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 2027-2046 integrated resource plan, 2027-2029 Action Plan and 2027-2029 Energy Supply Plan.	Docket No. 26-05___

VOLUME 29 OF 41

TECHNICAL APPENDIX
TRASMISSION PLAN

TRAN-1

FILED UNDER CONFIDENTIAL SEAL

TRAN-2

FILED UNDER CONFIDENTIAL SEAL

TRAN-3

FILED UNDER CONFIDENTIAL SEAL

TRAN-4

FILED UNDER CONFIDENTIAL SEAL

TRAN-5

FILED UNDER CONFIDENTIAL SEAL

TRAN-6

FILED UNDER CONFIDENTIAL SEAL

TRAN-7

FILED UNDER CONFIDENTIAL SEAL

TRAN-8

FILED UNDER CONFIDENTIAL SEAL

TRAN-9

FILED UNDER CONFIDENTIAL SEAL

TRAN-10

FILED UNDER CONFIDENTIAL SEAL

TRAN-11

NEVADA POWER COMPANY D/B/A NV ENERGY (NVES)
SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY (NVEN)

APPENDIX TRAN-11

FT SAGE - PSREC TIA FOR FT. SAGE INTERCONNECTION 11-3-24 EXECUTED

March 2026

TRANSMISSION INTERCONNECTION AGREEMENT

SERVICE AGREEMENT #24-000067

Between

SIERRA PACIFIC POWER COMPANY d/b/a NV ENERGY

and

PLUMAS SIERRA RURAL ELECTRIC COOPERATIVE

Dated as of
11/3/2024

Table of Contents:

APPENDIX

TRANSMISSION INTERCONNECTION AGREEMENT

This TRANSMISSION INTERCONNECTION AGREEMENT (the "Agreement") dated 11/3/2024 is entered into by and between SIERRA PACIFIC POWER COMPANY d/b/a NV Energy ("SPPC"), a Nevada corporation, as the owner of the SPPC Transmission System. SPPC and PLUMAS SIERRA RURAL ELECTRIC COOPERATIVE ("Plumas Sierra") are sometimes referred to herein individually as a "Party" and collectively as the "Parties."

WITNESSETH:

WHEREAS, SPPC owns and operates the SPPC Transmission System; and

WHEREAS, Plumas Sierra owns its own transmission system within the California Independent System Operator's Balancing Authority Area; and

WHEREAS, the Parties seek to establish an electrical interconnection between their respective transmission systems; and

WHEREAS, the SPPC Transmission System is currently interconnected to the Plumas Sierra transmission system at the Marble Substation and the Parties would like to establish an additional interconnection point at SPPC's Ft. Sage Substation; and

WHEREAS, SPPC and Plumas Sierra desire to set forth in this Agreement the requirements, scope, and terms and conditions for the interconnection interconnecting their respective transmission systems, and to define the continuing responsibilities and obligations of the Parties with respect thereto.

NOW, THEREFORE, in consideration of the mutual representations, covenants, and agreements hereinafter set forth, and intending to be legally bound hereby, the Parties hereto agree as follows:

ARTICLE 1
DEFINITIONS

1.1 **Definitions**. Wherever used in this Agreement with initial capitalization, the following terms shall have the meanings specified or referred to in this ARTICLE 1.

"Abnormal Condition" shall mean any condition on a Party's transmission system or the transmission system of other utilities which is outside normal operating parameters such that facilities are operating outside their normal ratings or reasonable operating limits for the facilities have been exceeded but which has not resulted in an Emergency. An Abnormal Condition may include, but is not limited to, high or low deviations in voltage, frequency, power flow, equipment temperature, equipment pressures, or other operating parameters.

"Affected System" shall mean an electric system other than the Interconnection Provider's Transmission System that may be affected by the proposed interconnection.

"Affiliate" shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

"Agreement" shall mean this Transmission Interconnection Agreement by and between SPPC and Plumas Sierra, including all appendices attached hereto, as the same may be amended, supplemented, revised, altered, changed or restated in accordance with its terms.

"Balancing Authority" shall mean Nevada Power Company in its role as the registered Balancing Authority for the NPC and SPPC transmission systems.

"Balancing Authority Area" shall mean the collection of generation, transmission and loads within the metered boundaries of the NPC and SPPC transmission systems.

"Breach" shall mean the failure of a Party to perform or observe any material term or condition of this Agreement.

"Breaching Party" shall mean a Party that is in Breach of this Agreement.

"Commercial Operation Date" shall mean the date on which the Interconnection Facilities are completed and commence Commercial Operation as agreed to by the Parties pursuant to Appendix B of this Agreement and transmission service under the Network Integration Transmission Service Agreement commences.

"Confidential Information" shall have the meaning set forth in ARTICLE 17 of this Agreement.

"Default" shall have the meaning set forth in ARTICLE 14 of this Agreement.

"Effective Date" shall have the meaning set forth in ARTICLE 2 of this Agreement.

"Electric Reliability Organization" shall mean the organization certified by FERC to propose and enforce mandatory standards for the reliable operation and planning of the bulk power system throughout the United States of America.

"Emergency" shall mean a condition or situation which is deemed likely to endanger public safety and/or health, life, or property, or imminently likely to cause an adverse effect (as determined in accordance with Prudent Utility Practices) on the Parties' transmission systems or transmission systems of others to whom the Parties are indirectly connected.

"FERC" shall mean the Federal Energy Regulatory Commission or its successor.

"Force Majeure" shall have the meaning set forth in ARTICLE 13 of this Agreement.

"FPA" shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq. as it may be amended from time to time.

"Hazardous Substances" shall mean those substances, materials, products, or wastes which are classified as hazardous or toxic under any applicable Law proposed or in effect as of the date of execution of this Agreement.

"Indemnifying Party" shall have the meaning set forth in ARTICLE 11 of this Agreement.

"In-Service Date" shall mean the date upon which the Interconnection Customer reasonably expects to energize the Interconnection Facilities.

"Interconnection Facilities" shall mean those facilities described in Appendices A and B and depicted in the one-line diagram in Appendix C.

"Interconnection Customer" shall mean the Party interconnecting to the Interconnection Provider's Transmission System at the Point(s) of Interconnection.

"Interconnection Provider" shall mean Sierra Pacific Power Company in its role as owner and operator of the Sierra Pacific Power Company Transmission System.

"Interconnection Provider's Transmission System" shall mean the transmission system facilities owned and operated jointly by Sierra Pacific Power Company and Nevada Power Company (or their successors) used for the provision of transmission services under the NV Energy OATT.

"Law" shall mean any federal, state and local law, statute, ordinance, regulation, order, action, policy or other governmental requirement, as amended or that may be enacted or promulgated subsequently.

"Metering Equipment" shall have the meaning set forth in ARTICLE 4 of this Agreement.

"Modification" shall mean any new construction, additions, alterations, design changes or the abandonment, retirement, relocation or rearrangement of the Parties' transmission systems or Interconnection Facilities.

"NERC" shall mean North American Electric Reliability Corporation or its successor.

"NESC" shall mean the National Electrical Safety Code, as may be amended from time to time.

"Network Upgrades" shall mean the additions, modifications, and upgrades to the Interconnection Provider's Transmission System required at or beyond the point at which the Interconnection Customer's Interconnection Facilities connect to the Interconnection Provider's Transmission System.

"NPC" shall mean Nevada Power Company d/b/a NV Energy and its permitted successors and assigns.

"NV Energy OATT" shall mean that certain Open Access Transmission Tariff on file with FERC and designated NV Energy, Inc. Operating Companies Open Access Transmission Tariff as it may be amended or superseded from time to time.

"Operational Change" shall mean any material change in the day-to-day routine, practices or procedures pertaining to the operation of either Party's transmission system but excluding any change in connection with either a planned or unplanned outage or an Emergency.

"OSHA" shall mean the Occupational Safety and Health Administration or its successor.

"Point of Change of Ownership" shall mean the points at which SPPC ownership of the Interconnection Provider's Transmission System end and the Plumas Sierra's ownership of its transmission facilities begin, as depicted in the one-line diagram in Appendix C.

"Point(s) of Interconnection" shall mean the point, as depicted in the one-line diagram in Appendix C, where the Interconnection Facilities connect to the Interconnection Provider's Transmission System.

"Prudent Utility Practice" shall mean any of the acts, practices, methods, equipment, materials, specifications and standards engaged in or approved in connection with a significant portion of the electric utility industry which, as applicable, in the exercise of professional judgment in light of the facts known at the time a decision was made, could have been expected to accomplish the desired result in a manner consistent with applicable Laws, Electric Reliability Organization requirements, reliability, safety, performance, dependability, efficiency, environmental protection, economy and expedition. Prudent Utility Practices are not intended to be limited to the optimum practice or method to the exclusion of other practices or methods, but rather to be a spectrum of possible but reasonable practices and methods.

"PUCN" shall mean the Public Utilities Commission of Nevada, or its successor.

"Regulatory Requirements" shall mean any of the applicable practices, methods and acts required by NERC, FERC, OSHA, PUCN and the WECC, or other governmental agencies or regional entity having jurisdiction over the Parties with regard to the subject matter of this Agreement, or the successor of any of them.

"Reasonable Efforts" shall mean, with respect to an action required to be attempted or taken by a Party under this Agreement, efforts that are timely and consistent with Prudent Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

"SPPC" shall mean Sierra Pacific Power Company d/b/a NV Energy, and its successors in interest.

"SCADA" shall mean Supervisory Control and Data Acquisition equipment.

"Switching and Tagging" shall mean the Parties' switching and tagging procedures, as they may be amended from time to time.

"System Protection Facilities" shall mean the equipment, including necessary protection signal communications equipment, required to protect (i) the Interconnection Provider's Transmission System from faults or other electrical disturbances occurring on Interconnection Customer's Interconnection Facilities and (ii) Interconnection Customer's Interconnection Facilities from faults or other electrical system disturbances occurring on the Interconnection Provider's

Transmission System or on other delivery systems or other generating systems to which the Interconnection Provider's Transmission System is directly connected.

"WECC" shall mean the Western Electricity Coordinating Council, or its successor.

ARTICLE 2
EFFECTIVE DATE, TERM, SUSPENSION, AND TERMINATION

2.1 **Effective Date**. The Effective Date of this Agreement shall be the date of executing by the Parties, or such other effective date established by the FERC.

2.2 **Term.** This Agreement shall remain in full force and effect from the Effective Date until or unless terminated in accordance with this ARTICLE 2.

2.3 **Suspension.** Interconnection Customer reserves the right, upon written notice to Interconnection Provider, to suspend at any time all work by Interconnection Provider associated with the construction and installation of Interconnection Provider's Interconnection Facilities required under this Agreement with the condition that Interconnection Provider's Transmission System shall be left in a safe and reliable condition in accordance with Prudent Utility Practice and Interconnection Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Interconnection Provider (i) has incurred pursuant to this Agreement prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Interconnection Provider's Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Interconnection Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Interconnection Provider shall obtain Interconnection Customer's authorization to do so. Interconnection Provider shall invoice Interconnection Customer for such costs pursuant to ARTICLE 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Interconnection Provider required under this Agreement pursuant to this Section 2.3, and has not requested Interconnection Provider to recommence the work required under this Agreement on or before the expiration of three (3) years following commencement of such suspension, this Agreement shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Interconnection Provider, if no effective date is specified.

2.4 **Termination.**

2.4.1 This Agreement may be terminated at any time by mutual agreement of the Parties.

2.4.2 Either Party may terminate this Agreement, upon the occurrence of any the following events: (i) permanent removal of the Interconnection Provider's Interconnection Facilities or the Interconnection Customer's Interconnection Facilities from service, which shall occur only upon mutual agreement; (ii) in an event of Default as provided in ARTICLE 14; or (iii) upon a request to FERC subject to the provisions of Section 205 or 206 of the FPA by any Party seeking termination of this Agreement.

2.4.3 **Termination Costs**. If a Party elects to terminate this Agreement pursuant to Section 2.4, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the non-terminating Party's receipt of such notice of termination, that are the responsibility of the terminating Party under this Agreement. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination.

2.4.4 **FERC Approval**. No termination hereunder shall become effective until the Party seeking termination tenders to FERC notice of termination of this Agreement and FERC has accepted such notice of termination, to the extent required by FERC regulations.

2.4.5 **Disconnection**. Upon termination of this Agreement, the Parties will take all appropriate steps to disconnect the Interconnection Customer's Interconnection Facilities from the Interconnection Provider's Transmission System. All costs required to effectuate such disconnection shall be borne by the Interconnection Customer, unless such termination resulted from Interconnection Provider's Default of this Agreement or the Interconnection Provider is otherwise expressly provided as responsible for these costs under this Agreement.

2.4.6 **Survival**. This Agreement shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this Agreement; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this Agreement or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

2.5 **Regulatory Filing**. Interconnection Provider shall file this Agreement with FERC for filing pursuant to the FERC's Rules and Regulations under 18 C.F.R. Part 35. The Interconnection Customer agrees to reasonably cooperate with the Interconnection Provider with respect to such filing and to provide any information, including the filing of testimony, reasonably requested by Interconnection Provider, to comply with applicable Regulatory Requirements.

ARTICLE 3
PURPOSE AND SCOPE

3.1 **Purpose**. The purpose of this Agreement is to set forth the scope, terms and conditions for the interconnection of the Interconnection Customer's Interconnection Facilities to the Interconnection Provider's Transmission System, along with the continuing responsibilities and obligations related to such interconnection.

3.2 **Scope**. This Agreement pertains only the terms and conditions of the electric interconnections described herein.

3.2.1 The execution of this Agreement does not constitute a request for, nor the provision of, any transmission delivery service under the NV Energy OATT, and does not convey any right to deliver electricity to any specific customer or point of delivery. Interconnection Provider makes no representations to Interconnection Customer regarding the availability of transmission service

on the Interconnection Provider's Transmission System, and Interconnection Customer agrees that the availability of transmission service on the Interconnection Provider's Transmission System may not be inferred or implied from Interconnection Provider's execution of this Agreement. If Interconnection Customer desires to obtain transmission service on the Interconnection Provider's Transmission System, Interconnection Customer must request such service in accordance with the provisions of the NV Energy OATT.

3.2.2 Pursuant to the Network Integration Transmission Service Agreement, executed by the parties on July 2, 2024, which may be amended from time to time, capacity has been granted to Interconnection Customer by the Interconnection Provider through the Interconnection Facilities contemplated by this agreement.

3.2.3 Nothing in this Agreement shall be interpreted as a request by Interconnection Customer or a commitment by Interconnection Provider to install any facilities other than those identified in Appendix A.

ARTICLE 4
INTERCONNECTION FACILITIES

4.1 **Engineering, Procurement and Construction of Interconnection Customer's Interconnection Facilities**

4.1.1 Interconnection Customer shall, at its sole expense, engineer, procure equipment for, and construct the Interconnection Customer's Interconnection Facilities, as set forth in Appendix A, using Prudent Utility Practice and standards and specifications provided in advance by Interconnection Provider and in compliance with all Regulatory Requirements.

4.1.2 Interconnection Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall make such changes to the Interconnection Facilities as may reasonably be required by Interconnection Provider, in accordance with Prudent Utility Practice and all Regulatory Requirements, to ensure that the Interconnection Facilities are compatible with the technical specifications, operational control, and safety requirements of Interconnection Provider. Interconnection Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Interconnection Facilities.

4.1.3 Prior to commencement of construction, Interconnection Customer shall provide to Interconnection Provider a schedule for construction of the Interconnection Facilities, and shall promptly respond to requests for information from Interconnection Provider.

4.1.4 At any time during construction, Interconnection Provider shall have the right to gain access to the Interconnection Facilities and to conduct inspections of the same, subject to the requirements of Section 6.3.

4.1.5 At any time during construction, should any phase of the engineering, equipment procurement, or construction of the Interconnection Facilities not meet the standards and

specifications provided by Interconnection Provider, Interconnection Customer shall be obligated to remedy any such deficiencies, and will be responsible for the costs of remedying such deficiencies.

4.1.6 Interconnection Customer shall indemnify Interconnection Provider for claims arising from the interconnection of the Interconnection Facilities to the Interconnection Provider's Transmission System under the terms and procedures of Section 11.1.

4.1.7 Within one hundred twenty (120) days after completion, Interconnection Customer shall deliver to Interconnection Provider "as-built" drawings, information, and any other documents that are reasonably required by Interconnection Provider to assure that the Interconnection Facilities are built to the standards and specifications required by Interconnection Provider and in compliance with all Regulatory Requirements.

4.2 Interconnection Provider's Interconnection Facilities and Network Upgrades

4.2.1 In accordance with ARTICLE 5, the Interconnection Customer shall pay for the cost of the Interconnection Provider's Interconnection Facilities itemized in Appendix A of this Agreement and the Interconnection Customer shall securitize the cost of the Network Upgrades itemized in Appendix A of this Agreement.

4.2.2 **Special Provisions for Affected Systems**. The Interconnection Customer will work with any Affected Systems to mitigate impacts to the Affected Systems. The Interconnection Customer will be responsible to coordinate the payment of any required facilities by Affected Systems outside of this Agreement.

4.3 Metering

4.3.1 **General**. Interconnection Customer shall comply with the applicable Electric Reliability Organization requirements. Unless otherwise agreed by the Parties, Interconnection Provider shall install "Metering Equipment", at Interconnection Customer's expense, at the Point of Interconnection, or at another metering point compensated to the Point of Interconnection, prior to any operation of Interconnection Customer's Interconnection Facilities and shall own, operate, test and maintain such Metering Equipment. If Interconnection Provider's Metering Equipment is not installed at the Point of Interconnection, Interconnection Customer shall have the right to review the programming to be used by Interconnection Provider in the metering arrangement involving compensation to the Point of Interconnection. Such programming will use industry standard concepts and algorithms along with site specific values. If Interconnection Customer has different site specific values than those determined by Interconnection Provider, Interconnection Customer shall forward its calculations to Interconnection Provider for review and reconciliation. Power flows to and from the Interconnection Customer's transmission system shall be measured at or, at Interconnection Provider's option, compensated to the Point of Interconnection. The meters will be programmed to measure real power flow (in kilowatthours) and reactive power flow (in kilovarhours) in both directions independently. Interconnection Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall be responsible for the costs associated with any equipment required in order for it to receive such metering quantities.

4.3.2 **Standards**. Interconnection Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable American National Standards Institute ("ANSI") standards.

4.3.3 **Testing of Metering Equipment**. Interconnection Provider shall inspect and test all Interconnection Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Interconnection Provider shall, at Interconnection Customer's expense, inspect or test such Metering Equipment more frequently than every two (2) years. Interconnection Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time the Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced, at the expense of Interconnection Customer, in order to provide accurate metering. If the Metering Equipment fails to register, or if the measurement made by the Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Interconnection Provider shall adjust the measurements by correcting all measurements for the period during which the Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

4.3.4 **Metering Data**. Each Party shall have the right to retrieve metering data from the Metering Equipment. At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Interconnection Provider and to one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from and/or to the Point of Interconnection.

4.4 Communications

4.4.1 **Relay and Line Protection**. Relay communications shall be provided via dedicated path in accordance with WECC requirements for protection of transmission lines interconnecting two (2) electric utilities and in accordance with Interconnection Provider's standards.

4.4.2 **Fiber**. The relay path shall be provided via fiber optic cable. System protection using the fiber optic cable shall be performed using relays that support a direct fiber interface such as the Schweitzer Engineering Laboratories (SEL) 311L. Interconnection Provider will identify the specific type and model of relays to be used by both Interconnection Provider and Interconnection Customer.

4.4.3 **Cost Sharing of Fiber**. Any sharing of costs for fiber optic cable and/or any provision of an Indefeasible Right of Use ("IRU") in any fiber optic cable by Interconnection Provider to Interconnection Customer or by Interconnection Customer to Interconnection Provider will be addressed in a separate agreement between the Parties.

4.4.4 **No Annexation**. Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

ARTICLE 5
COST RESPONSIBILITY FOR INTERCONNECTION FACILITIES AND NETWORK UPGRADES

5.1 Interconnection Facilities

5.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities as itemized in Appendix A of this Agreement. The Interconnection Provider shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs will be invoiced according to ARTICLE 12 and the Milestones in Appendix B to this Agreement.

5.1.2 In accordance with ARTICLE 6, the Interconnection Customer shall be responsible for all expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Interconnection Provider's Interconnection Facilities.

5.2 Network Upgrades

5.2.1 Interconnection Provider shall design, procure, construct, install, and own the Network Upgrades described in Appendix A of this Agreement. The Interconnection Customer shall be responsible for securitizing all Network Upgrade costs per the Milestone in Appendix B of this Agreement. Such security shall be released once the Network Upgrades described in Appendix A of this Agreement are completed and the Commercial Operation Date attained, subject to the final audit in Appendix B of this Agreement. If the Commercial Operation Date is not attained, and the Network Upgrades described in Appendix A of this Agreement have been fully or partially constructed pursuant to the terms of this Agreement, the Interconnection Provider may draw upon the security provided to recover the costs of the Network Upgrades that have been constructed to date.

ARTICLE 6
OPERATIONS AND MAINTENANCE

6.1 **Interconnection Provider Obligations**. Interconnection Provider shall own, operate and maintain the Interconnection Provider's Transmission System in accordance with Prudent Utility Practice.

6.2 **Interconnection Customer Obligations**. Unless otherwise agreed to by the Parties, the Interconnection Customer shall be responsible for the operations and maintenance expenses of the Interconnection Provider's Interconnection Facilities installed in accordance with Section 6.11 of this Agreement. Interconnection Customer shall at its own expense, operate and maintain the

Interconnection Customer's Interconnection Facilities on its side of the Point(s) of Interconnection in accordance with Prudent Utility Practice.

6.3 **Access Rights**. Any Party performing work in connection with this Agreement ("accessing Party") under or in close proximity to the Interconnection Facilities shall (a) abide by all Laws and rules applicable to such work, including, but not limited to, all applicable NERC and WECC reliability standards and the requirements of the NESC, OSHA, and Chapter 455 of the Nevada Revised Statutes; and (b) perform all work in accordance with the electrical practices of the Party whose Interconnection Facilities are being accessed. In addition, when work is being performed in connection with this Agreement on real property that a Party has a right to use and may legally allow the accessing Party to use (the "Premises"), the accessing Party shall provide adequate prior notice, abide by all Laws applicable to the work and use of the Premises and comply with all safety, security and work rules applicable to the work and use of the Premises, whether required by Law or the other Party. For purposes of this section, "adequate prior notice" means at least ten (10) business days prior written notice to the other Party that identifies who will be accessing the Premises, the work that will be performed on the Premises, the dates and hours the work will be performed and provides a copy of all required permits. The other Party, at the accessing Party's cost, shall have the right to have a representative present during all times the accessing Party's personnel are on the premises.

6.4 **Operations**

6.4.1 **General**. Each Party shall comply with the applicable Electric Reliability Organization requirements. Interconnection Customer shall ensure that the operations of its Interconnection Customer's Interconnection Facilities are operated in accordance with requirements of the Balancing Authority Area. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with applicable Laws and Regulatory Requirements.

6.4.2 **Interconnection Provider Obligations**. Interconnection Provider shall cause the Interconnection Provider's Interconnection Facilities and Network Upgrades to be operated, maintained and controlled in a safe and reliable manner and in accordance with this Agreement and Prudent Utility Practice. Interconnection Provider shall provide operating instructions to Interconnection Customer consistent with this Agreement and Interconnection Provider's operating protocols and procedures as they may change from time to time. Interconnection Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

6.4.3 **Interconnection Customer Obligations**. Interconnection Customer shall at its own expense operate, maintain and control Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Agreement and Prudent Utility Practice. Interconnection Customer shall operate Interconnection Customer's Facilities in accordance with all applicable requirements of Interconnection Provider's Balancing Authority Area.

6.4.4 **Voltage Control and Supply of Reactive Power**. Each Party shall use Reasonable Efforts in accordance with Prudent Utility Practice to limit variations and fluctuations in voltages and to meet reactive power requirements of its respective system and loads so as to minimize

adverse effects upon the operation of the electrical facilities or system of the other Party. Interconnection Customer shall also acquire sufficient reactive resources within its transmission system to protect the voltage levels under normal and contingency conditions. This includes the Interconnection Customers' share of the reactive requirements for generators interconnecting to the Interconnection Customer's transmission system.

6.5 **Outages and Interruptions.**

6.5.1 **Outage Authority and Coordination**. Each Party may, in accordance with Prudent Utility Practice and in coordination with the other Party, remove from service any of its respective Interconnection Facilities that may impact the other Party's Interconnection Facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

6.5.2 **Outage Schedules**. Interconnection Provider shall post scheduled outages of its transmission facilities on its Open Access Same-Time Information System ("OASIS"). Interconnection Customer shall submit its planned maintenance schedules for Interconnection Customer's Interconnection Facilities to Interconnection Provider a minimum of sixty (60) days in advance of the commencement of any such maintenance. Interconnection Customer shall update its planned maintenance schedules as necessary. Interconnection Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Interconnection Provider's Transmission System.

6.5.3 **Outage Restoration**. If an outage on a Party's facilities adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

6.5.4 **Unplanned Outages**. In the event of an unplanned outage of a Party's transmission system that adversely affects the other Party's transmission system, each Party will use efforts consistent with Prudent Utility Practice and applicable Regulatory Requirements to restore the facility(ies) to service as soon as is practicable.

6.6 **System Protection and Other Control Requirements**.

6.6.1 Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of Interconnection Customer's Interconnection Facilities. Interconnection Provider shall install at its expense any System Protection Facilities that may be required on Interconnection Provider's Interconnection Facilities or the Interconnection Provider's

Transmission System as a result of the interconnection of Interconnection Customer's Interconnection Facilities to the Interconnection Provider's Transmission System.

6.6.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Prudent Utility Practice.

6.6.3 Each Party shall be responsible for protection of its Interconnection Facilities consistent with Prudent Utility Practice.

6.6.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in this ARTICLE 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or tripping of the Interconnection Facilities.

6.6.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Prudent Utility Practice.

6.6.6 Prior to the Commercial Operation Date each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Prudent Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. Such tests require that all protective relays and lockout contacts be activated.

6.6.7 **Requirements for Protection**. In compliance with Prudent Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of Interconnection Customer's Interconnection Facilities to any short circuit occurring on the Interconnection Provider's Transmission System not otherwise isolated by Interconnection Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Interconnection Provider's Transmission System. Interconnection Customer shall be solely responsible to disconnect Interconnection Customer's Interconnection Facilities if conditions on the Interconnection Provider's Transmission System could adversely affect Interconnection Customer.

6.7 **Switching and Tagging Rules**. Each Party shall provide the other Party a copy of its Switching and Tagging rules that are applicable to the other Party's activities. Such Switching and Tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable Switching and Tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

6.8 **Disturbance Analysis Data Exchange**. The Parties will cooperate with one another in the analysis of disturbances to either Interconnection Customer's transmission system or the Interconnection Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Prudent Utility Practice.

6.9 **Maintenance**

6.9.1 **Interconnection Provider Obligations**. Interconnection Provider shall maintain the Interconnection Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this Agreement and the requirements of the Balancing Authority Area.

6.9.2 **Interconnection Customer Obligations**. Interconnection Customer shall maintain Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Agreement.

6.9.3 **Coordination.** The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Facilities.

6.9.4 **Secondary Systems**. Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

6.10 **Inspections and Testing**.

6.10.1 **Inspections**. The Parties shall perform routine inspection and testing of their respective Interconnection Facilities in accordance with Prudent Utility Practice and applicable Regulatory Requirements as may be necessary to ensure the continued operations of each Party's transmission systems in a safe and reliable manner.

6.10.2 **Right to Observe Testing**. The Parties shall have the right to observe the testing of the other Party's Interconnection Facilities, the performance of which testing may reasonably be expected to affect the reliability of the observing Party's Interconnection Facilities. The observing Party shall provide the other Party reasonable advanced notice of such testing, to the extent practicable.

6.10.3 **Observation of Deficiencies**. If either Party observes any condition it believes may be inconsistent with Prudent Utility Practice and applicable Regulatory Requirements with respect to the other Party's Interconnection Facilities that might reasonably be expected to adversely affect the observing Party's Interconnection Facilities, the observing party shall notify the other Party. Notwithstanding the forgoing, the observing Party shall have no liability for failure to give such notice.

6.11 **Operating and Maintenance Expenses**. For the term of the Agreement, Interconnection Customer shall reimburse Interconnection Provider for all reasonable expenses, including overheads, associated with operating, maintaining, repairing, and replacing Interconnection Provider's Interconnection Facilities. Any such charges under this section shall be invoiced annually according to ARTICLE 12.

ARTICLE 7
EMERGENCIES

7.1 **Generally**. Each Party agrees to comply with the emergency procedures set forth by the NERC and/or WECC, or the direction of the applicable Balancing Authority, or other Regulatory Requirements.

7.2 **Notice**. Each Party shall provide the other Party with verbal notification that is prompt under the circumstances of an Emergency that may reasonably be expected to affect the other Party's transmission system, to the extent the notifying Party is aware of the Emergency.

7.3 **Immediate Action**. In the event of an Emergency, the Party becoming aware of the Emergency may, in accordance with Prudent Utility Practice and applicable Regulatory Requirements and using its reasonable judgment, take such action with respect to its own facilities as is reasonable and necessary to prevent, avoid, or mitigate injury, danger and/or loss of life or property. The Parties shall, consistent with Prudent Utility Practice and applicable Regulatory Requirements, take whatever actions or inactions the Parties deem necessary during an Emergency, in order to: (i) preserve public health and safety; (ii) preserve the reliability of the Interconnection Provider's Transmission System; (iii) limit or prevent damage; and (iv) expedite restoration of service.

7.4 **Abnormal Conditions**. To the extent either Party is aware of any Abnormal Condition, such Party, subject to the satisfaction of and compliance with Regulatory Requirements, will make reasonable efforts to promptly notify the other Party of such Abnormal Condition if it may reasonably be expected to affect that Party's use of its Interconnection Facilities. However, the failure of any Party to provide notice in conformance with this Section 7.4 shall not constitute a material breach of this Agreement.

ARTICLE 8
MODIFICATIONS OR OPERATIONAL CHANGES

8.1 **Generally**. Each Party may make Modifications or Operational Changes to its transmission system, at its own expense, on its side of the Point(s) of Interconnection.

8.2 **Notice**. Each Party shall provide notice of planned Modifications or Operational Changes to WECC in the manner and form required by WECC procedures prior to making any such Modifications or Operational Changes and in accordance with all applicable Regulatory Requirements.

ARTICLE 9
ENVIRONMENTAL RELEASES

Each Party shall notify the other Party, first verbally and then in writing, of the release of or discovery of any Hazardous Substances (including, without limitation, asbestos-containing materials and polychlorinated biphenyls) while conducting the activities contemplated under this Agreement. Initial verbal notification shall be as soon as possible after discovery but in no event later than twenty-four (24) hours after the Party becomes aware of the occurrence or condition. Each of the Parties shall take all appropriate measures to assure that any contractors engaged by

such Party are obligated to timely communicate to said Party any release or discovery of Hazardous Substances associated with their contracted activities.

ARTICLE 10
ASSIGNMENT

10.1 **Successors and Assignees**. Following the Effective Date, this Agreement, and the rights and obligations created thereby, shall bind and inure to the benefit of the successors, and permitted assignees of the Parties.

10.2 **Consent**. No Party hereto may assign any rights or obligations hereunder without obtaining the written consent of the other Party, which consent shall not unreasonably be withheld, except transfers by operation of law, consolidation or merger, for the purpose of granting to a secured party a security interest in this Agreement pursuant to a mortgage, indenture or other security instrument, or a sale by one of the parties of its entire electric utility facilities. Notwithstanding the foregoing, either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement.

ARTICLE 11
INDEMNITY, CONSEQUENTIAL DAMAGES, AND INSURANCE

11.1 **Indemnity.** Each Party shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inaction of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

11.1.1 **Indemnified Person**. If an indemnified person is entitled to indemnification under this ARTICLE 11 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Section 11.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

11.1.2 **Indemnifying Party**. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this ARTICLE 11, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

11.1.3 **Indemnity Procedures**. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Section 11.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceeding if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be unreasonably withheld, conditioned or delayed.

11.2 **Consequential Damages.** In no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including, but not limited to, loss of profit or revenue, loss of the use of equipment, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.3 **Insurance.** Each Party shall, at its own expense, maintain in force throughout the period of this Agreement, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

11.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

11.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification), products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

11.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

11.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Fifteen Million Dollars ($15,000,000) per occurrence/Fifteen Million Dollars ($15,000,000) aggregate.

11.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this Agreement against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to the anniversary date of cancellation or any material change in coverage or condition.

11.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the polices are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

11.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

11.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to, and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

11.3.9 Within ten (10) days following execution of this Agreement, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required pursuant to this Agreement, executed by each insurer or by an authorized representative of each insurer.

11.3.10 Notwithstanding the foregoing, each Party may self-insure up to One Million Dollars ($1,000,000) in order to meet the minimum insurance requirements of Sections 11.3.1 through 11.3.7 to the extent it maintains a self-insurance program; provided, that such Party's self-insurance program meets the minimum insurance requirements of Sections 11.3.1 through 11.3.7.

Each Party may self-insure for amounts in excess of One Million Dollars ($1,000,000) in order to meet the minimum insurance requirements of Sections 11.3.1 through 11.3.7 to the extent it maintains a self-insurance program; provided, that such Party's senior secured debt is rated at investment grade or better by Standard & Poor's or Moody's and that its self-insurance program meets the minimum insurance requirements of Sections 11.3.1 through 11.3.7. For any period of time that a Party's senior secured debt is unrated or is rated at less than investment grade by Standard & Poor's or Moody's, such Party's self-insurance option shall be limited to One Million Dollars ($1,000,000). In the event that a Party is permitted to self-insure pursuant to this Section 11.3.10, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in this ARTICLE 11.

11.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Agreement.

ARTICLE 12
INVOICES

12.1 **General**. The Interconnection Provider shall submit to the Interconnection Customer invoices of amounts due in accordance with the Milestones as listed in Appendix B.

12.2 **Final Invoice for Interconnection Provider's Transmission Facilities**. Within six (6) months after completion of the construction of Interconnection Provider's Interconnection Facilities, Interconnection Provider shall provide an invoice of the final costs and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the amounts paid by Interconnection Customer and to ascertain deviations, if any, between the actual costs incurred by Interconnection Provider and the amount paid by Interconnection Customer. Interconnection Provider shall refund to Interconnection Customer, or Interconnection Customer shall pay to Interconnection Provider, any amount by which the actual payments made by Interconnection Customer to Interconnection Provider exceeds the actual costs of construction incurred by Interconnection Provider within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 **Annual Invoice for Operations and Maintenance**. On or about one year from the Effective Date, and annually henceforth for the term of the Agreement, Interconnection Provider shall invoice Interconnection Customer for the preceding year's operations and maintenance charges for the Interconnection Providers' Interconnection Facilities in accordance with Section 6.11 of this Agreement.

12.4 **Payment**. Invoices shall be rendered to the paying Party at the address specified in the Notices in Appendix D pursuant to the payment dates listed in the Milestones within Appendix B. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the invoicing Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this Agreement.

12.5 **Disputes**. In the event of a billing dispute between Interconnection Provider and Interconnection Customer, Interconnection Provider shall continue to provide Interconnection Service under this Agreement as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Interconnection Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Interconnection Provider may stop work under this Agreement and provide notice to Interconnection Customer of a Default pursuant to ARTICLE 14. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other

ARTICLE 13
FORCE MAJEURE

13.1 **General**. Notwithstanding anything in this Agreement to the contrary, neither Party shall be considered to be in default or breach of this Agreement or liable in damages or otherwise responsible to the other Party for any delay in or failure to carry out any of its obligations under this Agreement if, and only to the extent that, it is unable to perform or is prevented from performing by an event of Force Majeure. A Force Majeure exemption from liability will extend for the period of time necessitated by such event of Force Majeure. Such event of Force Majeure will not relieve either Party of its obligation to make payments hereunder.

13.2 **Definition**. The term "Force Majeure" as used herein means those causes beyond the reasonable control of the Party affected, which, through the exercise of Prudent Utility Practice and reasonable care, that Party could not have avoided or overcome and which wholly or in part prevents such Party from performing its obligations under this Agreement, including, without limitation, the following: any act of God; labor disturbance; act of the public enemy; war; insurrection; riot; fire; storm; flood; sun spots; lightning strikes; earthquake; explosion; breakage or accident to machinery or equipment; electric system disturbance; order, regulation, or restriction imposed by governmental, military, or lawfully established civilian authorities; action of any court or governmental authority; or any other cause of a similar nature beyond a Party's reasonable control.

13.3 **Limitations**. In the event of Force Majeure, a Party's obligations can only be excused to the extent and for the period that the Party's inability to perform is caused by an event of Force Majeure affecting the Party and only to the extent of the duration of the same, provided that the Party claiming Force Majeure shall make all reasonable efforts to cure, mitigate or remedy the effects of the Force Majeure event. Nothing herein shall be construed to require either Party to settle a labor dispute, lockout or strike.

13.4 **Notice**. A Party claiming Force Majeure as a basis for being excused from performance of its obligations under this Agreement must (i) provide verbal notice that is prompt under the circumstances, followed by written notice of the occurrence of the Force Majeure event to the other Party no later than five (5) business days after the Party knows of the occurrence of the event, where such notice provides an estimate of the event's expected duration and the probable impact on the performance of the Party's obligations hereunder; (ii) exercise all reasonable efforts in accordance with Prudent Utility Practice to continue to perform its obligations under this Agreement; (iii) expeditiously take reasonable action to correct or cure the Force Majeure event,

provided, however, that settlement of strikes or other labor disputes is completely within the sole discretion of the Party affected by such strike or labor dispute; and (iv) provide prompt notice to the other Party of the cessation of the Force Majeure event. Failure to provide notice of the occurrence of the Force Majeure event required hereunder shall preclude such Party from relying upon Force Majeure to excuse its failure to perform or avoid breach or default as a result of such failure.

ARTICLE 14
BREACH, CURE AND DEFAULT

14.1 **Breach**. A breach of this Agreement shall occur upon the failure by a Party to perform any material term or condition of this Agreement.

14.2 **Events of Breach**. A breach of this Agreement shall include the following: (a) The failure to comply with any material term or condition of this Agreement, including but not limited to any material breach of a representation, warranty or covenant made in this Agreement; (b) If a Party: (i) by decree of a court of competent jurisdiction, is adjudicated bankrupt or insolvent; (ii) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (iii) makes a general assignment for the benefit of its creditors; or (iv) consents to the appointment of a receiver, trustee or liquidator; (c) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement; (d) Failure of either Party to provide such access rights, or a Party's attempt to revoke or terminate such access rights, as provided under this Agreement; or (e) Failure of either Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement or to satisfy Regulatory Requirements.

14.3 **Cure and Default**.

14.3.1 A Party automatically will be deemed to be in "Default" of this Agreement upon the occurrence of any one of the events described in Sections 14.2(b)(ii)-(iv) of the Agreement.

14.3.2 Upon the occurrence of any event of breach other than those described in Sections 14.2(b)(ii)-(iv), the Party not in breach (hereinafter the "Non-Breaching Party"), when it becomes aware of any such breach, shall give written notice of the breach to the breaching Party (the "Breaching Party"). Such notice shall set forth, in reasonable detail, the nature of the breach, and where known and applicable, the steps necessary to cure such breach. Upon receiving written notice of the breach hereunder, the Breaching Party shall have thirty (30) days to cure such breach. If the breach is such that it cannot be cured within such thirty (30) calendar day time period, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the breach, or to commence reasonable and appropriate steps to cure the breach, within such thirty (30) calendar day time period, the Breaching Party will be in "Default" of the Agreement.

14.3.3 Upon the occurrence of a Default, the Non-Breaching Party may, subject to the limitations contained in this ARTICLE 14, terminate this Agreement by providing written notice of termination to the other Party, except that where a Default has been disputed by the Breaching Party, termination of this Agreement on account of such Default may not occur absent a final, binding and non-appealable decision by FERC, an arbitrator, or a court of competent authority having jurisdiction, making a determination of said Default.

14.4 **Right to Compel Performance**. Notwithstanding the foregoing, upon the occurrence of Default, the non-breaching Party shall be entitled to (i) commence an action to require the breaching Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (ii) exercise such other rights and remedies as it may have in equity or at law. Neither Party shall be required to post any guaranty, letter of credit, bond or other security to obtain an order or decree of specific performance.

ARTICLE 15
LABOR RELATIONS

Each Party agrees to immediately notify the other Party, verbally and then in writing, of any labor dispute or anticipated labor dispute of which its management has actual knowledge that might reasonably be expected to affect the operations of the other Party with respect to this Agreement.

ARTICLE 16
SUBCONTRACTOR

16.1 **Generally**. Nothing in this Agreement shall prevent a Party from utilizing the services of such subcontractors as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services.

16.2 **Responsibility of Principal**. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. Each Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor it hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon a Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

16.3 **No Third Party Beneficiary**. No subcontractor is intended to be, nor will it be deemed to be, a third party beneficiary of this Agreement.

16.4 **No Limitation by Insurance**. The obligations under this ARTICLE 16 will not be limited in any way by any limitation on a subcontractor's insurance.

ARTICLE 17
CONFIDENTIALITY

17.1 **Nondisclosure**. Neither Party shall disclose any Confidential Information of the other Party obtained pursuant to or in connection with the performance of this Agreement to any third

party without the express written consent of the other Party, except that either Party may produce Confidential Information in response to a subpoena, discovery request or other compulsory process issued by a judicial body or governmental agency upon reasonable notice to the Party whose Confidential Information it is. Neither Party shall disclose information designated as Critical Energy Infrastructure Information (as defined in 18 C.F.R. §388.113) except as permitted by applicable Regulatory Requirements.

17.2 **Definition**. "Confidential Information" means any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as Confidential by the Party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this Agreement. Confidential Information shall not include information that the receiving Party can demonstrate (i) is generally available to the public other than as a result of a disclosure by the receiving Party; (ii) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (iii) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party, after due inquiry, was under no obligation to the other Party to keep such information confidential; (iv) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (v) was disclosed with the prior written approval of the disclosing Party; (vi) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or breach of this Agreement; or (vii) is required, in accordance with this ARTICLE 17, to be disclosed by any federal or state government or agency or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement held in a court or agency of competent jurisdiction. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential. Finally, for the purposes of this Agreement, information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed verbally or by inspection, if the Party providing the information verbally informs the Party receiving the information that the information is confidential.

17.3 **Standard of Care**. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination.

17.4 **Use of Confidential Information**. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this Agreement or its Regulatory Requirements, or in any proceeding under ARTICLE 19 or in any administrative agency or court of competent jurisdiction addressing any dispute arising under this Agreement, subject either to a confidentiality agreement with all participants (including, if applicable, arbitrator(s)) or to a protective order.

17.5 **Survival**. The confidentiality provisions of this ARTICLE 17 shall survive termination of this Agreement for a period of three (3) years.

17.6 **FERC Access to Confidential Information**. Notwithstanding anything in this ARTICLE 17 to the contrary, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party may, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. The Party shall notify the other Party to the Agreement when it is notified by FERC or its staff that a request for disclosure of, or decision to disclose, Confidential Information has been received, at which time either of the Parties may respond before such information is made public, consistent with 18 C.F.R. § 388.112.

ARTICLE 18
AUDIT RIGHTS

Subject to the requirements of confidentiality under ARTICLE 17 of the Agreement, any Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party and, at its own costs and expenses, to audit each other's accounts and records pertaining to the other Party's performance and/or satisfaction of obligations arising under this Agreement. Said audit shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to obligations under this Agreement.

ARTICLE 19
DISPUTE RESOLUTION

19.1 **Submission**. Prior to providing any notice of any claim or dispute that either Party may have against the other arising out of this Agreement, the Parties shall work in good faith to informally resolve any dispute through negotiations by the Parties. In the event the Parties cannot resolve their dispute through good faith negotiations, the disputing Party shall submit a notice of dispute in writing to the other Party not later than sixty (60) days after the circumstances which gave rise to the claim or dispute have taken place. This submission of any claim or dispute shall include a concise statement of the question or issue in dispute, together with relevant facts and documentation to fully support the claim.

19.2 **Alternative Dispute Resolution**. If any such claim or dispute arises, the Parties shall use their best efforts to resolve the claim or dispute, initially through good faith negotiations or upon the failure of such negotiations, through mutually agreed to alternative dispute resolution ("ADR") techniques; however, either Party may terminate its participation in ADR during any stage of ADR and proceed under Section 19.4.

19.3 **Technical Disputes**. With respect to disputes which the Parties mutually agree are exclusively technical in nature, the Parties shall work informally in good faith to resolve such technical disputes. In the event the Parties are unable to resolve their technical disputes, the Parties will elevate such disputes to its respective officers and directors for such officers and directors to resolve. In the event, the Parties' officers and directors cannot resolve such technical dispute, the

Parties, shall provide a notice of dispute to the non-disputing Party and follow the procedures set forth in Section 19.1 above.

19.4 **Arbitration**. Except as provided in Section 19.4.1.1, if any claim or dispute arising hereunder is not resolved within sixty (60) days after notice thereof to the other Party, either Party may demand in writing the submission of the dispute to binding arbitration in Nevada, unless the Parties mutually agree upon another location and shall be heard by one neutral arbitrator under the American Arbitration Association's Commercial Arbitration Rules ("Arbitration Rules"); provided, however, that in the event of a conflict between the Arbitration Rules and the terms and provisions of this ARTICLE 19, the terms and provisions of this ARTICLE 19 shall govern. The Parties shall each bear one-half of the arbitrator's fees and expenses, but shall bear their own costs and expenses (including attorneys' and expert witness fees and expenses) incurred in the arbitration proceeding.

19.4.1 **Arbitration Procedures**. Any arbitration initiated under this ARTICLE 19 shall be conducted by a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose an arbitrator, both of which shall sit on a three-member arbitration panel. The two arbitrators so chosen shall, within twenty (20) days, select a third arbitrator to chair the arbitration panel. Any arbitrator selected pursuant to this Section 19.4.1 must be knowledgeable in matters that are the subject of the dispute. The arbitrator(s) shall conduct the arbitration in accordance with the Arbitration Rules in effect at the time arbitration is initiated under this ARTICLE 19; provided, however, that, in the event of a conflict between the Arbitration Rules and the terms and provisions of this ARTICLE 19, the terms and provisions of this ARTICLE 19 shall govern.

19.4.1.1 **Submission of Dispute to FERC**. Notwithstanding anything to the contrary in this ARTICLE 19, the arbitration and dispute resolution requirements of this Agreement shall not bar either Party from seeking relief from the FERC under this Agreement at any time, and shall not be construed as a waiver of any rights either party may have under the FPA.

19.4.2 **No Authority to Modify Agreement**. The arbitrator(s) shall have the authority only to interpret and apply the terms and conditions of this Agreement and shall have no power to modify or change any such terms or conditions.

19.4.2.1 The arbitrator(s) shall be required to follow any and all applicable federal, state, or local laws and regulations.

19.4.2.2 Remedies shall be awarded in accordance with the following:

19.4.2.3 The arbitrator(s) may not award punitive damages, multiple damages, or any other damages which are not measured by the prevailing Party's actual damages.

19.4.2.4 Any award of damages must be determined, limited and controlled by the limitation of liability provision of this Agreement.

19.4.2.5 The arbitrator(s) may, in his or her discretion, award pre-award and post-award interest on any damages awarded; provided, however, that the rate of interest may not

exceed a rate equal to that based on the FERC methodology set forth in Section 35.19a of FERC's regulations (18 C.F.R. Section 35.19a).

19.4.3 **Timing and Nature of Decision**. Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment. The decision must be in writing and contain the reasons for the decision. The decision and award of the arbitrator shall be final and binding upon the Parties, their successors, and assigns; provided, however, that such decision and award may be challenged solely on the grounds that the conduct of the arbitrator, or the decision and award itself, violated the standards set forth in the Federal Arbitration Act. Judgment upon the award rendered by the arbitrator may be entered in any court having jurisdiction. The decision must also be filed with FERC if it affects FERC-jurisdictional rates, terms and conditions of service or facilities. Notwithstanding this Section 19.4.3, the Parties understand and agree that any decision by the arbitrator is not binding on FERC to the extent FERC exercises jurisdiction over the dispute.

19.5 **Procedures**. The procedures for the resolution of disputes set forth herein shall be the sole and exclusive procedures for the resolution of disputes; provided, however, that a Party may seek a preliminary injunction or other preliminary judicial relief if in its judgment such action is necessary to avoid irreparable damage or to preserve the status quo. Despite such actions, the Parties will continue to participate in good faith in the procedures specified herein. All applicable statutes of limitations and defenses based upon the passage of time shall be tolled while the procedures specified herein are pending. The Parties will take such action, if any, required to effectuate such tolling. Each Party is required to continue to perform its undisputed obligations under this Agreement pending final resolution of a dispute. All negotiations pursuant to these procedures for the resolution of disputes will be confidential, and shall be treated as compromise and settlement negotiations for purposes of the Federal Rules of Evidence and State Rules of Evidence.

ARTICLE 20
NOTICES AND COMMUNICATIONS

20.1 Unless otherwise specified herein, all notices, requests, claims, demands and other communications required or permitted to be given under this Agreement must be in writing, and must be given (and will be deemed to have been duly given if so given) by hand delivery, cable, telecopy (confirmed in writing), overnight express delivery, or telex, or by mail (registered or certified, postage prepaid) to the respective Parties as outlined in Appendix D.

20.2 Any Party may change its address or designated representative for notices by notice to the other in the manner provided above by giving five (5) Business Days written notice prior to the effective date of the change.

20.3 Notwithstanding Section 20.1, any notice hereunder concerning an Emergency or other occurrence requiring prompt attention, or as necessary during day-to-day operations, may be made by telephone or in person provided that such notice is confirmed in writing promptly thereafter. Notice in an Emergency, or as necessary during day-to-day operations, shall be provided to the shift supervisor at Interconnection Provider's transmission control center.

ARTICLE 21
MISCELLANEOUS PROVISIONS

21.1 **Governing Law**.

21.1.1 This Agreement and all rights and obligations of the Parties hereunder are subject to all applicable state and federal laws and all applicable duly-promulgated orders and regulations and duly-authorized actions taken by the executive, legislative, or judicial branches of government, or any of their respective agencies, departments, authorities, or other instrumentalities having jurisdiction.

21.1.2 When not in conflict with or preempted by federal law, this Agreement will be governed by and construed in accordance with the laws of the State of Nevada without giving effect to the conflict of law principles thereof.

21.1.3 Except for those matters covered in this Agreement and which are either jurisdictional to FERC or submitted to arbitration pursuant to ARTICLE 19 herein, any action arising out of or concerning this Agreement must be brought in any state or federal court of competent jurisdiction in the State of Nevada. The Parties hereby consent to the jurisdiction of any state or federal court of competent jurisdiction in the State of Nevada for the purpose of hearing and determining any action not subject to FERC's jurisdiction.

21.2 **Compliance with Law**. In performing its obligations under this Agreement, each Party shall comply with all applicable Laws and Regulatory Requirements.

21.3 **Taxes**. Except as otherwise provided in this Agreement, each Party agrees to pay any and all local, state, federal sales, use, excise, or any other taxes which are now, or in the future may be, assessed and legally owed by such Party pertaining to goods provided and/or the services performed under this Agreement.

21.4 **Relationship of the Parties**. Nothing in this Agreement is intended to create a partnership, joint venture, or other joint legal entity making any Party jointly or severally liable for the acts of the other Party. Unless otherwise agreed to in a writing signed by all Parties, no Party shall have any authority to create or assume in the other Party's name or on its behalf any obligation, express or implied, or to act or purport to act as the other Party's agent or legally empowered representative for any purpose whatsoever. Each Party shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of persons by that Party to perform under this Agreement, including all federal, state, and local income, social security, payroll and employment taxes and statutorily-mandated workers' compensation coverage. None of the persons employed by either Party shall be considered employees of the other Party for any purpose; nor shall either Party represent to any person that such persons are or shall become employees of the other Party. Except as expressly provided for herein, no Party shall be liable to any third party in any way for any engagement, obligation, commitment, contract, representation, or for any negligent act or omission to act of the other Party.

21.5 **No Third Party Rights**. Nothing in this Agreement, express or implied, is intended to confer on any person, other than the Parties hereto, any benefits, interests, rights, or remedies under or by reason of the Agreement.

21.6 **Waiver**. Except as otherwise provided in this Agreement, a Party's compliance with any obligation, covenant, agreement, or condition herein may be waived by the Party entitled to the benefits thereof only by a written instrument signed by the Party granting such waiver, but such waiver or failure to insist upon strict compliance with such obligation, covenant, agreement, or condition will not operate as a waiver of, or estoppel with respect to, any subsequent or other failure.

21.7 **Amendment**. Except as otherwise set forth herein, this Agreement may be amended or modified only by a writing executed by the authorized representatives of both Parties. Nothing contained herein shall be construed as affecting in any way the right of the party furnishing service under this rate schedule to unilaterally make application to the FERC for a change in rates under section 205 of the FPA and pursuant to the FERC's Rules and Regulations promulgated thereunder. Specifically, Interconnection Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the FPA and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 206 or any other applicable provision of the FPA and FERC's rules and regulations thereunder; provided, that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the FPA and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

21.8 **Severability**. If any term, condition, covenant, restriction or other provision of this Agreement is held by a court or regulatory agency of competent jurisdiction or by legislative enactment to be invalid, void or otherwise unenforceable, the remainder of the terms, conditions, covenants, restrictions and other provisions of this Agreement shall remain in full force and effect unless such an interpretation would materially alter the rights and privileges of any Party hereto. If any term, condition, covenant, restriction or other provision of this Agreement is held invalid, void or otherwise unenforceable, the Parties shall attempt to negotiate an appropriate and equitable replacement, revision or adjustment to the provision of this Agreement to restore the benefits and obligations conferred under the original Agreement.

