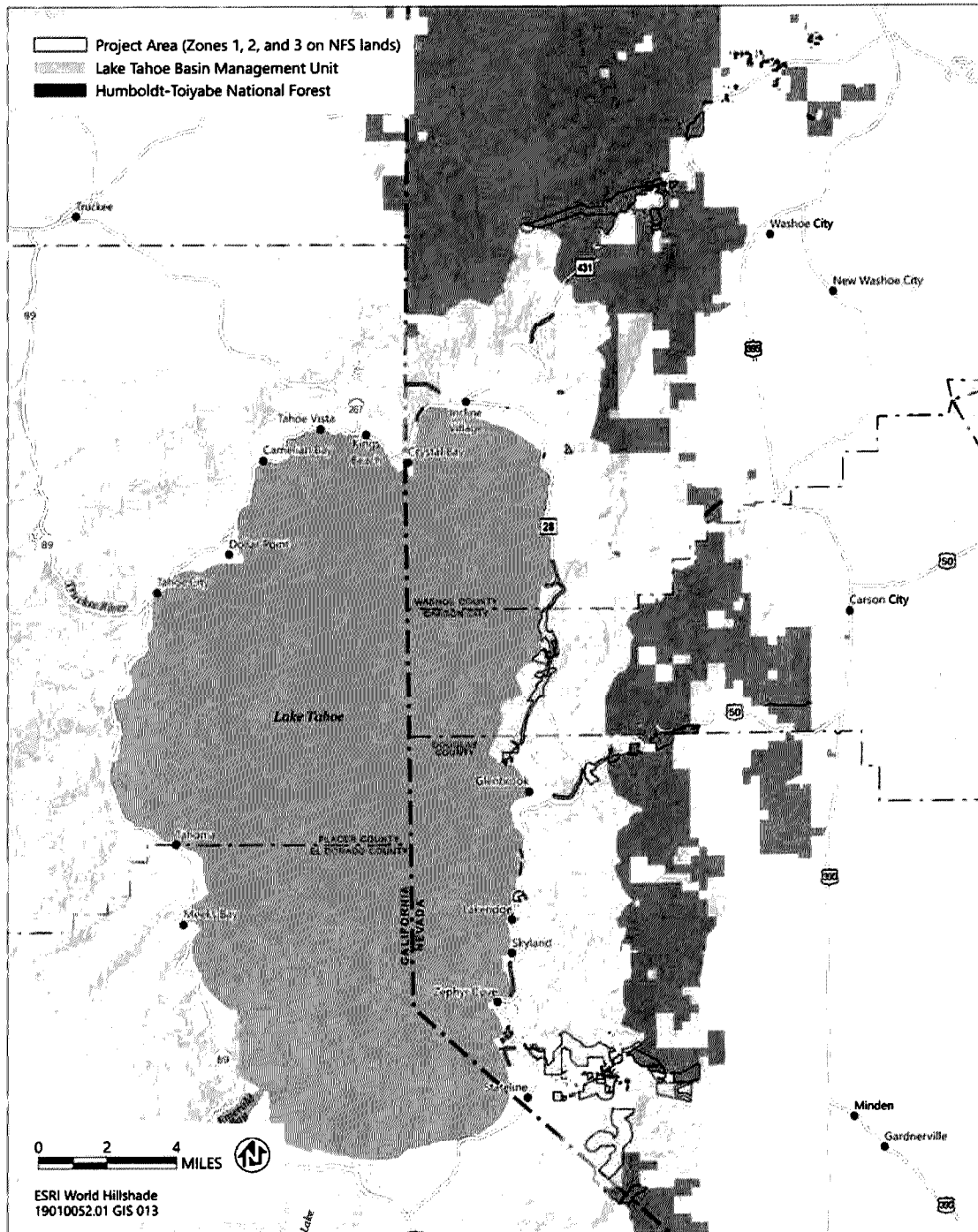
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Project Overview Map

Sources: Data received from Nevada Energy in 2020 and USFS in 2021



## **APPENDIX E. LETTERS OF SUPPORT**

This Section includes letters of support from:

- Nevada Division of Forestry
- Nevada Fire Chiefs Association
- Elko County Fire Protection
- Northern Nevada Fire Chiefs



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## NEVADA DIVISION OF FORESTRY

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STATE OF NEVADA  
Department of Conservation & Natural Resources

Joseph Lombardo, Governor  
James A. Settlemeier, Director  
Kacey KC. State Forester/Firewarden

February 13, 2023

To: NV Energy, NVE-Natural Disaster Protection Plan Team & Mark Regan  
P.O. Box 98910  
Las Vegas, NV 89151-0001

Re: NV Energy Fire Mitigation Program Support

Nevada Division of Forestry (NDF) acknowledges the value of wildfire mitigation conducted by any and all organizations and individuals in Nevada. Wildfire respects no boundaries and therefore we all must work together to do our part in helping prevent the occurrence, spread and destructive force of wildfires on our economy, industry, infrastructure, communities and natural resources. NDF appreciates NV Energy's partnership that has allowed both organizations to plan and implement strategies provide effective wildfire management both to NVE infrastructure and to communities and ecosystems. The following areas emphasize portions of the partnership that are creating positive differences in the wildfire challenges facing Nevada.

### **Risk Assessment Mapping**

As part of wildfire mitigation, prevention, and control, our agency and partners needed an objective way to assess and map risks and threats statewide to design effective mitigation strategies. To fulfill this need, NDF adopted the West Wide Wildfire Risk Assessment map that can be found by the public and our partners in NDF's Natural Resource and Fire Information Portal (<https://forestry.nv.gov/gis-mapping>). This map was also used by the Division to inform our interagency Shared Stewardship landscape scale priorities as well as our Natural Resource and Watershed Action Plan. NV Energy and our other partners have also adopted the use of this for many purposes.

This mapping product was produced by an independent contractor in 2011 using the best available science encompassing values at risk (communities, infrastructure, watersheds, habitat, etc.), coupled with fire threat areas formed with inputs such as historic wildfire occurrences, fuels, vegetation, weather zones, and more. This was the first nationwide risk map that utilized comprehensive data sets and produced comparable results across the United States, including Nevada. It is critical all partners use the best available science and comparable data to prioritize landscape scale, cross-jurisdictional fuel reduction and infrastructure hardening projects. It would be very confusing to the public and our implementation of wildfire mitigation actions would be inconsistent if organizations use different risk rating systems. NDF and our partners understand that the age of the map combined with changes in the natural and developed environments is requiring an updated map be produced that is accurately reflecting current conditions. NDF supports and is pursuing the update and uses of a newer product that would also help NV Energy prioritize treatments in elevated wildfire risk areas across their service territories.

NDF has reviewed the updated NVE tier maps, which includes the addition of Tier 1, and has overlaid the wildfire risk data discussed in this section, and finds that these areas are of elevated risk to wildfire and should be considered under the NDPP and SB329 for treatments to reduce wildfire risk including system hardening. The approach of using all moderate and above risk areas is consistent with State

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practice when assessing elevated risk to state facilities as well as when assessing risk to lands within local fire protection districts who opt to participate in the Wildland Fire Protection Program. NDF prioritizes most treatments in the moderate and above categories; however, also recognizes the value of risk mitigation in low categories when in proximity to critical infrastructure and/or natural resources.

#### **Wildfire Mitigation and Protection Enhancements**

NDF and our wildfire mitigation partners identified the need for public utility companies to be a part of the solutions necessary to ensure that infrastructure remains protected and does not contribute to the overall risks to adjacent communities and natural resources. The critical infrastructure managed by utilities takes specialized approaches to ensure that wildfire does not destroy them nor requires them to be shut off for long durations for public safety. NDF's partnership with NV Energy and the investments by both parties have increased capacity to reduce fuels in elevated risk areas, increased responsiveness to wildfire threats through greater amounts of initial attack firefighting crews and provided flexibility to do both with the same crews across the state. This collaborative approach is a novel and dynamic way to address needs identified by multiple partners in high priority and high-risk areas. The flexibility to be able to move crews across the state as workload, weather conditions, logistical restraints, and wildfire risks dictate allows expedited implementation and responsive emergency coverage. Overall, this partnership in conjunction with a larger Nevada Shared Stewardship Strategy has increased the number of acres treated for hazardous fuels across the state. These investments reduce negative impacts to human health, local economies, and the natural environment at a lesser cost than that of suppression.

#### **Conclusion**

NDF appreciates this opportunity to provide comment on the Natural Disaster Protection Planning conducted by NV Energy, particularly that portion affecting wildfires. NDF's partnership with NV Energy has resulted in a safer, more dependable, and enhanced wildfire management approach that is improving the quality of life of all Nevadan's. We hope that NV Energy continues managing wildfire hazards and risks in their Rights-of-Way and surrounding their infrastructure sustainably into the future.

Sincerely,

A handwritten signature in black ink, appearing to read 'Kacey KC', with a long horizontal flourish extending to the right.

Kacey KC  
State Forester/Firewarden



February 16, 2023

To: NV Energy, NVE-Natural Disaster Protection Plan Team & Mark Regan  
P.O. Box 98910  
Las Vegas, NV 89151-0001

Re: NV Energy Fire Mitigation Program Support

The Nevada Fire Chiefs Association (NFCA) is supportive of NV Energy's proposed "Tier 1" fire risk zone to better identify areas having "heightened" fire risk. The proposed changes more closely align NV Energy's fire risk zones with the existing Nevada Division of Forestry fire risk map our members use in the Wildland Fire Protection Program. It also helps ensure those areas with unique history, such as a record of structures lost to wildland fires due primarily to rapid fire spread in annual invasives, are identified and included.

Wildfire respects no boundaries and we all must work together to do our part in helping prevent the occurrence, spread and destructive force of wildfires on our economy, industry, infrastructure, communities and natural resources. The NFCA is pleased to acknowledge the value of wildfire mitigation conducted by any and all organizations and individuals in Nevada. Our partnership with NV Energy's has allowed our members to plan and implement strategies that provide effective fuel reduction and wildfire management both to NVE infrastructure and to our communities and natural environments.

It is critical all partners use the best available science and data to prioritize landscape scale, cross-jurisdictional fuel reduction and infrastructure hardening projects. The NFCA has reviewed the updated NVE tier maps, which includes the addition of Tier 1, and finds that the identified areas of elevated risk ("heightened risk") to wildfire are consistent with the observation and experience of the just over 100 Fire Departments and Districts that make up our membership and protect the vast majority of Nevada from wildfires.

NFCA members prioritize most fuel treatments in the moderate and above categories, however, we also recognize the value of risk mitigation in lower categories when fire history, seasonally abundant fine fuels, proximity to critical infrastructure or critical natural resources, identify a heightened risk. The NFCA appreciates this opportunity to provide comment on the Natural Disaster Protection Planning conducted by NV Energy. Our partnership with NV Energy has resulted in a safer, more dependable, and enhanced wildfire management, improved and enhanced wildfire suppression, and protects the quality of life of all Nevadan's. We look forward to working with NV Energy in the future.

Sincerely,

A handwritten signature in black ink, appearing to read 'Rich Harvey', with a stylized flourish at the end.

Rich Harvey  
Fire Chief, Central Lyon County Fire Protection District  
Executive Board Member, Nevada Fire Chiefs Association



## Elko County Fire Protection District

Matt Petersen, Fire Chief

John Pitts, Division Chief - Operations

Steven Hamilton, Division Chief - Prevention

Clancy Harman, Division Chief - Wildland

155 South Ninth Street

Elko, NV 89801

Telephone - (775) 738-9960

Web - <http://www.elkocountynv.net>

The Elko County Fire Protection District and rural fire agencies in northeastern Nevada are highly invested in wildland fire mitigation through the NV Energy partnership. We understand and support the wildfire mitigation that is conducted by all organizations and individuals in Nevada. In Elko County and rural Nevada, local wildland fires not only affect us, but they also impact us from miles and miles away and hundreds of thousands of acres away. For example, in 2018 the Martin Fire burned from north of Winnemucca into Elko County recorded as the largest in state history burning over 400,000 acres. This not only impacted infrastructure and communities in Humboldt County but also communities and infrastructure in Elko County. It is imperative for NV Energy and the regulating boards/agencies to acknowledge that fires do not show boundaries and do not stop at lines on maps.

Risk assessment maps incorporate large amounts of data to include but not limited to, wildfire threat, fuel loading, wildfire risk, community danger, populations, vegetation management, treatments and many other factors. Together we treat these for the heightened risk factors. They are adjusted on regular intervals, through either DOI, USDA, the State of Nevada, or other creditable partners. The wildland fire risk maps show heightened threat areas which address seasonal and long-term trends to enable and empower agencies to utilize their experience and historical knowledge, ensuring we are protecting values through the appropriate treatments.

It is essential that we are using the best and most up to date mapping science. Getting this data widely distributed in a timely manner empowers cooperating agencies to make the best-informed decisions in mitigating fuels and hazards. This is why the current programs are so successful.

Only treating tiered areas that do not match the wildland fire risk and the heightened threat areas it creates confusion and does not accurately and effectively allow agencies to mitigate the true threat of fires that impacted infrastructure. Making the threat areas coincide with the treatments will create less confusion and better the perception from the invested public in displaying that we are using common sense treatments and utilizing our local knowledge to treat for mitigation.

Elko County in conjunction with NDF and other partners support updating of the tiered maps to include wildland fire risk and heightened threat areas.

Elko County is highly invested in the success of the NDPP, and the mitigation work partnered with NV Energy and the State of Nevada. These partnerships have been a successful avenue to engage increased pace and scale of our mitigation efforts. It is critical for the continued success of these programs to utilize current and accepted practices and align tiers and treatments to elevated and heightened threat areas.

Sincerely Matthew J. Petersen *Elko County Fire Chief*

A handwritten signature in black ink, appearing to read "Matt Petersen", enclosed within a large, loopy oval scribble.

Page 1 of 1



**NORTHERN NEVADA FIRE CHIEFS ASSOCIATION**  
PRESIDENT – SCOTT LINDGREN, TDFPD SLINDGREN@TAHOEFIRE.COM 775-580-5321  
VICE-PRESIDENT – RYAN SOMMERS, NLTFPD RSOMMERS@NLTFPD.NET 775-690-7505  
TREASURER – SANDY MUNNS

February 21, 2023

To: NV Energy, NVE-Natural Disaster Protection Plan Team & Mark Regan  
P.O. Box 98910  
Las Vegas, NV 89151-0001

Re: NV Energy Fire Mitigation Program Support

The Northern Nevada Fire Chiefs Association (NNFCA) is in support of NV Energy’s proposed “Tier 1” fire risk zone to better identify areas having “Heightened” fire threat. The proposed changes more closely align NV Energy’s fire risk zones with the existing Nevada Division of Forestry fire risk map our members use in the Wildland Fire Protection Program. It also helps ensure those areas with unique history, such as a record of structures damaged or destroyed by wildland fires due primarily to rapid fire spread in annual fuels, are identified and included.

It is critical all partners use the best available science and data to prioritize landscape scale, cross-jurisdictional fuel reduction and infrastructure hardening projects. Our Departments have reviewed the updated NVE tier maps, which includes the addition of Tier 1, and finds that the identified areas of elevated risk (“Heightened threat”) to wildfire are consistent with the observation and experience of the Fire Departments and Districts that make up our membership and protect the vast majority of Northern Nevada from wildfires.

Our Departments prioritize fuel treatments in the moderate and above categories, however, we also recognize the value of risk mitigation in lower categories when fire history, seasonally abundant fine fuels, proximity to critical infrastructure or critical natural resources, identify a heightened risk. The NNFCA appreciates this opportunity to provide comment on the Natural Disaster Protection Planning conducted by NV Energy. Our partnership with NV Energy has resulted in a safer, more dependable, and enhanced wildfire management, improved and enhanced wildfire suppression, and protects the quality of life of all Nevadan’s. We look forward to working with NV Energy in the future.

Sincerely,

Scott Lindgren  
Fire Chief, Tahoe Douglas Fire Protection District  
Chairman, Northern Nevada Fire Chiefs Association

# APPENDIX F. UNDERGROUNDING PRIORITIZATION MAPS

## Project 1: Sierra Undergrounding Phase 1

Figure F1. Curry Street 1280

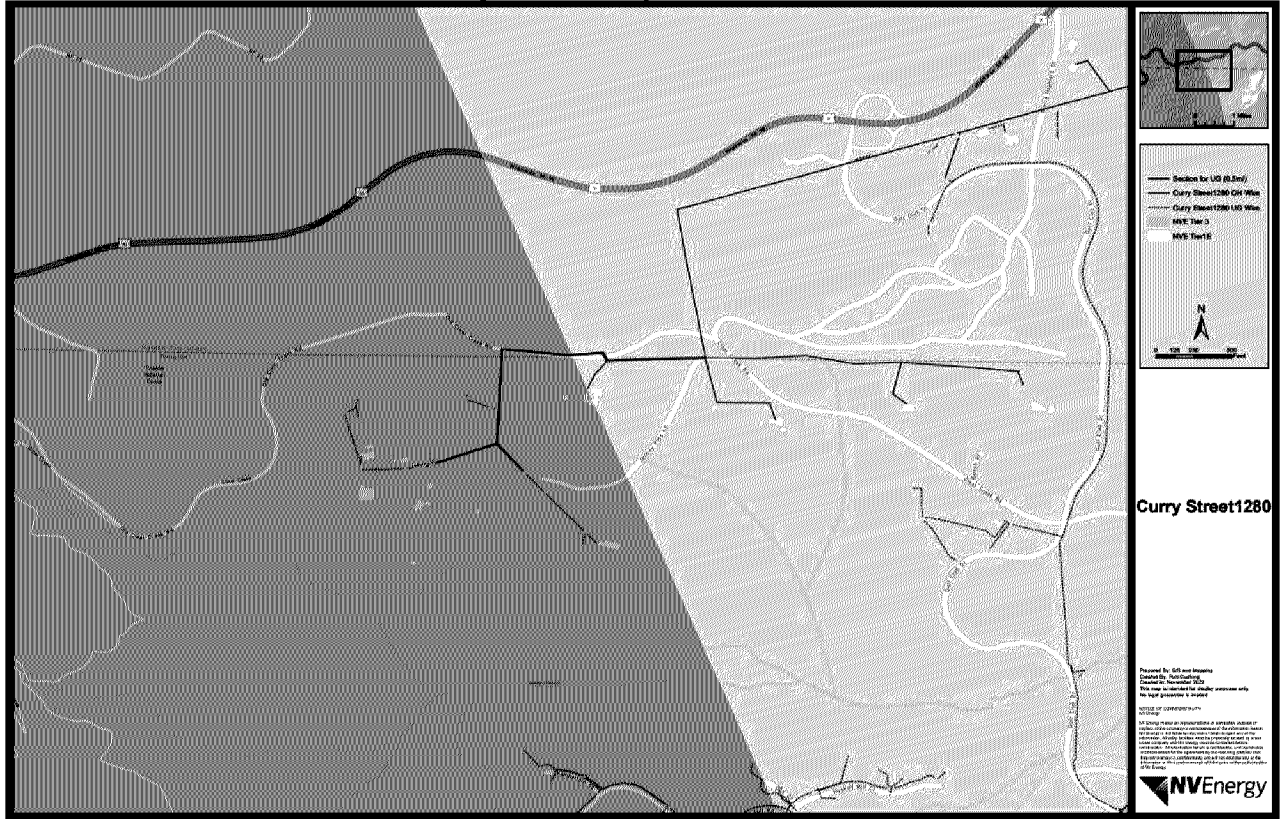


Figure F2. Downs 1285

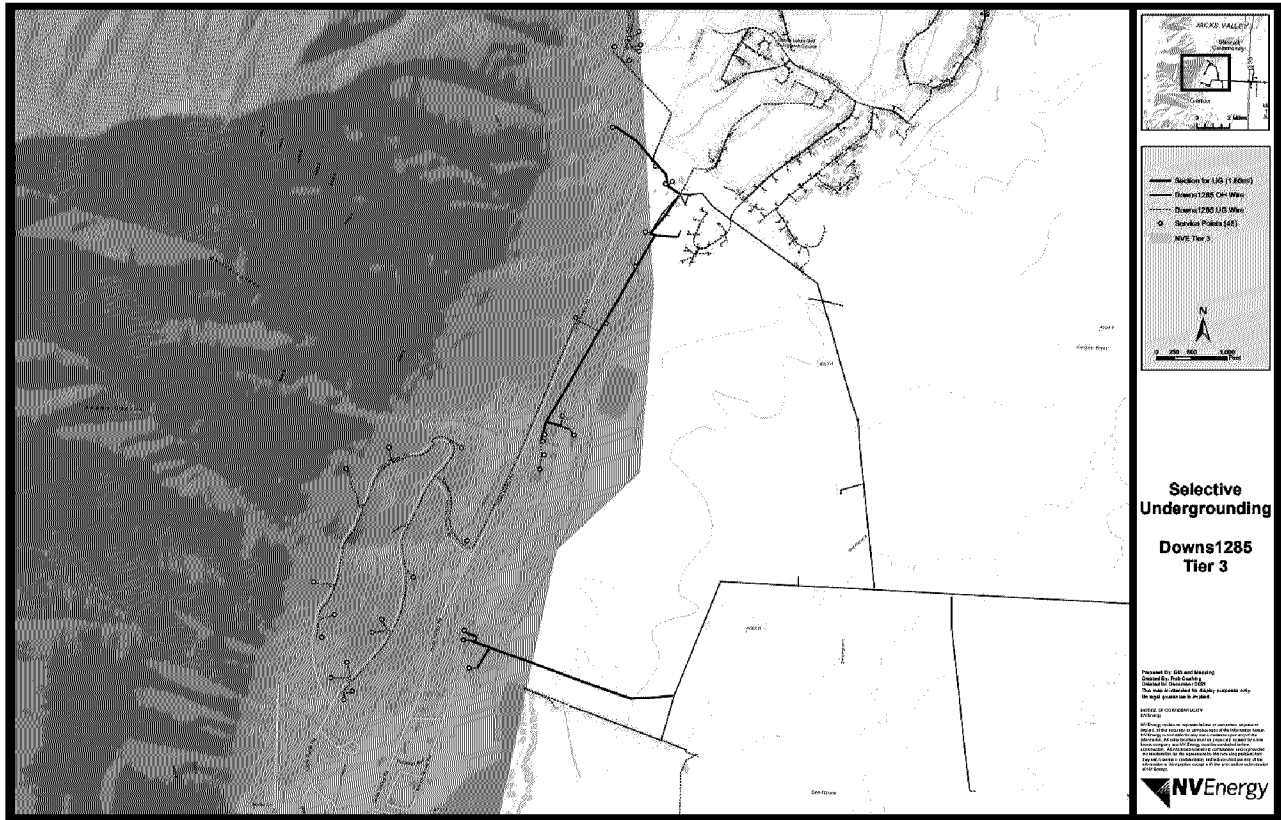


Figure F3. Round Hill 1504

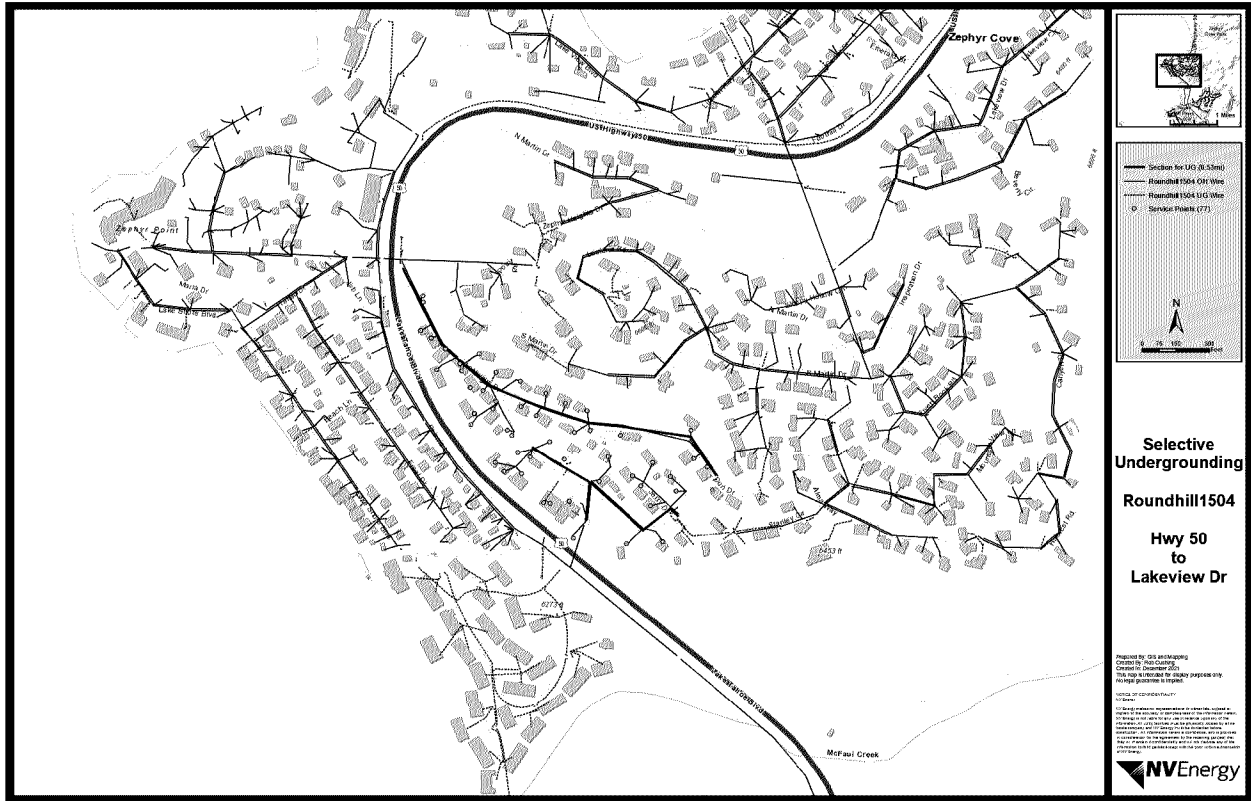
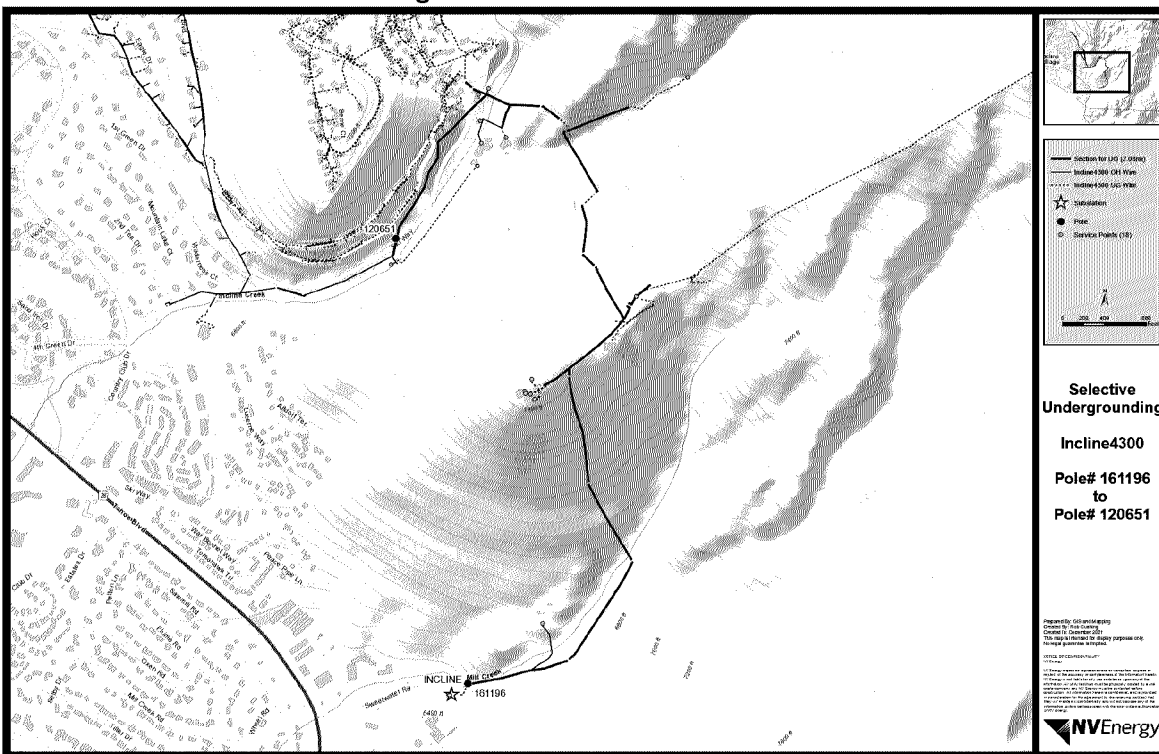


Figure F4. Incline 4200 Phase 3



Figure F5. Incline 4300 Phase 3



Project 2 Sierra Undergrounding Phase 2

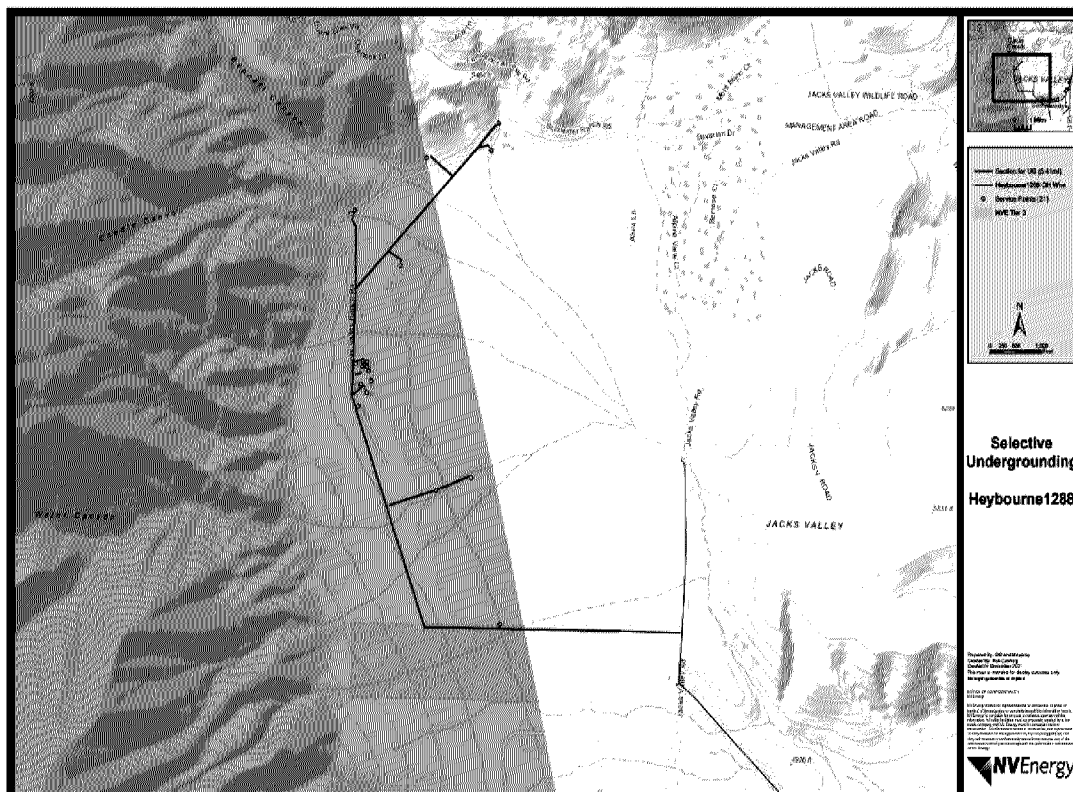
Figure F6. Incline 4300 Phase 1



Figure F7. Incline 4300 Phase 4



Figure F8. Heybourne 1288



Project 3: Sierra Undergrounding Phase 3

Figure F9. Muller 1295

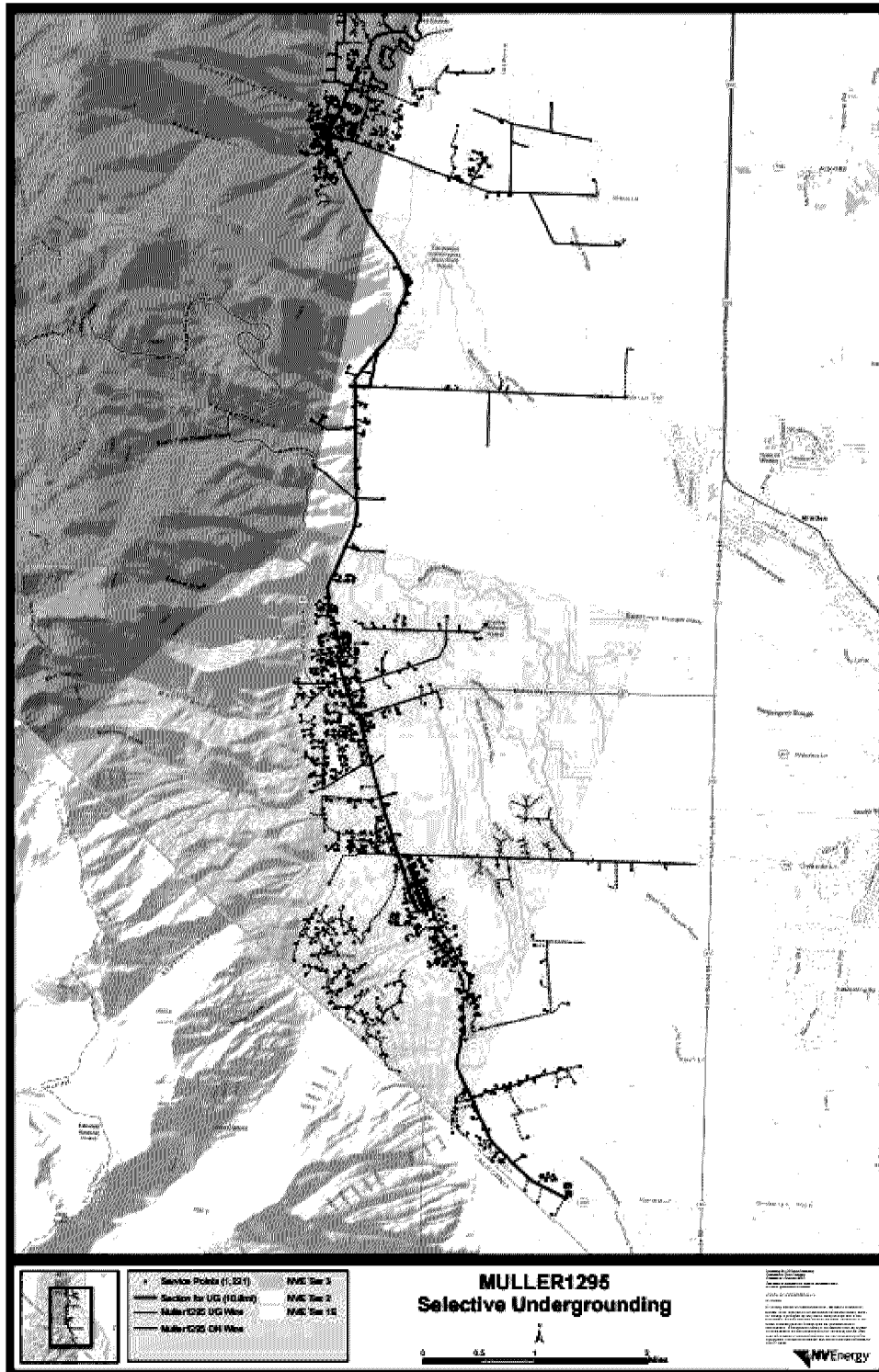


Figure F10. Incline 4200 Phase 1

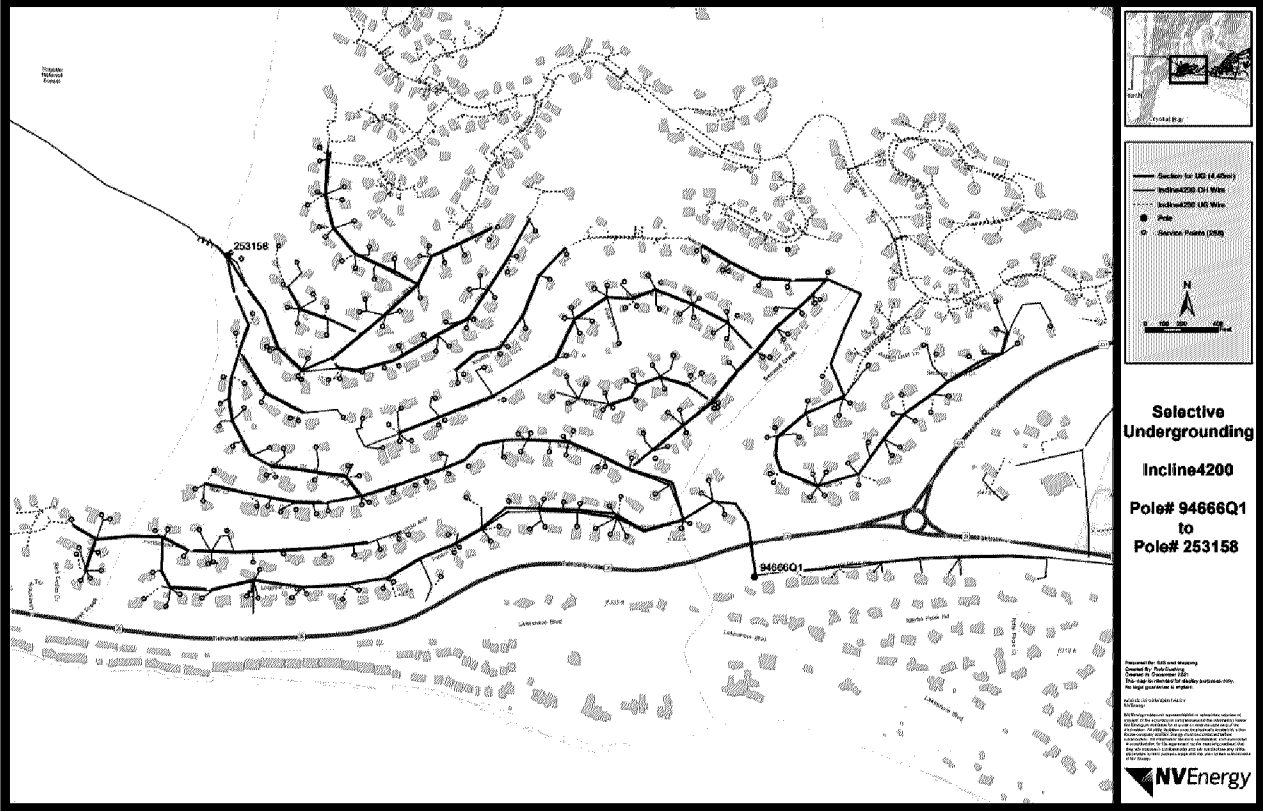


Figure F11. Incline 4200 Phase 2



Figure F12. Incline 4100 Phase 2



Figure F13. Incline 4200 Phase 4



Project 4: Sierra Undergrounding, Cost Sharing Partnerships

Figure F14. Incline 4100 Phase 3

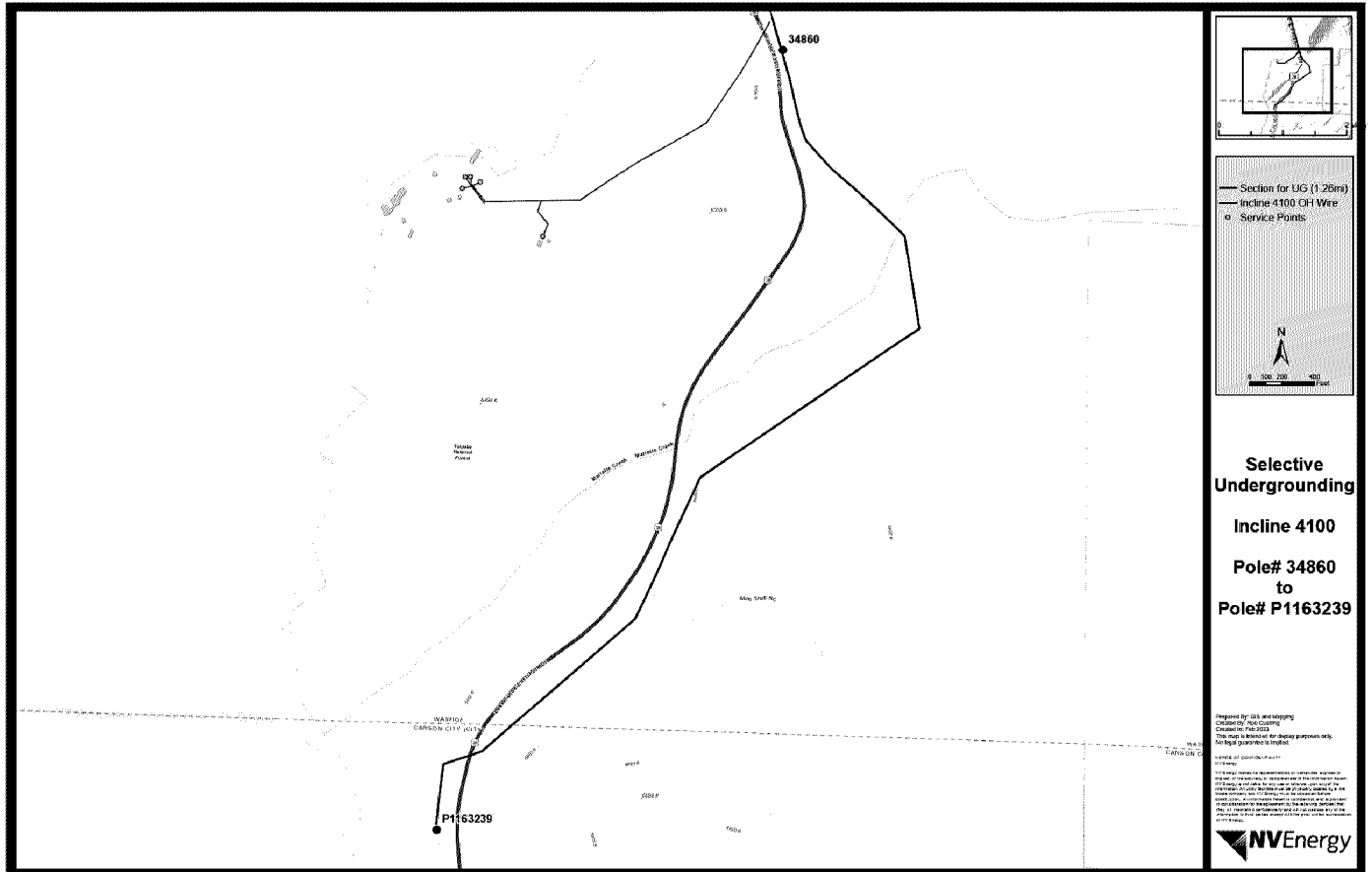


Figure F15. Glenbrook 2302 Phase 1

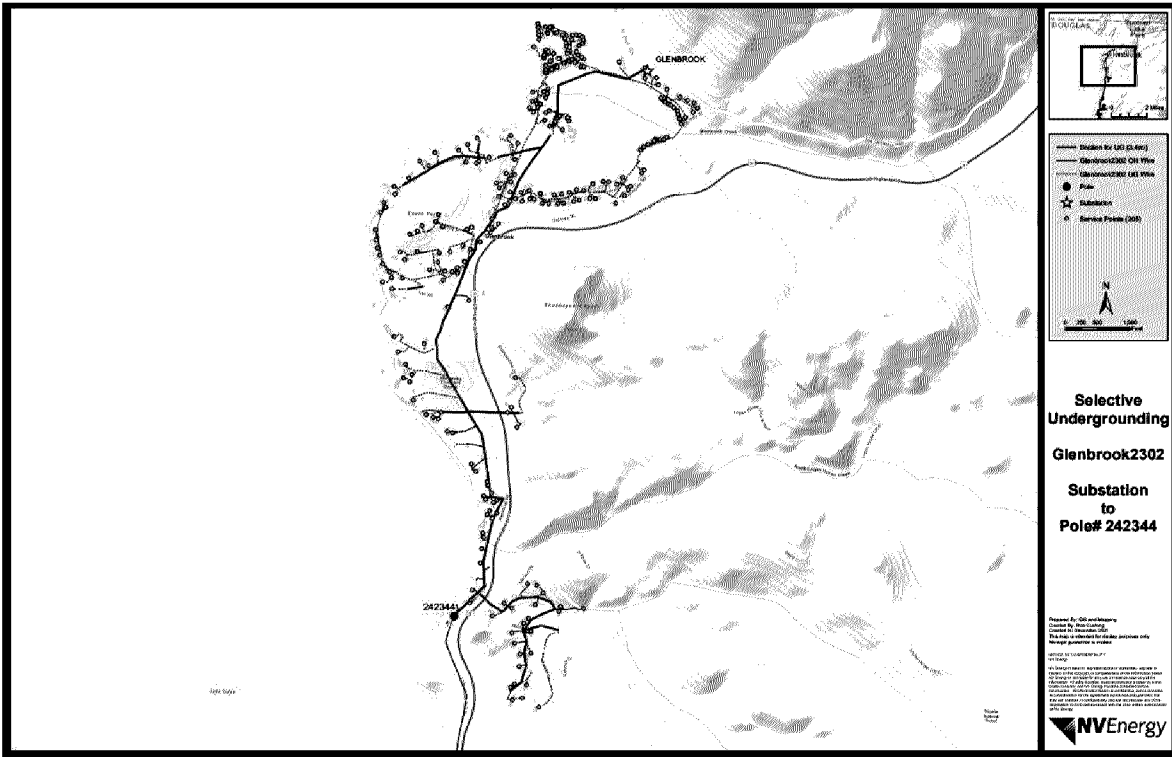


Figure F16. Glenbrook 2302 Phase 4

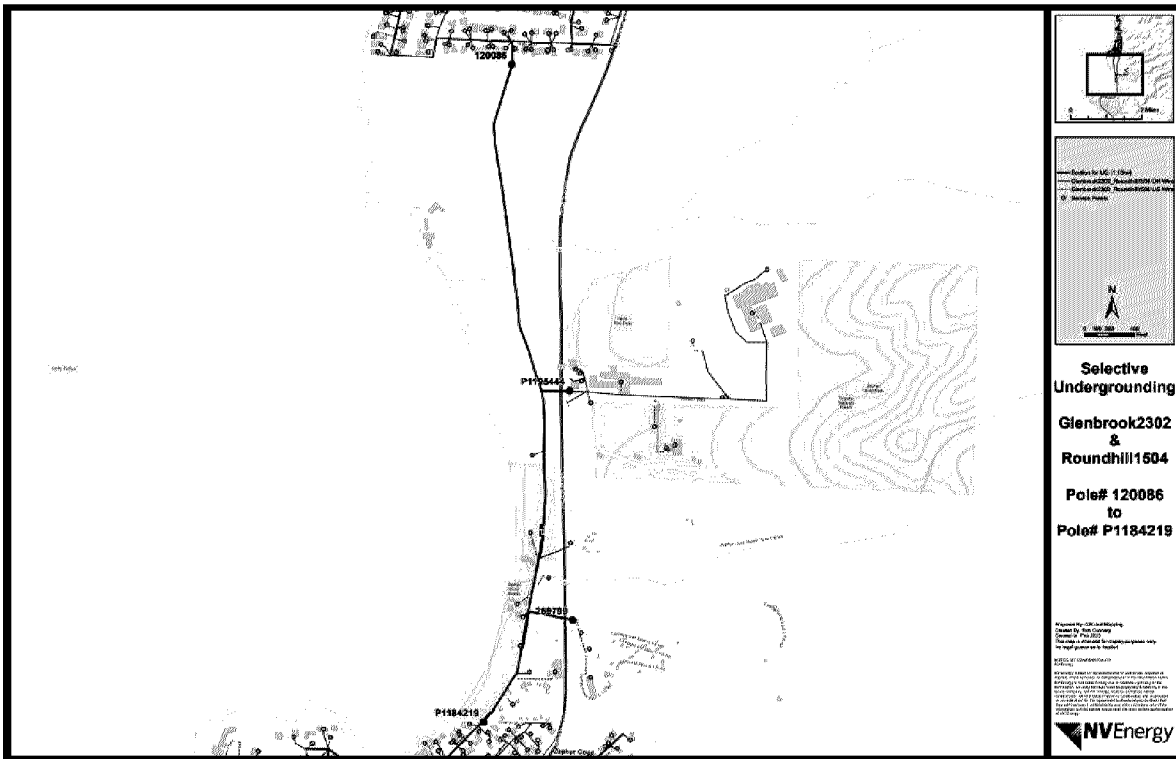


Figure F17. Glenbrook 2305 Phase 1

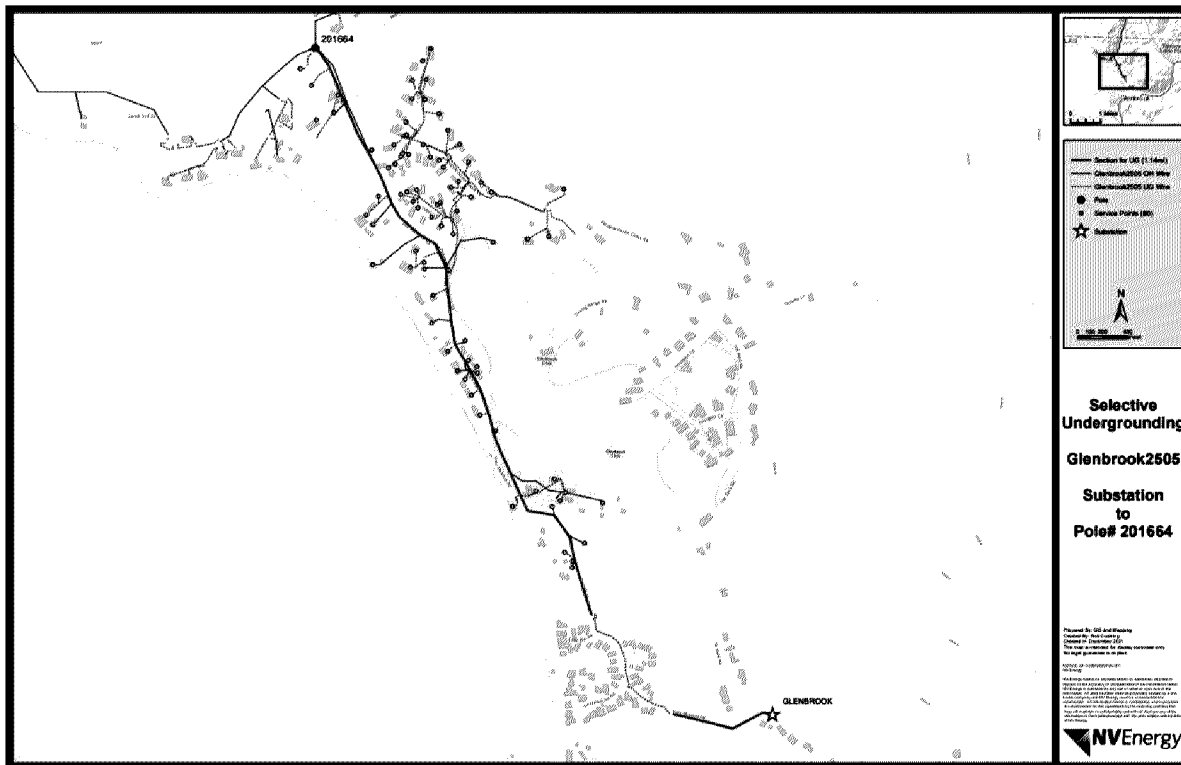
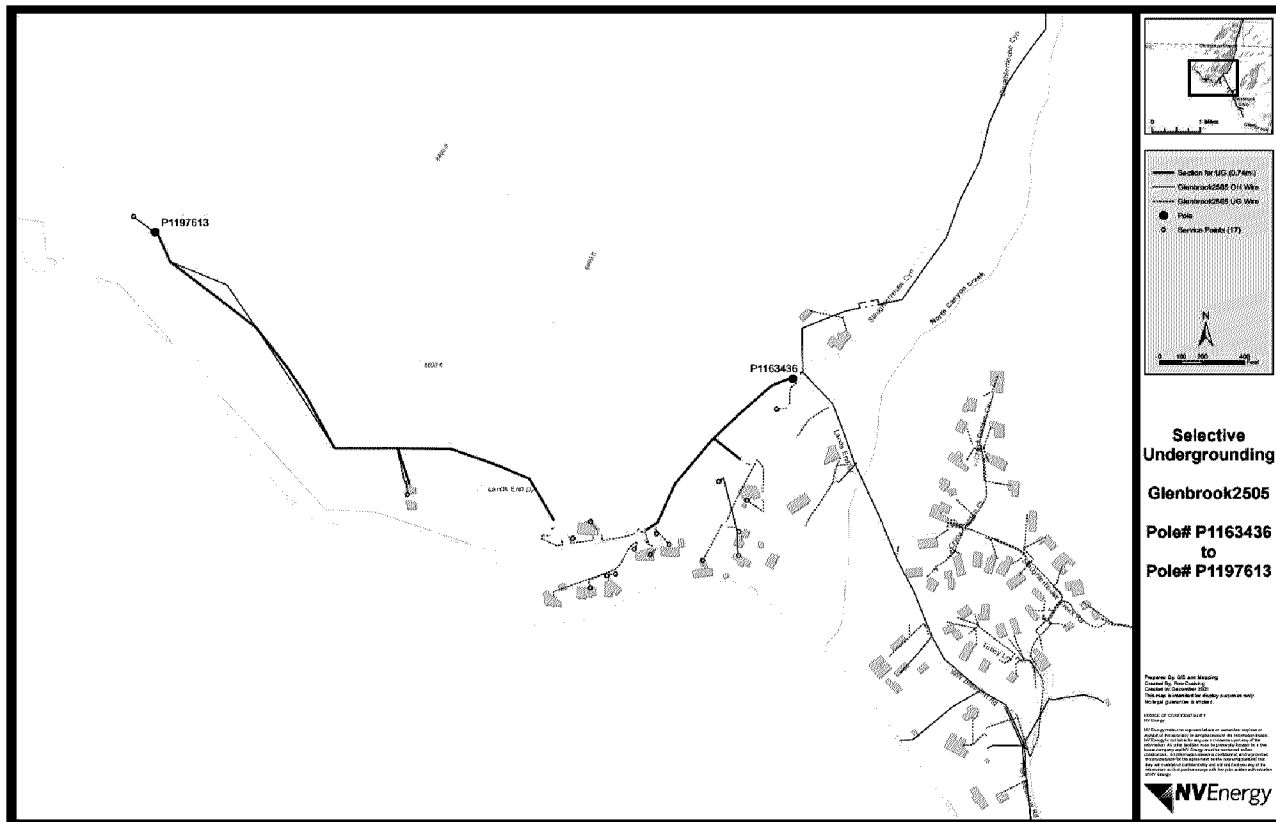