21.9 **Headings and Captions**. Article headings and/or other captions are included in this Agreement for reference purposes only and shall not constitute a part of this Agreement or in any way affect the meaning or interpretation of this Agreement. Whenever used herein the singular number shall include the plural, the plural shall include the singular, and the use of any gender shall include all genders.

21.10 **Further Assurances**. Each Party shall do such other and further acts and things, and shall execute and deliver such instruments and documents, as the other Party(ies) reasonably requests from time to time in furtherance of the purposes of this Agreement.

21.11 **Entire Agreement**. This Agreement, including all schedules, appendices and other attachments hereto and made part hereof, sets forth the entire understanding and agreement of the Parties as to the subject matter of this Agreement and merges and supersedes all prior written and

verbal understandings, offers, agreements, commitments, representations, writings, discussions or other communications of every kind between the Parties pertaining to the Interconnection Facilities, and constitutes the entire agreement between the Parties with respect to its subject matter, and as to all other representations, understandings, or agreements which are not fully expressed herein.

21.12 **Rights Cumulative**. The rights and remedies set forth in this Agreement are cumulative and non-exclusive.

21.13 **Counterparts**. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

ARTICLE 22
COMPLIANCE WITH REGULATORY STANDARDS

22.1 Each Party acknowledges that the responsibility to operate, maintain, dispatch or manage their transmission facilities in compliance with any and all applicable standards or protocols of NERC or WECC shall rest solely with the Party owning and/or operating such respective Interconnection Facilities, as appropriate, and nothing in this Agreement purports to share such NERC or WECC compliance obligations between the Parties. Notwithstanding anything in this Agreement to the contrary, the Parties further agree that any liability associated with noncompliance of NERC or WECC standards or protocols rests solely with the Party whose actions results in the noncompliance of such standards.

22.2 To the extent either Party determines, in its sole discretion, that it needs to undertake certain efforts to ensure compliance with any applicable NERC or WECC standards or protocols, then the other Party shall use its best efforts to assist, and shall in no way interfere with, that Party's efforts for compliance with any and all applicable NERC or WECC standards or protocols. Each Party shall provide the other with reasonable advance notice of any required efforts associated with necessary compliance activities undertaken pursuant to this Section 22.2. Should either Party not provide the other with any information or assistance for any compliance activities, either Party shall have the right to undertake any necessary actions to ensure its compliance with NERC or WECC standards or protocols.

IN WITNESS WHEREOF, the Parties have caused their authorized representatives to execute this Agreement as of the date first above written.

INTERCONNECTION PROVIDER

Sierra Pacific Power Company
d/b/a NV Energy

By: Signed by: Eric Schwarzrock 03ABF48120874E8...

Title: VP, Customer Solutions

Date: 11/3/2024

INTERCONNECTION CUSTOMER

Plumas Sierra Rural Electric Cooperative

By: Signed by: Robert Marshall 7F8A19F9C24141A...

Title: _____

Date: 11/2/2024

APPENDIX

Appendix A	Interconnection Facilities, Estimated Costs and Responsibilities
Appendix B	Milestones
Appendix C	Interconnection Details and One-line Diagram
Appendix D	Notices

Appendix A

**Interconnection Facilities, Estimated Costs
And Responsibilities**

Point of Interconnection:
The Point of Interconnection shall be a new 345 kV terminal at Ft. Sage substation. A new 69/345 kV 50 MVA transformer shall interconnect the Interconnection Customer's extension of its 69 kV system. See Appendix C.

Point of Change of Ownership:
The Point of Change of Ownership will be at 69 kV dead end structure outside the Interconnection Provider's Ft. Sage substation. The structure for the landing will be the point where the Interconnection Customer's 69 kV transmission line terminates on the Interconnection Provider-owned structure and the Interconnection Provider's line to Ft. Sage. The preliminary location identified for the Point of Change of Ownership dead-end structure is: 40° 4'40.41"N, 119°58'44.18"W
See Appendix C.

Nominal Delivery Voltage: 69 kV

Balancing Authority Area Metering Interchange Voltage: 69 kV

Requirements:
1. This interconnection with the PSREC system will be split at Plumas Sierra's Beckwourth substations such that Quincy, Mohawk, Graeagle, Sierraville, and Marble substations will be served by the Quincy-Marble 69 kV path, and the remainder of the Plumas Sierra load will be served radially out of Ft. Sage. Under this configuration, there are no parallel operations between Ft. Sage and CAISO.
2. Plumas Sierra will remain tied to PG&E at Quincy and NV Energy at Marble.
3. If the Ft. Sage tie fails PSREC loads can be re-energized through the Marble-Quincy tie but would not results in parallel operation with Ft. Sage.
4. If the PG&E/Quincy tie fails or is interrupted such that Plumas Sierra requires an alternate feed, then Plumas Sierra may be connected solely at Ft. Sage or temporarily at Ft. Sage. Plumas Sierra will be required to make additional corresponding Transmission Service arrangements to serve additional load.

1. <u>Interconnection Customer's Interconnection Facilities:</u>

a. Interconnection Customer's Interconnection Facilities and the Parties' responsibilities for such facilities shall include the following:

1. <u>Interconnection Customer's Transmission Line to the Point of Change of Ownership</u>
   a. The Interconnection Customer will design, permit, procure, and construct approximately 11.5 miles of 69 kV transmission lead line from Plumas Sierra's SIAD substation to the proposed Point of Change of Ownership dead-end structure.
   b. Transmission Line must include:
      i. Fiber Optic Cable or equivalent capable of providing single communication path from the Interconnection Customer's SIAD Substation to the Interconnection Provider's Ft. Sage Substation.
      ii. Static wire(s) and adequate overvoltage protection.

iii. The Interconnection Customer may provide extra Fiber Optic Cable and coil the cable at the Point of Change of Ownership for the Interconnection Provider to install from the Point of Change of Ownership to the Point of Interconnection.

2. System Protection Facilities
   a. Interconnection Customer is responsible for the electrical protection of Interconnection Customer's Interconnection Facilities consistent with Good Utility practice.
   b. Interconnection Customer's 69 kV line protection relays at Ft. Sage Substation must be compatible with the Interconnection Provider's dual SEL-411Lline relays at the Ft. Sage Substation; and
   c. The Interconnection Customer must submit their intended protection and communications plan for the Interconnection Customer's Interconnection Facilities to the Interconnection Provider for mutual review and agreement.

3. Right-of-Way, Jurisdictional and Environmental Permitting
   a. The Interconnection Customer must obtain all necessary property, rights-of-way, and permits from all federal, state, local and/or private land-owners and jurisdictions for all Network Upgrades and both the Interconnection Provider's Interconnection Facilities and/or Direct Assignment Facilities needed to accommodate this interconnection including, but not limited to:
      i. All related facilities at Plumas Sierra's transmission line;
      ii. All installations required to interconnect Interconnection Customer's transmission line to the Point of Interconnection at Ft Sage Substation, including the 345/69 kV transformer at Ft. Sage Substation;
      iii. The dead-end structure, isolation switch, and substation entrance fence outside of Ft Sage Substation;
      iv. All necessary access roads to Interconnection Provider's Interconnection Facilities and Network Upgrades; and
      v. Interconnection Customer's and Interconnection Provider's temporary work areas including but not limited to equipment and material storage yards, construction yards and staging areas, and temporary disturbance areas planned and reasonably required for construction (e.g., access, wire stringing)
   b. If a BLM and/or a California Environmental Quality Act (CEQA) permit or right-of-way grants are required for any facilities under this Agreement, the Interconnection Customer will be responsible for all environmental studies, analyses, reports, and mitigation treatments associated with its BLM land use authorization process for the entire project (Interconnection Provider's facilities and Interconnection Customer's facilities), including but not limited to the BLM and CEQA's Environmental Impact Statement, Biological Assessment, Cultural/Paleontological Resource Reports, etc.
   c. The Interconnection Provider will provide specifications needed for right-of-way and permitting applications to the Interconnection Customer for all Interconnection Provider Interconnection Facilities and Network Upgrades, if any; and
   d. The Interconnection Customer will provide all right-of-way and permitting applications to the Interconnection Provider for review and comment prior to submittal to the appropriate agencies.

2. Interconnection Provider's Interconnection Facilities:

a. Interconnection Provider's Interconnection Facilities and the Parties' responsibilities for such facilities shall include the following:

a. Point of Change of Ownership

a. The Interconnection Provider will design, procure, and construct approximately 0.25 miles of 954 ACSR kV specifications transmission lead line with OPGW from the Point of Change of Ownership dead-end structure to Ft. Sage substation. The Interconnection Customer will provide extra conductor and coil the conductor at the Point of Change of Ownership for the Interconnection Provider to install from the Point of Change of Ownership to the Point of Interconnection.

b. The Interconnection Provider will design, procure, and install a 69 kV dead-end structure for the landing of the Interconnection Customer's transmission line. There will be a visual disconnect switch between Plumas Sierra's transmission line termination at the Point of Change of Ownership structure and the Interconnection Provider's line to Ft. Sage. The dead-end structure will be the Point of Change of Ownership.

i. The preliminary location identified for the Point of Change of Ownership dead-end structure is: 40° 4'40.41"N, 119°58'44.18"W

ii. The actual Point of Change of Ownership dead-end structure location will be determined by the Interconnection Provider prior to the Interconnection Customer's initiation of the permitting, design, and construction.

iii. The Interconnection Customer will permit the Point of Change of Ownership dead-end structure and switch outside of the Interconnection Provider's Ft. Sage substation.

b. Ft. Sage Substation upgrades required and directly assigned to Plumas Sierra

a. The Interconnection Customer requested service from Ft Sage at 69 kV, which is a voltage that does not currently exist on Interconnection Provider's current facilities at Ft. Sage. Through discussions and evaluation under the Facilities Study and coordination with interconnection customer, it was determined that the common bus that currently houses two 345/24.9 kV transformers can be extended to house a third transformer as part of the Transmission Interconnection Agreement. Once complete Ft Sage Substation can then house a new 345/69kV transformer which can be installed at the Interconnection Customer's cost for this service.

b. The Interconnection Provider will design, procure, and construct a new 345/69 kV 50 MVA transformer at Ft. Sage Substation

i. One (1) 69 kV breaker on the low side of the transformer will be required.

c. Telecommunications

a. The Interconnection Provider will design, procure, and install as needed one (1) RTU and necessary communications equipment at Ft. Sage Substation to incorporate the Interconnection Customer's communications.

d. Metering

a. The Interconnection Provider will install one (1) 69 kV meter and instrument transformers (CT's and PT's) for this interconnection inside the Interconnection Provider's Ft. Sage Substation and compensated to the Point of Interconnection.

b. The Interconnection Customer's Quincy tie will not be in parallel operations with the Plumas Sierra load served out of Ft. Sage Substation. If any additional metering for a Balancing Authority Area tie will be required by an Affected System

or other regulatory agency, the Interconnection Customer will be responsible for the cost of the additional metering.

3. **Network Upgrades:**

The following Network Upgrades are required pursuant to this Transmission Interconnection Agreement:

a. Point of Interconnection – Bus Expansion at Ft. Sage Substation

1. Substation
   a. The Interconnection Provider will design, procure, and expand the existing bus on the south side of the substation to allow for a third transformer to be installed.
2. Telecommunications
   a. The Interconnection Provider will design, procure, and install necessary equipment at Ft. Sage Substation to incorporate SCADA data.
   b. The Interconnection Provider will design, procure, and install a standard telecom build for a new control house located at Ft. Sage Substation. Includes but is not limited to: equipment racks, multiplexer, rectifiers, batteries, routers, and an alarm system.

4. Affected Systems:

a. PG&E, the California Independent System Operator ("CAISO"), and/or the Bonneville Power Administration ("BPA") are neighboring systems and may be affected by the proposed Plumas Sierra interconnection.
b. No Adverse Impacts were identified on Affected Systems as a result of Interconnection Provider's analyses of this interconnection. If Adverse Impacts are subsequently identified by Interconnection Provider or an Affected System, additional studies may be required.
c. Interconnection Customer will need to coordinate with the Affected System(s) with respect to conducting any additional studies. If additional studies are required by the Affected System(s), Transmission Customer will be required to make arrangements with the Affected System(s) to pay the estimated costs of such studies upfront, will be responsible for the actual costs of such studies, and may be required to execute a separate agreement to have such studies conducted.
d. Any new facilities required by the Affected System(s) to mitigate impact will be paid for by the Interconnection Customer; and
e. Resolution of any issues identified by the Affected System(s) prior to energization of the transmission-to-transmission interconnection is required.

5. Balancing Authority Area Change:

a. Interconnection Provider will coordinate with the Interconnection Customer to seek approval by NERC and/or WECC and any Governmental Authority, as appropriate, for approval of a change in Balancing Authority Area boundaries. Interconnection Provider has undertaken no investigation and made no representations about the costs or actions required to effectuate a change in Balancing Authority Area boundaries. As soon as reasonably practicable after initiating that approval process, Interconnection Provider shall notify Interconnection Customer of any costs to be incurred or actions required to be taken in order to receive said approval for change in Balancing Authority Area boundaries. Notwithstanding anything to the contrary in this Agreement, Interconnection Customer shall pay all costs required to be incurred by Interconnection Provider or Transmission Customer to facilitate the change in Balancing Authority Area boundary. After receiving Interconnection Provider's estimate of costs and actions required to facilitate the change in Balancing Authority Area boundaries, Interconnection Customer shall pay the estimated costs to proceed, actual charges will be paid by the Interconnection customer.

6. Cost Estimates:

a. As set forth in this Agreement in the definition of "Interconnection Provider's Interconnection Facilities", Interconnection Customer is responsible for the actual costs of construction of Interconnection Provider's Interconnection Facilities.
b. Interconnection Customer is responsible for the Interconnection Facilities and the Tax Gross-up payment of the applicable rate at the In-Service Date of the Interconnection Provider's Interconnection Facilities.
c. Cost responsibility for the Facilities shall be as follows:
   1. Interconnection Provider's Interconnection Facilities: Interconnection Customer must provide a cash payments totaling $10.875M as described in Appendix B: Milestones.
   2. Network Upgrades: Interconnection Customer must provide security totaling $7.245M as described in Appendix B: Milestones.

Transmission Interconnection Requirements				
	Total $MM		**Network Upgrades $MM**	**Interconnection Provider's Interconnection Facilities $MM**
Substation				
345/69 kV transformer, one 69 kV breaker, and associated protection	$9.810			$10.300
Expand existing bus on south side of substation and construct new control house	$6.690		$6.690	
Transmission Lines				
0.25 miles 120 kV spec. line, Switch, and Point of Change of Ownership Structure	$0.363			$0.363
Telecommunications				
Fiber splicing at the 69 kV Sub/POCO	$0.074			$0.074
Communication upgrades at Ft. Sage	$0.555		$0.555	
Metering				
69 kV metering	$0.138			$0.138
Total:	**$18.120**		**$7.245**	**$10.875**

Appendix B

Milestones

INTERCONNECTION MILESTONES		
Interconnection Customer's Project Milestones		**Due Dates**
1	Interconnection Customer to pursue all necessary permits	upon execution
2	Interconnection Customer to provide Interconnection Provider with certification of all insurance pursuant to Article 11.3 of the Agreement	within 10 days of the execution of the Agreement
3	Interconnection Customer and Interconnection Provider to hold the Project Initiation Meeting	within 30 days of FERC approval
4	Interconnection Customer and Interconnection Provider to setup regular project meeting schedule	within 30 days of FERC approval
5	Interconnection Customer to provide cash to the Interconnection Provider in the amount of $150,000 towards the Interconnection Provider's Interconnection Facilities	Upon Execution
6	Interconnection Customer to provide Interconnection Provider with drafts of all right-of-way and permitting applications for Interconnection Provider equipment	8/1/2024
7	Interconnection Customer to submit all required permit applications and/or amendments to permit applications for Interconnection Provider equipment	2/1/2025
8	Interconnection Customer to provide Preliminary One-line with Protection Scheme Descriptions to Interconnection Provider	4/1/2025
9	Interconnection Customer to provide cash to the Interconnection Provider in the amount of $4,900,000 towards the Interconnection Provider's Interconnection Facilities	2/1/2025
10	Interconnection Customer to provide security to the Interconnection Provider in the amount of $2,415,000 towards the Network Upgrades	2/1/2025
11	Interconnection Customer to provide security to the Interconnection Provider in the amount of $2,415,000 towards the Network Upgrades	5/1/2026
12	Interconnection Customer to provide cash to the Interconnection Provider in the amount of $3,190,000 towards the Interconnection Provider's Interconnection Facilities	5/1/2026
13	Interconnection Customer to provide Interconnection Provider with copies of completed permits from all required federal, state, county & local entities including, but not limited to, BLM Right-of-Way Grant (if determined to be applicable), CEQA, Special Use Permits, Grading Permits, Building Permits, etc.	11/1/2026
14	Interconnection Customer to provide signed Grant of Easement, Access Agreement, and other required documents to Interconnection Provider	12/1/2026
15	Interconnection Customer to complete access roads to the Point of Change of Ownership structure and accepted by Interconnection Provider, if required	4/1/2027

Agreed to by:

For the Transmission Provider Signed by: Eric Schwarzrock 03ABFF4B1720874E6 Date 11/3/2024

For the Interconnection Customer Signed by: Robert Marshall 7FBA19F9C24141A Date 11/2/2024

Milestones—continued

16	Interconnection Customer to provide cash to the Interconnection Provider in the amount of $2,635,000 towards the Interconnection Provider's Interconnection Facilities	4/1/2027
17	Interconnection Customer to provide security to the Interconnection Provider in the amount of $2,415,000 towards the Network Upgrades	4/1/2027
18	Interconnection Customer to complete protection relays and OPGW fiber; End to End Fiber Test reports to be provided to Interconnection Provider	6/1/2028
19	Interconnection Customer to resolve any issues identified by Affected Systems and provide supporting documentation to Interconnection Provider	2/1/2028
20	Interconnection Customer and Interconnection Provider to finalize the required telemetry information for operations	1/1/2027
21	Interconnection Customer and Interconnection Provider to coordinate with necessary regulatory agencies including NERC and WECC on Balancing Authority Area Change	4/1/2025
22	Interconnection Customer and Interconnection Provider resolve all issues and complete Balancing Authority Area Change	within one month of in-service date
23	Interconnection Customer to initiate pre-energization meeting	meeting must be held at least 1 week prior to In-Service Customer Date
24	Interconnection Customer to complete Interconnection Customer's Interconnection Facilities (provide notice to Interconnection Provider in writing)	must be provided at least 1 week prior to In-Service Customer Date
25	Interconnection Customer and Interconnection Provider hold the pre-energization Meeting	meeting must be held at least 1 week prior to In-Service Customer Date
26	Interconnection Customer Facility Trip Testing - Provide written notice to the Interconnection Provider	Must be completed prior to the In-Service date with written notice by the Interconnection Customer to the Interconnection Provider
27	In-Service Date	**12/1/2028**
28	Interconnection Customer to complete Section 7 form and all restoration activities and assign a portion of Interconnection Customer's BLM grant to Interconnection Provider for the Interconnection Provider's Interconnection Facilities	Within one (1) month of In-Service Date
29	Upon completion of the final audit, the Interconnection Customer to provide cash to the Interconnection Provider for CIAC tax gross up for the Interconnection Provider's Interconnection Facilities at the applicable rate when the Interconnection Facilities are placed in-service, if applicable.	Within one (1) month of the final audit being provided to the Interconnection Customer

Agreed to by:

For the Transmission Provider Signed by: Eric Schwarzrock 03ABF48120874E6... Date 11/3/2024

For the Interconnection Customer Signed by: Robert Marshall 7F8A19F9C24141A... Date 11/2/2024

Interconnection Provider Project Milestones		
1	Interconnection Provider's Interconnection Facilities Completed for Customer In-Service Date	Q4 2028 provided that all necessary approvals by Governmental Authorities are received, Interconnection Customer's required facilities are constructed, tested and ready for service per Interconnection Customer milestones above, and the Interconnection Customer has provided required securities and notices to the Interconnection Provider per Interconnection Customer milestones above.

Agreed to by:

For the Transmission Provider Signed by: Eric Schwarzrock 03ABF48120874E8 Date 11/3/2024

For the Interconnection Customer Signed by: Robert Marshall 7FBA19F9C24141A Date 11/2/2024

Appendix C

Interconnection Details

Point of Interconnection:
The Point of Interconnection shall be the extended bus on the south side of Ft. Sage substation. A new 69/345 kV 50 MVA transformer shall interconnect the Interconnection Customer's extension of its 69 kV system. See Appendix C.

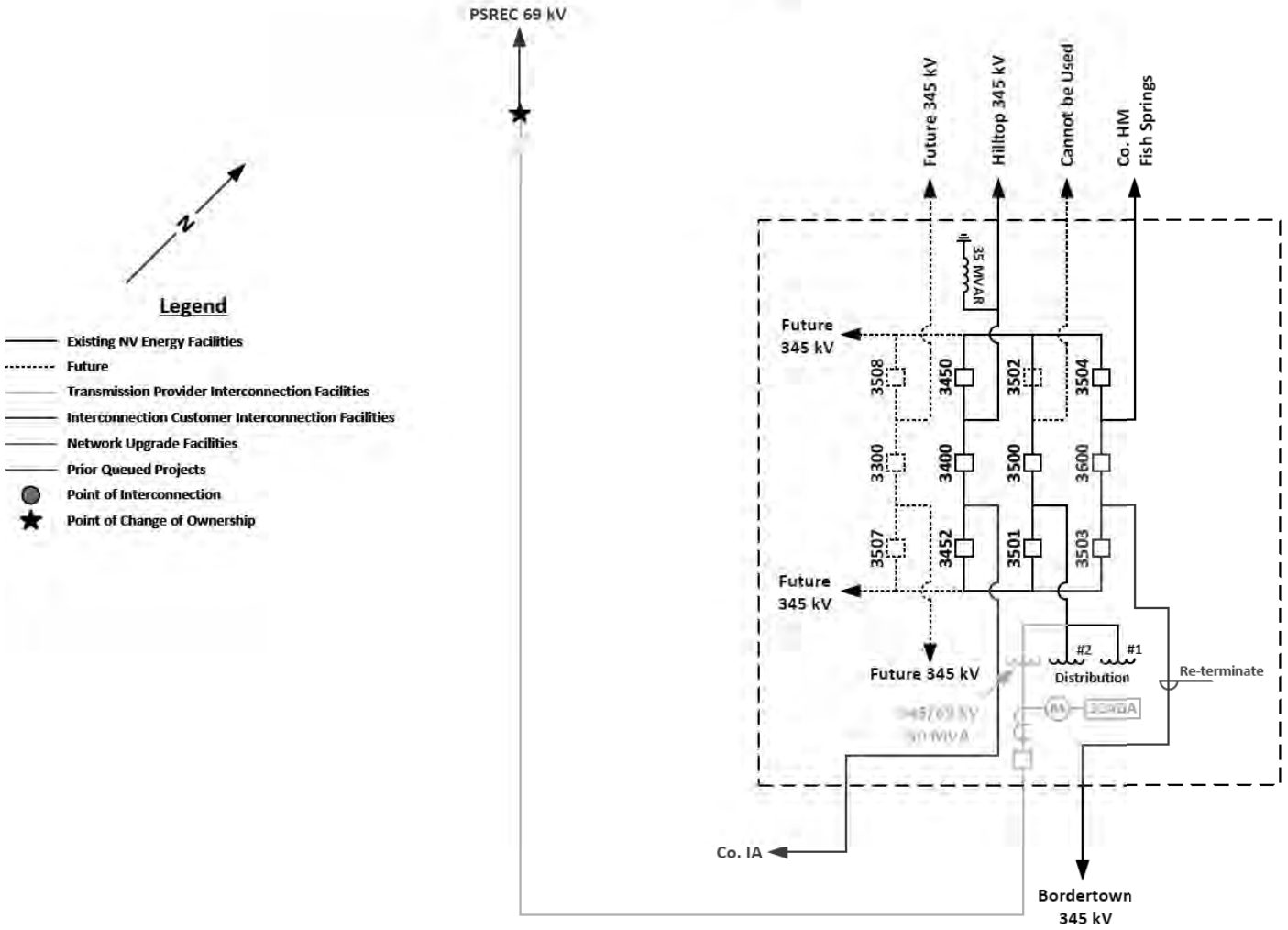
Point of Change of Ownership:
The Point of Change of Ownership will be at 69 kV dead end structure 0.25 miles outside the Interconnection Provider's Ft. Sage substation. The structure for the landing will be the point where the Interconnection Customer's 69 kV transmission line terminates on the Interconnection Provider-owned structure and the Interconnection Provider's line to Ft. Sage. The preliminary location identified for the Point of Change of Ownership dead-end structure is: 40° 4'40.41"N, 119°58'44.18"W
See Appendix C.

Nominal Delivery Voltage: 69 kV

Balancing Authority Area Metering Interchange Voltage: 69 kV

One Line Diagram

NVEnergy	PSREC NITS-345/69 kV at Ft. Sage	10/23/2024



Appendix D:
Addresses for Delivery of Notices and Billings

Notices:

Unless otherwise provided in this Agreement, any written notice demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

Interconnection Provider

Interconnection Provider:	Sierra Pacific Power Company d/b/a NV Energy
Attention:	Manager, Transmission Business Services
Address:	6100 Neil Road or PO Box 10100
City:	Reno
State:	NV
Zip:	89511
Phone:	775-834-3881
Fax:	775-834-3047
E-Mail:	TransmissionPolicy@nvenergy.com

Interconnection Customer

Interconnection Customer:	Plumas-Sierra Rural Electric Cooperative
Attention:	Bob Marshall, CEO/GM
Address:	73233 State Route 70
City:	Portola
State:	CA
Zip:	96122
Phone:	530-832-6076
Fax:	
E-Mail:	bob.marshall@psrec.com

Billings and Payments:

Billings and payments shall be sent to the addresses set out below:

Interconnection Provider

Interconnection Provider:	Sierra Pacific Power Company d/b/a NV Energy
Attention:	Manager, Transmission Business Services
Address:	6100 Neil Road or PO Box 10100
City:	Reno
State:	NV
Zip:	89511
Phone:	775-834-3881
Fax:	775-834-3047
E-Mail:	TransmissionPolicy@nvenergy.com

Interconnection Customer

Interconnection Customer:	Plumas-Sierra Rural Electric Cooperative
Attention:	Accounts Payable
Address:	73233 State Route 70
City:	Portola
State:	CA
Zip:	96122
Phone:	530-832-4261
Fax:	
E-Mail:	accountspayable@psrec.coop

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Any notice or request required or permitted to be given by either party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

Interconnection Provider

Interconnection Provider:	Sierra Pacific Power Company d/b/a NV Energy
Attention:	Project Manager
Address:	6100 Neil Road or PO Box 10100
City:	Reno
State:	NV
Zip:	89511
Phone:	775-834-3881
Fax:	775-834-3047
E-Mail:	TransmissionPolicy@nvenergy.com

Interconnection Customer

Interconnection Customer:	Plumas-Sierra Rural Electric Cooperative
Attention:	Jason Harston
Address:	73233 State Route 70
City:	Portola
State:	CA
Zip:	96122
Phone:	530-832-6035
Fax:	
E-Mail:	jason.harston@psrec.com

Designated Operating Executive:

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Provider

Interconnection Provider:	Sierra Pacific Power Company d/b/a NV Energy
Attention:	Director, Grid Operations and Reliability
Address:	6100 Neil Road or PO Box 10100

City:	Reno
State:	NV
Zip:	89511
Phone:	775-834-3776
Fax:	775-834-3047
E-Mail:	ESCCOperations@nvenergy.com

Interconnection Customer

Interconnection Customer:	Plumas-Sierra Rural Electric Cooperative
Attention:	Jason Harston
Address:	73233 State Route 70
City:	Portola
State:	CA
Zip:	96122
Phone:	530-832-6035
Fax:	
E-Mail:	jason.harston@psrec.com

TRAN-12

NEVADA POWER COMPANY D/B/A NV ENERGY (NVES)
SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY (NVEN)

APPENDIX TRAN-12

NORTHWEST - GRIDLIANCE WEST TIA AT NORTHWEST RS 169 EXECUTED

March 2026

TRANSMISSION INTERCONNECTION AGREEMENT

RATE SCHEDULE NO. 169

Between

NEVADA POWER COMPANY d/b/a NV ENERGY

and

GridLiance West LLC

Dated as of

10/08/2025

Table of Contents:

APPENDIX

TRANSMISSION INTERCONNECTION AGREEMENT

This TRANSMISSION INTERCONNECTION AGREEMENT (the "Agreement") dated as of 10/08/2025 is entered into by and between NEVADA POWER COMPANY d/b/a NV Energy ("NPC" or "Interconnection Provider"), a Nevada corporation, as the owner of the NPC Transmission System and GRIDLIANCE WEST LLC, a Delaware limited liability company ("GLW" or "Interconnection Customer"). NPC and GLW are sometimes referred to herein individually as a "Party" and collectively as the "Parties."

WITNESSETH:

WHEREAS, NPC owns and operates the NPC Transmission System; and

WHEREAS, GLW plans to construct a 230 kV AC transmission line between NPC's Northwest 230 kV switchyard and GLW's DesertView 230 kV switchyard; and

WHEREAS, the Parties seek to establish an electrical interconnection between their respective transmission systems; and

WHEREAS, NPC and GLW desire to set forth in this Agreement the requirements, scope, and terms and conditions for the interconnection interconnecting the GLW 230 kV line to the NPC Transmission System, and to define the continuing responsibilities and obligations of the Parties with respect thereto.

NOW, THEREFORE, in consideration of the mutual representations, covenants, and agreements hereinafter set forth, and intending to be legally bound hereby, the Parties hereto agree as follows:

ARTICLE 1
DEFINITIONS

1.1 **Definitions**. Wherever used in this Agreement with initial capitalization, the following terms shall have the meanings specified or referred to in this ARTICLE 1.

"Abnormal Condition" shall mean any condition on a Party's transmission system or the transmission system of other utilities which is outside normal operating parameters such that facilities are operating outside their normal ratings or reasonable operating limits for the facilities have been exceeded but which has not resulted in an Emergency. An Abnormal Condition may include, but is not limited to, high or low deviations in voltage, frequency, power flow, equipment temperature, equipment pressures, or other operating parameters.

"Affected System" shall mean an electric system other than the Interconnection Provider's Transmission System that may be affected by the proposed interconnection.

"Affiliate" shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

"Agreement" shall mean this Transmission Interconnection Agreement by and between NPC and GLW, including all appendices attached hereto, as the same may be amended, supplemented, revised, altered, changed or restated in accordance with its terms.

"Balancing Authority" shall mean Nevada Power Company in its role as the registered Balancing Authority for the SPPC and NPC transmission systems.

"Balancing Authority Area" shall mean the collection of generation, transmission and loads within the metered boundaries of the SPPC and NPC transmission systems.

"Breach" shall mean the failure of a Party to perform or observe any material term or condition of this Agreement.

"Breaching Party" shall mean a Party that is in Breach of this Agreement.

"Commercial Operation Date" shall mean the date on which the Interconnection Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix B of this Agreement.

"Confidential Information" shall have the meaning set forth in ARTICLE 17 of this Agreement.

"Default" shall have the meaning set forth in ARTICLE 14 of this Agreement.

"Effective Date" shall have the meaning set forth in ARTICLE 2 of this Agreement.

"Electric Reliability Organization" shall mean the organization certified by FERC to propose and enforce mandatory standards for the reliable operation and planning of the bulk power system throughout the United States of America.

"Emergency" shall mean a condition or situation which is deemed likely to endanger public safety and/or health, life, or property, or imminently likely to cause an adverse effect (as determined in accordance with Prudent Utility Practices) on the Parties' transmission systems or transmission systems of others to whom the Parties are indirectly connected.

"FERC" shall mean the Federal Energy Regulatory Commission or its successor.

"Force Majeure" shall have the meaning set forth in ARTICLE 13 of this Agreement.

"FPA" shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq. as it may be amended from time to time.

"Hazardous Substances" shall mean those substances, materials, products, or wastes which are classified as hazardous or toxic under any applicable Law proposed or in effect as of the date of execution of this Agreement.

"Indemnifying Party" shall have the meaning set forth in ARTICLE 11 of this Agreement.

"In-Service Date" shall mean the date upon which the Interconnection Customer reasonably expects to energize the Interconnection Facilities.

"Interconnection Facilities" shall mean those facilities described in Appendices A and B and depicted in the one-line diagram in Appendix C.

"Interconnection Customer" shall mean the Party interconnecting to the Interconnection Provider's Transmission System at the Point(s) of Interconnection.

"Interconnection Provider" shall mean Nevada Power Company in its role as owner and operator of the Nevada Power Company Transmission System.

"Interconnection Provider's Transmission System" shall mean the transmission system facilities owned and operated jointly by Sierra Pacific Power Company and Nevada Power Company (or their successors) used for the provision of transmission services under the NV Energy OATT.

"Law" shall mean any federal, state and local law, statute, ordinance, regulation, order, action, policy or other governmental requirement, as amended or that may be enacted or promulgated subsequently.

"Metering Equipment" shall have the meaning set forth in ARTICLE 4 of this Agreement.

"Modification" shall mean any new construction, additions, alterations, design changes or the abandonment, retirement, relocation or rearrangement of the Parties' transmission systems or Interconnection Facilities.

"NERC" shall mean North American Electric Reliability Corporation or its successor.

"NESC" shall mean the National Electrical Safety Code, as may be amended from time to time.

"NPC" shall mean Nevada Power Company d/b/a NV Energy and its permitted successors and assigns.

"NV Energy OATT" shall mean that certain Open Access Transmission Tariff on file with FERC and designated NV Energy, Inc. Operating Companies Open Access Transmission Tariff as it may be amended or superseded from time to time.

"Operational Change" shall mean any material change in the day-to-day routine, practices or procedures pertaining to the operation of either Party's transmission system but excluding any change in connection with either a planned or unplanned outage or an Emergency.

"OSHA" shall mean the Occupational Safety and Health Administration or its successor.

"Point of Change of Ownership" shall mean the points at which NPC ownership of the Interconnection Provider's Transmission System end and the TWE's ownership of its transmission facilities begin, as depicted in the one-line diagram in Appendix C.

"Point(s) of Interconnection" shall mean the point, as depicted in the one-line diagram in Appendix C, where the Interconnection Facilities connect to the Interconnection Provider's Transmission System.

"Prudent Utility Practice" shall mean any of the acts, practices, methods, equipment, materials, specifications and standards engaged in or approved in connection with a significant portion of the electric utility industry which, as applicable, in the exercise of professional judgment in light of the facts known at the time a decision was made, could have been expected to accomplish the desired result in a manner consistent with applicable Laws, Electric Reliability Organization requirements, reliability, safety, performance, dependability, efficiency, environmental protection, economy and expedition. Prudent Utility Practices are not intended to be limited to the optimum practice or method to the exclusion of other practices or methods, but rather to be a spectrum of possible but reasonable practices and methods.

"PUCN" shall mean the Public Utilities Commission of Nevada, or its successor.

"Regulatory Requirements" shall mean any of the applicable practices, methods and acts required by NERC, FERC, OSHA, PUCN and the WECC, or other governmental agencies or regional entity having jurisdiction over the Parties with regard to the subject matter of this Agreement, or the successor of any of them.

"Reasonable Efforts" shall mean, with respect to an action required to be attempted or taken by a Party under this Agreement, efforts that are timely and consistent with Prudent Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

"SPPC" shall mean Sierra Pacific Power Company d/b/a NV Energy, and its successors in interest.

"SCADA" shall mean Supervisory Control and Data Acquisition equipment.

"Switching and Tagging" shall mean the Parties' switching and tagging procedures, as they may be amended from time to time.

"System Protection Facilities" shall mean the equipment, including necessary protection signal communications equipment, required to protect (i) the Interconnection Provider's Transmission System from faults or other electrical disturbances occurring on Interconnection Customer's Interconnection Facilities and (ii) Interconnection Customer's Interconnection Facilities from faults or other electrical system disturbances occurring on the Interconnection Provider's Transmission System or on other delivery systems or other generating systems to which the Interconnection Provider's Transmission System is directly connected.

"WECC" shall mean the Western Electricity Coordinating Council, or its successor.

ARTICLE 2
EFFECTIVE DATE, TERM, SUSPENSION, AND TERMINATION

2.1 **Effective Date**. The Effective Date of this Agreement shall be the date of executing by the Parties, or such other effective date established by the FERC.

2.2 **Term.** This Agreement shall remain in full force and effect from the Effective Date until or unless terminated in accordance with this ARTICLE 2.

2.3 **Suspension.** Interconnection Customer reserves the right, upon written notice to Interconnection Provider, to suspend at any time all work by Interconnection Provider associated with the construction and installation of Interconnection Provider's Interconnection Facilities required under this Agreement with the condition that Interconnection Provider's Transmission System shall be left in a safe and reliable condition in accordance with Prudent Utility Practice and Interconnection Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Interconnection Provider (i) has incurred pursuant to this Agreement prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Interconnection Provider's Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Interconnection Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Interconnection Provider shall obtain Interconnection Customer's authorization to do so. Interconnection Provider shall invoice Interconnection Customer for such costs pursuant to ARTICLE 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Interconnection Provider required under this Agreement pursuant to this Section 2.3, and has not requested Interconnection Provider to recommence the work required under this Agreement on or before the expiration of three (3) years following commencement of such suspension, this Agreement shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Interconnection Provider, if no effective date is specified.

2.4 **Termination.**

2.4.1 This Agreement may be terminated at any time by mutual agreement of the Parties.

2.4.2 Either Party may terminate this Agreement, upon the occurrence of any the following events: (i) permanent removal of the Interconnection Provider's Interconnection Facilities or the Interconnection Customer's Interconnection Facilities from service; (ii) in an event of Default as provided in ARTICLE 14; or (iii) upon a request to FERC subject to the provisions of Section 205 or 206 of the FPA by any Party seeking termination of this Agreement.

2.4.3 **Termination Costs**. If a Party elects to terminate this Agreement pursuant to Section 2.4, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the non-terminating Party's receipt of such notice of termination, that are the responsibility of the terminating Party under this Agreement. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination.

2.4.4 **FERC Approval**. No termination hereunder shall become effective until the Party seeking termination tenders to FERC notice of termination of this Agreement and FERC has accepted such notice of termination, to the extent required by FERC regulations.

2.4.5 **Disconnection**. Upon termination of this Agreement, the Parties will take all appropriate steps to disconnect the Interconnection Customer's Interconnection Facilities from the

Interconnection Provider's Transmission System. All costs required to effectuate such disconnection shall be borne by the Interconnection Customer, unless such termination resulted from Interconnection Provider's Default of this Agreement or the Interconnection Provider is otherwise expressly provided as responsible for these costs under this Agreement.

2.4.6 **Survival**. This Agreement shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this Agreement; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this Agreement or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

2.5 **Regulatory Filing**. Interconnection Provider shall file this Agreement with FERC for filing pursuant to the FERC's Rules and Regulations under 18 C.F.R. Part 35. The Interconnection Customer agrees to reasonably cooperate with the Interconnection Provider with respect to such filing and to provide any information, including the filing of testimony, reasonably requested by Interconnection Provider, to comply with applicable Regulatory Requirements.

ARTICLE 3
PURPOSE AND SCOPE

3.1 **Purpose**. The purpose of this Agreement is to set forth the scope, terms and conditions for the interconnection of the Interconnection Customer's Interconnection Facilities to the Interconnection Provider's Transmission System, along with the continuing responsibilities and obligations related to such interconnection.

3.2 **Scope**. This Agreement pertains only the terms and conditions of the electric interconnections described herein.

3.2.1 The execution of this Agreement does not constitute a request for, nor the provision of, any transmission delivery service under the NV Energy OATT, and does not convey any right to deliver electricity to any specific customer or point of delivery. Interconnection Provider makes no representations to Interconnection Customer regarding the availability of transmission service on the Interconnection Provider's Transmission System, and Interconnection Customer agrees that the availability of transmission service on the Interconnection Provider's Transmission System may not be inferred or implied from Interconnection Provider's execution of this Agreement. If Interconnection Customer desires to obtain transmission service on the Interconnection Provider's Transmission System, Interconnection Customer must request such service in accordance with the provisions of the NV Energy OATT.

3.2.2 Nothing in this Agreement shall be interpreted as a request by Interconnection Customer or a commitment by Interconnection Provider to install any facilities other than those identified in Appendix A.

ARTICLE 4
INTERCONNECTION FACILITIES

4.1 **Engineering, Procurement and Construction of Interconnection Customer's Interconnection Facilities**

4.1.1 Interconnection Customer shall, at its sole expense, engineer, procure equipment for, and construct the Interconnection Customer's Interconnection Facilities, as set forth in Appendix A, using Prudent Utility Practice and standards and specifications provided in advance by Interconnection Provider and in compliance with all Regulatory Requirements.

4.1.2 Interconnection Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall make such changes to the Interconnection Facilities as may reasonably be required by Interconnection Provider, in accordance with Prudent Utility Practice and all Regulatory Requirements, to ensure that the Interconnection Facilities are compatible with the technical specifications, operational control, and safety requirements of Interconnection Provider. Interconnection Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Interconnection Facilities.

4.1.3 Prior to commencement of construction, Interconnection Customer shall provide to Interconnection Provider a schedule for construction of the Interconnection Facilities, and shall promptly respond to requests for information from Interconnection Provider.

4.1.4 At any time during construction, Interconnection Provider shall have the right to gain access to the Interconnection Facilities and to conduct inspections of the same, subject to the requirements of Section 6.3.

4.1.5 At any time during construction, should any phase of the engineering, equipment procurement, or construction of the Interconnection Facilities not meet the standards and specifications provided by Interconnection Provider, Interconnection Customer shall be obligated to remedy any such deficiencies, and will be responsible for the costs of remedying such deficiencies.

4.1.6 Interconnection Customer shall indemnify Interconnection Provider for claims arising from the interconnection of the Interconnection Facilities to the Interconnection Provider's Transmission System under the terms and procedures of Section 11.1.

4.1.7 Within one hundred twenty (120) days after completion, Interconnection Customer shall deliver to Interconnection Provider "as-built" drawings, information, and any other documents that are reasonably required by Interconnection Provider to assure that the Interconnection Facilities are built to the standards and specifications required by Interconnection Provider and in compliance with all Regulatory Requirements.

4.2 **Interconnection Provider's Interconnection Facilities**

4.2.1 In accordance with ARTICLE 5, the Interconnection Customer shall pay for the cost of the Interconnection Provider's Interconnection Facilities itemized in Appendix A of this Agreement.

4.2.2 **Special Provisions for Affected Systems**. The Interconnection Customer will work with any Affected Systems to mitigate impacts to the Affected Systems prior to energization of the interconnection facilities. The Interconnection Customer will be responsible to coordinate the payment of any required facilities by Affected Systems outside of this Agreement.

4.3 **Metering**

4.3.1 **General**. Interconnection Customer shall comply with the applicable Electric Reliability Organization requirements. Unless otherwise agreed by the Parties, Interconnection Provider shall install "Metering Equipment", at Interconnection Customer's expense, at the Point of Interconnection, or at another metering point compensated to the Point of Interconnection, prior to any operation of Interconnection Customer's Interconnection Facilities and shall own, operate, test and maintain such Metering Equipment. If Interconnection Provider's Metering Equipment is not installed at the Point of Interconnection, Interconnection Customer shall have the right to review the programming to be used by Interconnection Provider in the metering arrangement involving compensation to the Point of Interconnection. Such programming will use industry standard concepts and algorithms along with site specific values. If Interconnection Customer has different site-specific values than those determined by Interconnection Provider, Interconnection Customer shall forward its calculations to Interconnection Provider for review and reconciliation. Power flows to and from the Interconnection Customer's transmission system shall be measured at or, at Interconnection Provider's option, compensated to the Point of Interconnection. The meters will be programmed to measure real power flow (in kilowatthours) and reactive power flow (in kilovarhours) in both directions independently. Interconnection Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall be responsible for the costs associated with any equipment required in order for it to receive such metering quantities.

4.3.2 **Standards**. Interconnection Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable American National Standards Institute ("ANSI") standards.

4.3.3 **Testing of Metering Equipment**. Interconnection Provider shall inspect and test all Interconnection Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Interconnection Provider shall, at Interconnection Customer's expense, inspect or test such Metering Equipment more frequently than every two (2) years. Interconnection Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time the Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced, at the expense of Interconnection Customer, in order to provide accurate metering. If the Metering Equipment fails to register, or if the measurement made by the Metering Equipment during a test varies by more

than two percent from the measurement made by the standard meter used in the test, Interconnection Provider shall adjust the measurements by correcting all measurements for the period during which the Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

4.3.4 **Metering Data**. Each Party shall have the right to retrieve metering data from the Metering Equipment. At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Interconnection Provider and to one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from and/or to the Point of Interconnection.

4.4 Communications

4.4.1 **Relay and Line Protection**. Relay communications shall be provided via dedicated and redundant paths in accordance with WECC requirements for protection of transmission lines interconnecting two (2) electric utilities and in accordance with Interconnection Provider's standards. For this interconnection a third redundant path may also be used.

4.4.2 **Fiber**. The primary, secondary and tertiary relay paths shall be provided via fiber optic cable. System protection using the fiber optic cable shall be performed using relays that support a direct fiber interface such as Schweitzer Engineering Laboratories relays. Interconnection Provider will identify the specific type and model of relays to be used by both Interconnection Provider and Interconnection Customer.

4.4.3 **Cost Sharing of Fiber**. Any sharing of costs for fiber optic cable and/or any provision of an Indefeasible Right of Use ("IRU") in any fiber optic cable by Interconnection Provider to Interconnection Customer or by Interconnection Customer to Interconnection Provider will be addressed in a separate agreement between the Parties.

4.4.4 **No Annexation**. Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

ARTICLE 5
COST RESPONSIBILITY FOR INTERCONNECTION FACILITIES

5.1 Interconnection Facilities

5.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities as itemized in Appendix A of this Agreement. The Interconnection Provider shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs will be invoiced according to ARTICLE 12 and the Milestones in Appendix B to this Agreement.

5.1.2 In accordance with ARTICLE 6, the Interconnection Customer shall be responsible for all expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Interconnection Provider's Interconnection Facilities.

ARTICLE 6
OPERATIONS AND MAINTENANCE

6.1 **Interconnection Provider Obligations**. Interconnection Provider shall own, operate and maintain the Interconnection Provider's Transmission System in accordance with Prudent Utility Practice.

6.2 **Interconnection Customer Obligations**. Unless otherwise agreed to by the Parties, the Interconnection Customer shall be responsible for the operations and maintenance expenses of the Interconnection Provider's Interconnection Facilities installed in accordance with Section 6.11 of this Agreement. Interconnection Customer shall, at its own expense, operate and maintain the Interconnection Customer's Interconnection Facilities on its side of the Point(s) of Interconnection in accordance with Prudent Utility Practice.

6.3 **Access Rights**. Any Party performing work in connection with this Agreement ("accessing Party") under or in close proximity to the Interconnection Facilities shall (a) abide by all Laws and rules applicable to such work, including, but not limited to, all applicable NERC and WECC reliability standards and the requirements of the NESC, OSHA, and Chapter 455 of the Nevada Revised Statutes; and (b) perform all work in accordance with the electrical practices of the Party whose Interconnection Facilities are being accessed. In addition, when work is being performed in connection with this Agreement on real property that a Party has a right to use and may legally allow the accessing Party to use (the "Premises"), the accessing Party shall provide adequate prior notice, abide by all Laws applicable to the work and use of the Premises and comply with all safety, security and work rules applicable to the work and use of the Premises, whether required by Law or the other Party. For purposes of this section, "adequate prior notice" means at least ten (10) business days prior written notice to the other Party that identifies who will be accessing the Premises, the work that will be performed on the Premises, the dates and hours the work will be performed and provides a copy of all required permits. The other Party, at the accessing Party's cost, shall have the right to have a representative present during all times the accessing Party's personnel are on the premises.

6.4 **Operations**

6.4.1 **General**. Each Party shall comply with the applicable Electric Reliability Organization requirements. Interconnection Customer shall ensure that the operations of its Interconnection Customer's Interconnection Facilities are operated in accordance with requirements of the Balancing Authority Area. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with applicable Laws and Regulatory Requirements.

6.4.2 **Interconnection Provider Obligations**. Interconnection Provider shall cause the Interconnection Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this Agreement and Prudent Utility Practice. Interconnection Provider shall provide operating instructions to Interconnection Customer consistent with this Agreement and Interconnection Provider's operating protocols and procedures as they may change from time to time. Interconnection Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

6.4.3 **Interconnection Customer Obligations**. Interconnection Customer shall at its own expense operate, maintain and control Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Agreement and Prudent Utility Practice. Interconnection Customer shall operate Interconnection Customer's Facilities in accordance with all applicable requirements of Interconnection Provider's Balancing Authority Area.

6.4.4 **Voltage Control and Supply of Reactive Power**. Each Party shall use Reasonable Efforts in accordance with Prudent Utility Practice to limit variations and fluctuations in voltages and to meet reactive power requirements of its respective system and loads so as to minimize adverse effects upon the operation of the electrical facilities or system of the other Party. Interconnection Customer shall also acquire sufficient reactive resources within its transmission system to protect the voltage levels under normal and contingency conditions. This includes the Interconnection Customers' share of the reactive requirements for generators interconnecting to the Interconnection Customer's transmission system.

6.5 **Outages and Interruptions.**

6.5.1 **Outage Authority and Coordination**. Each Party may, in accordance with Prudent Utility Practice and in coordination with the other Party, remove from service any of its respective Interconnection Facilities that may impact the other Party's Interconnection Facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

6.5.2 **Outage Schedules**. Interconnection Provider shall post scheduled outages of its transmission facilities on its Open Access Same-Time Information System ("OASIS"). Interconnection Customer shall submit its planned maintenance schedules for Interconnection Customer's Interconnection Facilities to Interconnection Provider a minimum of sixty (60) days in advance of the commencement of any such maintenance. Interconnection Customer shall update its planned maintenance schedules as necessary. Interconnection Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Interconnection Provider's Transmission System.

6.5.3 **Outage Restoration**. If an outage on a Party's facilities adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of

service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

6.5.4 **Unplanned Outages**. In the event of an unplanned outage of a Party's transmission system that adversely affects the other Party's transmission system, each Party will use efforts consistent with Prudent Utility Practice and applicable Regulatory Requirements to restore the facility(ies) to service as soon as is practicable.

6.6 **System Protection and Other Control Requirements**.

6.6.1 Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of Interconnection Customer's Interconnection Facilities. Interconnection Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Interconnection Provider's Interconnection Facilities or the Interconnection Provider's Transmission System as a result of the interconnection of Interconnection Customer's Interconnection Facilities to the Interconnection Provider's Transmission System.

6.6.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Prudent Utility Practice.

6.6.3 Each Party shall be responsible for protection of its Interconnection Facilities consistent with Prudent Utility Practice.

6.6.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in this ARTICLE 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or tripping of the Interconnection Facilities.

6.6.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Prudent Utility Practice.

6.6.6 Prior to the Commercial Operation Date each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Prudent Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. Such tests require that all protective relays and lockout contacts be activated.

6.6.7 **Requirements for Protection**. In compliance with Prudent Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of Interconnection Customer's Interconnection Facilities to any short circuit occurring on the Interconnection Provider's Transmission System not otherwise isolated by Interconnection Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Interconnection Provider's Transmission System. Interconnection Customer shall be solely

responsible to disconnect Interconnection Customer's Interconnection Facilities if conditions on the Interconnection Provider's Transmission System could adversely affect Interconnection Customer.

6.7 **Switching and Tagging Rules**. Each Party shall provide the other Party a copy of its Switching and Tagging rules that are applicable to the other Party's activities. Such Switching and Tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable Switching and Tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

6.8 **Disturbance Analysis Data Exchange**. The Parties will cooperate with one another in the analysis of disturbances to either Interconnection Customer's transmission system or the Interconnection Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Prudent Utility Practice.

6.9 **Maintenance**

6.9.1 **Interconnection Provider Obligations**. Interconnection Provider shall maintain the Interconnection Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this Agreement and the requirements of the Balancing Authority Area.

6.9.2 **Interconnection Customer Obligations**. Interconnection Customer shall maintain Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Agreement.

6.9.3 **Coordination.** The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Facilities.

6.9.4 **Secondary Systems**. Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

6.10 **Inspections and Testing**.

6.10.1 **Inspections**. The Parties shall perform routine inspection and testing of their respective Interconnection Facilities in accordance with Prudent Utility Practice and applicable Regulatory Requirements as may be necessary to ensure the continued operations of each Party's transmission systems in a safe and reliable manner.

6.10.2 **Right to Observe Testing**. The Parties shall have the right to observe the testing of the other Party's Interconnection Facilities, the performance of which testing may reasonably

be expected to affect the reliability of the observing Party's Interconnection Facilities. The observing Party shall provide the other Party reasonable advanced notice of such testing, to the extent practicable.

6.10.3 **Observation of Deficiencies**. If either Party observes any condition it believes may be inconsistent with Prudent Utility Practice and applicable Regulatory Requirements with respect to the other Party's Interconnection Facilities that might reasonably be expected to adversely affect the observing Party's Interconnection Facilities, the observing party shall notify the other Party. Notwithstanding the forgoing, the observing Party shall have no liability for failure to give such notice.

6.11 **Operating and Maintenance Expenses**. For the term of the Agreement, Interconnection Customer shall reimburse Interconnection Provider for all reasonable expenses, including overheads, associated with operating, maintaining, repairing, and replacing Interconnection Provider's Interconnection Facilities including an annual operations charge for such facilities as outlined in Appendix A.5.d. Any such charges under this section shall be invoiced [annually] according to ARTICLE 12.

ARTICLE 7
EMERGENCIES

7.1 **Generally**. Each Party agrees to comply with the emergency procedures set forth by the NERC and/or WECC, or the direction of the applicable Balancing Authority, or other Regulatory Requirements.

7.2 **Notice**. Each Party shall provide the other Party with verbal notification that is prompt under the circumstances of an Emergency that may reasonably be expected to affect the other Party's transmission system, to the extent the notifying Party is aware of the Emergency.

7.3 **Immediate Action**. In the event of an Emergency, the Party becoming aware of the Emergency may, in accordance with Prudent Utility Practice and applicable Regulatory Requirements and using its reasonable judgment, take such action with respect to its own facilities as is reasonable and necessary to prevent, avoid, or mitigate injury, danger and/or loss of life or property. The Parties shall, consistent with Prudent Utility Practice and applicable Regulatory Requirements, take whatever actions or inactions the Parties deem necessary during an Emergency, in order to: (i) preserve public health and safety; (ii) preserve the reliability of the Interconnection Provider's Transmission System; (iii) limit or prevent damage; and (iv) expedite restoration of service.

7.4 **Abnormal Conditions**. To the extent either Party is aware of any Abnormal Condition, such Party, subject to the satisfaction of and compliance with Regulatory Requirements, will make reasonable efforts to promptly notify the other Party of such Abnormal Condition if it may reasonably be expected to affect that Party's use of its Interconnection Facilities. However, the failure of any Party to provide notice in conformance with this Section 7.4 shall not constitute a material breach of this Agreement.

ARTICLE 8
MODIFICATIONS OR OPERATIONAL CHANGES

8.1 **Generally**. Each Party may make Modifications or Operational Changes to its transmission system, at its own expense, on its side of the Point(s) of Interconnection.

8.2 **Notice**. Each Party shall provide notice of planned Modifications or Operational Changes to WECC in the manner and form required by WECC procedures prior to making any such Modifications or Operational Changes and in accordance with all applicable Regulatory Requirements.

ARTICLE 9
ENVIRONMENTAL RELEASES

Each Party shall notify the other Party, first verbally and then in writing, of the release of or discovery of any Hazardous Substances (including, without limitation, asbestos-containing materials and polychlorinated biphenyls) while conducting the activities contemplated under this Agreement. Initial verbal notification shall be as soon as possible after discovery but in no event later than twenty-four (24) hours after the Party becomes aware of the occurrence or condition. Each of the Parties shall take all appropriate measures to assure that any contractors engaged by such Party are obligated to timely communicate to said Party any release or discovery of Hazardous Substances associated with their contracted activities.

ARTICLE 10
ASSIGNMENT

10.1 **Successors and Assignees**. Following the Effective Date, this Agreement, and the rights and obligations created thereby, shall bind and inure to the benefit of the successors, and permitted assignees of the Parties.

10.2 **Consent**. No Party hereto may assign any rights or obligations hereunder without obtaining the written consent of the other Party, which consent shall not unreasonably be withheld, except transfers by operation of law, consolidation or merger, for the purpose of granting to a secured party a security interest in this Agreement pursuant to a mortgage, indenture or other security instrument, or a sale by one of the parties of its entire electric utility facilities. Notwithstanding the foregoing, either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement.

ARTICLE 11
INDEMNITY, CONSEQUENTIAL DAMAGES, AND INSURANCE

11.1 **Indemnity.** Each Party shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inaction of its obligations under this Agreement on behalf of the

Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

11.1.1 **Indemnified Person**. If an Indemnified Person is entitled to indemnification under this ARTICLE 11 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Section 11.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

11.1.2 **Indemnifying Party**. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this ARTICLE 11, the amount owing to the Indemnified Person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

11.1.3 **Indemnity Procedures**. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Section 11.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceeding if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be unreasonably withheld, conditioned or delayed.

11.2 **Consequential Damages.** In no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including, but not limited to, loss of profit or revenue, loss of the use of equipment, cost of temporary equipment or services, whether based in whole or in part

in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.3 **Insurance.** Each Party shall, at its own expense, maintain in force throughout the period of this Agreement, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

11.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

11.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification), products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

11.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

11.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Fifteen Million Dollars ($15,000,000) per occurrence/Fifteen Million Dollars ($15,000,000) aggregate.

11.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this Agreement against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to the anniversary date of cancellation or any material change in coverage or condition.

11.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the polices are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond

the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

11.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

11.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to, and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

11.3.9 Within ten (10) days following execution of this Agreement, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required pursuant to this Agreement, executed by each insurer or by an authorized representative of each insurer.

11.3.10 Notwithstanding the foregoing, each Party may self-insure up to One Million Dollars ($1,000,000) in order to meet the minimum insurance requirements of Sections 11.3.1 through 11.3.7 to the extent it maintains a self-insurance program; provided, that such Party's self-insurance program meets the minimum insurance requirements of Sections 11.3.1 through 11.3.7. Each Party may self-insure for amounts in excess of One Million Dollars ($1,000,000) in order to meet the minimum insurance requirements of Sections 11.3.1 through 11.3.7 to the extent it maintains a self-insurance program; provided, that such Party's senior secured debt is rated at investment grade or better by Standard & Poor's or Moody's and that its self-insurance program meets the minimum insurance requirements of Sections 11.3.1 through 11.3.7. For any period of time that a Party's senior secured debt is unrated or is rated at less than investment grade by Standard & Poor's or Moody's, such Party's self-insurance option shall be limited to One Million Dollars ($1,000,000). In the event that a Party is permitted to self-insure pursuant to this Section 11.3.10, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in this ARTICLE 11.

11.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Agreement.

ARTICLE 12
INVOICES

12.1 **General**. The Interconnection Provider shall submit to the Interconnection Customer invoices of amounts due in accordance with the Milestones as listed in Appendix B.

12.2 **Final Invoice for Interconnection Provider's Transmission Facilities**. Within six (6) months after completion of the construction of Interconnection Provider's Interconnection Facilities, Interconnection Provider shall provide an invoice of the final costs and shall set forth

such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the amounts paid by Interconnection Customer and to ascertain deviations, if any, between the actual costs incurred by Interconnection Provider and the amount paid by Interconnection Customer. Interconnection Provider shall refund to Interconnection Customer, or Interconnection Customer shall pay to Interconnection Provider, any amount by which the actual payments made by Interconnection Customer to Interconnection Provider exceeds the actual costs of construction incurred by Interconnection Provider within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 **Annual Invoice for Operations and Maintenance**. On or about one year from the Effective Date, and annually henceforth for the term of the Agreement, Interconnection Provider shall invoice Interconnection Customer for the preceding year's operations and maintenance charges for the Interconnection Providers' Interconnection Facilities in accordance with Section 6.11 of this Agreement.

12.4 **Payment**. Invoices shall be rendered to the paying Party at the address specified in the Notices in Appendix D pursuant to the payment dates listed in the Milestones within Appendix B. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the invoicing Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this Agreement.

12.5 **Disputes**. In the event of a billing dispute between Interconnection Provider and Interconnection Customer, Interconnection Provider shall continue to provide Interconnection Service under this Agreement as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Interconnection Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Interconnection Provider may stop work under this Agreement and provide notice to Interconnection Customer of a Default pursuant to ARTICLE 14. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other.

ARTICLE 13
FORCE MAJEURE

13.1 **General**. Notwithstanding anything in this Agreement to the contrary, neither Party shall be considered to be in default or breach of this Agreement or liable in damages or otherwise responsible to the other Party for any delay in or failure to carry out any of its obligations under this Agreement if, and only to the extent that, it is unable to perform or is prevented from performing by an event of Force Majeure. A Force Majeure exemption from liability will extend for the period of time necessitated by such event of Force Majeure. Such event of Force Majeure will not relieve either Party of its obligation to make payments hereunder.

13.2 **Definition**. The term "Force Majeure" as used herein means those causes beyond the reasonable control of the Party affected, which, through the exercise of Prudent Utility Practice and reasonable care, that Party could not have avoided or overcome and which wholly or in part

prevents such Party from performing its obligations under this Agreement, including, without limitation, the following: any act of God; labor disturbance; act of the public enemy; war; insurrection; riot; fire; storm; flood; sun spots; lightning strikes; earthquake; explosion; breakage or accident to machinery or equipment; electric system disturbance; order, regulation, or restriction imposed by governmental, military, or lawfully established civilian authorities; action of any court or governmental authority; or any other cause of a similar nature beyond a Party's reasonable control.

13.3 **Limitations**. In the event of Force Majeure, a Party's obligations can only be excused to the extent and for the period that the Party's inability to perform is caused by an event of Force Majeure affecting the Party and only to the extent of the duration of the same, provided that the Party claiming Force Majeure shall make all reasonable efforts to cure, mitigate or remedy the effects of the Force Majeure event. Nothing herein shall be construed to require either Party to settle a labor dispute, lockout or strike.

13.4 **Notice**. A Party claiming Force Majeure as a basis for being excused from performance of its obligations under this Agreement must (i) provide verbal notice that is prompt under the circumstances, followed by written notice of the occurrence of the Force Majeure event to the other Party no later than five (5) business days after the Party knows of the occurrence of the event, where such notice provides an estimate of the event's expected duration and the probable impact on the performance of the Party's obligations hereunder; (ii) exercise all reasonable efforts in accordance with Prudent Utility Practice to continue to perform its obligations under this Agreement; (iii) expeditiously take reasonable action to correct or cure the Force Majeure event, provided, however, that settlement of strikes or other labor disputes is completely within the sole discretion of the Party affected by such strike or labor dispute; and (iv) provide prompt notice to the other Party of the cessation of the Force Majeure event. Failure to provide notice of the occurrence of the Force Majeure event required hereunder shall preclude such Party from relying upon Force Majeure to excuse its failure to perform or avoid breach or default as a result of such failure.

ARTICLE 14
BREACH, CURE AND DEFAULT

14.1 **Breach**. A breach of this Agreement shall occur upon the failure by a Party to perform any material term or condition of this Agreement.

14.2 **Events of Breach**. A breach of this Agreement shall include the following: (a) The failure to comply with any material term or condition of this Agreement, including but not limited to any material breach of a representation, warranty or covenant made in this Agreement; (b) If a Party: (i) by decree of a court of competent jurisdiction, is adjudicated bankrupt or insolvent; (ii) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (iii) makes a general assignment for the benefit of its creditors; or (iv) consents to the appointment of a receiver, trustee or liquidator; (c) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement; (d) Failure of either Party to provide such access rights, or a Party's attempt to revoke or terminate such access rights, as provided under this Agreement; or (e) Failure of either Party to provide information or data to the other Party as

required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement or to satisfy Regulatory Requirements.

14.3 **Cure and Default**.

14.3.1 A Party automatically will be deemed to be in "Default" of this Agreement upon the occurrence of any one of the events described in Sections 14.2(b)(ii)-(iv) of the Agreement.

14.3.2 Upon the occurrence of any event of breach other than those described in Sections 14.2(b)(ii)-(iv), the Party not in breach (hereinafter the "Non-Breaching Party"), when it becomes aware of any such breach, shall give written notice of the breach to the breaching Party (the "Breaching Party"). Such notice shall set forth, in reasonable detail, the nature of the breach, and where known and applicable, the steps necessary to cure such breach. Upon receiving written notice of the breach hereunder, the Breaching Party shall have thirty (30) days to cure such breach. If the breach is such that it cannot be cured within such thirty (30) calendar day time period, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the breach, or to commence reasonable and appropriate steps to cure the breach, within such thirty (30) calendar daytime period, the Breaching Party will be in "Default" of the Agreement.

14.3.3 Upon the occurrence of a Default, the Non-Breaching Party may, subject to the limitations contained in this ARTICLE 14, terminate this Agreement by providing written notice of termination to the other Party, except that where a Default has been disputed by the Breaching Party, termination of this Agreement on account of such Default may not occur absent a final, binding and non-appealable decision by FERC, an arbitrator, or a court of competent authority having jurisdiction, making a determination of said Default.

14.4 **Right to Compel Performance**. Notwithstanding the foregoing, upon the occurrence of Default, the non-breaching Party shall be entitled to (i) commence an action to require the breaching Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (ii) exercise such other rights and remedies as it may have in equity or at law. Neither Party shall be required to post any guaranty, letter of credit, bond or other security to obtain an order or decree of specific performance.

ARTICLE 15
LABOR RELATIONS

Each Party agrees to immediately notify the other Party, verbally and then in writing, of any labor dispute or anticipated labor dispute of which its management has actual knowledge that might reasonably be expected to affect the operations of the other Party with respect to this Agreement.

ARTICLE 16
SUBCONTRACTOR

16.1 **Generally**. Nothing in this Agreement shall prevent a Party from utilizing the services of such subcontractors as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services.

16.2 **Responsibility of Principal**. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. Each Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor it hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon a Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

16.3 **No Third Party Beneficiary**. No subcontractor is intended to be, nor will it be deemed to be, a third party beneficiary of this Agreement.

16.4 **No Limitation by Insurance**. The obligations under this ARTICLE 16 will not be limited in any way by any limitation on a subcontractor's insurance.

ARTICLE 17
CONFIDENTIALITY

17.1 **Nondisclosure**. Neither Party shall disclose any Confidential Information of the other Party obtained pursuant to or in connection with the performance of this Agreement to any third party without the express written consent of the other Party, except that either Party may produce Confidential Information in response to a subpoena, discovery request or other compulsory process issued by a judicial body or governmental agency upon reasonable notice to the Party whose Confidential Information it is. Neither Party shall disclose information designated as Critical Energy Infrastructure Information (as defined in 18 C.F.R. §388.113) except as permitted by applicable Regulatory Requirements.

17.2 **Definition**. "Confidential Information" means any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as Confidential by the Party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this Agreement. Confidential Information shall not include information that the receiving Party can demonstrate (i) is generally available to the public other than as a result of a disclosure by the receiving Party; (ii) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (iii) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party, after due inquiry, was under no obligation to the other Party to keep such information confidential; (iv) was independently developed by the receiving Party without reference to Confidential Information of

the disclosing Party; (v) was disclosed with the prior written approval of the disclosing Party; (vi) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or breach of this Agreement; or (vii) is required, in accordance with this ARTICLE 17, to be disclosed by any federal or state government or agency or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement held in a court or agency of competent jurisdiction. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential. Finally, for the purposes of this Agreement, information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed verbally or by inspection, if the Party providing the information verbally informs the Party receiving the information that the information is confidential.

17.3 **Standard of Care**. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination.

17.4 **Use of Confidential Information**. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this Agreement or its Regulatory Requirements, or in any proceeding under ARTICLE 19 or in any administrative agency or court of competent jurisdiction addressing any dispute arising under this Agreement, subject either to a confidentiality agreement with all participants (including, if applicable, arbitrator(s)) or to a protective order.

17.5 **Survival**. The confidentiality provisions of this ARTICLE 17 shall survive termination of this Agreement for a period of three (3) years.

17.6 **FERC Access to Confidential Information**. Notwithstanding anything in this ARTICLE 17 to the contrary, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party may, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. The Party shall notify the other Party to the Agreement when it is notified by FERC or its staff that a request for disclosure of, or decision to disclose, Confidential Information has been received, at which time either of the Parties may respond before such information is made public, consistent with 18 C.F.R. § 388.112.

ARTICLE 18
AUDIT RIGHTS

Subject to the requirements of confidentiality under ARTICLE 17 of the Agreement, any Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party and, at its own costs and expenses, to audit each other's accounts and records pertaining to the other Party's performance and/or satisfaction of obligations arising under this Agreement. Said audit shall be performed at the offices where such accounts and records are maintained and shall

be limited to those portions of such accounts and records that relate to obligations under this Agreement.

ARTICLE 19
DISPUTE RESOLUTION

19.1 **Submission**. Prior to providing any notice of any claim or dispute that either Party may have against the other arising out of this Agreement, the Parties shall work in good faith to informally resolve any dispute through negotiations by the Parties. In the event the Parties cannot resolve their dispute through good faith negotiations, the disputing Party shall submit a notice of dispute in writing to the other Party not later than sixty (60) days after the circumstances which gave rise to the claim or dispute have taken place. This submission of any claim or dispute shall include a concise statement of the question or issue in dispute, together with relevant facts and documentation to fully support the claim.

19.2 **Alternative Dispute Resolution**. If any such claim or dispute arises, the Parties shall use their best efforts to resolve the claim or dispute, initially through good faith negotiations or upon the failure of such negotiations, through mutually agreed to alternative dispute resolution ("ADR") techniques; however, either Party may terminate its participation in ADR during any stage of ADR and proceed under Section 19.4.

19.3 **Technical Disputes**. With respect to disputes which the Parties mutually agree are exclusively technical in nature, the Parties shall work informally in good faith to resolve such technical disputes. In the event the Parties are unable to resolve their technical disputes, the Parties will elevate such disputes to its respective officers and directors for such officers and directors to resolve. In the event, the Parties' officers and directors cannot resolve such technical dispute, the Parties, shall provide a notice of dispute to the non-disputing Party and follow the procedures set forth in Section 19.1 above.

19.4 **Arbitration**. Except as provided in Section 19.4.1.1, if any claim or dispute arising hereunder is not resolved within sixty (60) days after notice thereof to the other Party, either Party may demand in writing the submission of the dispute to binding arbitration in Nevada, unless the Parties mutually agree upon another location and shall be heard by one neutral arbitrator under the American Arbitration Association's Commercial Arbitration Rules ("Arbitration Rules"); provided, however, that in the event of a conflict between the Arbitration Rules and the terms and provisions of this ARTICLE 19, the terms and provisions of this ARTICLE 19 shall govern. The Parties shall each bear one-half of the arbitrator's fees and expenses, but shall bear their own costs and expenses (including attorneys' and expert witness fees and expenses) incurred in the arbitration proceeding.

19.4.1 **Arbitration Procedures**. Any arbitration initiated under this ARTICLE 19 shall be conducted by a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose an arbitrator, both of which shall sit on a three-member arbitration panel. The two arbitrators so chosen shall, within twenty (20) days, select a third arbitrator to chair the arbitration panel. Any arbitrator selected pursuant to this Section 19.4.1 must be knowledgeable in matters that are the subject of the dispute. The arbitrator(s) shall conduct the arbitration in accordance with

the Arbitration Rules in effect at the time arbitration is initiated under this ARTICLE 19; provided, however, that, in the event of a conflict between the Arbitration Rules and the terms and provisions of this ARTICLE 19, the terms and provisions of this ARTICLE 19 shall govern.

19.4.1.1 **Submission of Dispute to FERC**. Notwithstanding anything to the contrary in this ARTICLE 19, the arbitration and dispute resolution requirements of this Agreement shall not bar either Party from seeking relief from the FERC under this Agreement at any time, and shall not be construed as a waiver of any rights either party may have under the FPA.

19.4.2 **No Authority to Modify Agreement**. The arbitrator(s) shall have the authority only to interpret and apply the terms and conditions of this Agreement and shall have no power to modify or change any such terms or conditions.

19.4.2.1 The arbitrator(s) shall be required to follow any and all applicable federal, state, or local laws and regulations.

19.4.2.2 Remedies shall be awarded in accordance with the following:

19.4.2.3 The arbitrator(s) may not award punitive damages, multiple damages, or any other damages which are not measured by the prevailing Party's actual damages.

19.4.2.4 Any award of damages must be determined, limited and controlled by the limitation of liability provision of this Agreement.

19.4.2.5 The arbitrator(s) may, in his or her discretion, award pre-award and post-award interest on any damages awarded; provided, however, that the rate of interest may not exceed a rate equal to that based on the FERC methodology set forth in Section 35.19a of FERC's regulations (18 C.F.R. Section 35.19a).

19.4.3 **Timing and Nature of Decision**. Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment. The decision must be in writing and contain the reasons for the decision. The decision and award of the arbitrator shall be final and binding upon the Parties, their successors, and assigns; provided, however, that such decision and award may be challenged solely on the grounds that the conduct of the arbitrator, or the decision and award itself, violated the standards set forth in the Federal Arbitration Act. Judgment upon the award rendered by the arbitrator may be entered in any court having jurisdiction. The decision must also be filed with FERC if it affects FERC-jurisdictional rates, terms and conditions of service or facilities. Notwithstanding this Section 19.4.3, the Parties understand and agree that any decision by the arbitrator is not binding on FERC to the extent FERC exercises jurisdiction over the dispute.

19.5 **Procedures**. The procedures for the resolution of disputes set forth herein shall be the sole and exclusive procedures for the resolution of disputes; provided, however, that a Party may seek a preliminary injunction or other preliminary judicial relief if in its judgment such action is necessary to avoid irreparable damage or to preserve the status quo. Despite such actions, the Parties will continue to participate in good faith in the procedures specified herein. All applicable statutes of limitations and defenses based upon the passage of time shall be tolled while the procedures specified herein are pending. The Parties will take such action, if any, required to

effectuate such tolling. Each Party is required to continue to perform its undisputed obligations under this Agreement pending final resolution of a dispute. All negotiations pursuant to these procedures for the resolution of disputes will be confidential, and shall be treated as compromise and settlement negotiations for purposes of the Federal Rules of Evidence and State Rules of Evidence.

ARTICLE 20
NOTICES AND COMMUNICATIONS

20.1 Unless otherwise specified herein, all notices, requests, claims, demands and other communications required or permitted to be given under this Agreement must be in writing, and must be given (and will be deemed to have been duly given if so given) by hand delivery, cable, telecopy (confirmed in writing), overnight express delivery, or telex, or by mail (registered or certified, postage prepaid) to the respective Parties as outlined in Appendix D.

20.2 Any Party may change its address or designated representative for notices by notice to the other in the manner provided above by giving five (5) Business Days written notice prior to the effective date of the change.

20.3 Notwithstanding Section 20.1, any notice hereunder concerning an Emergency or other occurrence requiring prompt attention, or as necessary during day-to-day operations, may be made by telephone or in person provided that such notice is confirmed in writing promptly thereafter. Notice in an Emergency, or as necessary during day-to-day operations, shall be provided to the shift supervisor at Interconnection Provider's transmission control center.

ARTICLE 21
MISCELLANEOUS PROVISIONS

21.1 **Governing Law**.

21.1.1 This Agreement and all rights and obligations of the Parties hereunder are subject to all applicable state and federal laws and all applicable duly-promulgated orders and regulations and duly-authorized actions taken by the executive, legislative, or judicial branches of government, or any of their respective agencies, departments, authorities, or other instrumentalities having jurisdiction.

21.1.2 When not in conflict with or preempted by federal law, this Agreement will be governed by and construed in accordance with the laws of the State of Nevada without giving effect to the conflict of law principles thereof.

21.1.3 Except for those matters covered in this Agreement and which are either jurisdictional to FERC or submitted to arbitration pursuant to ARTICLE 19 herein, any action arising out of or concerning this Agreement must be brought in any state or federal court of competent jurisdiction in the State of Nevada. The Parties hereby consent to the jurisdiction of any state or federal court of competent jurisdiction in the State of Nevada for the purpose of hearing and determining any action not subject to FERC's jurisdiction.

21.2 **Compliance with Law**. In performing its obligations under this Agreement, each Party shall comply with all applicable Laws and Regulatory Requirements.

21.3 **Taxes**. Except as otherwise provided in this Agreement, each Party agrees to pay any and all local, state, federal sales, use, excise, or any other taxes which are now, or in the future may be, assessed and legally owed by such Party pertaining to goods provided and/or the services performed under this Agreement.

21.4 **Relationship of the Parties**. Nothing in this Agreement is intended to create a partnership, joint venture, or other joint legal entity making any Party jointly or severally liable for the acts of the other Party. Unless otherwise agreed to in a writing signed by all Parties, no Party shall have any authority to create or assume in the other Party's name or on its behalf any obligation, express or implied, or to act or purport to act as the other Party's agent or legally empowered representative for any purpose whatsoever. Each Party shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of persons by that Party to perform under this Agreement, including all federal, state, and local income, social security, payroll and employment taxes and statutorily-mandated workers' compensation coverage. None of the persons employed by either Party shall be considered employees of the other Party for any purpose; nor shall either Party represent to any person that such persons are or shall become employees of the other Party. Except as expressly provided for herein, no Party shall be liable to any third party in any way for any engagement, obligation, commitment, contract, representation, or for any negligent act or omission to act of the other Party.

21.5 **No Third Party Rights**. Nothing in this Agreement, express or implied, is intended to confer on any person, other than the Parties hereto, any benefits, interests, rights, or remedies under or by reason of the Agreement.

21.6 **Waiver**. Except as otherwise provided in this Agreement, a Party's compliance with any obligation, covenant, agreement, or condition herein may be waived by the Party entitled to the benefits thereof only by a written instrument signed by the Party granting such waiver, but such waiver or failure to insist upon strict compliance with such obligation, covenant, agreement, or condition will not operate as a waiver of, or estoppel with respect to, any subsequent or other failure.

21.7 **Amendment**. Except as otherwise set forth herein, this Agreement may be amended or modified only by a writing executed by the authorized representatives of both Parties. Nothing contained herein shall be construed as affecting in any way the right of the party furnishing service under this rate schedule to unilaterally make application to the FERC for a change in rates under section 205 of the FPA and pursuant to the FERC's Rules and Regulations promulgated thereunder. Specifically, Interconnection Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the FPA and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 206 or any other applicable provision of the FPA and FERC's rules and regulations thereunder; provided, that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered.

Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the FPA and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

21.8 **Severability**. If any term, condition, covenant, restriction or other provision of this Agreement is held by a court or regulatory agency of competent jurisdiction or by legislative enactment to be invalid, void or otherwise unenforceable, the remainder of the terms, conditions, covenants, restrictions and other provisions of this Agreement shall remain in full force and effect unless such an interpretation would materially alter the rights and privileges of any Party hereto. If any term, condition, covenant, restriction or other provision of this Agreement is held invalid, void or otherwise unenforceable, the Parties shall attempt to negotiate an appropriate and equitable replacement, revision or adjustment to the provision of this Agreement to restore the benefits and obligations conferred under the original Agreement.

21.9 **Headings and Captions**. Article headings and/or other captions are included in this Agreement for reference purposes only and shall not constitute a part of this Agreement or in any way affect the meaning or interpretation of this Agreement. Whenever used herein the singular number shall include the plural, the plural shall include the singular, and the use of any gender shall include all genders.

21.10 **Further Assurances**. Each Party shall do such other and further acts and things, and shall execute and deliver such instruments and documents, as the other Party(ies) reasonably requests from time to time in furtherance of the purposes of this Agreement.

21.11 **Entire Agreement**. This Agreement, including all schedules, appendices and other attachments hereto and made part hereof, sets forth the entire understanding and agreement of the Parties as to the subject matter of this Agreement and merges and supersedes all prior written and verbal understandings, offers, agreements, commitments, representations, writings, discussions or other communications of every kind between the Parties pertaining to the Interconnection Facilities, and constitutes the entire agreement between the Parties with respect to its subject matter, and as to all other representations, understandings, or agreements which are not fully expressed herein.

21.12 **Rights Cumulative**. The rights and remedies set forth in this Agreement are cumulative and non-exclusive.

21.13 **Counterparts**. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

ARTICLE 22
COMPLIANCE WITH REGULATORY STANDARDS

22.1 Each Party acknowledges that the responsibility to operate, maintain, dispatch or manage their transmission facilities in compliance with any and all applicable standards or protocols of NERC or WECC shall rest solely with the Party owning and/or operating such respective Interconnection Facilities, as appropriate, and nothing in this Agreement purports to share such NERC or WECC compliance obligations between the Parties. Notwithstanding anything in this

Agreement to the contrary, the Parties further agree that any liability associated with noncompliance of NERC or WECC standards or protocols rests solely with the Party whose actions results in the noncompliance of such standards.

22.2 To the extent either Party determines, in its sole discretion, that it needs to undertake certain efforts to ensure compliance with any applicable NERC or WECC standards or protocols, then the other Party shall use its best efforts to assist, and shall in no way interfere with, that Party's efforts for compliance with any and all applicable NERC or WECC standards or protocols. Each Party shall provide the other with reasonable advance notice of any required efforts associated with necessary compliance activities undertaken pursuant to this Section 22.2. Should either Party not provide the other with any information or assistance for any compliance activities, either Party shall have the right to undertake any necessary actions to ensure its compliance with NERC or WECC standards or protocols.

IN WITNESS WHEREOF, the Parties have caused their authorized representatives to execute this Agreement as of the date first above written.

INTERCONNECTION PROVIDER

Nevada Power Company
d/b/a NV Energy

By: Jimmy Daghlian
Jimmy Daghlian (Oct 8, 2025 07:42:19 PDT)

Title: VP, Engineering and Project Management

Date: 10/08/2025

INTERCONNECTION CUSTOMER

GridLiance West LLC

By: Jaime Hoffman
Jaime Hoffman (Oct 3, 2025 07:44:18 PDT)

Title: ident

Date: 10/03/2025

APPENDIX

Appendix A	Interconnection Facilities, Estimated Costs and Responsibilities
Appendix B	Milestones
Appendix C	Interconnection Details and One-line Diagram
Appendix D	Notices

Appendix A

Interconnection Facilities, Estimated Costs And Responsibilities

Point of Interconnection:
The Point of Interconnection shall be a new 230 kV terminal at Interconnection Provider's Northwest 230 kV switchyard.
See Appendix C.

Point of Change of Ownership:
The point of change of ownership (POCO) for this second Northwest – Desert View 230 kV line will use the existing POCO structure (Structure X24992) for the existing Northwest – Desert View 230 kV line #1 which is located just outside the Northwest 230 kV substation.
See Appendix C.

Nominal Delivery Voltage: 230 kV

Balancing Authority Area Metering Interchange Voltage: 230 kV

Requirements:

1. All Contingent Facilities identified in the System Impact Study and Facilities Study have been completed and in-service. These facilities include:
   Transmission lines associated with the Greenlink Project.
   a. Walker River – Northwest 525 kV
   b. Walker River 525/345 kV (2) transformers
   c. Walker River 345/230 kV (2) transformers
   d. Walker River 345/120 kV (2) transformers
   e. Walker River – Mira Loma 345 kV line
   f. Walker River – Comstock Meadows 345 kV line
   g. Harry Allen – Northwest 525 kV line
   h. Modification to the Lenzie RAS
2. GLW is completing all permitting for this project. All substation site locations will be fully discussed and approved by NV Energy.

1. <u>Interconnection Customer's Interconnection Facilities:</u>

a. Interconnection Customer's Interconnection Facilities and the Parties' responsibilities for such facilities shall include the following:

1. <u>Interconnection Customer's Transmission Line to the Point of Change of Ownership</u>
   a. The Interconnection Customer will design, permit, procure, and construct approximately 4.3 miles of 230 kV transmission lead line from GLW's DesertView substation to the existing Point of Change of Ownership dead-end structure.
   b. Transmission Line must include:
      i. Fiber Optic Cable or equivalent capable of providing redundant communication paths from the Interconnection Customer's DesertView Substation to the Interconnection Provider's Northwest Substation.

ii. Interconnection Customer shall provide two independent communication paths to the Northwest 230 kV Switchyard for both Desert View – Northwest 230 kV lines (existing #1 line as well as new #2 line)
iii. Static wire(s) and adequate overvoltage protection.
iv. The Interconnection Customer will provide extra Fiber Optic Cable and coil the cable at the Point of Change of Ownership for the Interconnection Provider to install from the Point of Change of Ownership to the Point of Interconnection.

2. System Protection Facilities
   a. Interconnection Customer is responsible for the electrical protection of Interconnection Customer's Interconnection Facilities.
   b. Interconnection Customer's 230 kV line protection relays at DesertView Substation must be compatible with the Interconnection Provider's line relays at the Northwest Substation.
   b. The Interconnection Customer must submit their intended protection and communications plan for the Interconnection Customer's Interconnection Facilities to the Interconnection Provider for review and agreement.

3. Right-of-Way, Jurisdictional and Environmental Permitting
   a. The Interconnection Customer must obtain all necessary property, rights-of-way, and permits from all federal, state, local and/or private land-owners and jurisdictions for all Interconnection Provider Interconnection Facilities needed to accommodate this interconnection including, but not limited to:
      i. All related facilities for the transmission line;
      ii. All installations required to interconnect Interconnection Customer's transmission line to the Point of Interconnection at Northwest Substation;
      iii. The dead-end POCO structure and substation entrance fence outside of Northwest Substation;
      iv. All access Roads to all Interconnection Provider's Interconnection Facilities; and
      v. Interconnection Customer's and Interconnection Provider's temporary work areas including but not limited to equipment and material storage yards, construction yards and staging areas, and temporary disturbance areas planned and reasonably required for construction (e.g., access, wire stringing).
   b. If a BLM right-of-way grant is required for any facilities under this Agreement, the Interconnection Customer will be responsible for all environmental studies, analyses, reports, and mitigation treatments associated with its BLM land use authorization process for the entire project (Interconnection Provider's facilities and Interconnection Customer's facilities), including but not limited to the BLM's Environmental Impact Statement, Biological Assessment, Cultural or Paleontological Resource Reports, etc.
   c. The Interconnection Provider will provide specifications needed for right-of-way and permitting applications to the Interconnection Customer for all Interconnection Provider Transmission Facilities; and
   d. The Interconnection Customer will provide all right-of-way and permitting applications to the Interconnection Provider for review and comment prior to submittal to the appropriate agencies.

2. Interconnection Provider's Interconnection Facilities:

a. Interconnection Provider's Interconnection Facilities and the Parties' responsibilities for such facilities shall include the following:

1. Point of Change of Ownership.
    a. Re-conductor the existing Desert View – Northwest 230 kV line from the Substation A-frame to the POCO with bundle (2) TS Pennel conductor to match the conductor proposed by GLW.
    b. Second Desert View – Northwest 230 kV line from the Substation A-frame to the POCO with bundle (2) TS Pennel conductor to match the conductor proposed by GLW.

2. Point of Interconnection – Northwest 230 kV Switchyard
    a. Replace the existing 2301E, 2301W, 2302E, 2302W, 2303E, 2303W disconnect switches with 3,000 A rated switches to match the existing breaker ratings.
    b. Replace the existing breaker jumpers for the 2301, 2302, and 2303 breakers with 2-1590 AAC conductor to match the existing breaker ratings.
    c. Move the existing Northwest 2308 breaker into the 2309 breaker position and add new breaker panel for the 2309 breaker.
    d. Install one 3,000 A rated, 230 kV breaker, bus work, and other associated facilities, including protection, Supervisory Control and Data Acquisition, etc. as further described herein.
    e. This breaker to be installed in the Northwest 2308 breaker position. NVE will use an existing spare breaker from another project to meet the requested in-service date.
    f. GLW will be responsible for funding the purchase of a replacement breaker.
    g. Re-terminate the existing Iron Mountain – Northwest Line #1 to a new terminal position at Northwest substation.
    h. Replace line protection relays for the Iron Mountain – Northwest Line #1 at both Iron Mountain and Northwest including new line panel at Northwest.
    i. Re-terminate the existing Iron Mountain – Northwest Line #2 to a new terminal position at Northwest substation.
    j. Metering and Communications: Metering and communication equipment required to integrate the second Desert View – Northwest 230 kV line.
    k. Associated relay protection upgrades for the existing 230 kV east and west buses and Northwest – Desert View 230 kV line, and relay protection for the second Northwest – Desert View 230 kV line.

3. Additional Facilities - Required and costs directly assigned to GLW
    a. Leavitt Substation:
        i. Replace the 138 kV line drops at Leavitt Substation on the Leavitt – Gilmore 138 kV line.
    b. LV Cogen – Pecos 138 kV line:
        i. Correct clearance violations on the LV Cogen – Pecos 138 kV line between Craig and LV Cogen to increase the MOT of the wire to 392 deg F.
        ii. Replace line and breakers relays at Pecos and LV Cogen substation.

4. Telecommunications
    a. The Interconnection Provider will design, procure, and install necessary communications equipment at Northwest Substation to incorporate the Interconnection Customer's communications.
    b. The Interconnection Provider will design, procure, and install:

i. the necessary fiber and conduit from the Point of Change of Ownership into Northwest substation for both communication paths.
ii. fiber patch panels for GLW fibers.
iii. Connect NVE meters to GLW Line terminal.
iv. Run fiber jumpers to relays in Northwest Control Enclosure
v. Replace existing OPGW cables from the POCO into the Northwest substation control enclosure with upgraded 96 and 144 count fiber cables. Replace fiber patch panels within the Northwest 230 kV Telecom Room and splice the new cables at the POCO.

5. Metering
   a. Interconnection Provider will design, procure and install all primary, secondary, and auxiliary equipment for a new 230 kV meter within the Northwest 230 kV Switchyard.
   b. Interconnection Provider will design, procure and install 230 kV instrument transformers (CT's and PT's) for this interconnection inside the Interconnection Provider's Northwest Substation and compensated to the Point of Interconnection.

6. Protection
   a. Interconnection Provider will design, procure, and install the necessary primary and secondary relays and associated equipment at the Northwest 230 kV Switchyard.
   b. Interconnection Customer must coordinate with Interconnection Provider for protection. Only Schweitzer Engineering Laboratories (SEL) line relays shall be used at both Northwest and Desert View substations for this interconnection.
   c. Interconnection Customer must submit the intended protection and communications plan to the Interconnection Provider for review and approval.

7. Right-of-Way, Jurisdictional and Environmental Permitting
   a. Interconnection Customer must obtain all necessary rights-of-way and permits from all federal, state, local and/or private landowners and jurisdictions for all interconnection facilities needed to accommodate this transmission to transmission interconnection including, but not limited to the 230 kV AC transmission line between Northwest 230 kV Switchyard and the POCO, and substation equipment at Northwest substation.
   b. The potential permits for which GLW may be required to secure include, but are not limited to:
      i. Federal land rights
      ii. Utility Environmental Protection Act (EPA) Permit
      iii. Army Corps of Engineers Water Permit
      iv. Special Use Permit
      v. Air, dust, stormwater and/or grading permits
   c. NV Energy will provide specifications needed for federal right-of-way and other permit applications to the Interconnection Customer for all NV Energy-owned facilities; and
   d. GLW will provide all right-of-way and permit applications to the Transmission Provider for review and comment prior to submittal to the appropriate agencies.

3. Affected Systems:

a. LADWP, SCE, WAPA, CAISO, DesertLink, and VEA have been identified as potentially affected systems based on the outcomes of the system impact study and may be affected by the proposed GLW interconnection.

b. The Interconnection Customer is responsible for ensuring that its project's impact on regional systems is addressed and, if need be, mitigated to the satisfaction of the impacted owner(s).

c. If other Adverse Impacts are subsequently identified by Interconnection Provider or an Affected System, additional studies may be required.

d. Interconnection Customer will need to coordinate with the Affected System(s) with respect to conducting any additional studies. If additional studies are required by the Affected System(s), Interconnection Customer will make arrangements with the Affected System(s) to pay the estimated costs of such studies upfront, will be responsible for the actual costs of such studies, and may be required to execute a separate agreement to have such studies conducted.

e. Any new facilities required by Affected Systems to mitigate impact will be paid for by the Transmission Customer.

f. Resolution of any issues identified by Affected Systems is required prior to energization of the transmission-to-transmission interconnection.

5. Cost Estimates:

a. As set forth in this Agreement in the definition of "Interconnection Provider's Interconnection Facilities", Interconnection Customer is responsible for the actual costs of construction of Interconnection Provider's Interconnection Facilities.

b. Interconnection Customer is responsible for the Interconnection Facilities and the Tax Gross-up payment of the applicable rate at the In-Service Date of the Interconnection Provider's Interconnection Facilities.

c. Cost responsibility for the Facilities shall be as follows:

1. The cost estimates include the required Interconnection Facilities for this transmission-to-transmission interconnection request. The estimated total cost of the Interconnection Facilities is $9.5M. GLW will be required to fund the full cost of the Interconnection Facilities. The payments and their timing will be driven by the various procurement and construction activities as outlined in Appendix B. The cost estimates provided are +/- 20%. The cost estimates are in 2024 dollars and do not include any tax gross-up. All costs will be trued up to actual costs when the project is completed.

d. Interconnection Customer shall pay to Interconnection Provider an annual operations charge for annual operation of the Interconnection Facilities on January 1 of each year following the in-service date. The operations charge shall be equal to $40,000/year which shall be increased annually for any increase during the preceding 12 months in the Customer Price Index – All Urban Consumers (CPI-U).

e. In addition, Interconnection Customer shall be responsible for paying to the Interconnection Provider actual costs for the maintenance of the Interconnection Provider's Interconnection Facilities which are for the sole benefit of the Interconnection Customer. Interconnection Provider shall invoice such costs in accordance with Section 6.11 and Section 12.3.

GridLiance West Project COST RESPONSIBILITY	
	Interconnection Provider's Interconnection Facilities $MM
Substation	
1-230 kV PCB, switches, buswork, line D-end structure, engineering, construction, foundations, steel, conduit, grounding, etc. Replace jumpers and disconnect switches associated with the 2301, 2302, and 2303 breakers. Move the existing 2308 breaker to the 2309 breaker position.	5.17
Replace line drops at Leavitt Substation	0.22
Relay upgrades at LV Cogen (part of clearance violation correction)	0.87
Relay upgrades at Pecos (part of clearance violation correction)	0.56
Relay upgrades at Iron Mountain (part of Iron Mountain line re-termination)	0.40
Upgrade Fiber runs from POCO into Telecom Room and replace existing runs for both GLW lines	0.10
Transmission Line	
230 kV Substation Entrance	0.60
Reconductor existing Desert View – Northwest 230 kV Line to bundle (2) – TS Pennel conductor	0.40
Correct clearance violations on the Craig – LV Cogen 138 kV line	1.08
Metering	
230 kV Meter	0.07
Lands/Permitting/Right-of-Way	
ROW Permitting coordination	0.03
Total:	**9.50**

Appendix B

Milestones

INTERCONNECTION MILESTONES		
Interconnection Customer's Project Milestones		**Due Date**
1	Interconnection Customer to pursue all necessary permits	upon execution
2	Interconnection Customer to provide Interconnection Provider with certification of all insurance pursuant to Article 11.3 of the Agreement	within 10 days of the execution of the Agreement
3	Interconnection Customer and Interconnection Provider to hold the Project Initiation Meeting	ongoing
4	Interconnection Customer and Interconnection Provider to setup regular project meeting schedule	ongoing
5	Interconnection Customer to provide cash to the Interconnection Provider in the amount of $100,000 towards the Interconnection Provider's Interconnection Facilities (IPIF)	Upon Execution
6	Interconnection Customer to provide completed documentation (e.g. signed Right of Entries) to Interconnection Provider allowing for site access, survey, and study work	within 30 days of FERC approval
7	Interconnection Customer to provide Interconnection Provider with drafts of all right-of-way and permitting applications for Interconnection Provider equipment necessary to interconnect the Interconnection Customer's Interconnection Facilities between the Interconnection Provider's property and the POCO structure VEA/GLW X24922.	40 Business Days prior to Interconnection Customer's submittal to the applicable agencies
8	Interconnection Customer to submit all required permit applications and/or amendments to permit applications for Interconnection Provider equipment necessary to interconnection the Interconnection Customer's Interconnection Facilities between the Interconnection Provider's existing property to the POCO VEA/GLW X24922 and provide Interconnection Provider with copies of all submittal packages	10 Business Days following Interconnection Customer's submittal to the applicable agencies
9	Interconnection Customer to provide Preliminary One-line drawing with Protection Scheme Descriptions to Interconnection Provider	Within 10 Business Days following Execution of Agreement

Agreed to by:

For the Interconnection Provider Jimmy Daghlian Jimmy Daghlian (Oct 8, 2025 07:42:19 PDT) Date 10/08/2025

For the Interconnection Customer Jaime Hoffman (Oct 3, 2025 07:44:18 PDT) Date 10/03/2025

Milestones--continued

10	Interconnection Customer to provide signed Telemetry Points Worksheet to Transmission Provider	Within 10 Business Days following Execution of Agreement
11	Interconnection Customer to provide cash to the Interconnection Provider in the amount of $7,125,000 towards the Interconnection Provider's Interconnection Facilities (IPIF)	Within 120 Business Days following Execution of Agreement
12	Interconnection Customer will provide all documents pertaining to the deed, transfer, or assignment of property or Right-of-Way Grant for the proposed facilities to Interconnection Provider for review and approval	Withing 10 Business Days following issuance from applicable permitting agency
13	Interconnection Customer to provide Interconnection Provider with copies of completed permits from all required federal, state, county & local entities including, but not limited to, BLM Right-of-Way Grant (if determined to be applicable), UEPA, Special Use Permits, Grading Permits, Building Permits, etc.	Withing 10 Business Days following issuance from applicable permitting agency
14	Interconnection Customer to provide documentation/verification and executed easements to Interconnection Provider for all access roads	Withing 10 Business Days following issuance from applicable permitting agency
15	Interconnection Customer to provide signed Grant of Easement, Access Agreement, and other required documents to Interconnection Provider	Withing 10 Business Days following issuance from applicable permitting agency
16	Interconnection Customer to complete access roads to the Point of Change of Ownership structure and accepted by Interconnection Provider	Withing 10 Business Days following issuance from applicable permitting agency
17	Interconnection Customer to provide cash to the Interconnection Provider in the amount of $2,275,000 towards the Interconnection Provider's Interconnection Facilities (IPIF).	Within 30 Calendar Days prior to expected synch and energization
18	Interconnection Customer to provide DC load centers dedicated for Interconnection Provider communications equipment and RTU	Within 10 Calendar Days prior to expected synch and energization

Agreed to by:

For the Interconnection Provider Jimmy Daghlian Jimmy Daghlian (Oct 8, 2025 07:42:19 PDT) Date 10/08/2025

For the Interconnection Customer Jaime Hoffman Jaime Hoffman (Oct 3, 2025 07:44:18 PDT) Date 10/03/2025

19	Interconnection Customer to complete installation and testing of protection relays and fiber terminations; End-to-End Test Reports to be provided to Interconnection Provider	Within 10 Calendar Days prior to expected synch and energization
20	Interconnection Customer to resolve any issues identified by Affected Systems and provide supporting documentation to Interconnection Provider	Within 10 Calendar Days prior to expected synch and energization
21	Interconnection Customer and Interconnection Provider to finalize the required telemetry information for operations	Within 10 Calendar Days prior to expected synch and energization
22	Interconnection Customer and Interconnection Provider to complete the PRC-027 System Protection Coordination Letter.	Within 10 Calendar Days prior to expected synch and energization
23	Interconnection Customer to initiate pre-energization meeting	meeting must be held at least 1 week prior to In-Service Customer Date
24	Interconnection Customer to complete Interconnection Customer's Interconnection Facilities (provide notice to Interconnection Provider in writing)	must be provided at least 1 week prior to In-Service Date
25	Interconnection Customer and Interconnection Provider hold the pre-energization Meeting	meeting must be held at least 1 week prior to In-Service Date
26	Interconnection Customer Facility Trip Testing - Provide written notice to the Interconnection Provider	Must be completed prior to the In-Service date with written notice by the Interconnection Customer to the Interconnection Provider
27	In-service Date	Oct 2028
28	Interconnection Customer to complete Section 7 form and all restoration activities and assign a portion of Interconnection Customer's BLM grant to Interconnection Provider for the Interconnection Provider's Interconnection Facilities	Within one (1) month of In-Service Date
29	True-Up. The Interconnection Customer to provide cash to Interconnection Provider (or receive cash refund from Interconnection Provider) for CIAC tax gross up for the Interconnection Provider's Interconnection Facilities at the applicable rate when the Interconnection Facilities are placed in-service as determined following completion of the final true-up.	Within one (1) month of Project Complete Interconnection

Agreed to by:

For the Transmission Provider Jimmy Daghlian (Oct 8, 2025 07:42:19 PDT) Date 10/08/2025

For the Interconnection Customer Jaime Hoffman (Oct 3, 2025 07:44:18 PDT) Date 10/03/2025

Milestones--continued

	Interconnection Provider Project Milestones	
30	Interconnection Provider's Interconnection Facilities Completed for Customer In-Service Date	**Q3 2028** provided that all necessary approvals by Governmental Authorities are received, Interconnection Customer's required facilities are constructed, tested and ready for service per Interconnection Customer milestones above, and the Interconnection Customer has provided required securities and notices to the Interconnection Provider per Interconnection Customer milestones above.

Agreed to by:

For the Transmission Provider Jimmy Daghlian Jimmy Daghlian (Oct 8, 2025 07:42:19 PDT) Date 10/08/2025

For the Interconnection Customer Jaime Hoffman Jaime Hoffman (Oct 3, 2025 07:44:18 PDT) Date 10/03/2025

Appendix C

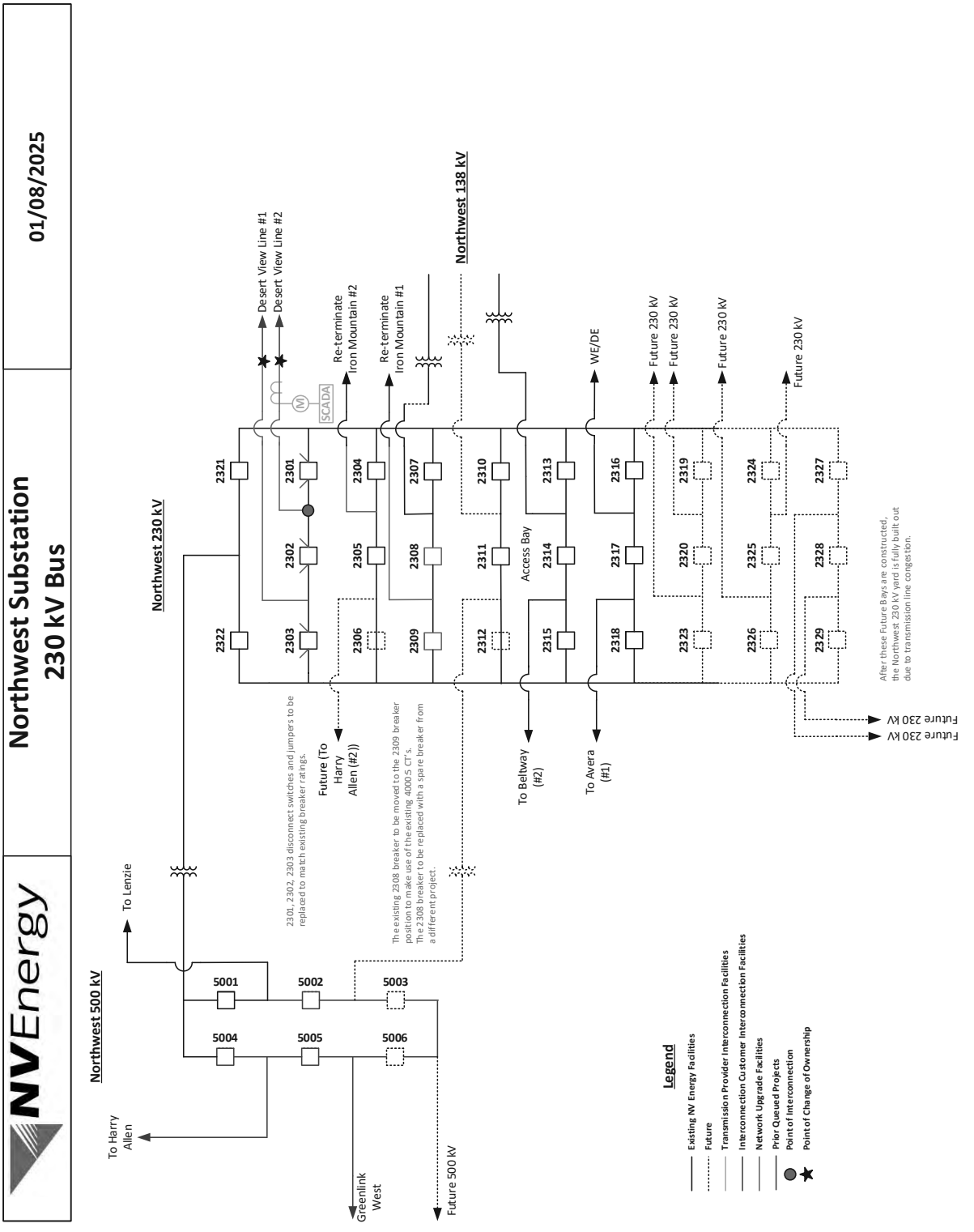
Interconnection Details

Point of Interconnection:
The Point of Interconnection shall be a new 230 kV terminal at Interconnection Provider's Northwest 230 kV switchyard.