Figure F18. Glenbrook 2305 Phase 2



Project 5: Nevada Power Undergrounding, Mt. Charleston

Figure F19. Angel Peak 401, 402, 403

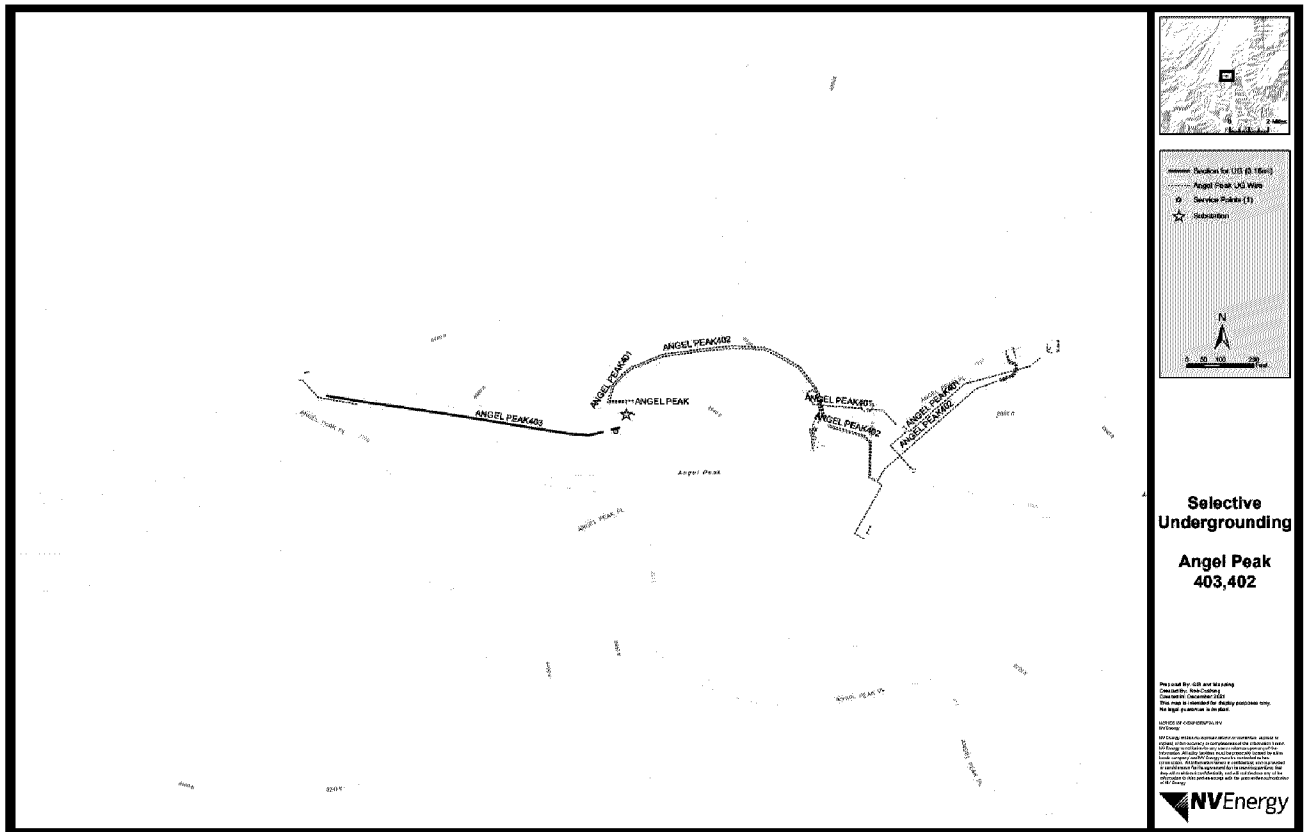


Figure F20. Canyon 3401

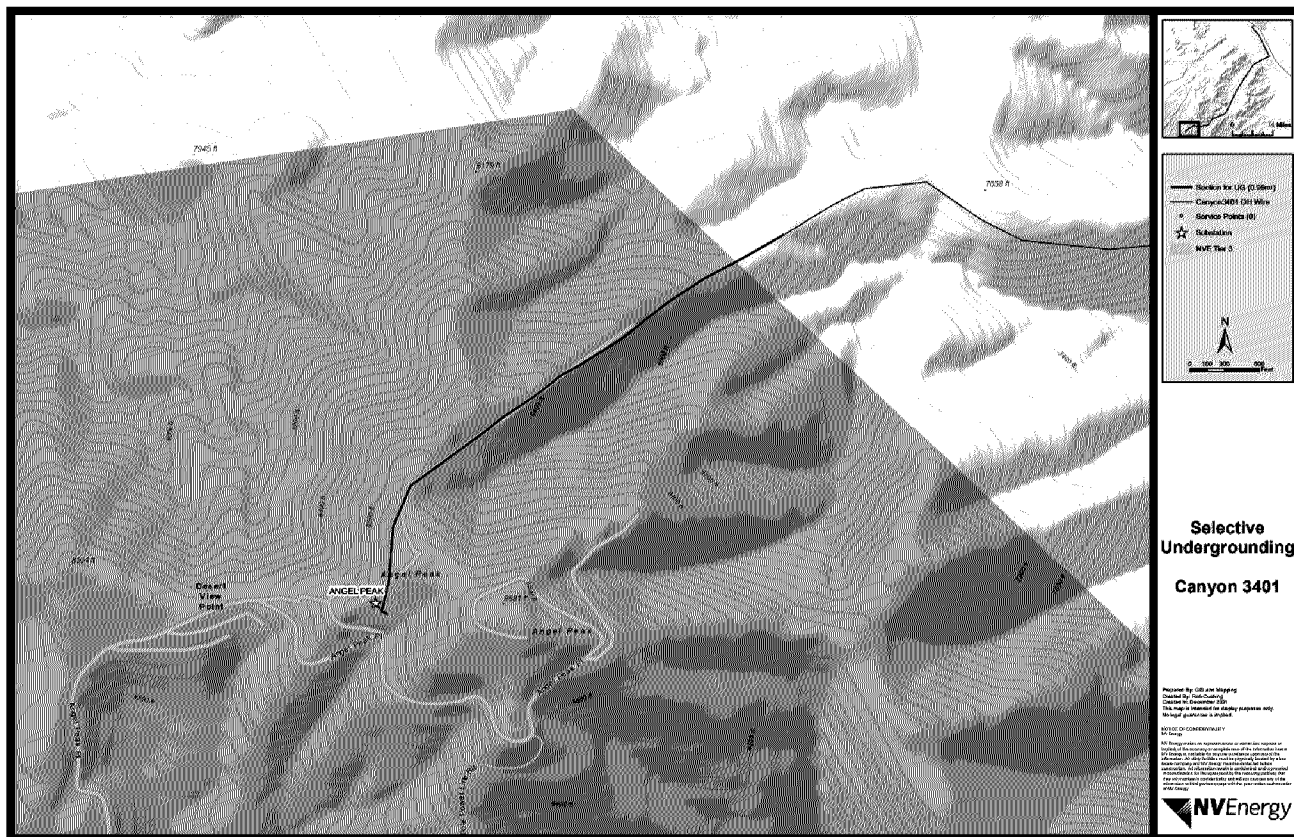


Figure F21. Angel Peak 3402

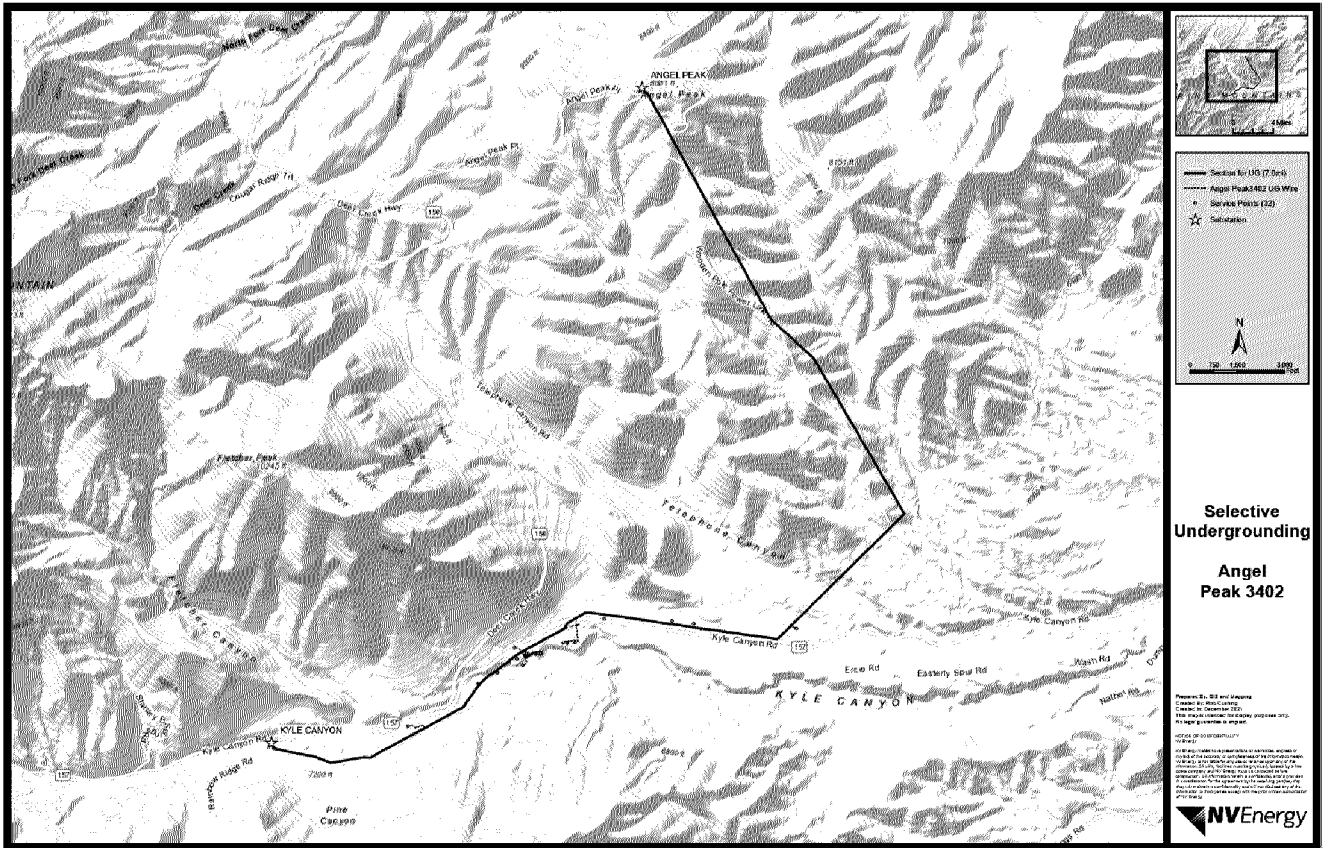


Figure F22. NW1215 to KC1201

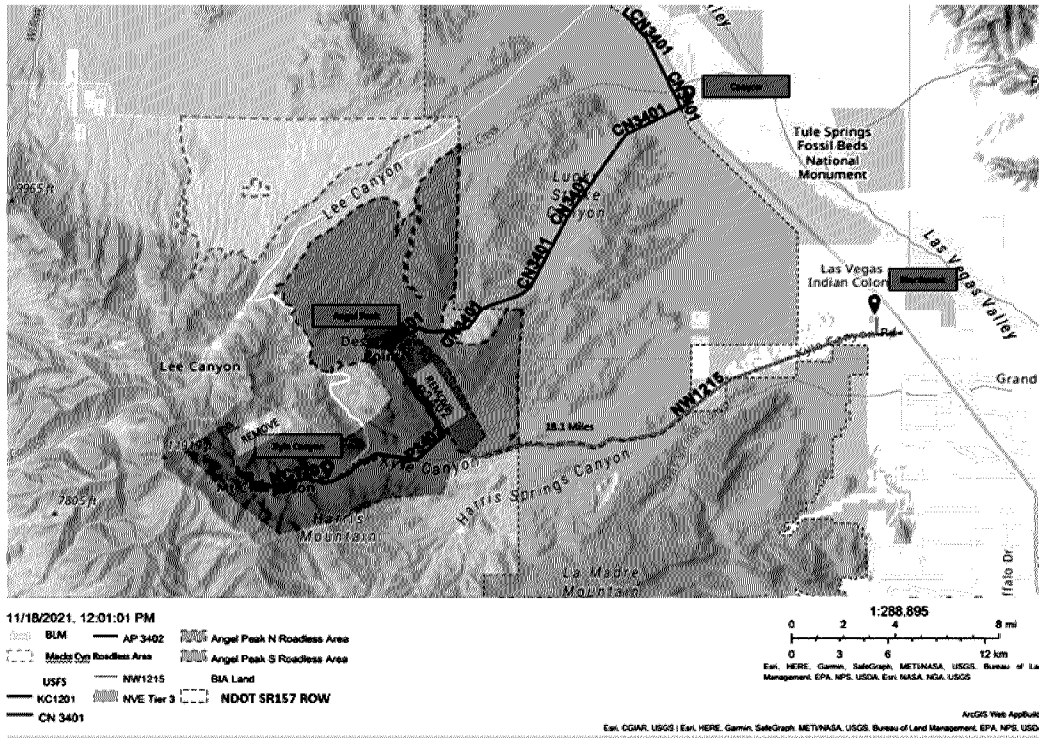
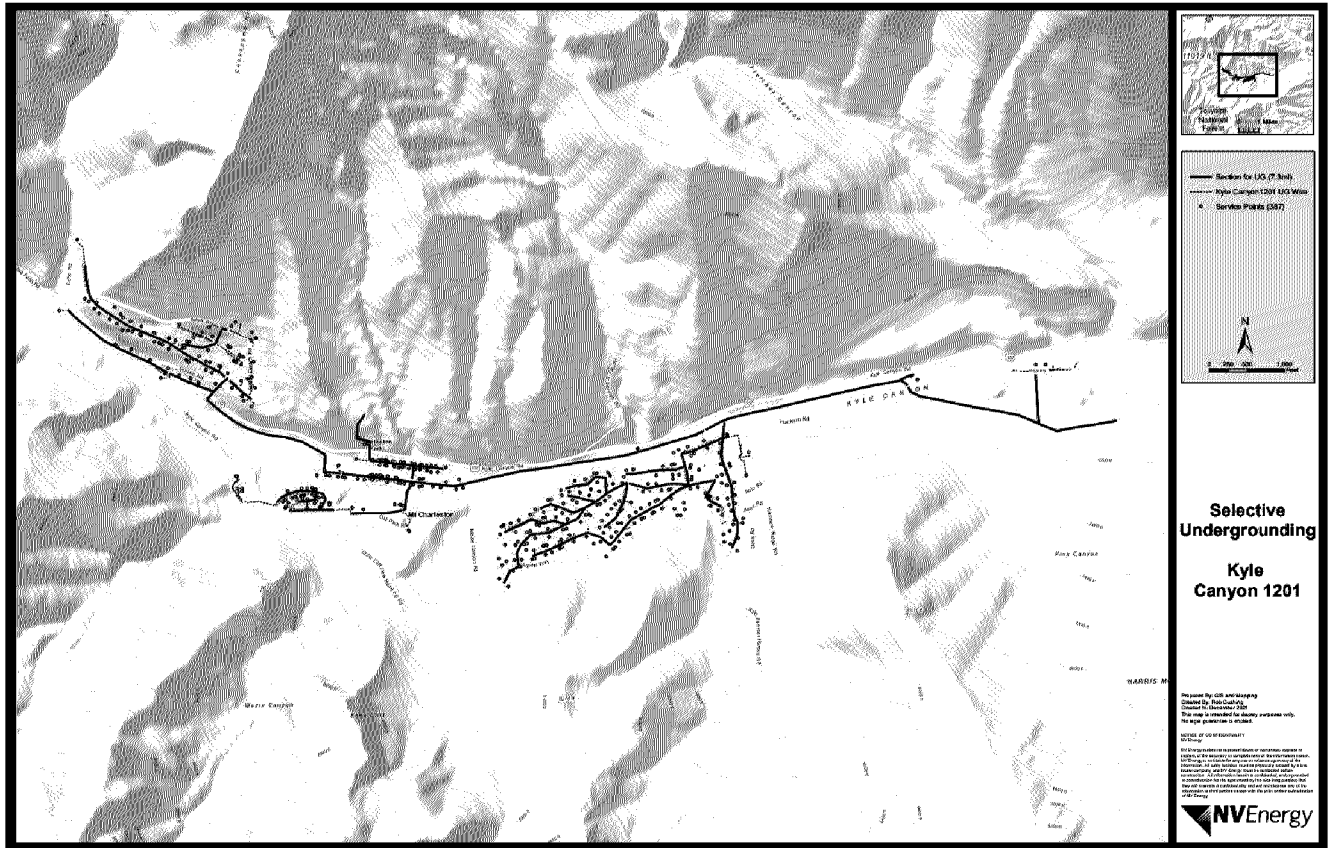


Figure F23. Kyle Canyon 1201



## APPENDIX G. CRITICAL CROSSINGS TABLE

**Table G1. Pole Stoppers and Critical Crossings Nevada Power - Capital**

DISTRIBUTION CRITICAL CROSSINGS												
Crossing	Project ID	Construction	Area	Circuit	# of Poles	Status	Design	Permitting	Construction	Completed		
Apex	3004507097	Fall 2022	North	GYP1210	1	CONSTRUCT			X			
Desert Inn (N) I-15	3004507451	Fall 2022	Strip/North	HI1220	2	CONSTRUCT				X		
Desert Inn (S) I-15	3004507528	Fall 2022	Strip/North	STR1203	2	COMPLETE				X		
Harmon	3004507498	Fall 2022	South	RS1205	1	CONSTRUCT			X			
% By Year	0%	0%	67%	33%								
Washing ton	3004506497	Spring 2023	North	MI1208	1	EXTPEND		X				
Craig	3004065331	Spring 2023	North	LO1203	2	EXTPEND		X				
Boulder Hwy	3004506590	Spring 2023	South	SA1212	1	EXTPEND		X				
Desert Inn (N) US-95	3004507505	Fall 2023	South	PL1206	2	EXTPEND		X				
Desert Inn (S) US-95	3004507532	Fall 2023	South	PL1206	2	EXTPEND		X				
Sahara	3004507161	Fall 2023	North	HI1211	2	EXTPEND		X				
% By Year	0%	100%	0%	0%								
TRANSMISSION CRITICAL CROSSINGS												
Crossing	Project ID	Construction	Area	Circuit	# of Poles	Status	Design	Permitting	Construction	Completed		
Artesian-Mayfair	0010009983	Spring 2022	North	69 kV	2	COMPLETE				X		
% By Year	0%	0%	0%	100%								
Lincoln-Pecos	0010009973	Spring 2023	North	138 kV	2	CONSTRUCT			X			
Lincoln-Pecos	0010009974	Spring 2023	North	138 kV	1	CONSTRUCT			X			
Indian Springs Tap of Mercury-Northwest	0010009972	Spring 2023	North	138 kV	1	EXTPEND		X				
Tenaya-Westside	0010009982	Fall 2023	North	138 kV	2	EXTPEND		X				

Tenaya-Westside	0010009 983	Fall 2023	North	138 kV	2	EXTPEN D		X		
Riverroad-Davis Tap-Kincwell-Searchlight	0010009 976	Fall 2023/Spring 2024	South	69 kV	2	EXTPEN D		X		
Riverroad-Davis Tap-Kincwell-Searchlight	0010009 977	Fall 2023/Spring 2024	South	69 kV	2	EXTPEN D		X		
Searchlight-Gas Pipeline-Mead	0010009 978	Fall 2023/Spring 2024	South	69 kV	2	EXTPEN D		X		
Searchlight-Gas Pipeline-Mead	0010009 979	Fall 2023/Spring 2024	South	69 kV	2	EXTPEN D		X		
% By Year	0%	81%	19%	0%						

## APPENDIX H. COPPER WIRE VARIANCE TABLE

Table H1. Copper Wire Variances

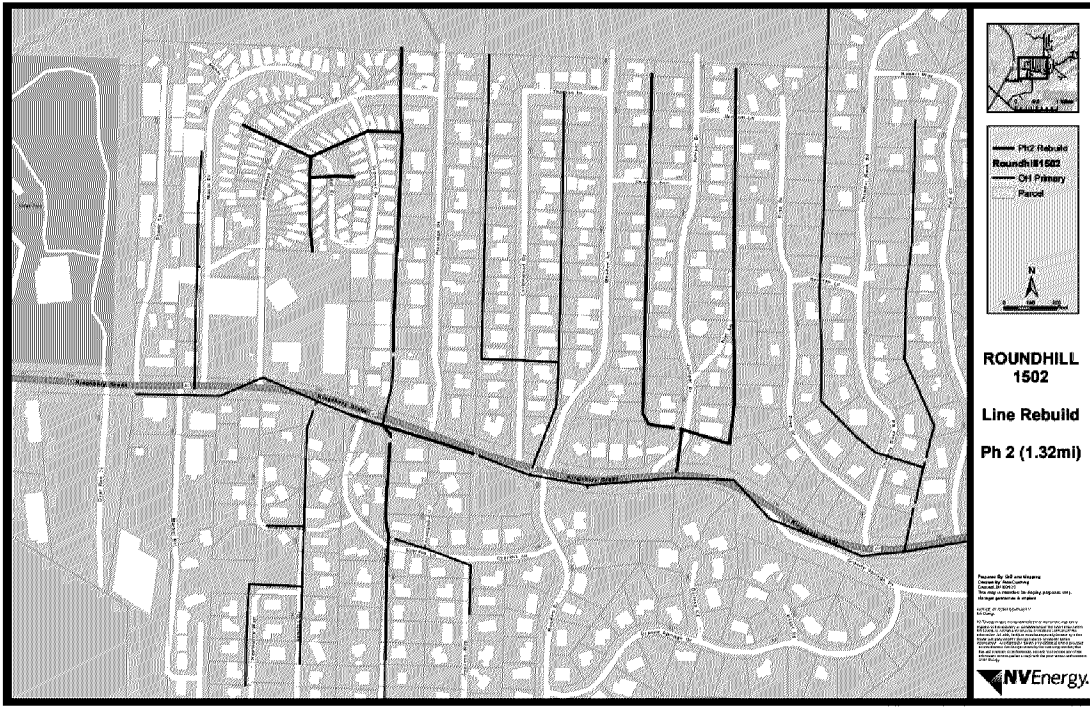
Tier	Circuit	Est. Linear Feet	Design	Permitting	Construction	Completed
3	Glenbrook 2302 Ph 1	7,174				X
3	Glenbrook 2302 Ph 2	7,392	X			
3	Round Hill 1504	6,890				X
3	Glenbrook 2505	2,127	Moved to Selective Undergrounding NDPP			
3	Glenbrook 2600	603				X
3	Incline 4100 Ph1	4,191				X
3	Incline 4100 Ph2	9,504			X	
3	Incline 4100 Ph3-4	13,233		X		
% By Category			14%	26%	19%	37%
Multi	Heybourne 1288	19,900		X		
2	Steamboat 212	4,391	Moved to GRC			
2	Steamboat 213	14,520	X			
2	Virginia City 213	13,200	X			
Multi	Muller 1295	8,801			X	
2	Winnemucca 205	811		X		
2	Last Chance 211	10,815	Moved to 2027 Plan to ensure mapping and field condition consistencies.			
2	Last Chance 218	3,679				
2	Last Chance 221	20,464				
2	Last Chance 212	15,840	X	X		
% By Category			39%	33%	8%	0%

Table H2. SPPC Copper Wire Variance 2022

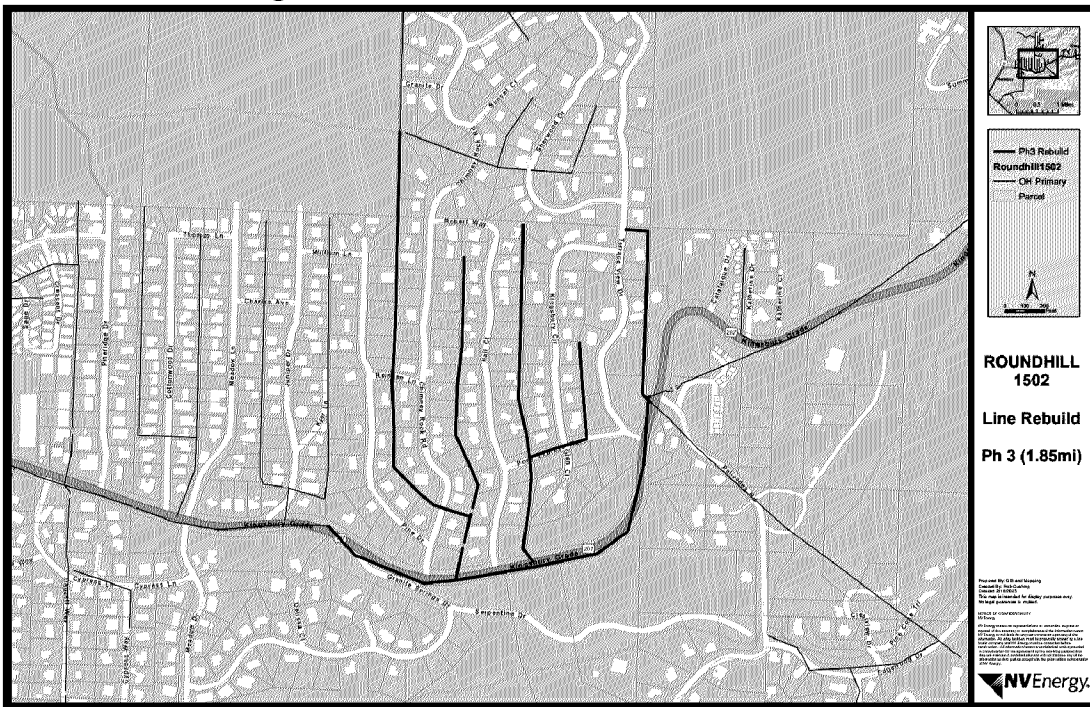
Monsoon	Circuit	Est. Linear Feet	Design	Permitting	Construction	Completed
Phase 1	Haven 1203	2,479				X
Phase 1	Lynwood 1205	2,076				X
Phase 1	Lincoln 1214	3,416				X
Phase 1	Claymont 1228	3,464				X
Phase 1	Cabana 1205	1,427			X	
Phase 1	Whitney 1201	16,587			X	
<b>% By Category / Total</b>		<b>29,449</b>	<b>0%</b>	<b>0%</b>	<b>61%</b>	<b>39%</b>
Phase 2	Carey 1208	2,012				X
Phase 2	Flamingo 1212	4,413				X
Phase 2	Pearl 1204	4,827			X	
Phase 2	Garces 1205	6,149			X	
<b>% By Category / Total</b>		<b>17,401</b>	<b>0.0%</b>	<b>0.0%</b>	<b>63%</b>	<b>37%</b>
Phase 3	Carey 1215	5,689			X	
Phase 3	Shadow 1209	5,825			X	
Phase 3	Miller 1208 (1)	7,300			X	
Phase 3	Miller 1208 (2)	7,003				X
<b>% By Category / Total</b>		<b>25,817</b>	<b>0%</b>	<b>0%</b>	<b>73%</b>	<b>27%</b>
Phase 4	Leavitt 1204	4,040		X		
Phase 4	Leavitt 1213	1,547				X
Phase 4	Mayfair 1215	2,152				X
Phase 4	San Francisco 1217	1,377			X	
Phase 4	North Las Vegas 1203	2,651			X	
Phase 4	North Las Vegas 1211	2,690		X		
<b>% By Category / Total</b>		<b>14,457</b>	<b>0%</b>	<b>47%</b>	<b>28%</b>	<b>26%</b>
Phase 5	Miller 1207	1,387	X			
Phase 5	Michael Way 1202 & 1213	2,312	X			
Phase 5	Whitney 1202 & 1206	1,721	X			
Phase 5	El Rancho 1203 Phase 1	4,500	X			
Phase 5	El Rancho 1203 Phase 2	4,737	X			
<b>% By Category / Total</b>		<b>14,657</b>	<b>100%</b>	<b>0%</b>	<b>0%</b>	<b>0%</b>
Phase 6	Water Street 1210	3,890	X			
Phase 6	Washington 1201	1,043	X			
Phase 6	Washington 1206 Phase 1	3,700	X			
Phase 6	Washington 1206 Phase 2	3,766	X			
Phase 6	Alta 1210	1,970	X			
<b>% By Category / Total</b>		<b>14,369</b>	<b>100%</b>	<b>0%</b>	<b>0%</b>	<b>0%</b>

# APPENDIX I. OVERHEAD REBUILDS MAPS

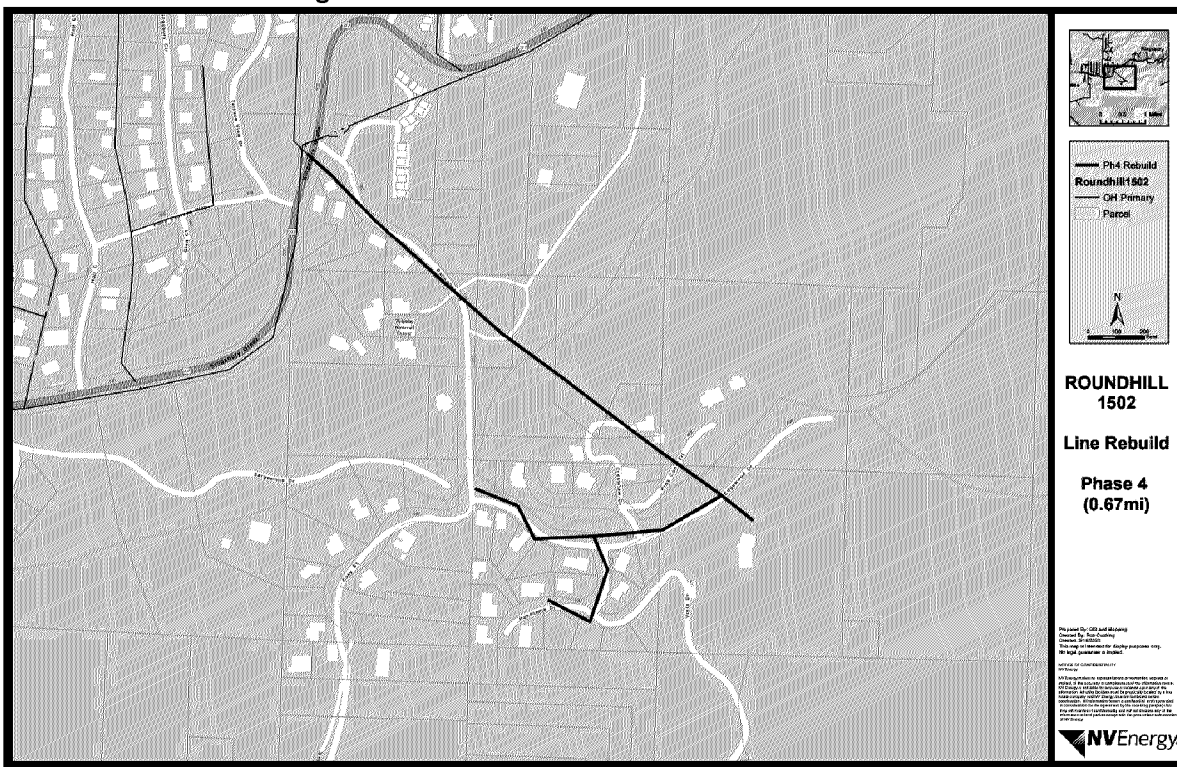
## Figure I 1. Round Hill Overhead Rebuild Phase 2



## Figure I 2. Round Hill Overhead Rebuild Phase 3



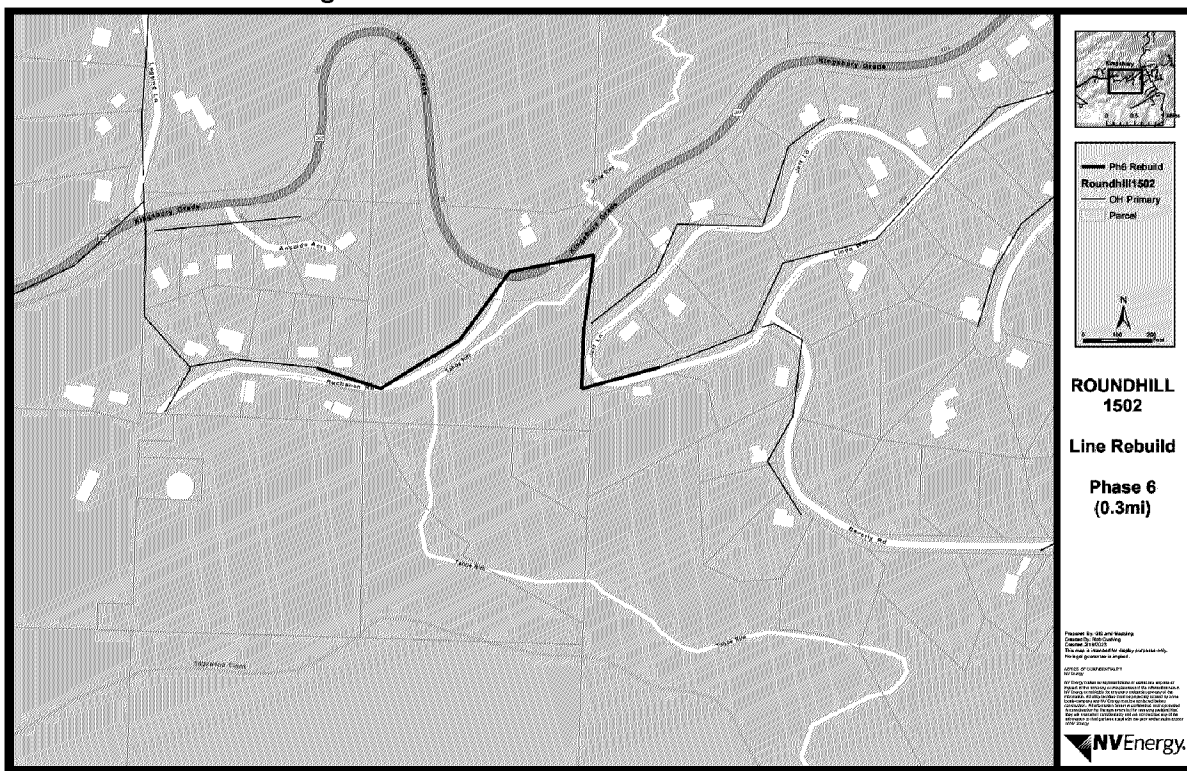
**Figure I 3. Round Hill Overhead Rebuild Phase 4**