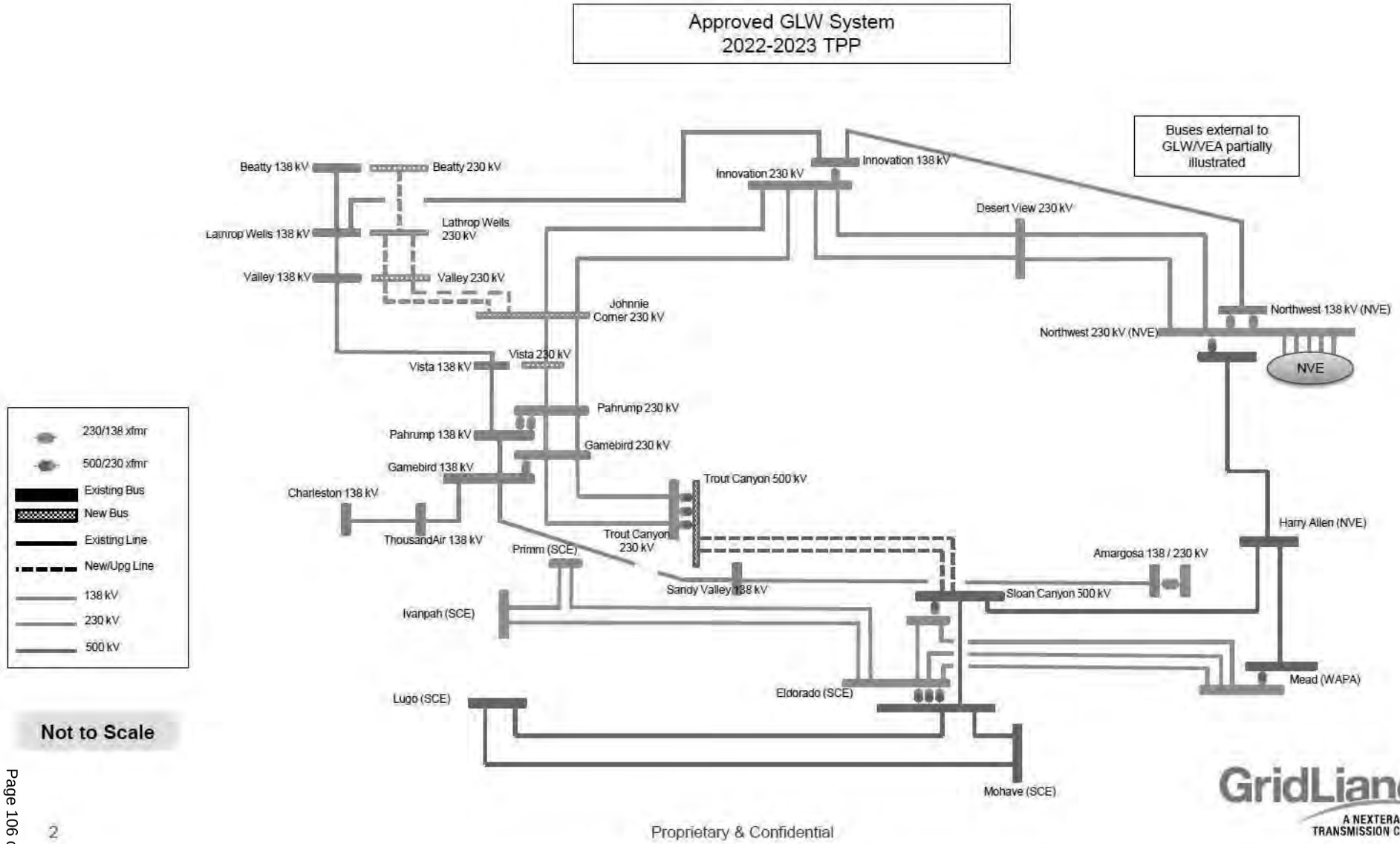
Point of Change of Ownership:
The point of change of ownership (POCO) for this second Northwest – Desert View 230 kV line will use the existing POCO structure (Structure X24992) for the existing Northwest – Desert View 230 kV line #1 which is located just outside the Northwest 230 kV substation.

Nominal Delivery Voltage: 230 kV

Balancing Authority Area Metering Interchange Voltage: 230 kV


One Line Diagram
Northwest Substation
230 kV Bus
01/08/2025
NVEnergy
Northwest 500 kV
Northwest 230 kV
Northwest 138 kV
To Lenzie
To Harry Allen
Greenlink West
Future 500 kV
5001
5002
5003
5004
5005
5006
2321
2322
2301
2302
2303
2304
2305
2306
2307
2308
2309
2310
2311
2312
2313
2314
2315
2316
2317
2318
2319
2320
2323
2324
2325
2326
2327
2328
2329
Desert View Line #1
Desert View Line #2
SCADA
Re-terminate Iron Mountain #2
Re-terminate Iron Mountain #1
Access Bay
WE/DE
Future 230 kV
Future 230 kV
Future 230 kV
Future 230 kV
Future 230 kV
Future 230 kV
Future (To Harry Allen (#2))
To Beltway (#2)
To Avera (#1)
2301, 2302, 2303 disconnect switches and jumpers to be replaced to match existing breaker ratings.
The existing 2308 breaker to be moved to the 2309 breaker position to make use of the existing 4000:5 CT's. The 2308 breaker to be replaced with a spare breaker from a different project.
After these Future Bays are constructed, the Northwest 230 kV yard is fully built out due to transmission line congestion.
Legend
Existing NV Energy Facilities
Future
Transmission Provider Interconnection Facilities
Interconnection Customer Interconnection Facilities
Network Upgrade Facilities
Prior Queued Projects
Point of Interconnection
Point of Change of Ownership

One Line Diagram of GLW Area Upgrades



Appendix D:
Addresses for Delivery of Notices and Billings

Notices:

Unless otherwise provided in this Agreement, any written notice demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

Interconnection Provider

Interconnection Provider:	Nevada Power Company d/b/a NV Energy
Attention:	Director, Transmission Business Services
Address:	6100 Neil Road or PO Box 10100
City:	Reno
State:	NV
Zip:	89511
Phone:	775-834-3881
Fax:	775-834-3047
E-Mail:	TransmissionPolicy@nvenergy.com

Interconnection Customer

Interconnection Customer:	GridLiance West LLC
Attention:	Attn: Business Services C5B/JBC
Address:	700 Universe Blvd.
City:	Juno Beach
State:	FL
Zip:	33410
Phone:	
Fax:	
E-Mail:	DL-GLW-Interconnection@nexteraenergy.com with a copy to: Elizabeth.Ramey@nexteraenergy.com

Billings and Payments:

Billings and payments shall be sent to the addresses set out below:

Interconnection Provider

Interconnection Provider:	Nevada Power Company d/b/a NV Energy
Attention:	Director, Transmission Business Services
Address:	6100 Neil Road or PO Box 10100
City:	Reno
State:	NV
Zip:	89511
Phone:	775-834-3881
Fax:	775-834-3047
E-Mail:	TransmissionPolicy@nvenergy.com

Interconnection Customer

Interconnection Customer:	GridLiance West LLC
Attention:	Attn: Accounting ACG/JB
Address:	700 Universe Blvd.
City:	Juno Beach
State:	FL
Zip:	33410
Phone:	
Fax:	
E-Mail:	payables@gridliance.com with a copy to: Kimberly.Ioannides@nexteraenergy.com

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Any notice or request required or permitted to be given by either party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

Interconnection Provider

Interconnection Provider:	Nevada Power Company d/b/a NV Energy
Attention:	Sr. Contracts Specialist
Address:	7155 Lindell Rd M/S B57SC or PO Box 98910
City:	Las Vegas
State:	NV
Zip:	89118
Phone:	702-402-6646
Fax:	702-402-2448
E-Mail:	TransmissionPolicy@nvenergy.com

Interconnection Customer

Interconnection Customer:	GridLiance West LLC
Attention:	Attn: Business Services C5B/JBC
Address:	700 Universe Blvd
City:	Juno Beach
State:	FL
Zip:	33410
Phone:	
Fax:	
E-Mail:	DL-GLW-Interconnection@nexteraenergy.com with a copy to: Elizabeth.Ramey@nexteraenergy.com

Designated Operating Executive:

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Provider

Interconnection Provider:	Nevada Power Company d/b/a NV Energy
Attention:	Director, Grid Operations and Reliability
Address:	7155 Lindell Rd M/S B57SC or PO Box 98910
City:	Las Vegas
State:	NV
Zip:	89118
Phone:	702-402-6614
Fax:	702-402-2448
E-Mail:	ESCCOperations@nvenergy.com

Interconnection Customer

Interconnection Customer:	GridLiance West LLC
Attention:	President of GridLiance West LLC
Address:	700 Universe Blvd
City:	Juno Beach
State:	FL
Zip:	33410
Phone:	
Fax:	
E-Mail:	DL-GLW-Interconnection@nexteraenergy.com with a copy to: Elizabeth.Ramey@nexteraenergy.com

TRAN-13

NEVADA POWER COMPANY D/B/A NV ENERGY (NVES)
SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY (NVEN)

APPENDIX TRAN-13

NITSA 17-00004 BTW NPC AND SWITCH SOUTH - 14TH AR

March 2026

FOURTEENTH AMENDED AND RESTATED

ATTACHMENT F-1

RETAIL ACCESS

FORM OF SERVICE AGREEMENT FOR

NETWORK INTEGRATION TRANSMISSION SERVICE

BETWEEN

NEVADA POWER COMPANY d/b/a NV ENERGY

(TRANSMISSION PROVIDER)

AND

SWITCH, LTD.

(ELIGIBLE CUSTOMER / NETWORK CUSTOMER)

DATED: 09/22/2025

Attachment F-1:
Retail Access Form of Service Agreement For Network Integration Transmission Service

1.0 This Service Agreement, dated as of 09/22/2025, is entered into, by and between **NV Energy** ("Transmission Provider"), and **Switch, Ltd.** ("Eligible Customer" / "Network Customer"). The Network Customer and Designated Agent are collectively referred to in this Attachment F-1 as "Network Customer".

2.0 The Eligible Customer certifies it has satisfied or meets the requirements to obtain open Retail Access Transmission Service pursuant to Retail Access under which the Transmission Provider offers unbundled retail transmission service.

3.0 The Network Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Transmission Provider's Open Access Transmission Tariff ("Tariff").

4.0 The Network Customer has provided to the Transmission Provider an Application Deposit in the amount of **$0.00**, in accordance with the provisions of Section 29.2 of the Tariff.

5.0 Service under this agreement shall commence on the later of: (l) the requested service date as indicated in the Specifications for Network Integration Transmission Service, Section 2; (2) the date on which construction of any Direct Assignment Facilities are completed; (3) the date that Network Upgrades are completed (or in the alternative, a temporary release of capacity as set forth in the Specifications for Network Integration Transmission Service is provided); or (4) such other date as it is permitted to become effective by the Commission. A Network Customer having point(s) of interconnection on Transmission Provider's Transmission System shall be required to have a Network Operating Agreement in place prior to commencement of transmission service hereunder. Service under this agreement shall terminate on June 1, 2047.

6.0 The Transmission Provider agrees to provide and the Transmission Network Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff, this Service Agreement and the Network Operating Agreement as they may be amended from time to time.

7.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Manager, Transmission Business Services
NV Energy
6100 Neil Rd. M/S S3B40
Reno, NV 89511
Email: TransmissionPolicy@nvenergy.com

Eligible Customer / Network Customer:

Switch, Ltd.
7135 S. Decatur Blvd.
Las Vegas NV, 89118
Email: Energy@switch.com

8.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:	Jimmy Daghlian Jimmy Daghlian (Sep 22, 2025 09:14:00 PDT)	VP, Engineering and Project Management	09/22/2025
	Name	Title	Date

Eligible Customer / Network Customer: Rachel Kent

By:	Alise Porto (Sep 19, 2025 17:03:21 PDT)	SVP POWER & Sustainability	09/19/2025
	Name	Title	Date

Service Agreement #17-00004

SPECIFICATIONS FOR RETAIL ACCESS NETWORK INTEGRATION TRANSMISSION SERVICE

1.0 This Service Agreement, dated as of 09/22/2025, is entered into, by and between **NV Energy** ("Transmission Provider"), and **Switch, Ltd.** ("Eligible Customer" / "Network Customer"). The Network Customer and Designated Agent are collectively referred to in this Attachment F-1 as "Network Customer". The eligible retail customer or End-Use Customer with an authorized agency certified it has satisfied or meets the requirements to obtain open Retail Access Transmission Service pursuant to Retail Access under which the Transmission Provider offers unbundled retail transmission service.

2.0 Term of Network Service: **30 Years**

Requested Start Date: The later of Section 5.0 above, 0:00 Pacific Standard Time June 1, 2017, or when the Eligible Customer begins to take service pursuant to an order by the Public Utilities Commission authorizing the Eligible Customer to take service pursuant to Nevada Revised Statute Chapter 704B.

Termination Date: 0:00 Pacific Standard Time **June 1, 2047**

3.0 Description of capacity and/or energy to be transmitted by Transmission Provider across the Transmission Provider's Transmission System (including electric control area in which the transaction originates):

360 MW of the eligible retail customer or authorized agency's requirements may originate from firm resources located outside of the Transmission Provider's Control Area and will be transmitted across the Transmission Provider's Transmission System from the Point(s) of Receipt listed below. The remaining MWs of the eligible customer or authorized agency Requirements (Network Load plus Losses) will originate from inside the Transmission Provider's Control Area as designated in Section 4.0. Non-firm energy will be transmitted on an as available basis when requested by the eligible customer or authorized agency.

This 360 MW load will be served with secondary network service (6nn) on an as-available basis until the earlier of the following: (1) firm capacity on NV Energy's system becomes available; or (2) such time the Network Upgrades identified in the System Impact Study-Network Integrated Transmission System Request (August 26, 2025) are completed. At the time of execution of this NITSA , the identified Network Upgrades are planned for completion during 2030 but are subject to change as required due to permitting, material procurement, and labor availability. The Transmission Provider shall provide the requested updates upon written request by the Transmission Customer.

Point(s) of Receipt	Point(s) of Delivery	MW or % of Load
Mead 230 kV Substation	Southsys	100%

4.0 Network Resources

(1) Transmission Customer Generation Owned: None.

(2) Transmission Customer Generation Purchased:

Source	Total Capacity	Capacity Designated as Network Resource
Non NV Energy firm system sale	Up to Full Requirements (360 MW)	Up to Full Requirements (360 MW)

(3) Total Network Resources: (1) + (2) = **Up to Full Requirements (360 MW)**

5.0 Transmission Load:

(1) Eligible customer or authorized agency's Network Load: Eligible customer or authorized agency's Network Load measured at the Point(s) of Delivery listed below is its full load requirement as it changes from time to time, including load growth. Eligible customer or authorized agency's most recent coincident peak load measured at Point(s) of Delivery and adjusted for distribution and transmission losses as appropriate is **360 MW**.

Service Agreement #17-00004

Point(s) of Delivery Description of Network Load(s)						
	Premise #	**Facility Name**	**Address**	**Delivery Voltage Level**	**Type**	**MW or % of Load**
1	2086141	NAP.04	4495 East Sahara Avenue, Las Vegas, NV 89104	480V	Primary	0.49%
2	2152541		4495 East Sahara Avenue, Las Vegas, NV 89104	480V	Primary	0.59%
3	2185541	NAP.06	4475 East Sahara Avenue, Las Vegas, NV 89104	480V	Primary	1.40%
4	2185265		4475 East Sahara Avenue, Las Vegas, NV 89104	480V	Primary	1.22%
5	2192255	NAP.07	7135 South Decatur Blvd. Las Vegas, NV 89118	480V	Backup	0.00%
6	2192256		7135 South Decatur Blvd. Las Vegas, NV 89118	480V	Backup	0.00%
7	2193699		7135 South Decatur Blvd. Las Vegas, NV 89118	12.47kV	Primary	3.69%
8	2195912		7135 South Decatur Blvd. Las Vegas, NV 89118	480V	Primary	0.06%
9	2185318		7135 South Decatur Blvd. Las Vegas, NV 89118	480V	Backup	0.00%
10	2239518		7135 South Decatur Blvd. Las Vegas, NV 89118	12.47kV	Primary	4.19%
11	2248194		7135 South Decatur Blvd. Las Vegas, NV 89118	12.47kV	Primary	4.14%
12	2253743		7135 South Decatur Blvd. Las Vegas, NV 89118	12.47kV	Primary	3.91%
13	2261555		7135 South Decatur Blvd. Las Vegas, NV 89118	12.47kV	Primary	3.46%
14	2284712		7135 South Decatur Blvd. Las Vegas, NV 89118	12.47kV	Primary	1.31%
15	2271616		7135 South Decatur Blvd. Las Vegas, NV 89118	12.47kV	Primary	1.33%

Service Agreement #17-00004

16	2265112	NAP.08	5225 W Capovilla Avenue, Las Vegas, NV 89118	12.47kV	Primary	4.29%
17	2273939		5225 W Capovilla Avenue, Las Vegas, NV 89118	12.47kV	Primary	4.16%
18	2287576		5225 W Capovilla Avenue, Las Vegas, NV 89118	12.47kV	Primary	4.21%
19	2294460		5225 W Capovilla Avenue, Las Vegas, NV 89118	12.47kV	Primary	3.13%
20	2292546	NAP.09	7365 Lindell Road, Las Vegas, NV 89139	480V	Primary	0.04%
21	2292637		7365 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	4.89%
22	2310939		7365 Lindell Road, Las Vegas, NV 89139	12.47kV	Backup	0.00%
23	2305578		7365 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	4.11%
24	2309004		7365 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	4.41%
25	2299042		7365 Lindell Road, Las Vegas, NV 89139	480V	Backup	0.00%
26	2326062		7365 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	4.09%
27	2489872		7365 Lindell Road, Las Vegas, NV 89139	12.47kV	Backup	0.00%
28	2489873		7365 Lindell Road, Las Vegas, NV 89139	12.47kV	Backup	0.00%
29	2489874		7365 Lindell Road, Las Vegas, NV 89139	12.47kV	Backup	0.00%
30	2323883	NAP.10	7375 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	5.35%
31	2323884		7375 Lindell Road, Las Vegas, NV 89139	480V	Primary	0.05%
32	2351010		7375 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	3.29%
33	2333782		7375 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	5.02%
34	2489875	NAP.11	7375 Lindell Road, Las Vegas, NV 89139	12.47kV	Backup	0.00%
35	2489876		7375 Lindell Road, Las Vegas, NV 89139	12.47kV	Backup	0.00%
36	2489877		7375 Lindell Road, Las Vegas, NV 89139	12.47kV	Backup	0.00%
37	2345742		7380 Lindell Road, Las Vegas, NV 89139	12.47kV	Backup	0.00%

38	2345886		7380 Lindell Road, Las Vegas, NV 89139	480V	Primary	0.06%
39	2364772	NAP.12	7380 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	4.46%
40	2374465		7380 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	2.89%
41	2380856	NAP.15	7380 Lindell Road, Las Vegas, NV 89139	12.47kV	Primary	4.61%
42	2321941	NAP.12	5325 W Capovilla Avenue, Las Vegas, NV 89118	480V	Primary	0.92%
43	2436071	NAP.14	5325 W Capovilla Avenue, Las Vegas, NV 89118	12.47kV	Primary	0.04%
44	2405468	NAP.15	5660 W Badura Ave Las Vegas NV 89118	12.47kV	Temp. Primary	0.00%
45	2439855	NAP.16	5660 W Badura Ave Las Vegas NV 89118	12.47kV	Temp. Primary	0.00%
46	2474013	NAP.14	5680 Badura Ave Las Vegas NV 89118	12.47kV	Temp. Primary	0.00%
47	2474014	NAP.14	5680 Badura Ave Las Vegas NV 89118	12.47kV	Temp. Primary	0.00%
48	2491580	LAS 3	6755 W. Maule Ave	230 kV	Revenue	14.19%
49	2491687	LAS 3	6755 W. Maule Ave. 2	230 kV	Revenue	0.00%
50	TBD by Q4 2025	NAP.16	APN 176-01-201-006 (Q4 2025)	TBD by Q4 2025		TBD by Q4 2025

Total Network Load = **360 MW Coincident Peak**

6.0 Designation of party subject to reciprocal service obligation: None.

7.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

(1) Load Ratio Share of Annual Transmission Revenue Requirement.

(2) Facilities Study Charge: A Facilities Study was not required. System Impact Study was performed by Transmission Provider on January 10, 2025, that determined that NCA2 Solar as network resource can be used to serve Switch loads in Southern Nevada upon completion of upgrades identified in LGIA #22-00014.

(3) Direct Assignment Facilities Charge: Pursuant to the Network Operating

Agreement, the Transmission Provider will require metering at each Point of Delivery and will install the associated communications for real time data for this Network Integration Transmission Service Request. The Transmission Provider shall estimate the cost for the engineering, design and construction and require a deposit in this amount prior to completing any work. The Transmission Provider shall charge and the Network Customer shall pay the actual costs of the installation of the customer required facilities.

For 360 MW load request interconnecting at Mead 230 kV, Northwest 500/230 kV Transformer Bank #7 is required. The Transmission Customer is responsible for providing security for all the identified network upgrades, as identified in the Facilities Study provided August 26, 2025, totaling $54.4 million.

(4) Ancillary Services:

(a) Scheduling System, Control and Dispatch Service: Schedule 1 and Schedule 1-A of the Tariff as it may be amended from time to time.

(b) Regulation and Frequency Response Service: Transmission Customer will purchase this ancillary service from the Transmission Provider per Schedule 3 of the Tariff as it may be amended from time to time. Transmission Customer has the right to change its election by providing written notice to the Transmission Provider per the terms and conditions of the Tariff.

(c) Energy Imbalance Service: Per Schedule 4, Schedule 9, and/or Attachment P, Section 8.1 of the Tariff, as it may be amended from time to time, and as applicable to the Transmission Customer's schedules.

(d) Operating Reserve - Spinning Reserve Service: Per Schedule 5 of the Tariff as it may be amended from time to time.

(e) Operating Reserve - Supplemental Reserve Service: Per Schedule 6 of the Tariff as it may be amended from time to time.

(f) Redispatch Charges: Pursuant to the Tariff.

(6) Power Factor Requirements: This will be billed for under the applicable Distribution Only Service Agreement for each Point of Delivery and is not included herein.

8.0 Eligible Retail Customer Rights: Native Load import rights to the Transmission Provider released under this Agreement are granted to the eligible retail customer upon whose behalf the Network Customer/Designated Agent may obtain transmission service and will remain with the eligible retail customer. If the eligible retail customer chooses a new Network Customer/Designated Agent, the transmission rights will be transferred to the new Network Customer/Designated Agent on behalf of the eligible retail customer. If the eligible retail customer elects to return to bundled retail electric service, the released rights will revert back to the Native Load for use in service to the bundled retail customer.

Transmission Provider:

By: Jimmy Daghlian (Sep 22, 2025 14:00 PDT)	VP, Engineering and Project Management	09/22/2025
Name	Title	Date

Eligible Customer / Network Customer: Rachel Kent

By: Alise Porto (Sep 19, 2025 17:03:21 PDT)	SVP POWER & Sustainability	09/19/2025
Name	Title	Date

NITSA 17-00004 btw NPC and Switch South - 14th AR - 09-19-2025 - FOR EXECUTION

Final Audit Report 2025-09-22

Created:	2025-09-19
By:	Charanya Suri (charanya.suri@nvenergy.com)
Status:	Signed
Transaction ID:	CBJCHBCAABAA_nK4hfrsBAvc9IHQi7zEZ-qZdA8HFX7C

"NITSA 17-00004 btw NPC and Switch South - 14th AR - 09-19-2025 - FOR EXECUTION" History

Document created by Charanya Suri (charanya.suri@nvenergy.com)
2025-09-19 - 7:05:38 PM GMT- IP address: 198.180.160.252

Document emailed to Adrien Marshall (adrien.marshall@nvenergy.com) for approval
2025-09-19 - 7:15:55 PM GMT

Email viewed by Adrien Marshall (adrien.marshall@nvenergy.com)
2025-09-19 - 8:08:12 PM GMT- IP address: 104.47.58.254

Document approved by Adrien Marshall (adrien.marshall@nvenergy.com)
Approval Date: 2025-09-19 - 8:08:37 PM GMT - Time Source: server- IP address: 198.180.160.252

Document emailed to Rachel Kent (rkent@switch.com) for approval
2025-09-19 - 8:08:39 PM GMT

Email viewed by Rachel Kent (rkent@switch.com)
2025-09-19 - 11:22:12 PM GMT- IP address: 71.35.2.139

Document approved by Rachel Kent (rkent@switch.com)
Approval Date: 2025-09-19 - 11:22:31 PM GMT - Time Source: server- IP address: 71.35.2.139

Document emailed to Alise Porto (alise@switch.com) for signature
2025-09-19 - 11:22:32 PM GMT

Email viewed by Alise Porto (alise@switch.com)
2025-09-20 - 0:02:40 AM GMT- IP address: 24.241.128.96

Document e-signed by Alise Porto (alise@switch.com)
Signature Date: 2025-09-20 - 0:03:21 AM GMT - Time Source: server- IP address: 24.241.128.96

Document emailed to Jimmy Daghlian (jimmy.daghlian@nvenergy.com) for signature
2025-09-20 - 0:03:23 AM GMT

Email viewed by Jimmy Daghlian (jimmy.daghlian@nvenergy.com)
2025-09-22 - 2:37:29 PM GMT- IP address: 104.47.56.254

Document e-signed by Jimmy Daghlian (jimmy.daghlian@nvenergy.com)
Signature Date: 2025-09-22 - 4:14:00 PM GMT - Time Source: server- IP address: 192.206.180.200

Agreement completed.
2025-09-22 - 4:14:00 PM GMT

TRAN-14

NEVADA POWER COMPANY D/B/A NV ENERGY (NVES)
SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY (NVEN)

APPENDIX TRAN-14

CONFIDENTIAL TPL-001 2025 APPENDIX A - CORRECTIVE ACTION PLANS

March 2026

2025 Transmission Planning Assessment Appendix A – Corrective Action Plans

NVEnergy

Contents

NVEnergy

Purpose

This appendix includes NV Energy's 10-year plan for capital investment and long-term switching configurations for the Transmission Network to mitigate identified reliability risks.

Reliability Risks

Upon performing reliability analysis for TPL-001-5.1 (and other NERC standards), NV Energy identifies risks to Transmission Network reliability.

Those risks include:

- Exceedances of System Operating Limits (SOL/IROL) or Facility Ratings for
  - MVA (Transformers)
  - Currents (All other equipment)
  - Voltages (At substation buses)
- System performance not meeting:
  - NERC requirements, or
  - NVE Reactive Power Margin (RPM) requirements
  - Other NVE requirements

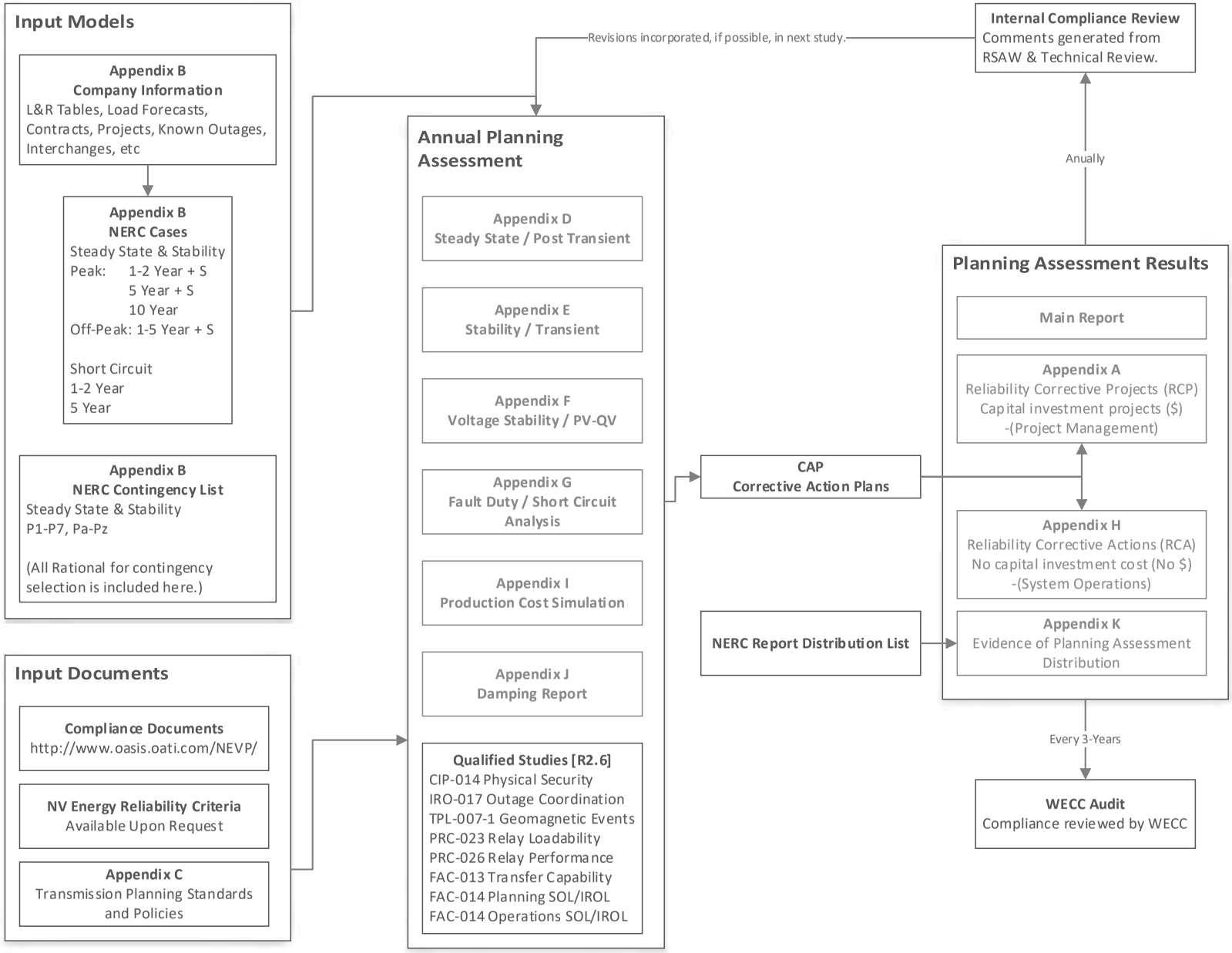
Those risks are shown in detail in the following appendices:

- Appendix D - Steady State
- Appendix E - Transient Stability
- Appendix F - Voltage Stability
- Appendix G - Short Circuit

Corrective Action Plans

To mitigate risks identified in this study, Corrective Action Plans (CAP) are proposed that include:

- Reliability Corrective Projects RCP
- Remedial Action Schemes RAS
- Operations & Maintenance O&M
- Manual Operator Actions MOA
- Reliability Corrective Actions RCA


Input Models
Appendix B
Company Information
L&R Tables, Load Forecasts, Contracts, Projects, Known Outages, Interchanges, etc
Appendix B
NERC Cases
Steady State & Stability
Peak: 1-2 Year + S
5 Year + S
10 Year
Off-Peak: 1-5 Year + S
Short Circuit
1-2 Year
5 Year
Appendix B
NERC Contingency List
Steady State & Stability
P1-P7, Pa-Pz
(All Rational for contingency selection is included here.)
Input Documents
Compliance Documents
http://www.oasis.oati.com/NEVP/
NV Energy Reliability Criteria
Available Upon Request
Appendix C
Transmission Planning Standards and Policies
Revisions incorporated, if possible, in next study.
Annual Planning Assessment
Appendix D
Steady State / Post Transient
Appendix E
Stability / Transient
Appendix F
Voltage Stability / PV-QV
Appendix G
Fault Duty / Short Circuit Analysis
Appendix I
Production Cost Simulation
Appendix J
Damping Report
Qualified Studies [R2.6]
CIP-014 Physical Security
IRO-017 Outage Coordination
TPL-007-1 Geomagnetic Events
PRC-023 Relay Loadability
PRC-026 Relay Performance
FAC-013 Transfer Capability
FAC-014 Planning SOL/IROL
FAC-014 Operations SOL/IROL
CAP
Corrective Action Plans
NERC Report Distribution List
Internal Compliance Review
Comments generated from RSAW & Technical Review.
Anually
Planning Assessment Results
Main Report
Appendix A
Reliability Corrective Projects (RCP)
Capital investment projects ($)
-(Project Management)
Appendix H
Reliability Corrective Actions (RCA)
No capital investment cost (No $)
-(System Operations)
Appendix K
Evidence of Planning Assessment Distribution
Every 3-Years
WECC Audit
Compliance reviewed by WECC

Related Requirements [TPL-001-5.1]

Corrective Action Plans [R2.7] [R2.8]

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

NVEnergy

Table 1

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11]	SLG	EHV, HV	Yes	Yes
		2. Loss of a bipolar DC line				

NVEnergy

Appendix A

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11]
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Corrective Action Plans

Entity	CAP	Description	Planning ISD	OPC ID	NERC Required
N	1009	California - Bordertown 120kV Line	2025-05-09	CAPETD1000009160	Yes
N	1071	Western Nevada Master Plan	Ongoing	Multiple	Yes
N	1076	Buckeye Substation Rebuild	2026-11-06	CAPETD1000007405	Yes
N	1080	North Underrated Breaker Replacements - Rusty Spike	2027-05-31	NVEPM00000099	Yes
N	1080	North Underrated Breaker Replacements - Dove	2027-05-31	NVEPM00000098	Yes
N	1081	121kV Breaker Limitations	Ongoing		Yes
N	1088	Ft Churchill 120kV Rebuild (Greenlink Project)	2027-05-28		Yes
N	1089	Millers & Silver Peak UVLS	2024-12-31	NVEPM00000101	Yes
N	1111	#106 Uprate (Mt. Rose - Washoe Switching Station)	2030-06-01		Yes
N	1114	#146 Eagle - East Tracy 120 kV Line Uprate	2025-05-29	CPCCCR1000000533	Yes
N	1116	Eight Mile Creek Capacitor Bank Upgrade	2024-05-31	NVEPM00000403	Yes
N	1116	Maggie Creek Capacitor Bank Upgrade	2024-05-31	NVEPM00000402	Yes
N	1117	Coyote Creek 345 kV Breaker Additions	2024-06-01	NVEPM00000097	Yes
N	1121	Pinenut 120 kV Conversion	2030-05-28	NVEPM00000007	Yes
N	1123	Replace Sugarloaf 183 breaker	2030-06-01		Yes
N	1124	Replace Patrick 177 breaker	2030-06-01		Yes
S	2065	Tolson 230/138 kV Bank 2 and Tolson - Ford 138 kV line	2028-06-01	CAPETD1000002223	Yes
S	2067	Craig - Pecos 138 kV Uprate	2025-06-01	CAPETD1000006181	Yes
S	2069	Beltway - Cheyenne 138 kV line addition	2022-05-31	NVEPM00000043	Yes
S	2070	Pebble - Tolson 138 kV line uprate	2026-06-01	CAPETD1000002378	Yes
S	2073	Claymont - Spencer 138 kV Line Uprate	2029-06-01	NVEPM00000044	Yes
S	2074	Harry Allen 230 kV Series Bus Reactors	2026-05-31	CAPETD1000002722	Yes
S	2076	Gilmore - Leavitt 138 kV line uprate	2027-06-01	NVEPM00000359	Yes
S	2077	Magnolia - NSO 230 kV Line Addition	2035-06-01	NVEPM00000036	Yes
S	2079	Clark - Warm Springs 138 kV Line Uprate	2029-06-01	NVEPM00000049	Yes
S	2080	South Underrated Breaker Replacements - 69 kV Breakers	2026-06-01	CAPETD1000001450	Yes
S	2080	South Underrated Breaker Replacements - Faulkner	2027-06-01	CPKNMX1000000010	Yes

Entity	CAP	Description	Planning ISD	OPC ID	NERC Required
S	2080	South Underrated Breaker Replacements - Northwest CCVT's	2027-04-29	CAPETD1000002728	Yes
S	2080	South Underrated Breaker Replacements - Bushing Cap Replacement Project	Ongoing	CPKNMX1000000010	Yes
S	2080	South Underrated Breaker Replacements - Crystal	2028-06-01		Yes
S	2081	Clark - Green Valley - Wigwam 138 kV Line Uprate	2028-06-01		Yes
S	2090	Cabana - Clark 138 kV Line Drop Replacement	2028-06-01	NVEPM00000405	Yes
S	2091	Faulkner - Warm Springs 138 kV Line Uprate	2028-06-01	NVEPM00000045	Yes
S	2096	Clark - Spencer 138 kV Lines #1 and #2 Reconductor	2029-06-01	NVEPM00000046	Yes
S	2102	Re-terminate Equestrian - Mead 230 kV Line #2	2030-06-01		Yes
S	2104	Northwest 525/230 kV Bank #7	2030-12-01	NVEPM00000018	Yes
S	2105	Faulkner 230/138 Bank #2	2035-06-01		Yes
S	2106	Northwest 230/138kV Bank #3	2035-06-01		Yes
S	2107	Claymont - Strip 138 kV Line Uprate	2035-06-01		Yes
N	3002	MOA: Carson 60kV Normal Open	n/a: MOA		Yes
N	3005	MOA: Open Valley Road 606 Breaker	n/a: MOA		Yes
N	3007	MOA: Ft Churchill Must-Run	n/a: MOA		Yes
N	3009	MOA: Valmy Must-Run	n/a: MOA		Yes
N	3011	MOA: 230 kV Generation Limitation	n/a: MOA		Yes
S, N	4001	TPL-001-5.1 SPF Corrective Projects	Ongoing		Yes
S, N	4002	Protection System Clearing Time Reduction	Ongoing		Yes
N	1065	Mason Valley / Smith Valley 120kV Source (Buckeye 120 kV Fold In)	2026-06-01		No
N	1099	Fallon 120kV Source	2026-12-31	CAPETD1000008475	No
N	1110	#670 Buckeye - Heybourne 63 kV Line Uprate	2028-06-01		No
N	1112	Tonopah 120/60 kV Transformer addition	2028-06-01	CAPETD1000007555	No
N	1119	Addition of Cap Banks at Mason Valley / Smith Valley	2025-06-01	NVEPM00000100	No
S	2068	Arden - Oquendo 69 kV Uprate and Oquendo Cap Bank	2024-06-01	NVEPM00000050	No
S	2079	Mayfair - San Francisco 69 kV Reconductor	2028-06-01	NVEPM00000041	No
S	2082	Mayfair 69 kV Line Drop Replacement	2028-06-01	NVEPM00000042	No
S	2084	San Francisco 6905 breaker replacement	2025-06-01	NVEPM00000406	No

Entity	CAP	Description	Planning ISD	OPC ID	NERC Required
S	2086	Miller - NLV 69kV Uprate	2024-06-01	NVEPM00000047	No
S	2100	Speedway and Gypsum Capacitor Banks Additions	2027-06-01		No
S	2101	Goat 230/69 kV Substation + Goat - Speedway 69kV Line Uprate	2030-06-01		No
S	2108	Lake Las Vegas - Mead 69 kV Line Uprate	2030-06-01		No
S	2109	Equestrian - Lake Las Vegas 69 kV Line Uprate	2030-06-01		No

NVEnergy

NERC-Required

#1009 California - Bordertown 120kV Line

Summary:

The California - Bordertown 120 kilovolt (kV) line project that includes approximately 12 miles of new 120kv transmission line, a 345 to 120 kV transformer addition at Bordertown, and a line terminal addition at California substation is required to mitigate multiple potential NERC TPL-001-4 violations and to improve operation of the bulk electric system in northwest Reno. A new RAS is required for loss of the Bordertown – North Valley 345 kV line which will to open the 120 kV system if it is overloaded during this contingency. The project was originally approved by the Nevada Public Utilities Commission in 2007 in Sierra's Integrated Resource Plan (Docket No. 07-06049) and re-approved every three years in subsequent Integrated Resource Plan filings.

A Supplemental AFE is being requested to cover the cost increases experienced for material, resources, and increased property values in the past four years. The project was suspended in October 2020 through January 2022. Upon resuming the project, the design has had to be redone to incorporate revised standards and specifications for replacement material. Additional scope, such as the Remedial Action Scheme at Northwest substation, has also become necessary due to system changes during the project suspension.

Problem Statement:

The Bordertown - California 120 kV line project is required to relieve line overloads by transfer moving load to the 345 kV system from the existing 120 kV system that serves the Reno load. The California - Bordertown 120 kV line and the new 345/120 kV transformer at Bordertown is required to provide the additional source to the 120 kV system load. Transmission Planning's analysis identified the following P1 contingencies cause overloads.

- N-1 Penney's Tap overloads California – Washoe 120kV (103%) and North Valley Road – Reno 120kV line (120%)
- N-1 Washoe Switching Station overloads Northwest – Penney's Tap 120kV line (114%)
- N-1 Valley Road – Reno 120 kV overloads Northwest – Penney's Tap 120kV line (125%) and North Valley Road to Penny's Tap line (104%)

The project is required to mitigate these potential NERC TPL-001-4 violations and improves operation of the bulk electric system (BES) in northwest Reno, and to reduce load on the California substation phase shifter. A new RAS is required for loss of the Bordertown – North Valley 345 kV line which will to open the 120 kV system if it is overloaded during this contingency.

Project Scope:

Construct about 12 miles of 120 kV line from Bordertown to California Substation with 2-954 ACSR conductor. Rebuild a significant portion of California substation and add a 120 kV terminal. Rebuild the south half of the Bordertown substation in order to add a 345/120 kV 280 MVA transformer and a 120 kV line terminal.

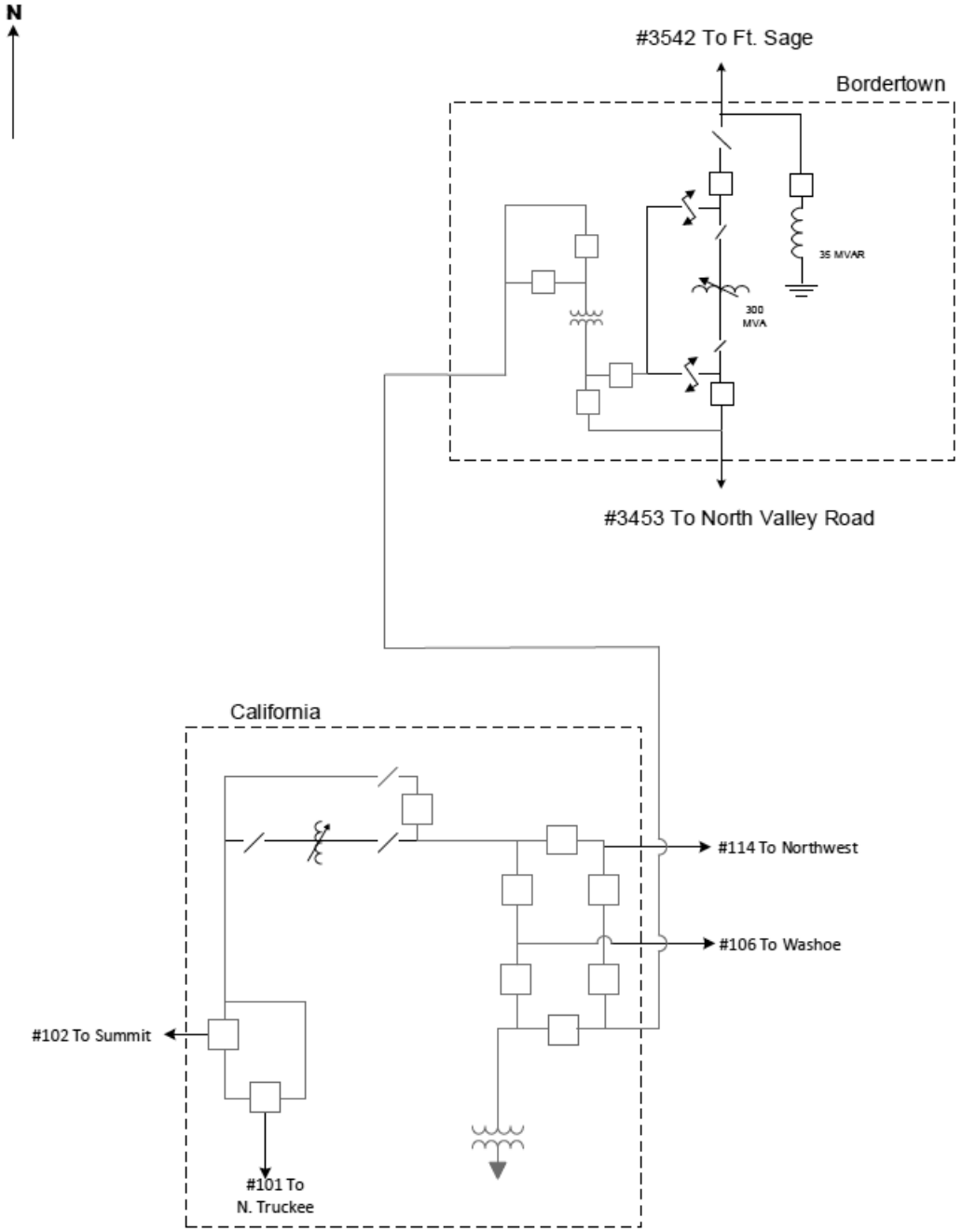


Figure 1: California - Bordertown 120kV Line

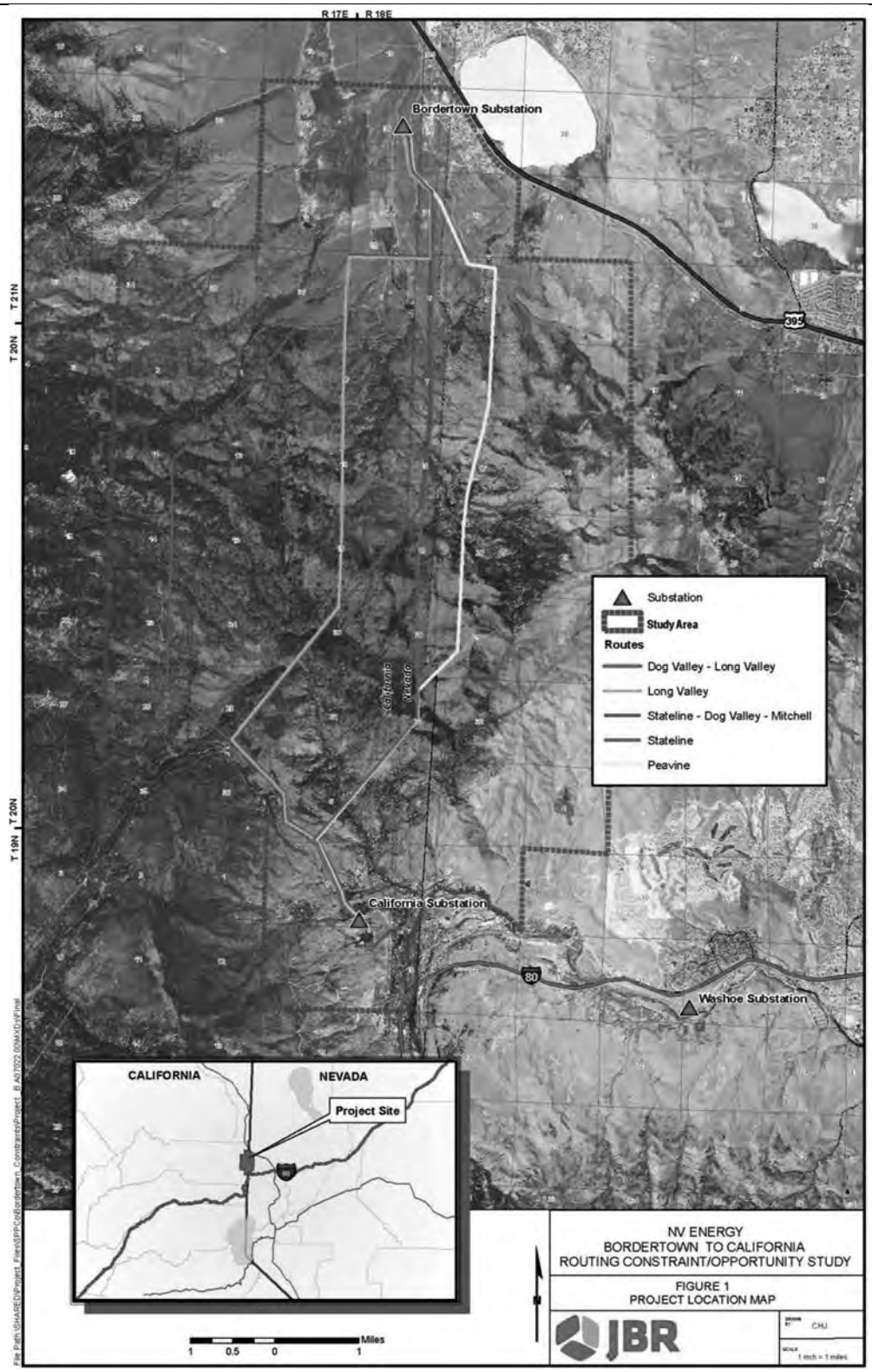


Figure 2: California - Bordertown 120kV Line

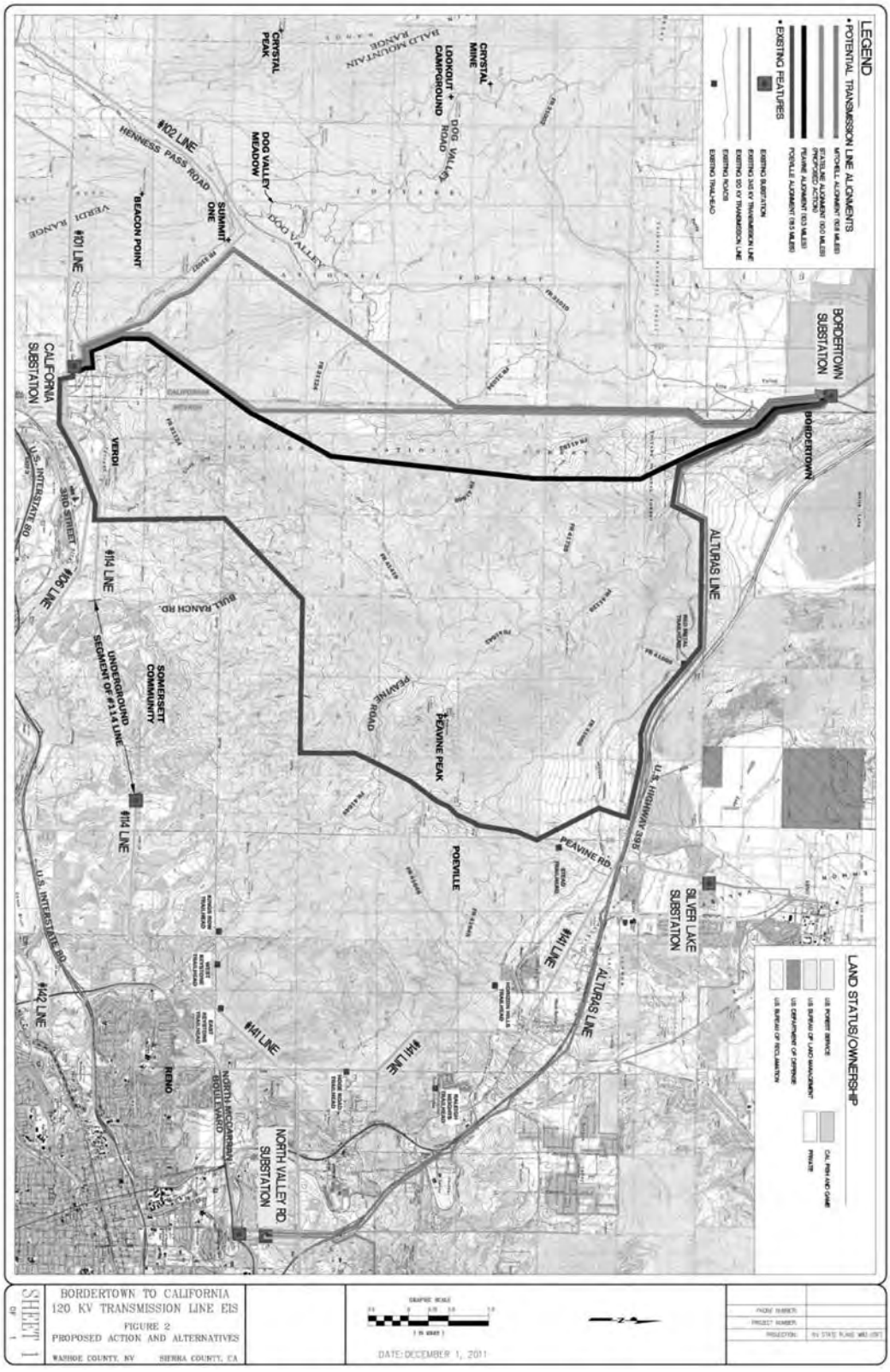


Figure 3: California - Bordertown 120kV Line

#1071 Western Nevada Master Plan

Summary:

The TRI Center area has received load requests in the thousands of MW's. To support this load, the Western Nevada Master Plan was created to outline what projects are required to support this load and when these projects are required. The timing for these projects are based on the most recent load forecasts provided by the customers. These forecasts along with changing load requests can shift the timing of various projects. These projects represent the current scope for the TRI Center area and may change as needed.