**Figure I 4. Round Hill Overhead Rebuild Phase 5**



**Figure I 5. Round Hill Overhead Rebuild Phase 6**



**Figure I 6. Round Hill Overhead Rebuild Phase 7**



Figure I 7. Round Hill Overhead Rebuild Phase 8



Figure I 8. Muller 1295 Line Rebuild Tier 3

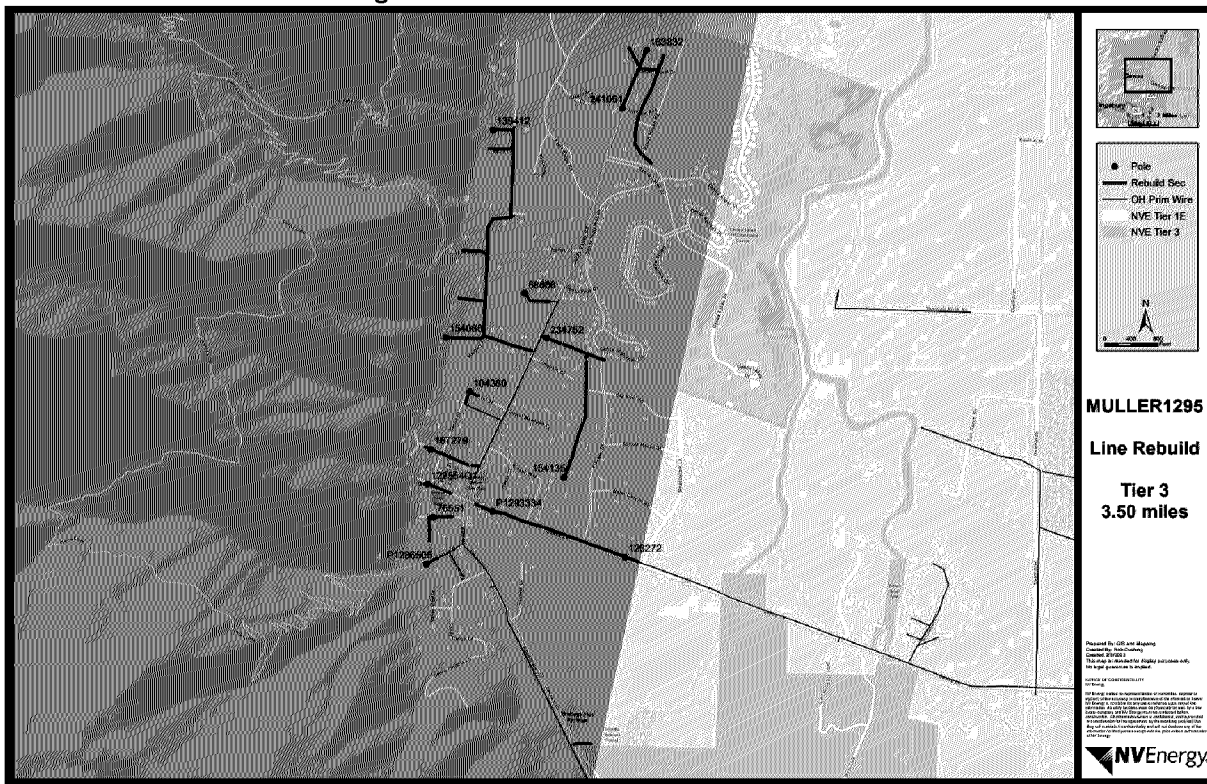


Figure I 9. Muller 1295 Line Rebuild Tier 2

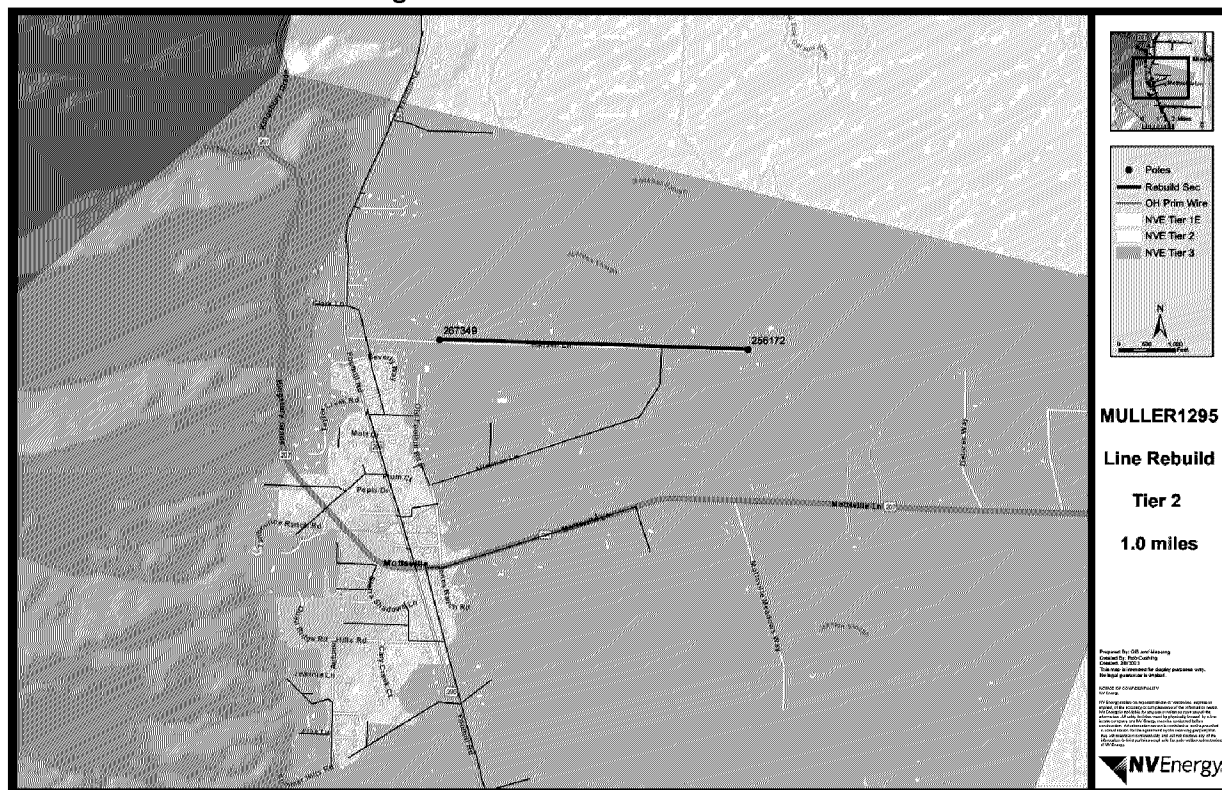


Figure I 10. Curry Street 1280 Line Rebuild Section 1

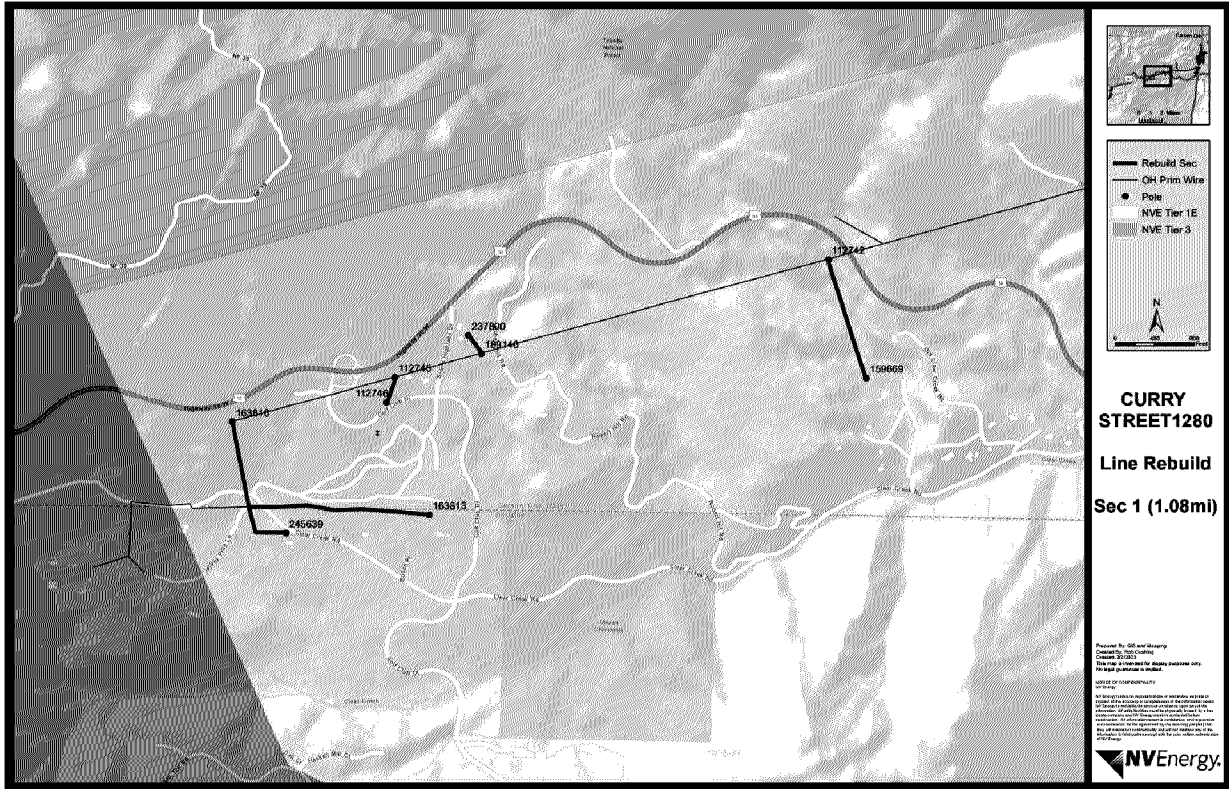


Figure I 11. Curry Street 1280 Line Rebuild Section 2

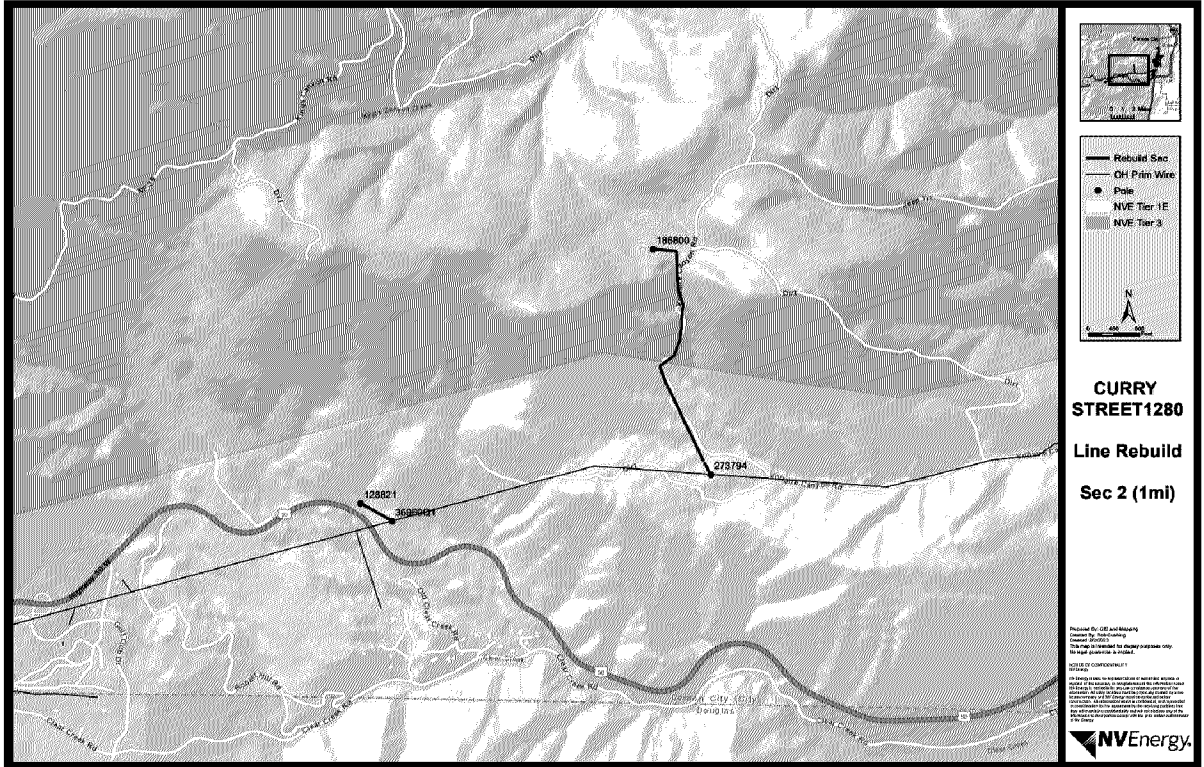


Figure I 12. Mt Rose 210 Line Rebuild Phase 1

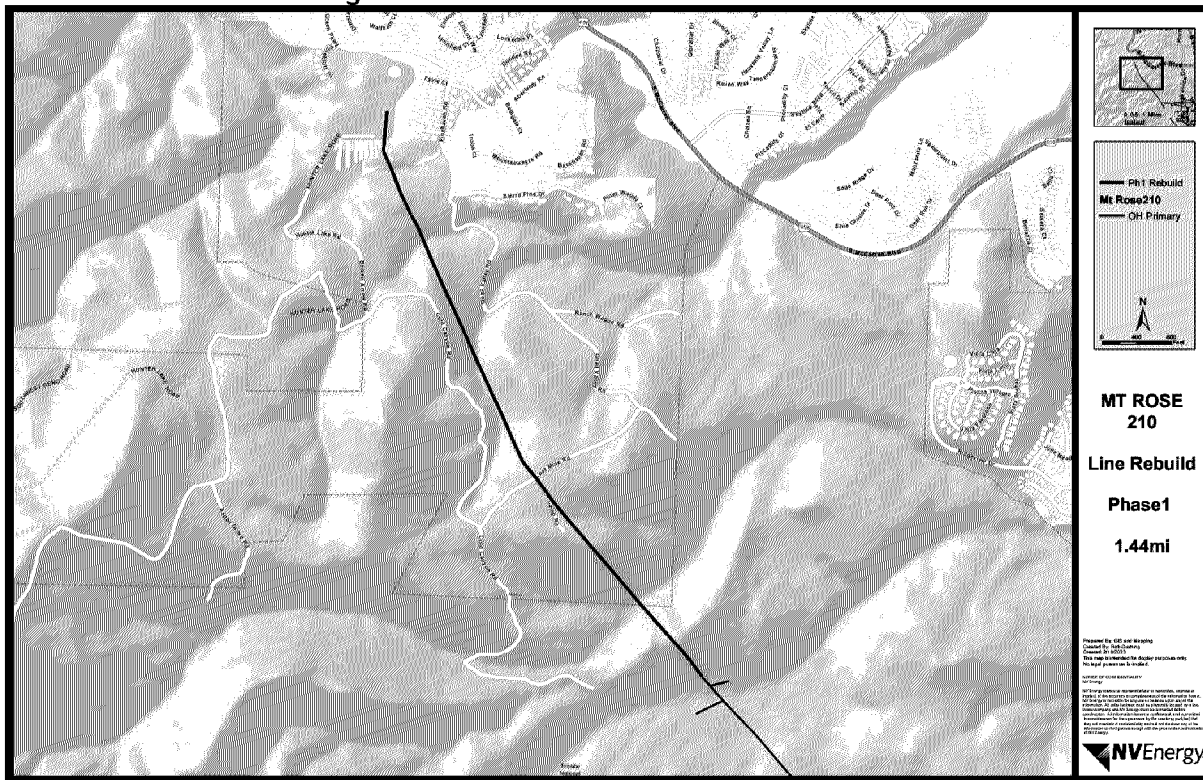


Figure I 13. Mt Rose 210 Line Rebuild Phase 2

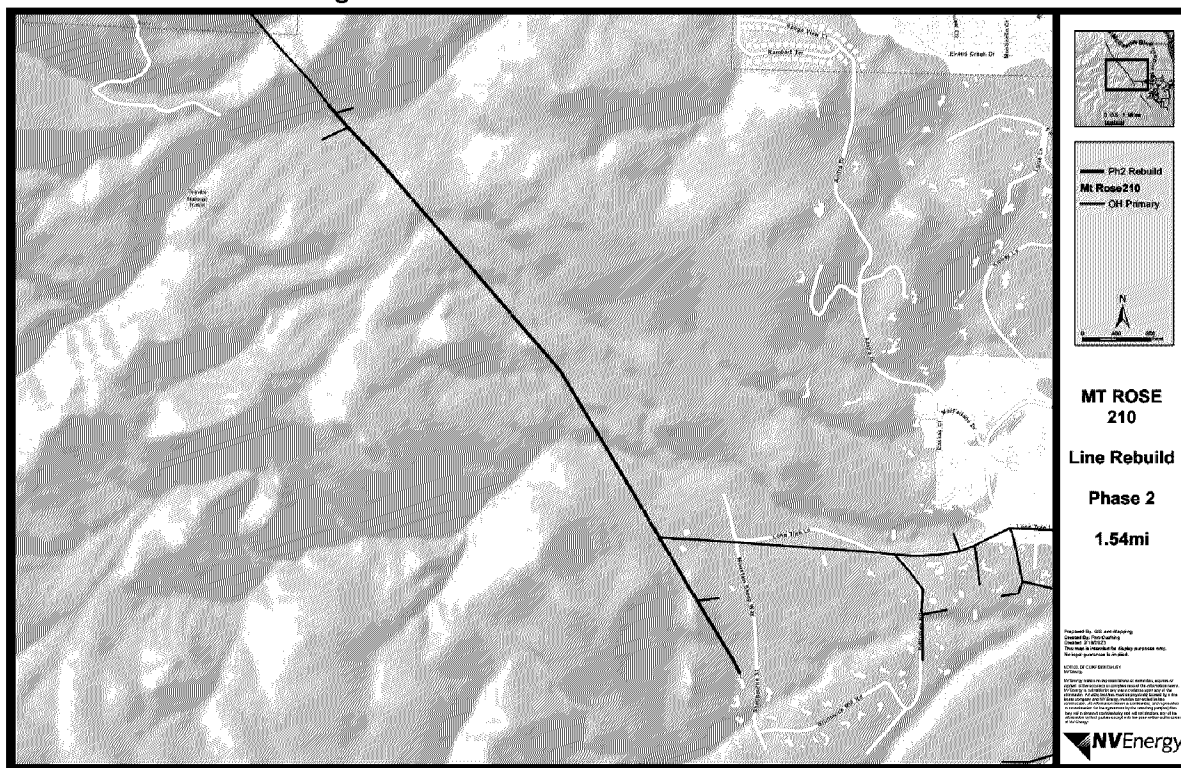


Figure I 14. Mt Rose 210 Line Rebuild Phase 3

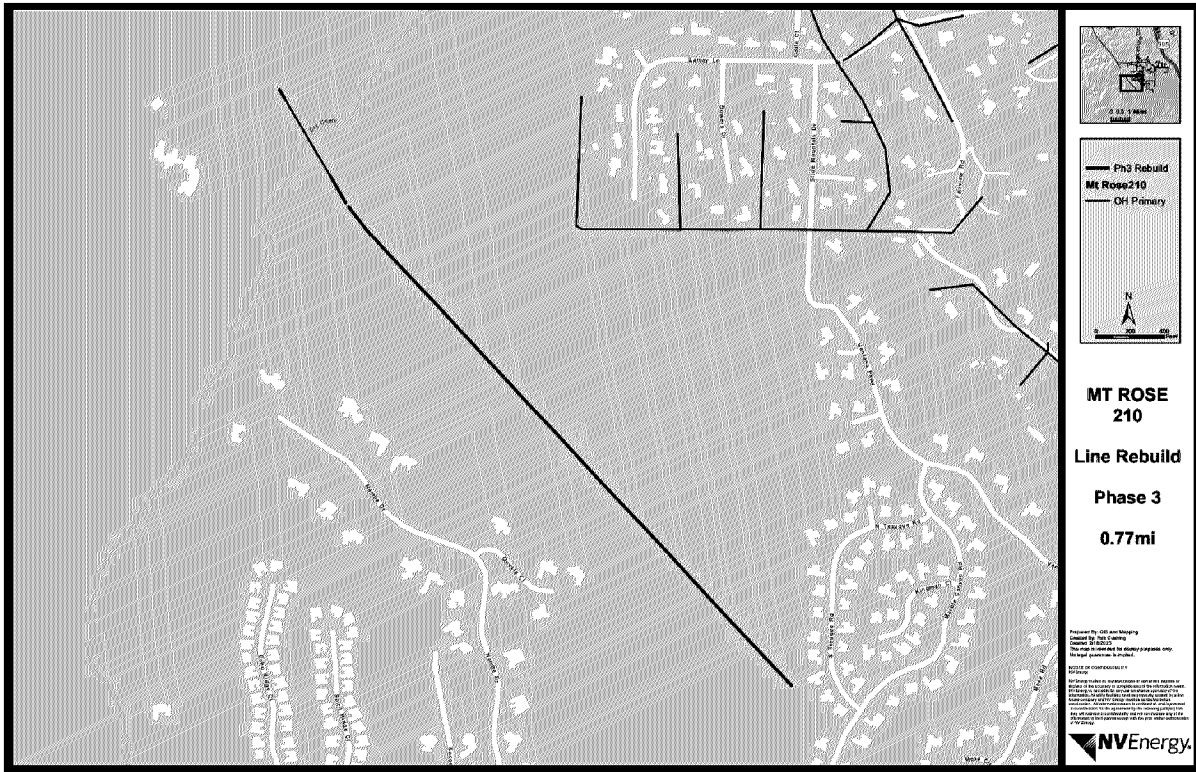


Figure I 15. Chimney Peak Line Rebuild Phase 2



**Figure I 16. Incline 4100 Line Rebuild Section 2**



**Figure I 17. Incline 4100 Line Rebuild Section 4**



Figure I 18. Incline 4100 Line Rebuild Section 6



## **APPENDIX J. NDPP TIER 3 TOTAL UNDERGROUNDING SUMMARY**

Two items related to undergrounding are presented in this Appendix:

J1. NDPP Tier 3 Total Undergrounding Summary Plan

J2. NDPP Selective Undergrounding Plan Segment Prioritization

## J.1 NDPP TIER 3 TOTAL UNDERGROUNDING SUMMARY PLAN



### NDPP Tier 3 Total Undergrounding

#### 2023 Summary Plan

##### PLAN SUMMARY

The objective of the Tier 3 Total Undergrounding Summary Plan is to provide an overview of the tasks to completely underground all remaining overhead distribution lines located within Tier 3 fire risk areas as directed in the Second Modified Final Order. This plan provides a high-level, order of magnitude estimates of what it could take to completely underground these lines as well as detail the benefits and drawbacks of total undergrounding.

##### APPLICABILITY

This plan applies to the Tier 3 primary distribution circuits. Mainline is generally described as the backbone feeder, typically a three-phase primary source for laterals. Laterals branch from mainlines to source areas with single-phase or two-phase (delta) primary lines. Distribution transformers convert voltages to serve customer connection points through secondary and service laterals that extend from the transformers.

##### Northern Nevada Tier 3 Circuits

- |                     |                 |                 |
|---------------------|-----------------|-----------------|
| • Curry Street 1280 | Downs 1285      | Glenbrook 2302  |
| • Glenbrook 2505    | Glenbrook 2600  | Heybourne 1288  |
| • Incline 4100      | Incline 4200    | Incline 4300    |
| • Kingsbury 2800    | Mueller 1295    | Round Hill 1502 |
| • Round Hill 1503   | Round Hill 1504 |                 |

##### Southern Nevada Tier 3 Circuits

- |                   |                |                  |
|-------------------|----------------|------------------|
| • Angel Peak 3402 | Angel Peak 401 | Angel Peak 402   |
| • Angel Peak 403  | Canyon 3401    | Kyle Canyon 1201 |

##### ASSUMPTIONS

In order to have a base starting point for this plan, multiple assumptions have been made and are detailed below:

- Overhead Covered Conductor Rebuilds:
  - If covered conductor rebuilds are to continue under programs such as Copper Wire Replacement, this plan will potentially be replacing updated overhead fire mitigation equipment before the end of its useful life.
  - If covered conductor rebuilds are to cease with potential implementation of this Total Undergrounding Plan, no other overhead rebuilds will be completed within the Tier 3 fire risk area.

- If a primary circuit contains secondary wire on the same pole, the secondary wire will be undergrounded along with the primary conductor. Pole lines containing secondary wire and service wire only will remain in an overhead configuration.
- Customer panels will not be converted i.e., if it is currently an overhead panel, it will remain an overhead panel.
- This plan assumes that all existing overhead lines can be feasibly undergrounded.
- **All estimates are rough order of magnitude estimates due to no construction having been completed on any Natural Disaster Protection Plan undergrounding segments as of the writing of this plan.**
- Rough order of magnitude estimates contained within this plan assume a 2.5% cost escalation factor. This factor was derived from industry standard RS Means and CBRE historical cost trends (note: years 2020 through 2022 were not factored into this average due to unprecedented effects caused by the COVID-19 Pandemic).

**OVERVIEW AND ORDER OF MAGNITUDE**

The below tables provide an overview of total line miles to underground in Tier 3 as well as a rough order of magnitude of timeline and cost:

Tier 3 Total Undergrounding		
Total Overhead Line Miles	Order of Magnitude (\$)	Total Duration (Years)
141.2	\$ 770,695,849	47

Breakdown of Tier 3 Total Undergrounding		
	Miles to Underground	Order of Magnitude (\$)
Total	141.2	\$ 770,695,849
2 and 4 Miles	5.78	\$ 15,478,000
Mt Charleston	15.96	\$ 71,405,737
Remaining Prioritization Segments	43.26	\$ 229,150,824
Other Unidentified Overhead	76.38	\$ 454,661,288

Note 1: The dollar values and duration estimates displayed above are rough orders of magnitude and are not official estimates.

**DISCUSSION**

With a catastrophic fire becoming a more statistically likely event, utilities and public utility commissions alike have turned to a multitude of fire mitigation and system hardening techniques to reduce the likelihood of a utility-caused ignition, with targeted undergrounding efforts being one of the more widely discussed methods. While multiple West Coast utilities are pushing undergrounding to the forefront of their wildfire risk mitigation plans, it does not appear to be the only industry standard for fire mitigation. Utilities such as Xcel Energy’s Colorado Service Territory have opted not to include strategic undergrounding in their wildfire mitigation plans. Citing ballooning undergrounding costs, that are nearly ten times the cost to rebuild the same lines utilizing covered conductor, as well as the extended time frames for deployment and removing the risk from the system. In other service territories in the West, utility providers are actively pursuing undergrounding of select circuits or select circuit segments such as San Diego Gas & Electric, Southern California Edison, Pacific Gas & Electric and PacifiCorp. This is also being done in conjunction with circuit rebuilds using covered conductor and other fire mitigation/system hardening programs.

**Benefits**

Modeling software, such as Technosylva’s Wildfire Risk Reduction Module, indicate that by undergrounding existing overhead conductor, the risk of ignition by utility-owned equipment is reduced by upwards of 90 to 95%. Along with the overall risk of ignition, another major benefit to undergrounding is the overall increase to system reliability in general, as well as during various weather events. Underground primary facilities are much less susceptible to damage due to high winds, rain, snow, and vegetation issues. While failures do still occur in underground facilities, outages are less likely in major weather events. In addition, the occurrence of PSOM events can potentially be reduced in areas with underground distribution, conceivably lowering the emergency outage impacts to customers living in high fire risk areas. Furthermore, the below list identifies supplemental benefits to undergrounding:

- Reduction in Detailed Inspection and Patrols
  - Over time, with converting overhead lines to underground, the Companies would begin to realize a cost savings in the detailed inspection, patrols, and priority correction budgets. It is important to note that this savings would not be instantaneous but would be gradual with the reduction of overhead line miles. Additionally, the need for detailed inspections, patrols, and corrections cannot be completely eliminated. Below is a reference table showing an annualized cost of the inspections and corrections for Tier 3 2023 thru 2025:

	Patrols Cost	Inspection Cost	P0 Capital Cost	P0 OMAG Cost	P1 Capital Cost	P1 OMAG Cost	Year Total Spend
<b>2023</b>	\$157,795.80	\$0.00	\$24,200.00	\$2,860.00	\$798,600.00	\$94,380.00	\$1,077,835.80
<b>2024</b>	\$255,970.20	\$0.00	\$24,200.00	\$2,860.00	\$798,600.00	\$94,380.00	\$1,176,010.20
<b>2025</b>	\$255,970.20	\$392,046.00	\$48,400.00	\$28,600.00	\$7,139,000.00	\$918,060.00	\$8,782,076.20
						<b>3 Year Total</b>	\$11,035,922.20

- Reduction in Vegetation Management Patrols/Trimming/Clearing
  - Similar to the inspection and correction program, the Companies would begin to realize cost savings in the vegetation management required to maintain the current circuits in Tier 3. While vegetation management will still be necessary in areas, such as near substations, pad-mounted equipment, vaults etc. the need and order of magnitude could be generally decreased over time with converting overhead distribution lines to underground. Below is a reference table depicting annualized costs of vegetation management in the Tier 3 areas for 2024 - 2026.

<b>NPC</b>			
<b>Tier 3</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>
<b>Tree Trimming</b>	\$ 234,500.00	\$ 173,530.00	\$ 133,618.00
<b>Pole Grubbing/ROW Clearing</b>	\$ 4,245,179.00	\$ 1,200,000.00	\$ 1,200,000.00
<b>Total</b>	\$ 4,481,703.00	\$ 1,375,555.00	\$ 1,335,644.00

<b>SPPC</b>

Tier 3	2024	2025	2026
<b>Tree Trimming</b>	\$ 3,303,696.00	\$ 3,750,400.00	\$ 3,472,340.00
<b>Pole Grubbing/ROW Clearing</b>	\$ 15,953,767.00	\$ 14,953,767.00	\$ 13,953,767.00
<b>Total</b>	\$ 19,259,487.00	\$ 18,706,192.00	\$ 17,428,133.00

\*\*Note: Actual percent reduction of risk varies and is dependent on multiple variables such as current fuel loading, fuel moisture content, drought conditions, etc.

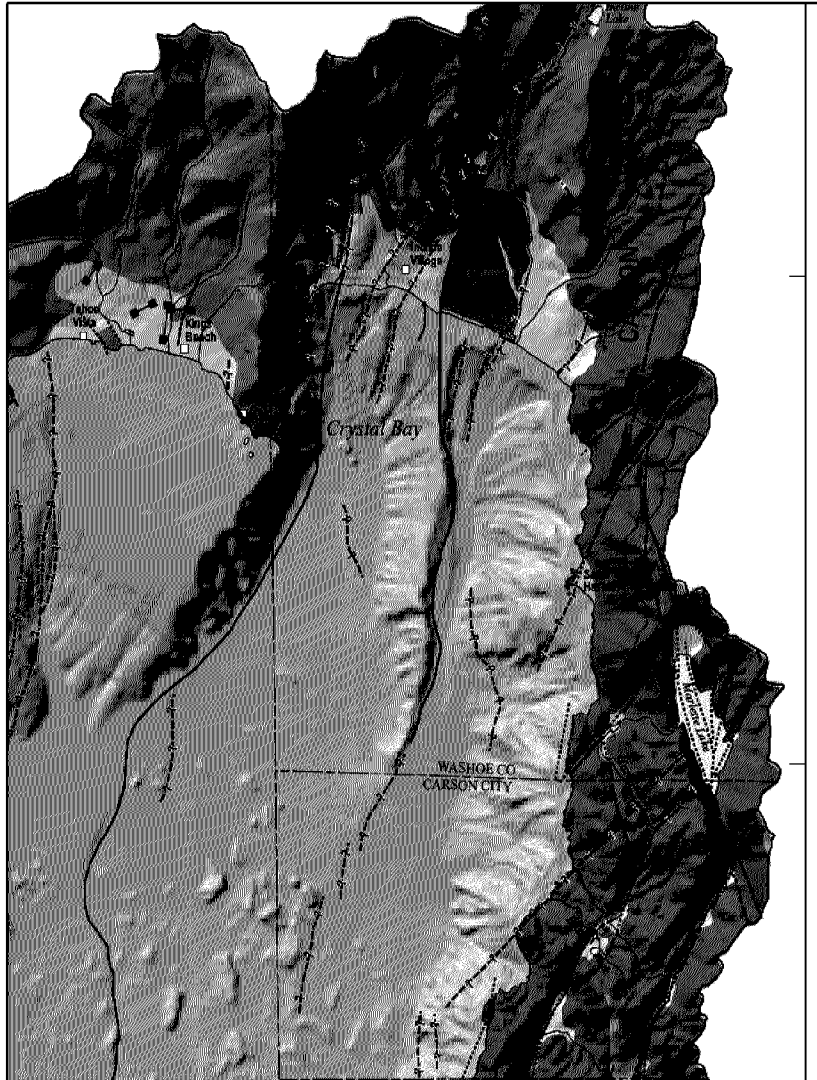
### Drawbacks

While providing numerous benefits, mass undergrounding of distribution circuits has multiple drawbacks that must also be considered listed below:

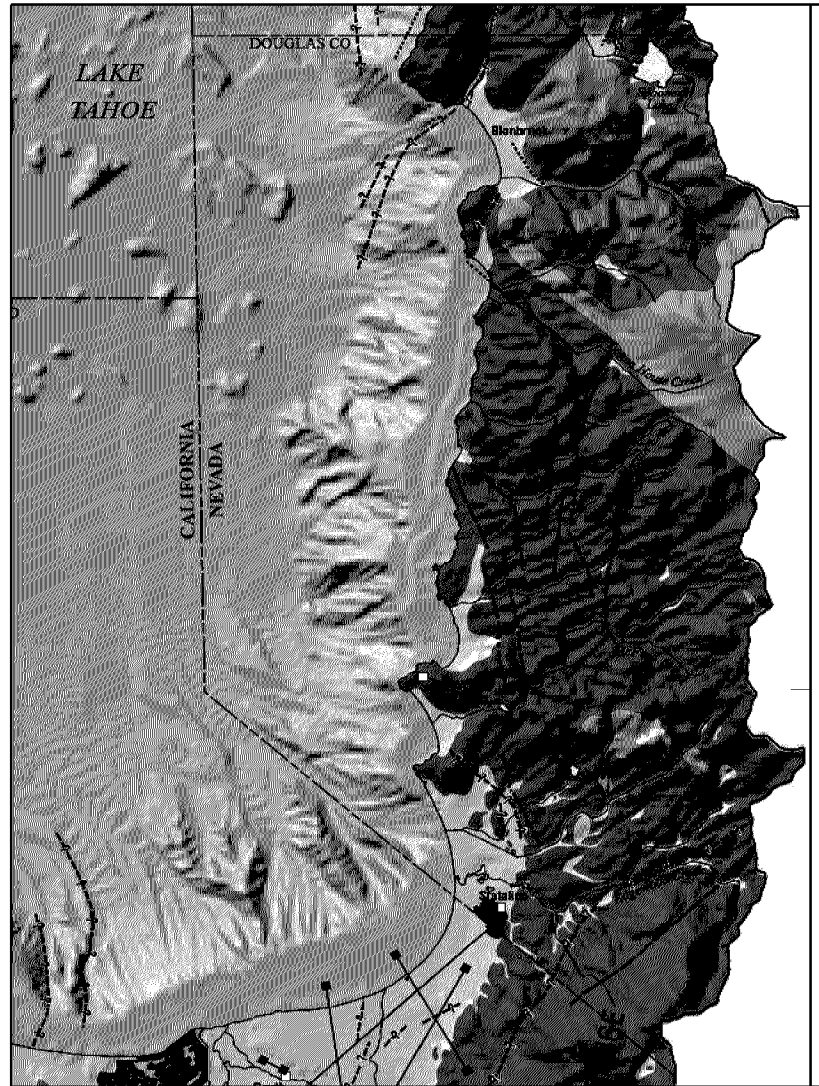
- **Cost**
  - While undergrounding provides numerous benefits to the system and environment, a serious consideration in undergrounding is the overall cost when compared to other system hardening programs. Programs such as line rebuilds with covered conductor cost two to five times less than undergrounding, which is an enormous consideration to take as the overall financial impact to rate payers could be drastic.
- **Extended Timeline/System Deployment Delay**
  - Timeline for deployment is another drawback to whole distribution system undergrounding in Tier 3. Undergrounding requires substantially more civil construction work to take place prior to the distribution line or equipment being installed and/or energized. Based off prior new business and capital construction undergrounding projects in the Tier 3 areas, it is estimated that on average one mile of underground infrastructure (conduit, vaults, and pads) can be installed per segment per season. This is due to numerous variables such as the geologic properties in the Tier 3 areas as well compressed construction seasons. These items will be discussed more in depth below.
- **Complex Permitting and Design**
  - Tier 3 presents numerous different permitting and design hurdles in general, but undergrounding adds additional layers of complexity. Depending on the location and alignment of the trench and facilities, full sets of civil plan and profile designs must be completed to meet the encroachment and excavation permit requirements established by the County or State Agencies. Furthermore, new easement acquisitions will more than likely be necessary to facilitate the undergrounding of most if not all Tier 3 distribution lines. While NV Energy has had success thus far in obtaining easements from private landowners, this could be a lengthy process in some instances. Although most NV Energy primary voltage distribution facilities have easements that allow access, maintenance, and potential rebuild capabilities, they generally do not cover trenching and placing facilities underground in those areas.

- Terrain/Geology of Tier 3
  - The geology and terrain of the Tier 3 risk areas is difficult to put it simply. Per the U.S. Geological Survey maps provided below and in Attachment A, the terrain is covered in an assortment of intrusive igneous and volcanic rock, meaning excavation could be extremely tough as these areas generally contain granite and other hard rock formations. In addition to hard rock excavation, some segments of overhead circuit run through steep forested terrain, further slowing down civil excavation production.
- Limited Construction Seasons
  - Due to the high alpine location of much of Tier 3 areas, winter weather has a drastic impact on construction schedules. For the Tahoe area in particular, there is an established grading season from May 1<sup>st</sup> through October 15<sup>th</sup> each year, set by the Tahoe Regional Planning Agency. While lines construction may still proceed during the off season, depending on weather condition, grading efforts are limited to a narrow 5.5-month window.
- Restoration Efforts
  - While underground facilities are generally more reliable when exposed to a major weather event or storm, when a failure does occur, troubleshooting that failure can take considerably longer. This is due to not being able to visually patrol the underground facilities, as well as during certain months, underground infrastructure can be buried by multiple feet of snow further delaying the troubleshooting and restoration of the outage.
- Impacts to Customers and Community
  - Due to many of the factors listed above, underground construction is a lengthy process. With primary facilities needing to be installed either in the shoulder behind curb or in the roadway itself, civil and lines construction will have a significant impact to the traveling public in the form of road closures and lane/speed reductions in the work areas. In addition, private properties will have to be excavated in to accommodate vaults and pad-mounted equipment, impacting walkways/driveways and landscaping.
- New Business Requirements
  - There is still an issue that new facilities are not required to be installed underground in these areas. If we are to embark on a 100% underground Plan for Tier 3, the Commission has the issue that the current ordinances do not require undergrounding (except maybe in Douglas County that probably still allows variances and exceptions)

▪ **FIGURE A – North Lake Tahoe**











▪ **FIGURE B – South Lake Tahoe**

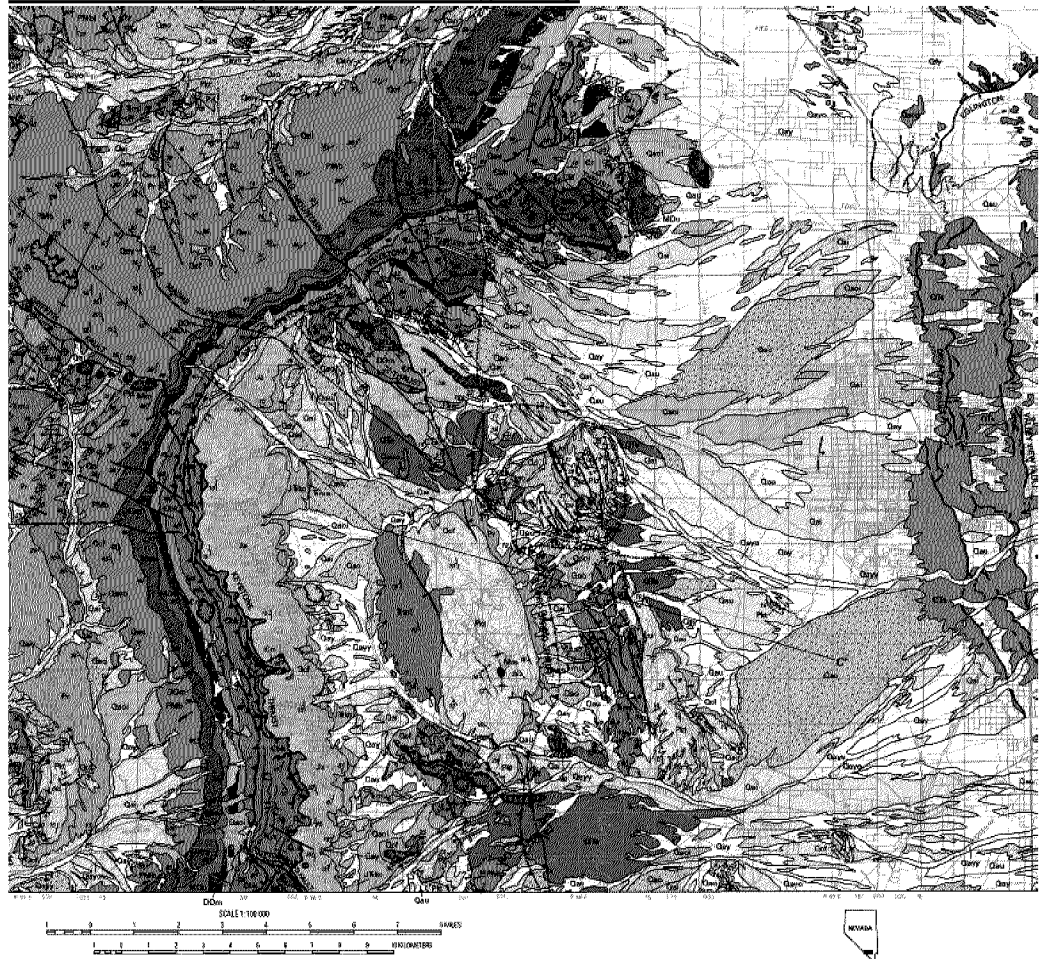


■ **FIGURE C – Tahoe Geologic Map Legend**

**Geologic units**




































































-  **Construction fill**—Lithology unknown.
-  **Younger alluvium** (Holocene and Pleistocene)—Moderately sorted sand and gravel of beach and lacustrine terrace deposits; clay, silt, sand, and gravel of flood plains; clay, silt, and sand of lake deposits; sandy-gravelly debris and coarse angular blocks of landslides and talus deposits; sand, gravel, and boulders of alluvial fans.
-  **Glacial till** (Pleistocene)—Clay, silt, and sand to large weathered granitic boulders; mostly preserved as moraines.
-  **Glacial outwash deposits** (Pleistocene)—Unconsolidated, poorly sorted boulders, cobbles, gravel, sand, and silt.
-  **Older alluvium** (Pliocene and Miocene)—Fluvial and lacustrine conglomerate, sandstone, and shale; rockslide-avalanche deposits consisting of large volcanic blocks in matrix of mudstone and ash.
-  **Volcanic rocks** (Pleistocene to Oligocene)—Rhyolitic tuffs of Oligocene age, mudflows of Pliocene and Miocene age, lava flows, and shallow intrusive bodies of Pleistocene, Pliocene, and Miocene age composed of basalt, andesite, latite, and dacite. Mostly found in northern and northwestern parts of the basin.
-  **Intrusive igneous rocks** (Cretaceous and Jurassic)—Compositions include granodiorite, diorite, quartz monzonite, granite, adamellite, alaskite, gabbro, and aplite dikes. Forms the bedrock basement of the Lake Tahoe basin.
-  **Metamorphic rocks** (Jurassic and Triassic)—Metamorphosed volcanic rocks, sandstone, siltstone, and limestone. Forms a small part of the bedrock basement west of Fallen Leaf Lake and east and southeast of Glenbrook.

■ **FIGURE D – Spring Mountain Geologic Map**



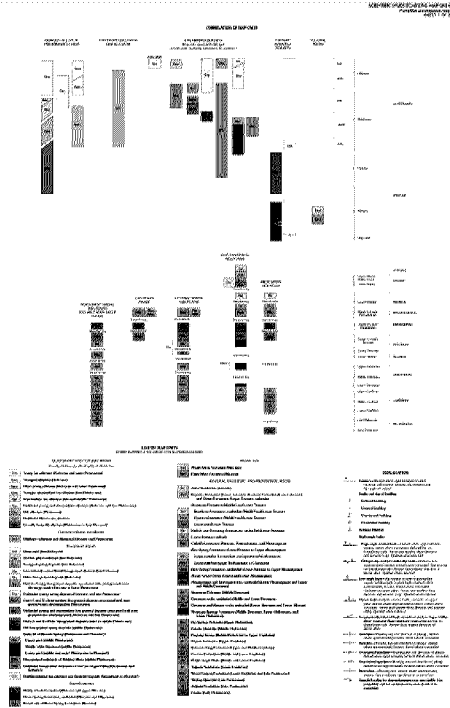
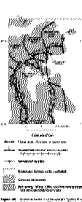
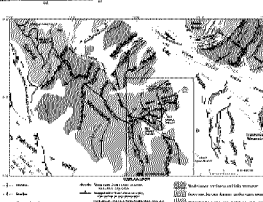
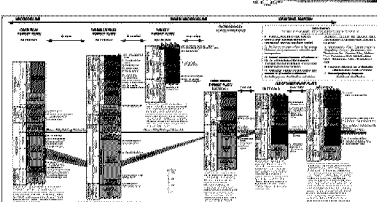
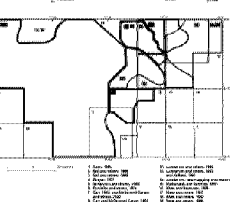
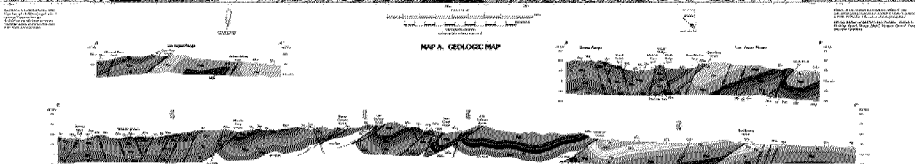
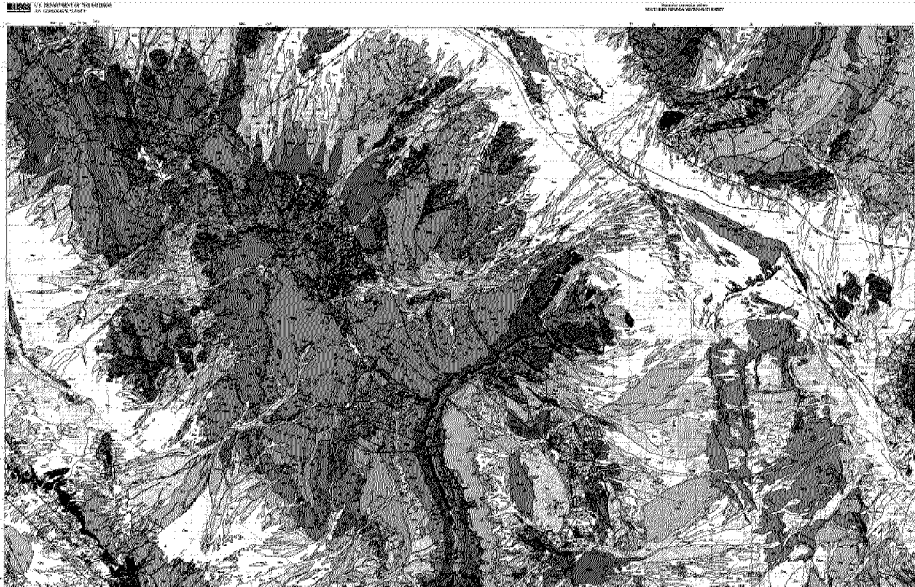
■ **FIGURE E – Spring Mountain Geologic Map Legend**

LIST OF MAP UNITS  
 (Detailed descriptions of map units are in the accompanying pamphlet.)

QUATERNARY AND TERTIARY ROCKS		Volcanic rocks	
Gravelly alluvium, predominantly of alluvial fans		 Tmd	Mount Davis Volcanics (Miocene)
 Qay	Young fan alluvium (Holocene and latest Pleistocene)	 Tmv	Patsy Mine Volcanics (Miocene)
 Qayy	Youngest alluvium (Holocene)	MESOZOIC, PALEOZOIC, AND PROTEROZOIC ROCKS	
 Qayo	Older young alluvium (Holocene and latest Pleistocene)	 Ja	Aztec Sandstone (Jurassic)
 Qaiy	Younger intermediate fan alluvium (late Pleistocene)	 Jkts	Kayenta Formation (Lower Jurassic), Moenave Formation (Lower Jurassic), and Chinle Formation (Upper Triassic), undivided
 Qai	Intermediate fan alluvium (late and middle? Pleistocene)		Moenkopi Formation (Middle? and Lower Triassic)
 Qau	Undivided young and intermediate alluvium (Holocene and late Pleistocene)	 Tm	Moenkopi Formation, undivided (Middle? and Lower Triassic)
 Qao	Old alluvium (Pleistocene)	 Tma	Upper red member (Middle? and Lower Triassic)
 Qaol	Undivided Pleistocene alluvium	 Tml	Lower unit (Lower Triassic)
 Qat	Gravelly basalt-fill alluvium (Pleistocene to late Miocene?)	 Pic	Kaibab and Toroweap Formations, undivided (Lower Permian)
Footslope colluvium and alluvium		 Pr	Lower Permian redbeds
 Qaf	Hillslope colluvium and alluvium (Holocene and Pleistocene)	 Pnc	Callville Limestone (Permian, Pennsylvanian, and Mississippian)
Fine-grained deposits		 Pnw	Bird Spring Formation (Lower Permian to Upper Mississippian)
 Qd	Dune sand (late Holocene)	 Pnw	Upper member (Leonardian and uppermost Wolfcampian)
 Qey	Modern plays sediment (late Holocene)	 Pnw	Lower member (upper Wolfcampian to Chesterian)
 Qayy	Youngest spring deposits (late Holocene)	 Pnw	Bird Spring Formation, undivided (Lower Permian to Upper Mississippian)
 Qay	Youngest spring deposits (late Holocene)	 Pnw	Monte Cristo Group (Upper and Lower Mississippian)
 Qay	Youngest spring deposits (late Holocene)	 Pnw	Mississippian and Devonian rocks, undivided (Lower Mississippian and Upper and Middle Devonian)
 Qay	Youngest spring deposits (late Holocene)	 Dm	Simonson Dolomite (Middle Devonian)
 Qay	Youngest spring deposits (late Holocene)	 Dv	Devonian rocks, undivided (Middle and Lower Devonian)
 Qay	Youngest spring deposits (late Holocene)	 Dsu	Devonian and Silurian rocks undivided (Lower Devonian and Lower Silurian)
 Qay	Youngest spring deposits (late Holocene)	 Msf	Mountain Springs Formation (Middle Devonian, Upper Ordovician, and Lower Ordovician)
 Qay	Youngest spring deposits (late Holocene)	 Oss	Ely Springs Dolomite (Upper Ordovician)
 Qay	Youngest spring deposits (late Holocene)	 Oq	Eureka Quartzite (Middle Ordovician)
 Qay	Youngest spring deposits (late Holocene)	 Ocp	Pogonip Group (Middle Ordovician to Upper Cambrian)
 Qay	Youngest spring deposits (late Holocene)	 Oc	Nopah Formation (Upper Cambrian)
 Qay	Youngest spring deposits (late Holocene)	 Ck	Bonanza King Formation (Upper and Middle Cambrian)
 Qay	Youngest spring deposits (late Holocene)	 Cb	Carrara Formation (Middle and Lower Cambrian)
 Qay	Youngest spring deposits (late Holocene)	 Ca	Bright Angel Shale (Middle and Lower Cambrian)
 Qay	Youngest spring deposits (late Holocene)	 Cs	Tapeats Sandstone (Lower Cambrian)
 Qay	Youngest spring deposits (late Holocene)	 Cz	Wood Canyon Formation (Lower Cambrian and Late Proterozoic)
 Qay	Youngest spring deposits (late Holocene)	 Ss	Stirling Quartzite (Late Proterozoic)
 Qay	Youngest spring deposits (late Holocene)	 Jn	Johnnie Formation (Late Proterozoic)
 Qay	Youngest spring deposits (late Holocene)	 G	Gneiss (Early Proterozoic)
 Qaf	Gravelly basalt-fill alluvium (Pleistocene to late Miocene?)		
Basin-fill deposits			
 Qm	Muddy Creek Formation (Pliocene and upper Miocene)		
 Qhs	Horse Spring Formation, undivided (Miocene and Oligocene)		
 Qbu	Basalt unit of Horse Spring Formation (Miocene)		

**ATTACHMENT A**





## **Citations**

- 1) <https://www.transmission.xcelenergy.com/About/FAQ#:~:text=Because%20the%20costs%20associated%20with%20new%20and%20existing,or%20all%20of%20a%20transmission%20lines%20project%20underground.>
- 2) USGS TAHOE MAP:  
[https://water.usgs.gov/GIS/metadata/usgswrd/XML/sim3063\\_Tahoe\\_Geophysical.xml](https://water.usgs.gov/GIS/metadata/usgswrd/XML/sim3063_Tahoe_Geophysical.xml)
- 3) USGS Mt. Charleston MAP:  
<https://pubs.er.usgs.gov/publication/sim2814>

# J.2 NDPP SELECTIVE UNDERGROUNDING PLAN SEGMENT PRIORITIZATION



2022 NDPP Selective Undergrounding Plan  
Segment Prioritization

2017 Plan Risk Rank	2022 Plan Risk Rank	Weighted Ranking	2022 Risk Score (Originality)	2022 Risk Score (Originality) Change in Score	Circuit	Length	Service Points	Dev. Cost: (Per Loading)	Trench	Fire Growth Potential	Accessibility	Value at Risk	Total	Undergrounding Phase Value					
														Comprehensibility	Accessibility (Substation & Transformer)	Accessibility (Substation & Transformer)	Value at Risk		
1	1	41,800	41,800	0.000	***Circuit 2100***	0.5	5	1	5	4	5	13	13	1	3	4	25	26	
2	2	41,800	41,798	-0.200	***Downs 1102***	0.3	1	1	1	3	3	4	16	15	4	4	5	28	28
3	3	41,800	41,800	0.000	***Appl Peak 401, 402, 403***	0.15	1	1	1	3	3	3	25	25	2	3	5	19	17
4	4	41,800	41,798	-0.200	Indefn 1100 Phase 1	0.25	1	1	1	3	3	4	24	24	4	4	2	21	21
5	5	41,800	41,798	-0.200	Indefn 1100 Phase 1	0.47	1	1	1	3	3	4	24	24	3	3	2	21	21
6	6	41,800	41,798	-0.200	Indefn 1100 Phase 1	0.47	1	1	1	3	3	4	24	24	3	3	2	21	21
7	7	41,800	41,798	-0.200	Indefn 1100 Phase 1	0.47	1	1	1	3	3	4	24	24	3	3	2	21	21
8	8	41,800	41,798	-0.200	Indefn 1100 Phase 1	0.47	1	1	1	3	3	4	24	24	3	3	2	21	21
9	9	41,800	41,798	-0.200	***72000011 1101***	0.13	1	1	1	3	3	3	21	21	4	4	4	28	28
10	10	41,800	41,798	-0.200	***72000011 1101***	0.13	1	1	1	3	3	3	21	21	4	4	4	28	28
11	11	41,800	41,798	-0.200	Indefn 1100 Phase 1	0.05	1	1	1	3	3	3	21	21	2	2	4	22	22
12	12	41,800	41,798	-0.200	***Indefn 2100 Phase 1***	0.47	1	1	1	3	3	4	24	24	2	2	4	17	17
13	13	41,800	41,798	-0.200	***Indefn 2100 Phase 1***	0.47	1	1	1	3	3	4	24	24	2	2	4	17	17
14	14	41,800	41,798	-0.200	***Indefn 2100 Phase 1***	0.47	1	1	1	3	3	4	24	24	2	2	4	17	17
15	15	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
16	16	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
17	17	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
18	18	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
19	19	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
20	20	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
21	21	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
22	22	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
23	23	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
24	24	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
25	25	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
26	26	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
27	27	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
28	28	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
29	29	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
30	30	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
31	31	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
32	32	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
33	33	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
34	34	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22
35	35	41,800	41,798	-0.200	Indefn 1100 Phase 2	0.13	1	1	1	3	3	3	21	21	2	2	4	22	22

\*\*\*These circuits represent segments of undergrounding that were selected and design progressed in parallel with creation of the Selective Undergrounding Plan per Decisions 20-02011 and 20-02012, paragraph 2.1.4.\*\*\*

## APPENDIX K. TABLE OF ABBREVIATIONS

The following abbreviations are used in the NDPP:

AHJ	Authorities Having Jurisdiction	NVE	NV Energy
APE	Area of Potential Effects	OMAG	Operations Maintenance Administrative and General
BA	Biological Assessment	PAC	Protected activity centers
BE	Biological Evaluation	PDZ	Proactive De-energization Zone
BLM	Bureau of Land Management	PSOM	Public Safety Outage Management
BMP	Best Management Practices	PUCN	Public Utilities Commission of Nevada
BVLOS	Beyond Visual Line of Sight	ROW	Right-of-Way
CMU	Concrete masonry unit	RPM	Resource protection measures
CRC	Customer Resource Centers	SEZ	Stream environment zones
DBA	Diameter at Breast Height	SFHA	Special Flood Hazard Areas
EA	Environmental assessment	SOPA	Schedule of Proposed Actions
EIS	Environmental impact statement	SPPC	Sierra Pacific Power Company
ERO	Emergency Response Organization	TRPA	Tahoe Regional Planning Authority
ESA	Endangered Species Act	TTD	Tahoe Transportation District
EWG	Expert Working Group	UAV	Unmanned Aerial Vehicle or “Drone”
FOA	Funding Opportunity Announcement	USDA	United States Department of Agriculture
GRC	General Rate Case	USFS	United States Forest Service
HRCA	Home range core areas	USGS	United States Geological Survey
HTA	Heightened Threat Areas	VC	Virginia City
HTNF	Humboldt-Toiyabe National Forest	WRRM	Wildfire Risk Reduction Model
ICS	Incident Command Structure	WUI	Wildland Urban Interface
IDT	Interdisciplinary Team		
LEA	Line Extension Agreement		
LOP	Limited operating period		
LTBMU	Lake Tahoe Basin Management Unit		
NDF	Nevada Division of Forestry		
NDPP	Natural Disaster Protection Plan		
NOAA	National Oceanic and Atmospheric Administration		
NPC	Nevada Power Company		

**JESSE MURRAY**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2023 Natural Disaster Protection Plan  
Docket No. 23-03xxx

Prepared Direct Testimony of

**Jesse Murray**

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

A. My name is Jesse Murray. My current position is Vice President, Electric Delivery for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, “NV Energy” or the “Companies”). My business address is 1 Ohm Place in Reno, Nevada. I am filing testimony on behalf of the Companies.