Project Scope:

Phase 1 - 2026

- West Tracy - Comstock Meadows 345 kV Line
- Comstock Meadows 345/120 kV Transformer #1

Phase 2 - 2027

- Walker River – Comstock Meadows 345 kV Line #1 (with a line fold to Mackay Substation)
- Walker River – Mira Loma 345 kV Line
- Gosling 345 kV Switching Station (Line fold of West Tracy – Comstock Meadows 345 kV Line)

Phase 3 - 2028

- Comstock Meadows 345/120 kV Transformer #2
- Walker River – Comstock Meadows 345 kV Line #2 (with a line fold to Nighthawk Substation)
- West Tracy 345/120 kV Transformer #2
    - West Tracy – Wild Horse 120 kV Line

Phase 4 - 2029

- Comstock Meadows – Chukar 345 kV Line
- Chukar 345/120 kV Transformer #1

Phase 5 - 2030

- Chukar 345/120 kV Transformer #2

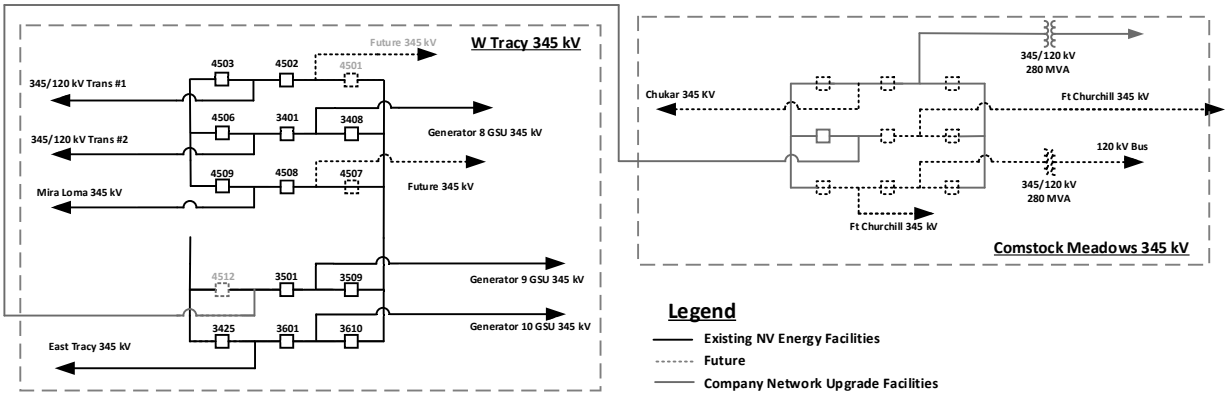
Phase 6 - 2031

- Walker River 525/345 kV Transformers #3 and #4
- Lantern – Chukar 345 kV Line
    - Line to be folded into Viking Switching Station and Vaquero 345/120 kV Substation

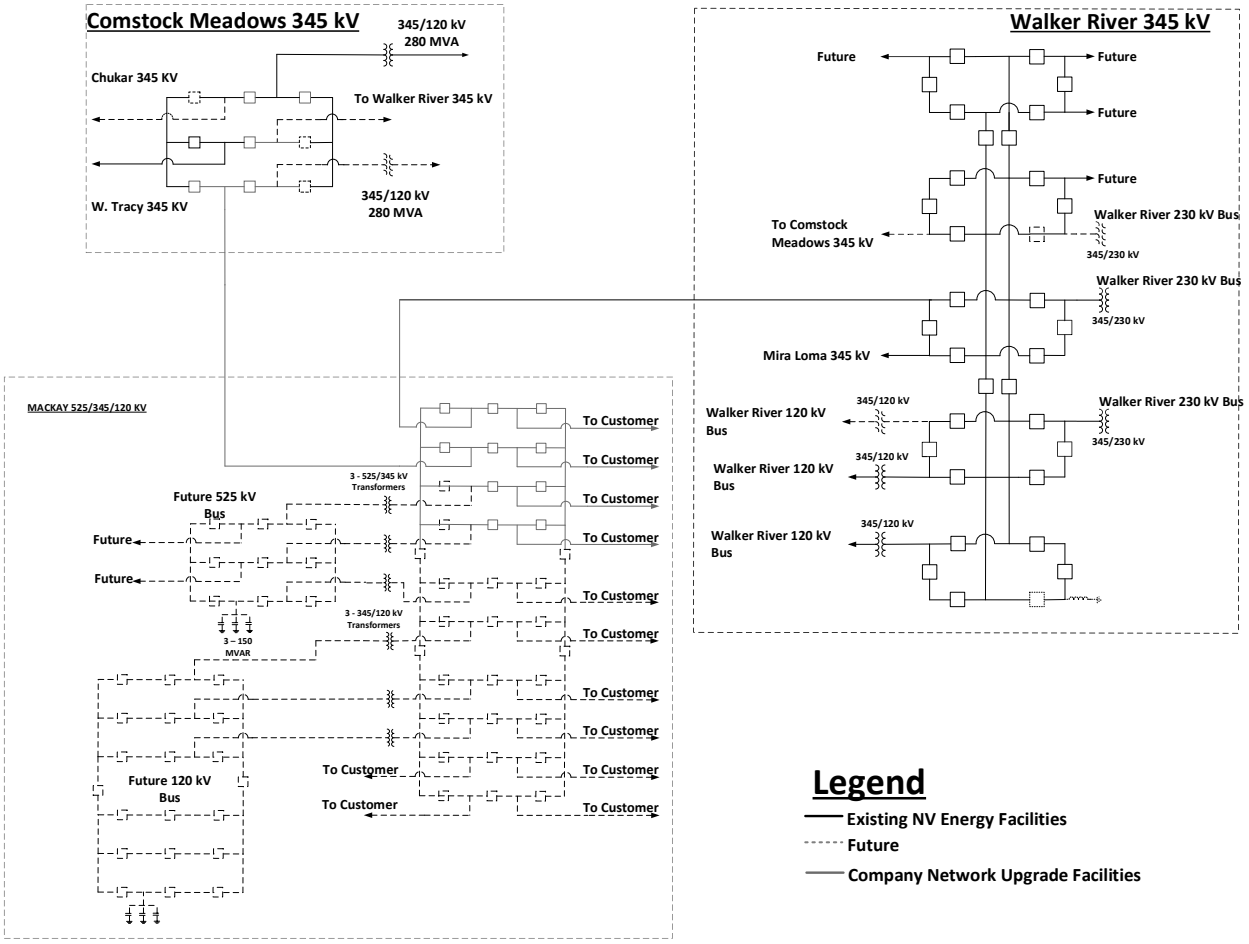
NVEnergy

Appendix A

NVEnergy	Western Nevada Master Plan Phase I: W. Tracy – Comstock Meadows 345 kV	12/15/2025



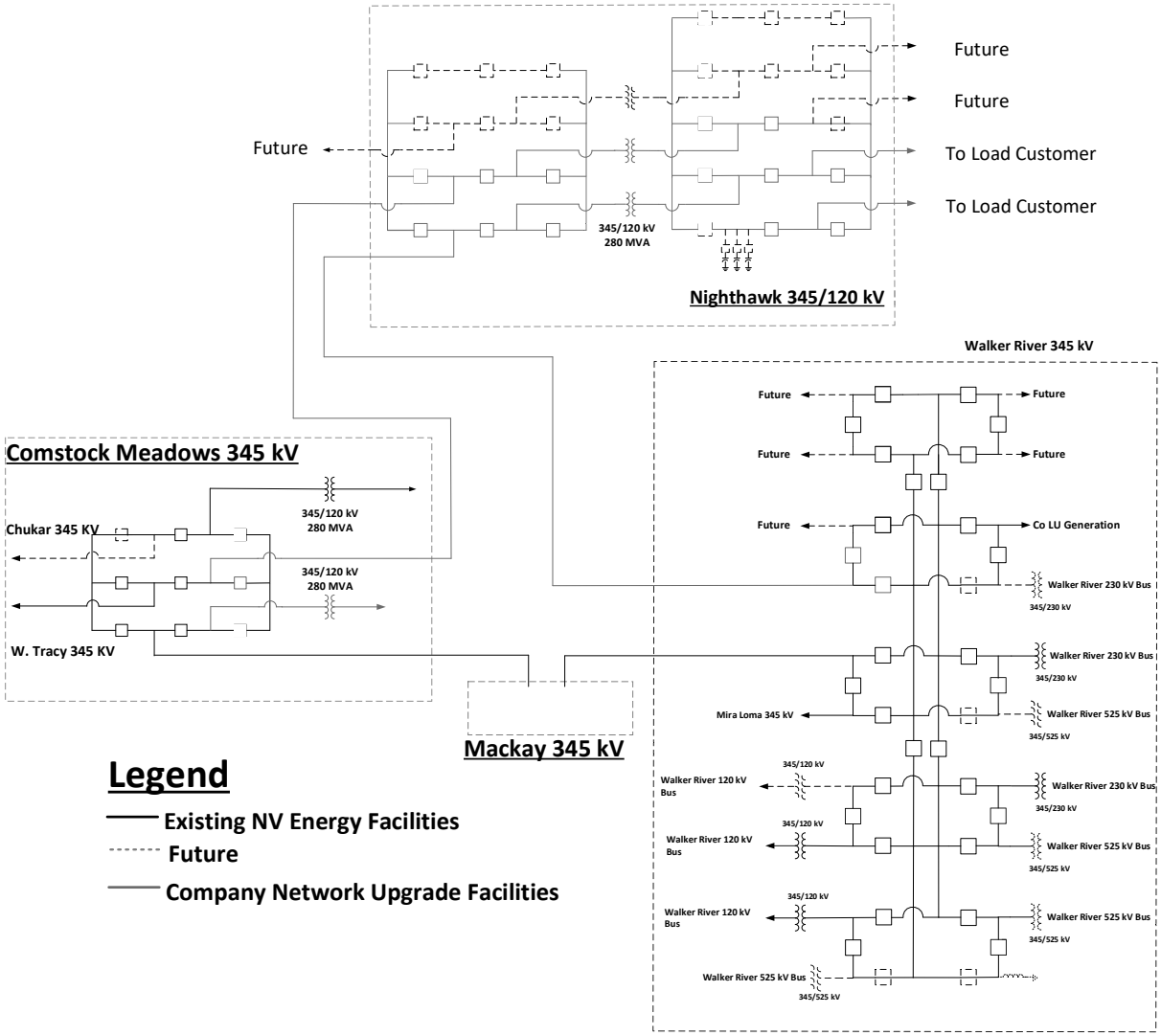
NVEnergy	Western Nevada Master Plan Phase 2: Comstock Meadows – Walker River 345 kV line with Line Fold into Mackay Substation	12/15/2025



NVEnergy

Appendix A

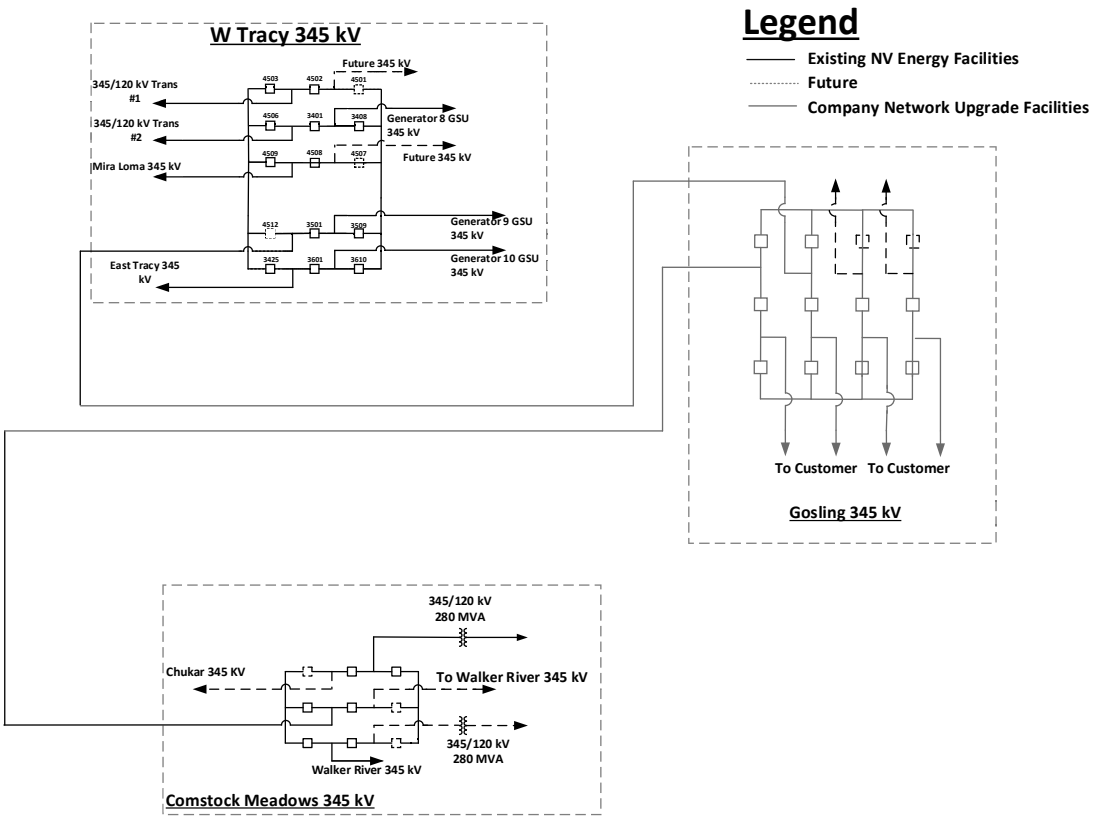
NVEnergy	Western Nevada Master Plan Phase 3: Comstock Meadows – Walker River 345 kV line #2 with Line Fold into Nighthawk Substation	12/17/2025



NVEnergy

Appendix A

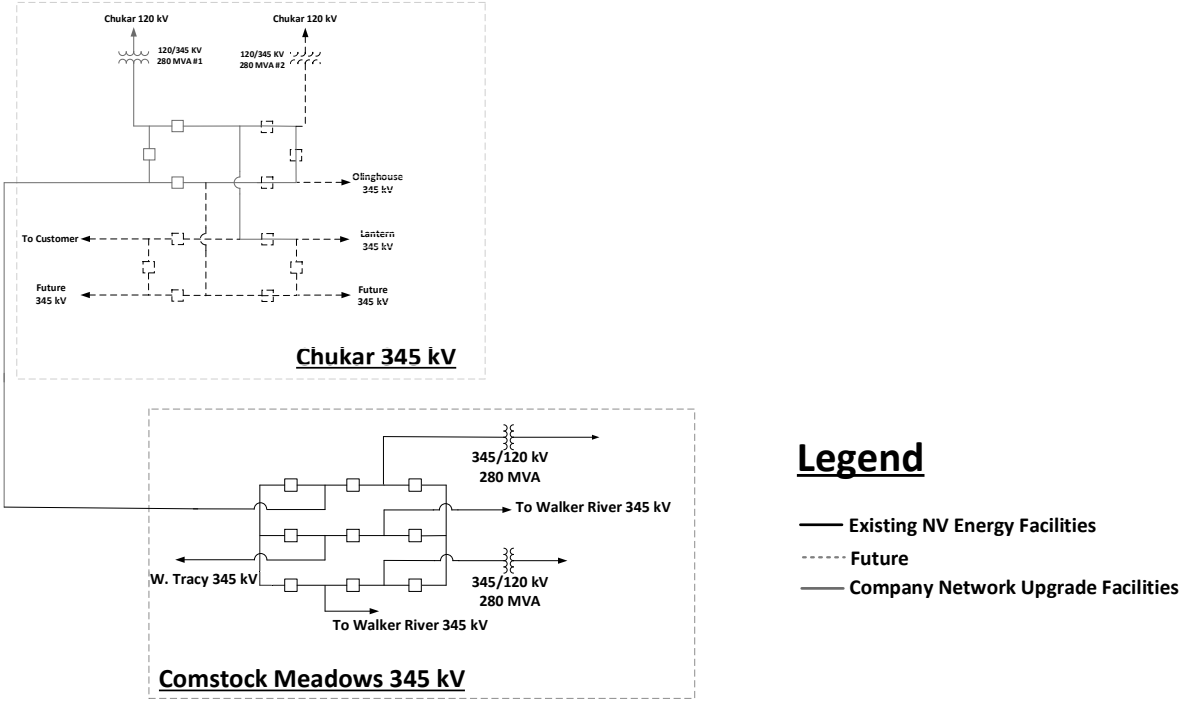
NVEnergy	Western Nevada Master Plan Phase 2: Line Fold of W. Tracy – Meadows 345 kV line into the new Gosling 345 kV substation	12/15/2025



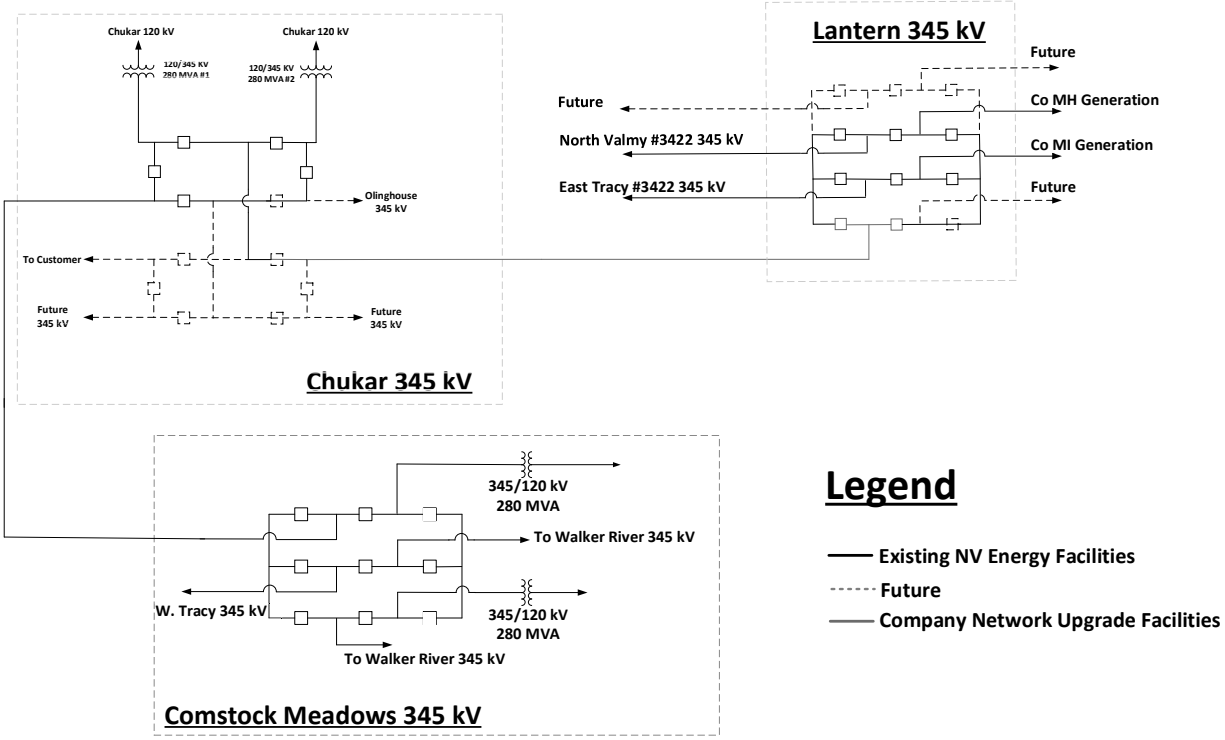
NVEnergy

Appendix A

NVEnergy	Western Nevada Master Plan Phase 4: Comstock Meadows – Chukar 345 kV Line	12/15/2025



NVEnergy	Western Nevada Master Plan Phase 6: Chukar – Lantern 345 kV Line	12/15/2025



NVEnergy

#1076 Buckeye Substation Rebuild

Summary:

NERC TPL-001-5 violation for breaker failure and bus outages which are N-1 contingencies. This project is contingent to create line positions required for the Pine Nut #627, Buckeye - Heybourne - Brunswick 60 to 120 kV conversions which are also mitigation for TPL-001-5 violations.

The purpose of this project is to rebuild Buckeye substation to improve reliability for customers in the Carson Valley and South Lake Tahoe areas. Buckeye substation is an old 120/60 kV substation built with a radial bus configuration on both the 120 kV and 60 kV sides. This means that any 120 kV bus faults or breaker failure events at this substation and take out the entire substation, which would be five 120 kV lines and, three 60 kV lines, a distribution transformer, and a 120/60 kV transformer. This results in significant customer outages. By rebuilding the substation to a folded breaker and a half configuration, this eliminates a single contingency taking the entire substation offline. The plan is to rebuild the 120 kV portion of Buckeye substation adjacent to the existing substation on land already owned by NV Energy. The rebuilt substation will also be designed to accommodate conversion of the 60 kV lines to 120 kV in the future. The 60 kV bus will not be upgraded as a part of this rebuild. This project will look similar to the rebuild that occurred for Brunswick substation.

Previous iterations of this project proposed building a new Stockyard substation in a new location that would replace Buckeye. There was also a consideration to build Stockyard substation and rebuild Buckeye, moving most of the 120 kV to Stockyard and leaving the 60 kV and distribution at Buckeye. These plans were abandoned based on cost and feedback from Douglas county indicating there would be significant challenges building Stockyard in the new proposed location about 1 mile north of the existing Buckeye substation.

Problem Statement:

In 2018, the Grid Reliability Improvement Program identified Buckeye substation as the worst performing substation in northern Nevada based on it being first in customer outage hours and the number of affected customers in a five year period. The factors leading to poor performance are the substation configuration and age of equipment (50 to 60 years old). Buckeye Substation is the primary southern substation source for the Carson Valley. It is also the only 120 kV source to South Lake Tahoe. The substation bus structures are aging lattice with eight radial terminals, including 5 lines, 2 transformer feeds and 1 capacitor bank. The substation has a history of long duration and large impact outages. It is susceptible to bus faults and any bus fault or breaker failure causes an outage to the entire 120 kV substation.

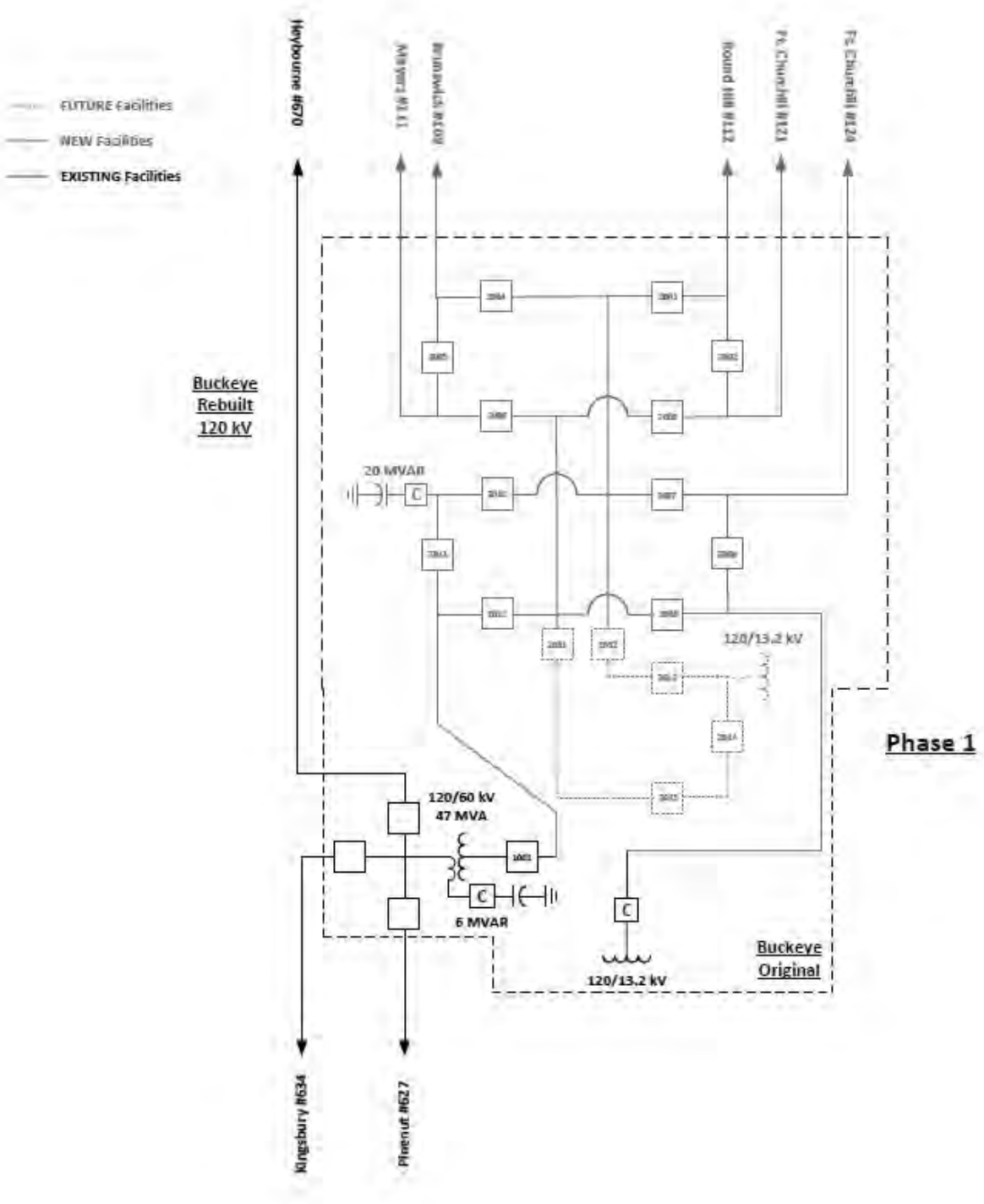
The project's original scope was to construct a new 120/60/12.5 kV substation to replace Buckeye substation in its entirety. The revised plan is to rebuild only the 120 kV and 12 kV portions of the substation adjacent to the existing substation on land already owned by NVE. The 60 KV yard would not be upgraded, but the 120 kV yard will be designed to accommodate conversion of the 60 kV lines to 120 kV over time.

Project Scope:

NVEnergy

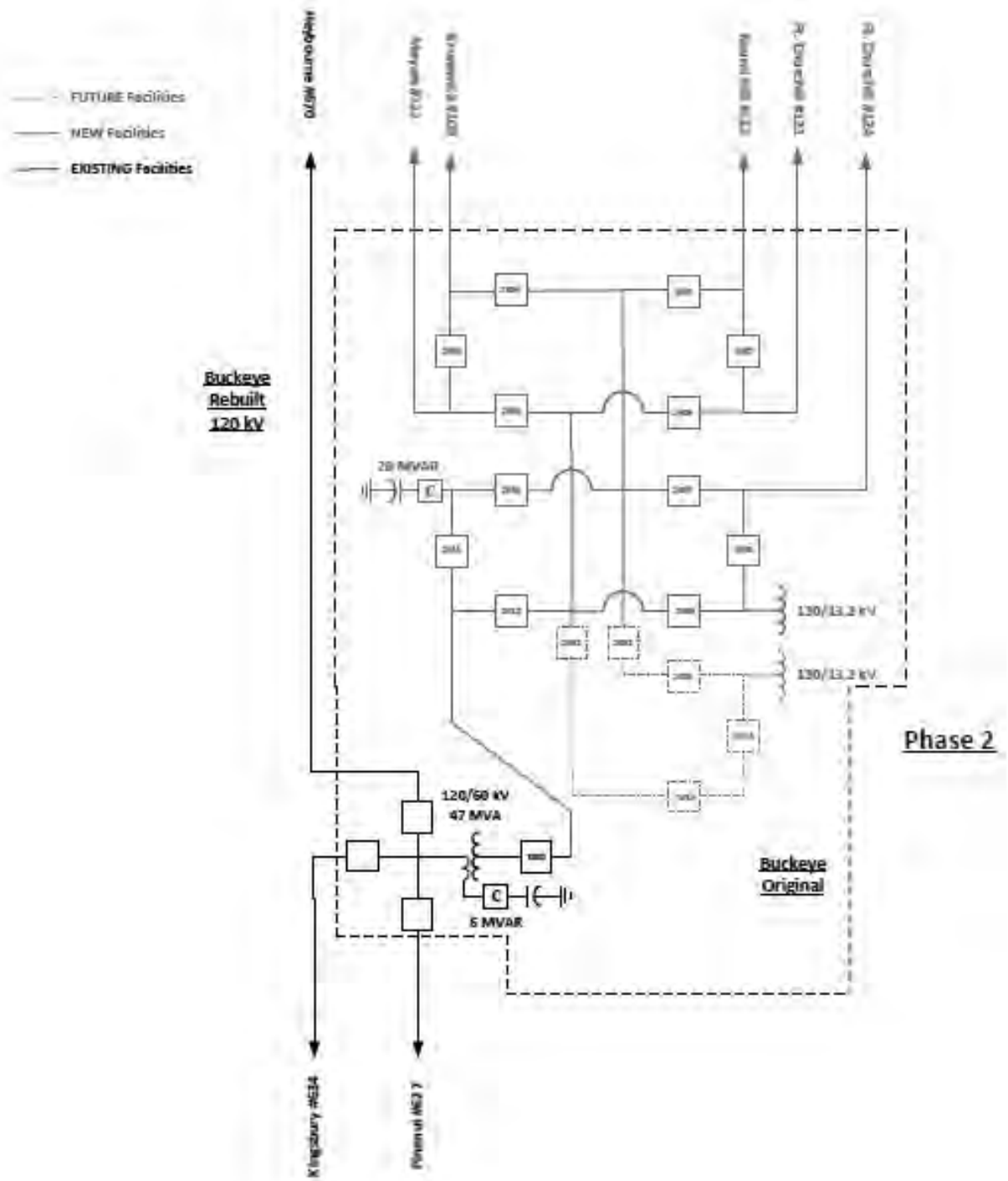
Appendix A

Rebuild the Buckeye 120 kV bus to breaker-and-a-half scheme.



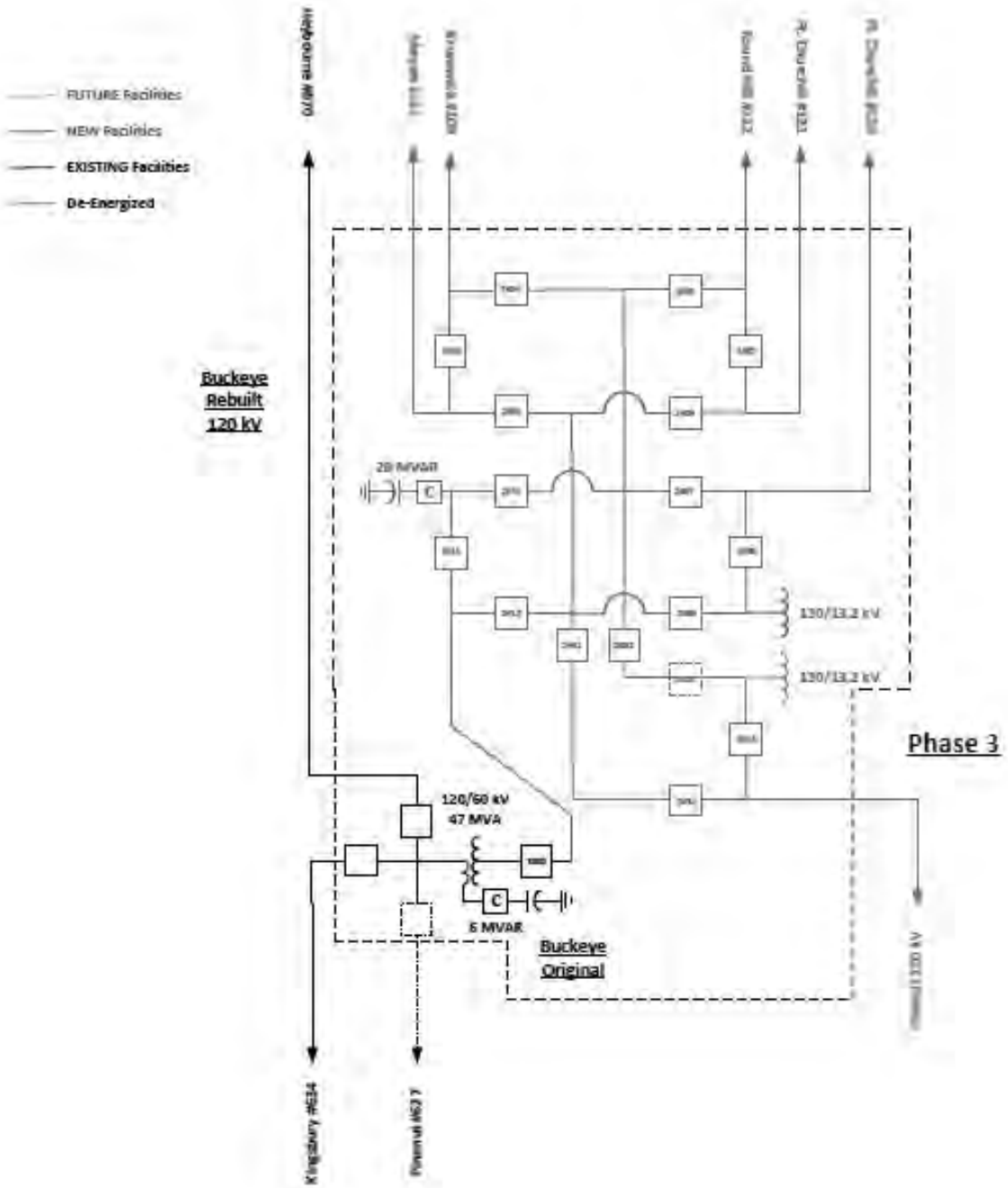
NVEnergy

Appendix A



NVEnergy

Appendix A



#1080 North Underrated Breaker Replacements

System Deficiencies

Transmission Planning and System Protection have identified under-rated breakers and bus-work in the 10-year planning horizon which will require upgrades to support the full expected fault duty at the sites.

Corrective Action Plan

Replace BES Underrated Breakers and bus at multiple locations based on short circuit analysis results. (See TPL-001-5.1 R2, Part 2.3)

For the Northern System, the following breakers are required to be replaced:

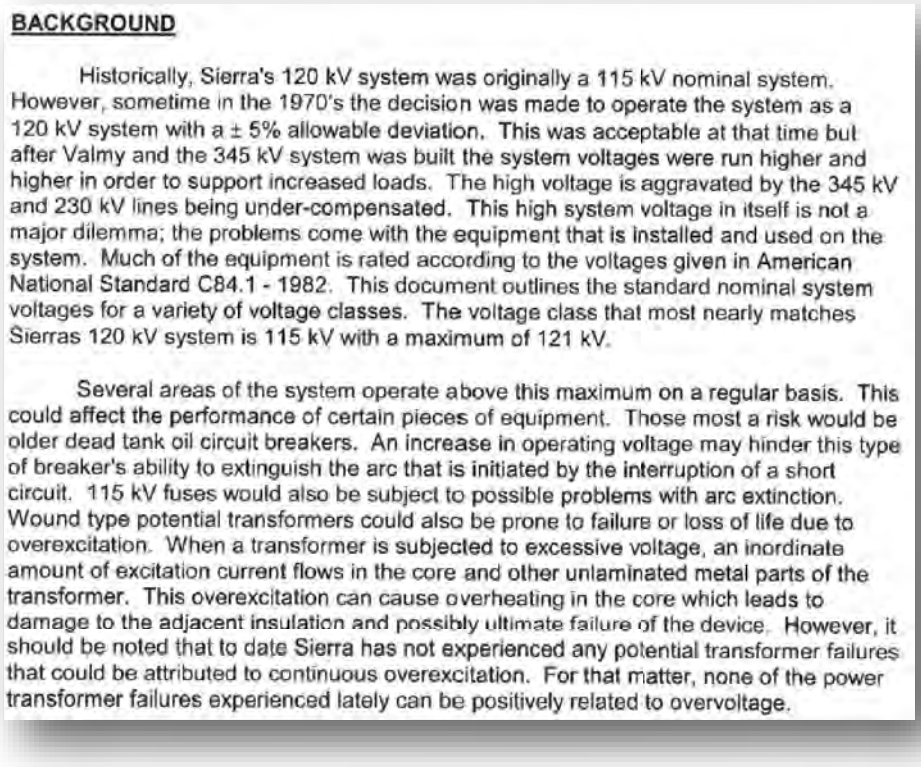
- 2027 (With Greenlink West)
  - Dove 179
  - Dove 180
  - Dove 181
  - Dove 182
  - Dove 190
  - Dove 1003
  - Rusty Spike 174
- 2028 (With Greenlink North)
  - Dove 1001
  - Dove 1002

#1081 121kV Breaker Limitations

Problem Statement:

As recently as 2017 and 2018, Transmission Planning at NV Energy began identifying voltage limitations on equipment in substations, and attempting to respect those voltage limits when performing planning assessments. Most of the abnormally low voltage limitations on NV Energy system are due to the mix of equipment being used on the 120kV network.

A memo from 1993 very succinctly summarizes the background of this problem and goes into detail on tap changes and capacitor bank changes recommended to minimize risk due to operating equipment at higher than rated voltages. An excerpt of the background is included.



BACKGROUND

Historically, Sierra's 120 kV system was originally a 115 kV nominal system. However, sometime in the 1970's the decision was made to operate the system as a 120 kV system with a ± 5% allowable deviation. This was acceptable at that time but after Valmy and the 345 kV system was built the system voltages were run higher and higher in order to support increased loads. The high voltage is aggravated by the 345 kV and 230 kV lines being under-compensated. This high system voltage in itself is not a major dilemma; the problems come with the equipment that is installed and used on the system. Much of the equipment is rated according to the voltages given in American National Standard C84.1 - 1982. This document outlines the standard nominal system voltages for a variety of voltage classes. The voltage class that most nearly matches Sierras 120 kV system is 115 kV with a maximum of 121 kV.

Several areas of the system operate above this maximum on a regular basis. This could affect the performance of certain pieces of equipment. Those most a risk would be older dead tank oil circuit breakers. An increase in operating voltage may hinder this type of breaker's ability to extinguish the arc that is initiated by the interruption of a short circuit. 115 kV fuses would also be subject to possible problems with arc extinction. Wound type potential transformers could also be prone to failure or loss of life due to overexcitation. When a transformer is subjected to excessive voltage, an inordinate amount of excitation current flows in the core and other unlaminated metal parts of the transformer. This overexcitation can cause overheating in the core which leads to damage to the adjacent insulation and possibly ultimate failure of the device. However, it should be noted that to date Sierra has not experienced any potential transformer failures that could be attributed to continuous overexcitation. For that matter, none of the power transformer failures experienced lately can be positively related to overvoltage.

Figure 4: Excerpt from May 20, 1993 Memo [By: Tom Wiltzius] [To: Kerry Flanagan]

An assessment was performed to determine highest risk locations for operating substation equipment above known breaker voltage limitations. Based on 8760 hourly average voltage queries for 2024, locations were assessed to determine the percentage of hours in 2024 which were recorded above the known breaker limits. This list was sorted based on the percentage of hours in which voltage was above the known breaker limits, whether over-voltage conditions were identified in a powerflow study, and other considerations such as requests by system control or projects at a particular location.

The final table, sorted by preferred order of replacement, is listed below.

NVEnergy

Appendix A

Substation	High Limit	Percentage of Time Above High Limit (Historical)	Bus above limit in Cases
Adobe	121	100.0%	Yes
Humboldt	121	90.3%	Yes
Last Chance	121	90.3%	
Eight Mile	121	49.4%	
North Truckee	121	34.7%	Yes
North Valmy	121	34.7%	Yes
Coyote Creek	121	17.6%	Yes
Maggie Creek	121	5.9%	
Sugarloaf	121	2.2%	
Rusty Spike	121	39.0%	
Jerrit	121	98.3%	Yes
Silverlake	121	56.8%	
Winnemucca	121	56.8%	
Airport	121	54.2%	
Lonely	121	53.3%	
Desert Peak	121	51.3%	
Muller	121	34.7%	
North Valley Roa	121	34.7%	
Mount Rose	121	29.3%	
Fort Churchill	121	27.8%	
Incline	121	23.4%	
Spanish Springs	121	20.9%	
Osgood	121	19.6%	
Patrick	121	16.2%	
Roundhill	121	15.6%	
Grass Valley	123	14.2%	
Eagle	121	13.5%	
Oreana	121	13.5%	
Overland	121	13.5%	
Panama	123	13.5%	
Emerson	121	12.6%	
Fairview	121	12.6%	
Carson	121	7.4%	
Mark Twain	123	5.9%	
Trolley	121	5.7%	
Boulder Basin	121	3.3%	
Anaconda Moly	121	3.3%	
Bell Creek	121	3.3%	
Battle Mountain	121	3.3%	
Greg Street	121	3.1%	
Buckeye	121	2.4%	
Northwest	121	2.4%	
Steamboat	121	2.2%	
Thorne	121	2.2%	
Millers	121	1.4%	
Bella Vista	121	0.5%	
Fernley	123	0.0%	
Reno	121	0.0%	
Tiads	121	0.0%	

Breaker Voltage Limit Exceedances in 2024

Project Scope:
Replace 120kV system breakers rated below 126kV in Northern Nevada substations. Identify all ancillary equipment rated below 126kV at the site as a part of the project scope, and upgrade those facilities identified.

The priority is to be based on locations that have historically operated above the equipment limitations, locations that have been identified in a powerflow study as exceeding the voltage rating, and input from the various operating groups.

Based on the priority list, the following breakers are proposed to be replaced first. As these projects are completed, additional sites will be added:

1. Adobe
   - 1001 Circuit Switcher
   - 1002 Circuit Switcher
2. Humboldt
   - 136 Breaker
   - 137 Breaker
   - Cap #1 Circuit Switcher
3. Last Chance
   - 1001 Circuit Switcher
4. Eight Mile
   - 137 Breaker
   - 156 Breaker
   - 178 Breaker
   - Cap #1 Circuit Switcher
5. Coyote Creek
   - 1001 Breaker
   - 150 Breaker
6. Maggie Creek
   - Cap #1 Circuit Switcher
7. Silverlake
   - 1002 Circuit Switcher
   - 1003 Circuit Switcher
   - 141 Breaker
8. Airport
   - 172 Breaker
   - 174 Breaker
   - 1003 Breaker
   - 1004 Breaker
9. Sugarloaf
   - 1001 Circuit Switcher (To be replaced with CAP #1123)
10. Patrick
    - 116 Breaker (To be replaced with CAP #1124)

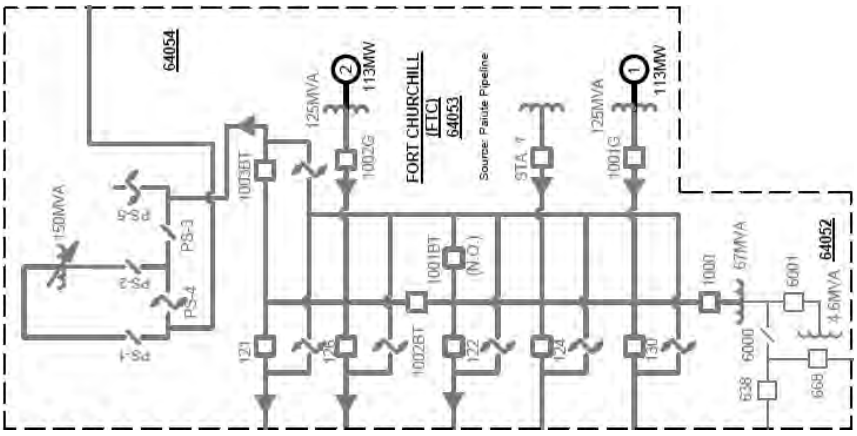
NVEnergy

Appendix A

#1088 Ft Churchill Substation Rebuild

Problem Statement:

Ft Churchill is currently configured as shown below. The North and South Ft Churchill buses are Main & Transfer schemes, with a bus-tie 1002BT breaker connecting between the two main buses. This configuration means that the entire substation is lost for a failure of the 1002BT bus-tie breaker.



TPL-001-4 defines P2 (Internal Breaker Fault) and P4 (Stuck Breaker) contingencies in Table 1, and specifies that:

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

Loss of Ft Churchill Substation due to a 1002BT breaker P2 or P4 event can cause voltages below 90% on BES (120kV) buses at: Buckeye, Stateline, Muller, Round Hill, Meyers, Downs, Fairview, Dayton, Incline, etc.

It can also cause overloads of the following circuits:

FROM NO	FROM NAM	FROM KV	TO NO	TO NAME	TO KV	CKI
64020	BRUNSWCK	120	64089	OVRLNDTP	120	1
64025	CAL SUB	120	64136	WASHOE	120	1
64027	CARSON T	120	64079	MT ROSE	120	1
64079	MT ROSE	120	64136	WASHOE	120	1
64089	OVRLNDTP	120	64453	DOWNS	120	1
64450	EMERSON	120	64026	CARSON	120	1
64450	EMERSON	120	64027	CARSON T	120	1
64453	DOWNS	120	64022	BUCKEYE	120	1
64486	TRW	120	64020	BRUNSWCK	120	1
64486	TRW	120	64116	TRACY E	120	1

Project Scope:

Re-build Ft Churchill 120kV bus to a breaker-and-a-half scheme to the West of the existing Ft Churchill substation site. This rebuild is part of the Greenlink West project scope at the Walker River substation.

#1089 Millers & Silver Peak UVLS

Background:

The Millers - Silver Peak 55 kV system serves approximately 10-12 MW of load in Esmerelda and Nye counties (Southwestern SPPC territory). The major loads include the towns of Tonopah, Silver Peak, Gabbs, and Manhattan. In addition, several telecommunications sites, government entities, and mining loads are served from the system. Due to the remote location, these loads are served exclusively from the 55 kV system and most of them are tapped directly from the line serving them. As a result, when there is any outage to the 55 kV system, it threatens to drop load for an extended duration. The 55 kV system also includes NVE's Silver Peak tie-line with SCE.

The 2018 NERC reliability analysis identified potential low voltage violations near the Millers 57.5 kV system under certain loading conditions following the loss of the 125/62.3 kV Millers Transformer. This contingency, if experienced, could result in a local voltage collapse and loss of the entire load and tie line.

Problem Statement:

Project will address existing deficiency of NERC TPL-001-5 which requires the system to meet NV Energy voltage criteria. Following a loss of the Millers 120/55 kV transformer (a P1 event), the 55 kV system between Millers and Silver Peak including Tonopah, Gabbs, Goldfield, and Round Mountain bus voltages drop well below 0.90 p.u. violating NV Energy Voltage criteria. According to the criteria, 55 kV bus voltages must remain above 0.90 p.u. under P1 conditions. The proposed solution is an automatic scheme of staged load shedding to correct voltages and minimize the risk of losing the entire area. In addition, the scheme will prevent the low voltage condition from propagating to the rest of the system.

Additionally, during TPL-007-2 assessments, voltage collapse of the 55kV and 120kV systems has also been seen for conditions where:

1) Summer Peak Loading is present,

2) A GIC/GMD event begins to occur, at a magnitude of 8V / km, and
   A P1 of [Anaconda – Millers 120kV] or [Anaconda 230/120kV] occurs.

Furthermore, for those conditions, overloads of the Millers 120/55kV transformer may occur.

Project Scope:

Install a UVLS scheme at Millers and Silver Peak substations, which are coordinated to do the following:

- Trip Millers 503, 504, 505, and 506 Circuit Breakers for voltages below 52kV for 3 seconds.
- Trip Silver Peak 503 and 508 Circuit Breakers for voltages below 52kV for 5 seconds.

This will isolate the 55kV system and prevent damage to customer equipment if voltage collapse begins to occur.

#1111 #106 Uprate (Mount Rose – Washoe Switching Station)

Summary:

A portion of the #106 line from Mount Rose – Washoe Switching Station can overload for certain P1 events involving the #127 Line, the #1102 Line, or the #3426 Line.

Project Scope:

To mitigate this problem, the #106 line from Mount Rose – Washoe Switching Station should be reconductored with 954 ACSR conductor, approximately 4.47 miles. All substation equipment at both Mount Rose and Washoe Switching Station are rated appropriately. No equipment will need to be replaced at those locations.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F	Conductor MOT (°F)
N	120	T	Yes		#106	1	California Sub / Washoe Sw Sta	0.05	ARBUTUS	795	AAC	1	203		203
N	120	T	Yes		#106	2	California Sub / Washoe Sw Sta	1.16	ORCHID	721	ACAR	1		203	203
N	120	T	Yes		#106	3	California Sub / Washoe Sw Sta	0.51	IBIS	397.5	ACSR	1		212	212
N	120	T	Yes		#106	4	California Sub / Washoe Sw Sta	0.88	ARBUTUS	795	AAC	1	203		203
N	120	T	Yes		#106	5	California Sub / Washoe Sw Sta	0.89	IBIS	397.5	ACSR	1		212	212
N	120	T	Yes		#106	6	California Sub / Washoe Sw Sta	0.73	TERN	795	ACSR	1		212	212
N	120	T	Yes		#106	7	California Sub / Washoe Sw Sta	0.57	IBIS	397.5	ACSR	1		212	212
N	120	T	Yes		#106	8	Washoe Sw Sta / Mt Rose	0.01	ARBUTUS	795	AAC	1	203		203
N	120	T	Yes		#106	9	Washoe Sw Sta / Mt Rose	4.46	ORCHID	721	ACAR	1		203	203

All conductor on the #106 line from Mount Rose – Washoe Switching Station needs to be replaced with 954 ACSR conductor.

#1114 #146 Eagle – East Tracy 120 kV Line Uprate

Problem Statement:

The #146 line from Eagle – Tracy consists of mostly 4/0 ACSR and is rated for 77 MVA. For high distribution loads a P2 event for opening the Dove terminal of the #190 Dove – Fernley line will overload the #146 line. This overload was also identified during multiple generation interconnection studies.

Per LGIA Service Agreement #19-00055, initially executed as of November 7, 2019, Company HN (i.e. ORNI 36 LLC , re-assigned from affiliate company USG Nevada LLC as of 3/14/2022; "San Emidio 2") has interconnected their new North Valley Generating Facility to NV Energy, via a 58-mile 120kV lead line, tying into a new 120kV terminal at Eagle Substation. The customer owned lead line approximately parallels the existing DC line from San Emidio to Eagle (ref. Link Code AA9). The new Generating Facility Capacity is planned to ultimately be 45 MW net at the Point of Interconnection. Ormat's facility will be completed in two phases, with Phase 1 to have a 25 MW output and Phase 2 a 20 MW output. This uprate to 1949 ACCC conductor was called out during the generation interconnection.

Project Scope:

To mitigate this problem, it's recommended that the entire #146 Eagle – East Tracy line (~21 miles) be rebuilt using 1949 ACCC conductor.

#1116 Eight Mile Creek / Maggie Creek Capacitor Bank Upgrade

Summary:

The Carlin Trend is a major mining hub in Nevada serving over 300 megawatts of load and sourced by NV Energy's northeastern 345 kV system. The area has historically suffered from low voltage performance due to its remote location and inductive load profile. NV Energy has addressed the low voltage conditions by installing capacitor banks at several of NV Energy's substations in the area. However, following the recent initiation of a seasonal economic reserve shut-down of Valmy generation and planned future retirement, the low voltage conditions have resurfaced.

For the loss of the #137 Eight Mile Creek – Humboldt 120 kV line, voltages at Adobe, Eight Mile Creek, and Last Chance can fall below 0.9 pu depending on the status of generation at Newmont and/or the planned capacitor banks at Bell Creek substation.

Project Scope:

Maggie Creek and Eight Mile Creek substation both contain existing capacitor banks that can easily be expanded by adding additional cans or replacing the existing 150 kVAR cans with 250 kVAR cans to obtain a higher rated capacitor bank. The 12 MVAR capacitor bank at Maggie Creek should be upgraded to 27 MVAR and the 12 MVAR capacitor bank at Eight Mile Creek should be upgraded to 16 MVAR.

NVEnergy

#1117 Coyote Creek 345 kV Breaker Additions

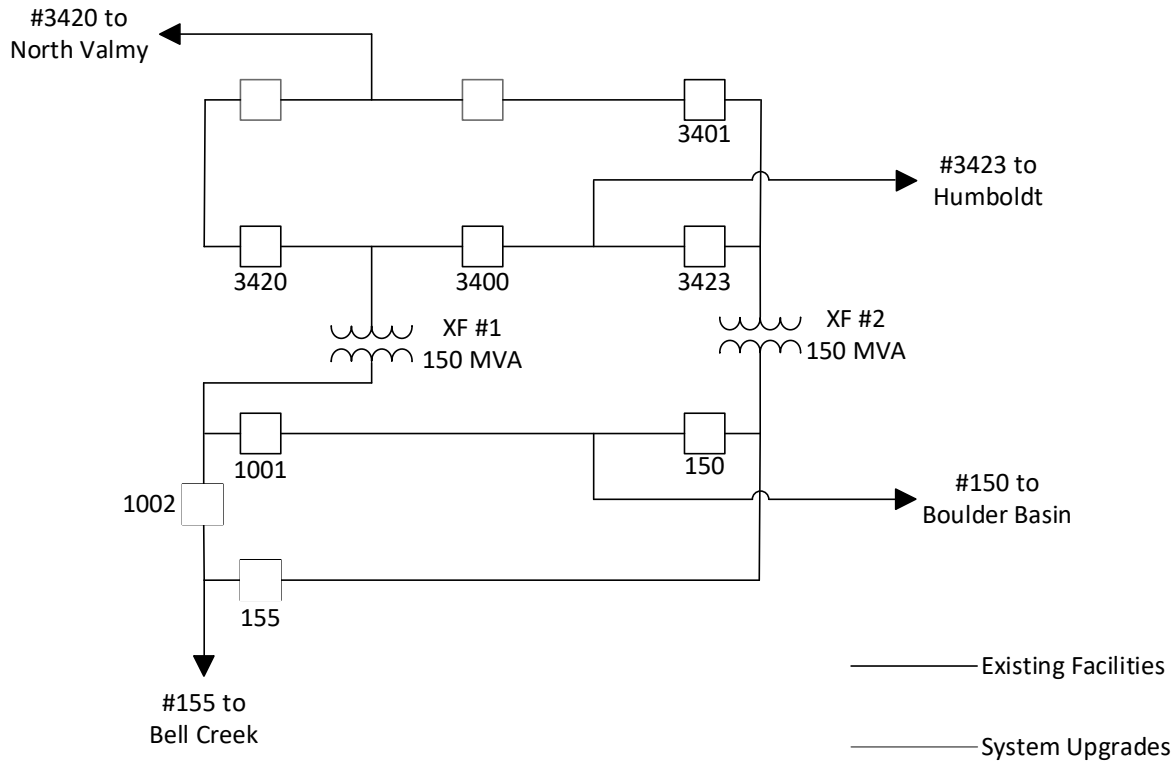
Summary:

The #3420 Coyote Creek – North Valmy 345 kV line shares a breaker at Coyote Creek with both the 345/120 kV Transformer #1 and 345/120 kV Transformer #2. For a breaker fail event of the Coyote Creek 3420 breaker, the #3420 line and Transformer #1 will both open. For a breaker fail event of the Coyote Creek 3401 breaker, the #3420 line and Transformer #2 will both open. When Path 16 is set for heavy imports into the Northern system, the loss of both the #3420 line and one of the 345/120 kV Transformers will overload the remaining Transformer to 130% of its emergency rating. To maintain the import rating on Path 16, this overload will need to be mitigated.