2. **Q. WHAT ARE YOUR DUTIES IN YOUR CURRENT POSITION?**

A. I am responsible for overseeing the electric transmission and distribution lines operations and maintenance, electric meter operations, and electric delivery support organizations for the Companies. I also oversee the emergency management, vegetation management, and reliability programs for the Companies. Finally, I oversee the strategic development and execution of the Companies’ Natural Disaster Protection Plan (“NDPP”) as directed by Senate Bill 329 of the Nevada Legislature and codified in NRS 704.7983. This plan drives the mitigation of potential wildfires and other natural disasters that could impact or be caused by the Companies’ electric facilities.

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

3 A. I hold a Bachelor of Science degree in Chemical Engineering and a Master of  
4 Business Administration degree from the University of Nevada, Reno. I joined the  
5 Companies in 2008 as an Engineer at Frank A. Tracy Generating Station. Since  
6 that time, I have held several positions in the Companies, including Plant  
7 Engineering Manager, Maintenance Manager, Asset Management Programs  
8 Manager, and Renewable Energy Programs Director. I assumed the role of Vice  
9 President, Gas Delivery in November 2017 and assumed oversight of the NDPP in  
10 April 2021. I assumed my current position in February 2022. Before joining the  
11 Companies, I worked in several engineering positions, including as a nuclear and  
12 chemical waste technical specialist. I also served as a design lead and project  
13 manager in manufacturing and commercial building construction. I am a licensed  
14 Professional Chemical Engineer in Nevada. I was also an intern with the  
15 Companies before starting my professional career. More details regarding my  
16 professional background and experience are set forth in **Exhibit Murray-Direct-**  
17 **1.**

18  
19 4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY  
20 WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA  
21 (“COMMISSION”)?

22 A. Yes, I have submitted testimony and appeared before the Commission many times,  
23 most recently in Docket No. 22-08001, the Second Amendment to the Natural  
24 Disaster Protection Plan. A complete list can be found in **Exhibit Murray-Direct-**  
25 **1.**

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

- A. The purpose of my testimony is to:
- I. Provide an overview of the Second Triennial Natural Disaster Protection Plan (the “Plan”).
  - II. Discuss the overall strategic approach and policy considerations of the Plan.
  - III. Outline the primary elements and budgetary requests of the Plan.
  - IV. Discuss the differences contained within the Plan when compared to the inaugural plan filed in 2020.

**6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

- A. I am sponsoring or co-sponsoring the following Exhibits:
- Exhibit Murray-Direct-1 – Statement of Qualifications**
- Exhibit B**, The Second Triennial Natural Disaster Protection Plan, specifically I sponsor or co-sponsor the following portions of the Plan:
- Section 1 – Risk Based Approach – Natural Disaster Risk Awareness and Drivers
  - Section 1.1 – Risk Driven Decision Making Framework
  - Section 2 – Natural Disaster Protection Strategies and Programs
  - Section 8 – Financials

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1 **I. OVERVIEW OF THE REASON AND NECESSITY OF FILING THE PLAN**

2 **7. Q. WHY ARE THE COMPANIES FILING THIS PLAN?**

3 **A.** The 2019 Nevada Legislature passed Senate Bill 329 and that statute was signed  
4 into law on May 22, 2019. This bill addressed provisions relating to the prevention  
5 of natural disasters. The Companies, along with stakeholders from Nevada fire  
6 agencies, emergency management organizations, local and state governments and  
7 citizens of communities throughout Nevada supported the passage of Senate Bill  
8 329. Now codified as NRS 704.7983, the statute requires that the Companies file  
9 an NDPP by June 1, 2020, and every third year thereafter. Additionally, LCB File  
10 No. R085-19 contains approved regulations under NRS 704.7983. The regulations  
11 require the Companies to file a Plan on or before March 1, 2020, and every third  
12 year after under Section 8. This filing is intended to satisfy those requirements.

13  
14 **8. Q. WHY IS THE PLAN IMPORTANT FOR THE STATE OF NEVADA?**

15 **A.** Communities throughout Nevada and the western United States have experienced  
16 more frequent and severe wildfires and other natural disasters in recent years. Some  
17 of these disasters were initiated by electric utility infrastructure, while other natural  
18 disasters not caused by electric infrastructure nonetheless impacted that  
19 infrastructure and the communities it serves. Stakeholders to this Plan recognize  
20 that climate change, increasing fuel loading and land use practices, as well as aging  
21 electric infrastructure, contribute to an increasing risk that needs to be addressed.  
22 In the inaugural plan filed on February 28, 2020, in Docket No. 20-02031, the  
23 Companies and other stakeholders embarked on developing and executing such a  
24 plan for the very first time and with great success. The Legislature understood that  
25 these contributing factors would continue to exist for many years to come, which  
26 is the basis for the recurring requirement to file new plans at specified intervals.

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This Plan will build upon the success and lessons learned from the inaugural plan, and its two subsequent amendments, to deliver further risk reduction to protect Nevada’s communities and preserve Nevada’s environmental and natural resources.

**9. Q. WHAT WAS ACCOMPLISHED IN THE INAUGURAL PLAN?**

**A.** First, the Companies hired key personnel whose expertise has leveraged a Plan that delivers on the intent of Senate Bill 329 to mitigate the negative effect of natural disasters on Nevada, its natural resources and the economy. One of these key personnel is Alex Hoon, a full-time meteorologist who focuses on natural disaster risk drivers and improved situational awareness. Mr. Hoon provides testimony in support of this Plan, applying his expertise to deploy situational awareness systems for the Companies, including weather stations, fire cameras, fuel moisture sampling, and wildfire risk modeling technology. The Companies have also added expertise in fire mitigation, emergency management, and mapping. Mr. Mark Regan, who provides testimony for this Plan, represents some of that critical additional expertise. As the inaugural plan has evolved, the Companies have implemented improved methodologies to identify risks by leveraging this expertise, along with new technologies and techniques to deploy resources more effectively—both for planned NDPP activities and unplanned emergency events.

Some of the programs from the inaugural plan are now nearing completion. These include the grey wire replacement, covered conductor pilots, and expulsion fuse replacements in extreme risk areas. In addition, the Companies are now fully engaged in larger construction projects like pole replacements, undergrounding, and overhead rebuilds. Such construction work has led to improved response to the

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needs of the community and effective working parameters with partner agencies. This has also driven collaborative improvements such as permitting waivers, formalized agreements and other accommodations to expedite timelines. Some components of cyclical programs, including vegetation management and patrols and inspections, are transitioning into an established cadence. Corrections are being evaluated to gauge whether chronic conditions occur on specific circuits or segments, which can lead to decisions to rebuild or replace as a more cost-effective alternative than repeated ad-hoc repairs.

Communications programs have expanded beyond emergency situations to better help communities prepare for outages and understand different aspects of the NDPP. Some organizations, such as the United States Forest Service (“USFS”), have requested increased communications from NV Energy public information professionals. The increased emphasis on communications is reflected in a dedicated Communications section of the Plan.

The partnerships that the Companies have formed with the fire agencies are a critical success for this program. It is a win-win collaboration. These partnerships have fostered critical services, including fuels mitigation work and operational support for utility work in heightened risk areas. The partnership also allows the fire agencies to add incremental resources to increase their firefighting and emergency support capabilities to better protect their communities. This concept has been widely recognized as an innovative component to our plan that other states and utilities look to adopt.

1 Finally, the companies have greatly improved and expanded their emergency  
2 management and response capabilities, driven not only by the creation of the public  
3 safety outage management (“PSOM”) program but also by responding to natural  
4 disaster events such as the Tamarack Fire, the Caldor Fire, and the New Year’s  
5 winter storms at the beginning of 2023. The Companies’ emergency response  
6 organization now functions and integrates into larger regional emergency  
7 management organizations, providing critical resources, communications, and  
8 resources for a variety of needs impacting Nevadans in relation to natural disasters.  
9 The Companies have executed on several PSOMs in both northern and southern  
10 Nevada, proving the concept to be an effective tool when extreme weather  
11 conditions are present.

12  
13 **II. OVERALL STRATEGIC APPROACH AND POLICY CONSIDERATIONS OF**  
14 **THE PLAN**

15 **10. Q. WHAT IS THE PRIMARY GOAL OF THIS PLAN?**

16 **A.** First and foremost, this Plan aims to ensure public safety and preserve Nevada’s  
17 environmental and natural resources. In achieving that goal, the Companies seek  
18 to balance risk mitigation with the resources and funding required to mitigate that  
19 risk. A particular focus is placed on wildfire risk reduction, but the Companies also  
20 recognize that the Plan must address other natural disasters. As part of the Plan  
21 development process, extensive Expert Working Group (“EWG”) sessions were  
22 held to gather input from expert stakeholders throughout the state related to these  
23 goals and include such input into the elements of this Plan.

1 11. Q. **HOW HAS THIS PLAN EVOLVED FROM THE INAUGURAL PLAN?**

2 A. The Companies now have three years of execution experience within the plan.  
3 Improved understanding has been gained on capabilities, opportunities and  
4 expertise required to be successful. Much progress has been made in all areas, and  
5 the Companies endeavored to incorporate this improved understanding into this  
6 Plan.

7  
8 The Companies have expanded collaboration to identify and respond to risks. This  
9 includes working with similarly situated utilities and continued engagement from  
10 the EWG. The Plan reflects emerging industry best practices in a number of areas  
11 including vegetation management and resilient corridors, as well as seasonal work  
12 practices that leverage capabilities of public safety partners. Collaboration with  
13 expert partners is a recognized best practice to prioritize and focus where efforts  
14 matter the most and create synergies with other organizations. Broader information  
15 reach improves situational awareness that is leveraged in operations, emergency  
16 response and other initiatives.

17  
18 Regular collaboration on the development of the Plan is reflected through resilience  
19 and ruggedization initiatives that can best support vulnerable communities. Lessons  
20 learned through the pandemic reflect innovations in communications and  
21 community support, for example, through temporary Community Resource Centers  
22 that are focused and nimble. Communications and public outreach have expanded  
23 beyond safety notifications as ruggedization projects that require outages to  
24 complete are underway.

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This Plan includes valuable lessons learned in the following areas:

- The importance of working with permitting agencies to better understand and forecast approval timelines for various activities.
- The need to ensure clear, concise, and regular communications with affected customers to drive improved understanding of how risks are being mitigated and what short-term impacts can be expected as work progresses.
- The need for integrated planning on the various programs to ensure that resources are expended as effectively as possible.
- The importance of focused analysis on contracted labor resources required to execute on the programs, and the benefits of levelizing of work to ensure stable retention of those resources over the course of the Plan.
- The need to improve situational and conditional awareness to effectively assess comparative risk on various electrical infrastructure components throughout the service territories.
- The need to further leverage the innovative and unique nature of the relationships established with the local fire agencies to conduct fuels mitigation and also support emergency and operational activities.

**12. Q. WHAT DIRECTION DOES THIS PLAN LAY OUT FOR THE UPCOMING THREE YEARS?**

**A.** First, this Plan focus is on completing work already identified in the inaugural plan and subsequent amendments. The Companies have adjusted the Plan to address the natural disaster risk drivers based on experience to date, expert meteorologist advice and collaboration with the EWG. Based on refreshed fire threat analysis from REAX engineering and discussions with the EWG, NV Energy is proposing

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modifications to wildfire risk tiers as described further in Section III of this testimony.

Observations of compromised grid performance under the circuit resilience program have resulted in ruggedization programs for monsoon-prone areas in southern Nevada to protect against cascading toppling poles. Hardening along critical evacuation routes in natural disaster areas remains an ongoing priority to protect public safety. With three years of experience, the Companies are proposing a phased and levelized project implementation approach for copper wire replacement, circuit rebuilds, circuit patrols, and detailed inspections, using a full calendar year to implement programs across elevated risk areas to lower cost and drive efficiencies. Broadened communications efforts include preparing communities for necessary outages to complete this resilience work. The Companies continue to refine and improve on programs to prepare for wildfire season, including harmonizing emergency management and operations into a broadened collaborative Incident Command Structure for PSOM and natural disaster events.

This Plan also includes advanced technology initiatives to minimize outage impacts, such as increased sectionalization, microgrid alternatives for back-up power and a comprehensive assessment for protective devices to assure maximum efficacy and threat avoidance in heightened risk areas.

This Plan begins to realize the full benefits of the Technosylva wildfire platform, a next generation software that provides wildfire forecasting and threat analysis that can be used in combination with other programs and platforms. Ties with

1 infrastructure maps and the infrastructure database, Maximo, will drive superior  
2 risk analysis. An understanding of both natural disaster threat propensity with  
3 infrastructure conditions affords the Companies the ability to protect public safety  
4 while reducing outages and prioritizing mitigating actions.

5  
6 Vegetation management is another focus of this plan. In the inaugural plan, the  
7 Companies committed to working toward defined cycles for vegetation  
8 management that reduce the amount of fuels around electric infrastructure. Those  
9 programs are now in full swing. One emergent issue to achieve levelized cycles of  
10 vegetation management is that initial treatments are still in process while recurring  
11 cycles of treatment must also now be undertaken. This results in the necessity to  
12 execute on additional work to complete both the initial treatments and the recurring  
13 treatments at the same time. Mr. Jay Wiggins discusses this more in his testimony.

14  
15 Finally, the Plan looks to place more emphasis and resources on longer term  
16 investments while maintaining recurring activities that reduce controllable risk on  
17 the electric system. The Companies have now completed permitting and designs  
18 that allow more effective execution on such long-term investments that will reduce  
19 risk on the infrastructure over much longer time horizons.

20  
21 **13. Q. WHAT CONSIDERATIONS DID THE COMPANIES EXAMINE AND**  
22 **CONSIDER AS PART OF THE DEVELOPMENT OF THIS PLAN?**

23 **A.** There are three main areas that need to be addressed as part of this Application.  
24 The first is the content of the Plan itself. What activities, milestones, and projects  
25 should be included in the Plan? Second is the issue of incrementality. How do the  
26 elements of this Plan relate to existing activities undertaken by the Companies prior  
27

1 to the creation of this Plan and how are those costs incurred and compared with  
2 legacy activities? Third is the question of cost allocation. How should the costs  
3 incurred as part of this Plan be allocated amongst customers throughout the state?  
4

5 Regarding Plan content, I provide a summary in Section III of this testimony.  
6 Additionally, the Companies will present several witnesses including Ms. Danyale  
7 Howard, Mr. Jay Wiggins, Mr. Mark Regan, and Mr. Alex Hoon to discuss the Plan  
8 content in detail.  
9

10 Regarding incrementality for the Plan period, the Companies propose continuing  
11 the existing structure as outlined in the most recent Modified Final Order regarding  
12 regulatory asset recovery issued in Docket No. 22-03006 with just a few minor  
13 alterations described in more detail in the next question.  
14

15 Regarding cost allocation for the Plan period, the Companies propose maintaining  
16 the existing cost allocation structure as established in several previous regulatory  
17 asset recovery filings, which includes a single statewide rate for all operations,  
18 maintenance and general administration (“OMAG”) costs and a jurisdictional rate  
19 for capital costs. The reasons for the proposal are covered more completely in the  
20 2022 regulatory asset recovery filing testimony I file concurrent with this Plan  
21 filing. To summarize that position, the Companies contend that preventing natural  
22 disasters is critical to the entire state of Nevada, which is what led the Legislature  
23 to pass SB 329 in 2019 in order to try to prevent disasters such as the Camp Fire.  
24 The Companies strongly believe that the statewide impacts associated with a fire or  
25 other natural disaster would include devastating effects on tourism, tax revenue,  
26 jobs, and health costs. Based on the experience in other states, my 2022 regulatory  
27

1 asset recovery filing testimony details that a catastrophic natural disaster carries the  
2 potential to impact utility reliability and resiliency on a statewide basis and that  
3 recovery from a such a natural disaster will be felt on a statewide, if not regional,  
4 basis. As such, the existing cost allocation provides a fair balance that recognizes  
5 these realities. As part of Directive No. 4 of the Modified Final Order in Docket  
6 No. 22-03006, the Companies present expert witness Mr. Jeremy Aguero who  
7 delivers an analysis assessing those benefits associated with the NDPP that support  
8 continuing this allocation.  
9

10 **14. Q. PLEASE DESCRIBE THE INCREMENTALITY APPROACH THE**  
11 **COMPANIES PROPOSE FOR THIS PLAN.**

- 12 **A.** In the Modified Final Order from Docket No. 22-03006, the Commission provided  
13 the following approach for OMAG cost inclusion in the regulatory asset recovery:
- 14 1. Non-represented labor costs for NDPP dedicated positions outlined in the  
15 original plan, considering that those positions did not exist prior to the program.
  - 16 2. Expenditures under the PSOM, Risk-Based Approach, Situational Awareness  
17 and System Hardening due to their novel nature applicable only to the NDPP.
  - 18 3. A comparison of combined service territory program costs in patrols,  
19 inspections, corrections, and vegetation management to “regular business”  
20 incurred costs, the difference which would have to be higher than a three-year  
21 average cost inclusive of General Rate Case (“GRC”) test years.<sup>1</sup>  
22

23 In the several years of reviewing this program, the Commission along with several  
24 intervenors have made it clear that the concern with this program is a potential  
25 double collection of costs from customers, once through general rates and then  
26 again through the regulatory asset recovery. Through the preponderance of

27 <sup>1</sup> Modified final Order Docket No. 22-03006 Paragraph 76.

1 discussion, refinement, and analysis associated with those reviews, the Companies  
2 believe that a transparent and well-defined process now exists to make the  
3 determination of incrementality and proposes in this application to maintain that  
4 approach.

5  
6 One minor change that has to occur with this Plan period is that by the time the Plan  
7 is effective, and NV Energy seeks to recover the costs associated with this Plan,  
8 both Sierra and Nevada Power will have completed another cycle of GRCs, which  
9 changes the basis of the prior three-year average applied by the Commission. Sierra  
10 completed a GRC in 2022 utilizing 2021 as a test year (Docket No. 22-06014),  
11 while Nevada Power will file a GRC in 2023 using 2022 as the test year. Once the  
12 2023 Nevada Power GRC is complete, the Companies may consider moving the  
13 three-year average period for determining incrementality of NDPP costs in the next  
14 NDPP regulatory asset case, anticipated to be filed in March 2024. The  
15 Commission's process of using a three-year average as a baseline for incrementality  
16 leaves no doubt as to what amounts are required to achieve incrementality going  
17 forward.

18  
19 Additionally, the Companies propose adding dedicated non-represented positions,  
20 not currently in rates, that will bring required skill sets to continue to effectively  
21 evaluate, analyze, and execute on these programs. The Companies propose that  
22 these additional positions also be deemed as incremental in the Plan along with  
23 those dedicated employees called out in the inaugural plan. Ms. Danyale Howard  
24 and Mr. Jay Wiggins discuss those positions further as part of their testimony.

1 **III. PRIMARY ELEMENTS AND OVERALL BUDGET REQUEST OF THE PLAN**

2 **15. Q. WHAT ARE THE PRIMARY ELEMENTS OF THIS PLAN?**

3 **A.** This Plan will have the same look and feel of the inaugural plan, and the Companies  
4 are not proposing to change the major categories of work included in the Plan. The  
5 Plan complies with the adopted regulations in LCB File R085-19, addressing eight  
6 primary areas:

- 7 • Risk-Based Approach
- 8 • Natural Disaster Protection Strategies and Programs
- 9 • Communications and Outreach
- 10 • Advanced Technologies and Strategies
- 11 • Grant Pursuits
- 12 • Metrics Performance and Monitoring
- 13 • Resource Sufficiency
- 14 • Financials

15 The Natural Disaster Protection Strategies and Programs section of the Plan  
16 specifically complies with the requirements in Section 7.2 of the adopted  
17 regulations in LCB File R085-19 by addressing the following issues:

- 18 • Situational Awareness
- 19 • Operational Practices
- 20 • Emergency Management and Proactive De-Energization (including PSOM)
- 21 • Vegetation Management
- 22 • Conditional Awareness: Circuit Patrols, Detailed Inspections and  
23 Corrections
- 24 • Grid Resilience and System Hardening

1 Mr. Mark Regan, Mr. Jay Wiggins, and Mr. Alex Hoon will cover the Risk  
2 Based Approach, Vegetation Management, Situational Awareness and PSOM  
3 areas in more detail. Ms. Danyale Howard will address Operational Practices,  
4 Inspections and Corrections, and System Hardening in more detail.  
5

6 **16. Q. WHAT BUDGET ARE THE COMPANIES PROPOSING FOR THIS PLAN**  
7 **AND WHAT IS DRIVING THE CHANGES IN COST?**

8 **A.** For the 2024-2026 period, the Companies request \$373,059,298 in total  
9 expenditures for the Plan that would be recoverable through the NDPP regulatory  
10 asset, assuming incrementally can be validated as part of the recovery filing. This  
11 includes \$201,961,191 in OMAG and \$171,098,107 in Capital investment.  
12 Separately, and described in more detail below, the Companies are requesting that  
13 execution of the Plan that includes identified and approved capital projects related  
14 to natural disaster risk mitigation and grid resiliency, amounting to a determination  
15 \$92,585,685 in costs, be deemed prudent. The Companies would seek to recover  
16 these additional investments through each service territory's next GRC as normal  
17 operating capital.<sup>2</sup> These projects are *not* included as part of the requested budget  
18 authorization for this Plan. Tables 66 and 67 in the Plan provide the breakdown of  
19 costs for inclusion in the authorized budget for this Plan by activity and service  
20 territory. Table 24 in the Plan provides the breakdown of capital investments the  
21 Companies are requesting be approved and deemed prudent but would not be  
22

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23 <sup>2</sup> The Companies recognize that NRS 704.7983(6) requires that all prudent and reasonable expenditures made by an  
24 electric utility to develop and implement the NDPP must be recovered as a separate monthly rate charged to the  
25 customers. While the Companies would seek to have capital projects approved as part of this Plan related to natural  
26 disaster risk mitigation and grid resiliency be recovered as normal operating capital with other rate case costs, the  
27 Companies are open to discussing whether customer bills must reflect NDPP-related costs recovered in a rate case. It  
may be arguable that NRS 704.7983(6) does apply given the broader benefits of the costs that the NV Energy seeks  
to recover in a rate case. Nonetheless, under the current rate case schedule, the capital costs at issue will likely first  
be recovered in Nevada Power's rate case in 2026, so there is time for NV Energy to meet and confer on this issue  
with Staff and other interested parties.

1 recovered through the regulatory asset and instead would be recovered through each  
2 utility's next applicable GRC.

3  
4 NV Energy's focus is on implementing previously requested projects and  
5 programs, leveraging the Companies' improved understanding to gain efficiencies.  
6 Initiatives continue to focus on public safety and to systematically reduce risk.  
7 Priorities are established based on risk analysis and in collaboration with the EWG.

8  
9 While the cost of the patrols, inspections and corrections, lightning arresters, and  
10 resource sufficiency initiatives have decreased, the cost of the remaining initiatives  
11 in the Plan have increased, particularly system hardening and vegetation  
12 management. For system hardening, the increase is attributable to the focus of the  
13 capital projects moving from a design and permitting focus to actual construction.  
14 For vegetation management, cost increases are driven by inflationary pressures and  
15 supply chain constraints, in addition to the catch-up component of dealing with  
16 initial treatments while also now maintaining the cyclical treatments that was  
17 previously discussed.

18  
19 This Plan also identifies benefits that may accrue to customers based on potential  
20 grant awards. Since the inaugural plan, grant opportunities are more prevalent based  
21 on more recent federal announcements of Bipartisan Infrastructure Law ("BIL"),  
22 Infrastructure Investment and Jobs Act ("IIJA"), Inflation Reduction Act ("IRA"),  
23 and others. While affording potential customer benefits, grant awards are  
24 contingent upon a successful competitive grant application, the Companies'  
25 matching contribution, and ongoing management and reporting to access funding.

1 17. Q. WHY ARE THE COMPANIES PROPOSING TO EXCLUDE SOME  
2 CAPITAL PROJECT COST RECOVERY FROM THE SCOPE OF THIS  
3 PLAN?

4 A. Through the various regulatory proceedings related to this Plan over the past few  
5 years, a few common themes have emerged. This includes a general desire to move  
6 toward a “normal operating” model as the program matures. It also includes a  
7 discussion and concern around risk assessment and the ancillary benefits of the  
8 NDPP work that are unrelated to the goal of the NDPP, such as reliability and  
9 customer service enhancements.

10  
11 The Companies strive to improve the quality, efficacy, and efficiency of the  
12 program and a critical element of this is being responsive to stakeholder input. As  
13 such, the Companies are now taking a narrower view of what capital investments  
14 should be included in the regulatory recovery of this program. Investments that are  
15 predominantly driven by risk mitigation would still be included in the program. An  
16 example would be undergrounding and expulsion fuse replacement. Other projects  
17 that have risk mitigation benefits, but also non-NDPP benefits including reliability,  
18 would be placed in the latter bucket outside of the NDPP program. This would  
19 include some overhead rebuilds, aged pole replacements and other rebuilds not  
20 fully contained within a wildfire risk area.

21  
22 As noted above, NV Energy proposes that the Commission approve certain capital  
23 projects related to natural disaster risk mitigation and grid resiliency in this Plan  
24 and find that the execution of the Plan with those approved projects is prudent. NV  
25 Energy’s proposal to seek approval of a Plan that includes these projects, but shifts  
26 cost recovery to the GRC based on a Commission determination that the execution  
27

1 of the Plan with those projects is prudent, recognizes both the need to adjust the  
2 Companies’ “normal operations” to evolving climate conditions and the  
3 Commission’s current draft regulations in Section 13 of LCB File No. R011-22 that  
4 envisions future cost recovery proceedings being filed with a rate case.<sup>3</sup> While the  
5 Companies understand that the regulations as reflected in LCB File No. R011-22  
6 are not final or effective, there is an expectation that NDPP-related work in the  
7 future will be part of the normal course of business and NV Energy has elected to  
8 build a bridge to that future with its proposal in this case. The determination of  
9 prudence that NV Energy seeks for the projects outlined in this Plan but for which  
10 it will seek recovery in a rate case is reflective of other practices before the  
11 Commission, including resource planning, where the utility demonstrates through  
12 robust analysis why the projects should be approved but seeks recovery of those  
13 projects in a rate case.

14  
15 Moreover, the Companies’ proposal is consistent with the Commission’s discussion  
16 in the Order on the Second Amendment regarding approval in the inaugural plan  
17 for the scope of work for patrols, inspections and corrections in Non-Tier and Non-  
18 Tier Wildland-Urban Interface (“WUI”) areas. In that discussion, the Commission  
19 acknowledges that the Companies may seek approval of projects in an NDPP for  
20 which cost recovery may be sought in base rates.<sup>4</sup>

21  
22 In some cases, the delineation between NDPP programs and programs designated  
23 for GRC cost recovery may be hard to define, and there may be some projects that  
24 could fall into both categories. Ms. Danyale Howard discusses this more in her  
25 testimony, but in those cases the Companies look to include some of those projects

26 <sup>3</sup> Procedural Order No. 9, Docket No. 19-06009, at Attachment 1 (Sept. 9, 2022). Attachment 1 is LCB File No.  
27 R011-22, as returned to the Commission from the Legislative Counsel Bureau.

<sup>4</sup> Docket No. 22-08001, Order, at 48-49, ¶ 175.

1 in the Plan to allow for a year-round balancing of the work to optimize labor  
2 resources under the Plan.

3  
4 **18. Q. FOR THE OMAG COMPONENTS OF THE PROPOSED BUDGET, WHAT**  
5 **IS THE COMPANIES' APPROACH TO INCLUDING COSTS AS PART OF**  
6 **THIS PLAN?**

7 **A.** The Companies are also sensitive to stakeholder and Commission concerns around  
8 “mission creep” associated the OMAG activities. In the second amendment to the  
9 inaugural plan in Docket No. 22-08001, the Companies requested funding to  
10 perform patrols, inspections, corrections and vegetation management in areas  
11 defined in the first Triennial Plan but not funded. These included areas known as  
12 WUI, and non-tiered areas presumed to be low risk from the threat of wildfire.  
13 For this next Plan, the Companies are proposing that the patrols, inspections,  
14 corrections, and vegetation management recoverable through this plan be limited  
15 only to areas where wildfire risk is present as defined by the Nevada Division of  
16 Forestry State Fire Risk Maps (“Fire Risk Maps”). Mr. Regan covers this in more  
17 detail in his testimony, but the request will be only to fund these activities through  
18 the Plan in areas where the Fire Risk Maps identify an area where fire risk is  
19 moderate or higher. This approach is consistent with NRS 704.7983 Section 2(a)  
20 and discussed in the Second Amendment Docket No. 22-08001 in which  
21 intervenors requested focus on areas of “heightened threat.” This approach also  
22 coincides with the requirement under NRS 704.7983 Section 3 that this Plan adhere  
23 to and comply with the International Wildland-Urban Interface Code. This code  
24 requires certain activities be completed and aligns with the moderate fire risk  
25 designation from the Fire Risk Maps. For patrols, inspections, corrections, and  
26 vegetation management outside of these areas, the Companies would conduct these  
27

1 activities at their discretion in the normal course of business and request to recover  
2 such activities as a part of ongoing GRCs for each service territory. This excludes  
3 the Grid Resiliency component of patrols, inspections, and corrections, as this is an  
4 ongoing program from the first Plan specifically focused on monsoon risk areas in  
5 Southern Nevada, and the Companies request that this program remain as part of  
6 the Plan.

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8 The Companies also request that other OMAG aspects of this program including  
9 PSOM, Situational Awareness, and Risk Based Approach, continue to be included  
10 in the program and recoverable through the Plan because those areas are unique to  
11 the mission of the program and ensure that the Companies remain well positioned  
12 to address any number of other natural disasters that may impact their facilities and  
13 customers.

14  
15 **IV. DIFFERENCES BETWEEN THE INAUGURAL PLAN AND THIS PLAN**

16 **19. Q. CAN YOU SUMMARIZE THE CHANGES BEING MADE TO THIS PLAN?**

17 **A.** As previously discussed, the elements and structure of the Plan remain the same as  
18 for the inaugural plan. There are changes to requested budgets and certain program  
19 elements incorporated into each individual program that are discussed in detail in  
20 both the Plan and by various witnesses.

21  
22 The following list is a highlight of changes:

- 23 1. A change in approach to include capital projects within the Plan as discussed in  
24 Section III of this testimony and sponsored by Ms. Danyale Howard.
- 25 2. A change in approach to the scope of patrols, inspections, corrections and  
26 vegetation management to limit Plan-included activities to moderate wildfire  
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risk areas and above as discussed in Section III of this testimony and sponsored by Ms. Danyale Howard, and Mr. Jay Wiggins.

3. The creation of a new “Tier 1” wildfire area in addition to the existing Tier 1E, Tier 2, and Tier 3 areas that exist in the current plan to align with the Fire Risk Maps. This new tier represents moderate fire risk areas and is sponsored by Mr. Mark Regan and Mr. Alex Hoon.
4. The promotion of an area encompassing the Virginia City Highlands in Storey County from Tier 2 to Tier 3, sponsored by Mr. Mark Regan and Mr. Alex Hoon.
5. The inclusion of a system protection study to analyze the new devices that have been installed as part of this Plan and how they can be more effectively used and coordinated going forward, sponsored by Ms. Danyale Howard.
6. An assumption that known grant opportunities may provide customer benefits for this Plan. Such assumptions are included in the budget.
7. Three additional incremental positions funded through the regulatory asset that include an engineer to specialize in emerging technologies, a data scientist to drive enhanced modeling as required in Compliance Item 5 of the Order from Docket No. 22-08001, and a communications specialist that can enhance plan communications and strategies to more effectively inform customers and stakeholders of the plan elements.

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1 20. Q. **REGARDING THE INCLUSION OF A NEW TIER AND CHANGES TO**  
2 **THE MAPS, WHY ARE THE COMPANIES PROPOSING TO MAKE**  
3 **THESE CHANGES IN THE PLAN?**

4 A. Mr. Mark Regan and Mr. Alex Hoon will cover this in more detail, but the  
5 Companies have committed to analyzing and refining elements of this Plan as more  
6 knowledge is gained through the execution of this program. The changes in these  
7 tier designations are designed to more closely align the boundaries of this program  
8 with the accepted authoritative map of risk assessment that is used by fire agencies  
9 throughout the state for various activities.

10  
11 21. Q. **REGARDING THE SYSTEM PROTECTION STUDY, WHY ARE THE**  
12 **COMPANIES PROPOSING TO MAKE THESE CHANGES IN THE PLAN?**

13 A. Ms. Danyale Howard will cover this topic more in her testimony, but the  
14 Companies have deployed a number of novel facilities and devices in extreme and  
15 high-risk areas during the inaugural plan. Such facilities were deployed primarily  
16 to address an acute risk, but now that they are deployed, the Companies need to  
17 further study their operations in a real-world environment, understand other  
18 ancillary capabilities and challenges associated with the new equipment and  
19 develop plans to optimize those devices going forward to further enhance their  
20 effectiveness over the long term.

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1 22. Q. **WHY ARE THE COMPANIES BUILDING ASSUMPTIONS TO OBTAIN**  
2 **GRANTS IN THE PLAN BUDGET?**

3 A. The Commission has directed the Companies to seek out and improve their grant  
4 identification, application and procurement process. In Docket No. 22-03006, the  
5 Commission issued Directive No. 5 in its Order to provide details around the  
6 Companies' grant plan.<sup>5</sup> The Plan complies with that directive and further assumes  
7 the successful procurement of those grants to offset costs of the program.  
8

9 23. Q. **REGARDING THE ADDITIONAL POSITIONS, WHY ARE THE**  
10 **COMPANIES PROPOSING SUCH POSITIONS IN THE PLAN?**

11 A. Ms. Danyale Howard will cover this topic more in her testimony, but the  
12 Companies continue to require emergent specialized support to execute on the  
13 various program elements. One example is the requirement to provide further  
14 analytical detail in their modeling and risk assessment efforts. Such a position was  
15 not contemplated in the inaugural plan. Another example is the addition of a  
16 dedicated communications specialist that can provide general education and  
17 community outreach and help coordinate specific targeted communication with  
18 customers who may be temporarily impacted by the large volume of distribution  
19 level work being undertaken that result in planned interruptions.  
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27 <sup>5</sup> Docket No. 22-03006, Modified Final Order, at 64, Directive No. 5.

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**IV. CONCLUSION**

**24. Q. DOES THE PROPOSED PLAN DEMONSTRATE IMPROVEMENTS IN THE PROGRAM SINCE ITS INCEPTION?**

A. Yes. The Companies have consistently stated that improvement, refinement, and incorporation of emerging best practices and stakeholder input are critical to the long-term success of the program. The amount of work undertaken in the inaugural Plan was an aggressive and ambitious scope that touched many different areas of the Companies' infrastructure. Lessons learned in assessment, materials procurement, work management and scheduling, and resource levelizing are all now included in this Plan.

**25. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

A. Yes.

**Statement of Qualifications  
for  
JESSE E. MURRAY, P.E.**

**Summary of Qualifications**

20 plus years of engineering and utility leadership experience. Broad experience in process design, utility operations, problem analysis, project management, business operations, risk analysis, and financial analysis. Extensive knowledge in energy market fundamentals, combustion and steam turbines, contract negotiation/administration, and commercial construction techniques.

**Professional Experience**

***Vice President, Electric Delivery and Natural Disaster Protection***

*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy  
February 2022 – Present*

Responsible for overseeing lines operations and maintenance, meter operations, operations support, emergency management, and vegetation management activities for NV Energy's electric transmission and distribution assets. Also responsible for executing the Natural Disaster Protection Plan as required by SB 329 of the 2019 Nevada Legislature and NRS 704.7983.

***Vice President, Gas Delivery and Natural Disaster Protection***

*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy  
November 2017 – February 2022*

Responsible for overseeing the operations, engineering, construction, compliance, service, and financial activities of NV Energy's gas distribution utility. Responsible for executing the Natural Disaster Protection plan as required by SB 329 of the 2019 Nevada Legislature and NRS 704.7983. The plan addresses and mitigates wildfire and other natural disaster risks that could impact or be caused by electric facilities in high risk areas (natural disaster protection added April 2021).

***Director, Renewable Energy Programs***

*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy  
March 2015 - November 2017*

Responsible for the implementation of several behind the meter customer renewable generation programs as required by NRS 701B. This included overseeing the development of the annual plan, management of the customer incentive process, interfacing with community stakeholders, and ensuring compliance with regulations.

***Manager, Maintenance***

*Sierra Pacific Power Company d/b/a NV Energy  
March 2014 – March 2015*

Responsible for leading the engineering and maintenance organization at Frank A. Tracy and Fort Churchill generating stations. Managed a staff that provided plant maintenance and engineering support, equipment performance testing, and execution of plant betterment projects. Responsible for developing and executing

long term business plans, including capital and O&M budgeting, workforce design, and major maintenance scheduling.

***Manager, Asset Management Programs, Power Generation***

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

*June 2013 – March 2014*

Responsible for designing and implementing an Asset Management Program for NV Energy's 6,000MW natural gas and coal fired generation fleet. Responsible for all aspects of the program, including strategic planning, financial justification, quantitative risk assessment, resource prioritization, outage scheduling, and alliance contracting.

***Manager, Plant Engineering and Technical Services***

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

*August 2011 – June 2013*

Responsible for leading the engineering and maintenance organization at Frank A. Tracy and Fort Churchill generating stations. Managed a staff that provided engineering support, equipment performance testing, and execution of plant betterment projects. Responsible for developing and executing long term business plans, including capital and O&M budgeting, and major maintenance scheduling.

***Staff Engineer***

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

*January 2008 – August 2011*

Provided plant engineering services at Frank A. Tracy and Fort Churchill Generating Stations. Included a focus on process design, water treatment, major maintenance, and plant betterment.

***Engineer III***

*International Game Technology*

*October 2003 - January 2008*

Responsible for managing major construction and space planning projects. Directed major real estate transactions on commercial buildings and undeveloped land. Managed major capital improvement projects throughout the project life cycle. Conducted property searches for new offices in developing markets, and negotiated the lease terms for these new properties. Managed existing leases at 40 locations in North America.

***Associate Engineer***

*Bechtel BWXT Idaho – Idaho National Engineering Laboratory*

*June 2002 - October 2003*

Characterized and managed chemically hazardous radioactive waste as prescribed by the Resource Conservation and Recovery Act (RCRA). Initiated and coordinated commercial disposition shipments to reduce nuclear and hazardous waste inventory within the State of Idaho.

**Education**

***Master of Business Administration, University of Nevada, Reno, December 2007***

*Bachelor of Science with High Distinction in Chemical Engineering, University of Nevada Reno, June 2002*

*State of Nevada Professional Engineering License 21314, Chemical Engineering*

**Appearances in front of the Public Utilities Commission of Nevada**

- 15-07041/2 Net Metering Cost of Service Docket
- 16-02006 Renewable Generations Annual Plan
- 16-03003 Nevada Power Annual Deferred Energy Accounting Adjustment
- 16-03004 Sierra Pacific Power Annual Deferred Energy Accounting Adjustment
- 16-03005 Sierra Pacific Gas Annual Deferred Energy Accounting Adjustment
- 16-07001 Sierra Pacific Power Company Triennial Integrated Resource Plan
- 16-08027 Nevada Power Second Amendment to the Triennial Integrated Resource Plan
- 17-02007 Renewable Generations Annual Plan
- 17-03001 Nevada Power Annual Deferred Energy Accounting Adjustment
- 17-03002 Sierra Pacific Power Annual Deferred Energy Accounting Adjustment
- 17-03003 Sierra Pacific Gas Annual Deferred Energy Accounting Adjustment
- 21-03004 Natural Disaster Protection Plan 2020 Regulatory Asset Recovery
- 22-03006 Natural Disaster Protection Plan 2021 Regulatory Asset Recovery
- 22-08001 2<sup>nd</sup> Amendment to the 2020-2023 Natural Disaster Protection Plan

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AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JESSE MURRAY, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2023

  
JESSE MURRAY

**DANYALE HOWARD**

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**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2023 Natural Disaster Protection Plan  
Docket No. 23-03xxx

Prepared Direct Testimony of

**Danyale Howard**

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

**A.** My name is Danyale Howard. My current position is Director of Natural Disaster Protection Plan Program Execution for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of the Companies.

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

**A.** I have 26 years of experience in the utility industry, holding several positions within the Companies. Before assuming my current role, I held the role of Director, Distribution Design services where I oversaw five offices responsible for electric and gas and project management of distribution line extensions subject to the Rule 9 Line Extension tariff, local governmental franchise agreements, and electric distribution planned capital maintenance projects for NV Energy’s northern Nevada region. In June 2021, I assumed my current role as Director, Natural

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Disaster Protection. My statement of qualifications is attached as **Exhibit Howard-Direct-1.**

**3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?**

**A.** I am responsible for the implementation of the Natural Disaster Protection Plan (“NDPP”), ensuring compliance with the projects and programs pursuant to NRS 704.7983. My responsibilities include oversight and management of projects and programs focused on inspections, patrols and corrections as well as the project management and construction of the various system hardening efforts contained within the NDPP. The NDPP strategies mitigate risk due to the potential effects of wildfires and other natural disasters on NV Energy’s electric facilities.

**4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?**

**A.** Yes. I have submitted testimony and appeared before the Commission in the Joint Application of Nevada Power and Sierra’s Underground Management Plan (“UMP”) filing in Docket No. 19-05027, Sierra’s 2019 general rate case (“GRC”) filing in Docket No. 19-06002, the 2020 NDPP Regulatory Asset Recovery Docket No. 21-03040, the 2021 NDPP Regulatory Asset Recovery filing in Docket No. 22-03006, and the 2022 Nevada Power/Sierra NDPP Second Amendment filing in Docket No. 22-08001. My professional background and experience are provided in **Exhibit Howard-Direct-1.**

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

**A.** The purpose of my testimony is to sponsor elements of the Companies' Second Triennial Natural Disaster Protection Plan (the "Plan") related to specific projects and programs. The specific programs that I sponsor, and my testimony addresses are:

- Circuit Patrols, Detailed Inspections and Corrections
- System Hardening Strategy
- Investment Sharing
- Selective Undergrounding Segment Prioritization
- Cost Sharing Undergrounding Opportunities
- Total Tier 3 Undergrounding Plan
- Distribution Overhead Rebuilds
- Copper Wire Removal
- Expulsion Fuse Replacement
- Lightning Arresters
- Tree Attachments
- Grid Ruggedization, Critical Crossings and Pole Stoppers
- Substation Hardening
- Fire Mesh Program Extension
- Advanced Technology: System Protection Study

**6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

**A.** I am sponsoring or co-sponsoring the following Exhibits:  
**Exhibit Howard-Direct-1** – Statement of Qualifications  
**Exhibit B**, The Second Triennial Natural Disaster Protection Plan, specifically I sponsor or co-sponsor the following portions of the Plan:

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- Section 2.5 – Conditional Awareness: Circuit Patrols, Detailed Inspections and Corrections
- Section 2.6 – Grid Resilience and System Hardening
- Section 4.2 – Section Protection Study
- Appendices F, G, H, I and J

**7. Q. IS THERE AN OVERARCHING THEME IN THE PLAN FOR PATROLS AND INSPECTION AND SYSTEM HARDENING?**

**A.** Yes. The general theme for the patrols, inspections and corrections and system hardening programs is refining the efficiency and effectiveness of the NDPP projects and programs that originated in the inaugural triennial Plan.

The Companies have gained significant insight about the logistics, costs and opportunities to further improve the execution of the NDPP. Overall, the Plan is a continuation of workflows extending from the inaugural triennial Plan, creating a foundation to further develop practices and policies needed to meet the continuing changes in the environment and evolving public utility safety standards. In this Plan, the Companies identify opportunities to refine the efficiency of risk mitigation applications while striving to maximize the outputs and limit customer impact.

Notable objectives for this Plan include:

1. Increased cost predictability by striving to achieve levelized work schedules.
2. A plan to transition certain NDPP system hardening projects to the general rate recovery mechanism.
3. Focus on the heightened fire risk tiers and Circuit Resiliency areas for patrols and inspections.
4. Incorporation of overhead rebuilds into Plan initiatives to reduce mobilization costs, improve planned outage efficiencies, and pick up elements of overlapping initiatives.

1 **CIRCUIT PATROLS AND DETAILED INSPECTIONS**

2 **8. Q. ARE THERE ANY SIGNIFICANT CHANGES FOR THE PATROLS AND**  
3 **INSPECTIONS PROGRAM?**

4 A. Yes. The Companies have completed the second cycle of detailed inspections in  
5 the Tier 3 Wildfire Tier<sup>1</sup> and Circuit Resilience<sup>2</sup> areas and annual patrols  
6 throughout both programs. 2022 also marked the first full season of NDPP system  
7 hardening construction for northern and southern Nevada. Based on that  
8 experience, the Companies recommend the following:

- 9
- 10 1. Move the Circuit Resiliency patrols and detailed inspections to
- 11 Conditional Awareness, Section 2.5 of the second triennial NDPP. The
- 12 Circuit Resiliency patrols and inspections program was previously
- 13 categorized under the Line Ruggedization, Natural Disaster Risk Zone
- 14 (non-wildfire) section of the NDPP.
- 15 2. Update the wildfire tier patrols and inspections schedules to reflect
- 16 elevating Virginia City Highlands to Tier 3 and include a proposed Tier
- 17 1, to refine and replace the former WUI Tier.
- 18 3. Remove the non-Tier wildfire risk areas from the NDPP circuit patrols
- 19 and detailed inspections program and related cost recovery.
- 20 4. Adjust patrols and inspections schedules in this Plan to lay the
- 21 groundwork for future levelized work schedules.
- 22 5. Add milestones to address Priority 1 corrections identified through the
- 23 patrols and inspections.

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26 <sup>1</sup> The Wildfire Tier Patrol and Inspection Program targets wildfires and grassland fires in designated Tiers 3, 2, 1E  
and 1, with Tier 1 refining and replacing the former Wildland Urban Interface (“WUI”) Tier.

27 <sup>2</sup> The Circuit Resilience Patrol and Inspection Program is currently focused on Southern Nevada distribution circuits  
impacted by wind, flood, microburst and monsoon events.

1 9. Q. PLEASE EXPLAIN THE FREQUENCY OF NDPP CIRCUIT PATROLS  
2 AND DETAILED INSPECTIONS.

3 A. The Companies’ recommended patrols and inspections frequency for Heightened  
4 Threat Areas (“HTAs”) is shown below in Tables 1 and 2. The Companies have  
5 met or exceeded this frequency each year since 2019, which was the  
6 commencement of the inaugural Plan.  
7

8 Table 1. Patrols and Inspections Frequency – HTA Wildfire Risk

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 Patrol		Detailed Inspection	
	Fire Risk Tiers 3, 2, 1E	Fire Risk Tier 1	Fire Risk Tiers 3, 2, 1E	Fire Risk Tier 1
	Annual*	Every 4 years	Every 5 years except every 3 years for Tier 3	Every 10 years

13 \* Detailed inspection only for years when patrol and inspection fall on the same year

16 Table 2. Patrols and Inspections Frequency – HTA Circuit Resiliency

Circuit Resiliency			
Circuit Patrol and Detailed Inspection Frequency			
Overhead Transformers, Switching / Protective Devices, Regulators / Capacitors, Conductor and Cables, Wood Poles and other overhead assets	NPC Top 20 Worst Performing Circuits	Circuit Patrol	Detailed Inspection
		1 thru 20	1 thru 10
		Annual*	Every 4 years

20 \* Detailed inspection only for years when patrol and inspection fall on the same year

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28 Howard - DIRECT

10. Q. PLEASE EXPLAIN WHY THE COMPANIES ARE RECOMMENDING ADJUSTED PATROLS AND INSPECTIONS SCHEDULES FOR THE PLAN.

A. The Companies’ proposed schedule aims to promote predictable costs for the patrols and inspections program. The Companies seek to accomplish this by levelizing the total number of pole inspections (and associated corrections) on a year-by-year basis. This will help to reduce or eliminate dynamic cost swings between years. The Companies cannot levelize schedules immediately due to the timing of Tier 2 and Tier 1E inspections without exceeding the acceptable frequency noted in Table 1 and Table 2. This challenge is due to the timing of Tier 1E and Tier 2 patrols and inspections coming due in 2024. However, the schedules presented in this NDPP are adjusted to levelize the total number of patrols and inspections to the extent possible. This adjustment initiates a trend to flatten, or levelize the schedule completely in the coming years beyond this Plan. Tables 3 and 4 show the adjusted fire tier patrols and inspections schedules recommended for this second triennial NDPP.

Table 3. Fire Tier Patrols (Adjusted) – SPPC and NPC OMAG Costs

	Pole Count			Total	Cost Forecast			Plan
	2024	2025	2026	Poles	2024	2025	2026	Budget
Tier 3 NPC	485	0	485	970	\$ 22,863	\$ -	\$ 22,863	\$ 45,726
Tier 3 SPPC	7,589	0	5,059	12,648	\$ 357,745	\$ -	\$ 238,481	\$ 596,226
Tier 2 SPPC	0	8,022	8,022	16,044	\$ -	\$ 141,287	\$ 108,261	\$ 249,548
Tier 1E SPPC	29,265	13,169	16,096	58,530	\$ 1,134,167	\$ 375,402	\$ 655,321	\$ 2,164,890
Tier 1 NPC	501	501	501	1,503	\$ 23,617	\$ 23,617	\$ 23,617	\$ 70,851
Tier 1 SPPC	5,656	5,656	5,656	16,968	\$ 266,624	\$ 266,624	\$ 266,624	\$ 799,872
Total NPC	986	501	986	2,473	\$ 46,480	\$ 23,617	\$ 46,480	\$ 116,577
Total SPPC	42,510	26,847	34,833	104,190	\$ 1,758,536	\$ 783,313	\$ 1,268,687	\$ 3,810,536

Table 4. Fire Tier Inspections (Adjusted)– SPPC and NPC OMAG Costs

	Pole Count			Total Poles	Cost Forecast			Plan Budget
	2024	2025	2026		2024	2025	2026	
Tier 3 NPC	-	485	-	485	\$ -	\$ 35,017	\$ -	\$ 35,017
Tier 3 SPPC	-	7,589	2,530	10,119	\$ -	\$ 547,926	\$ 182,666	\$ 730,592
Tier 2 SPPC	10,028	2,006	2,006	14,040	\$ 724,022	\$ 144,833	\$ 144,833	\$ 1,013,688
Tier 1E SPPC	-	16,096	13,169	29,265	\$ -	\$ 1,162,131	\$ 950,802	\$ 2,112,933
Tier 1 NPC	334	334	334	1,002	\$ 24,115	\$ 24,115	\$ 24,115	\$ 72,345
Tier 1 SPPC	3,770	3,770	3,770	11,310	\$ 272,194	\$ 272,194	\$ 272,194	\$ 816,582
Total NPC	334	819	334	1,487	\$ 24,115	\$ 59,132	\$ 24,115	\$ 107,362
Total SPPC	13,798	29,461	21,475	64,734	\$ 996,216	\$ 2,127,084	\$ 1,550,495	\$ 4,673,795

11. Q. ARE NDPP CIRCUIT PATROLS AND DETAILED INSPECTIONS ONLY FOCUSED ON WILDFIRE HTAS?

A. No. In addition to inspections and patrols in wildfire HTAs, the NDPP includes patrols and inspections in other non-wildfire HTAs with the most significant nature-caused outage issues. These HTAs are susceptible to monsoon events, which have impacted infrastructure because of flood and wind events. The non-wildfire HTAs are in southern Nevada, in the Nevada Power service territory. The patrols and inspections program targeting non-wildfire natural disasters is referred to as the Circuit Resiliency patrols and inspections program.

The second triennial NDPP combines both the fire tier and Circuit Resiliency patrols and inspection programs into a single section called Conditional Awareness: Circuit Patrols, Detailed Inspections and Corrections. This is a change from the inaugural plan, which included the Circuit Resiliency patrols and inspections program under the Grid Ruggedization initiative. Grouping these two patrols and inspections programs together provides better visibility for all NDPP patrols and inspections performed on the Companies' overhead system.

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12. Q. HOW ARE THE PATROLS AND INSPECTIONS LOCATIONS IDENTIFIED FOR THE CIRCUIT RESILIENCY PROGRAM?

A. The Circuit Resiliency program directs the Companies to identify the Top 20 nature-caused outage impacted distribution circuits. These circuits are divided into two groups. The first group includes the top ten worst performing circuits. The second group contains the next ten worst performing circuits (circuits 11 through 20 in the worst-performing assessment). The Companies perform circuit patrols annually for both groups and perform detailed inspections on the top ten worst performing circuits once every four years. In a year when a patrol and detailed inspection are scheduled to occur in the same year, only the detailed inspection will occur. This helps the Companies identify and correct overhead equipment problems to mitigate the potential effects of natural disasters.

13. Q. ARE THE COMPANIES RECOMMENDING ANY CHANGES TO THE CIRCUIT RESILIENCY PATROLS AND INSPECTIONS SCHEDULE?

A. No. Unlike the wildfire tier patrols and inspections program, the Circuit Resiliency patrols and inspections schedule is already as level as can be based on the number of patrols and inspections scheduled and required frequency. Table 5 shows the frequency of patrols and inspections combined by year and cost. 2025 escalated costs are attributable to a detailed inspection cycle becoming due that year.

Table 5. Circuit Resilience Patrols and Inspections Schedules and OMAG Cost

NPC	Pole Count			Cost Forecast			Plan Budget
	2024	2025	2026	2024	2025	2026	
Circuits 1-10	2,750	2,750	2,750	129,635	198,550	129,635	457,820
Circuits 11-20	2,750	2,750	2,750	129,635	129,635	129,635	388,905
Total	5,500	5,500	5,500	259,270	328,185	259,270	846,725

1 ***CORRECTIONS RESULTING FROM PATROLS AND INSPECTIONS***

2 **14. Q. ARE THERE ANY CHANGES TO THE WAY THE COMPANIES WILL**  
3 **ADDRESS CORRECTIONS IN THE PLAN?**

4 **A.** Yes. The Companies completed system and reporting enhancements to identify and  
5 fully execute identified corrections. In the Plan, the Companies identify the  
6 existing Priority 1 backlogged corrections and recommend milestones to complete  
7 existing and future corrections.

8  
9 **15. Q. HOW DO THE COMPANIES USE PATROLS AND INSPECTIONS DATA**  
10 **TO INFORM CORRECTIONS ACTIVITIES?**

11 **A.** Taken with the other programs, including risk area identification, the patrols and  
12 inspections provide a more thorough picture of risk related to the Companies'  
13 infrastructure. With this natural disaster risk picture, the Companies can align  
14 projects and programs toward risk reduction activities, including corrections, based  
15 on situational and conditional information.

16  
17 **16. Q. PLEASE EXPLAIN HOW SYSTEM AND REPORTING ENHANCEMENTS**  
18 **ENABLE THE COMPANIES TO FULLY EXECUTE CORRECTIONS,**  
19 **SPECIFICALLY THE PRIORITY 1 CORRECTIONS BACKLOG.**

20 **A.** To initiate compliance with the inaugural NDPP, the Companies used contractor  
21 software, tools, and databases as an interim solution to perform detailed inspections  
22 and quickly identify and resolve highest priority risks. The contractor software  
23 allowed the Companies to quickly implement a detailed inspection program. The  
24 Companies recognized that as the program matured, they also needed the ability to  
25 filter, analyze, and prioritize condition data more efficiently and for the long-term.  
26 In July 2021, the NDPP leadership identified business requirements for an  
27

enhancement to Maximo, the Companies' asset management module, and the Companies achieved an initial scope of work to initiate Maximo code modifications. This system enhancement enabled the Companies to upload inspection export data from an Excel format and route it directly into the asset management module within Maximo. This enhancement was put into production in February 2022.

Once the Maximo enhancements and data transfers were completed in 2022, the Companies used PowerBI software to create a dashboard with the capability to assess, organize, and filter the patrol, inspection, and correction data in a usable format. Within Maximo, the Companies realized the capability to create a corrective repair action for projects based on the field conditions. Figures 1 and 2 are snapshots of the dashboard created to organize and track corrections.

Figure 1. Conditional Awareness, Inspections Corrections Report Example

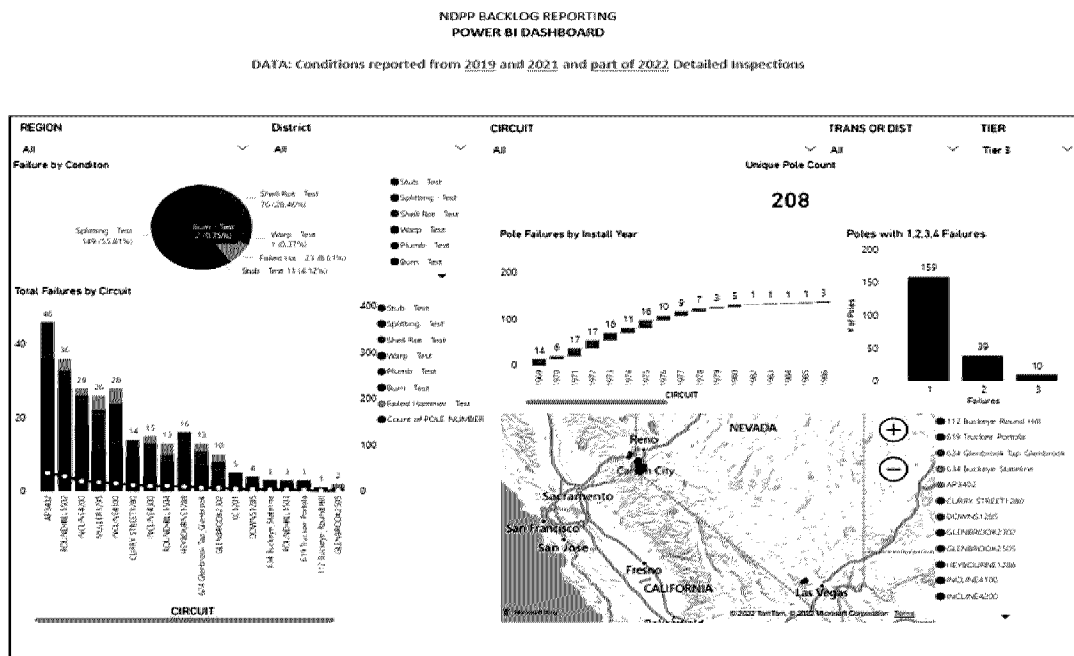
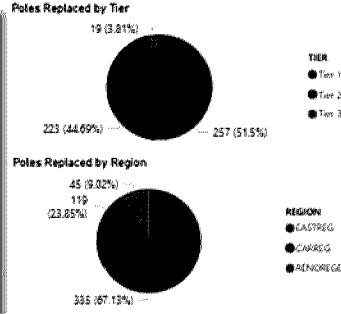
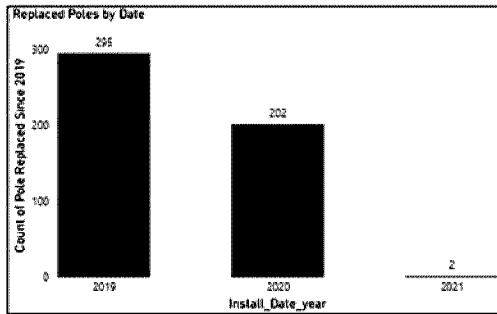


Figure 2. Conditional Awareness: Corrections Tracking Report Example

DATA: Conditions reported from 2019 and 2021 and part of 2022 Detailed Inspections

**POLE REPLACEMENTS COMPLETE -- All Locations**

ID NUMBER	INSTALL DATE	REGION	DISTRICT	TIER	INSTALL WORK ORDER NUMBER	CIRCUIT	PRIORITY 1	SUM - Copy
P1193057	4/12/19	CARREG	33	Tier 3	3003654580	634 Buckeye_StateLine		
P1194579	4/30/19	EASTREG	25	Tier 2	3003819368	653 Winnemucca_Dusch Flat	stranded_jumper/Yes	
P1187251	1/4/19	EASTREG	26	Tier 2	3002493217	ADOBE203	Change insulator Type:Steel Steel Quantity:1	
P1189668	1/9/19	EASTREG	26	Tier 2	3002846280	ADOBE203		
P9003067	5/16/19	EASTREG	26	Tier 2	3003921958	ADOBE203		
P1182639	7/30/19	EASTREG	26	Tier 2	3001133702	ADOBE203		
P1182642	7/30/19	EASTREG	26	Tier 2	3001133702	ADOBE203		
P1182644	7/30/19	EASTREG	26	Tier 2	3001133702	ADOBE203		
P1182651	7/30/19	EASTREG	26	Tier 2	3001133702	ADOBE203		
P1182653	7/30/19	EASTREG	26	Tier 2	3001133702	ADOBE203		
P1182654	7/30/19	EASTREG	26	Tier 2	3001133702	ADOBE203		
P1182656	7/30/19	EASTREG	26	Tier 2	3001133702	ADOBE203		
P1192396	5/3/19	CARREG	16	Tier 1	3003385548	BRUNSWICK2508	pole_deterioration/Splitting	
P1194431	8/13/19	CARREG	16	Tier 1	3003453981	BRUNSWICK2608	animal_guards/Missing	
P1192567	2/6/20	CARREG	16	Tier 1	3003385074	BRUNSWICK2608	Hardware/Missing/loose	
P1192234	5/7/19	RENOREG	12	Tier 2	3003422696	CALIFORNIA204		



**499**  
Count of Pole Replaced Since 2019

During the inaugural NDPP period, the Companies' GIS team also developed mobile application software to facilitate inspections and patrols to replace contractor software.

Given these enhancements, 5,289 Priority 1 OMAG corrections and 2,463 Priority 1 pole replacements were grouped by circuit, prioritized, and scheduled to begin deployment in 2023. The Priority 1 OMAG corrections are scheduled to be complete by 2024 year-end, after which the Companies anticipate a standardized schedule for resolving newly found OMAG corrections. The Priority 1 pole replacements are contingent on design and permitting timelines. The second triennial NDPP section 2.5.1 explains that 33% of new corrections found will be resolved within twelve months of inspection data validation, with the remaining 66% resolved within twenty-four months of inspection data validation. NV Energy

will continue to resolve Priority 0 corrections immediately and at a 100% completion rate.

Except for the actual backlog of corrections, all forecasted correction counts and cost estimates for anticipated corrections are based on actual corrections run rates from 2019 through 2021. Cost estimates for OMAG corrections are forecasted below based on a Corrections milestone of 33% completion year one and 66% completion year two.

Tables 6 and 7 show the 2024 through 2026 estimated costs for Nevada Power and Sierra’s anticipated OMAG corrections for fire tier patrols and inspections.

Table 6. Fire Tier Corrections Sierra OMAG

Sierra	OMAG Corrections Counts			Cost Forecast			Plan
	2024	2025	2026	2024	2025	2026	Budget
Actual Backlog	937	937	937	\$ 2,436,200	\$ 2,436,200	\$ 2,436,200	\$ 7,308,600
Forecasted	1,217	2,035	1,612	\$ 1,609,309	\$ 3,584,764	\$ 5,109,165	\$ 10,303,238
<b>Total</b>	<b>2,154</b>	<b>2,972</b>	<b>2,549</b>	<b>\$ 4,045,509</b>	<b>\$ 6,020,964</b>	<b>\$ 7,545,365</b>	<b>\$ 17,611,838</b>

Table 7. Fire Tier Corrections Nevada Power OMAG

Nevada Power	OMAG Corrections Counts			Cost Forecast			Plan
	2024	2025	2026	2024	2025	2026	Budget
Actual Backlog	-	-	-	\$ -	\$ -	\$ -	\$ -
Forecasted	139	716	139	\$ 102,073	\$ 257,162	\$ 276,448	\$ 635,683
<b>Total</b>	<b>139</b>	<b>716</b>	<b>139</b>	<b>\$ 102,073</b>	<b>\$ 257,162</b>	<b>\$ 276,448</b>	<b>\$ 635,683</b>

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1 Tables 8 and 9 show the 2024 through 2026 estimated costs for Nevada Power and  
2 Sierra's anticipated capital corrections (pole replacements) for fire tier patrols and  
3 inspections.

4 Table 8. Fire Tier Corrections Sierra Capital

Sierra	2024-2026			
	Budget	2024 Forecast	2025 Forecast	2026 Forecast
Inspections & Corrections	\$ 9,764,401	\$ 2,616,201	\$ 3,989,534	\$ 3,158,666
Tier 1 Priority Pole Replacements	\$ 2,493,953	\$ 774,667	\$ 886,203	\$ 833,083
Tier 1E Priority Pole Replacements	\$ 4,052,582	\$ 1,433,068	\$ 1,283,197	\$ 1,336,317
Tier 2 Priority Pole Replacements	\$ 600,233	\$ 200,933	\$ 222,567	\$ 176,733
Tier 3 Priority Pole Replacements	\$ 2,617,633	\$ 207,533	\$ 1,597,567	\$ 812,533

9 Table 9. Fire Tier Corrections Nevada Power Capital

Nevada Power	2024-2026	2024	2025	2026
	Budget	Forecast	Forecast	Forecast
Inspections & Corrections	\$ 1,828,714	\$ 274,751	\$ 695,508	\$ 858,455
Tier 1 Priority 1 Pole Replacement	\$ 1,124,575	\$ 201,909	\$ 461,333	\$ 461,333
Tier 3 Priority 1 Pole Replacement	\$ 704,139	\$ 72,842	\$ 234,175	\$ 397,122

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Tables 10 and 11 show the 2024 through 2026 estimated costs for Nevada Power anticipated OMAG and capital corrections (pole replacements) for Circuit Resiliency patrols and inspections. Cost estimates for OMAG corrections shown in Table 10 are forecasted below based on a Corrections milestone of 33% completion year one and 66% completion year two.

Table 10. Circuit Resiliency Corrections – Nevada Power OMAG

NPC	OMAG Repairs			Cost Forecast			Plan
	2024	2025	2026	2024	2025	2026	Budget
Circuits 1-10	29	594	29	573,749	748,862	1,110,148	2,432,759
Circuits 11-20	29	29	29	573,749	39,226	37,351	650,326
<b>Total</b>	<b>58</b>	<b>623</b>	<b>58</b>	<b>1,147,498</b>	<b>788,088</b>	<b>1,147,499</b>	<b>3,083,085</b>

Table 11. Circuit Resiliency Corrections – Nevada Power Capital

Nevada Power	2024-2026	2024	2025	2026
	Budget	Forecast	Forecast	Forecast
<b>Inspections &amp; Corrections - Circuit Resiliency</b>	<b>\$ 3,525,126</b>	<b>\$ 1,181,925</b>	<b>\$ 1,161,276</b>	<b>\$ 1,181,925</b>

17. **Q. HAVE THE COMPANIES MADE COLLABORATIVE IMPROVEMENTS TO SUPPORT NDPP CORRECTIONS, SPECIFICALLY THE POLE REPLACEMENTS?**

A. Yes. The Companies succeeded in modifying the existing Memorandum of Understanding (“MOU”) with the Tahoe Regional Planning Agency (“TRPA”) to expedite, to the extent possible, the replacement of single poles that are typically subject to long-lead times associated with planning and permitting. Under the modified MOU, single pole replacements located in TRPA’s land capability zones 7 thru 10 can be addressed without formal design and TRPA permitting. However, the pole replacements are still subject to other jurisdictional requirements. For

1 example, poles located within the United States Forest Service (“USFS”) area still  
2 require long-lead time permitting despite the TRPA MOU modification. USFS  
3 permits are typically processed in sequence, so the revised TRPA MOU decreases  
4 overall lead times by shortening one phase of permitting needed to replace  
5 identified poles.

6  
7 **18. Q. WHEN DO THE COMPANIES EXPECT TO SEE A DECREASE IN THE**  
8 **NUMBER OF CORRECTIONS?**

9 **A.** The Companies expect to see some correction levels decrease over time as the  
10 correction backlog is resolved, with adherence to an established completion rate for  
11 ongoing corrections and combined with the other system hardening  
12 recommendations presented in this second triennial NDPP. That said, the  
13 Companies do not expect correction levels to decrease during the second triennial  
14 NDPP.

15  
16 In some situations, the age and condition of the circuit indicate corrections will  
17 remain at a consistent rate as each inspection cycle occurs. In these cases, natural  
18 disaster risk, particularly fire risk, will not be effectively mitigated through a  
19 patchwork of corrections identified intermittently through each three- or four-year  
20 interval inspection cycle. Instead, the Companies recommend rebuilding segments  
21 or entire circuits to address ongoing costly repairs.

22  
23 In the future, completed corrections and all other system hardening updates  
24 uploaded to the Companies’ GIS maps and asset management module will inform  
25 the Technosylva Wildfire Risk Reduction Model (“WRRM”) application thereby  
26 creating a mechanism to measure risk reduction efforts. A Technosylva WRRM  
27

1 pilot application is scheduled for deployment in March 2023. Peer utilities report a  
2 one- to three-year developmental path and acclimation to steady state use of  
3 WRRM's data analytics. From there, risk refinement and prioritization is expected  
4 to occur and the Companies can formally develop processes and procedures to  
5 standardize project scoping using the risk reduction modeling features. Any  
6 projects initiated because of WRRM would then be subject to standard lead-times  
7 for capital projects, which is typically one- to three- years from project initiation  
8 depending on resource and permitting constraints.  
9

10 ***SYSTEM HARDENING AND GRID RESILIENCE***

11 **19. Q. ARE THERE ANY CHANGES TO THE SYSTEM HARDENING**  
12 **PROGRAM RECOMMENDED IN THIS PLAN COMPARED TO THE**  
13 **INAUGURAL NDPP?**

14 **A.** Yes. The Companies outline a system hardening strategy to increase efficiencies  
15 and expand the geographic footprint of risk mitigation by recommending overhead  
16 rebuild of certain circuits or segments of circuits. Additionally, the Companies  
17 propose a rationale to transition certain NDPP system hardening projects to a  
18 general rate recovery mechanism.  
19

20 **20. Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN SYSTEM**  
21 **RELIABILITY AND SYSTEM RESILIENCE.**

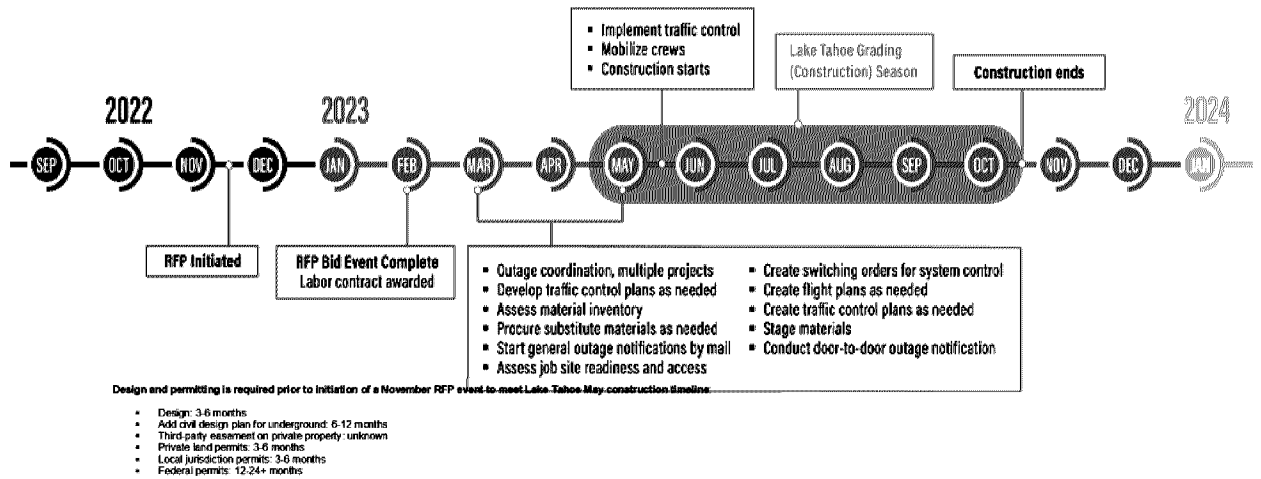
22 **A.** Reliability means the lights always come on when customers activate a switch.  
23 Resilience is very different. Resilience means that the critical parts of the electrical  
24 supply system can mitigate, survive, and/or recover from high impact threats.  
25 NDPP system hardening and grid ruggedization programs are aimed at enhancing  
26 resilience of the overhead electric system against the impacts of natural disasters  
27

1 and hardening the system, thereby reducing the potential for equipment caused  
2 events that can lead to a natural disaster.

3  
4 **21. Q. WHAT ARE THE TYPICAL PHASES OF A SYSTEM HARDENING OR**  
5 **RUGGEDIZATION PROJECT?**

6 **A.** The majority of system hardening projects are capital replacement projects of long  
7 duration. Capital projects typically require formal design-engineering and  
8 permitting that, together, create long lead times to construction. Construction  
9 duration can vary from a short to long timeframe depending on scope of the work.  
10 System hardening projects typically have three activity phases that take place across  
11 a multi-year period for each project. These typical phases are generalized below:  
12 Phase 1 – Design and Permitting – Lays out the technical details of the project and  
13 begins facilitation to meet jurisdictional permitting requirements. Underground  
14 projects also typically require submittal of civil plans and profile designs.  
15 Phase 2 – Civil Construction – Includes site readying and substructure installation.  
16 This can be excavation of a single hole or full civil construction, trench detail, and  
17 installation of vaults and a conduit system.  
18 Phase 3 - Line Construction – Includes electric infrastructure installation and  
19 preparing the project for operation after final inspections.  
20 Projects can take a number of years to complete, most system hardening and  
21 ruggedization initiatives in the Plan are a continuation of those previously presented  
22 in the inaugural NDPP and its amendments. Figure 3 shows a typical capital project  
23 workflow and the Lake Tahoe seasonal timeline.

Figure 3. Lake Tahoe Seasonal Construction Timeline



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

22. Q. ARE THERE ANY RESTRICTIONS ON HOW OR WHEN NV ENERGY CAN CONDUCT RUGGEDIZATION AND HARDENING PROJECTS?

A. Yes. Projects may have restrictions based on seasonal constraints or local ordinances. This can hamper seamless project implementation, especially when only narrow work windows exist for project activities. This results in an intermittent response to applying risk mitigation strategies. Throughout 2022, NV Energy evaluated the effectiveness of risk reduction system hardening efforts, seeking opportunities to improve future risk mitigation initiatives exclusively focused on Tier 3. The Companies assessed project types, locations, timing, and cost to increase overall efficiency and effectiveness. Significant challenges were identified in areas where risk reduction activities must take place during short seasonal construction windows, as is commonly found in Tier 3. The Companies found that the system hardening program cost profiles could be improved by managing a portfolio of projects that allows the Companies to shift resources from Tier 3 to lower tiers during months construction is not possible in Tier 3.

1 The Companies experienced increased system hardening costs for seasonal  
2 mobilization due to “work starts” and “work stops” based on seasonal constraints.  
3 The industry has concluded that significant additional costs are embedded within  
4 projects that require seasonal mobilization with long duration work stoppages.  
5 Actual costs to mobilize contract resources for the NDPP projects that were  
6 constructed during the 2022 Lake Tahoe season were at least \$1,000,000, and an  
7 additional 35% of the cost of each unique project was attributable to remobilization  
8 of contract resources performing single asset replacement projects, rather than a  
9 broader programmatic approach, across many noncontiguous sites. These projects  
10 include trip savers, single pole replacements and short segments of copper wire  
11 replacement.

12  
13 **23. Q. HOW ARE THE COMPANIES PROPOSING TO OPTIMIZE SYSTEM**  
14 **HARDENING CONTRACT RESOURCES AND INCREASE RISK**  
15 **MITIGATION?**

16 **A.** The Companies are proposing a programmatic approach for system hardening  
17 projects that would levelize workload over the course of the year and reduces  
18 remobilization costs. To achieve this, the Companies will establish project scopes  
19 two to three years in advance. Part of this resource optimization includes adding a  
20 number of overhead rebuilds to the portfolio of system hardening activities.  
21 Overhead rebuilds consist of replacing bare wire and aged poles for certain  
22 segments of circuits within Tier 3, Tier 2, and a small portion of Tier 1E. The

23 Companies propose rebuilding portions of the following circuits:

- 24 1. Incline 4100
- 25 2. Round Hill 1502
- 26 3. Muller 1295
- 27 4. Curry 1280
- 28 5. Mt. Rose 210
6. Chimney Peak 201 Phase 3

1 24. Q. WHAT IS THE SIGNIFICANCE, FROM A RISK PERSPECTIVE, OF  
2 ADDRESSING TIER 2 AND TIER 1E OVERHEAD CIRCUITS ALONG  
3 THE SIERRA MOUNTAIN RANGE?

4 A. The high-risk circuits and segments referenced in Q&A 22 were identified along  
5 the eastern front of the Sierra Mountain Range where fires have previously  
6 occurred. These circuits exist in Tier 2 and a small portion of Tier 1E where  
7 downslope windstorms are typical. Southwesterly winds aloft are pushed down the  
8 slopes of the eastern Sierra and Carson Range. Under the right atmospheric  
9 conditions, these winds accelerate as they hit the foothills and can bring damaging  
10 wind gusts greater than 60 miles per hour. These windstorms happen annually and  
11 can coincide with periods of prolonged dry weather. The typical wind direction is  
12 from the west to southwest. Any fire that starts under these extreme westerly or  
13 southwesterly winds can explode in size in a matter of minutes, exhibiting extreme  
14 fire behavior with rapid rates of spread, moving quickly into neighborhoods and  
15 businesses. From 2020 to 2022, weather stations in this area reported very severe  
16 windstorms, and at a greater frequency since 2020. These circuits and segments  
17 also have less complex permitting requirements and are excellent candidates to  
18 complement the Tier 3 system hardening work in the Tahoe area because they can  
19 be constructed between October and May each year, *i.e.*, the off-season for Tier 3  
20 construction.

21  
22 The ability to work across Tiers, particularly in similar geographic areas such as  
23 Tier 3 and Tier 2 along the Sierra Mountain Range, provides a larger footprint of  
24 risk reduction and reduces seasonal mobilization and demobilization costs.  
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1 25. Q. WHAT ARE THE ADVANTAGES OF TAKING A PORTFOLIO  
2 APPROACH TO RUGGEDIZATION AND SYSTEM HARDENING  
3 ACTIVITIES?

4 A. The year-round system hardening efforts in this Plan seek to realize the full  
5 potential of the NDPP’s risk reduction efforts. Under a portfolio approach, the  
6 Companies would use resources to accomplish system hardening projects across  
7 the HTAs, allowing NV Energy to manage its workforce more efficiently by  
8 utilizing resources during the Tier 3 off-season. The ability to contract labor  
9 resources across a calendar year and within in small geographic area reduces  
10 mobilization costs and assures access to qualified resources. The Companies’  
11 system hardening focus continues to be in Tier 3, but the ability to efficiently  
12 coordinate work on targeted circuits to address accumulated corrections, fuse  
13 replacements, and remove bare wire from high-risk fire zones using holistic  
14 planning and engineering to accommodate hardened poles and wires greatly  
15 improves efficiency and effectiveness.

16  
17 26. Q. WHAT ARE ADDITIONAL ADVANTAGES OF TAKING A PORTFOLIO  
18 APPROACH TO RUGGEDIZATION AND SYSTEM HARDENING  
19 ACTIVITIES?

20 A. The portfolio approach enables external stakeholders to coordinate their workforces  
21 efficiently to accommodate NDPP program deployment. During the inaugural  
22 NDPP, the Companies made positive strides collaborating with several local, state  
23 and federal agencies to coordinate efforts and streamline processes where possible.  
24 Collaboration centered on the needs of the Companies to execute the NDPP while  
25 promoting public safety for the communities served by these other agencies. One  
26 prevailing message was clear—external partners, such as permitting agencies, other  
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utilities and communication providers, require the Companies to provide predictable and advanced notice and scheduling to prepare and coordinate their own resources based on NDPP field actions.

The Companies recognized that condensing a volume of outage-dependent work and funneling it into a small geographic area within a seasonal timeframe such as Tier 3, led to significant impacts for local communities. The ability to provide year-round risk reduction activities enables the Companies to potentially reduce outage impacts to single communities by “smoothing out” risk reduction activities among other high-risk areas, specifically the eastern front of the Sierra Nevada Mountain range. The proposed portfolio approach reduces seasonal mobilization costs and incorporating circuit segment rebuilds reduces asset-by-asset mobilization costs. Lastly, incorporating linear year-round construction enables the Companies to seek more predictable contract rates through bulk contracts, minimizing dynamic peaks in project-by-project pricing.

An additional benefit to the portfolio approach for NDPP system hardening efforts is the added efficiencies gained in replacing expulsion fuses and lighting arresters as an embedded and synchronized part of other NDPP system hardening initiatives such as overhead line rebuilds. Having a single outage will reduce the impact of these NDPP projects on customers.

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1 **SYSTEM HARDENING - SHARED CAPITAL INVESTMENT**

2 **27. Q. PLEASE EXPLAIN THE SHARED CAPITAL INVESTMENT**  
3 **RECOMMENDATION FOR SYSTEM HARDENING PROJECTS.**

4 **A.** The concept of a shared capital investment is a new element to the NDPP. The  
5 Companies evaluated capital system hardening projects with the objective of  
6 transitioning, partially or fully, NDPP risk mitigation revenue requirements to a  
7 general rate recovery mechanism over time.

8  
9 Key actions associated with this transition include:

- 10 • Develop a plan to transition certain NDPP capital system hardening  
11 project and program costs, in full or in part, to the GRC cost recovery;
- 12 • Assess capital system hardening projects to determine a rubric for  
13 classifying project costs as GRC or NDPP;
- 14 • Maintain adequate oversight and management of all NDPP projects  
15 based on public safety and quantifiable risk reduction. Projects  
16 classified for cost recovery under GRC that remain within oversight of  
17 the Plan are referred to as “NDPP-GRC” projects;
- 18 • Manage coordinated scheduling and sequenced workflow for both  
19 NDPP and NDPP-GRC projects to capture synergies of project  
20 interdependencies to reduce overall costs and system outage impacts;
- 21 • Maintain transparency for all NDPP projects, regardless of the recovery  
22 mechanism, through the annual September 1 update and March 1  
23 Regulatory Asset Recovery filing.

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28 Howard - DIRECT

1 28. Q. WHAT RATIONALE DID THE COMPANIES USE TO CLASSIFY  
2 PROJECTS AS EITHER NDPP OR NDPP-GRC?

3 A. The proposed cost sharing classification approach is based on the accrued benefits  
4 of the work, whether more heavily benefiting a core NDPP element or more evenly  
5 distributed between NDPP and GRC. Classifying a project as NDPP-GRC does not  
6 alleviate any risks identified through the Plan’s Risk Assessment. While all projects  
7 provide safety and reliability benefits, this assessment seeks to recognize the  
8 proportionally weighted benefits. Table 12 shows the recommended classification  
9 of NDPP and NDPP-GRC projects.

10 Table 12. Shared Capital Investment Classifications

System Hardening	Discussion	NDPP	NDPP-GRC
Selective Underground Segment Prioritization	Ranked and recommended for undergrounding by fire agency – fire risk	X	
Cost Sharing Undergrounding	The current cost sharing project scopes (segments) are within the Selective Underground Segment Prioritization Plan so same consideration applies as above – fire risk	X	
Expulsion Fuse Replacement	Specific to high fire risk tiers. Traditional expulsion fuses are still standard in Tier 1 and non-fire tier areas – fire risk	X	
Mt. Rose 210	Ready for construction prior to 2024 therefore irrelevant for this assessment. Construction will commence under GRC classification		X
Tree Attachments	Violates vegetation clearance with added risk in drying conditions – fire risk	X	
Chimney Peak Rebuild	Prior justification was based on reliability not resilience or ruggedization - reliability		X
Substation Barrier Hardening	Resilience – hardening materials specific to ignition risk - fire risk	X	
Mt. Charleston Overhead and Underground Rebuild	Proposed tier 3 segments (5 miles) identified by fire agencies in the Selective Underground Segment Prioritization Plan – fire risk. Proposed new 1201 circuit from Northwest substation to Kyle Canyon is Tier 1 (13.5 miles) undergrounding not related to fire risk.	X	X
Critical Crossings	Ruggedization/Resilience – monsoon	X	
Pole Stoppers	Ruggedization/Resilience – monsoon	X	
Pole Replacements	Based on vintage age 70% of useful life	X	X
Copper wire replacement SPPC	SPPC baseline 47 miles identified through NDPP as extreme public safety risk and fire risk	X	X
Copper wire replacement NPC	Ruggedization/Resilience – monsoon	X	
Incline 4100 Overhead Rebuild	Ruggedization/Resilience high number of poles and corrections in highest risk fire area in the same areas identified by fire agencies. – fire risk	X	
Overhead rebuilds	Tier 2 projects along the minimum required to maintain year-round risk removal work – this “bundle” of projects interacts with NDPP seasonal work to reduce significant remobilization costs and dynamic contract costs. Segments are selected by risk level, geographic proximity to NDPP work and <u>only</u> permitting that works with other NDPP projects	X	X

Table 13 shows the overall proposed 2024-2026 split between GRC and NDPP.

Table 13. NDPP – GRC Capital Investment Amounts

Capital - GRC	2024 GRC	2025 GRC	2026 GRC	Total GRC
NPC	4,349,822	13,103,396	15,851,712	33,304,930
SPPC	12,997,500	17,261,148	29,022,107	59,280,755
<b>Grand Total</b>	<b>17,347,322</b>	<b>30,364,544</b>	<b>44,873,819</b>	<b>92,585,685</b>

Capital - NDPP	2024 NDPP	2025 NDPP	2026 NDPP	Total NDPP
NPC	13,261,534	15,977,636	14,253,993	43,493,163
SPPC	48,262,078	43,670,386	35,672,479	127,604,943
<b>Grand Total</b>	<b>61,523,613</b>	<b>59,648,022</b>	<b>49,926,472</b>	<b>171,098,107</b>

**UNDERGROUNDING**

29. Q. ARE THERE ANY CHANGES TO THE WAY THE COMPANIES WILL ADDRESS UNDERGROUNDING IN THE SECOND TRIENNIAL PLAN?

A. There are no significant changes to the execution of undergrounding other than to move projects forward and into an active workflow. The Plan addresses 20 of the 32 segments identified by fire agencies as being in areas that present the highest risk potential for a catastrophic event. It is important to note that executing on 20 underground segments does not mean 20 segments will be undergrounded during the term of the second triennial Plan. The 20 segments will be addressed in various project phases during the second triennial NDPP. Most undergrounding project lifecycles extend beyond 2026.

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1 30. Q. PLEASE DISCUSS THE CHALLENGES ASSOCIATED TO  
2 UNDERGROUNDING IN TIER 3.

3 A. Lead times for undergrounding projects in Tier 3 are long. This is the result of  
4 permitting requirements, extensive excavation, and the need for conduit system  
5 installation before actual relocation of the overhead lines. Risk remains present  
6 during the relocation of high-risk sections. During the construction period,  
7 controllable risk is managed through patrols, inspections, corrections, and  
8 vegetation management programs. Undergrounding project cost estimates in this  
9 Plan are based on current market estimates with added contingency factors. The  
10 costs of NDPP undergrounding projects scheduled for civil construction in 2023  
11 will inform future undergrounding estimates. Estimates will be refined as  
12 geological assessments and subsurface surveys expose subterrain conditions for the  
13 various recommended undergrounding locations in and around the Lake Tahoe  
14 basin, which is situated on a composition of dense granite, and Mt. Charleston,  
15 which is situated on a mix of granite and limestone.

16  
17 31. Q. PLEASE OUTLINE THE SECOND TRIENNIAL NDPP  
18 RECOMMENDATIONS TO EXECUTE ON THE NDPP SELECTIVE  
19 UNDERGROUND PRIORITIZATION PLAN SEGMENTS.

20 A. The Plan section 2.6.4. lays out the Companies' plan to address 20 of the 32  
21 segments of circuits identified in the NDPP Selective Underground Prioritization  
22 Plan. Segments proposed to be addressed during this Plan period are grouped into  
23 five tables based on the sequence of prior approvals and/or project  
24 interdependencies. Each table references the following:

- 25 • Priority Rank, NDPP Selective Underground Prioritization Plan
- 26 • Service Territory

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- Approximate length in miles
- Map reference, Second Triennial NDPP Appendix F.
- Prior approved scope and docket number
- Recommended work scope 2024-2026
- Cost recovery mechanism
- Indication if overall segment scope of work extends beyond 2026

Each grouping of Sierra segments addressed exclusively by the Companies is referred to as a “Phase” of the NDPP Selective Underground Prioritization Plan. Three phases are represented as Sierra’s total cost responsibility. Segments addressed through a cost sharing partnership are grouped and referred to as Sierra Cost Sharing Undergrounding. Mt. Charleston is being addressed within this NDPP as a single rebuild project with its own individual phases, therefore Mt. Charleston projects share a unique grouping. Mt. Charleston projects are a combination of overhead and underground rebuild and distinct projects include both NDPP and GRC recovery mechanism. The Mt. Charleston rebuild is described in detail in the second triennial Plan section 2.6.4.

The Companies emphasize that every effort has been made to provide appropriate estimates, including contingency factors. However, the dynamic labor market and supply chain issues will influence actual costs. Although each grouping includes a scope of work recommended for 2024 through 2026, completion of work is contingent on permitting, labor and material resources.

Some segments of circuit identified for undergrounding were also identified for potential inclusion in the copper wire replacement program. To determine the best

1 mitigation application, the Companies collaborated with local fire agencies, electric  
2 operations, and vegetation management specialists to assess environmental and  
3 asset conditions against the timing associated with undergrounding or replacing the  
4 copper wire with an overhead covered conductor solution. In some cases, segments  
5 within the underground plan are determined to need a faster solution therefore  
6 overhead covered conductor is used instead of undergrounding. In other cases,  
7 conditions warrant the segment remaining on track for undergrounding.  
8

9 **32. Q. PLEASE DESCRIBE THE NDPP SELECTIVE UNDERGROUND**  
10 **SEGMENTS THAT ARE ALSO COST SHARING PARTNERSHIPS.**

11 **A.** Several segments addressed in the underground plan will be completed through cost  
12 sharing partnerships. Glenbrook Undergrounding, Incorporated, is leading the  
13 effort to underground approximately five miles of overhead line in the Glenbrook,  
14 Nevada area. The Glenbrook undergrounding segments, initiated January 2021 by  
15 Glenbrook Undergrounding, Incorporated, will be the first undergrounding cost  
16 sharing partnership, anticipated to commence civil excavation spring 2023.  
17 Additionally, the Tahoe Transportation District has concentrated what funding it  
18 has acquired to coordinate its timeline with NDPP to initiate undergrounding  
19 approximately one mile along the east shore bike path, as previously approved in  
20 the Second Modified Final Order in Docket Nos. 20-02031 and 20-02032. Finally,  
21 the USFS has joined NV Energy in preliminary discussions to promote a cost  
22 sharing partnership to underground a segment of circuit located in the area known  
23 as the Zephyr Cove Resort. The five cost sharing partnerships address 7.3 miles  
24 identified within the NDPP Selective Underground Prioritization Plan.  
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1 33. Q. WHY IS NV ENERGY RECOMMENDING A COMPLETE REBUILD FOR  
2 THE SOURCE INTO KYLE CANYON AT MOUNT CHARLESTON?

3 A. Fire agencies identified the entirety of the Mt. Charleston distribution system as  
4 being located in an area at extreme risk for fire ignition and catastrophic spread due  
5 to environmental conditions, lack of evacuation routes, and the volume of tourists  
6 that frequent the mountain each year. The Plan recommends maintaining progress  
7 on all Mt. Charleston undergrounding initiatives previously approved for the Angel  
8 Peak circuits in Docket Nos. 20-02031 and 20-02032 and combining with the first  
9 phase of the Mt. Charleston rebuild.

10  
11 Mt. Charleston Rebuild Project Profile

12 The configuration of the electric system at Mt. Charleston results in frequent  
13 PSOMs to the entire area each fire season due to the weather conditions that are  
14 often isolated to Angel Peak, despite the fact that weather conditions at Kyle  
15 Canyon do not warrant PSOM. The frequent PSOMs are largely because Angel  
16 Peak substation is the source for Kyle Canyon. Because of this, Kyle Canyon  
17 residents are often de-energized when local conditions do not require it, due to the  
18 location of their source.