Project Scope:

The Transmission Planning proposed mitigation for this contingency is to install two 345 kV breakers for the #3420 line so that a breaker fail event does not trip both the #3420 line and one of the two 345/120 kV Transformers.

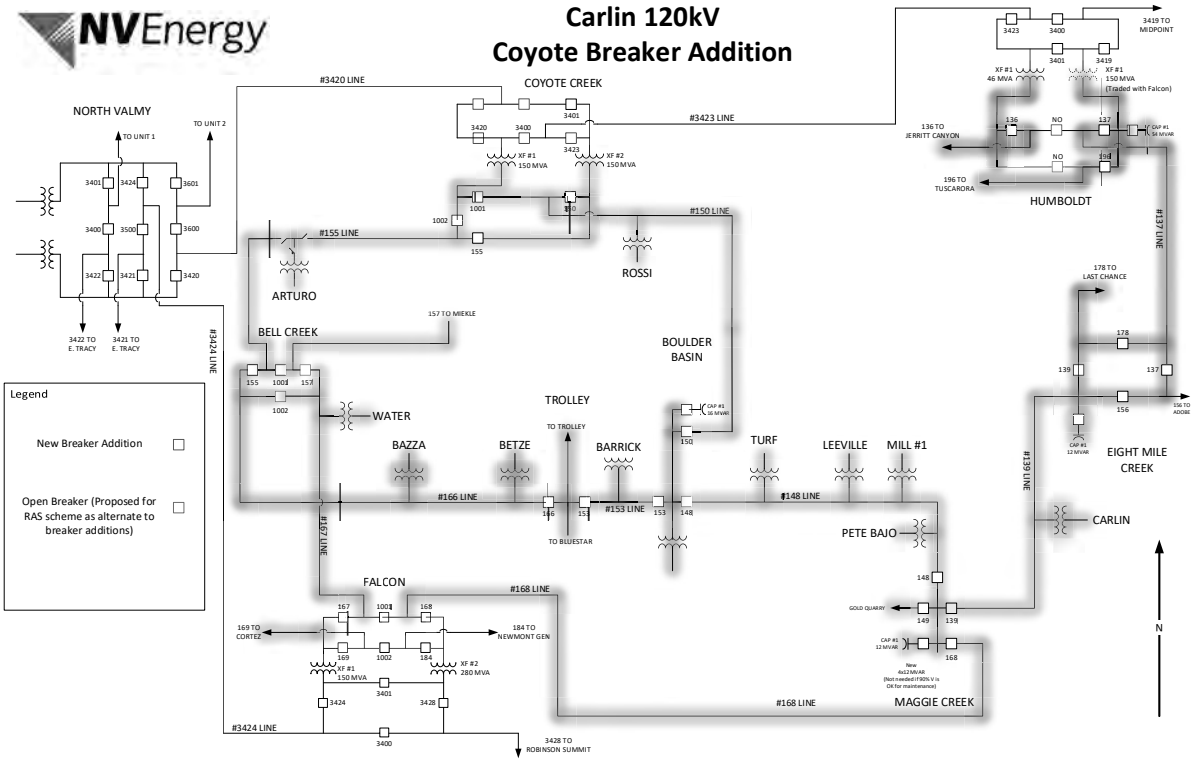
Two alternatives to the breaker installation were considered. The first alternative considered, was the replacement of both 345/120 kV 150 MVA transformers with 280 MVA transformers. The second alternative considered was a new RAS scheme that would send trips to Boulder Basin and Bell Creek to split the Carlin Trend load between Coyote Creek, Falcon and Humboldt. Based on costs and complexity, it was determined that the breaker additions would be the simplest solution to mitigate the overload.



Preferred Mitigation – Install two breakers at Coyote Creek

NVEnergy

Appendix A



Alternative RAS scheme to split the Carlin Trend

#1121 Pinenut 120 kV Conversion

Summary:

The load growth of the South Carson Valley in the Gardnerville and Dresslerville areas have loaded the Buckeye and Pinenut substations to 20.8MVA or 101.4% and 22.4MVA or 84.5% respectively. Plans are already underway to re-build the Buckeye sub however no plans exist to address the 60kV source and heavily loaded Pinenut substation. The Buckeye 120/60 kV Bank is expected to exceed its normal rating by 2033 based on the current load forecast. Converting the Pinenut load to 120 kV would offload the Buckeye 60 kV system and reduce N-0 overloads on the Buckeye 120/60 kV bank.

Geographically Pinenut is isolated not only from its neighboring substations and a radial 60kV source, the 627 line from Buckeye (approx. 5 miles), but it is also isolated as the southernmost substation in the Carson Valley.

Project Scope:

Convert the existing Pinenut Transmission Service from 60kV to 120kV. Replace or rebuild the required substation bus, and associated equipment in Pinenut Substation to increase reliability to the commercial and residential loads in Gardnerville area. This project required the Buckeye substation rebuild project (CAP #1076) to be complete first.

#1123 Sugarloaf 183 and 1001 Breaker Replacement

Summary:

Loss of the #3426 East Tracy – North Valley Road 345 kV line can overload the #183 Pah Rah – Sugarloaf 120 kV line. This line is limited by the 183 breaker at Sugarloaf. Due to the CT's required for the 120 kV bus protection, the CT's on the 183 breaker need to be wired to use a CT Ratio of 600:5. With a thermal rating factor of 1 for the CT's, the CT's are the limiting element on the #183 line. This breaker is also rated for a maximum voltage rating of 121 kV. Replacing this breaker would eliminate the CT limitation and the voltage limitation imposed on this breaker.

Project Scope:

Replace the 183 breaker at Sugarloaf with a 145 kV rated breaker. The breaker CT's should be ordered with a thermal rating factor of at least 2.0. The Sugarloaf 1001 Circuit Switcher should be replaced with a 145 kV rated Circuit Switcher at the same time to eliminate any operational voltage limitations at Sugarloaf.

#1124 Patrick 116 and 177 Breaker Replacement

Summary:

A P4 of the Mira Loma 4504 or 4505 breaker (trips the #3429 Mira Loma – West Tracy 345 kV line and one 345/120 kV Bank) can overload the #177 Patrick – West Tracy 120 kV line by 117.8% of its rating. This line is limited by the 177 breaker jumpers at Patrick. This breaker is also rated for a maximum voltage rating of 121 kV. Replacing this breaker along with the jumpers and disconnect switches would remove the voltage limitation and improve the breaker rating to match the rating of the line conductor

Project Scope:

Replace the 177 breaker at Patrick with a 2,000 A, 145 kV rated breaker. The breaker jumpers and disconnect switches should also be replaced with 2,000 A equipment. The Patrick 116 breaker is also rated for 121 kV and should be replaced with a 2,000 A, 145 kV rated breaker and 2,000 A breaker jumpers and disconnect switches to eliminate any operational voltage limitations at Patrick.

#2065 Tolson 230/138 kV Bank 2 and Tolson – Ford 138 kV Line

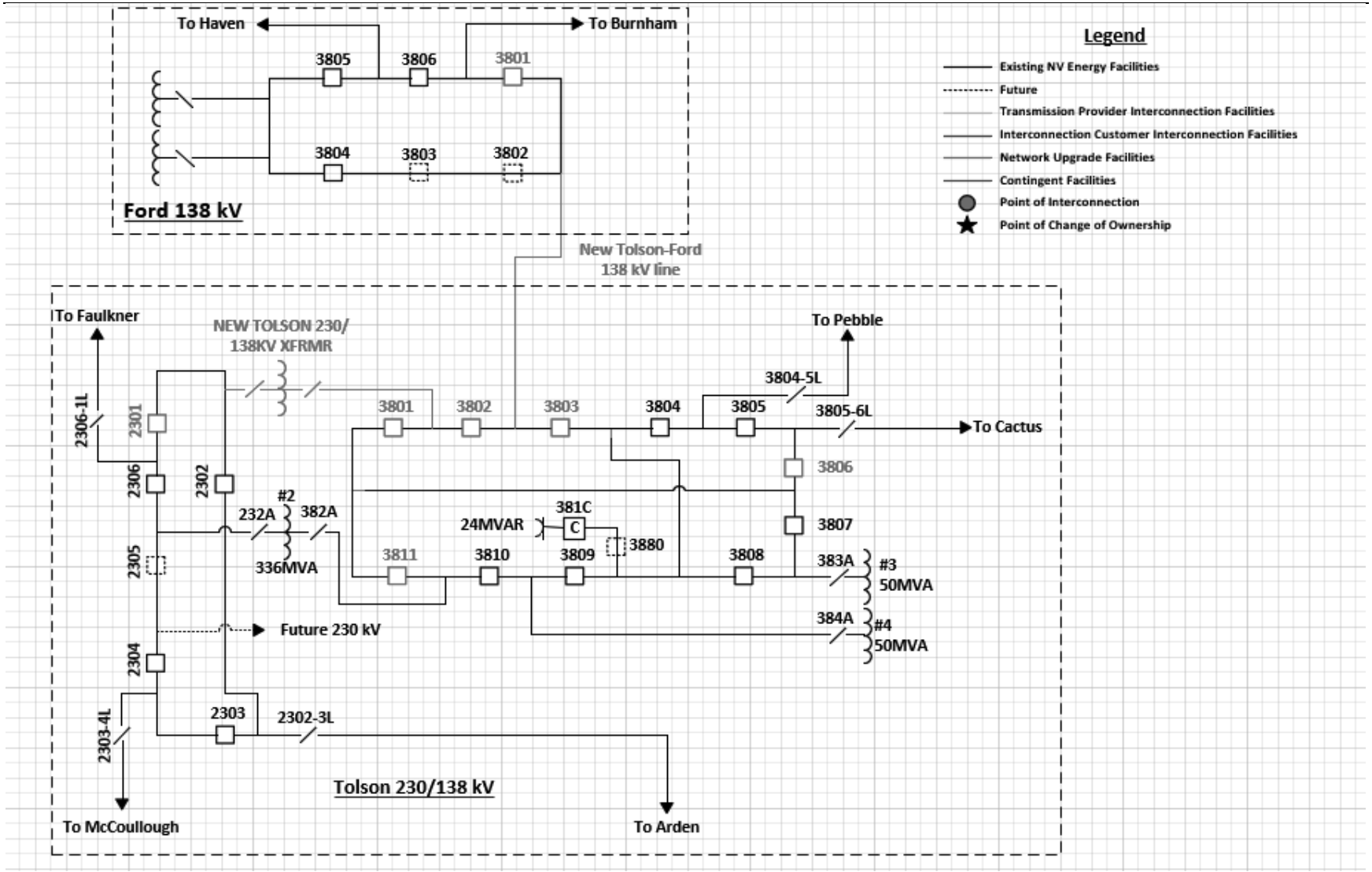
Summary:

TPL-001-5 violations were observed for an N-1 contingency of the Arden - Tolson 230 kV line, as well as breaker fail events for the Arden 2305, 2306, 2314, Faulkner 2314, and Magnolia 2305 breakers. These contingencies will overload the existing Tolson 230/138 kV bank when generation at Clark is reduced. To remove generation restrictions and allow for economical generation dispatch, it is recommended that the second Tolson 230/138 kV bank be installed.

A P7 (N-2) of the Pebble – Tolson and Pebble – Wilson 138 kV lines will overload the Arden – Haven and Haven – Ford 138 kV lines. Additionally, a combination of P6 contingencies involving the Arden – Haven, Pebble – Tolson, and Pebble – Wilson 138 kV lines will overload the remaining line. After the addition of the second Tolson 230/138 kV bank, these overloads will increase. Installing a new 138 kV line from Tolson – Ford, will mitigate these overloads. It will also provide an additional 138 kV line at Tolson to help distribute the additional flows when the second Tolson bank is installed.

Project Scope:

Transmission Planning is proposing to install a second 230/138 kV transformer at Tolson substation and a new 138 kV line between Tolson and Ford. This line should be geographically diverse from the existing Pebble – Tolson 138 kV line.


To Haven
To Burnham
3805
3806
3801
3804
3803
3802
Ford 138 kV
Legend
Existing NV Energy Facilities
Future
Transmission Provider Interconnection Facilities
Interconnection Customer Interconnection Facilities
Network Upgrade Facilities
Contingent Facilities
Point of Interconnection
Point of Change of Ownership
New Tolson-Ford
138 kV line
To Faulkner
NEW TOLSON 230/
138KV XFRMR
To Pebble
3804-5L
3805-6L
To Cactus
2306-1L
2301
3801
3802
3803
3804
3805
3806
2306
2302
#2
232A
382A
336MVA
381C
24MVAR
C
3880
3807
2305
3811
3810
3809
3808
383A
#3
50MVA
384A
#4
50MVA
Future 230 kV
2304
2303
2302-3L
2303-4L
Tolson 230/138 kV
To McCoullough
To Arden

#2067 Craig – Pecos 138 kV Line Uprate

Summary:

Las Vegas Generating Station (LVC) is a 272 MW (Nominal) gas fired generating station in North Las Vegas. The resource provides power to the 138 kV system in the northern part of the Las Vegas Valley. Currently, the plant has two paths to reach load: the LV Cogen – Highland 138 kV line and the LV Cogen – Craig – Pecos 138 kV line. The weak point on these paths is the Craig – Pecos line, which is limited to 932 A or ~ 223 MVA @ 138 kV. During low load, high generation conditions, loss of the LV Cogen – Highland line will overload the Craig – Pecos line. Must run limits are currently placed on LV Cogen under certain condition loading until this line can be reconductored.

With the 138 kV line fold into Millers the new system configuration results in the Craig – Pecos line exceeding its rating during heavy load. With the existing line rating on Craig – Pecos, after this line fold, the existing output limit currently placed on LV Cogen will need to remain for light load conditions, and a must run condition will be required on this generator under heavy load conditions. To remove the generation restrictions and allow NV Energy to dispatch generation as economically as possible (especially as PV generation increases), it is required that the Craig – Pecos line be reconductored from 954 ACSR to 954 ACSS to increase the rating from 272 MW to 345 MW.

Project Scope:

To mitigate this problem, it's recommended that the 3.7 miles of 954 AAC conductor from Craig to Pecos is replaced with 954 ACSS, rated for 392F MOT, to support a current of up to 1792A.

#2069 Beltway – Cheyenne 138 kV line addition

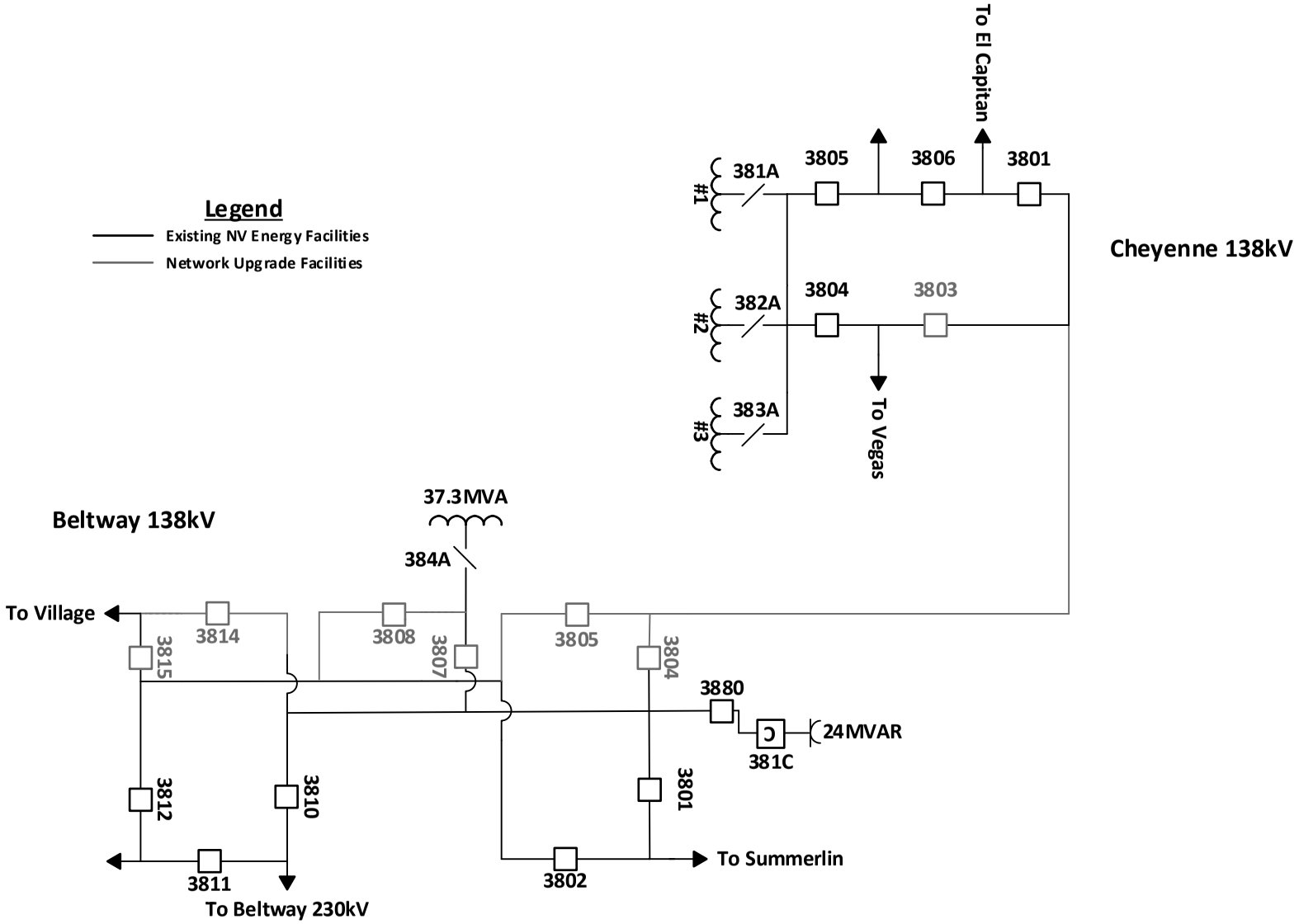
System Deficiencies

The 138kV loads at Cheyenne, El Capitan, Lone Mountain, Summerlin, and Vegas are served via three sources: Beltway, Northwest and Westside substations.

A P6 event consisting of two of those sources, will result in thermal overloads of the remaining source.

Project Scope:

Install a new 138 kV line between Beltway and Cheyenne substations to mitigate overloads for P6 events for loss of two 138 kV lines serving the load pocket between Beltway, Northwest and Westside substations. One 138 kV breaker will be required at Cheyenne to expand the ring for the new line. Six 138 kV breakers will be required at Beltway to create a new line terminal for the line to Cheyenne and convert the ring bus into a breaker and a half.


Legend
Existing NV Energy Facilities
Network Upgrade Facilities
To El Capitan
381A
#1
3805
3806
3801
Cheyenne 138kV
382A
#2
3804
3803
To Vegas
383A
#3
37.3MVA
Beltway 138kV
384A
To Village
3814
3815
3808
3807
3805
3804
3880
24MVAR
381C
3812
3810
3801
3811
3802
To Summerlin
To Beltway 230kV

#2070 Pebble – Tolson 138 kV Line Uprate

Summary:

For the 138kV load-serving loop between Arden and Pebble, Pebble is source by two 138 kV lines served by Tolson and Faulkner (Via Wilson substation)

[Multiple Connections] - Arden – Haven – Ford – Burnham – Pebble – [Multiple Connections]

A combination of P6 contingencies involving the Arden – Haven, Pebble – Wilson, and Faulkner – Wilson 138 kV lines will overload the Pebble – Tolson 138 kV line.

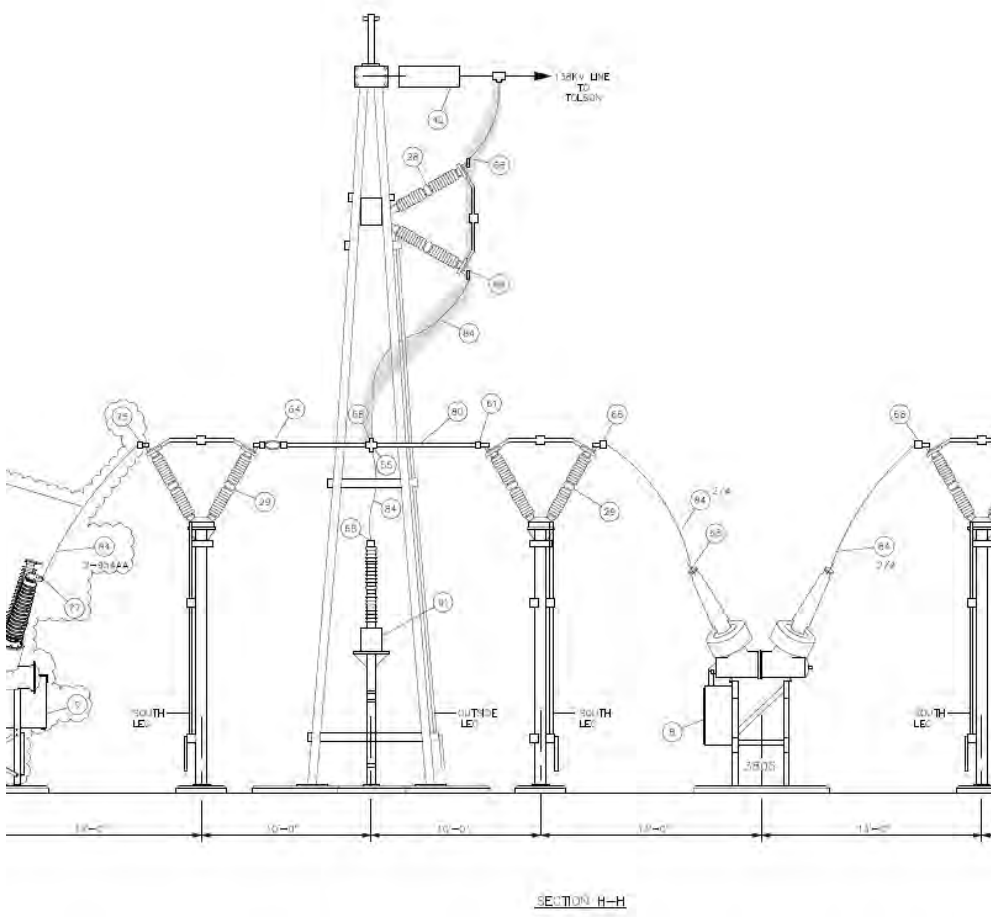
The proposed addition of the Tolson 230/138 kV Bank #2 may also create overloads on this line for various other contingencies.

Project Scope:

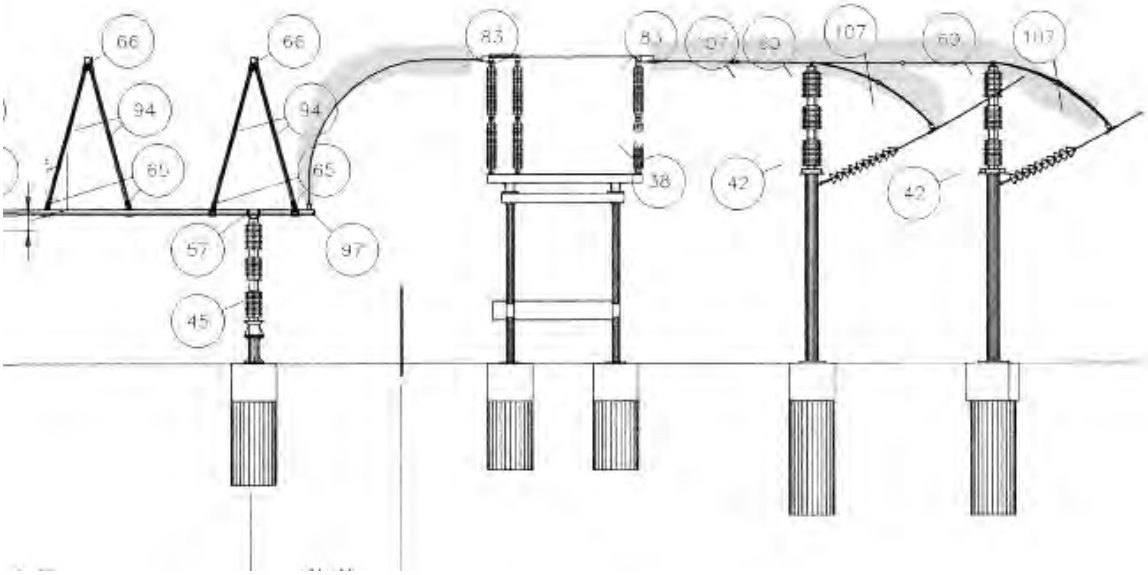
Reconductor the Pebble-Tolson 138 kV line, approximately 2.33 miles, with 954 ACSS conductor and replace the line drops at each location with matching conductor.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Region 1	Region 2	Old NEVP Nam	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F)	Conductor MOT (°F)
S	138	T	Yes		PB-TOL-138-1	1	Pebble - Tolson	Las Vegas		Pebble -	2.33	MAGNOLIA	954	AAC	1	203	225	203

All conductor on the Pebble – Tolson 138 kV line needs to be replaced with 954 ACSS conductor.



Pebble line terminal. Lind drop in the substation needs to be replaced with 2-954 AAC or equivalent to match the new line rating. The 3805-06L disconnect switch needs to be replaced with a 2000 A switch.



Tolson line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating.

#2073 Claymont - Spencer 138 kV line Uprate

Summary:

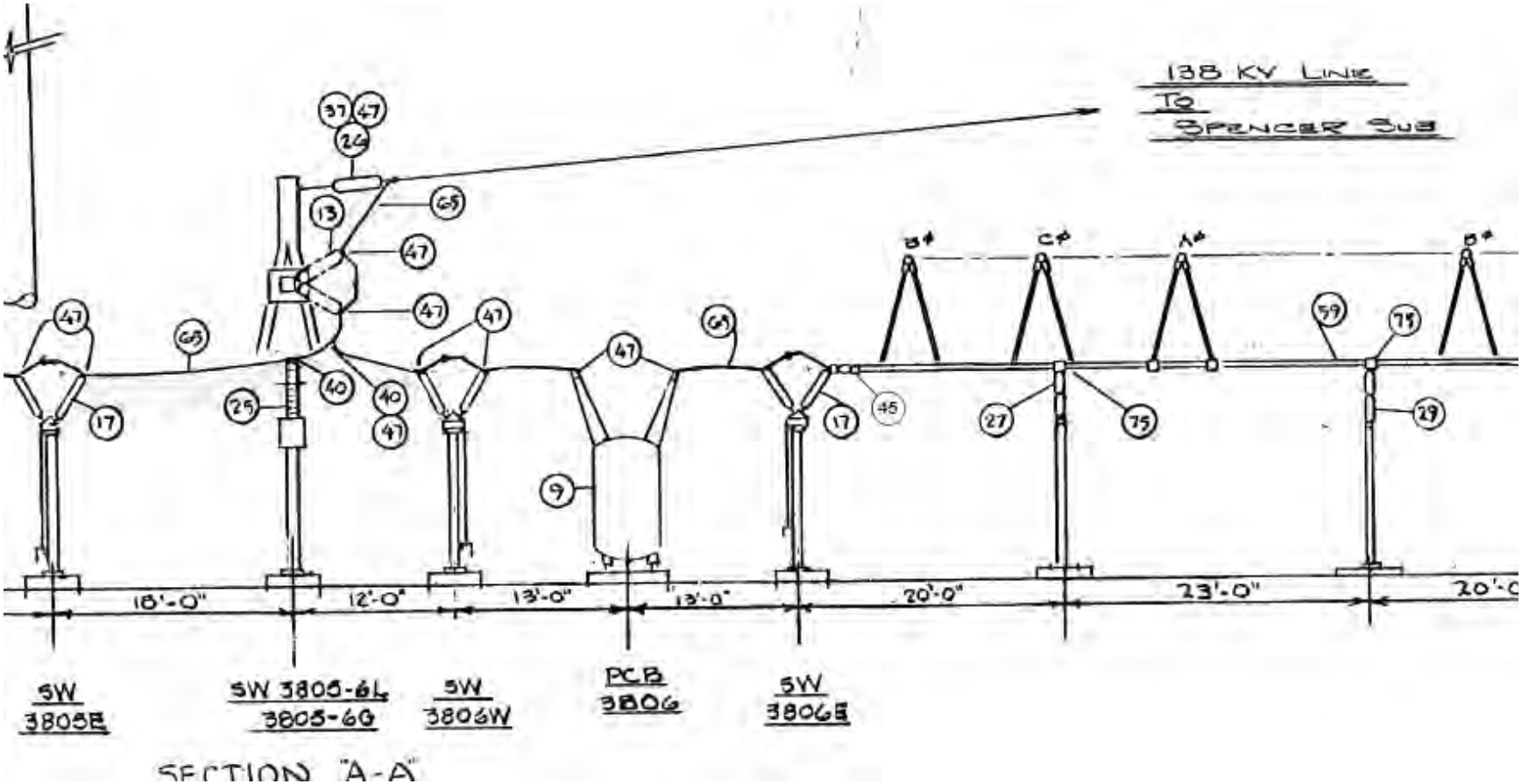
A P6 event consisting of the Clark - Claymont 138 kV line followed by the Clark – Russell - Claymont 138 kV line or a P4 event (breaker fail) of the Claymont 3802 breaker will cause the Claymont – Spencer 138 kV line to exceed its current rating by as much as 116% of the line rating.

Project Scope:

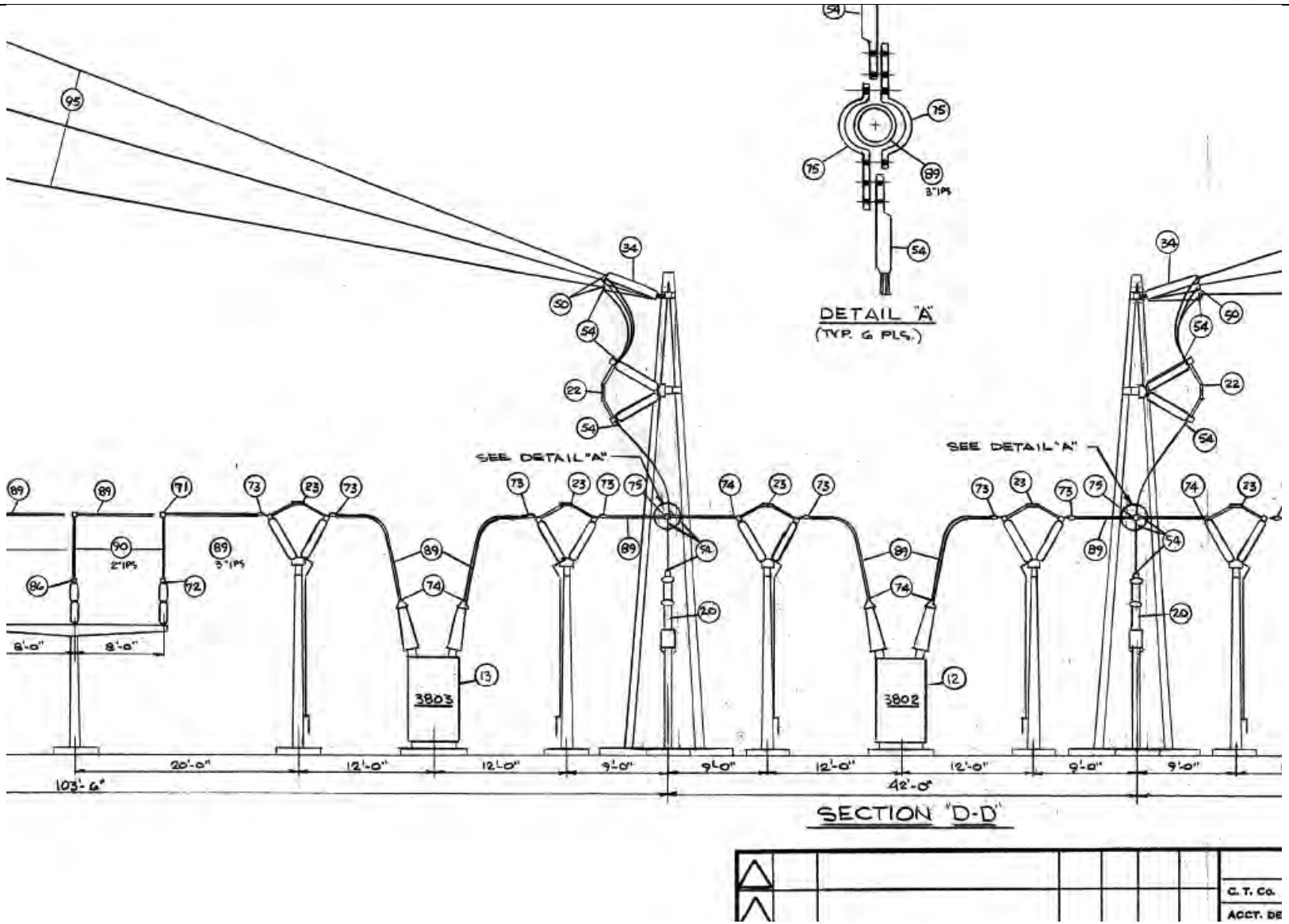
Reconductor the Claymont – Spencer 138 kV Line, approximately 0.77 miles, with 1026 ACCC conductor and replace the line drops and disconnect switches at both Claymont and Spencer to match conductor rating.

Regio	kV	FERC Class, Order 888	Non-NVE	Short Line ID	Sec ID	Line	Region 1	Region 2	Old NEVP Nam	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°	Conductor MOT (°F)
S	138	T		CM-SP-138-1	1	Claymont - Spencer	Las Vegas		Claymon	0.77	MAGNOLIA	954	AAC	1	203	203	203

All conductor on the Claymont – Spencer 138 kV line needs to be replaced with 1026 ACCC conductor.



Claymont line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The 3805-06L disconnect switch needs to be replaced with a 2000 A switch.



Spencer line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The 3802-03L disconnect switch needs to be replaced with a 2000 A switch.

#2074 Harry Allen 230 kV Series Bus Reactors

Summary:

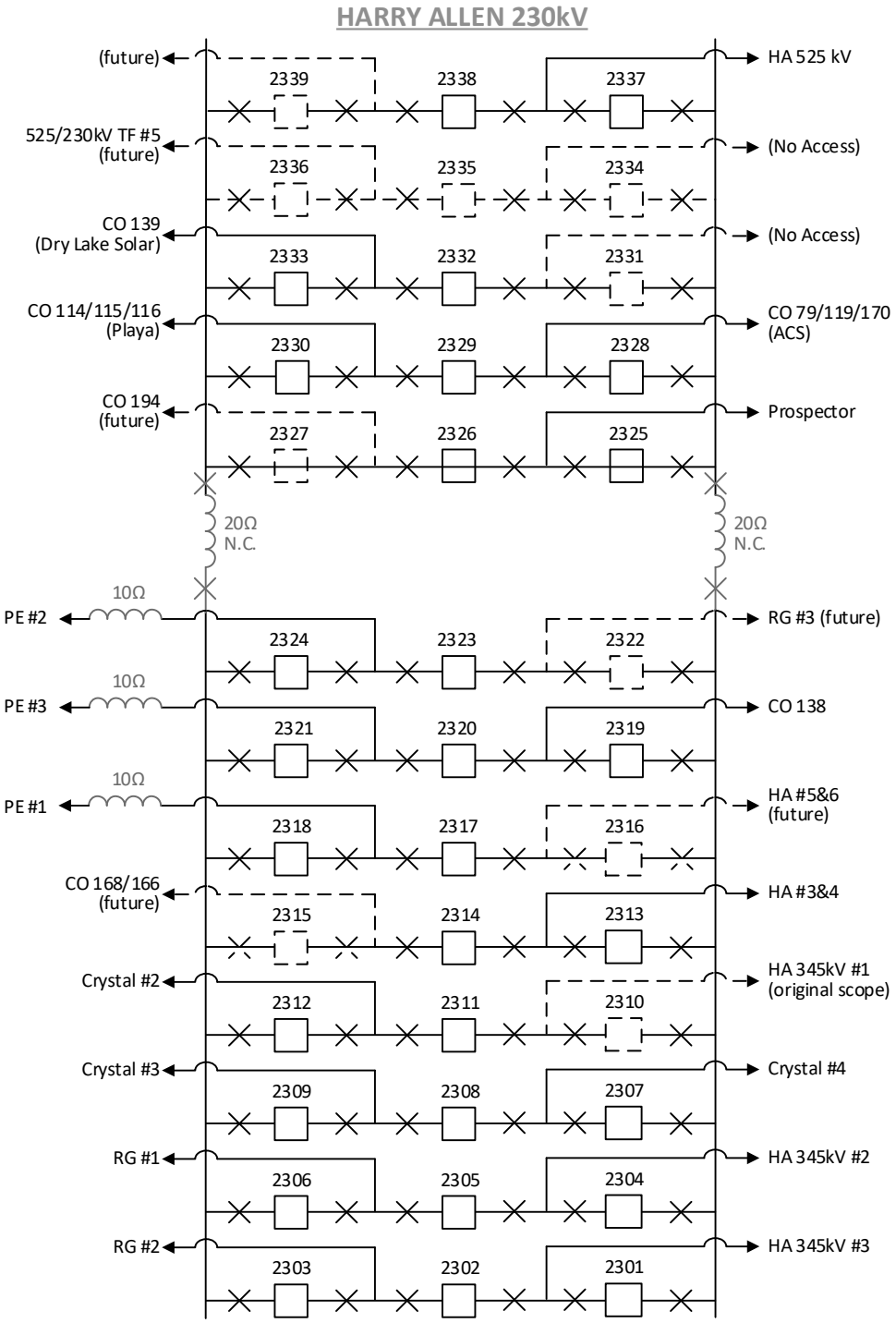
With the addition of the multiple generator interconnections at Harry Allen, Reid Gardner and Crystal, the addition of Pecos bank #5, and the Greenlink project, twenty-four of the Harry Allen 230 kV breakers and seventeen of the Pecos 138 kV breakers will exceed their current interrupting rating. Portions of the Harry Allen 230 kV bus may also need to be replaced to withstand the higher fault duty. The existing 138 kV breakers at Pecos have an interrupting rating of 63 kA. To increase the interrupting rating, 230 kV breakers would need to be installed at Pecos.

Project Scope:

Due to the large number of breakers required to be replaced at Harry Allen and Pecos, along with portions of the Harry Allen 230 kV bus, installing series reactors to decrease the fault current was determined to be the optimal solution. 2-20 ohm series reactors should be installed on the Harry Allen 230 kV bus and 10 ohm reactors on each of the Harry Allen – Pecos 230 kV lines.

NVEnergy

Appendix A



Harry Allen 230 kV Switching Diagram with series reactor installation

#2076 Gilmore – Leavitt 138 kV Line Uprate

Summary:

A P2 event consisting of opening the Pecos – Craig portion of the LV Cogen – Pecos 138 kV line will cause the Gilmore – Leavitt 138 kV line to exceed its current rating by 102%

Project Scope:

The Gilmore – Leavitt 138 kV line conductor is using 954 ACSS rated for up to 1792 A. The line drops at Leavitt consist of 954 AAC which limits the overall line rating to 1099 A. The line drops at Leavitt substation will be replaced with 2-954 AAC conductor to increase the line to the full rating of 1792A.

It should be noted that these line drops were not identified in the latest 2025 Planning Assessment. These line drops are to be replaced as part of the Northwest – Desert View 230 kV line #2 Interconnection

NVEnergy

#2077 Magnolia – NSO 230 kV Line

Summary:

TPL-001-5 violations were observed on the Tolson – McCullough 230 kV line for an N-1 contingency of the Eldorado – Magnolia 230 kV line along with multiple P4 events at Faulkner and Magnolia. Various P6 events involving 230 kV lines between the Eldorado Valley and Las Vegas also triggered an overload of this line.

After the proposed second Tolson 230/138 kV transformer addition, a P1 event of the Tolson – Faulkner line will also overload the Tolson – McCullough line.

This line was considered for a reconductor, but due to the line route through the Sloan Canyon National Conservation Area, and the potential permitting delays, a new line from NSO – Magnolia was considered instead.

After this new line is added, P4 events at Magnolia can still lead to overloads on the Tolson – McCullough line can still occur. Re-terminating the Arden – Magnolia line at Magnolia and adding new 230 kV breakers at Magnolia, will remove the P4 events from occurring at Magnolia.

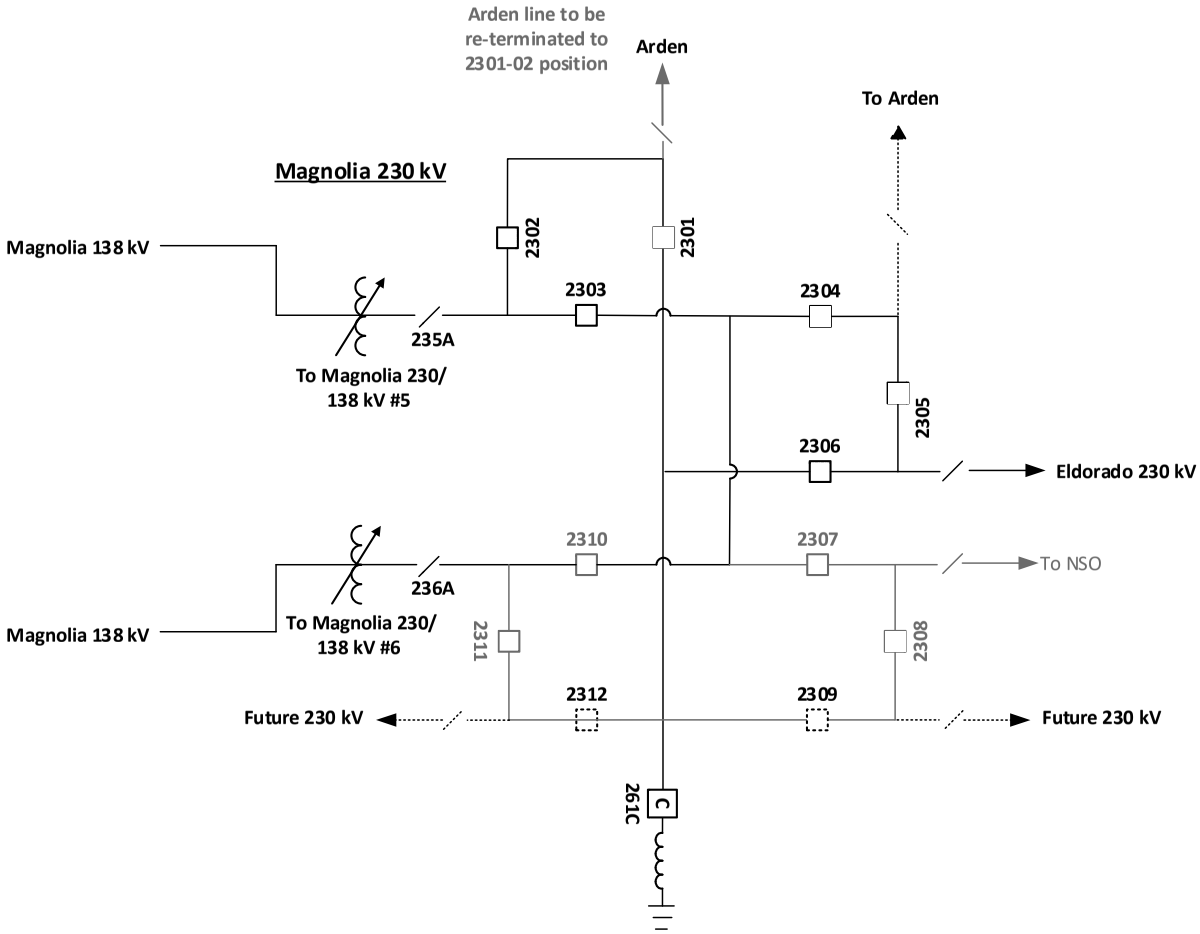
Note that the with the addition of the Northwest 525/230 kV Bank #7 planned for 2030, the In-Service date for this project has been moved to 2035.

Project Scope:

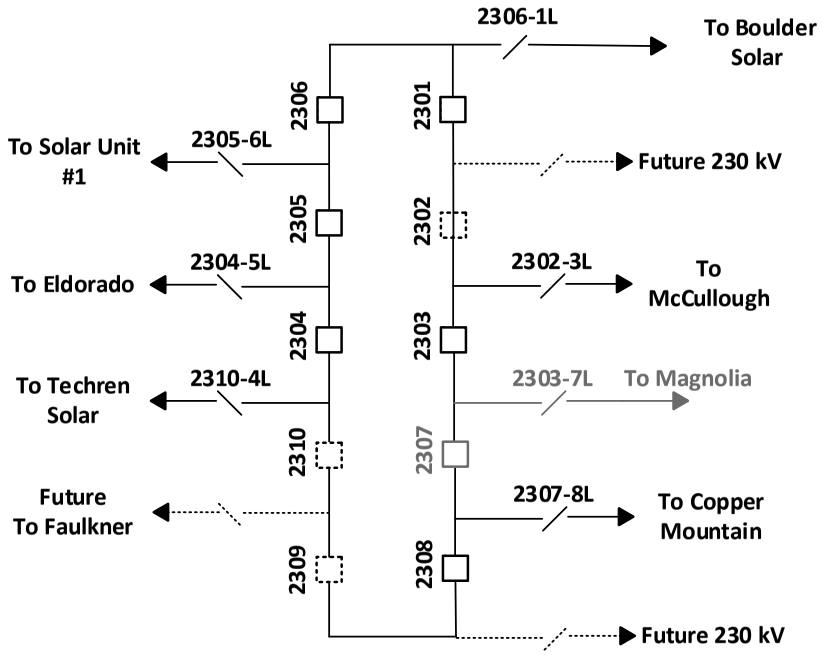
To mitigate this problem, the original Corrective Action Plan recommended that the 19.20 miles of 954 ACSR conductor from McCullough to Tolson was to be replaced with 954 ACSS, rated for 392F MOT, to support a current of up to 1792A. Based on environmental issues, the permitting for the line reconductor was deemed to be too timely, with a high chance of the permits being denied.

Construct a new 35 mile, Magnolia – NSO 230 kV transmission line with associated 230 kV substation terminal additions, telecommunications and protection equipment. This line is required to mitigate overloads on the Tolson – McCullough 230 kV line following a P1 event of the Tolson – Faulkner 230 kV line or the Eldorado – Magnolia 230 kV line. The Arden – Magnolia line should be re-terminated at Magnolia to avoid a breaker fail event tripping both the Arden – Magnolia and the Eldorado – Magnolia lines. Breakers should also be added to the 230/138 kV Bank #6 to avoid a breaker failure tripping both 230/138 kV banks.

NVEnergy	Magnolia 230 kV Substation	3/24/2025



NVEnergy	Nevada Solar One 230 kV Substation	3/24/2025



#2079 Clark – Warm Springs 138 kV line Uprate

Summary:

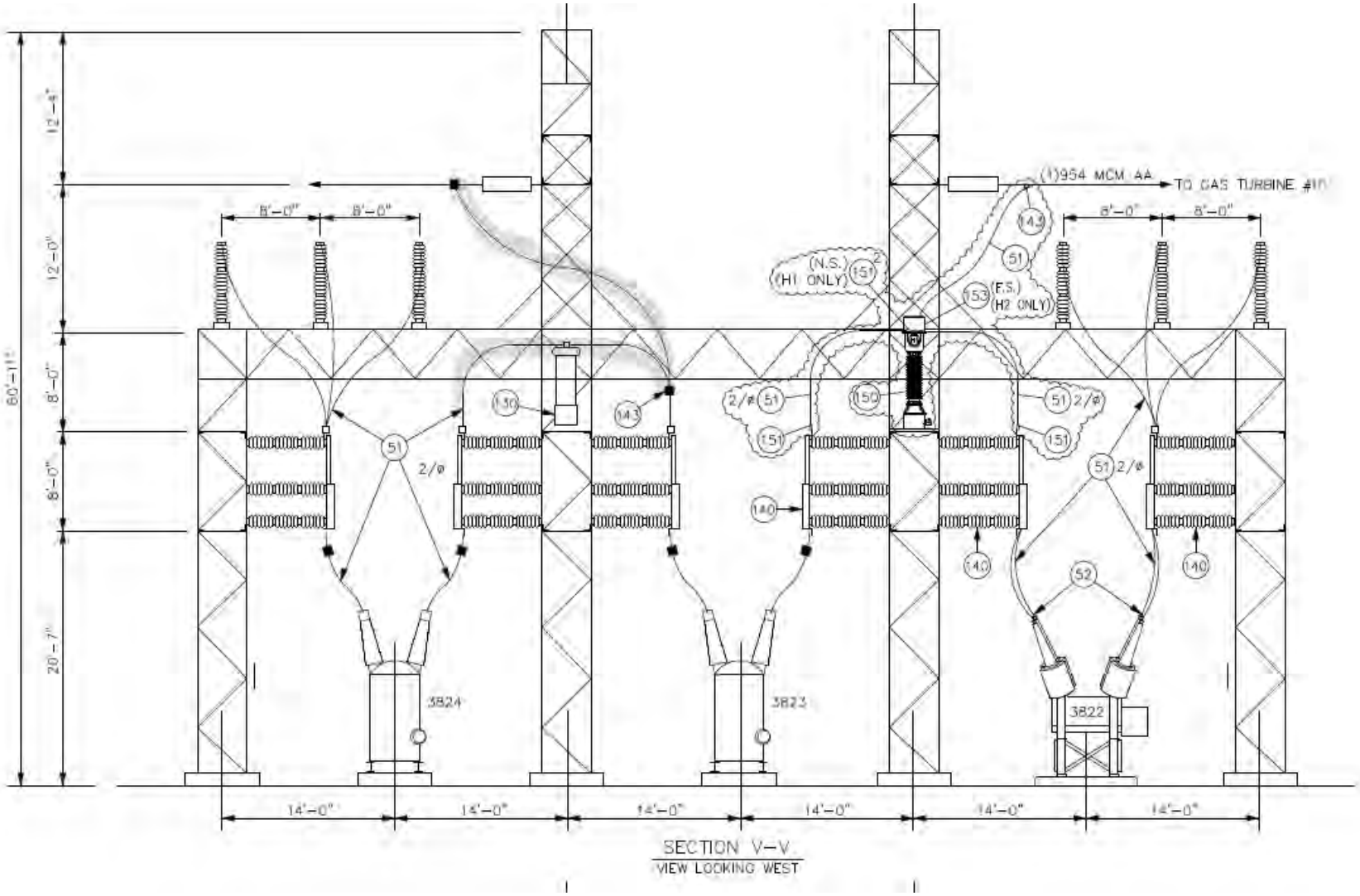
A P4 event (breaker failure) of the Clark 3827 (trips the Clark – Wigwam and the Clark – Cabana – Winterwood 138 kV lines) or a P6 event of the Clark – Wigwam and the Clark – Cabana – Winterwood 138 kV lines will overload the Clark – Warm Springs 138 kV line by 119.9% of its rating.