19  
20 As a result of the environmental conditions, the configuration of the system, and  
21 the antiquated and poorly situated location of the Kyle Canyon substation, the  
22 Companies determined that the best option to reduce community risk is to find an  
23 alternate source for Kyle Canyon. The Companies identified the Northwest  
24 substation as an alternate source for Kyle Canyon. Utilizing Northwest substation  
25 as a source for Kyle Canyon requires constructing a new eighteen mile direct-feed  
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distribution circuit from Northwest substation to Kyle Canyon. The proposed circuit is called the Northwest 1215 distribution circuit.

The proposed Northwest 1215 circuit is the first phase of the overall Mt. Charleston rebuild project proposed in the second triennial Plan. The proposed feeder extends approximately 13.5 miles within (proposed) Tier 1 and five miles within Tier 3. This circuit, specifically the portion outside of Tier 3, will be constructed underground pursuant to Clark County ordinance and not due to heightened fire risk. For this reason, costs associated to the Tier 1 section of this rebuild plan are recommended to be considered for recovery through the GRC recovery mechanism rather than the NDPP regulatory asset.

Utilizing an alternate source for Kyle Canyon and creating the direct-feed distribution circuit will allow the Companies to remove the Kyle Canyon substation and tie between Kyle Canyon and Angel Peak in future years beyond the triennial Plan. This rebuild and specifically the proposed Northwest 1215 circuit will provide more continuity of service compared with the current, temporary solution, which is a leased generator supporting Kyle Canyon residents during fire season. Although the generator does in fact decrease PSOM during fire season, it does not resolve the extreme risk present when the grid is energized. Appendix F to the second triennial illustrates the proposed rebuild design for Mt. Charleston.

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1 34. Q. PLEASE PROVIDE AN OVERVIEW OF THE SIERRA  
2 UNDERGROUNDING PROJECTS PRESENTED IN THE TRIENNIAL  
3 PLAN.

4 A. The Companies are requesting to execute projects in various stages of development  
5 from the NDPP Selective Underground Prioritized segments. The Companies are  
6 requesting funding to move previously approved projects from the design and  
7 permitting stages to the civil and lines construction phases. In other areas, the  
8 Companies have identified new undergrounding opportunities and are seeking  
9 funding for design and permitting activities. For most underground projects in the  
10 Plan, project completion will extend well beyond 2026. The Companies anticipate  
11 constructing approximately three miles of underground facilities in the Sierra  
12 territory during the second triennial Plan.

13  
14 The Companies are seeking to continue advancing undergrounding activities for  
15 the Sierra Phase 1<sup>3</sup> and Phase 2 projects during the triennial Plan period. The  
16 Commission previously approved the Companies' request to conduct design and  
17 permitting activities as well as some civil construction for the Sierra Phase 1 and  
18 Phase 2 projects in Docket Nos. 20-02031 and 22-08001. The Companies  
19 anticipate the Sierra Phase 1 project will continue civil construction and begin lines  
20 construction during the Plan period. The Sierra Phase 2 project will begin civil  
21 construction during this triennial Plan. In addition to continuing these projects, the  
22 Companies propose to conduct design and permitting activities and begin civil  
23 construction on the Sierra Phase 3 undergrounding project. Table 14 below  
24 provides an overview of the facilities included in the Sierra Phase 3 undergrounding  
25 project.

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27 <sup>3</sup> Previously referred to as the "2 miles and 4 miles" in the 2020 inaugural Plan.

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Table 14. Sierra Phase 3 Undergrounding Projects

NDPP Phase	Priority Rank	Service Territory	Title	Length in miles	Map Reference	Prior Docket No.	Prior Approval	2024-2026 Recommendation	Cost Recovery NDPP	Cost Recovery NDPP-GRC	Scope Extends Beyond 2026*
PH 3 Next 5 Segments	7	SPPC	Muller 1295	10.8	F9	NA	NA	Design/Permit and (start) Civil/Substructure	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
			<b>Total Miles</b>	<b>20.66</b>	*timelime based on permits, material and labor availability						

Table 15 below shows the facilities proposed for undergrounding through these cost sharing agreements.

Table 15. Sierra Cost Sharing Undergrounding

NDPP Phase	Priority Rank	Service Territory	Title	Length in miles	Map Reference	Prior Docket No.	Prior Approval	2024-2026 Recommendation	Cost Recovery NDPP	Cost Recovery NDPP-GRC	Scope Extends Beyond 2026*
Cost Sharing	19	SPPC	Incline 4100 Phase 3	1.1	F14	20-02031/ 20-02032	Seek Cost Sharing	Fund Lines Construction	NDPP	No	Yes
	17	SPPC	Glenbrook 2302 Ph 1	3.4	F15	22-08001	Cost Share	Adjust Credit			No
	26	SPPC	Glenbrook 2302 Ph 4	0.75	F16	None	No Prior Approval	Fund Lines Construction			No
	30	SPPC	Glenbrook 2505 Ph 1	1.14	F17	22-08001	Cost Share	Adjust Credit			No
	32	SPPC	Glenbrook 2505 Ph 2	0.74	F18	22-08001		Fund Credit			Yes
			<b>Total Miles</b>	<b>7.13</b>	*timelime based on permits, material and labor availability						

35. Q. IS TOTAL UNDERGROUNDING ALL TIER 3 FACILITIES THE BEST OPTION TO REDUCE RISK?

A. The second triennial NDPP Total Tier 3 Undergrounding Plan found in Appendix J examines the benefits and drawbacks of complete undergrounding in Tier 3. Although undergrounding is considered to mitigate 90% to 95% of risk associated with equipment caused ignition, it is not a practical application for all areas because it introduces new issues, such as constructability and future maintenance issues in areas where utility lines are not accessible by vehicle. Although undergrounding presents benefits, it is costly and involves extremely long lead times to realize the benefits. In some areas, overhead rebuilds using covered conductor offer similar

1 risk reduction benefits at a substantially lower cost and on a faster path to realized  
2 risk reduction. The Companies recommend following the existing approach to  
3 undergrounding by working collaboratively with fire agencies to assess options for  
4 each identified circuit. In the future, as the Companies implement and learn to use  
5 advanced technology such as Technosylva data analytics, risk prioritization will be  
6 refined, and the Companies will apply risk mitigation solutions as appropriate for  
7 the various geological and environmental scenarios presented across the HTAs.  
8

9 ***COPPER WIRE REPLACEMENT***

10 **36. Q. ARE THERE ANY CHANGES TO THE WAY THE COMPANIES WILL**  
11 **ADDRESS COPPER WIRE REPLACEMENT IN THE SECOND**  
12 **TRIENNIAL PLAN?**

13 **A.** The only change to the copper wire replacement program is related to whether  
14 certain copper wire projects will be classified as NDPP or NDPP-GRC for rate  
15 recovery as explained in the second triennial NDPP section 2.6.3, Shared Capital  
16 Investment – System Hardening. The 47 miles identified as Sierra’s Baseline  
17 Copper Wire Replacement Program will remain classified as an NDPP recoverable  
18 investment. Additional copper wire identified in Sierra’s territory, while still  
19 priority for removal, will be classified as NDPP-GRC and recovery for those costs  
20 will be sought through the general rate recovery mechanism.  
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1 **37. Q. WHAT IS THE COMPANIES' RECOMMENDATION IN THIS SECOND**  
2 **TRIENNIAL PLAN FOR COPPER WIRE REPLACEMENT?**

3 **A.** The 2020 inaugural Plan targeted the replacement of 47 miles of copper wire across  
4 northern Nevada tier areas. Copper wire in wildfire HTAs is replaced with covered  
5 conductor. Copper wire in monsoon HTAs is replaced with bare aluminum  
6 conductor. The copper wire addressed in the 2020 inaugural Plan was identified  
7 through the Companies' GIS mapping system. This group of copper wire is referred  
8 to as Sierra's Baseline Copper Wire to delineate this group from additional findings  
9 of copper wire identified throughout the NDPP patrols and inspections program.  
10 During 2022, NV Energy replaced 5.87 miles of copper wire in the Tier 3 Lake  
11 Tahoe areas. There are 13 miles of copper wire in northern Nevada presented in the  
12 Plan for replacement during 2024 through 2026, across Tiers 1E, 2, and 3 as shown  
13 in Table 16. Table 17 represents costs to perform the work.

14  
15 Table 16. Sierra Copper Wire Replacement

Sierra	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
<b>Copper Wire Replacement</b>	<b>\$ 10,379,675</b>	<b>\$ 4,356,147</b>	<b>\$ 4,148,528</b>	<b>\$ 1,875,000</b>

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19 Table 17. Projected Costs for Sierra Copper Wire Projects

NDPP Reference	Tier Tier	Service Territory	Length in miles	Miles Complete 2023*	Prior Docket No.	Prior Approval	2024-2026 Recommendation	Cost Recovery NDPP	Cost Recovery GRC	Scope Extends Beyond 2026*
Sierra Baseline 47 Miles	Tier 3	SPPC	8.6	5.87	20-02031/ 20-02032	Tier 3 Construction and Tier 2, 1E Design/Permitting	Construct Approximately 13.5 Miles	2.25	2.91	Yes
	Tier 2		9.35		2.7				Yes	
	Tier 1E		29.05						Yes	
	Total		47	5.87			10.59	2.91	27.63	

\*timeline based on permits, material and labor availability

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25 Through 2023, NV Energy is forecasting replacing 15.3 miles of small sized copper  
26 conductor in monsoon, thunderstorm, high wind and other HTAs in southern  
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Nevada. For this Plan period, the Companies recommend replacing the remaining 7.6 miles of copper wire in southern Nevada and performing an updated assessment of copper wire based on field verifications performed prior to 2024, as shown in Table 18. Table 19 represents costs to perform the work for this program.

Table 18. Nevada Power Copper Wire Replacement

	Priority Rank	Service Territory	Length in miles	Miles Complete 2023*	Docket No.	Prior Approval	2024-2026 Recommendation	Cost Recovery NDPP	Cost Recovery GRC	Scope Extends Beyond 2026*
Copper Wire	Monsoon	NPC	22.9	15.3	20-02031/ 20-02032	Design/Permit Construction	(continue) Design/Permit Construction	7.6	No	No
	WUI/Tier 1	NPC	TBD	TBD			TBD	Yes		

Table 19. Projected Costs for Nevada Power Copper Wire Projects

Nevada Power	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
Copper Wire Replacement	\$ 8,945,067	\$ 3,740,585	\$ 2,557,485	\$ 2,646,997

**NON-EXPULSION FUSE REPLACEMENT**

**38. Q. ARE THERE ANY CHANGES TO THE WAY THE COMPANIES WILL ADDRESS EXPULSION FUSE REPLACEMENT IN THE PLAN?**

**A.** Yes, the Companies will better coordinate the fuse replacement program to other projects and programs.

**39. Q. WHAT IS THE COMPANIES' RECOMMENDATION IN THIS PLAN?**

**A.** The Companies anticipate completing Tier 3 expulsion fuse replacements in 2024. The Companies recommend coordinating fuse replacements with other NDPP projects. Fuse replacements can easily be coordinated with other NDPP projects because the fuses are either already part of a compatible unit to a structure addressed in an NDPP project or are situated in close proximity to an NDPP project and can

be replaced as part of the same planned system outage. The inaugural NDPP outlined a rigid schedule by device (e.g., all lateral, then risers, and so forth) creating a scatter effect. Coordination of fuses with other scheduled projects, while still adhering to a prescribed rate of progress, increases efficiency and supports a contiguous footprint of risk reduction. The Companies will prioritize Tier 3 replacements first, followed by Tier 2 and Tier 1E, respectively.

As a continuation of the existing program, the Companies are requesting approval to begin the replacement of conventional expulsion fuses in Tier 2 and Tier 1E beginning in 2024. Table 20 represents the 2024 -2026 work schedule. Table 21, and Table 22 show the fuse replacement work and costs for this Plan period.

Table 20. Expulsion Fuse Replacement

NDPP Reference	Fire Tier	Service Territory	Title	Total Expulsion Fuses	Prior Docket No.	Prior Approval	2024-2026 Recommendation	Scope Extends Beyond 2026
Expulsion Fuse Replacements	Tier 3	SPPC	Capital - Electronic Fuse	46	20-02031 22-08001 20-02032	Replace expulsion fuses in Tier 3 area	Replacements of expulsion fuses Tier 2, Tier 1E	No
	Tier 2		Capital - Electronic Fuse	771				No
	Tier 1E		Capital - Electronic Fuse	596				Yes
	Tier 3		OMAG - Current Limiting	423				No
	Tier 2		OMAG - Current Limiting	2603				No
	Tier 1E		OMAG - Current Limiting	2134				Yes
<b>Total</b>				<b>6573</b>				

Table 21. Expulsion Fuse Replacement Proposed Budget – OMAG

Sierra Capital	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
<b>Expulsion Fuse Replacements</b>	<b>\$ 12,888,798</b>	<b>\$ 3,826,555</b>	<b>\$ 5,268,792</b>	<b>\$ 3,793,451</b>
Tier 1E	\$ 6,034,234	\$ 1,535,760	\$ 2,036,780	\$ 2,461,694
Tier 2	\$ 6,792,357	\$ 2,228,588	\$ 3,232,012	\$ 1,331,757
Tier 3	\$ 62,207	\$ 62,207		

Table 22. Expulsion Fuse Replacement Proposed Budget – Capital

Sierra OMAG	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
<b>Expulsion Fuse Replacements</b>	<b>\$ 8,776,514</b>	<b>\$ 2,730,801</b>	<b>\$ 2,719,306</b>	<b>\$ 3,326,407</b>
Tier 1E	\$ 4,170,029	\$ 625,469	\$ 1,193,104	\$ 2,351,456
Tier 2	\$ 4,267,162	\$ 1,766,009	\$ 1,526,202	\$ 974,951
Tier 3	\$ 339,323	\$ 339,323	\$-	\$-

**LIGHTNING ARRESTER REPLACEMENT**

40. Q. ARE THERE ANY CHANGES TO THE WAY THE COMPANIES WILL ADDRESS LIGHTNING ARRESTER REPLACEMENT IN THE SECOND TRIENNIAL PLAN?

A. Yes, but only in the way lightning arrester replacements are implemented to coordinate to other projects and programs. As written, the replacement of lightning arresters in the inaugural NDPP was anticipated to be a stand-alone initiative. However, a large number of lightning arresters were replaced as part of other NDPP projects and programs. Lightning arresters can easily be coordinated with other NDPP projects because they are either part of a compatible unit to a structure addressed in an NDPP project or are situated in close proximity to an NDPP project and can be replaced as part of the same planned work. If not coordinated with a specific project, lightning arrester replacement can be scheduled with a correction and worked in the same geographic area as other corrections. Table 23 shows the status of the Lighting Arrester Replacement Program.

Table 23. Status of the Lighting Arrester Replacement Program

NDPP Reference	Fire Tier	Service Territory	Title	Prior Docket No.	Prior Approval	2024-2026 Recommendation	Scope Extends Beyond 2026
Lightning Arrester Replacements	Tier 3	SPPC		20-02031	Perform engineering review and targeted replacements	Identify quantity and location and execute replacement of "gap" lightning arresters	No
	Tier 2	SPPC	NDPP Lightning Arrester Removals	22-08001			No
	Tier 1E	SPPC		20-02032			Yes

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**41. Q. WHAT IS THE COMPANIES' RECOMMENDATION IN THIS PLAN?**

**A.** The Companies will coordinate replacement of “gap” arresters with other NDPP projects wherever possible and request \$170,000 to address any identified Tier 2 and Tier 1E stand-alone “gap” arrester replacements in 2024-2026 as identified through detailed inspections. This will enable the Companies to begin replacement of the older type of gap arresters in Tier 2 and Tier 1E. Table 24 shows the requested funding over the Plan period.

Table 24. Lightning Arrester Replacement Program

OMAG	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
<b>Lightning Arrestors</b>	<b>170,000</b>	<b>55,000</b>	<b>57,000</b>	<b>58,000</b>
<b>SPPC</b>	<b>170,000</b>	<b>55,000</b>	<b>57,000</b>	<b>58,000</b>

***TREE ATTACHMENT REMOVAL***

**42. Q. ARE THERE ANY CHANGES TO THE WAY THE COMPANIES WILL ADDRESS THE TREE ATTACHMENT REMOVAL PROGRAM IN THE PLAN?**

**A.** No.

**43. Q. WHAT IS THE COMPANIES' RECOMMENDATION IN THIS PLAN?**

**A.** NV Energy proposes to remove 80 tree attachments per year starting in 2024. Based on this preliminary forecast, the Companies anticipate completing the tree attachment removal program in 12 years. Table 25 shows the tree attachment removal work planned 2024-2026. Table 26 shows cost for the work.

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Table 25. Tree Attachment Removal

NDPP Reference	Fire Tier	Service Territory	Title	Total Tree Attachments	Prior Docket No.	Prior Approval	2024-2026 Recommendation	Scope Extends Beyond 2026
Tree Attachment Removals	Tier 3	SPPC	NDPP Tree Attachment Removals	240	20-02031 22-08001 20-02032	Design/Permit and 2023 start construction	Design, permit and construction/removal of tree attachments	Yes
<b>Total</b>				<b>240</b>				

Table 26. Tree Attachment Removal Proposed Budget

Sierra	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
Tree Attachment Removals	\$ 6,367,254	\$ 2,060,000	2,121,800	2,185,454

**OVERHEAD REBUILDS**

**44. Q. WHAT IS THE COMPANIES’ PLAN WITH REGARD TO OVERHEAD CIRCUIT REBUILDS?**

**A.** The Companies recommendation to include some overhead rebuilds is a new recommendation.

**45. Q. WHY ARE THE COMPANIES RECOMMENDING OVERHEAD REBUILDS?**

**A.** Converting the legacy electric system infrastructure to modern fire mitigation design is a multi-year initiative. The recommended overhead rebuild projects are part of the Companies’ effort to achieve efficiencies that reduce remobilization costs, while maximizing the footprint of risk reduction where practical and possible. Coordination of NDPP projects in a small geographic area, such as Lake Tahoe, with limited electric feeds and a sensitive system protection scheme, is highly complex. Permitting constraints, customer impacts, and a short seasonal construction window compounds complexity. The Companies can gain efficiencies by using a programmatic approach for system hardening efforts where project scope

1 is set in motion 2-3 years in advance. Accomplishing this will take 2-3 years of  
 2 advanced design. Preparing this portfolio of “shovel ready” work projects,  
 3 coordinated with critical external stakeholders and communities, reflects  
 4 a significant improvement, and industry best practice.

5  
 6 This NDPP recommends overhead rebuild of the six circuit segments listed in  
 7 Q&A 28 and below, using covered conductor in a tree wire configuration. Tier 3  
 8 projects continue to remain highest priority for implementation. Implementing  
 9 the recommended segment rebuilds located in the lower Tiers in conjunction with  
 10 work in Tier 3 will allow risk mitigation work to be ongoing over the course of  
 11 a calendar year in areas with less complex permitting, creating a continuous  
 12 workflow, and using crews already deployed. The ability to perform formal  
 13 design of early phase projects promotes collaboration with permitting agencies  
 14 requesting project submittals one to two years in advance so they can determine  
 15 resource levels required to facilitate the needs of the utility among multiple  
 16 jurisdictions. Figure 4 lists the circuits proposed for partial rebuild.

20 Figure 4. Proposed Partial Circuit Rebuild

	Circuit Name	Fire Tier Location
21	1 Incline 4100	Tier 3
22	2 Round Hill 1502	Tier 3
23	3 Muller 1295	Tier 3, Tier 1E
24	4 Curry 1280	Tier 3, Tier 2
25	5 Mt. Rose 210	Tier 2
26	6 Chimney Peak 201 (Phase 3)	Tier 2

1 **46. Q. WHAT IS THE COMPANIES' RECOMMENDATION IN THIS PLAN?**

2 **A.** The Second Amendment to the 2020 NDPP in Docket No. 22-08001 approved  
3 funding for design and permitting for the six overhead rebuild segments shown in  
4 Table 27. The Companies recommend twenty-six miles of overhead rebuild on  
5 these segments of circuits. These projects are separated into either an NDPP or  
6 NDPP-GRC classification using the rationale outlined in the second triennial NDPP  
7 section 2.6.3. Maps of the line rebuild projects are provided in Appendix I.  
8

9 Table 27. Overhead Rebuilds

NDPP Reference	Circuits	Fire Tier	Service Territory	Total Miles Line Rebuilds	Length in miles 2024-2026	Prior Docket No.	Prior Approval	2024-2026 Recommendation	Cost Recovery NDPP-Miles	Cost Recovery GRC-Miles	Scope Extends Beyond 2026*-Miles
OH Rebuilds	Incline 4100	Tier 3	SPPC	28	4	22-08001	Design / Permit	Construction	4		24
	RH 1502	Tier 3		25	12					12	13
	Mt Rose 210	Tier 2		3	3					3	0
	Chimney Peak	Tier 2		2.7	1.65				1.65		0
	Curry 1280	Tier 3, 2		4	2				2		2
	Muller 1295	Tier 3, 1E		31	5				5		26
		<b>Total</b>			<b>91</b>				<b>26</b>		<b>11</b>

18  
19 The second triennial NDPP section 2.6.5.5. provides a general profile of each  
20 overhead rebuild request listed in Figure 4, in addition to 2024 – 2026 proposed  
21 planned work and costs by circuit.  
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**Q. ARE THE COMPANIES REQUESTING THAT ALL RISK REDUCTION SYSTEM HARDENING PROJECTS PRESENTED IN THE NDPP BE RECOVERED THROUGH THE NDPP REGULATORY ASSET?**

**A.** No. In the second triennial NDPP section 2.6.3., the Companies outline a recommendation to begin transitioning NDPP system hardening projects, partially or fully, to a general rate recovery mechanism over time. The Companies' proposed cost recovery classification approach is based on whether the accrued benefits of the work weigh more heavily toward a core NDPP element (*i.e.*, fire risk mitigation) or more toward general reliability. As noted in section 2.6.3, a GRC classification does not reflect change in any risks identified through the Plan Risk Assessment. Although all projects provide safety and reliability benefits, the Companies recommendation seeks to recognize the proportionally weighted benefits. The Companies are requesting a prudency determination for these projects as discussed in Mr. Jesse Murray's testimony. The overhead rebuild projects are classified as either an NDPP project or an NDPP-GRC project. Table 28 shows all second triennial NDPP capital projects, including the recommended overhead rebuilds. These projects are segregated by the recommended rate recovery mechanism rationale discussed in Q&A 28 and in the second triennial NDPP section 2.6.3.

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Table 28. Investment Amounts – NDPP-GRC and NDPP

NVE - Capital - GRC	Total GRC	2024 GRC	2025 GRC	2026 GRC
<b>NPC</b>	<b>33,304,930</b>	<b>4,349,822</b>	<b>13,103,396</b>	<b>15,851,712</b>
<b>Inspections &amp; Corrections</b>	<b>3,600,000</b>	<b>1,500,000</b>	<b>600,000</b>	<b>1,500,000</b>
Circuit Resiliency	3,600,000	1,500,000	600,000	1,500,000
<b>System Hardening</b>	<b>29,704,930</b>	<b>2,849,822</b>	<b>12,503,396</b>	<b>14,351,712</b>
Line Rebuild - Distribution	29,704,930	2,849,822	12,503,396	14,351,712
<b>SPPC</b>	<b>59,280,755</b>	<b>12,997,500</b>	<b>17,261,148</b>	<b>29,022,107</b>
<b>Inspections &amp; Corrections</b>	<b>36,891,255</b>	<b>2,000,000</b>	<b>12,591,148</b>	<b>22,300,107</b>
Pole Replacements	36,891,255	2,000,000	12,591,148	22,300,107
<b>System Hardening</b>	<b>22,389,500</b>	<b>10,997,500</b>	<b>4,670,000</b>	<b>6,722,000</b>
Copper Wire	3,622,500	3,622,500	-	-
Line Rebuild - Distribution	18,767,000	7,375,000	4,670,000	6,722,000
<b>Grand Total</b>	<b>92,585,685</b>	<b>17,347,322</b>	<b>30,364,544</b>	<b>44,873,819</b>

NVE - Capital - NDPP	Total NDPP	2024 NDPP	2025 NDPP	2026 NDPP
<b>NPC</b>	<b>43,493,163</b>	<b>13,261,534</b>	<b>15,977,636</b>	<b>14,253,993</b>
<b>Inspections &amp; Corrections</b>	<b>5,353,840</b>	<b>1,456,676</b>	<b>1,856,784</b>	<b>2,040,380</b>
Circuit Resiliency	3,525,126	1,181,925	1,161,276	1,181,925
Pole Replacements	1,828,714	274,751	695,508	858,455
<b>Risk Based Approach</b>	<b>35,467</b>	<b>11,854</b>	<b>11,807</b>	<b>11,807</b>
Resource Sufficiency	35,467	11,854	11,807	11,807
<b>Situational Awareness</b>	<b>389,211</b>	<b>125,300</b>	<b>129,686</b>	<b>134,225</b>
Wildfire Cameras	389,211	125,300	129,686	134,225
<b>System Hardening</b>	<b>37,714,645</b>	<b>11,667,704</b>	<b>13,979,360</b>	<b>12,067,581</b>
Copper Wire	8,945,067	3,740,585	2,557,485	2,646,997
Line Rebuilds - Distribution	15,906,102	2,750,000	7,594,065	5,562,037
Lines Ruggedization	10,958,376	3,472,019	3,727,810	3,758,547
Undergrounding	1,905,100	1,705,100	100,000	100,000
<b>SPPC</b>	<b>127,604,943</b>	<b>48,262,078</b>	<b>43,670,386</b>	<b>35,672,479</b>
<b>Inspections &amp; Corrections</b>	<b>9,764,401</b>	<b>2,616,201</b>	<b>3,989,534</b>	<b>3,158,666</b>
Pole Replacements	9,764,401	2,616,201	3,989,534	3,158,666
<b>Risk Based Approach</b>	<b>10,323</b>		<b>3,441</b>	<b>6,882</b>
Resource Sufficiency	10,323		3,441	6,882
<b>Situational Awareness</b>	<b>1,450,918</b>	<b>467,100</b>	<b>483,449</b>	<b>500,369</b>
Wildfire Cameras	1,450,918	467,100	483,449	500,369
<b>System Hardening</b>	<b>116,379,301</b>	<b>45,178,777</b>	<b>39,193,962</b>	<b>32,006,562</b>
Copper Wire	10,379,675	4,356,147	4,148,528	1,875,000
Line Rebuilds - Distribution	12,577,524	4,902,524	4,775,000	2,900,000
Line Rebuilds - Transmission	3,707,360	244,975	1,451,709	2,010,676
Non-Expulsion Fuses	12,888,798	3,826,555	5,268,792	3,793,451
Reclosers	2,900,000	2,900,000		
Substation Hardening	14,411,799	4,966,931	4,475,851	4,969,017
Tree Attachment Removals	6,367,254	2,060,000	2,121,800	2,185,454
Undergrounding	53,146,891	21,921,645	16,952,281	14,272,965
<b>Total</b>	<b>171,098,107</b>	<b>61,523,613</b>	<b>59,648,022</b>	<b>49,926,472</b>

1 ***SUBSTATION HARDENING INVESTMENTS***

2 **48 Q. ARE THERE ANY CHANGES TO THE WAY THE COMPANIES WILL**  
 3 **ADDRESS THE SUBSTATION HARDENING INITIATIVE IN THE**  
 4 **SECOND TRIENNIAL PLAN?**

5 **A.** No. The Plan recommends moving forward with the substation hardening initiative  
 6 based on the scope that originated in the inaugural Plan.

7  
 8 **49. Q. WHAT IS THE COMPANIES' RECOMMENDATION IN THIS SECOND**  
 9 **TRIENNIAL PLAN?**

10 **A.** In the second triennial Plan, the Companies recommend continuing the substation  
 11 hardening investments that began in the inaugural plan. Table 29 summarizes the  
 12 2024-2026 funding request. The Companies propose to construct the barrier walls  
 13 at Incline and Roundhill substations, complete the interior investments at the North  
 14 Truckee, Kingsbury, Incline, and Roundhill substations, and completely rebuild  
 15 Glenbrook substation. This will complete the substation hardening investments at  
 16 the five prioritized Tier 3 substations.

17  
 18 Table 29. Funding Requested for Substation Hardening

Sierra	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
Substation Hardening	\$ 14,411,799	\$ 4,966,931	\$ 4,475,851	\$ 4,969,017
Glenbrook Substation	\$ 8,379,764	\$ 1,244,521	\$ 3,722,715	\$ 3,412,528
Barrier Walls	\$ 978,293	\$ 978,293		
Interior	\$ 5,053,742	\$ 2,744,117	\$ 753,137	\$ 1,556,489

1 **LINE RUGGEDIZATION, POLE STOPPERS AND CRITICAL CROSSINGS**

2 **50. Q. ARE THERE ANY CHANGES TO THE LINE RUGGEDIZATION**  
 3 **INITIATIVES, SPECIFICALLY POLE STOPPERS AND CRITICAL**  
 4 **CROSSINGS?**

5 **A.** No. The Plan recommends moving forward with the line ruggedization program as  
 6 described in the inaugural plan.

7  
 8 **51. Q. WHAT IS THE COMPANIES' RECOMMENDATION IN THIS PLAN?**

9 **A.** The Companies seek authorization to continue the design, permitting, and  
 10 construction for the two remaining pole stopper circuits, future identified guyed  
 11 dead-end structures, and the 33 remaining critical crossing line ruggedization  
 12 locations that were previously identified.

13  
 14 Table 30 shows the pole stopper program's 2023 status. The Plan recommends  
 15 continuing design, permitting and construction on poles stoppers projects identified  
 16 prior to 2024.

17  
 18 Table 30. NPC Pole Stopper Program

NDPP Reference	Service Territory	Total Structures	Total Complete 2023*	Docket No.	Prior Approval	2024-2028 Recommendation	Cost Recovery NDPP	Cost Recovery GRC	Scope Extends Beyond 2026*	
Pole Stoppers	Transmission	NPC	36	36	20-02031/ 20-02032	Design/Permit Construction	(continue) Design/Permit Construction	Direct. Embed	No	No
	Transmission	NPC	TBD	TBD				Foundation		Yes

1 Table 31 shows critical crossings 2023 status. The second triennial Plan recommends  
2 continuing design, permitting and construction on 33 remaining structures.

3  
4 Table 31 NPC Critical Crossing Program

NDPP Reference	Service Territory	Total Structures	Total Complete 2023*	Prior Docket No.	Prior Approval	2024-2026 Recommendation	Cost Recovery NDPP	Cost Recovery GRC	Scope Extends Beyond 2026*	
Critical Crossings	Distribution	NPC	32	16	20-02031/ 20-02032	Design/Permit Construction	(continue) Design/Permit Construction	~16	No	Yes
	Transmission	NPC	48	14				~34		

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9 Table 32 shows 2024-2026 estimated costs for pole stoppers and critical crossings.

10  
11 Table 32. Nevada Power Pole Stoppers and Critical Crossings

Nevada Power	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
Grid Ruggedization	\$ 10,958,376	\$ 3,472,019	\$ 3,727,810	\$ 3,758,547
Critical Crossings	\$ 7,075,176	\$ 2,222,019	\$ 2,433,810	\$ 2,419,347
Pole Stoppers	\$ 3,883,200	\$ 1,250,000	\$ 1,294,000	\$ 1,339,200

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1 **FIRE MESH PROGRAM EXTENSION**

2 **52. Q. WHAT IS THE COMPANIES' RECOMMENDATION IN THIS PLAN?**

3 **A.** The Companies are proposing to deploy the fire-resistant pole wrap known as fire  
4 mesh beginning along critical evacuation routes, critical circuits, and higher fire  
5 ignition areas in Tier 2, Tier 1E and Tier 1 and Tier 3 where overhead rebuilds are  
6 not planned. The Companies will collaborate with electric operations and EWG fire  
7 agencies and use Technosylva evacuation maps and fire risk maps to determine  
8 prioritization of installation. Table 33 shows Plan costs for fire mesh installation.  
9

10 Table 33. Fire Mesh Program

	2024-2026	2024	2025	2026
	Budget	Forecast	Forecast	Forecast
<b>Fire Mesh</b>	<b>\$ 3,341,015</b>	<b>\$ 1,059,799</b>	<b>\$ 1,112,789</b>	<b>\$ 1,168,428</b>
<b>NPC</b>	<b>\$ 2,017,521</b>	<b>\$ 639,975</b>	<b>\$ 671,974</b>	<b>\$ 705,572</b>
<b>SPPC</b>	<b>\$ 1,323,494</b>	<b>\$ 419,824</b>	<b>\$ 440,815</b>	<b>\$ 462,856</b>

14 **SYSTEM PROTECTION STUDY**

15 **53. Q. WHY IS IT NECESSARY TO CONDUCT A FULL SYSTEM PROTECTION**  
16 **STUDY AT THIS TIME?**

17 **A.** Assessing the existing system protection schemes, specifically prioritizing an  
18 assessment to target the interaction of newly installed fire mitigation equipment  
19 with existing protection schemes, can significantly reduce the chance that a fault  
20 will result in wildfire ignition. The introduction of new industry standard fire  
21 mitigation materials and equipment, such as covered conductor and non-expulsion  
22 fuses such as the trip savers, needs to be assessed from an installed field perspective  
23 to better understand their interaction with other existing legacy devices on the  
24 electric system. Covered conductor and non-expulsion fuses are both industry  
25 standard for mitigating risk of fire ignition and spread, but the technology is still  
26  
27

1 new. In these early years of implementation, utilities industry-wide are reporting  
2 issues potentially associated with the interaction of the equipment, driving a need  
3 to make appropriate adjustments and unique coordination to each environment.  
4

5 A full system protection study of the current state, including the placement and  
6 coordination of trip savers and installation of covered conductor, will enable system  
7 engineers to appropriately endorse an appropriate protection scheme.  
8

9 **54. Q. IS THE RECOMMENDATION TO CONDUCT A SYSTEM PROTECTION**  
10 **STUDY A NEW INITIATIVE?**

11 **A.** Yes. The system protection study is a new initiative driven by the need to assess  
12 the interaction of new fire mitigation equipment and technologies, installed and in  
13 a field setting, with the current system protection scheme.  
14

15 **55. Q. WHAT IS THE COMPANIES' RECOMMENDATION IN THIS PLAN?**

16 **A.** The Companies recommend a system protection analysis containing three target  
17 objectives.  
18

19 **Objective 1 – Review and Potentially Revise NV Energy’s Distribution Fire**  
20 **Season Philosophy**

21 The Companies approach to distribution fire season is to disable fast curves and  
22 disable automatic reclosing, resulting in a single trip on the delay curve. Although  
23 disabling reclosing is consistent with other utilities, tripping the delay curve does  
24 not align with other major utilities practices in high fire risk areas. During fire  
25 season, Pacific Gas & Electric Company (“PG&E”), Southern California Edison  
26 (“SCE”), and San Diego Gas & Electric (“SDG&E”) set their relays to trip  
27

1 instantaneously or nearly instantaneously. This is crucial because faster clearing  
2 times result in less energy released during a fault, meaning less arcing and fewer  
3 hot particles and significantly reduced fire ignition risk.

4  
5 Major west coast utilities have reported fewer ignitions following implementation  
6 of fast fire season settings. PG&E reported an 80% decrease in reportable ignitions.  
7 However, there are tradeoffs with fast clearing times. Coordination with  
8 downstream devices is not guaranteed and consequently outages that would  
9 currently affect a small number of customers could be more likely to affect the  
10 entire feeder or a large portion thereof.

11  
12 NV Energy recommends performing a review of its fire season setting philosophy  
13 while considering the practices and experiences of other utilities. Aligning the  
14 Companies' philosophy with surrounding utilities may lead to a better outcome for  
15 public safety by significantly reducing fire ignition risk.

16  
17 **Objective 2 – Gang Operation of Trip Savers**

18 The 2021 Dixie fire was caused by only two out of three fuses blowing after a tree  
19 fell across all three phases of a distribution line. The remaining energized phase  
20 continued to fault through the downed tree which ultimately ignited a fire. Because  
21 the tree provided a high impedance path to ground, the fault current on the  
22 remaining energized phase was too low to blow the fuse. The risk of these high  
23 impedance faults occurring may be reduced by configuring all three phases of a trip  
24 saver to operate simultaneously in gang operation mode.

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As part of the NDPP, expulsion fuses on laterals and risers are being replaced with trip saver cutout mounted reclosers to prevent ignition due to hot particles from fuse operation. There is an opportunity to further reduce ignition risk for trip savers installed in two- or three-phase applications by configuring them to trip all three phases following operation on any individual phase.

**Objective 3 – Holistically Review and Revise Protection Setting on Distribution Circuits**

The risk of igniting a fire due to a fault is directly related to how long combustible material is exposed to arcing or hot particles from the fault. To ensure sufficient coordination between protective devices (*i.e.*, relays, reclosers, trip savers, fuses etc.) these devices generally have intentional delays before they operate for a fault. Minimizing these delays reduces the duration of the fault and inherently lowers the risk of combustibles igniting.

Recent replacement of expulsion fuses with trip saver electronic fuses has created an opportunity for improvement in fault clearing time. Given these recent changes in protective devices on feeders, there is an opportunity to optimize feeder protection as a whole to potentially lower fault clearing times and reduce fire risk.

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A system protection analysis and coordination study is a low-cost measure to potentially reduce clearing times but is not a replacement for other alternatives that directly and more fully address potential risks associated with other enhanced mitigation strategies. Table 34 shows 2024 costs for the recommended system protection study.

Table 34. System Protection Study

	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
Advanced Technologies - System Protection Study	200,000	200,000		
NPC	40,000	40,000		
SPPC	160,000	160,000		

56. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?
- A. Yes.

**Statement of Qualifications  
for  
DANYALE M. HOWARD**

**Professional Experience**

***Director, Natural Disaster Protection Program Execution***  
*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy*  
*June 2021 - Present*

Responsible for developing and implementing the Natural Disaster Protection Plan (“NDPP”) mitigation programs and projects, controls, technology development, engineering, resource allocation and program effectiveness.

***Director, Distribution Design Services, Northern Nevada***  
*Sierra Pacific Power Company d/b/a NV Energy*  
*April 2018 – June 2021*

Responsible for electric and gas design engineering and project coordination for distribution line extensions subject to Public Utilities Commission of Nevada (“PUCN”) Rule 9 tariff, local government franchise agreements and planned capital maintenance targets. Managed staff across five northern Nevada district offices.

***Manager, Distribution Design Services, Northern Nevada***  
*Sierra Pacific Power Company d/b/a NV Energy*  
*January 2016 – April 2018*

Responsible for electric and gas design engineering and project coordination for distribution line extensions subject to PUCN Rule 9 tariff, local government franchise agreements and planned capital maintenance targets. Managed staff across five northern Nevada district offices.

***Supervisor, Distribution Design Services***  
*Sierra Pacific Power Company d/b/a NV Energy*  
*March 2013 – January 2016*

Responsible for electric and gas design engineering and project coordination for distribution line extensions and facility relocation projects subject to PUCN Rule 9 tariff, local government franchise agreements and electric planned capital maintenance targets. Managed Truckee Meadows and Carson City offices.

***Team Leader, Field Services, Northern Nevada***  
*Sierra Pacific Power Company d/b/a NV Energy*  
*January 2011 – March 2013*

Responsible for developing, implementing, and supervising procedures for reading and data collections, accurate and cost-effective installation of electric meters and gas AMI modules. Managed staff across nine rural district locations.

***Utility Design Administrator II***  
*Sierra Pacific Power Company d/b/a NV Energy*  
*October 2004 – January 2011*

Responsible for performing design and project management of electric and gas distribution projects. Participated in the implementation of the Enterprise Work Asset Management (“EWAM”) project, creating business test scenarios, regression and user acceptance testing, and facilitated training across all northern Nevada districts.

***Analyst II, Revenue Protection***  
*Sierra Pacific Power Company d/b/a NV Energy*  
*December 1997 – October 2004*

Responsible for preparing and submitting exhibits, reports and legal documents related to utility theft and fraud. Past president of Western States Utility Theft Association (“WSUTA”), responsible for coordinating annual training and certification to utility investigators nationally.

***Meter Reader***  
*Sierra Pacific Power Company d/b/a NV Energy*  
*May 1997 – December 1997*

Responsible for collecting and recording accurate meter reads for electric and gas meters.

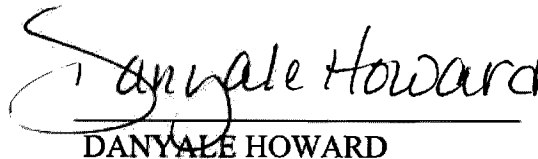
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AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, DANYALE HOWARD, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2023

  
DANYALE HOWARD

**JAY WIGGINS**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2023 Natural Disaster Protection Plan  
Docket No. 23-03xxx

Prepared Direct Testimony of

**Jay Wiggins**

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

A. My name is Jay Wiggins. I am the Director of Natural Disaster Protection Compliance and Operations Support for Nevada Power Company d/b/a NV Energy (“Nevada Power”), Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”). My business address is 6100 Neil Road, Reno, Nevada 89511. I am filing testimony on behalf of the Companies.

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

A. I began my career in the utility industry as an engineer with Southwest Gas in 2004 performing various functions including gas system design, project management, and compliance related activities. In 2006, I joined NV Energy as a gas compliance senior consultant to ensure compliance with state and federal pipeline safety regulations. In 2009, I became the manager of gas compliance operations where I oversaw the compliance, training, cathodic protection, metering, and system control functions in the NV Energy gas delivery business. In 2021, I became the

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Director of Natural Disaster Protection Compliance and Operations Support. My statement of qualifications is attached as **Exhibit Wiggins-Direct-1**.

**3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?**

A. As Director of Natural Disaster Protection Compliance and Operations Support, I am responsible for the fire mitigation, vegetation management and the emergency management teams, supporting electric system operations, and ensuring compliance with the Natural Disaster Protection Plan (“NDPP”). This includes overseeing the vegetation management program, emergency response to natural disaster events, mitigating the risk of wildfires, and the Public Safety Outage Management (“PSOM”) program.

**4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?**

A. Yes. I have submitted testimony and appeared before the Commission, most recently in Docket 22-08001, the Second Amendment to the 2020 Joint Natural Disaster Protection Plan.

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

A. The purpose of my testimony is to sponsor elements of the Companies’ 2023 Triennial Natural Disaster Protection Plan (the “Plan”) filing related to specific programs. My testimony provides details regarding the following specific programs:

- Vegetation Management
- Risk Based Approach – Emergency Response
- Risk Based Approach – Resource Sufficiency
- Public Safety Outage Management
- Intelligent Reclosers

**6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

A. I am sponsoring or co-sponsoring the following Exhibits:

- Exhibit Wiggins-Direct-1**, Statement of Qualifications
- Exhibit B**, The Second Triennial Natural Disaster Protection Plan, specifically I sponsor or co-sponsor the following portions of the Plan:
  - Section 2.1 – Situational Awareness (co-sponsored with Mr. Alexander Hoon and Mr. Mark Regan)
  - Section 2.2 – Operational Practices (co-sponsored with Mr. Mark Regan)
  - Section 2.3 – Emergency Management and Proactive De-Energization (PSOM) (co-sponsored with Mr. Mark Regan)
  - Section 2.4 – Vegetation Management (co-sponsored with Mr. Mark Regan)
  - Section 4.3 – Intelligent Reclosers
  - Section 7 – Resource Sufficiency

1 **I. VEGETATION MANAGEMENT**

2 **7. Q. DESCRIBE THE NDPP VEGETATION MANAGEMENT PROGRAM.**

3 A. The vegetation management program is vitally important to maintaining clearance  
4 distances between vegetation and the Companies' facilities, removing hazardous  
5 trees, building resilient corridors, and creating fuel breaks for wildfires. This work  
6 ultimately minimizes the chances of vegetation contacting lines and reduces the  
7 fuels that can be ignited near the Companies' facilities. The vegetation  
8 management program is a critical element to the NDPP to reduce heightened risk  
9 in wildland fire areas before longer-term system hardening programs are  
10 completed. Vegetation management plays an important role in improving and  
11 maintaining system resiliency for other types of natural disaster events such as  
12 winter storms, high wind events, and monsoons.

13  
14 The Vegetation Management Program in the context of the NDPP is for treatments  
15 in Tiers 3, 2, 1E, and 1 only. Non-tier vegetation management activities are funded  
16 through general rates.

17  
18 **8. Q. WHAT ARE THE PROPOSED CHANGES IN VEGETATION  
19 MANAGEMENT FROM THE INAUGURAL NDPP PLAN TO THIS PLAN?**

20 A. The first change from the inaugural plan to this Plan is setting new prescriptive  
21 patrolling requirements and vegetation management goals. Vegetation  
22 management requires a forester or other qualified person to perform patrols  
23 (evaluation) prior to tree trimming and pole grubbing/right of way ("ROW")  
24 clearing ahead of any scheduled work. These individuals identify trees and  
25 vegetation that will require treatment and ultimately provide the scope of work to  
26 the crews performing treatment in the NDPP areas. The Companies are requesting

1 to implement a prescriptive patrolling approach to identify vegetation that can cause  
2 hazardous conditions in a timely manner. Recent experience demonstrates the need  
3 for a prescriptive patrolling requirement. For example, in 2022, the Mt. Charleston  
4 area experienced severe drought, road salt, and beetle infestation that impacted over  
5 400 trees. The Companies performed multiple patrols and removed hundreds of  
6 hazard trees to ensure they did not impact company infrastructure. Those patrols  
7 were critical in identifying hazard trees between regular vegetation management  
8 cycles and demonstrated the importance in creating enhanced, prescribed patrolling  
9 requirements. The Plan includes a request to schedule patrolling and vegetation  
10 management objectives and timelines for work performance based on Tiers.

11  
12 The second change is a significant funding increase to achieve vegetative  
13 management cycles in a reasonable timeframe in order to reduce risk, taking into  
14 account increased costs due to inflationary pressures and the ongoing overlap  
15 between initial treatment and cyclical maintenance treatment costs.<sup>1</sup> Vegetation  
16 continues to be a significant risk to Company infrastructure for system resiliency  
17 and potential wildfire starts. This request balances risk reduction with reasonable  
18 and achievable goals. In 2022, the Companies experienced two identified  
19 vegetation contacts (trees falling into lines) during PSOM events in the Mt.  
20 Charleston area. These vegetation contacts had the potential to start fires in severe  
21 fire weather conditions that could have led to catastrophic consequences.  
22 Additionally, the 2022 New Year's Eve storm in northern Nevada demonstrated  
23 that vegetation contact with power lines impacted system resiliency and was a  
24

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25 <sup>1</sup> The Plan identifies how costs for vegetation management are increasing while NV Energy continues to work on its  
26 initial pass of vegetation management activities, while also undertaking the ongoing maintenance for those areas in  
27 which initial work has been done. Vegetation management costs should start to levelize once all initial work has been  
complete. As I note below in testimony, is anticipated that the initial cycle of tree trimming will be achieved by 2027  
and the initial cycle of pole grubbing/ROW clearing will be complete in 2032 for the Tiers 3, 2, 1E, and 1 areas.

1 leading cause of outages.<sup>2</sup> These events demonstrate the need to establish  
2 reasonable vegetation management cycles in the NDPP.

3  
4 **9. Q. WHY IS THERE AN INCREASE IN THE FUNDING REQUESTED FOR**  
5 **THE NDPP VEGETATION MANAGEMENT PROGRAM?**

6 A. There are two key items that are driving the increased request for funding in the  
7 NDPP Vegetation Management Program. First, the Plan reflects the cost increases  
8 the Companies' experienced executing the inaugural plan, which were higher than  
9 originally budgeted due to inflationary pressures and supply constraints. Second,  
10 this Plan is now covering both initial and continued maintenance treatments.