Project Scope:

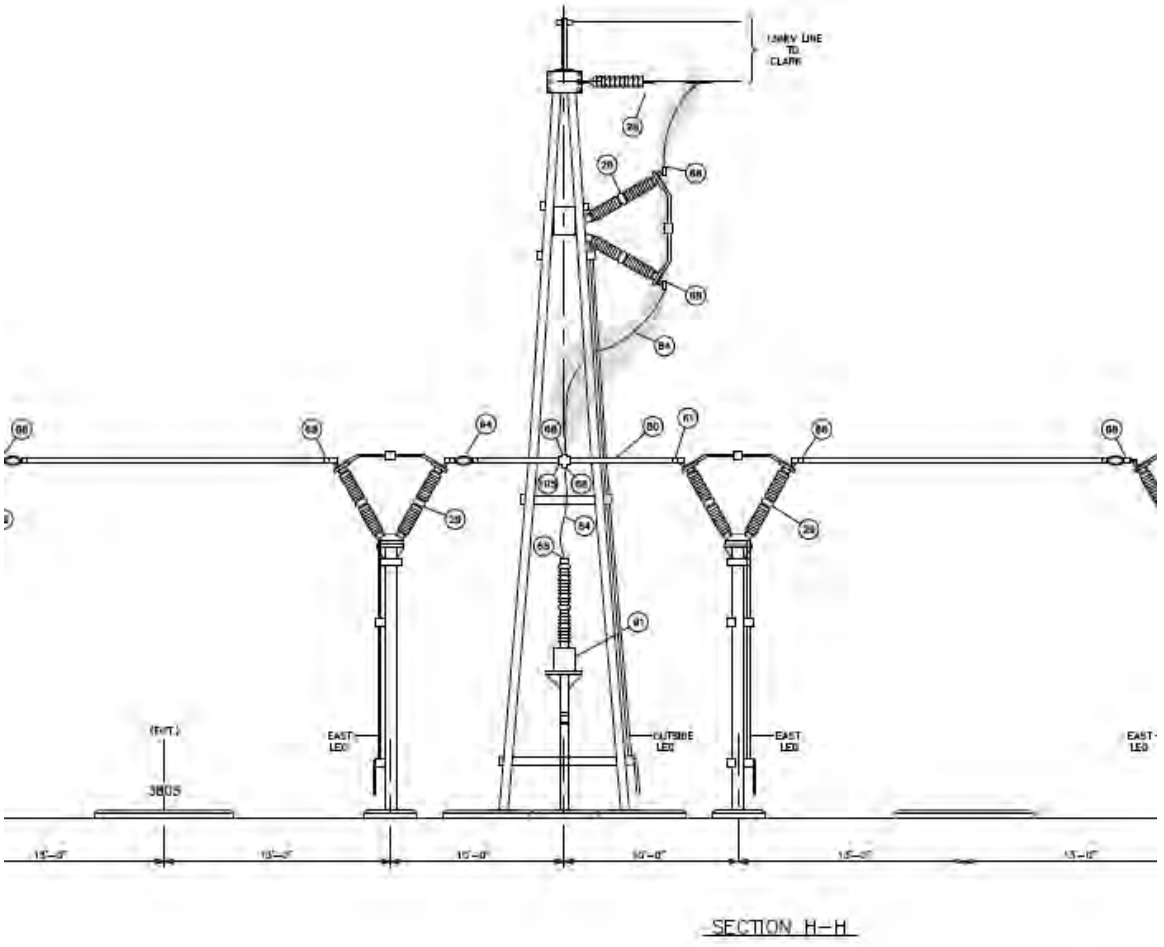
To mitigate this problem, the Clark – Warm Springs 138 kV line should be reconductored with 1026 ACCC conductor, approximately 3.94 miles. The line drops at Clark and Warm Springs will need to be replaced with 2-954 AAC conductor to match the line conductor. The Warm Springs 3805-06L disconnect switch will need to be replaced with a 2000 A switch.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F	Conductor MOT (°F)
S	138	T	Yes		CL-WSP-138-1	1	Clark - Warmsprings	3.94	MAGNOLIA	954	AAC	1	203	203	203

All conductor on the Clark – Warm Springs 138 kV line needs to be replaced with 1026 ACCC conductor.



Clark line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating.



Warm Springs line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The 3805-06L disconnect switch needs to be replaced with a 2000 A switch.

#2080 South Underrated Breaker Replacements

Summary:

Transmission Planning and System Protection have identified under-rated breakers and bus-work in the 5-year planning horizon which will require upgrades to support the full expected fault duty at the sites.

Project Scope:

Replace BES Underrated Breakers or install high capacitance CCVT's at multiple locations based on short circuit analysis results. (See TPL-001-5.1 R2, Part 2.3)

For the Southern System, the following breakers are required to be replaced:

- Various 69 kV breakers (currently being replaced with an ISD of 2026 for all breakers)
- The following breakers will need to be added to the Bushing Cap Replacement Project and high capacitance CCVT's will be required for higher interrupting breaker ratings
    - Arden 3801
    - Arden 3807
    - Clark 3808
    - Clark 3811
    - Clark 3814
    - Clark 3817
    - Westside 6905
    - Westside 6908
    - Westside 6910
- Replace existing CCVT's with high capacitance CCVT's for higher interrupting breaker ratings at Faulkner substation
    - Faulkner 2301
    - Faulkner 2303
    - Faulkner 2307
    - Faulkner 2309
    - Faulkner 2313
    - Faulkner 2315
- Replace existing CCVT's with high capacitance CCVT's for higher interrupting breaker ratings at Northwest substation
    - Northwest 2301
    - Northwest 2302
    - Northwest 2303
    - Northwest 2308
    - Northwest 2314
    - Northwest 2315

- Northwest 2316
- Northwest 2318

- The following breakers are required to be replaced with a higher interrupting rating
  - Crystal 2301
  - Crystal 2302
  - Crystal 2304
  - Crystal 2305
  - Crystal 2362
  - Crystal 2363

#2081 Clark – Green Valley – Wigwam 138 kV line Uprate

System Deficiencies

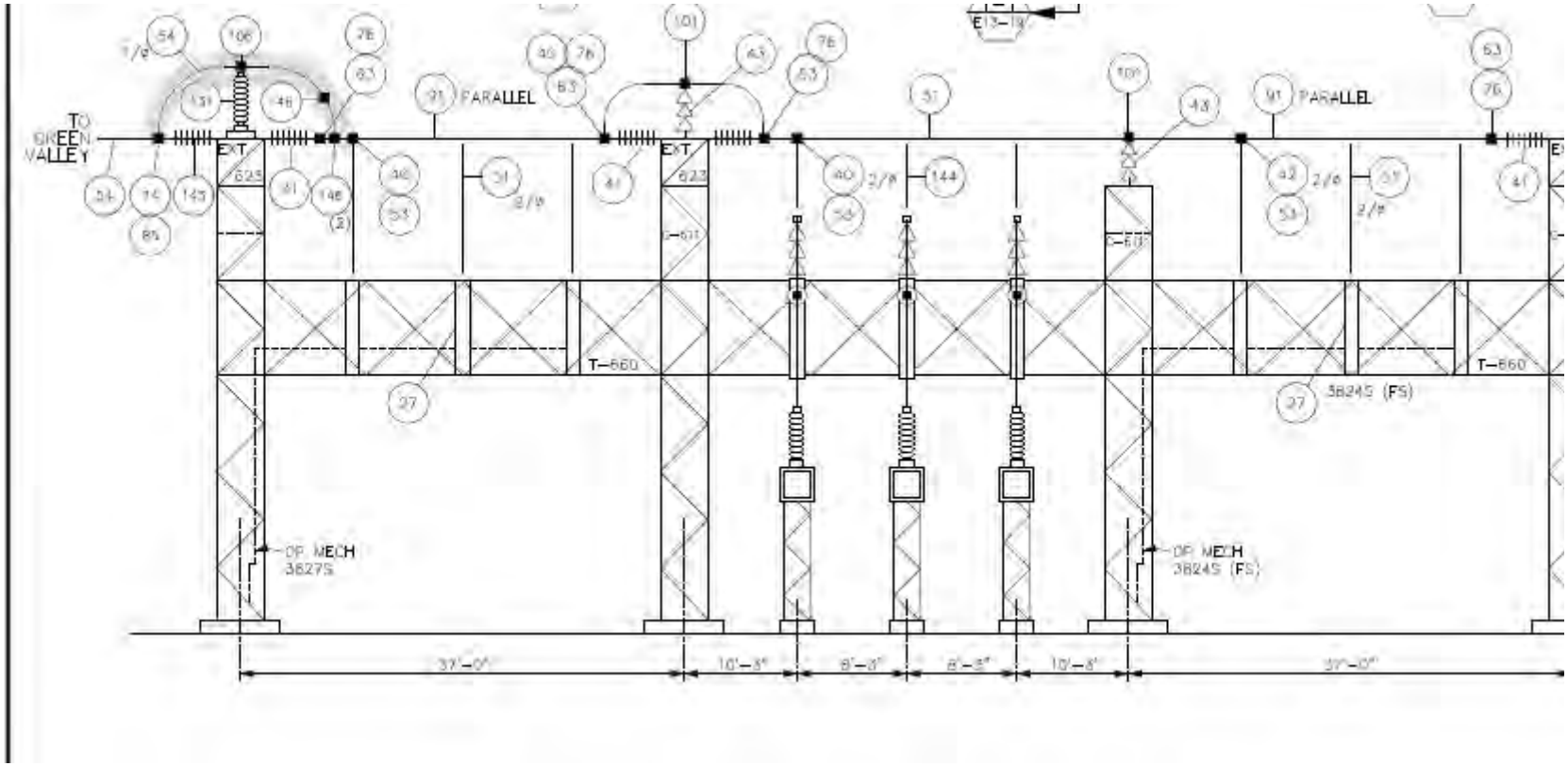
A P4 event (breaker failure) of the Faulkner 3802 breaker (trips Faulkner – Warm Springs 138 kV line and the Faulkner 230/138 kV Bank) or multiple P6 events involving the loss of the Clark – Cabana 138 kV line either the Faulkner – Warm Springs or Clark – Warm Springs 138 kV line will cause an overload of the Clark – Green Valley and Green Valley – Wigwam line by up to 132.6%. of the line rating.

Corrective Action Plan

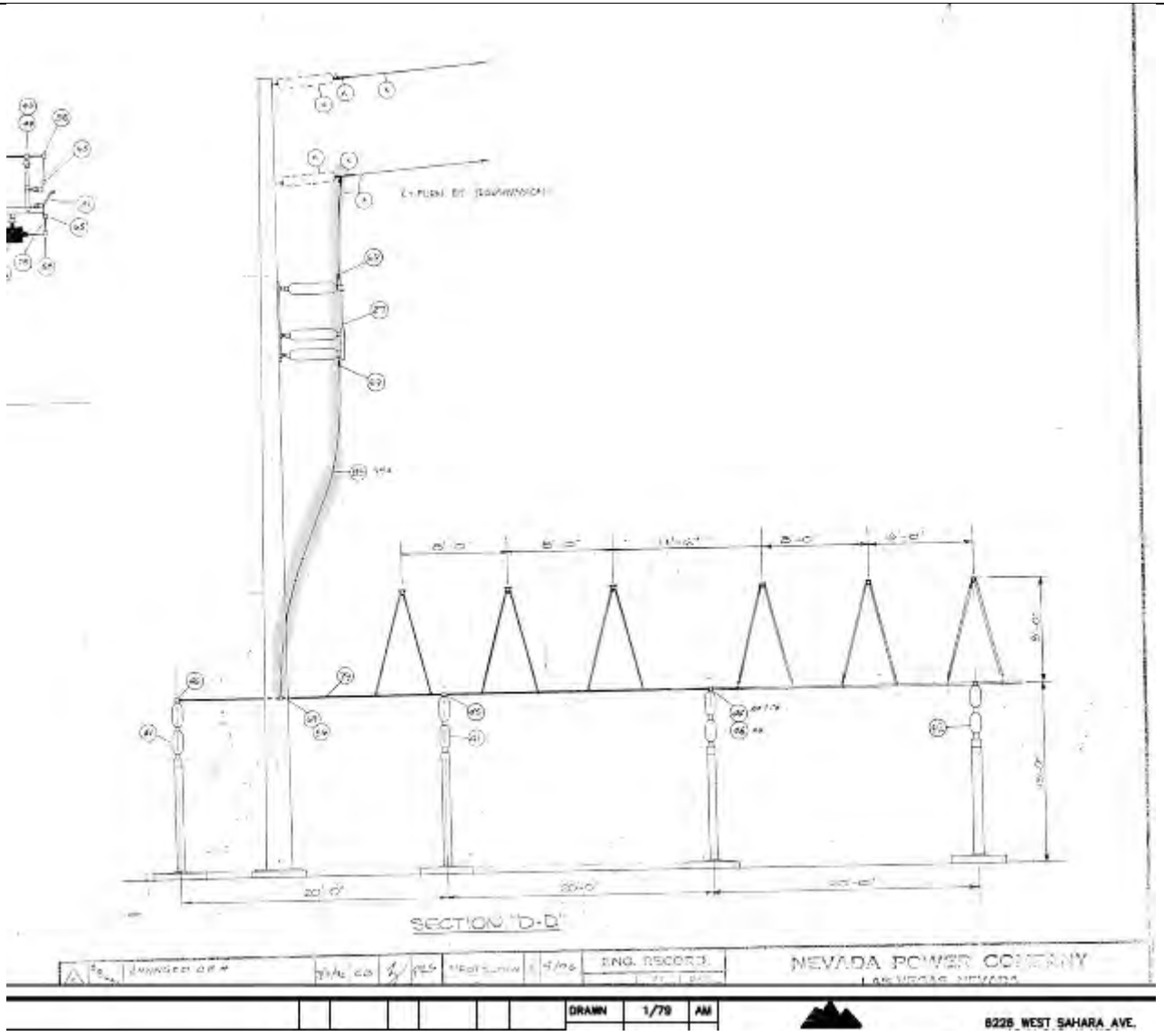
To mitigate this problem, the Clark – Green Valley 138 kV line should be reconductored with 1026 ACCC conductor, approximately 3.01 miles and the Green Valley – Wigwam 138 kV line should be reconductored with 1026 ACCC conductor, approximately 2.74 miles. The line drops at Clark, Green Valley and Wigwam Springs will need to be replaced with 2-954 AAC conductor to match the line conductor. The Green Valley 3801A, 3802A and the Wigwam 3801-02L disconnect switch will need to be replaced with a 2000 A switch.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F	Conductor MOT (°F)
S	138	T	Yes		CL-WI-138-1	1	Clark 138kV Bus to UG Riser X24406 OH	0.02	MAGNOLIA	954	AAC	1	203		203
S	138	T	Yes		CL-WI-138-1	2	X24406 to X24405 UG	0.07	2500kcm Cu 138kV XLPE UG Cable-Nexans	2500	CU,UG	1	194	N/A	194
S	138	T	Yes		CL-WI-138-1	3	X24405 to Green Valley Sub	2.99	MAGNOLIA	954	AAC	1	203		203
S	138	T	Yes		CL-WI-138-1	4	Green Valley - Wigwam	2.74	MAGNOLIA	954	AAC	1	203	203	203

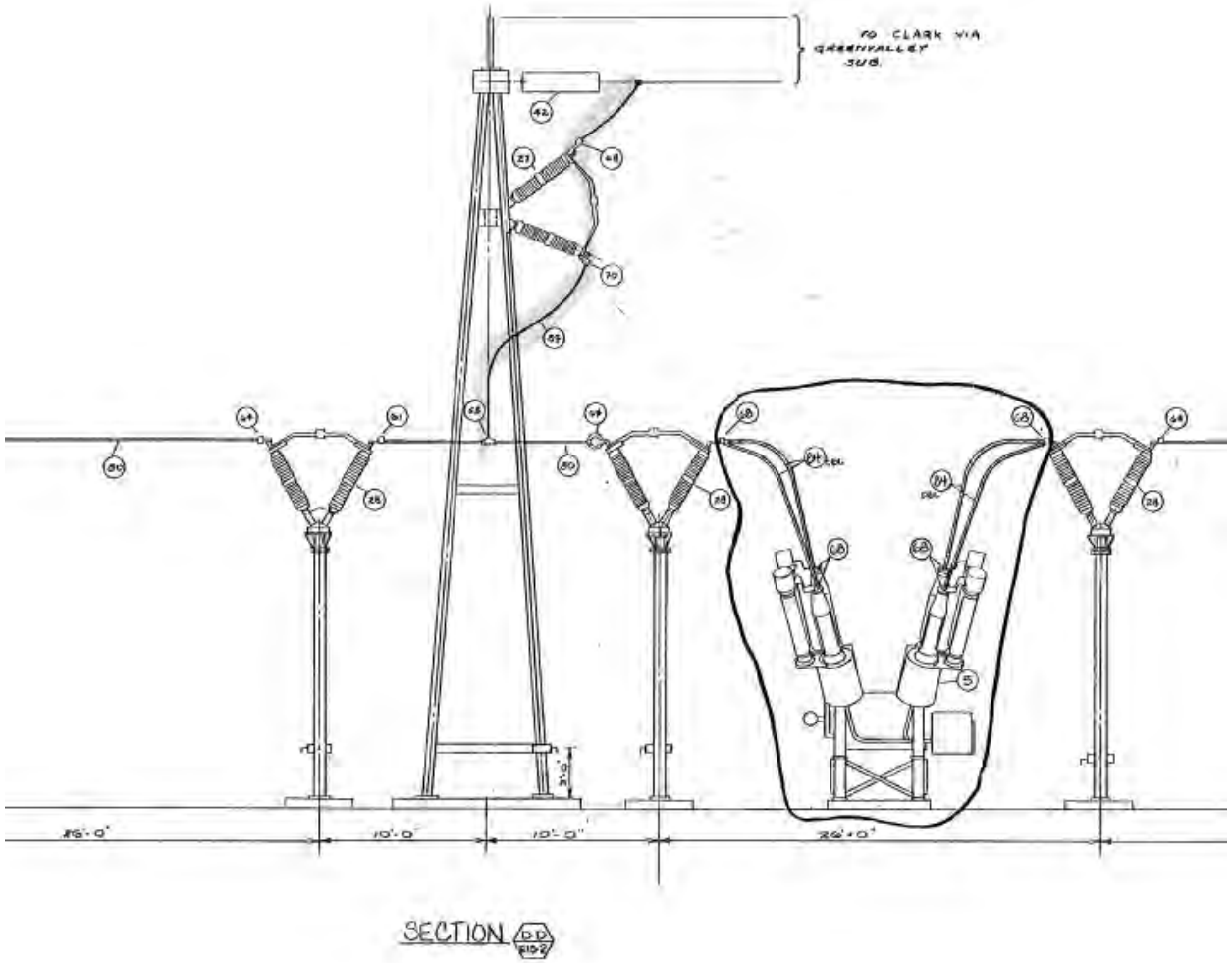
All overhead conductor on the Clark – Green Valley – Wigwam 138 kV line needs to be replaced with 1026 ACCC conductor.



Clark line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating.



Green Valley line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The 3801A and 3802A disconnect switch needs to be replaced with a 2000 A switch.



Wigwam line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The 3801-02L disconnect switch needs to be replaced with a 2000 A switch.

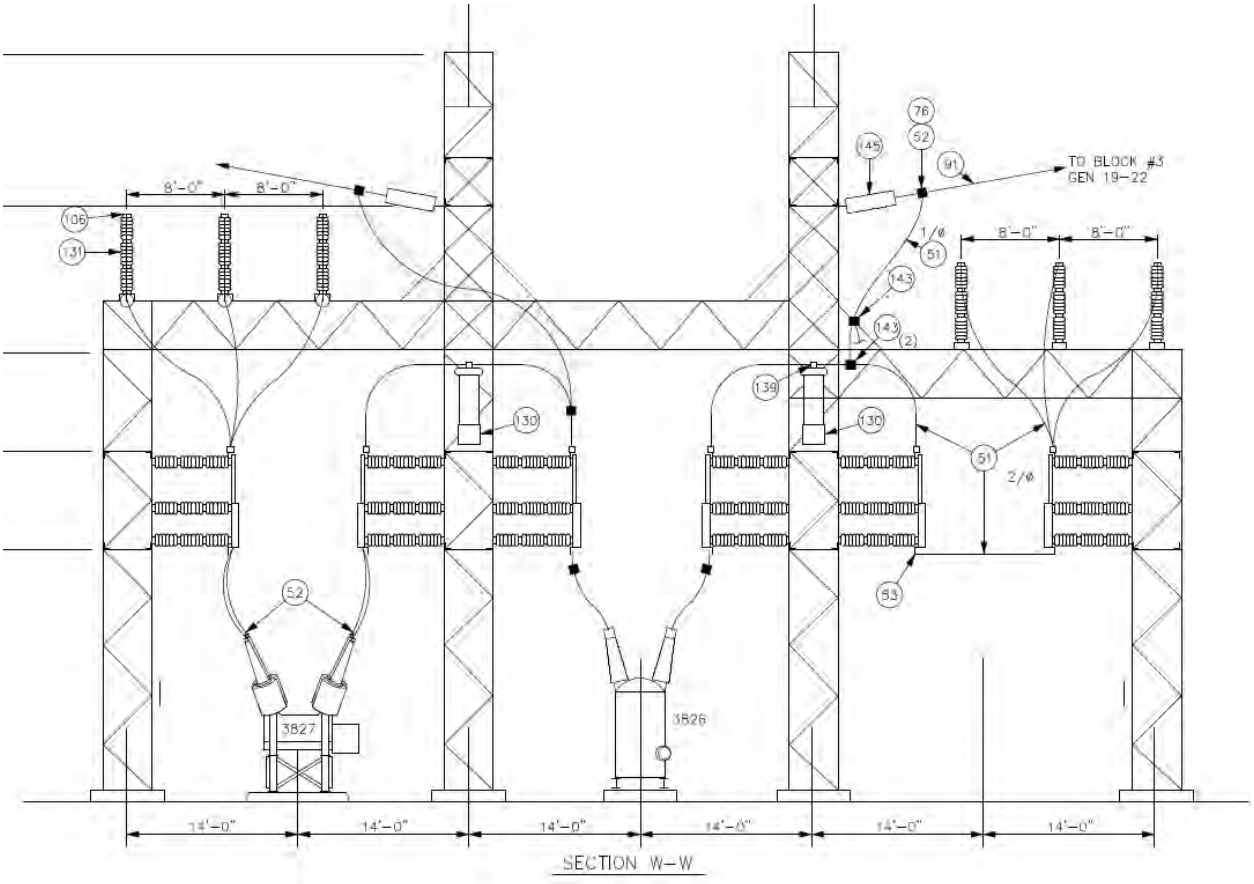
#2090 Cabana - Clark 138 kV Line Drop Replacement

Summary:

A P4 event (breaker fail) of the Clark 3824 breaker, will trip the Clark – Warmsprings 138 kV line and the Clark – Green Valley – Wigwam 138 kV line. This will force Clark Unit 10 and Power Block 3 through the Cabana – Clark 138 kV line. This contingency (or a P6 event (N-1-1) of these two lines) can overload the Cabana – Clark line by as much as 111% of the current line rating.

Project Scope:

The Cabana – Clark 138 kV line is limited by the line drops at Clark. The line drops are 954 AAC while the rest of the line is using 954 ACSS. Replacing the line drops at Clark will increase the rating of the line from 262.7 MVA to 427.8 MVA.



Line Drops on the Clark – Cabana 138 kV line were confirmed to be 954 ACSR. Line drops need to be at least 2-954 AAC to match the line conductor.

#2091 Faulkner – Warm Springs 138 kV line Uprate

Summary:

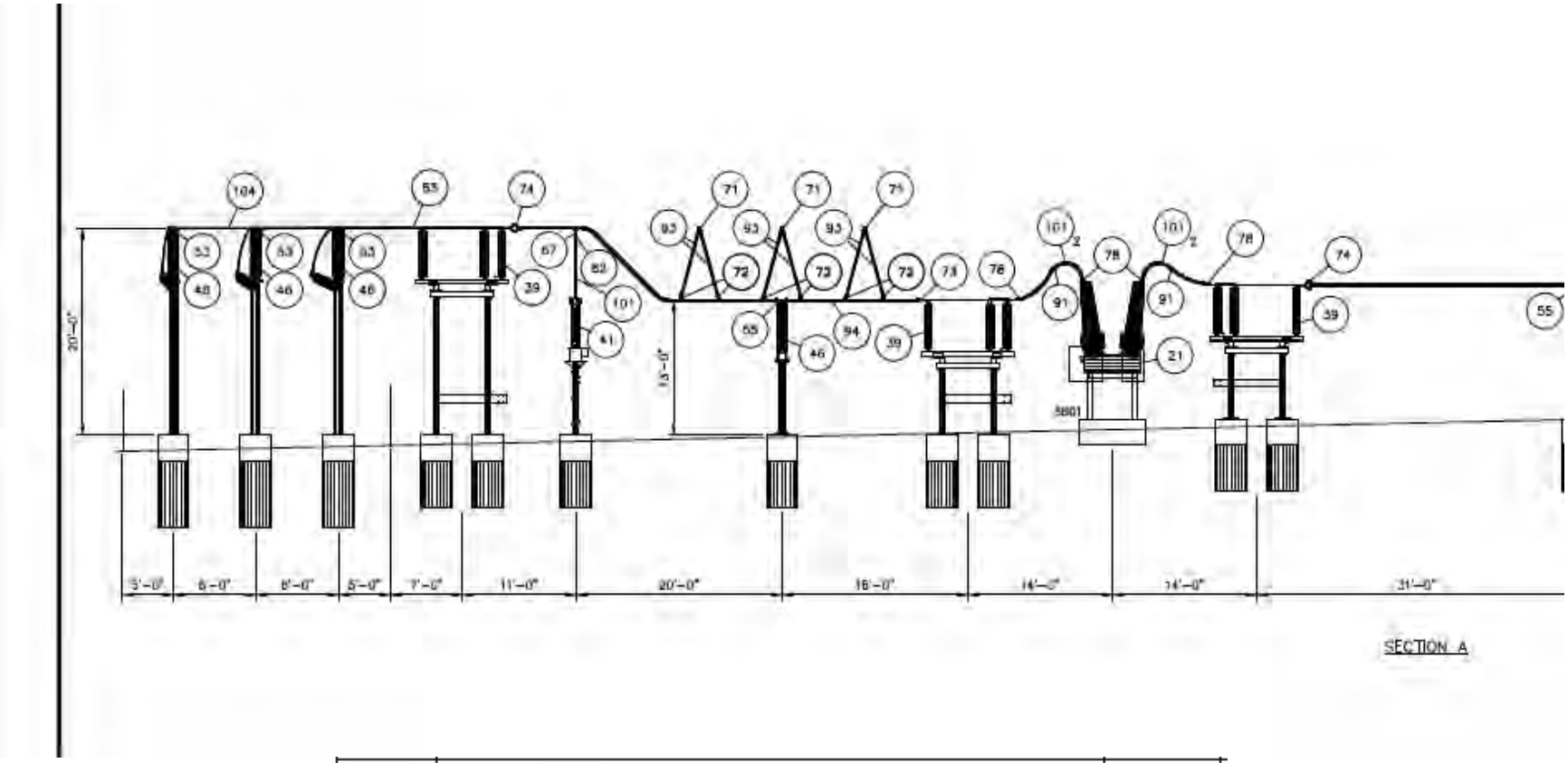
A P4 event (breaker fail) of the Clark 3827 breaker, will trip the Clark – Cabana 138 kV line and the Clark – Green Valley – Wigwam 138 kV line. This will force Clark Unit 10 and Power Block 3 along with generation at Saguaro through the Faulkner – Warm Springs 138 kV line. This contingency (or a P6 event (N-1-1) of these two lines) can overload the Faulkner – Warm Springs line by as much as 140% of the current line rating.

Project Scope:

To mitigate this problem, the Faulkner – Warm Springs 138 kV line should be reconductored with 1026 ACCC conductor, approximately 2.52 miles. The line drops at Faulkner and Warm Springs will need to be replaced with 2-954 AAC conductor to match the line conductor. The Warm Springs 3802-03L disconnect switch will need to be replaced with a 2000 A switch.

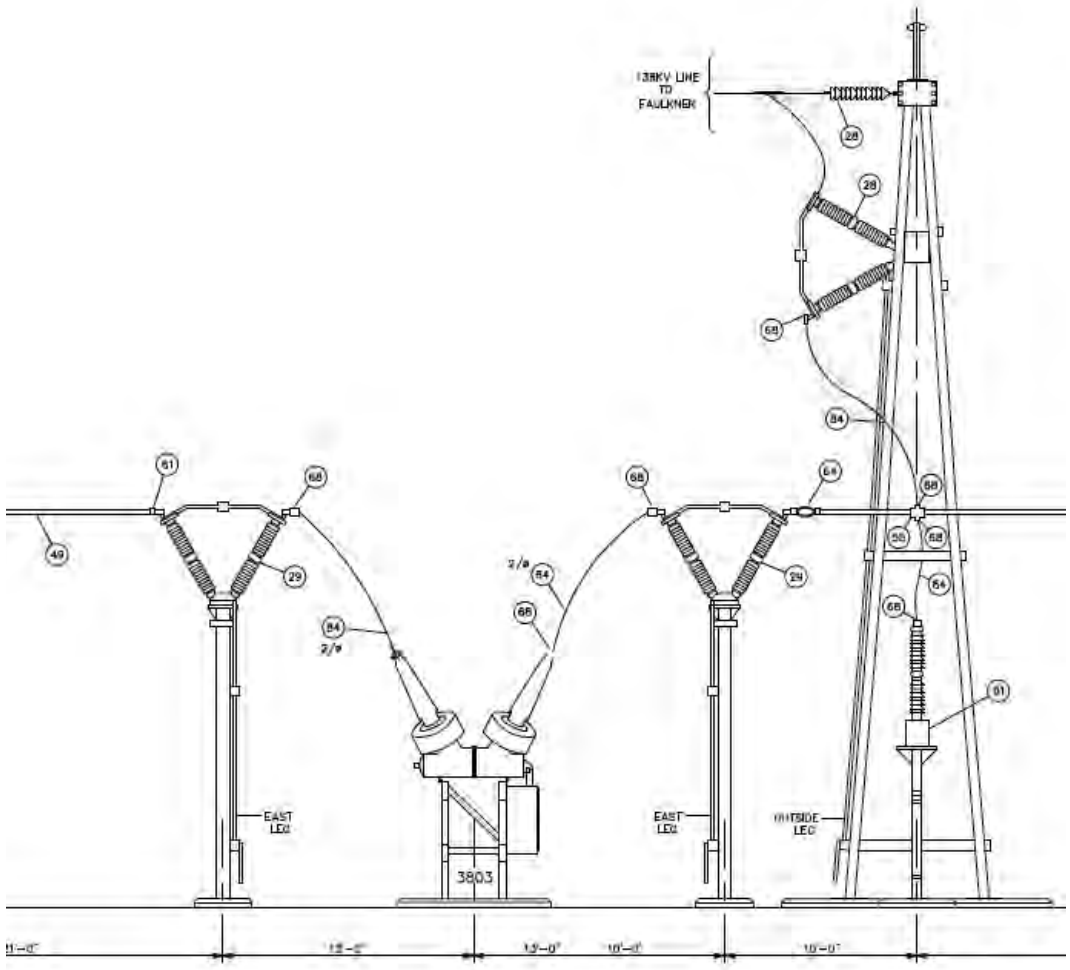
Regio	kV	FERC Class, Order 888	Non-NVE	Short Line ID	Sec ID	Line	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F)	Conductor MOT (°F)
S	138	T		FLK-WSP-138-1	1	Faulkner -X2797	0.97	MAGNOLIA	954	AAC	1	203		203
S	138	T		FLK-WSP-138-1	2	X2797- Warmsprings	1.55	CARDINAL	954	ACSR	1	203		212

All conductor on the Faulkner – Warm Springs 138 kV line needs to be replaced with 1026 ACCC conductor.



104	COND., 954 MCM, ACSR, 54/7 STR., 9000' REEL, SPEC. MC-21	171235

Faulkner line terminal. 954 ACSR conductor in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating.



Warm Springs line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The 3802-03L disconnect switch needs to be replaced with a 2000 A switch.

#2096 Clark - Spencer 138 kV lines #1 and #2 Uprate

Summary:

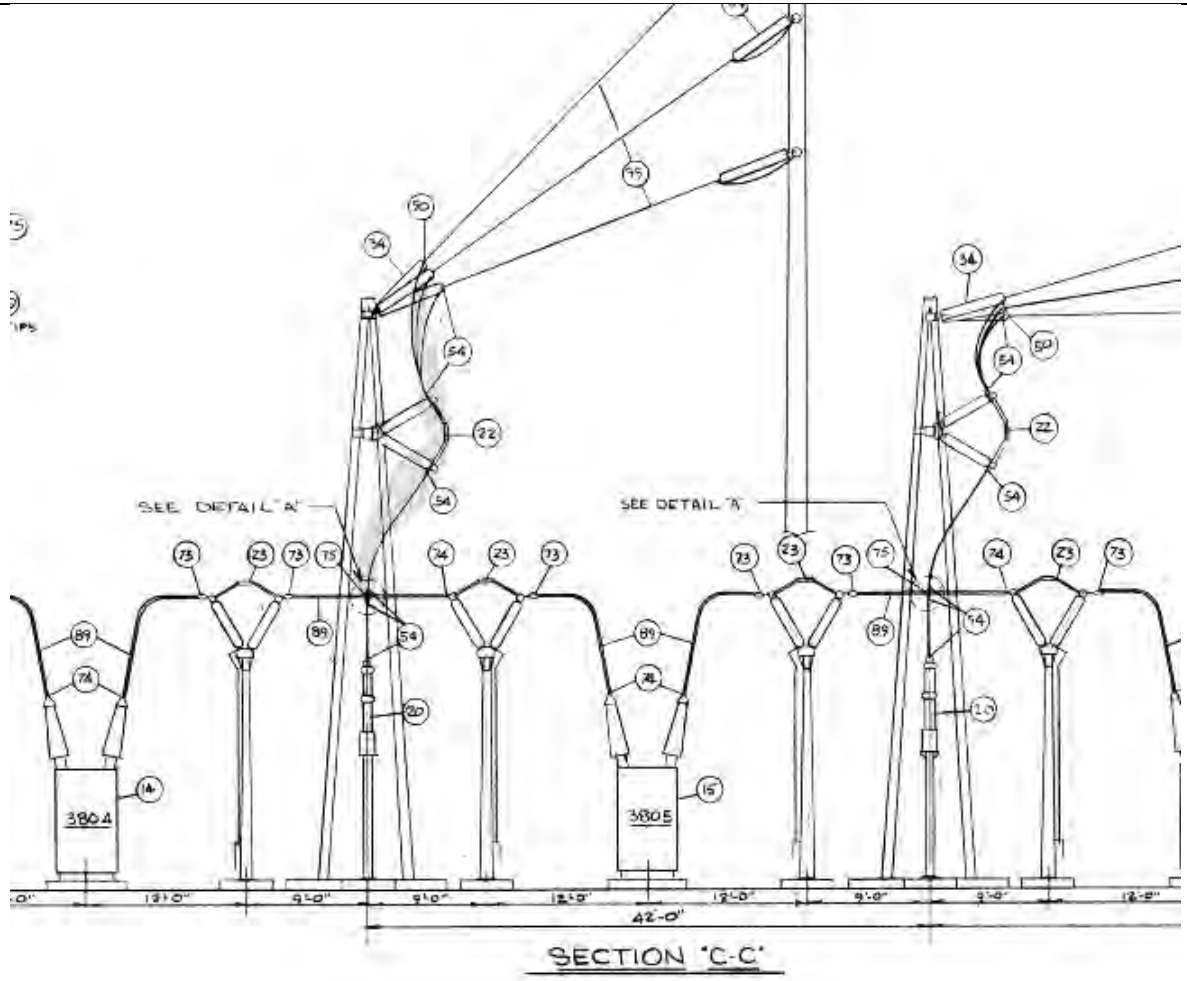
A P6 event involving the two Clark - Claymont 138 kV lines or a P4 event of the Claymont 3802 breaker (trips both Clark – Claymont lines), or a P4 of the Spencer 3802 breaker (trips the Clark – Spencer and Claymont – Spencer) will overload one or both Clark – Spencer 138 kV lines to up to 114.6 % of its rating by 2029.

Project Scope:

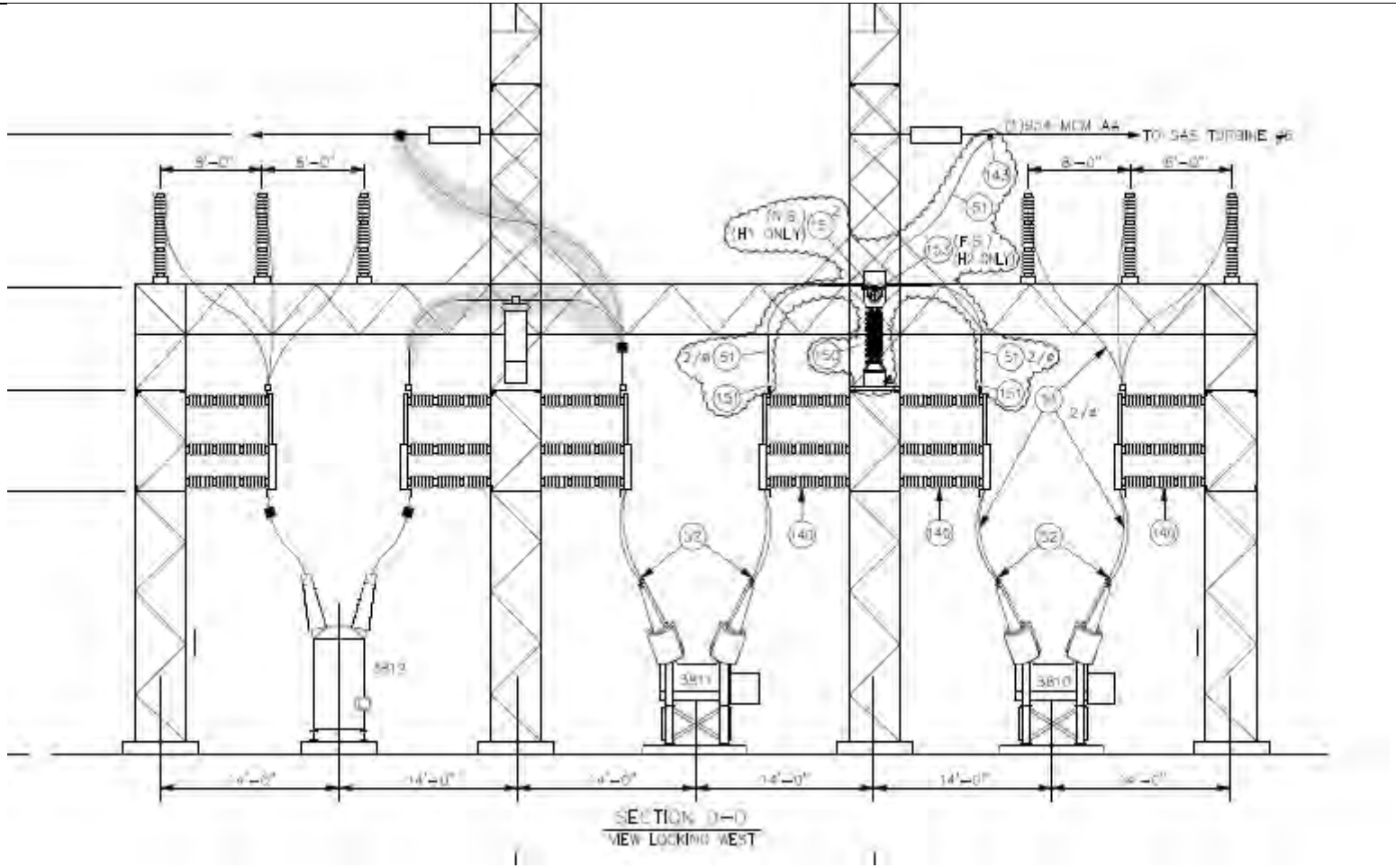
To mitigate this problem, for each Clark – Spencer 138 kV line, it's recommended that the 5.21 miles of 954 AAC conductor from Clark - Spencer is replaced with 1026 ACCC, rated for 392F MOT, to support a current of up to 1792A. The line drops at Clark and Spencer and the disconnect switches on both lines at Spencer will need to be replaced to match the conductor rating.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Region 1	Region 2	Old NEVP Nan	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F	Conductor MOT (°F)
S	138	T	Yes		CL-SP-138-1	1	Clark - Spencer #1	Las Vegas		Clark - S	5.21	MAGNOLIA	954	AAC	1	203	203	203
S	138	T	Yes		CL-SP-138-2	1	Clark - Spencer #2	Las Vegas		Clark - S	5.21	MAGNOLIA	954	AAC	1	203	203	203

All conductor on both Clark – Spencer 138 kV lines needs to be replaced with 1026 ACCC conductor.



Spencer line #2 terminal (Spencer Line #1 terminal requires the same upgrades). Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The 3801-2A and 3804-5A disconnect switches needs to be replaced with a 2000 A switch.



Clark line #1 terminal (Clark Line #2 terminal requires the same upgrades). Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating.

#2102 Re-terminate Equestrian – Mead 230 kV line #2

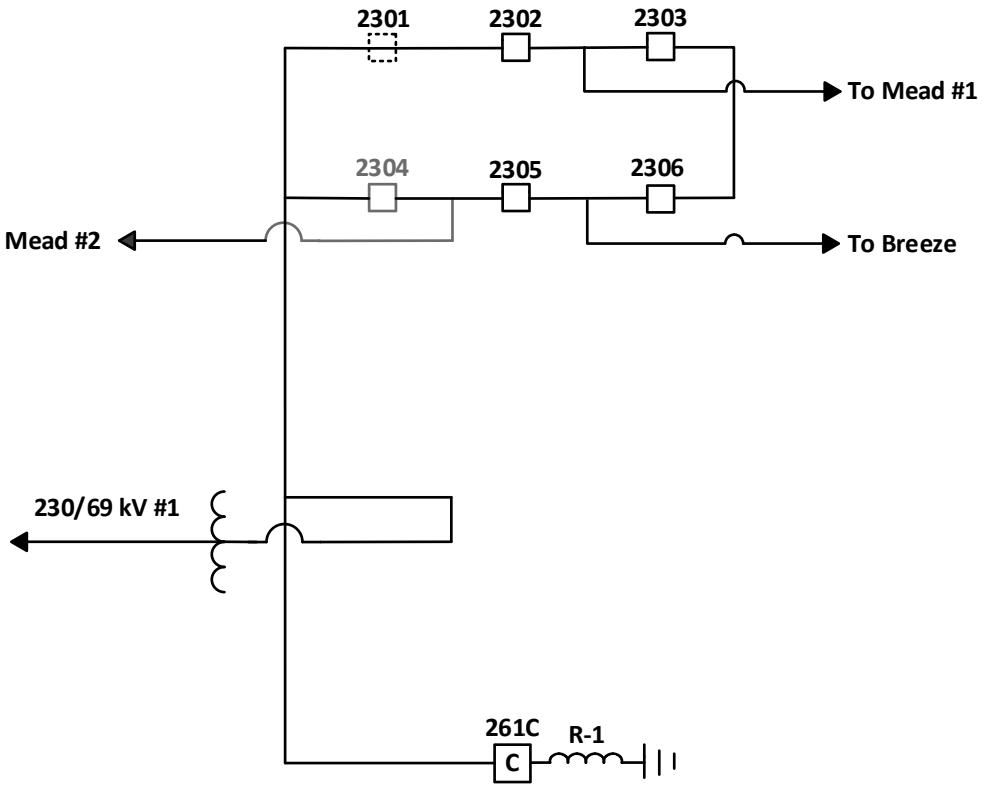
Summary:

A P4 event of the Equestrian 2302 breaker trips both the Equestrian – Mead 230 kV lines. Loss of these two lines can overload the Greenway – Mead 230 kV line by up to 108.3 % of its rating by 2030.

Project Scope:

To mitigate this problem, The Equestrian – Mead 230 kV Line #2 should be re-terminated into the 2304-05 position, to avoid a breaker fail event tripping both Equestrian – Mead 230 kV lines.

Equestrian 230 kV



#2104 Northwest 525/230 kV Bank #7

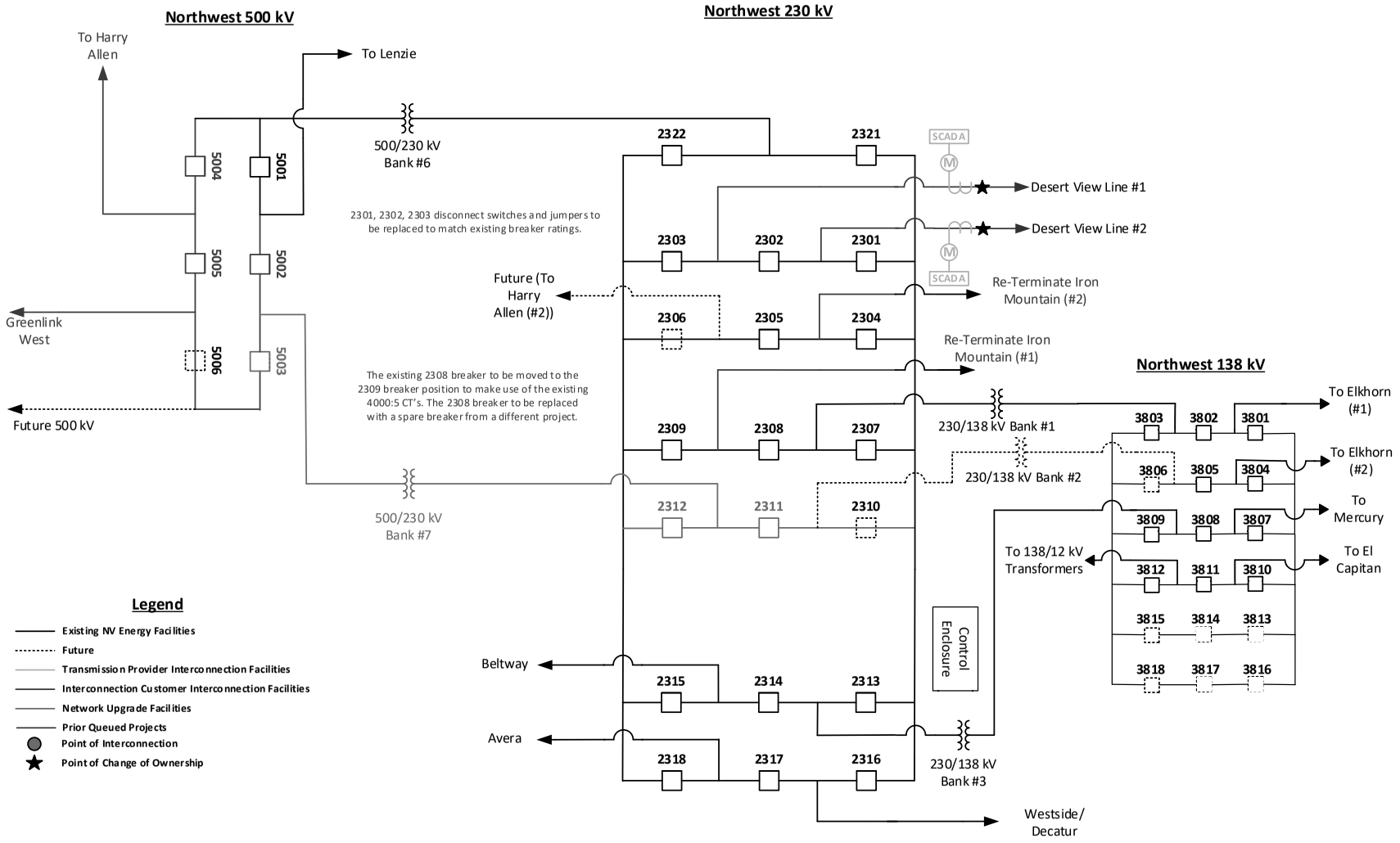
Summary:

Multiple P1 events in the Southern system were identified which overloaded various 230 kV line in the South-West area of Las Vegas. A new Magnolia – NSO 230 kV line was identified as the mitigation for these overloads. Subsequent to this mitigation being identified, the Northwest 525/230 kV Bank #7 was identified as being required for different DNR and TSR studies. The addition of this bank had the added impact of mitigating the 230 kV overloads for a few years allowing for a delay of the Magnolia – NSO 230 kV line.

Project Scope:

Install a new 525/230 kV transformer and associated breakers at Northwest substation. It may be necessary to upgrade 230 kV breakers and bus work as necessary because of the increased fault duty caused by the transformer addition. The complete scope for mitigating the interrupting rating of the breakers is being determined and will be included as part of the project scope.

NVEnergy	Northwest Substation 500/230/138 kV	12/1/2025



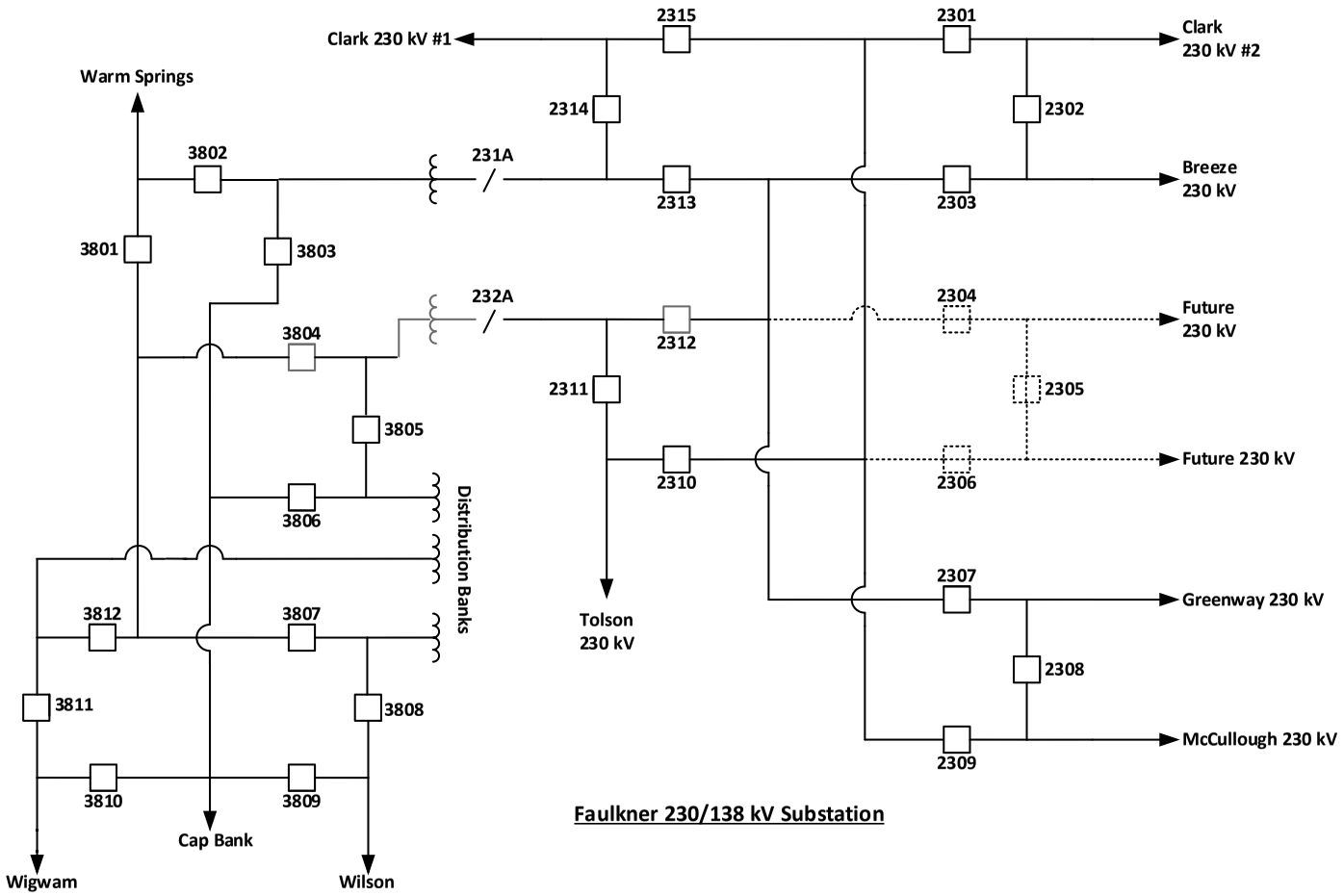
#2105 Faulkner 230/138 kV Bank #2

Summary:

Following the addition of the planned Magnolia – NSO 230 kV line (CAP #2077) in 2035, loss of one of the Tolson 230/138 kV Banks will overload the other Tolson 230/138 kV Bank by 102.4% of its rating. Installing a second 230/138 kV bank at Faulkner will eliminate the overload at Tolson.

Project Scope:

Install a second 230/138 kV transformer and associated breakers at Faulkner substation.



Faulkner 230/138 kV Substation

#2106 Northwest 230/138 kV Bank #2

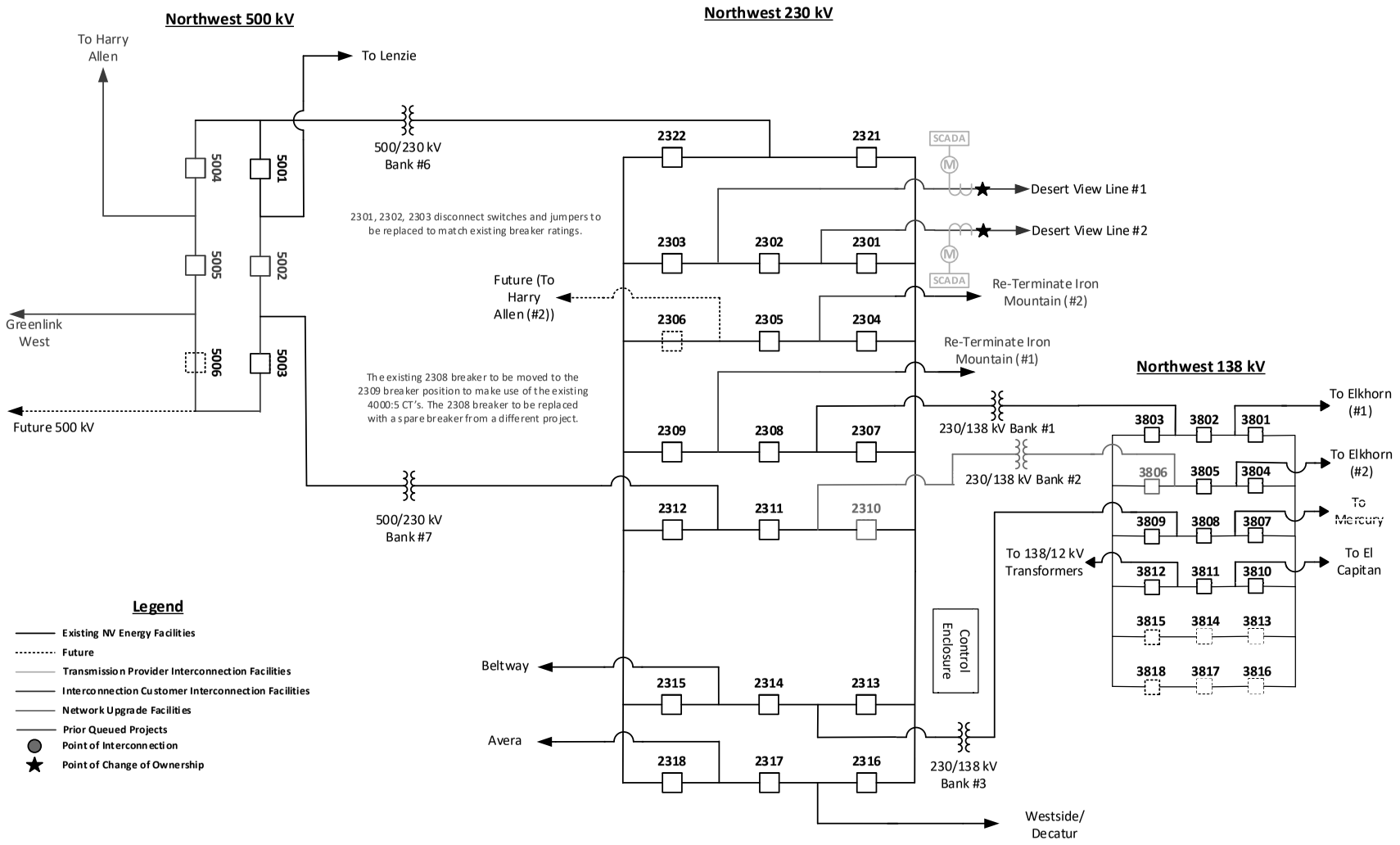
Summary:

Following the addition of the planned Northwest 525/230 kV Bank #7, loss of one of the existing 230/138 kV Banks at Northwest can overload the remaining 230/138 kV Bank by 101.6% of its rating by 2035.