11  
12 **10. Q. EXPLAIN WHY THE ACTUAL VEGETATION MANAGEMENT**  
13 **PROGRAM COSTS ARE HIGHER THAN ANTICIPATED IN THE**  
14 **INAUGURAL PLAN.**

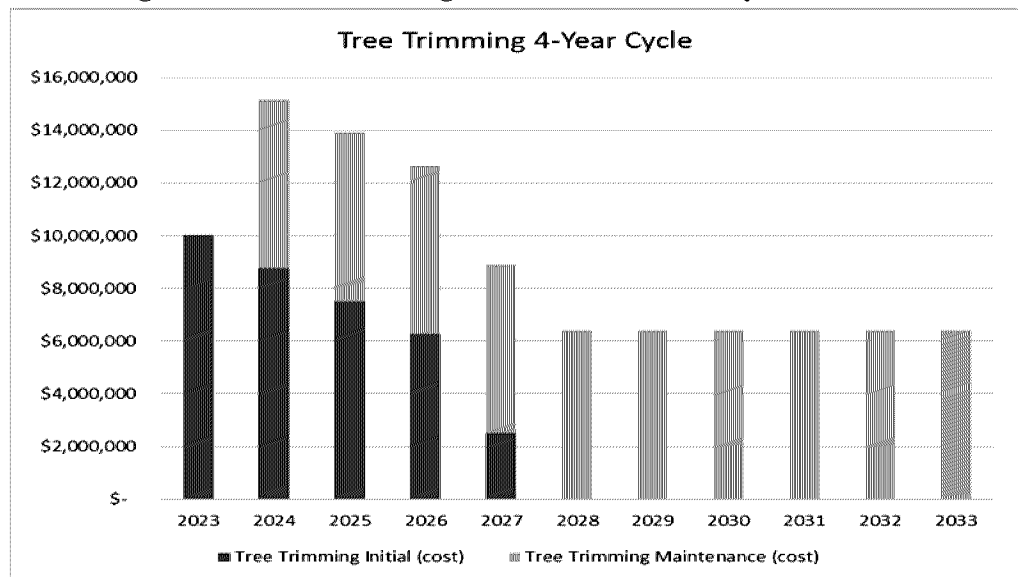
15 A. The Companies have seen dramatic increases in the costs for contracted services  
16 for tree trimming and other services such as logging and permitting. Although the  
17 Companies competitively bid contracted services, there is an overall inflationary  
18 pressure that was not anticipated, as well as increasing demand for vegetation  
19 management services from other western utilities, both of which have driven cost  
20 increases. For example, the Companies sought out aerial tree trimming services for  
21 a three-year contract through competitively bid processes in 2018 and in 2021. The  
22 lowest bid contractor for 2021 was 46 percent higher than the previous contract.  
23 The Companies also secured a three-year contract, using the competitive bid  
24 process, for utility foresters in 2019 and 2022. The 2022 contract price was  
25 approximately 25 percent higher than the 2019 contract.

26  
27 <sup>2</sup> For more information on this event, see Sierra's January 11, 2023 response and February 15, 2023 supplemental  
response in the Docket No. 23-01018.

1 11. Q. EXPLAIN WHY THE NDPP VEGETATION MANAGEMENT PROGRAM  
2 CURRENTLY HAS BOTH INITIAL TREATMENT AND MAINTENANCE  
3 COSTS.

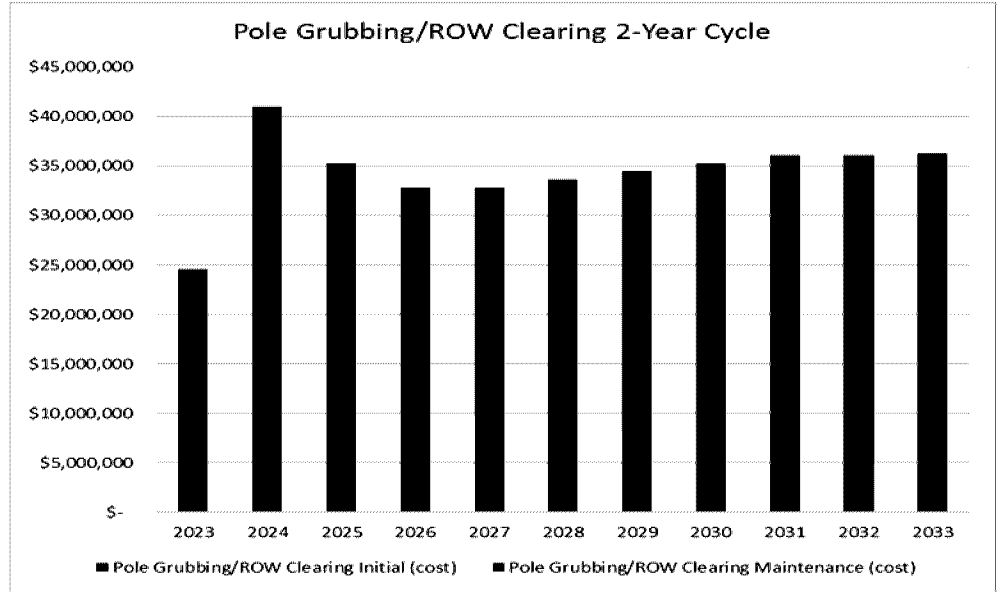
4 A. The initial treatment and ongoing maintenance costs for vegetation management  
5 are overlapping for this triennial Plan period. In other words, areas where NV  
6 Energy completed its initial treatment (both tree trimming and pole grubbing/ROW  
7 clearing) pursuant to the inaugural plan now require routine maintenance to sustain  
8 plan cycles. However, initial treatments are still underway in other areas. Until the  
9 initial treatment cycle has been completed in all NDPP areas, there will be an  
10 increased workload to simultaneously complete both initial treatment in the  
11 remaining high-risk areas as well as ongoing routine maintenance in some of the  
12 areas where the initial work under the inaugural plan has already been completed.  
13 Following the completion of all of the initial treatment in areas covered by the  
14 NDPP, there is an anticipated decrease in vegetation management program costs  
15 because only maintenance will costs remain. See Figures 1 and 2 below for  
16 estimated vegetation management program costs as related to initial and  
17 maintenance costs.

18 **Figure 1: Tree Trimming Costs for a 4-Year Cycle**



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**Figure 2: Pole Grubbing/ROW Clearing for an Average 2-Year Cycle**



This triennial Plan is critical to establishing a four-year cycle for tree trimming and a one-year or two-year cycle for pole grubbing/ROW clearing (depending on whether or not herbicides can be utilized). For analysis, a two-year average was used for pole grubbing/ROW clearing because some herbicides may be effective up to 3 years. It is anticipated that the initial NDPP tree trimming activities will be achieved by 2027 and the initial NDPP pole grubbing/ROW clearing activities will be complete in 2032 for the Tier 3, 2, 1E, and 1 areas. After the initial activities are complete, NV Energy will move to focusing on maintenance activities for these programs.

It is also important to note that the initial treatment costs in this Plan include significant expenses related to logging in the Tier 3 and Tier 2 areas. This logging is necessary to establish resiliency corridors and will help to reduce future maintenance expenses. In other words, if the tree is removed, there are no future

1 tree trimming costs because the ongoing pole grubbing/ROW clearing will remove  
2 any new trees that take root.

3  
4 **12. Q. HOW DOES GRANT FUNDING OFFSET VEGETATION MANAGEMENT**  
5 **PLAN BUDGETS?**

6 **A.** In this Plan, the Companies have included anticipated grant funding to offset the  
7 proposed triennial Plan budgets. Most grant funds are obtained by NV Energy’s  
8 contracted fire resources, the United States Forest Service, or another public agency  
9 for use in fuels treatment of specific expanded corridors surrounding transmission  
10 or distribution lines, mostly in the Zone 2 and Zone 3 areas.<sup>3</sup> Public agencies  
11 applying for grants must demonstrate they have adequate personnel and equipment  
12 available to execute on a project’s scope of work defined in the grant. It is  
13 important that the Companies fund public agencies with adequate personnel and  
14 equipment in order to obtain this grant funding. There is also a matching  
15 component to grants (variable but typically 10-50 percent) whereby total project  
16 costs are split by both the Companies and the grant fund receiver.

17  
18 There is no guarantee that grant funding will be obtained and the Companies may  
19 need to file amendments to the Plan to achieve plan goals if it does not materialize.

20 **Table 1** below shows the anticipated grant funding for the Plan.

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28 <sup>3</sup> As discussed in the Plan, resilient corridors focused on Wildfire Tiers specify Zones 1, 2, and 3 for clearance of ROWs.

**Table 1: Anticipated Grant Funding**

Funding Source	2024	2025	2026
SNPLMA-LTBMU	4,000,000	4,000,000	
Jasper HMGP		100,000	100,000
Long Valley	125,000	100,000	
Loyalton	100,000	100,000	
Rock Farm	150,000	350,000	200,000
Numbers		50,000	50,000
USFS TMFPD Contract	400,000	400,000	400,000
SNPLMA TMFPD	400,000	400,000	
SNPLMA TMFPD		1,500,000	1,500,000
SNPLMA NLTFPD	300,000	300,000	200,000
NLTFPD IVGID funding	50,000	50,000	50,000
NLTFPD -TRPA Grant		75,000	75,000
NLTFPD- USFS Contract	50,000	50,000	50,000
SNPLMA-LTBMU			4,000,000
TDFPD USFS Contract	50,000	50,000	50,000
USFS HTF Grant			
<b>Total</b>	<b>5,625,000</b>	<b>7,525,000</b>	<b>6,675,000</b>

**II. RISK BASED APPROACH – EMERGENCY RESPONSE**

**13. Q. DESCRIBE THE RISK BASED APPROACH – EMERGENCY RESPONSE PROGRAM.**

A. The NDPP emergency response program includes the expansion of the Companies’ existing emergency response organization, enhanced communications, and the use of contracted fire resources. The Companies’ emergency response organization has developed into a formal, incident command system, task-based structure for professional response to emergencies. The enhanced communications capabilities include the acquisition of company-owned Communications on Wheels (“COWs”). The contracted fire resources in the context of NDPP emergency response are used for advanced response to fire starts.

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1 14. Q. WHAT ARE THE PROPOSED CHANGES IN THE RISK BASED  
2 APPROACH – EMERGENCY RESPONSE FROM THE INAUGURAL  
3 PLAN TO THE PROPOSED PLAN?

4 A. There are only minor changes in the emergency response category from the  
5 inaugural plan to this proposed Plan. These changes are well documented through  
6 the previous regulatory asset filings and progress reports for the inaugural plan.<sup>4</sup>  
7 For example, the inaugural plan referenced using contracted emergency  
8 communications from FirstNet and Verizon. Instead, the Company has acquired  
9 company-owned COWs devices for emergency communications and the Plan  
10 outlines how the Companies will use these assets. In the inaugural plan, reference  
11 was made to the existing corporate emergency response protocols and incident  
12 command system. This Plan formalizes the all hazard on-call incident management  
13 teams trained in incident command system for wildfires and other disasters.

14  
15 This Plan recognizes that the Companies have developed certain efficiencies that  
16 were not considered in preparing the inaugural plan. For example, the Companies  
17 did not utilize WebEOC for internal emergency response, as the inaugural plan  
18 indicated, but instead has implemented MS Teams functionality to manage  
19 incidents. In addition, the Companies did not utilize Capstone for contracted  
20 advanced firefighting support as contemplated in the initial plan, but instead used  
21 partnerships and resources from local fire agencies to provide this service. The  
22 Capstone firefighting support was not used due to cost, availability, and it was not  
23 locally based for immediate responses.

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25  
26 <sup>4</sup> See, for example, Docket No. 22-08031, Second Report of Nevada Power Company d/b/a NV Energy and Sierra  
27 Pacific Power Company d/b/a NV Energy on the progress of its Natural Disaster Protection Plan for the Action Plan  
Period 2021-2022.

1 **VI. RISK BASED APPROACH – RESOURCE SUFFICIENCY**

2 **15. Q. DESCRIBE THE RISK BASED APPROACH – RESOURCE SUFFICIENCY**  
3 **PROGRAM.**

4 A. The NDPP resource sufficiency program provides sufficient resources to support  
5 and to execute the Plan. This includes some direct labor charges for fully dedicated  
6 personnel supporting the NDPP, costs and contracted resources associated with  
7 regulatory filings (including publishing notices), materials/supplies,  
8 telecommunications equipment, general expenses, travel, NDPP-related grant  
9 management, and activities not directly associated with the other programs.

10  
11 **16. Q. WHAT ARE THE PROPOSED CHANGES IN THE RISK BASED**  
12 **APPROACH – RESOURCE SUFFICIENCY FROM THE INAUGURAL**  
13 **NDPP PLAN TO THIS PROPOSED PLAN?**

14 A. There are no significant changes to this category. This will continue to fund the  
15 miscellaneous activities listed above. In addition to the items listed above there is  
16 specific funding for the addition of a senior engineer for supporting standards,  
17 technology, and overall program support. There is also funding for the addition of  
18 a corporate communications specialist for external communications in the NDPP.  
19 This position will be responsible for public outreach and communications regarding  
20 NDPP projects, programs, and potential outages related to system hardening. This  
21 position will also support the emergency response organization and perform the  
22 duties of public information officer when required. The Companies will also need  
23 a contracted telecommunications technician to support the COWs, radios, mobile  
24 devices, iPads, and the amateur radio emergency services associated with the  
25 NDPP. This also includes the costs associated with participation in the  
26 International Wildfire Risk Mitigation Consortium (“IWRMC”). The IWRMC is a  
27

1 is an industry-sponsored collaborative organization designed to facilitate the  
2 sharing of wildfire risk mitigation insights and discovery of innovative and unique  
3 utility wildfire practices. There is a slight reduction in overall resource sufficiency  
4 Plan costs due to previously dedicated NDPP employees transitioning to GRC  
5 funding for labor costs.  
6

7 **VII. PUBLIC SAFETY OUTAGE MANAGEMENT**

8 **17. Q. DESCRIBE THE PSOM PROGRAM.**

9 A. The PSOM program is the proactive de-energization of identified circuits and zones  
10 prior to extraordinary weather conditions that may pose threats to the public,  
11 customers, infrastructure, or the environment. This PSOM program addresses  
12 wildfire risk in Tier 3, Tier 2, and Tier 1E locations. This is an important program  
13 used to reduce wildfire risk until other measures, such as system undergrounding,  
14 are accomplished. As part of this program, there are costs associated with weather  
15 analytics, meteorologist, fire standby for red flag conditions, fuel sampling, de-  
16 energization, patrolling, restoration, customer resource centers, communications,  
17 and generator setup.  
18

19 **18. Q. WHAT ARE THE PROPOSED CHANGES IN THE PSOM PROGRAM**  
20 **FROM THE INAUGURAL NDPP PLAN TO THIS PROPOSED PLAN?**

21 A. There are several changes in the PSOM category from the inaugural plan to this  
22 proposed Plan. Most notably was the addition of Tier 2 and 1E to PSOM eligibility  
23 and the use of the composite risk index for evaluating execution of PSOM events.  
24 Both of those items were incorporated in the first amendment to the NDPP and will  
25 continue in the proposed Plan.  
26  
27

1 The change of Virginia City Highlands from Tier 2 to Tier 3 may result in increased  
2 de-energizations due to more rigid and lower threshold PSOM criteria for Tier 3  
3 areas.

4  
5 In this next Plan, the Companies will continue to look for opportunities to automate  
6 de-energization because execution of PSOM's is oftentimes performed by  
7 personnel performing field switching. The Companies will also evaluate field  
8 devices and locations to optimize PSOM boundaries to ensure that de-energization  
9 does not overly impact customers outside of the Tier areas.

10  
11 The NDPP proposes to align notifications, communication, and information sharing  
12 with telecommunications companies or Communications Infrastructure Providers  
13 ("CIPs") in a similar manner to protocols with local and state emergency  
14 management and fire resources. This would ensure advanced notification, with  
15 consistent and defined communication channels and single points of contact. The  
16 previous plan had CIP specific requirements that were unique and required special  
17 procedures to implement, but the proposed change would align CIP  
18 communications with protocols for other key personnel.

19  
20 **VII. ADVANCED TECHNOLOGIES – INTELLIGENT RECLOSERS**

21 **19. Q. DESCRIBE THE ADVANCED TECHNOLOGIES – INTELLIGENT**  
22 **RECLOSERS PILOT PROGRAM.**

23 A. Wildfire Tiers transect distribution lines in a non-continuous pattern. However, for  
24 the purposes of PSOMs, entire circuits are currently taken out of service even if  
25 portions of the circuit are not in a Wildfire Tier. This means that more customers  
26 are without power during a PSOM than safety requirements dictate.

1 Sectionalization of the grid through adding intelligent reclosers will allow safety  
2 outages to be more precisely directed to only the PDZs. Intelligent reclosers are an  
3 important service continuity component. Adding these devices will help reduce the  
4 number of customers impacted by a PSOM by adding load break, isolation devices  
5 near the transition points between non-Tiered and Tiered areas.

6  
7 In addition, using intelligent devices that can be remotely set to fire season fail safe  
8 mode as weather conditions dictate improves grid reliability when compared to the  
9 existing calendar-based approach. Being able to remotely set the system via  
10 telecommunications to fire season mode eliminates the need to physically send  
11 personnel to the field to change recloser protocols. Intelligent reclosers are a  
12 practical alternative to protecting lower ranked HTAs that may not be scheduled  
13 for resilience and hardening projects for many years.

14  
15  
16 **20. Q. WHAT ARE THE PROPOSED CHANGES IN THE INTELLIGENT**  
17 **RECLOSERS PROGRAM FROM THE INAUGURAL NDPP PLAN TO**  
18 **THIS PROPOSED PLAN?**

19 A. This is a new pilot project that is being added to the proposed plan. The Companies  
20 are requesting \$2.9 million in capital funding to pilot a project to install intelligent  
21 reclosers in the Tier 1E grasslands of northeastern Nevada. The ability to remotely  
22 operate 28 intelligent reclosers, equipped with communications and remote  
23 relaying, on 15 different circuits, and 6 lines will provide equivalent safety  
24 protection while decreasing the size of the area impacted by PSOM events. This  
25 area was chosen as a pilot project due to its remoteness and the size of the project.  
26 Other areas of the system, such as Tahoe, require the completion of a system

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protection study due to system complexity before deploying a similar intelligent recloser project. The Companies will evaluate this pilot project based upon constructability, proper device operation, reduction in field personnel manual operation support, reduction in PSOM circuit lengths impacted, and the success of remote communications. Based on these results, the Companies will determine if further deployments in other Tier areas would be beneficial.

**21. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

A. Yes.

**STATEMENT OF QUALIFICATIONS OF**  
**Jay Wiggins, P.E.**  
**Director, Natural Disaster Protection Compliance**  
**and Operations Support**  
**NV Energy**  
**6100 Neil Rd. Reno, NV 89511**  
**(775)834-5580 jay.wiggins@nvenergy.com**

Mr. Wiggins has been an employee of NV Energy over 15 years and has over 20 years of experience in the utility industry. He has worked in several positions that are primarily related to compliance, operations, emergency response, and the natural disaster protection plan. Mr. Wiggins has a master's degree in business administration and a Bachelor of Science degree in mechanical engineering. He is also a registered professional mechanical engineer in the state of Nevada.

### **Professional Experience**

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***Director, Natural Disaster Protection Compliance and Operations Support – NV Energy, Reno, NV ▪ 2021 – present***

- Provides planning and ongoing support for electric system operations and emergency management in all operational activities, including public safety outage management events, to mitigate the risk of wildfires and other natural disasters
- Responsible for ensuring the compliance of the natural disaster protection program with existing statutes, codes, and regulations
- Develops and maintains the public safety outage management plan, including field documentation, support systems deployment, resource requirements, decision criteria, emergency stakeholder coordination and recovery

***Manager, Gas Compliance Operations – NV Energy, Reno, NV ▪ 2009 – 2021***

- Direct compliance, training, cathodic protection, metering, system control, and administrative personnel to ensure that all regulatory and company commitments are met
- Investigate, audit, develop responses, and defend company interests during regulatory compliance inspections, petitions, and rate case proceedings
- Lead, develop, and execute the transmission and distribution integrity management programs to minimize operational risk and define strategic direction for capital and operations/maintenance expenses

***Consultant Senior, Gas Compliance – NV Energy, Reno, NV ▪ 2006 – 2009***

- Utilize knowledge and experience concerning U.S. Department of Transportation regulations to ensure compliance relating to gas distribution and transmission pipeline systems
- Conduct training, internal audits, procedural updates, and create systems for process improvement
- Represent company interests during formal and informal regulatory audits
- Provide data and solutions to corporate legal, rates/regulatory, and generation requests

***Engineer I / II – Southwest Gas Corporation, Carson City, NV ▪ 2001 – 2006***

- Design and provide project management for the construction of distribution gas pipeline systems and meter set assemblies throughout Northern Nevada service territory
- Interact with, coordinate, and obtain permits from various governmental jurisdictions as related to new and replacement gas pipeline projects
- Assist compliance staff during annual regulatory agency audits, conduct annual compliance training and train student engineering personnel

### **Education and Certifications**

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Bachelor of Science in Mechanical Engineering – University of Nevada, Reno, NV ▪ 2004  
 Master of Business Administration – University of Nevada, Reno, NV ▪ 2008  
 Registered Professional Engineer, Mechanical – State of Nevada ▪ 2013

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AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JAY WIGGINS, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2023



\_\_\_\_\_  
JAY WIGGINS

**MARK REGAN**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2023 Natural Disaster Protection Plan  
Docket No. 23-03xxx

Prepared Direct Testimony of

**Mark Regan**

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

A. My name is Mark Regan. My current position is Fire Mitigation Specialist/Fire Chief for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, “NV Energy” or the “Companies”). I work primarily out of Nevada Power’s offices at 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. Prior to joining NV Energy, I was a Division Chief/Fire Marshal. I have 30 years of experience in the fire service, holding the ranks of Firefighter, Engineer, Captain, Prevention Captain, and Fire Marshal/Division Chief. More details regarding my professional background and experience are attached as Exhibit Regan-Direct-1.

1 3. Q. **WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR**  
2 **CURRENT POSITION?**

3 A. I am responsible for providing leadership and program direction for the Companies’  
4 fire mitigation program. I lead and coordinate the development of short- and long-  
5 range fire mitigation program plans and integrate the fire mitigation program with  
6 other departments within the Companies and with external partners, including the  
7 Department of Agriculture, Bureau of Land Management (“BLM”), Fire Districts,  
8 and other Federal and State agencies. I maintain relationships with entities external  
9 to the Companies regarding fire management program issues. I also provide expert  
10 knowledge and liaison services between the Companies and first responders. I focus  
11 on asset protection, Emergency Operations Center integration and cause  
12 investigation. My role also includes safety training for first responders and  
13 employees of the Companies. I provide the Companies, contractors, and externals  
14 with expert knowledge in major project planning, safety mitigation, and  
15 professional agency liaisons in the wildfire and emergency services arena. I  
16 implement fire mitigation budgets and implement agreements with partners.

17  
18 4. Q. **HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**  
19 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**  
20 **(“COMMISSION”)?**

21 A. Yes. I filed testimony in the Natural Disaster Protection Plan (“NDPP”), Docket  
22 Nos. 20-02031 and 20-02032; the 2020 and 2021 NDPP Regulatory Asset  
23 Recovery Filings in Docket Nos. 21-03004 and 22-03006; the First Amendment to  
24 the NDPP in Docket No. 20-03040; and the Second Amendment to the NDPP in  
25 Docket No. 22-08001.

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

A. The purpose of my testimony is to sponsor elements of the Companies’ 2023 Triennial Natural Disaster Protection Plan (the “Plan”) filing related to the following specific issues:

- Updating The Wildfire Risk Tiers
- Wildland Urban Interface (“WUI”) Code Compliance
- Unmanned Aerial Vehicle and Satellite Imaging Pilot

6. Q. **WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

A. I am sponsoring or co-sponsoring the following Exhibits:

**Exhibit Regan-Direct-1**, Statement of Qualifications

**Exhibit B**, The Second Triennial Natural Disaster Protection Plan, specifically I sponsor or co-sponsor the following portions of the Plan:

- Section 1.2 – Natural Disaster Threats (co-sponsored with Mr. Alexander Hoon)
- Section 1.3 – Complying with the WUI Code
- Section 2.1 – Situational Awareness (co-sponsored with Mr. Alexander Hoon and Mr. Jay Wiggins)
- Section 2.2 – Operational Practices (co-sponsored with Mr. Jay Wiggins)
- Section 2.3 – Emergency Management and Proactive De-Energization (PSOM) (co-sponsored with Mr. Jay Wiggins)
- Section 2.4 – Vegetation Management (co-sponsored with Mr. Jay Wiggins)
- Section 3 – Communications and Outreach
- Section 4 – Advanced Technologies and Strategies
- Section 4.1 - Use of Unmanned Aerial Vehicles and Satellite imaging for Line Patrol, Vegetation Clearances and Perform Image Analytics
- Section 5 – Grant Pursuits

- Appendices A, B, C, D, and E

### UPDATING WILDFIRE RISK TIERS

7. **Q. ARE THE COMPANIES PROPOSING ANY CHANGES OR UPDATES TO THE HEIGHTENED WILDFIRE THREAT TIER AREAS?**

A. Yes, after analyzing the heightened wildfire threat areas using updated scientific data, current available wildfire risk rating maps, and current environmental conditions, the Companies recommend elevating the Virginia City (“VC”) Highlands (located in Storey County) from a Tier 2 to a Tier 3 wildfire risk area. The Companies also recommend creating a new Tier 1 to include areas at moderate or above wildfire risk consistent with state risk rating maps.

8. **Q. HOW DID THE COMPANIES ANALYZE THE HEIGHTENED WILDFIRE THREAT AREAS?**

A. The Companies engaged REAX Engineering (“REAX”) to analyze the areas across the state with heightened wildfire threat and to provide any recommended updates to the existing wildfire Tier areas. REAX analyzed the following: fire history; fire ignitions; value at risk (including communities, infrastructure, watersheds, habitat, grazing and standing timber); the Nevada Division of Forestry’s (“NDF”) Wildfire Risk Rating Map; and the United States Forest Service’s (“USFS”) Wildfire Risk to Communities maps. REAX used this data to identify heightened wildfire risk areas. REAX also analyzed the best way to align the fire risk Tiers with existing state risk maps. REAX recommended elevating the VC Highlands to Tier 3 and refining and replacing the WUI Tier with a new Tier 1 area designation.

1 The Companies also held several meetings with stakeholders from the Expert  
2 Working Group (“EWG”), which includes local fire districts, BLM, USFS and  
3 Tribal members, to discuss its wildfire tier designations. The EWG analyzed the  
4 information REAX provided along with the current wildfire risk rating map used  
5 by the state and federal agencies. The Companies note that the state risk rating  
6 maps use the NDF’s Wildfire Risk Rating Map and the USFS’s Wildfire Risk to  
7 Communities maps as inputs.

8  
9 The Companies and REAX presented to the EWG regarding the recommendations  
10 to elevate VC Highlands to Tier 3 and to refine and replace the WUI Tier with a  
11 new Tier 1. The EWG members either agreed or had no objections to the proposals.  
12 Appendix E to the Plan includes letters of support from EWG members, including  
13 fire districts and tribal groups. These changes help define the heightened wildfire  
14 threat areas consistent with NDF’s Wildfire Risk Rating Map. Adding the new Tier  
15 1 area would also bring the NDPP into compliance with International Wildland  
16 Urban Interface Code (“IWUIC”), which is required by state and local fire codes as  
17 well as the NDPP statutes and regulations.

18  
19 The full REAX reports for wildfire heightened threat areas are included in  
20 Appendix D to the NDPP. Additional information about Nevada’s Fire Risk  
21 policies and programs are available at the Nevada Resources & Fire Portal<sup>1</sup> and the  
22 USFS Wildfire Risk to Communities Map.<sup>2</sup>

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27 <sup>1</sup> [www.nevadaresourcesandwildfireinfo.com](http://www.nevadaresourcesandwildfireinfo.com).

<sup>2</sup> Available at <https://wildfirerisk.org/download/#GIS>.

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9. Q. CAN YOU PLEASE DESCRIBE THE NDF AND USFS MAPPING SYSTEMS AND FIRE RISK RATINGS THAT IDENTIFY THE FIRE RISK ACROSS THE STATE OF NEVADA?

A. The Companies used the NDF Wildfire Risk Rating Map and the USFS Wildfire Risk to Communities Map as the starting point for updating its tier areas. The NDF Wildfire Risk Rating Map represents the possibility of loss or harm occurring from a wildfire and is displayed in the Nevada Wildfire Risk Assessment (“WRA”) by the Fire Risk Index. The NDF Wildfire Risk Rating Map combines the likelihood of a fire occurring (“Fire Threat”) with those areas of most concern that are adversely impacted by fire (“Fire Effects”) to derive a single overall measure called the Wildfire Risk Index. It identifies areas with the greatest potential impacts from a wildfire considering the likelihood of an area burning and the impacts to values and assets aggregated together. The Fire Risk Index includes a scale from 0-9, as follows: 0. Urban, Agriculture, barren land that has zero vegetation or a body of water; 1. Very Very Low; 2. Very Low; 3. Low; 4. Low-Moderate; 5. Moderate; 6. Moderate-High; 7. High; 8. Very High; and 9. Extreme. Because all areas in Nevada have the Wildfire Risk Index calculated consistently, it allows for comparison and ordination of areas across the entire state.

NDF’s Fire Threat measure is closely related to the likelihood of an area burning. It is mapped as the Fire Threat Index in the Nevada WRA. NDF’s Fire Effects measure is comprised of two inputs: Aggregate Value Impacts and Suppression Difficulty. The Fire Effects Index identifies those areas that have important values that could be adversely impacted by a wildfire or might be in areas where fire suppression activities may be difficult.

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The USFS Wildfire Risk to Communities Map depicts components of wildfire risk for all lands in the United States that: (1) are landscape-wide (*i.e.*, measurable at every pixel across the landscape); and (2) represent in situ risk – risk at the location where the adverse effects take place on the landscape. The USFS index scale rates areas on the following 1-5 system: 1. Very Low; 2. Low; 3. Moderate; 4. High; and 5. Very High.

USFS uses the following risk ratings factors in its Wildfire Risk to Communities Map:

- Risk to Potential Structures (“RPS”) is a measure that integrates wildfire likelihood and intensity with generalized consequences to a home on every pixel. For every place on the landscape, it poses the hypothetical question, “What would be the relative risk to a house if one existed here?” This allows comparison of wildfire risk in places where homes already exist to places where new construction may be proposed. This dataset is referred to as Risk to Homes in the Wildfire Risk to Communities.
- Conditional Risk to Potential Structures (“CRPS”) is the potential consequences of fire to a home at a given location if a fire occurs there and if a home were located there. It is a measure that integrates different wildfire intensity using flame-length probability (FLP) with generalized consequences of wildfire on structures (*i.e.*, relative degree of damage or loss) at different wildfire intensities to a structure on every pixel, but does not account for the actual probability of fire occurrence. This is referred to as Wildfire Consequence in the Wildfire Risk to Communities web application.

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- Exposure Type is the spatial coincidence of wildfire likelihood and intensity with communities. This layer delineates where homes are directly exposed to wildfire from adjacent wildland vegetation, indirectly exposed to wildfire from indirect sources such as embers and home-to-home ignition, or not exposed to wildfire due to distance from direct and indirect ignition sources.
- Burn Probability (“BP”) is the annual probability of wildfire burning in a specific location. Referred to as Wildfire Likelihood in the Wildfire Risk to Communities web application.
- Conditional Flame Length (“CFL”) is the most likely flame length at a given location if a fire occurs, based on all simulated fires, which is an average measure of wildfire intensity.
- Flame Length Exceedance Probability – 4 ft (“FLEP4”) is the probability of having flame lengths greater than 4 feet if a fire occurs, on a 0 to 1 scale and indicates the potential for moderate to high wildfire intensity.
- Flame Length Exceedance Probability – 8 ft (“FLEP8”) is the probability of having flame lengths greater than 8 feet if a fire occurs, on a 0 to 1 scale and indicates the potential for high wildfire intensity.
- Wildfire Hazard Potential (“WHP”) is an index that quantifies the relative potential for wildfire that may be difficult to control, used as a measure to help prioritize where fuel treatments may be needed.

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1 10 Q. **WHY IS NV ENERGY PROPOSING TO ELEVATE THE VC HIGHLANDS**  
2 **AREA TO A TIER 3 WILDFIRE RISK?**

3 A. Based on risk modeling conducted by REAX, NV Energy is proposing to elevate  
4 the VC Highlands area to Tier 3. The conditions that exist within the VC Highlands  
5 area present a serious risk to the community in the event of a wildfire. The fuel  
6 type, fuel loading, fuel health, long narrow roads, high wind areas, structure density  
7 in the WUI, terrain, and water supply support categorizing VC Highlands as a Tier  
8 3 area. The VC Highlands area is identified as an extreme wildfire risk using the  
9 NDF Wildfire Risk Rating mapping and the USFS Wildfire Risk to Communities  
10 Map. Modeled Fire behavior under winds possible during a frontal passage  
11 indicates rapid potential rates of spread with passive flame lengths that would  
12 present suppression and control challenges. Based on these factors, the Companies  
13 propose to elevate the existing VC Highlands Proactive De-energization Zone from  
14 a Tier 2 to a Tier 3 area. EWG members either agreed or did not object to this re-  
15 designation. The REAX report recommending elevating the VC Highlands to Tier  
16 3 is included as Technical Appendix D.1 to the Plan.

17  
18 11 Q. **PLEASE PROVIDE AN OVERVIEW OF THE COMPANIES' PROPOSAL**  
19 **TO CREATE A NEW TIER 1 AREA TO REFINE AND REPLACE THE**  
20 **EXISTING WUI TIER.**

21 A. The Companies propose to create a new Tier 1 areas to refine and replace the prior  
22 WUI tier area. This proposal is based on review of the state wildfire risk rating  
23 maps and the REAX Engineering report discussed above. The Tier 1 is designed  
24 to include areas that are rated at moderate or higher wildfire risk based on the state  
25 maps. The Tier 1 designation will provide consistency between NV Energy's Tier  
26 areas and the state's risk rating maps. Tier 1 will cover approximately 2,162-line  
27

1 miles compared to the previously approved WUI Tier area that covered  
2 approximately 1,800-line miles. The 362-line miles increase associated with the  
3 new Tier 1 designation would only affect the proposed budgets for vegetation  
4 management Tier 1 treatments(resulting in an approximate 21% increase) and  
5 conditional awareness Tier 1 (resulting in an approximate 33% increase). NV  
6 Energy is not proposing to conduct other NDPP wildfire tier activities, *i.e.*, fuse  
7 replacement, copper wire removal, covered conductor, in the Tier 1 area.  
8

9 **12. Q. USING THE NDF WILDFIRE RISK RATING MAP, WHAT RISK RATING**  
10 **WOULD TIER 1 BE CATEGORIZED IN?**

11 A. Tier 1 includes areas categorized as moderate, moderate-high and high in the NDF  
12 Wildfire Risk Rating Map. A risk of moderate or above is considered to be a  
13 heightened wildland risk area.  
14

15 **13. Q. AT WHAT WILDFIRE RISK LEVEL DOES THE IWUIC REQUIRE**  
16 **MITIGATION REQUIREMENTS?**

17 A. The IWUIC requires mitigation in wildfire risk areas rated extreme, high and  
18 moderate. NV Energy’s proposed new Tier 1 is limited to areas at moderate or  
19 higher wildfire risk, therefore the IWUIC mitigation requirements apply to these  
20 areas. Pursuant to the NDPP statute and regulations, the Companies are required  
21 to meet the IWUIC.  
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14. Q. AFTER REVIEWING THE DATA, WHAT TIER HAD THE HIGHEST NUMBER OF WILDFIRE IGNITIONS AND STRUCTURES THAT COULD BE IMPACTED BY WILDFIRES?

A. Past fire occurrence provides an indication of where fires are likely to occur in the future. For that reason, the Companies analyzed two sources of fire history data to determine where wildfire ignitions historically occurred and the structures that could be impacted. The first is the USFS Fire Occurrence Database. This database includes 28 years (1992-2020) of fire ignition records as reported by local, state, and federal agencies. The second source is the Pyrecast fire polygons data, which has 20 years of fire perimeter records. The data from these two sources showed that the Tier 1 area had the highest number of ignitions, with 9,928 total ignitions, compared to 2,248 in the other Tiers combined. The Pyrecast data indicates the total number of structures in Tier 1 is about 160,877 compared to about 53,053 in the other Tiers combined.

**Table 1. Summary of fire history and structure counts within 120 meters (395 feet) buffer surrounding NV Energy’s current and proposed fire risk tiers.**

Tier	Ignitions	Structures
1	9,928	160,877
1E	966	26,097
2	774	19,785
3	508	7,168

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1 15. Q. PLEASE SUMMARIZE WHY IT IS APPROPRIATE TO CREATE A NEW  
2 TIER 1 DESIGNATION TO REFINE AND REPLACE THE PRIOR WUI  
3 TIER.

4 A. NV Energy is proposing to create a new Tier 1 area to designate areas with  
5 heightened wildfire risk, *i.e.*, areas designated as moderate and higher risk in the  
6 state risk rating maps. These areas are at heightened risk of wildfire and present  
7 risk to people and property. As a result, these require additional mitigation efforts  
8 under the state and local IWUIC and the NDPP statutes and regulations. The  
9 primary implication of the new Tier 1 designation will be an increase NDPP  
10 funding for vegetation management and conditional awareness. Creating the new  
11 Tier 1 area will allow NV Energy conduct appropriate vegetation management to  
12 lower wildfire risk in these heightened wildfire areas and help protect Nevada  
13 communities.

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15 **UNMANNED AERIAL VEHICLE AND SATELLITE IMAGING PILOT PROGRAM**

16 16. Q. PLEASE EXPLAIN WHY THE COMPANY IS PROPOSING A PILOT  
17 PROGRAM FOR UNMANNED AERIAL VEHICLES (“UAVS” OR  
18 “DRONES”)?

19 A. Industry best practices are introducing the use of UAVs or drones as well as satellite  
20 data for inspections and vegetation clearances. This technology and capability has  
21 seen dramatic improvements in quality and usefulness in the past several years. The  
22 Companies propose to continue to evaluate this technology as a pilot project for use  
23 line patrols, vegetation management, PSOM re-energization patrols, or other projects  
24 requiring visual observations. The pilot would evaluate best practices associated  
25 with having real-time video feeds from UAVs that could be remotely evaluated by  
26 lines personnel, fire responders, or other key personnel that require visual data and  
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information. The pilot would also evaluate the use of artificial intelligence technology systems to perform inspections of the circuits and the vegetation clearances. The Companies will also explore using high-resolution satellite data programs to provide predictive analysis for vegetation management treatments.

The Companies will use the pilot to evaluate the cost-benefits of a UAV program by reviewing the potential increase or decrease in work production, any safety or risk factors, the accuracy of the programs, long-term maintenance costs, and the development of industry best practices standards. These types of services are rapidly evolving, and the Companies are seeking funding to evaluate technologies for possible in-house UAV program that would be requested in a later filing. The Companies are requesting \$828,977 for the pilot program over the three-year NDPP period.

17. **Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**  
A. Yes.

## **STATEMENT OF QUALIFICATIONS**

### **MARK P. REGAN**

My name is Mark P. Regan. My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am the Fire Mitigation Specialist/Fire Chief for Nevada Power Company, d/b/a NV Energy, and Sierra Pacific Power Company, d/b/a NV Energy.

I was named Fire Mitigation Specialist/Fire Chief in September 2019. Prior to my current role, I was the Division Chief/Fire Marshal for North Lake Tahoe Fire Protection District from February 2012 through December 2019, where I retired with 30 years in the fire service.

On a daily basis, I enforced the 2018 International Fire Code (ICC Fire Code), 2018 International Wildland-Urban Interface Code, NFPA Standards and/or Nevada State Laws pertaining to fire codes. I conducted all plan reviews of buildings, fire alarm systems, fire sprinkler systems, and water supply systems. I conducted inspections of public and private buildings for compliance and conducted inspections of public assemblies. I was the lead negotiator with contractors and designers on issues relating to life safety and fire protection and evaluated alternative means and methods for construction. I also conducted all fire investigations from determining the fire origin to the prosecution of the arsonist, where my investigations helped convict 23 individuals for the crime of arson. I implemented the new technology, Emergency Reporting System (“ERS”) used for inspections, permits, plan reviews, pre-plans, vehicle maintenance, and defensible space.

As an Operational Division Chief, I conducted all daily station operations, emergency medical responses, fire responses, Haz-Mat incidences, water rescues, back-country rescues, and all other emergency incidences. On a continuous basis, I provided educational information to the public on fire and life safety. In addition, I provided training to fire district personnel. I also served as the Incident Safety Officer, meeting all applicable standards and policies concerning All Risk Fire Suppression, OSHA regulations, and NFPA standards.

When I joined North Lake Tahoe Fire Protection District in 2012, I was given the task to improve our Insurance Services Office (“ISO”) rating. We were evaluated 16 months after I was given the task and was able to implement and make changes to improve the District’s rating from a three to a two. After the District's most recent ISO evaluation, we were able to receive an ISO Class 1 rating effective March 1<sup>st</sup> 2019, becoming one of three Class 1 departments in the State of Nevada. This rating is a distinguished honor, being in the top 1% of Class 1 fire districts nationally.

I maintained a constant rapport with our community, our contractors, local media, our Fire Board, our County Commissioners, and our State and National Representatives in order to maintain our excellent relationships while working together. I was responsible for the planning and implementation of annual evacuation/disaster drills for North Lake Tahoe and Washoe County. I have conducted a total of 35 evacuation/disaster drills over my years of service, along with being responsible for the first-ever Bi-State full-scale evacuation

exercise and safety fair. This Bi-State exercise included resources from Nevada and California and also included the first-ever firefighting aircraft flying missions together with an Unmanned Aerial Vehicle (“UAV” or “Drone”).

I have also served as a member of the Washoe County Emergency Operation Center, Washoe County Evacuation Team and the Washoe County Emergency Management Disaster Planning and Training Committee. As a member of these committees, I reviewed and implemented the county's disaster and emergency plans, negotiated with competing stakeholders, collaborated in creating a recovery support strategy with departments and agencies who are responsible for the recovery support functions. During numerous emergencies, I was responsible for the evacuation of citizens and animals and at times up to 15,000 residents. I helped develop and implement recovery support strategies, facilitated disaster recovery coordination, supported the Local Disaster Recovery Manager and/or Tribal Disaster Recovery Coordinator. I worked closely with the state Disaster Recovery Coordinator and with the impacted community to establish relevant recovery measures and to incorporate mitigation and resilience-building into recovery plans and implementation.

I also served on State and National Incident Management Teams that responded to emergencies and disasters. Being part of these teams, I have gained extensive knowledge and experience with the management of emergencies, disaster recovery, mitigation, and resiliency planning. I also served as a Terrorist Liaison Officer for Northern Nevada.

On a national level, I was responsible for the evacuation of citizens and animals and at times up to 45,000 residents. I also negotiated with competing stakeholders, cultivated new and expanded existing relationships with personnel at the Federal, State, Tribal and local levels, including the private and nonprofit sectors.

I was also a member of the legislative committee for the Lake Tahoe Regional Fire Chiefs and the lobbyist for the Northern Nevada Chiefs. I served as the Prevention Chair for the Lake Tahoe Regional Chiefs. Also, I sat on the board for the Northern Nevada Fire Code Committee. I was the President for the Nevada International Association of Arson Investigators. I served on the Emergency Evacuation Team and Emergency Operating Center for Washoe County. I was also the leader of the Joint Information Team for Washoe County. I also served on the Washoe County Marijuana Code and Enforcement Board and was appointed as a member of the vacation rental code committee. In addition, I served as the President for the Lake Tahoe Regional Fire Chiefs Association.

From 1996 - 2012, while employed as a Firefighter/Engineer/Prevention Captain/Captain/Acting Battalion Chief with Sierra Fire Protection District/Nevada Division of Forestry, I developed the Defensible Space Inspection Program. I also developed the Preparing Residents in Disaster Evacuations Program ("P.R.I.D.E."), which has been adopted nationally by the Living with Fire Program, Ready-Set-Go, and Fire Adaptive Community Programs. I served on the committee of the Living with Fire Program. During this time I began my service as a member of Washoe County Emergency Operation Center, Washoe County Evacuation Team and the Washoe County Emergency

Management Disaster Planning and Training Committee and served on the State and National Incident Management Teams that responded to emergencies and disasters. Governor Sandoval appointed me to serve on his Schools Prepared and Ready Together Across Nevada Committee (“SPARTAN”) where we developed the emergency response plans for schools throughout Nevada. I also served as a Terrorist Liaison Officer for Northern Nevada and I continued this role when I was employed with North Lake Tahoe Fire Protection District.

In May 2008, I conducted the largest full-scale evacuation drill in the United States. During this time, over 4,000 residents were evacuated and 33 agencies, over 500 personnel, participated in this evacuation drill. Over 1,500 people and 300 animals checked into our evacuation center.

From 1990-1996 I was employed with Carson City Fire-Warren Engine Company. I held the rank of firefighter, operator and 2nd Assistant Volunteer Chief. During this time, I also served as a fire instructor for the fire academy.

In 2017, I was the guest speaker at the 2017 FEMA Region IX Leadership Workshop. I was the guest speaker at the Nevada Preparedness Summit in 2017 and 2019. In 2010, I was the guest speaker at the National Fire Chiefs Association. In 2009, 2010, 2011, 2017 & 2022 , I was the guest speaker at the Nevada Wildland Summit. I presented in 2020 at the Western Great Basin and Sierra Front Incident Management Summit.

My qualifications and certifications, which support my position as Fire Mitigation Specialist/Fire Chief, are as follows:

- **NFPA Chief Fire Officer**
- **S-520 Advanced Incident Management**
- **S-420 – Command and General Staff**
- **S-300 Extended Attack Incident Commander**
- **Multi-Hazard Emergency Planning**
- **Command 1A & IB**
- **Hazardous Materials Incident Commander**
- **Incident Safety Officer**
- **Health and Safety Officer**
- **International Code Counsel Fire Inspector II**
- **International Fire Plans Examiner**
- **Residential Sprinkler Plan Review**
- **Washoe County Management Classes**
- **ICC Inspection of Hood/Duct**
- **FI-210 Wildland Investigator Certified**
- **CFI-IAAI**
- **Fire Behavior in a Single Family Occupancy - National Fire Academy**
- **Inspector for Fire Protection for Commercial Occupancy –National Fire Academy**
- **Interviews & Interrogations**
- **Advanced Fire Investigation**
- **Court Room Certified**
- **Juvenile Fire setter Intervention Certification**
- **Public Information Officer I**
- **FEMA Incident Command 100, 200,300, 700, 800**
- **Class A Driver’s License**
- **Dozer Boss**
- **Class 3 Faller**
- **Lessons Learned / Fatality Fires**
- **Managing Company Tactical Operations – Decision Making**
- **Managing Company Tactical Operations – Preparation**
- **Health Care Respirator Training Programs**
- **Emergency Vehicle Operations – Train the Trainer**
- **Standards for Survival**
- **L-180 Human Factors in the Wildland**
- **NFPA Aerial Operations**
- **Confined Space Awareness**
- **S-230 Introduction to Incident Information**
- **I-200 Basic ICS**
- **S200 Initial Attack I.C.**
- **S270 Air Operations**
- **S231 Engine Boss**
- **EMT Intermediate**
- **S-211 Portable Pumps**
- **S-290 Intermediate Fire Behavior**
- **Radiological Training for First Responders**
- **Fire Instructor II**
- **Fire Systems Management, Class A & B Foam**
- **Wildland S-130**
- **Wildland I-100**
- **NFPA Firefighter II**

- **Fire Arson Detection & Business Inspection**
- **Fire Officer Development**
- **NFPA Fire Officer I**
- **NFPA Engine Operator**
- **NFPA Aerial Operator**
- **Pump Operations**
- **Haz-Mat Operations and Decontamination**

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AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MARK REGAN, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2023

  
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MARK REGAN

**CARY SHELTON-PATCHELL**

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**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2023 Natural Disaster Protection Plan  
Docket No. 23-03xxx

Prepared Direct Testimony of

**Cary Shelton-Patchell**

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

A. My name is Cary Shelton-Patchell. My current position is Director, Revenue Requirement and Regulatory Accounting for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”). My business address is 6100 Neil Road in Reno, Nevada. I am filing on behalf of the Companies.

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

A. I hold a Bachelor of Science degree in Business Administration from the University of Nevada, Reno, and I am a Certified Public Accountant. I joined the Companies in 1992 as the Accounting Manager at Lands of Sierra. Since that time, I have held several positions in the Companies, including Lead Revenue Accountant, Staff Accountant III, Regulatory Accounting Manager, Pricing Specialist, Senior Business Analyst and Revenue Requirement and FERC Manager. I assumed the

1 role of Director, Revenue Requirement and Regulatory Accounting in January  
2 2022.

3  
4 My statement of qualifications is attached as **Exhibit Shelton-Patchell-Direct-1**.

5  
6 **3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR**  
7 **CURRENT POSITION?**

8 A. As Director, Revenue Requirement and Regulatory Accounting, my responsibilities  
9 include the preparation of monthly regulatory earned rate of return reports, revenue  
10 reporting, revenue requirement calculations and jurisdictional allocations related to  
11 general rate case (“GRC”) filings.

12  
13 **4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**  
14 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**  
15 **(“COMMISSION”)?**

16 A. Yes. I have previously testified in front of the Commission in several dockets,  
17 which are listed in **Exhibit Shelton-Patchell-1**. Most recently I filed testimony in  
18 Nevada Power and Sierra’s merger application for the supplement filing, Docket  
19 No. 22-03028.

20  
21 **5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

22 A. The purpose of my testimony is to support the anticipated rate impact calculations  
23 for the Natural Disaster Protection Plan (“NDPP”) for plan years 2024, 2025 and  
24 2026.

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**6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

A. I am sponsoring the following Exhibits:

- **Exhibit Shelton-Patchell-1**, Statement of Qualifications

**7. Q. PLEASE DESCRIBE THE RATE COMPONENTS FOR THE NDPP.**

A. The NDPP rate components include: the NDPP Statewide Component and the NDPP Capital Component. The NDPP Statewide Component consists of the total NDPP Operations, Maintenance, Administrative and General (“OMAG”) Distribution costs and the NDPP allocated OMAG Transmission costs that are divided by total Nevada Power and Sierra kilowatt hour (“kWh”) sales to calculate the Statewide rate. The NDPP Capital Component is calculated for each Company and is the total NDPP Capital Distribution costs recorded and the NDPP allocated Capital Transmission costs.

The Nevada Power and Sierra Capital kWh rates are summed with the Statewide kWh rate, which results in different NDPP kWh rates for each Company.

**8. Q. PLEASE DESCRIBE THE RATE IMPACT CALCULATION FOR THE NDPP TRIENNIAL PERIODS 2024-2026 BASED UPON THE COMPANIES’ PROPOSED COSTS ALLOCATION.**

A. **Table-Shelton-Patchell – Direct -1** reflects the proposed NDPP rate impacts for Nevada Power and Sierra customers based upon the Companies’ proposal.

**Table-Shelton-Patchell -Direct -1**

**NDPP Rates per kWh**

	<b>NPC</b>	<b>SPPC</b>
2024	\$0.00211	\$0.00249
2025	\$0.00200	\$0.00290
2026	\$0.00209	\$0.00318

9. **Q. DID YOU CALCULATE A MONTHLY TYPICAL BILL IMPACT FOR RESIDENTIAL CUSTOMERS?**

A. Yes. **Table-Shelton-Patchell – Direct-2** shows the typical monthly bill impacts for single-family monthly bills.

**Table-Shelton-Patchell -Direct -2**

**Single Family Monthly Typical Bill Impacts**

	<b>NPC</b>	<b>SPPC</b>
2024	\$2.32	\$1.98
2025	\$2.20	\$2.31
2026	\$2.30	\$2.53

10. **Q. DID YOU MAKE ANY ASSUMPTIONS IN DEVELOPING THE RATE IMPACT CALCULATIONS?**

A. Yes. I made the following assumptions:

- The OMAG and capital costs follow what has been presented in this plan and would actually be incurred as planned.
- The recovery of the NDPP rider from customers does not result in any over- or under-recovery of these costs from customers.

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- Transmission and distribution capital and OMAG costs have been allocated between transmission and distribution based on how these costs have been incurred/recorded.
- The allocation of transmission costs for NDPP recovery is based on the most recent GRC for each company.
- The projected sales forecast filed in Docket No. 22-09006 was used to calculate the per kWh rates.

11. Q. DO YOU BELIEVE THESE ASSUMPTIONS ARE REASONABLE?

A. I believe these assumptions are reasonable and allow the Commission to see the impact.

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

A. Yes.

**Statement of Qualifications  
for  
CARY R. SHELTON-PATCHELL**

**Summary of Qualifications**

29 years of regulatory, accounting and utility leadership experience. Experience in regulatory and operations accounting areas. Extensive knowledge of regulatory activities and regulatory accounting for NV Energy's Nevada and California jurisdictions.

**Professional Experience**

***Director, Revenue Requirement and Regulatory Accounting***

*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy  
January 2022 - Present*

Responsible for regulatory filings, tariff development, Nevada deferred energy filings, revenue requirement calculations and jurisdictional allocations related to general rate case filings.

***Revenue Requirement and FERC Manager***

*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy  
May 2021 – January 2022*

Responsible for the preparation of regulatory earned rate of return, earnings sharing calculations and revenue requirement calculations in compliance with regulations and Commission directives for state and FERC jurisdictional filings. Managed fuel and purchased power recovery mechanisms and required filings along with the completion of various state and FERC reporting requirements.

***Senior Business Analyst***

*Sierra Pacific Power Company d/b/a NV Energy  
December 2016 – May 2021*

Responsible for compliance with company policies, procedures and regulations including SOX. Supported Sierra Pacific Power Gas Department in the development and reporting of budgets, forecasts and investments.

***Pricing Specialist***

*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy  
March 2008 – December 2016*

Responsible for the preparation of the Sierra Gas Department Embedded Cost of Service Study and Rate Design, the development and support of impact calculations for customers electing distribution only service, development of revenue budget inputs.

***Manager, Regulatory Accounting***

*Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy  
September 1999 - March 2008*

Responsible for the timely preparation of regulatory statements, adjustments and analyses, the implementation of accounting procedures to comply with regulatory orders and developments. Managed the preparation of calculations and studies pertaining to recorded revenues and lead/lag studies.

***Staff Accountant III, Restructuring Team***

*Sierra Pacific Power Company d/b/a NV Energy  
May 1998 - September 1999*

Responsible for the drafting of Sierra Pacific's comments filed with the Nevada Public Utilities Commission for past costs and proposed alternative seller licensing. Assisted in defining the accounting resources that were required to complete filings required by the restructuring initiatives implemented by the Nevada legislature and Public Utilities Commission of Nevada (PUCN). Assumed position of Remittance Processing Interim Supervisor and was responsible for costs, timing and implementation of a project to integrate processing of Nevada Power's mail-in payments into the Reno Remittance Department's workflow.

***Lead Revenue Accountant, Corporate Accounting***

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

*June 1994 - May 1998*

Responsible for company-wide margin/revenue reporting and prepared monthly revenue variance analysis for management. Implemented and developed accounting procedures for new revenue programs and specialized contracts. Participated as the accounting department representative in the Customer Management Reengineering Team, California Direct Access Implementation Team, and Customer Information System Replacement Team.

***Accounting Manager***

*Lands of Sierra*

*April 1992 - June 1994*

Responsible for monthly financial reporting and compliance with generally accepted accounting principles to Sierra Pacific Resources. Supervised staff in areas of general ledger, accounts payable, accounts receivable, job cost and cash management.

***Senior Staff Accountant***

*Deloitte & Touche, Reno*

*September 1989 - April 1992*

Responsible for planning and implementing financial and compliance audits in accordance with generally accepted auditing standards. Reviewed and evaluated internal control systems and analyzed financial statements and related footnote disclosures for compliance with generally accepted accounting principles.

**Prior Testimony Before the Nevada Public Utilities Commission**

01-10001	03-10001	06-11022	13-06003
01-11029	03-12002	07-12001	16-06007
01-11030	05-10003	10-06002	
02-2002	05-10005	11-06006	

**Education**

**Certified Public Accountant**, State of Nevada

**University of Nevada, Reno**

Bachelor of Science in Business Administration May 1989

**Continuing Education Courses**

- Utility Finance and Accounting for Financial Professionals
- Complying with Sarbanes-Oxley Section 404
- Electric Rates Advanced Course, Edison Electric Institute
- FASB/APB Update and Review

- Electric Utility Ratemaking Concepts
- Stranded Costs and Securitization: The Transition to a Restructured Industry, Edison Electric Institute
- Stranded Cost Recovery
- The Vital Role of Financial Performance, Western Electric Power Institute
- Competitive Billing Strategies
- Transforming Accounting & Finance, Western Electric Power Institute
- Pricing Strategies & Evolving Regulation
- Fundamentals of Utility Finance
- Introduction to Public Utility Accounting, American Gas Association/Edison Electric Institute

**Professional Affiliations**

- American Institute of Certified Public Accountants
- Nevada Society of Certified Public Accountants

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AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, CARY SHELTON-PATCHELL, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2023

*Cary Shelton-Patchell*

CARY SHELTON-PATCHELL

**ALEXANDER HOON**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

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

2023 Natural Disaster Protection Plan  
Docket No. 23-03xxx

Prepared Direct Testimony of

**Alexander Hoon**

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

A. My name is Alexander Hoon. My current position is Natural Disaster Protection Plan Senior Meteorologist for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”). My business address is 6100 Neil Road, Reno, Nevada 89511. I am filing testimony on behalf of the Companies.

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

A. I have been with NV Energy since October 2021. For the previous 15 years I worked for the National Weather Service in Reno, Nevada. I was the program manager for fire weather in Reno, and was also an incident meteorologist deployed to over 25 major wildfires across the western United States. My experience is primarily in fire weather, fire behavior, and operational weather decision support.

My statement of qualifications is attached as **Exhibit Hoon-Direct-1**.

1 3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR  
2 CURRENT POSITION?

3 A. As the Senior Meteorologist, I am responsible for short and long term weather  
4 forecasting for the Companies. I provide decision support to NV Energy leadership  
5 and operations for potential extreme weather natural disasters. I am also a key  
6 supporter for situational awareness systems for the Companies, including weather  
7 stations, fire cameras, artificial intelligence (“AI”), and wildfire risk modeling  
8 technology.  
9

10 4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY  
11 WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA  
12 (“COMMISSION”)?

13 A. No.  
14

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

16 A. The purpose of my testimony is to provide evidence regarding effects of climate  
17 change in Nevada, changes in the weather patterns and fire occurrences that we  
18 have seen in the last 20 years, and support for the steps NV Energy is taking to  
19 actively mitigate these increasing threats from extreme weather. I am also  
20 providing support for the situational awareness activities and Technosylva Wildfire  
21 Risk Modeling in the Natural Disaster Protection Plan (“NDPP” or “Plan”).  
22  
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28 Hoon - DIRECT

1 6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

2 A. I am sponsoring or co-sponsoring the following Exhibits:

3 Exhibit Hoon-Direct-1, Statement of Qualifications

4 Exhibit B, The Second Triennial Natural Disaster Protection Plan, specifically I  
5 sponsor or co-sponsor the following portions of the Plan:

- 6 • Section 1.2 – Natural Disaster Threats (co-sponsored with Mr. Mark Regan)
- 7 • Section 2.1 – Situational Awareness (co-sponsored with Mr. Mark Regan and  
8 Mr. Jay Wiggins)

9  
10 7. Q. HOW IS YOUR TESTIMONY ORGANIZED?

11 A. First, I provide evidence of how climate change is impacting natural disaster risks  
12 in Nevada, including wildfires and extreme weather events. In addition, I provide  
13 support for the situational awareness and Technosylva components of the NDPP.  
14

15 **THE EFFECTS OF CLIMATE CHANGE IN NEVADA**

16 8. Q. PLEASE EXPLAIN HOW CLIMATE CHANGE IS IMPACTING  
17 DISASTER RISKS IN NEVADA.

18 A. The effects of climate change are already here. We are seeing longer, drier periods  
19 that are having significant effects on drought and longer fire seasons. Also, when  
20 we do get precipitation, we are seeing heavier rain and snowfall from monsoons  
21 and atmospheric rivers. Climate change brings heightened threat of wildfires, high  
22 wind events, winter storms, thunderstorms/microbursts, monsoons/flash flooding,  
23 as well as heatwaves/drought to all regions of Nevada.  
24

25 ///

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28 Hoon - DIRECT

1 9. Q. PLEASE EXPLAIN HOW CLIMATE CHANGE HAS IMPACTED  
2 DROUGHT CONDITIONS IN NEVADA OVER THE PAST 20 YEARS.

3 A. The extended period of drought in the western United States from the year 2000 to  
4 2021 is now being classified as a “megadrought.” Research published in 2022  
5 shows that the period of 2000-2021 is the most intense 22-year western United  
6 States drought cycle since the year 800 C.E.<sup>1</sup>

7  
8 In fact, the 2020-2021 water year was the warmest and driest water year in modern  
9 record for both Nevada and California.<sup>2</sup> Anthropogenically caused-warming and La  
10 Niña-related precipitation deficits caused at least a sixfold increase in chance of  
11 recurrence for compound extreme low precipitation and high temperature in  
12 California–Nevada from October 2020 to September 2021, as compared to the  
13 previous climate regime of 1921-1950.

14  
15 The reason for this extended drought period over the last 20 plus years is directly a  
16 result of warmer overall temperatures and drier winters, which lead to less  
17 snowpack in the mountains and drier soils that stress vegetation. This research  
18 asserts that about 19 percent of this drought can be attributed to climate change.<sup>3</sup>

19  
20 Technically we are still in the same drought cycle as of winter 2023, due to the  
21 long-term effects of the drought across the western United States and Nevada,  
22 although we have had some recent beneficial rain/snow this season across the state  
23 that has helped to mitigate some of the shorter-term drought effects. According to

24 <sup>1</sup> Williams, A.P., Cook, B.I. & Smerdon, J.E. Rapid intensification of the emerging southwestern North American  
megadrought in 2020–2021. *Nat. Clim. Chang.* **12**, 232–234 (2022). <https://doi.org/10.1038/s41558-022-01290-z>

25 <sup>2</sup> Hoell, Andrew, et al. Water Year 2021 Compound Precipitation and Temperature Extremes in California and  
Nevada. *Bulletin of the American Meteorological Society*. Dec 2022. <https://doi.org/10.1175/BAMS-D-22-0112.1>. <sup>3</sup>

26 Williams, A.P., Cook, B.I. & Smerdon, J.E. Rapid intensification of the emerging southwestern North American  
27 megadrought in 2020–2021. *Nat. Clim. Chang.* **12**, 232–234 (2022). <https://doi.org/10.1038/s41558-022-01290-z>

1 the February 17, 2023 U.S. Drought Outlook California-Nevada Drought Status  
2 Update, the impacts of the rain and snowfall from the last few months have varied  
3 across the region, and large parts of Nevada did not receive as much precipitation  
4 as other parts of the Sierras and California.<sup>4</sup>  
5  
6

7 **10. Q. IS CLIMATE CHANGE IMPACTING THE OCCURRENCE OF**  
8 **EXTREME PRECIPITATION EVENTS IN NEVADA?**

9 A. Yes. One of the most well understood and researched aspects of climate change is  
10 its effect on rain and heavy precipitation events around the world.<sup>5</sup> In a warmer  
11 atmosphere, evaporation rates increase and transform more liquid water molecules  
12 into vapor state in the air. The atmosphere can hold about seven percent more water  
13 for every 1.0-degree Celsius (1.8-degree Fahrenheit) increase. This moisture-laden  
14 air can then drop heavier amounts of rainfall at one time, increasing the intensity of  
15 rain and snow events, including precipitation from monsoons and atmospheric  
16 rivers. The Earth’s atmosphere has already warmed about 1.3 degrees Celsius (2.3  
17 degrees Fahrenheit) since pre-industrial times, and researchers have observed  
18 heavier rain in storms, hurricanes, daily precipitation—and now in atmospheric  
19 rivers.<sup>6</sup>  
20  
21  
22

23 <sup>4</sup> Kalansky, Julie, Program Manager of California-Nevada Adaptation Program. California-Nevada Drought Status  
24 Update | February 17, 2023 | Drought.gov <https://www.drought.gov/drought-status-updates/california-nevada-drought-status-update-2023-02-17>

25 <sup>5</sup> Williams, A.P., Cook, B.I. & Smerdon, J.E. Rapid intensification of the emerging southwestern North American  
26 megadrought in 2020–2021. *Nat. Clim. Chang.* **12**, 232–234 (2022). <https://doi.org/10.1038/s41558-022-01290-z>

27 <sup>6</sup> Espinoza, V., Waliser, D. E., Guan, B., Lavers, D. A., & Ralph, F. M. (2018). Global analysis of climate change  
28 projection effects on atmospheric rivers. *Geophysical Research Letters*, 45, 4299– 4308.  
<https://doi.org/10.1029/2017GL076968>

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For example, in the Reno area, we have seen a significant shift in having more extreme precipitation days each year. Heavy precipitation amounts of greater than 1.0 inch or more in a single day occurred 25 times during the 63 year period between 1937-1999, which is an average of about 0.4 times per year. But, these extreme precipitation events have occurred 25 times in the last 23 years, between 2000-2022, for an average of 1.09 times per year (see Figure 1). That is nearly three times more often than prior to the year 2000. These extreme precipitation events primarily occur in northwest Nevada, due to the increased major atmospheric river events coming off the Pacific Ocean, but can affect northeast Nevada and southern Nevada as well.

According to the National Aeronautics and Space Administration (“NASA”) Jet Propulsion Laboratory (“JPL”) Study in 2018, there has been a ten percent increase in precipitation from major storms since pre-industrial times. The same study also projects that if greenhouse gas emissions continue at the current rate, there will be about ten percent fewer atmospheric rivers globally by the end of the 21st century. However, the findings also project that the atmospheric rivers will be, on average, about 25 percent wider and longer and that the global frequency of major atmospheric river conditions—like heavy rain and strong winds—will actually increase by about 50 percent.<sup>7</sup>

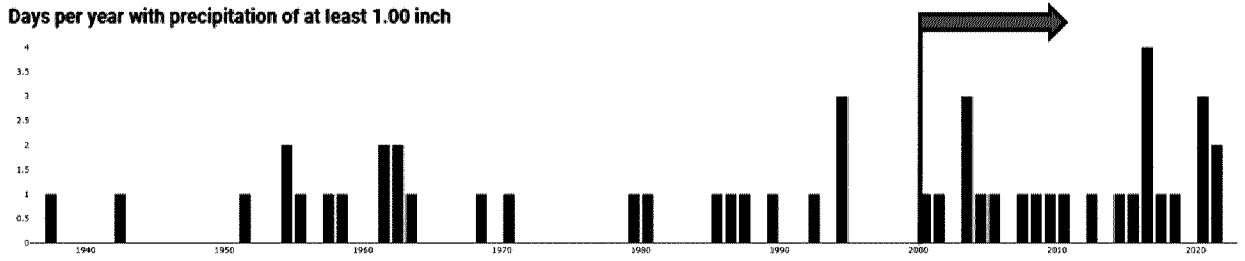
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<sup>7</sup> Espinoza, V., Waliser, D. E., Guan, B., Lavers, D. A., & Ralph, F. M. (2018). Global analysis of climate change projection effects on atmospheric rivers. *Geophysical Research Letters*, 45, 4299– 4308. <https://doi.org/10.1029/2017GL076968>

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**FIGURE 1  
EXTREME PRECIPITATION EVENTS IN RENO, NEVADA, SINCE 1937**



**U.S. CLIMATE RESILIENCE TOOLKIT CLIMATE EXPLORER (VERSION 3.1)**

Specifically for southern Nevada, climate change can lead to heavy summer monsoon rains and severe thunderstorm winds. The recent Intergovernmental Panel on Climate Change (“IPCC”) Sixth Assessment Report, which covers observed and potential future changes in the North American Monsoon in the Southwestern United States found modest evidence that monsoon rainfall has intensified since the 1970s, and this has been partly attributed to greenhouse gas emissions. On the other hand, there is not much agreement among projections for future change in the monsoon, except for regarding the timing—most projections suggest that, under continued climate change, the monsoon will start later in the summer and end later in the fall than it currently does.<sup>8</sup>

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<sup>8</sup> IPCC, 2021: *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, Chapter 8.3, In press, doi:10.1017/9781009157896. <https://www.ipcc.ch/report/ar6/wg1/chapter/chapter-8/>

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**11. Q. BASED ON THIS EVIDENCE, HAVE THE COMPANIES REEVALUATED THE NATURAL DISASTER RISKS FOR NEVADA SINCE THE FIRST TRIENNIAL PLAN?**

A. Yes. Based on this evidence presented above, and as well from working with the external Expert Working Groups around the state of Nevada, the Companies continue to identify wildfires as the highest threat to communities and power grid resiliency and reliability. Wildfires pose an annual threat that can impact large areas of the State with significant consequences, including potential for burning homes and communities in wildland-urban interface areas.

The second triennial NDPP also recognizes the elevated natural disaster threat from monsoons and flash flooding. Monsoons and flash flooding affect entire state, but the impacts are more acutely felt in southern Nevada. The southern Nevada severe thunderstorm events in 2022 demonstrate the risk and the damages that can be caused by these types of events. The Circuit Resiliency programs aims to address this risk for southern Nevada monsoon corridors as described in Section 2.5.2 of the NDPP.

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12. Q. **HOW DO THE EFFECTS OF CLIMATE CHANGE AFFECT WILDFIRE RISK IN NEVADA?**

A. Climate change affects wildfire risk every year in Nevada, whether through severe drought or heavy, wet precipitation. Both of which can exacerbate wildfire risks in the State of Nevada, but in different ways.

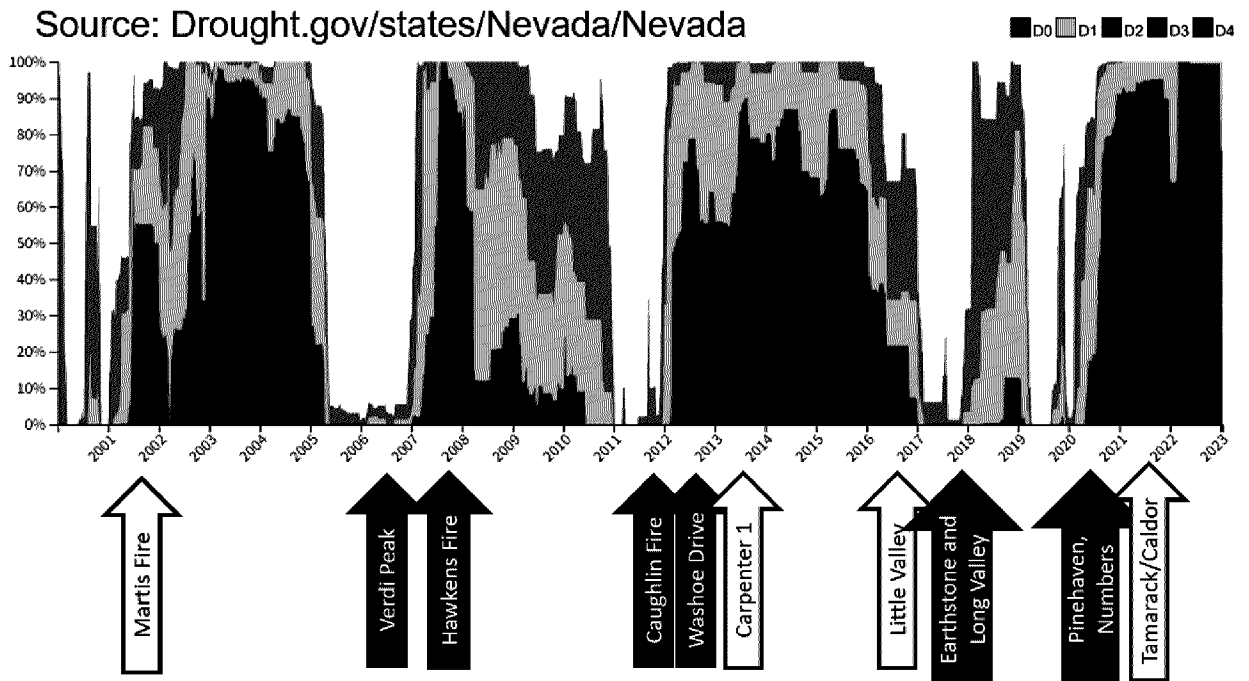
For the desert and foothill areas of Nevada, the primary carrier of wildfire is grass, particularly cheatgrass. On years when the state receives heavy precipitation, whether through heavy atmospheric river events or heavy monsoons, this brings increased grass growth in Nevada valleys. Heavy cheatgrass loading in the Great Basin is directly linked to having more large wildfires, and if not cleared, can last for years after the “wet winter.” Conversely, when the State has drought years, there is much less grass growth, which leads to less wildfire activity in the desert and foothill areas.

For the forested mountains of Nevada, the primary carrier of wildfire is heavy dead timber and timber litter. The wildfire risk for this fuel type is largely inverse to wildfire risk to the desert sagebrush-grass fuel type. After a heavy wet winter, heavier snowpack can reduce the effects of drought in the mountains, with healthier trees and brush, as well as moist soils. Drought, on the other hand, tends to increase large wildfire activity in the mountains due to drier soils, drier live trees and brush, and drier dead fuels.

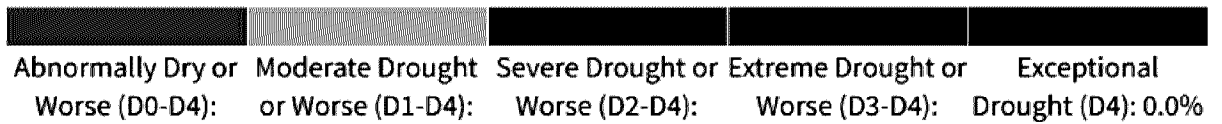
In summary, both drought and extreme precipitation events can increase wildfire impacts in the state in different ways. Figure 2 shows the major historical wildfires in Nevada plotted against historical drought conditions. The fires highlighted in

black represent sagebrush-grass wildfires, while those highlighted in white occurred in forested mountains. Because of climate change, the potential for seeing more extremities in the weather (drought and heavy precipitation) is increasingly likely.

**FIGURE 2  
HISTORICAL DROUGHT AND WILDFIRES NEVADA**



**U.S. Drought Monitor for NV**



Source(s): NDMC, NOAA, USDA  
Updates Weekly - 02/14/23

**Drought.gov**

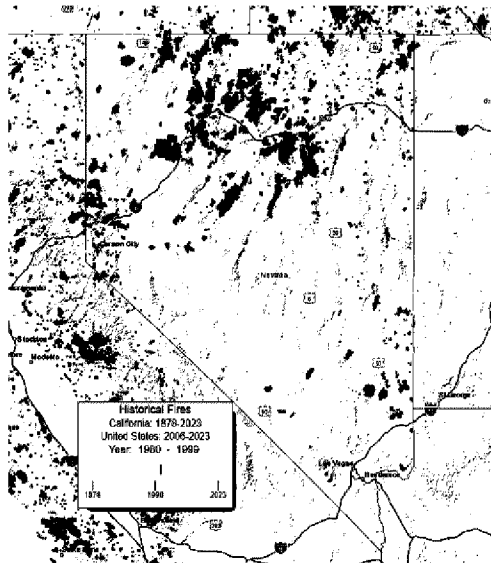
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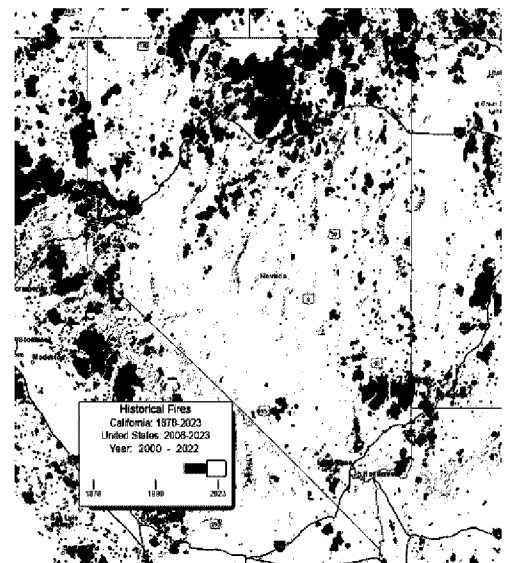
13. Q. DOES THE HISTORICAL NEVADA FIRE ACTIVITY SHOW THE IMPACTS OF CLIMATE CHANGE?

A. Since the year 2000, wildfires in Nevada have increased in acreage compared to fires in 1980s and 1990s. This is true for wildfires all across the state, including southern Nevada, northwestern Nevada, and northeastern Nevada. (See Figures 3-6.)

FIGURE 3  
HISTORICAL WILDFIRES IN NEVADA



Nevada Wildfires 1980-1999

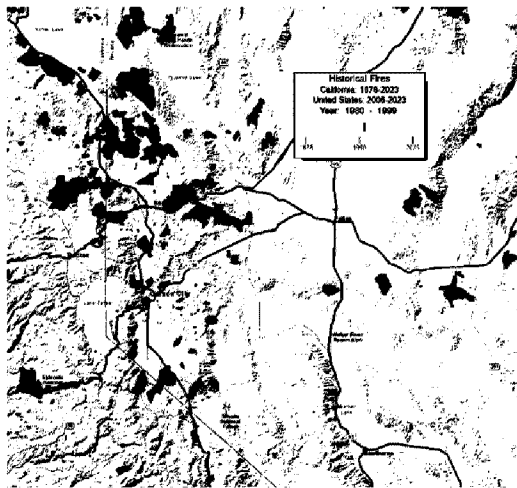


Nevada Wildfires 2000-2022

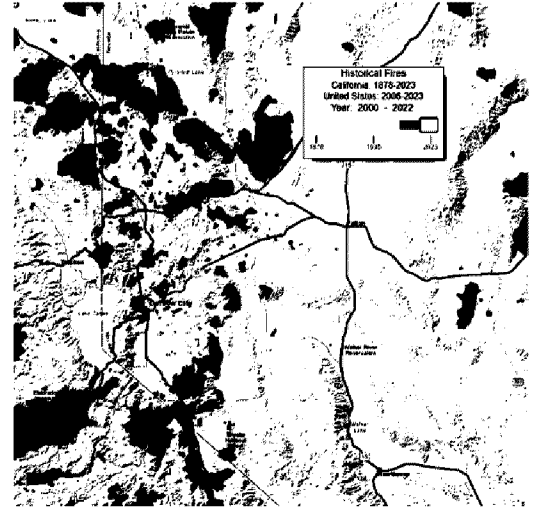
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**FIGURE 4**  
**HISTORICAL WILDFIRES IN NORTHWESTERN NEVADA**

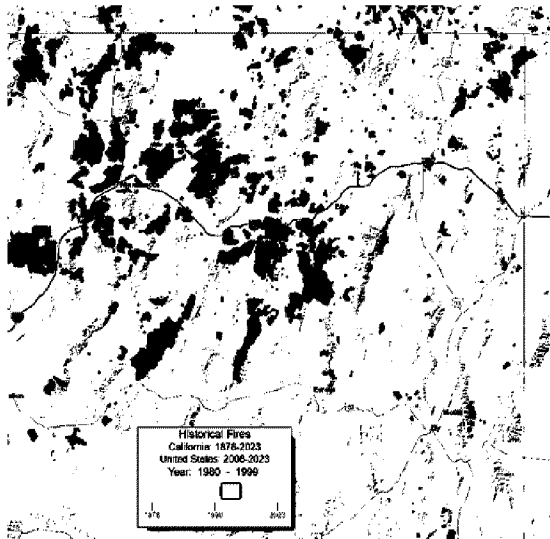


**Northwest Nevada  
Wildfires 1980-1999**

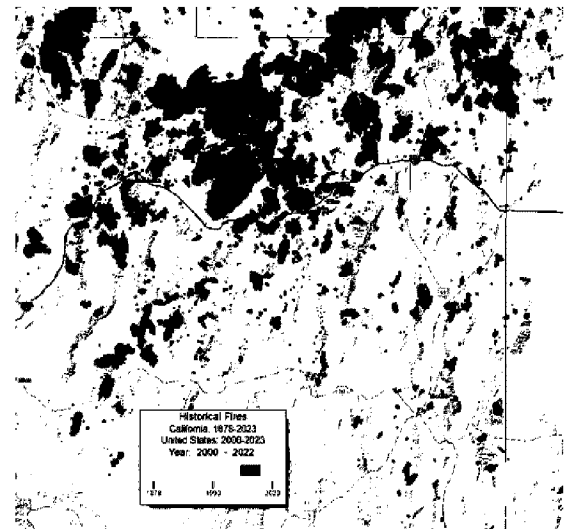


**Northwest Nevada  
Wildfires 2000-2022**

**FIGURE 5**  
**HISTORICAL WILDFIRES IN NORTHEASTERN NEVADA**

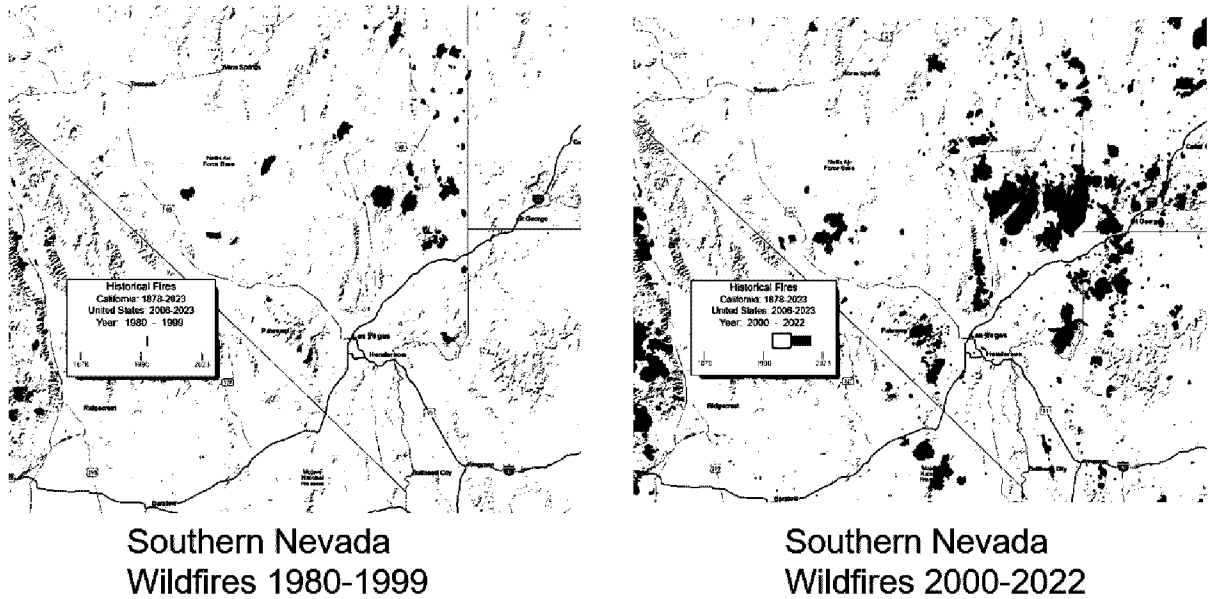


**Northeastern Nevada  
Wildfires 1980-1999**



**Northeastern Nevada  
Wildfires 2000-2022**

**FIGURE 6  
HISTORICAL WILDFIRES IN SOUTHERN NEVADA**



14. **Q. HAVE THE RECENT WINTER STORMS HAD A SIGNIFICANT IMPACT ON POTENTIAL FIRE CONDITIONS IN NEVADA?**

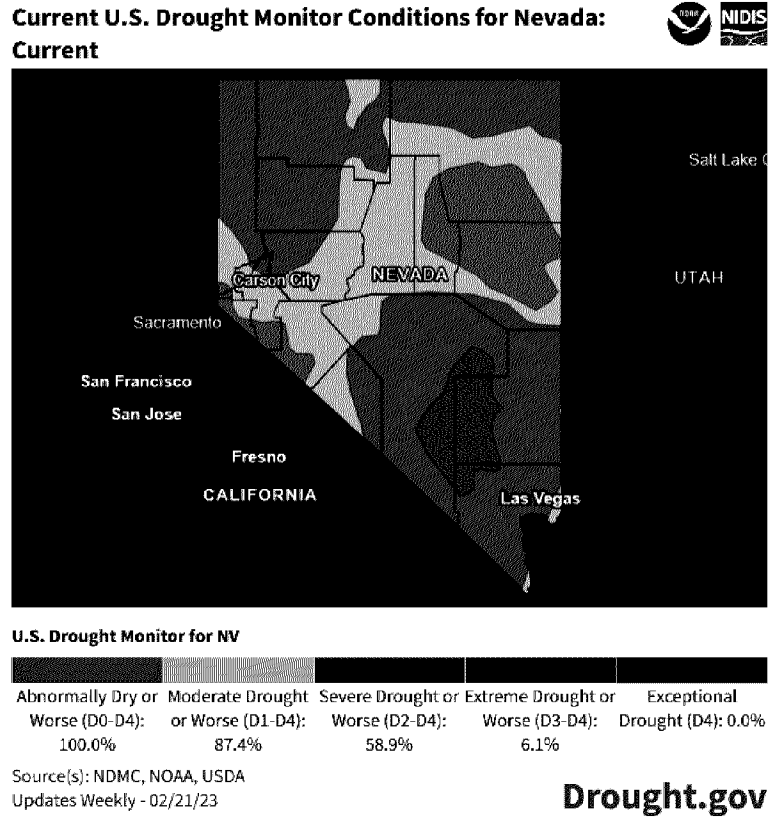
A. The recent wetter weather across the State of Nevada will have a potential impact on fire conditions this summer. After a wet summer monsoon season in 2022 and a wet and snowy winter in 2022-23, the drought conditions have improved quite a bit compared to the past few years. That being said, as of February 21, 2023, 59 percent of the state was still under severe or worse drought conditions (see Figure 7) and 87% remains in a moderate drought or worse. This will likely have the effect of having a less active wildfire season in the forested mountains and a more active fire season in the desert valleys for 2023 and potentially into 2024.

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**FIGURE 7**  
**CURRENT DROUGHT CONDITIONS IN NEVADA (AS OF FEB 21, 2023)**



**SITUATIONAL AWARENESS**

**15. Q. PLEASE PROVIDE A GENERAL OVERVIEW OF THE COMPANIES' EFFORTS TO INCREASE SITUATIONAL AWARENESS TO ADAPT TO CLIMATE CHANGE RISKS.**

A. With the heightened risk of wildfires, natural disasters and effects of climate change in our region, the Companies are planning to increase their situational awareness through weather monitoring, fire camera deployment, artificial intelligence ("AI"). The Companies' collaboration with partnering public agencies is key to the success of this plan.

1 16. Q. WHAT ARE THE PROPOSED CHANGES TO THE SITUATIONAL  
2 AWARENESS COMPONENTS OF THE INAUGURAL PLAN AS  
3 COMPARED TO THE PROPOSED PLAN?

4 A. The Companies plan to increase the number of fire cameras across the State. The  
5 Companies do not have specific plans to expand the standalone weather stations at  
6 this time, but may need to expand these if necessary, as discussed below.

7  
8 The Companies also plan to expand the use of Alchera FireScout AI technology in  
9 collaboration with the Bureau of Land Management (“BLM”). The Companies are  
10 continuing to do weekly fuel moisture samples across their heightened risk areas,  
11 with additional fuel sampling sites expected this year. Lastly, the Companies have  
12 a pilot project beginning this summer to install and use “FireBIRD” devices which  
13 are combined fire cameras/weather stations.

14  
15 17. Q. PLEASE PROVIDE MORE DETAIL REGARDING THE COMPANIES’  
16 EFFORTS TO INSTALL NEW WEATHER STATIONS ACROSS TIERED  
17 AREAS.

18 A. At this time, the Companies will continue to monitor and assess the current 65  
19 weather stations across the state to see if additional weather stations will be needed  
20 in the future. If there are areas that are identified that do not have enough coverage  
21 of weather stations and data, the Companies may need to ask for additional funding  
22 for weather stations in the future.

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1 18. Q. ARE THE COMPANIES CONTINUING TO INSTALL NEW WILDFIRE  
2 DETECTION CAMERAS?

3 A. Yes. The Companies plan to add ten additional cameras in partnership with  
4 University of Nevada, Reno, which will bring the total to 21 fire cameras. The  
5 Companies are also planning additional cameras through a partnership with the  
6 BLM. Through this partnership, the BLM is planning to install two new fire  
7 cameras on NV Energy infrastructure. This partnership will help the Companies to  
8 reduce the cost of adding additional cameras, as BLM will fund deployment for  
9 these other cameras. That will bring the total to three BLM cameras installed on  
10 NV Energy infrastructure. These cameras are mutually beneficial to both the BLM  
11 and NV Energy for situational awareness in wildland-urban interface areas.

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13 19. Q. PLEASE PROVIDE DETAILS REGARDING THE COMPANIES' PLANS  
14 TO DEPLOY ALCHERA FIRESCOUT AI TECHNOLOGY AND  
15 COORDINATION WITH THE BLM.

16 A. The Companies are currently in a pilot project using Alchera FireScout AI to  
17 monitor the Companies' fire cameras 24 hours a day, seven days a week. The AI  
18 algorithm monitors each frame taken by the fire cameras and scans for potential  
19 smoke plumes or thermal heat signatures that could indicate a new or advancing  
20 wildfire. The AI will then send out alerts to leadership at NV Energy, as well as  
21 partnering fire agencies, that there is a potential new fire on a specific camera.  
22 Because there is an AI helping to monitor the fire cameras, this could potentially  
23 result in a faster response to a wildfire by fire agencies, thus reducing risk to Nevada  
24 communities and NV Energy infrastructure.

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The Companies plan to expand their Alchera FireScout technology to the additional NV Energy cameras that will be installed in 2023 and beyond, as well as any additional cameras that will be installed through the BLM partnership discussed in Q&A 20, above.

**20. Q. PLEASE PROVIDE DETAILS REGARDING THE COMPANIES' PLANS TO DEPLOY FIREBIRD CAMERAS.**

A. FireBIRD is the name of an autonomous fire detection/weather station technology that is made by a company called Lindsey FireSense. Each FireBIRD device has eight cameras, six pointed in a downward direction and two lateral view cameras. These are to be used on targeted key right-of-ways to try to detect wildfires that are threatening or potentially caused by the electrical grid. These cameras are different from the current cameras that the Companies currently have, because they can be added directly onto specific power lines that have an extreme fire risk. They have a combined use as a weather station as well, measuring wind speed, direction, temperature, and humidity. The Companies are planning to start a pilot project for about six devices through Lindsey FireSense this summer in Southern Nevada. During the pilot project, the Companies will monitor the FireBIRD weather stations and fire cameras for dependable connection, data uploading, and timely alerts of any new wildfire detections. The Companies will use this data to evaluate the pilot project and determine whether to expand FireBIRD cameras use to other parts of the State.

21. Q. PLEASE PROVIDE THE BUDGET FOR THE SITUATIONAL AWARENESS PROGRAMS DETAILED IN YOUR TESTIMONY.

A. Table one describes the Situational Awareness OMAG budget for 2024-2026. Table 2 describes the Situational Awareness Capital Budget for 2024-2026.

**Table 1. Situational Awareness OMAG Budget**

OMAG	2024-2026 Budget	2024 Forecast	2025 Forecast	2026 Forecast
Weather Stations	426,929	138,125	142,268	146,536
NPC	69,504	22,487	23,161	23,856
SPPC	357,425	115,638	119,107	122,680
Wildfire Cameras	1,362,557	388,000	457,080	517,477
NPC	199,163	46,000	69,810	83,353
SPPC	1,163,394	342,000	387,270	434,124

**Table 2. Situational Awareness Capital Budget**

Capital	Budget	Forecast	Forecast	Forecast
Wildfire Cameras	\$ 1,840,129	\$ 592,400	\$ 613,135	\$ 634,594
NPC	\$ 389,211	\$ 125,300	\$ 129,686	\$ 134,225
SPPC	\$ 1,450,918	\$ 467,100	\$ 483,449	\$ 500,369

22. Q. PLEASE PROVIDE DETAILS REGARDING THE COMPANIES' PLANS TO DEPLOY TECHNOSYLVA WILDFIRE RISK ANALYSIS SOFTWARE.

A. The Companies' first deployment of Technosylva FireSim and FireCast was rolled out in early October 2022. FireCast and FireSim have shown promise, but the pilot project will continue into the 2023 fire season so that the Companies can evaluate the effectiveness of the analysis software with fire events and potential public safety outage management events.

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The Companies have also continued to work closely with Technosylva to pilot the Wildfire Risk Reduction Model (“WRRM”), which will be delivered in March 2023. If the pilot project is successful, the Technosylva WRRM is anticipated to be used as part of the Companies plan for vegetation management, inspections, and system hardening prioritization, as discussed in Sections 2.4, 2.5, and 2.6 of the plan. Technosylva is included in the Proactive Technology and Asset Management part of the plan.

**23. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

A. Yes.

**STATEMENT OF QUALIFICATIONS OF  
Alexander D. Hoon  
Senior Meteorologist, Natural Disaster Protection  
NV Energy  
6100 Neil Rd. Reno, NV 89511  
(775) 298-9050 alexander.hoon@nvenergy.com**

Mr. Hoon has been an employee of NV Energy a little over a year but has 20 years of operational weather forecasting experience. He has worked in many positions through his career, from the U.S. Air Force to the National Weather Service, specializing in fire weather and emergency response. Mr. Hoon has a Bachelor of Science degree in Atmospheric Science. He is also a veteran Incident Meteorologist and has deployed to over 25 major wildfire incidents across the Western U.S. to provide critical weather data to fire leadership and firefighters in field.

### **Professional Experience**

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***Senior Meteorologist, Natural Disaster Protection – NV Energy, Reno, NV ▪ 2021 – present***

- Prepares and disseminates operational weather reports prior to and during significant weather events, including Public Safety Power Shutoffs (PSOM).
- Integrates a wide range of meteorological data to provide continuously updated weather information to better manage the impacts of weather on the electric system and identified vulnerabilities.
- Monitors and reports to upper management real-time and forecast weather conditions on a recurring basis during storm events and major construction operational events.
- Continually maintains and enhances procedures for monitoring the company's weather network and associated alerting, including the siting of new weather stations and fire cameras.
- Improve all real-time and operational forecasts through process improvements via new technologies and advancements.
- Work closely with engineering and operational organizations to integrate weather information into fire risk mitigation and system hardening projects.
- Serves as the company's subject matter expert for all fire weather-related matters.

***Senior Meteorologist and Incident Meteorologist – National Weather Service, Reno, NV ▪ 2010 – 2021***

- Served as the shift leader responsible for quality and timeliness of all National Weather Service (NWS) forecast and service products, warnings, and advisories prepared and issued by the Weather Forecast Office (WFO).
- As incident meteorologist, embedded with Incident Management Teams to work with operations, logistics, safety, and planning of emergency situations. Briefed teams, cooperators, community leaders, public safety, and general public on the weather threats that are specific to their areas of concern.

***General Meteorologist – National Weather Service, Reno, NV ▪ 2010 – 2021***

- Conduct a weather watch which involves interpretation of Doppler radar data, satellite imagery, and the analysis of other hydrometeorological data for the preparation of all WFO warning, forecast and service products, including individual briefings.
- Serve as primary contact with other Federal, state, and local agencies such as Federal Aviation Administration (FAA), Federal Emergency Management Agency (FEMA), and emergency management and law enforcement officials over matters involving the initiation and implementation of immediate or emergency public health and safety measures based on NWS forecasts, warnings and watches.

***Weather Officer, Lead Forecaster – U.S. Air Force, Scott AFB, IL ▪ 2003 – 2006***

- Directed complex forecast production processes through detailed weather analysis and numerical model interpretations.
- Provided written forecast guidance and daily weather briefings to squadron and field unit forecasters that was leveraged in producing and disseminating tailored regional graphics, DOD installation forecasts, weather watches, warnings, and advisories, as well as air crew mission forecasts.

**Education and Certifications**

Bachelor of Science in Atmospheric Science – Texas A&M University, College Station, TX ▪ 2003  
Type 1 Incident Meteorologist – National Wildland Coordinating Group ▪ 2011

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AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ALEXANDER HOON, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2023

  
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ALEXANDER HOON