Project Scope:

Install a third 230/138 kV transformer (Bank #3) and associated breakers at Northwest substation.

NVEnergy	Northwest Substation 500/230/138 kV	12/1/2025



#2107 Claymont – Strip 138 kV Line Uprate

Summary:

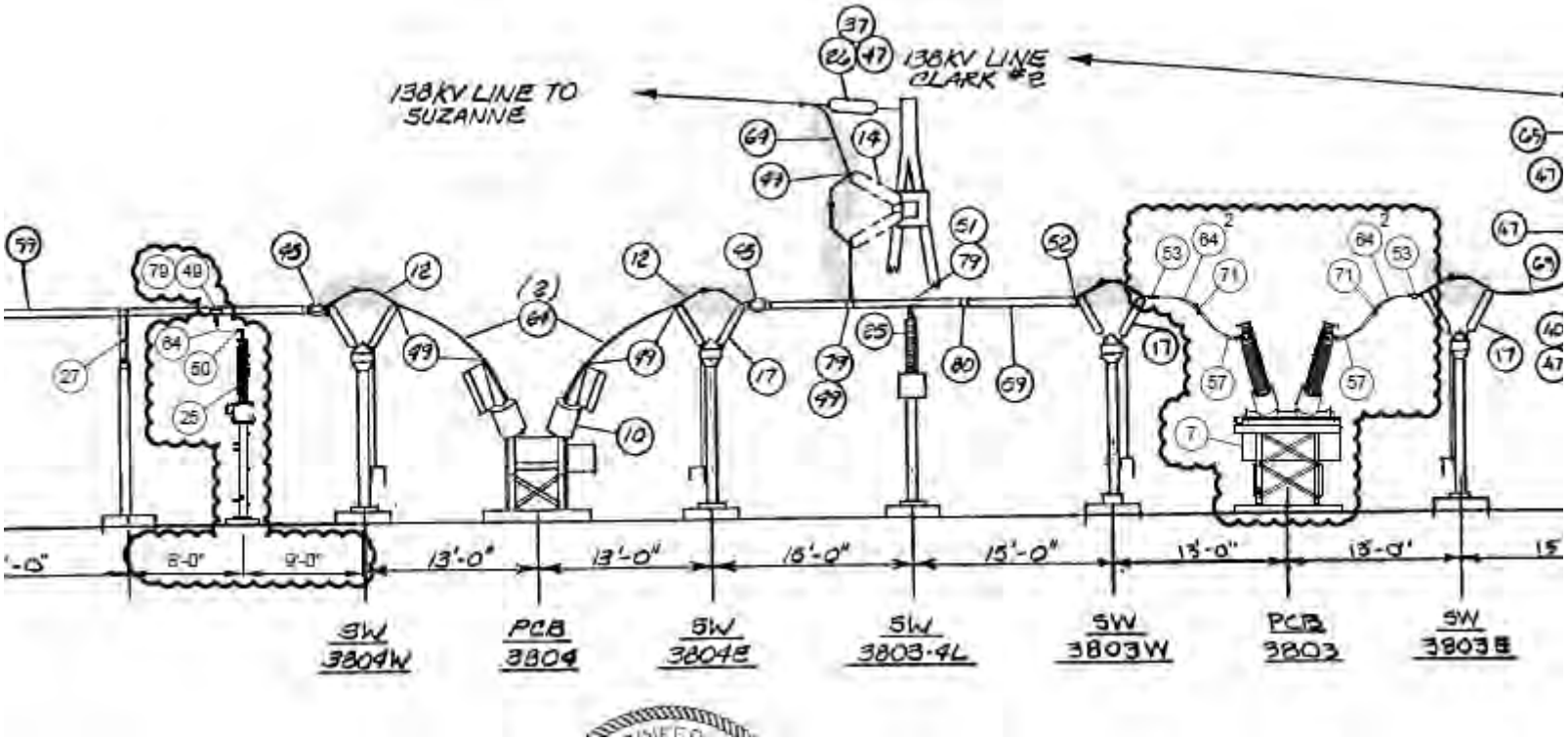
A P1 event of the Concourse – Clark 138 kV line or a P4 event (breaker fail) at Clark or Concourse that trips the Concourse – Clark 138 kV line will overload the Strip – Claymont line by as much as 106.2% of the current line rating.

Project Scope:

To mitigate this problem, the overhead portion of the Claymont – Strip 138 kV line should be reconductored with 1026 ACCC conductor, approximately 1.74 miles. The line drops at Claymont will need to be replaced with 2-954 AAC conductor to match the line conductor. The Claymont 3803 and 3804 breaker disconnect switches along with the 3803-04L disconnect switch will need to be replaced with 2000 A switches.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F	Conductor MOT (°F)
S	138	T	Yes		CM-STR-138-1	1	Claymont Sub to XNO	1.74	CARDINAL	954	ACSR	1	212	212	212
S	138	T	Yes		CM-STR-138-1	2	XNO to Strip Sub	0.12	2000kcm Cu 138kV XLPE UG Cable-NKT	2000	CU,UG	1	194	N/A	194

All 954 ACSR conductor on the Claymont – Strip 138 kV line needs to be replaced with 1026 ACCC conductor.



Claymont line terminal. The line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The Claymont 3803 and 3804 breaker disconnect switches along with the 3803-04L disconnect switch will need to be replaced with 2000 A switches.

#3002 MOA: Carson 60kV Normal Open

System Deficiencies

During summer-peak loads in the Carson load pocket, the following contingencies can be critical to the Carson 63kV system, causing overloads of the 120/60kV transformers, 60kV lines, and under-voltage.

- P1: Brunswick 120/63kV
- P4: Brunswick 2023 BF (Trips 120kV Cap & 120/60kV XF)
- P4: Brunswick 2024 BF (Trips 120/60kV XF)
- P4: Brunswick 6003 BF (Trips 120/60kV XF & #635 Line)
- P4: Brunswick 6004 BF (Trips 120/60kV & Black Start)
- P6: Brunswick 120/63kV & Ft Churchill 120/63kV
- P6: Brunswick 120/63kV & Ft Churchill 120kV Phase Shifter
- P6: Buckeye 120/63kV & Brunswick 120/63kV
- P6: Buckeye 120/63kV & Buckeye - Minden Tap - Kingsbury Tap - Stateline 63kV
- P6: Round Hill - Stateline 120kV & Brunswick 120/63kV
- P7: Round Hill - Stateline #160 & Stateline - Buckeye #634
- Pd: Bus Isol 64019 BRUNSWCK 63
- Pd: Bus Isol 64020 BRUNSWCK 120

Additionally, for configurations where Stateline / Round Hill / Muller 120kV loads are served radially from the 60kV system, low voltage on 120kV buses and overloads of 60kV elements may occur.

- P6: Buckeye - Meyers 120kV & Buckeye - Muller - Round Hill 120kV
- P6: Buckeye - Meyers 120kV & Round Hill - Stateline 120kV
- P6: Buckeye - Muller - Round Hill 120kV & Brunswick 120/63kV
- P6: Buckeye - Muller - Round Hill 120kV & Buckeye - Minden Tap - Kingsbury Tap - Stateline 63kV
- P6: Buckeye - Muller - Round Hill 120kV & Buckeye 120/63kV
- P6: Buckeye - Muller - Round Hill 120kV & Meyers - Stateline 63kV
- P6: Buckeye - Muller - Round Hill 120kV & Meyers 120/63kV

Corrective Action Plan

During Summer-Peak timeframe for Carson Load Pocket, normally open the following to sectionalize Carson 60kV. This configuration may also be applied during off-peak seasons in response to an N-1, in preparation for the next N-1.

- Mason – Brunswick 60kV
- Mason – Silver Springs 60kV
- Meyers – Stateline 60kV
- Minden – Kingsbury #634E Switch
- Glenbrook – Heybourne 60kV
- Virginia City #602 Circuit Breaker
- Minden #634 Switch

NVEnergy

#3005 MOA: Open Valley Road 606 Breaker

Summary:

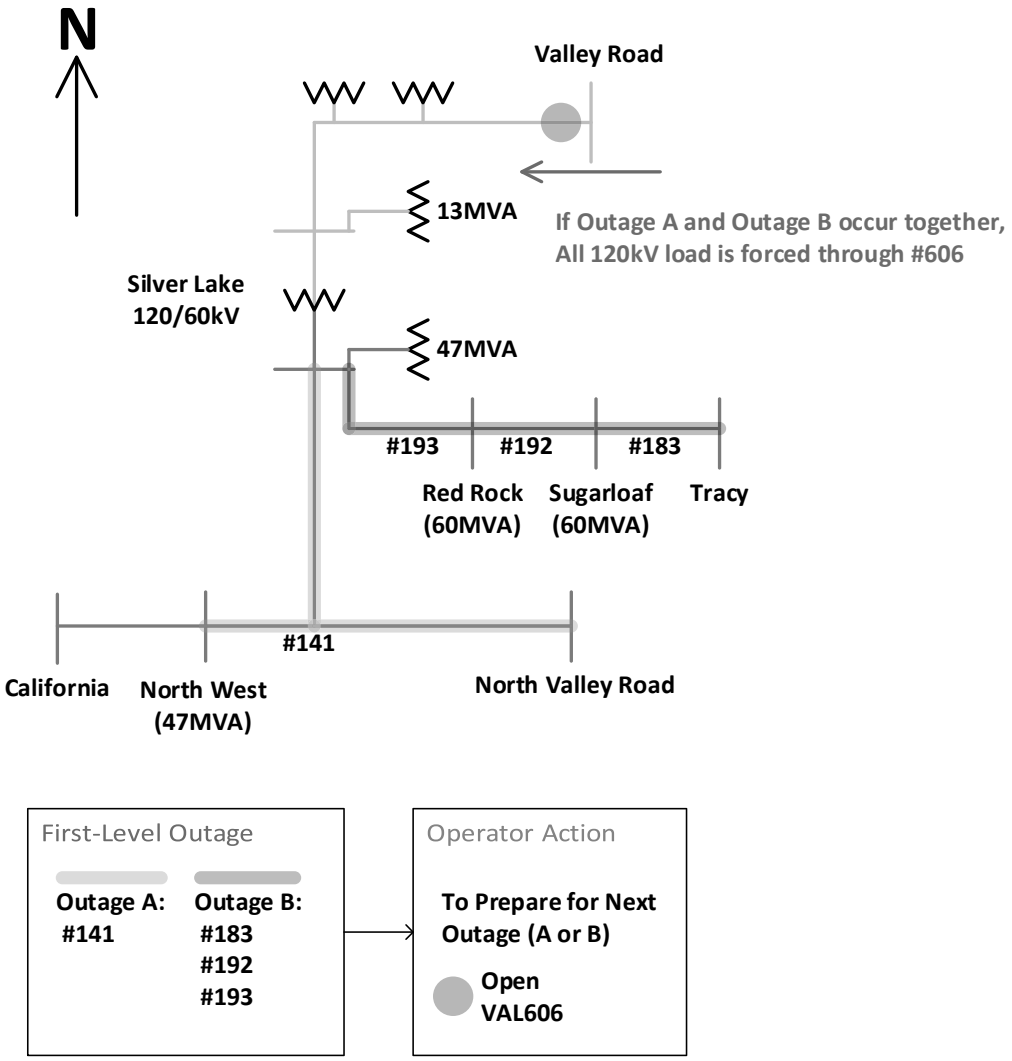
If any portion of
[Tracy - Sugarloaf - Red Rock - Silver Lake 120kV] opens, and
[Penny's Tap - (NW, NVR, SLK) 120kV] opens, (or vice-versa),

All 120kV load is served by the Silver Lake - Valley Road #606 60kV line, which causes overloads and voltage collapse on that system.

MOA Scope:

If one 120kV source opens, open the VAL606 breaker to prepare for the next 120kV source outage.

MOA: Open VAL 606



NVEnergy

#3007 MOA: Ft Churchill Must-Run

Summary:

The Carson City / South Lake Tahoe load pocket is served by the following generation and transmission sources (Excluding the 60kV lines, which have very limited capability):

- Generation:
  - Ft Churchill G1 113 MW
  - Ft Churchill G2 113 MW
  - Ft Churchill Apple Solar 20 MW
- Transmission:
  - Mt Rose – Carson Tap #107 120kV 124.7 MVA
  - East Tracy – Brunswick #108 120kV 141.8 MVA
  - Steamboat – Mark Twain #189 120kV 162.1 MVA
  - Thorne – Ft Churchill 120kV 119.5 MVA
  - Alpine – Ft Churchill 230kV 150 MVA

The amount of power coming into the pocket from the 230kV and Thorne side (Rural South) depends on the angle of the neighboring systems through Gonder and Robinson, and the Ft Churchill phase shifter, which adjusts power between those two connections in the 230/120kV Rural South loop. In general, those two sources may not be helping serve much load in the Carson pocket due to neighboring angles, and the phase shifter may be necessary to balance generation flow on the 230/120kV loop to prevent N-1 overloads in that pocket. Therefore, these two connections may not be relied on very much for serving the Carson pocket depending on the operating condition.

Excluding those two circuits connecting to the Rural South (Ft Churchill 230kV, Thorne 120kV), the remaining lines total to a rating of 428.6 MVA. The N-1 capacity of those three remaining circuits is 266.5 MVA, which is lower than expected Summer-Peak loads in the pocket which can be above 330MW, and does not account for any operational differences in balance between the circuits.

Because of this limitation, without Ft Churchill Generation during summer-peak loading conditions, the following single-contingencies of Carson Sources tend to cause overloads on the other Carson Sources into the load pocket.

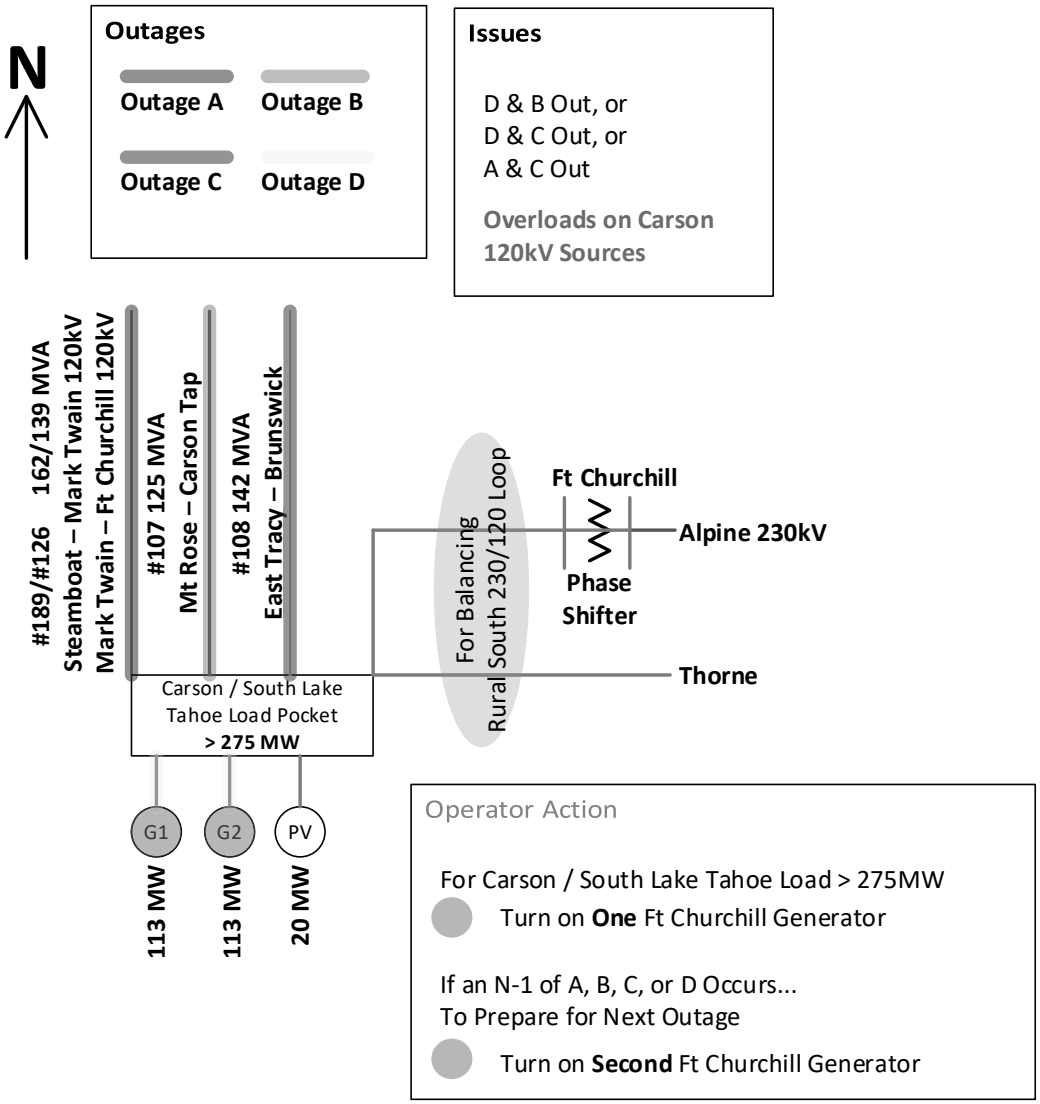
- P1: East Tracy – Brunswick #108 120kV Overload: Mt Rose – Carson Tap #107 120kV
- P1: Mt Rose – Carson Tap #107 120kV Overload: East Tracy – Brunswick #108 120kV

MOA Scope:

Ft Churchill generation must-run requirements are in effect for loads above 275 MW for the Carson / South Lake Tahoe load pocket, and can even be required at lower load levels depending on the operating condition and the balance in loading between the circuits sourcing the pocket.

Both Ft Churchill units should be available during Summer Peak conditions in case one of them ends up out-of-service. If one Ft Churchill generator goes out of service during summer peak (or a source into Carson is lost), the second Ft Churchill unit should be ramped up in its' place to prevent overloads for the next N-1 condition.

MOA: FTC Must-Run



#3009 MOA: Valmy Must-Run

Summary:

During Summer and Winter Peaks, with Newmont and Valmy 1 & 2 units all turned off, voltage may be low normally in Carlin Trend, and below 90% for N-1 conditions.

Normally opening the Carlin Trend will not resolve the problem, and reinforcement of the load pocket may also not resolve the issue. The problem arises as a result of low 345kV bus voltages sourcing the Carlin Trend due to insufficient generation in the load pocket, which is very far from any substantial generation sources.

The low voltages can be exacerbated by flows on the 345kV path with Idaho, as any extra flow on that path may suppress the voltage on the Carlin Trend 345kV lines even further.

MOA Scope:

Valmy #1 must run as determined by operational studies, prior to the start of the season.

Alternatives:

If Valmy generation, and Newmont generation, cannot run to support the Carlin Trend & Valmy region load pockets, another solution must be in place.

This can include one or multiple of the below options:

1) Replacement of the existing generation with more efficient conventional generation which will be available at all times for voltage support.
2) Replacement of the existing generation with renewable generation that has 24/7 STATCOM capabilities to produce substantial VAR support regardless of time-of-day.
3) New 345kV or 525kV lines into the pocket to support the demand.

NVEnergy

Appendix A

#3011 MOA: 230 kV Generation Limitation

Summary:

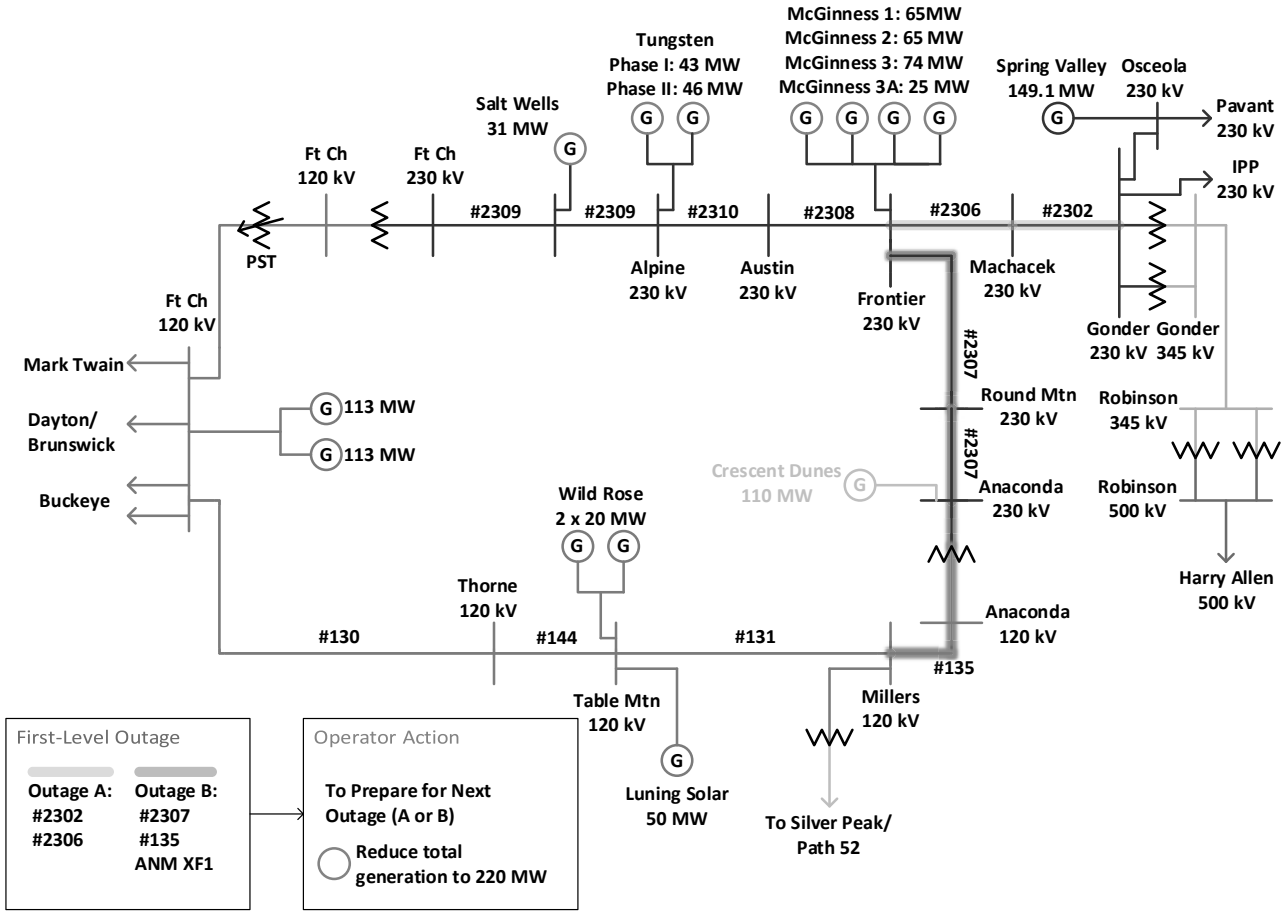
Generation additions to the 230 kV system between Fort Churchill and Frontier have reached a point where unstable conditions exist depending on the amount of generation and system conditions. To maintain stability, a limit has been placed on the total amount of generation that can placed on the line under nominal and various contingency scenarios.

Nominal Generation Output

Total generation on the 230 kV system should not exceed 330 MW with the system intact. Based on historical trends, we should not need to curtail generation to stay below this limit. If new 230 kV generation is brought online, these generators should be curtailed, if necessary, to stay below this threshold.

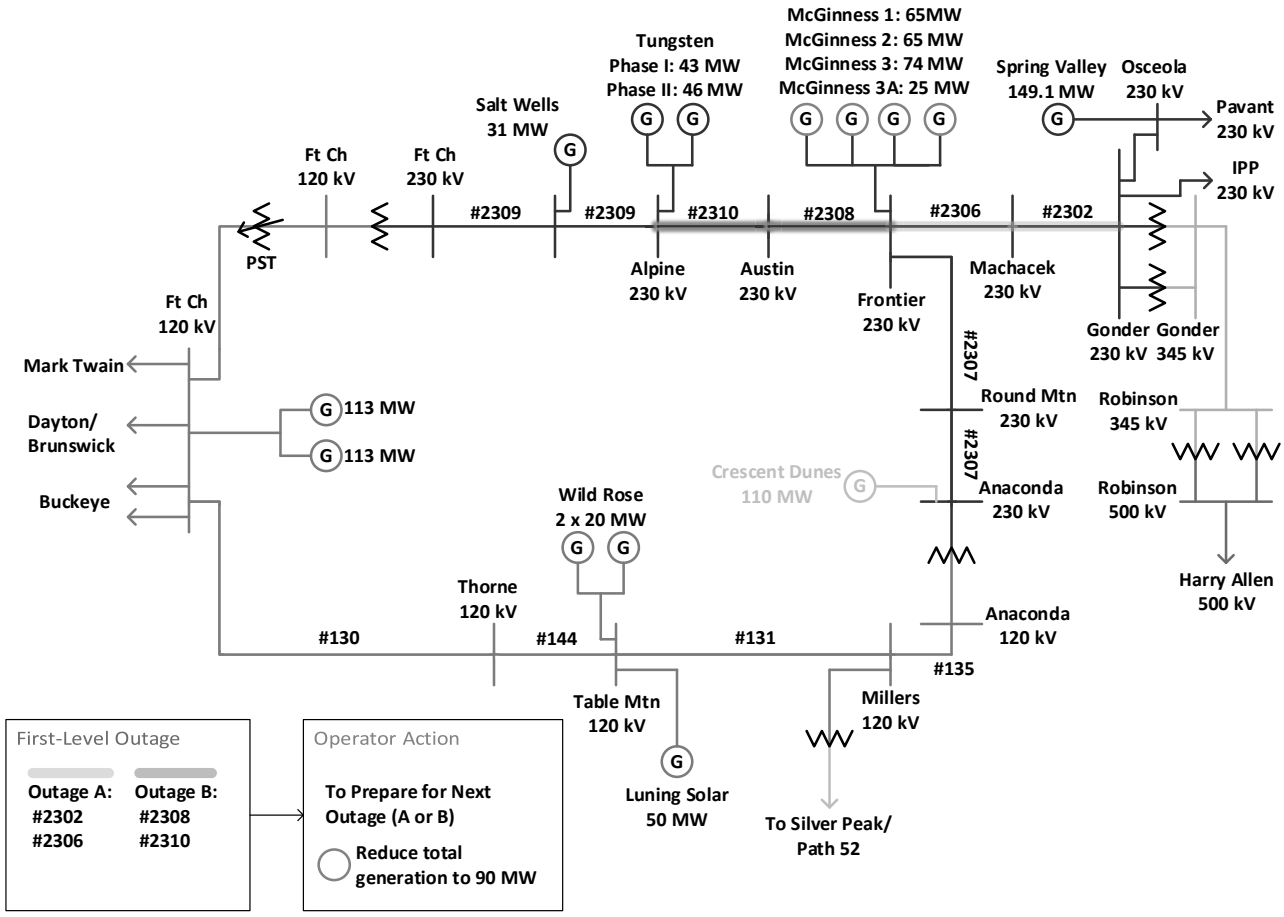
2307 Line, ANM 230/120 kV Transformer, 135 Line outage

For an outage of the 2307 Line, the 135 Line, or the Anaconda Moly 230/120 kV Transformer, 230 kV generation should be reduced to 220 MW to avoid stability issues for the next outage.



2308 Line or 2310 Line outage

For an outage of the 2308 Line or 2310 Line, generation at McGinness should be reduced to 90 MW to avoid stability issues for the next outage.

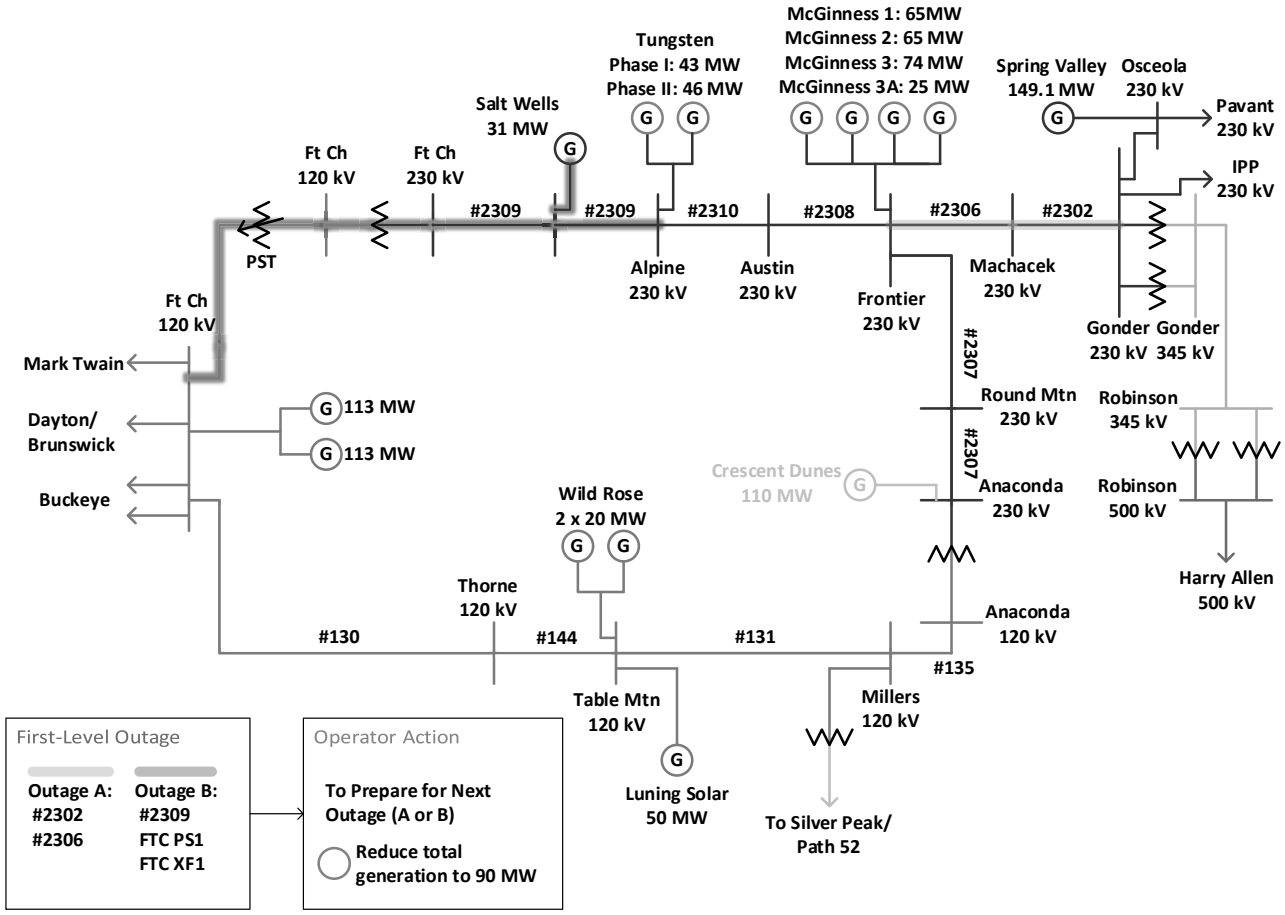


2302/2306 Line, 2309 Line, FTC 230/120 kV Transformer, FTC 120 kV Phase Shifter outage

For an outage of the 2302/2306 Line, 2309 Line, the Fort Churchill 230/120 kV Transformer or the Fort Churchill 120 kV Phase Shifter, 230 kV generation should be reduced to 90 MW to avoid stability issues for the next outage.

NVEnergy

Appendix A



#4001 TPL-001-5.1 SPF Corrective Projects

Summary:

Transmission Planning and System Protection worked to develop a list of all non-redundant Protection Systems as identified in Table 1 of TPL-001-5.1. Based on this list, a Corrective Action Plan was created based on the expected clearing for failure of the non-redundant protection system component (identified by System Protection) and the Critical Clearing Time required for that element (identified by Transmission Planning). For elements that have a critical clearing time violation for failure of the non-redundant Protection System a Corrective Action Plan was developed.

Project Scope

The following tables outline the Corrective Action Plan for failure of critical non-redundant Protection Systems

Footnote 13a. Relays (North)

Element Name	Terminal	Non-Redundant Relay	CAP
230kV Bus	Austin (230kV)	Differential (87B)	Install redundant bus diff relays
Transformer #1	Austin (230kV)	Differential (87T)	Install redundant bus diff relays
111 Line	Buckeye	EM Relays (67/67N)	Replace relays (BUC rebuild)
112 Line	Buckeye	EM Relays (67/67N)	Replace relays (BUC rebuild)
124 Line	Buckeye	EM Relays (67/67N)	Replace relays (BUC rebuild)
Capacitor Bank #2	Buckeye	Voltage Differential (87VP)	Replace relays (BUC rebuild)
120kV Bus	Buckeye	Differential (87B)	Replace relays (BUC rebuild)
120kV Bus	Fernley	Differential (87B1)	Install redundant bus diff relays
122 Line	Fort Churchill	EM Relays (67/67N)	Walker River 120 kV
124 Line	Fort Churchill	EM Relays (67/67N)	Walker River 120 kV
Bus #1	Fort Churchill	EM Relays (87B1)	Walker River 120 kV
Bus #2	Fort Churchill	EM Relays (87B2)	Walker River 120 kV
Phase Shifter #1	Fort Churchill	Exciter (87E/87S)	To Be Removed
Transformer #1	Fort Churchill	Differential (87T)	To Be Removed
230kV East Bus	Gonder (230kV)	Differential (87B1)	Install redundant bus diff relays
230kV West Bus	Gonder (230kV)	Differential (87B2)	Install redundant bus diff relays
Transformer #1	Patrick (120kV)	Differential (87T1)	(1) install 1001 Ckt Swr or breaker, (2) redundant xfmr relays, (3) redundant bus relays.
Transformer #1	Steamboat	Differential (87T1)	Install redundant xfmr diff relays
120kV Bus	Valley Road (120kV)	Differential (87B)	Install redundant bus diff relays

Footnote 13b. Communications (North)

Line	Does line use comm-aided protection trip?	Diverse & Redundant communications?	Alarm to System Control?	CAP
#113	Y	N	N	re-run. Use fiber to install redundant comm channel, add comm alarms at Eagle.

Footnote 13c. DC Supply (North) – None Required

Footnote 13d. Control Circuitry (North)

Substation	Terminal	Element Name	CAP
Dove	1103 Line	411L1/1103	Add TCM, Replace 1002. Link Code BTD
Dove	1103 Line	411L2/1103	Add TCM, Replace 1002. Link Code BTD
Dove	179 Line	411L1/179	Add TCM. Replace 179/1001. Link Code BTD
Dove	179 Line	411L2/179	Add TCM. Replace 179/1001. Link Code BTD
Dove	180 Line	BU Line Protection (180-21B)	Add TCM. Replace 180/1003. Link Code BTD
Dove	180 Line	Primary Line Protection (180-21P)	Add TCM. Replace 180/1003. Link Code BTD
Dove	181 Line	BU Line Protection (21B)	Add TCM. Replace 181/1001. Link Code BTD
Dove	181 Line	Primary Line Protection (21P)	Add TCM. Replace 181/1001. Link Code BTD
Dove	182 Line	BU Line Protection (21B)	Add TCM. Replace 182/1002. Link Code BTD
Dove	182 Line	Primary Line Protection (21P)	Add TCM. Replace 182/1002. Link Code BTD
Dove	191 Line	BU Line Protection (87B)	Add TCM. Replace 1003. Link Code BTD
Dove	191 Line	Primary Line Protection (21P)	Add TCM. Replace 1003. Link Code BTD
Dove	Bus #1	Differential (87B1B)	Add TCM. Replace breakers (not 1103). Link Code BTD
Dove	Bus #1	Differential (87B1P)	Add TCM. Replace breakers (not 1103). Link Code BTD
Dove	Bus #2	Differential (87B2B)	Add TCM. Replace breakers. Link Code BTD
Dove	Bus #2	Differential (87B2P)	Add TCM. Replace breakers. Link Code BTD
East Tracy	120kV South Bus (Bus #5)	Bus #5 Backup Differential (BUS5-87B5B)	Check BF CCT
East Tracy	120kV South Bus (Bus #5)	Bus #5 Primary Differential (BUS5-87B5P)	Check BF CCT
East Tracy	146 Line	411L1/146	Check BF CCT
East Tracy	146 Line	411L2/146	Check BF CCT
East Tracy	179 Line	411L1/179	Check BF CCT
East Tracy	179 Line	411L2/179	Check BF CCT

Substation	Terminal	Element Name	CAP
East Tracy	3422 Reactor #1	Differential (3422R1-87R1)	To be removed with Lantern line fold
East Tracy	3422 Reactor #1	Overcurrent (3422R1-51BUR1)	To be removed with Lantern line fold
East Tracy	3431 Reactor #2 (previously 3421 Reactor #1)	Differential (3431R2-87R2)	No CAP required. Create P5 specific contingency
East Tracy	3431 Reactor #2 (previously 3421 Reactor #1)	Overcurrent (3431R2-51BUR2)	No CAP required. Create P5 specific contingency
East Tracy	Clark Mountain GT #3 Line (Bus #7)	Differential (GT3-87B7)	Move relays to separate DC Panel
East Tracy	Clark Mountain GT #3 Line (Bus #7)	Overcurrent (GT3-50/51)	Move relays to separate DC Panel
Mira Loma	120kV East Bus #1	487B2/200E1	Add TCM. Check BF CCT
Mira Loma	120kV East Bus #1	587Z1/200E1	Add TCM. Check BF CCT
Mira Loma	120kV West Bus #1	487B2/200W1	Add TCM. Check BF CCT
Mira Loma	120kV West Bus #1	587Z1/200W1	Add TCM. Check BF CCT
Mira Loma	207-08 Terminal [MIR-PAT 120kV (116 Line)]	311L/207-08	Add TCM. Check BF CCT
Mira Loma	207-08 Terminal [MIR-PAT 120kV (116 Line)]	421/207-08	Add TCM. Check BF CCT
Mira Loma	208-09 Terminal [BLV-MIR 120kV (110 Line)]	311L/208-09	Add TCM. Check BF CCT
Mira Loma	208-09 Terminal [BLV-MIR 120kV (110 Line)]	421/208-09	Add TCM. Check BF CCT
Mira Loma	210-11 Terminal [MIR-SMD 120kV (127 Line)]	311L/210-11	Add TCM. Check BF CCT
Mira Loma	210-11 Terminal [MIR-SMD 120kV (127 Line)]	421/210-11	Add TCM. Check BF CCT
Mira Loma	211-12 Terminal [GRG-MIR 120kV (143 Line)]	311L/211-12	Add TCM. Check BF CCT

Substation	Terminal	Element Name	CAP
Mira Loma	211-12 Terminal [GRG-MIR 120kV (143 Line)]	421/211-12	Add TCM. Check BF CCT
Mira Loma	2592 Breaker / Tertiary Reactor R2	501-X/R2, 501-Y/092	No CAP required. Create P5 specific contingency
Mira Loma	Tertiary Reactor R2	587/R2	No CAP required. Create P5 specific contingency
North Valley Road	103 Line	BU Line Protection	Separate TC and BF to separate DC panels. Add TCM
North Valley Road	103 Line	Primary Line Protection	Separate TC and BF to separate DC panels. Add TCM
North Valley Road	1102 Circuit Switcher	351S/1102	Move TC1 and TC2 to separate DC Panels
North Valley Road	120kV West Bus (Bus #2)	487B2/200W1	Separate TC and BF to separate DC panels. Add TCM
North Valley Road	120kV West Bus (Bus #2)	587Z1/200W1	Separate TC and BF to separate DC panels. Add TCM
North Valley Road	141 Line	411L1/141	Separate TC and BF to separate DC panels. Add TCM
North Valley Road	141 Line	411L2/141	Separate TC and BF to separate DC panels. Add TCM
North Valley Road	142 Line	411L1/142	Add TCM.
North Valley Road	142 Line	411L2/142	Add TCM.
North Valley Road	Transformer #1	487E1/T1	Separate TC and BF to separate DC panels. Add TCM
North Valley Road	Transformer #1	487E2/T1	Separate TC and BF to separate DC panels. Add TCM
North Valley Road	Transformer #2	487E1/T2	Separate TC and BF to separate DC panels. Add TCM
North Valley Road	Transformer #2	487E2/T2	Separate TC and BF to separate DC panels. Add TCM
North Valmy	117 Line	411L1/117	Add TCM.
North Valmy	117 Line	411L2/117	Add TCM.

Substation	Terminal	Element Name	CAP
North Valmy	120 Line	411L1/120	Add TCM.
North Valmy	120 Line	411L2/120	Add TCM.
North Valmy	120kV North Bus #1 (previously Bus #6)	487B2/200N1	Add TCM.
North Valmy	120kV North Bus #1 (previously Bus #6)	587Z1/200N1	Add TCM.
North Valmy	120kV South Bus #1 (previously Bus #1)	487B2/200S1	Add TCM.
North Valmy	120kV South Bus #1 (previously Bus #1)	587Z1/200S1	Add TCM.
North Valmy	152 Line	BU Line Protection (152-21B)	Add TCM.
North Valmy	152 Line	Primary Line Protection (152-21P)	Add TCM.
North Valmy	186 Line	BU Line Protection (186-21B)	Add TCM.
North Valmy	186 Line	Primary Line Protection (186-21P)	Add TCM.
North Valmy	3420 Reactor #1	Differential (87R1)	Separate DC Panels, add second lockout
North Valmy	3420 Reactor #1	Overcurrent (51R1)	Separate DC Panels, add second lockout
North Valmy	3422 Reactor #1	Differential (87R1)	Separate DC Panels, add second lockout
North Valmy	3422 Reactor #1	Overcurrent (51R1)	Separate DC Panels, add second lockout
North Valmy	3422 Reactor #2	Differential (87R2)	Separate DC Panels, add second lockout
North Valmy	3422 Reactor #2	Overcurrent (51R2)	Separate DC Panels, add second lockout
North Valmy	345kV North Bus #1 (previously Bus #5)	487B2/400N1	Add TCM.
North Valmy	345kV North Bus #1 (previously Bus #5)	587Z1/400N1	Add TCM.
North Valmy	345kV South Bus #1 (previously Bus #2)	487B2/400S1	Add TCM.
North Valmy	345kV South Bus #1 (previously Bus #2)	587Z1/400S1	Add TCM.
North Valmy	Bus #3 (RSS)	421/BUS#3	Add TCM.
North Valmy	Bus #3 (RSS)	587Z/BUS#3	Add TCM.

Substation	Terminal	Element Name	CAP
North Valmy	Transformer #1	487E1/T1	Add TCM.
North Valmy	Transformer #1	487E2/T1	Add TCM.
North Valmy	Transformer #3	487E1/T3	Add TCM.
North Valmy	Transformer #3	487E2/T3	Add TCM.
West Tracy	3401-3408 Terminal [Unit 8-WTY 345kV (3408 Line)]	Differential (3408-87B8)	Separate Primary and BF Relays to separate DC Panels
West Tracy	345kV East Bus	587Z1/400E	Separate Primary and BF Relays to separate DC Panels
West Tracy	345kV East Bus	587Z2/400E	Separate Primary and BF Relays to separate DC Panels
West Tracy	345kV West Bus	487B2/400W	Separate Primary and BF Relays to separate DC Panels
West Tracy	345kV West Bus	587Z1/400W	Separate Primary and BF Relays to separate DC Panels
West Tracy	3601-3610 Terminal [Unit 10-WTY 345kV (3610 Line)]	Differential (3610-87B10)	Separate Primary and BF Relays to separate DC Panels

Footnote 13a. Relays (South)

Quantity	Element Name	Terminal	Non-Redundant Relay	CAP
1	CAP 1	ARDEN 138 kV	SEL-487V	Add redundant relay
1	CAP BK	AVERA 138 kV	SEL-287V	Add redundant relay
1	CAP BK	BELTWAY 138 kV	SEL-287V	Add redundant relay
1	CAP BK	BURNHAM 138 kV	SEL-487-V	Add redundant relay
1	CAP BK	DECATUR 138 kV	SEL-487V	Add redundant relay
1	CAP BK	DURANGO 138 kV	SEL-287V	Add redundant relay
1	CAP 2	FAULKNER 138 kV	SEL-287V	Add redundant relay
1	CAP BK	GILMORE 138 kV	SEL-487-V	Add redundant relay
1	CAP BK	GRAND TETON 230 kV	SEL-287V	Add redundant relay
1	CAP 1	HARRY ALLEN 230 kV	SEL-287V	Add redundant relay
1	CAP 2	HARRY ALLEN 230 kV	SEL-287V	Add redundant relay
1	CAP 3	HARRY ALLEN 230 kV	SEL-287V	Add redundant relay
1	CAP 4	HARRY ALLEN 230 kV	SEL-287V	Add redundant relay
1	CAP 5	HARRY ALLEN 230 kV	SEL-287V	Add redundant relay
1	CAP 1	HUALAPAI 138 kV	SEL-287V	Add redundant relay
1	CAP BK	IRON MOUNTAIN 138 kV	SEL-287V	Add redundant relay
1	CAP BK	LEAVITT 138 kV	SEL-487V	Add redundant relay
1	CAP BK	LINCOLN 138 kV	SEL-487V	Add redundant relay
1	CAP BK	LORENZI 138 kV	SEL-287V	Add redundant relay
1	CAP BK	NORTHWEST 138 kV	SEL-287V	Add redundant relay
1	BUS	NORTHWEST 230 kV	SBD	Reduce Z2 clearing time or add redundant relay
	BUS	NORTHWEST 230 kV	SBD	Reduce Z2 clearing time or add redundant relay
	BUS	NORTHWEST 230 kV	SBD	Reduce Z2 clearing time or add redundant relay
1	CAP 384C	PEBBLE 138 kV	SEL-287V	Add redundant relay
1	CAP 1	PECOS 138 kV	SEL-287V	Add redundant relay
1	CAP 2	PECOS 138 kV	SEL-287V	Add redundant relay

Quantity	Element Name	Terminal	Non-Redundant Relay	CAP
1	CAP 3	PECOS 138 kV	SEL-287V	Add redundant relay
1	BUS	POLARIS 138 kV	SEL-501 (OC1)	Reduce Z2 clearing time or add redundant relay
	BUS	POLARIS 138 kV	SEL-501 (OC1)	Reduce Z2 clearing time or add redundant relay
1	CAP 384C	POLARIS 138 kV	SEL-287V	Add redundant relay
1	CAP BK 1	QUAIL 138 kV	SEL-287V	Add redundant relay
1	CAP BK 2	QUAIL 138 kV	SEL-487-V	Add redundant relay
1	BK 3	REID GARDNER 230 kV	STD-16C	Reduce Z2 clearing time or add redundant relay
	BK 3	REID GARDNER 230 kV	STD-16C	Reduce Z2 clearing time or add redundant relay
	BK 3	REID GARDNER 230 kV	STD-16C	Reduce Z2 clearing time or add redundant relay
1	STUB BUS 2307-2308	REID GARDNER 230 kV	SEL-351 (ARM)	Reduce Z2 clearing time or add redundant relay
1	STUB BUS 2314-2314	REID GARDNER 230 kV	SEL-351 (ARM)	Reduce Z2 clearing time or add redundant relay
1	STUB BUS 2316-2317	REID GARDNER 230 kV	SEL-351 (ARM)	Reduce Z2 clearing time or add redundant relay
1	CAP BK	RILEY 138 kV	SEL-487V	Add redundant relay
1	BK 1-2-3	RUSSELL 138 kV	HU	Reduce Clark Clearing Times or replace with redundant relays
	BK 1-2-3	RUSSELL 138 kV	HU	Reduce Clark Clearing Times or replace with redundant relays
	BK 1-2-3	RUSSELL 138 kV	HU	Reduce Clark Clearing Times or replace with redundant relays
1	BUS	RUSSELL 138 kV	PVD	Reduce Clark Clearing Times or replace with redundant relays
	BUS	RUSSELL 138 kV	PVD	Reduce Clark Clearing Times or replace with redundant relays
	BUS	RUSSELL 138 kV	PVD	Reduce Clark Clearing Times or replace with redundant relays
1	CAP BK	TOLSON 138 kV	SEL-287V	Add redundant relay
1	CAP BK	VEGAS 138 kV	SEL-487V	Add redundant relay
1	CAP 384C	WASHBURN 138 kV	SEL-287V	Add redundant relay
1	CAP 385C	WASHBURN 138 kV	SEL-287V	Add redundant relay

Quantity	Element Name	Terminal	Non-Redundant Relay	CAP
1	BKR 3880	WESTSIDE 138 kV	SEL-351-S	Reduce Zone 2 Clearing Times or replace with redundant relays
1	BUS	WESTSIDE 138 kV	SEL-487B	Reduce Zone 2 Clearing Times or replace with redundant relays
1	BUS (XFMR)	WESTSIDE 138 kV	PVD	Reduce Zone 2 Clearing Times or replace with redundant relays
	BUS (XFMR)	WESTSIDE 138 kV	PVD	Reduce Zone 2 Clearing Times or replace with redundant relays
	BUS (XFMR)	WESTSIDE 138 kV	PVD	Reduce Zone 2 Clearing Times or replace with redundant relays
1	BUS N	WESTSIDE 138 kV	SBD	Reduce Zone 2 Clearing Times or replace with redundant relays
	BUS N	WESTSIDE 138 kV	SBD	Reduce Zone 2 Clearing Times or replace with redundant relays
	BUS N	WESTSIDE 138 kV	SBD	Reduce Zone 2 Clearing Times or replace with redundant relays
1	BUS S	WESTSIDE 138 kV	SBD	Reduce Zone 2 Clearing Times or replace with redundant relays
	BUS S	WESTSIDE 138 kV	SBD	Reduce Zone 2 Clearing Times or replace with redundant relays
	BUS S	WESTSIDE 138 kV	SBD	Reduce Zone 2 Clearing Times or replace with redundant relays
1	CAP 1	WESTSIDE 138 kV	SEL-487V	Add redundant relay
1	CAP 2	WESTSIDE 138 kV	SEL-487V	Add redundant relay
1	CAP 3	WESTSIDE 138 kV	SEL-487V	Add redundant relay

Footnote 13b. Communications (South) – None Required

Footnote 13c. DC Supply (South)

Substation	Single station DC Supply	Alarm for low voltage?	Alarm for open circuit?	CAP
Allen	Yes	Yes	no	Install new DC monitor
Alta	Yes	Yes	no	Install new DC monitor
Andrews	Yes	Yes	no	Install new DC monitor
Anthem	Yes	Yes	no	Install new DC monitor
Artesian	Yes	Yes	no	Install new DC monitor
Basic	Yes	Yes	no	Install new DC monitor
Bellagio	Yes	Yes	no	Install new DC monitor
Bicentennial	Yes	Yes	no	Install new DC monitor
Big Bend	Yes	Yes	no	Install new DC monitor
Bighorn	Yes	Yes	no	Install new DC monitor
Blade Runner	Yes	Yes	no	Install new DC monitor
Burnham	Yes	Yes	no	Install new DC monitor
Cabana	Yes	Yes	no	Install new DC monitor
Cactus	Yes	Yes	no	Install new DC monitor
Caesars Palace	Yes	Yes	no	Install new DC monitor
Camero	Yes	Yes	no	Install new DC monitor
Canyon	Yes	Yes	no	Install new DC monitor
Carey	Yes	Yes	no	Install new DC monitor
Charleston	Yes	Yes	no	Install new DC monitor
Cheyene	Yes	Yes	no	Install new DC monitor
City Of Henderson	Yes	Yes	no	Install new DC monitor
Clark Power Block 1	Yes	Yes	no	Install new DC monitor
Claymont	Yes	Yes	no	Install new DC monitor
Commerce	Yes	Yes	no	Install new DC monitor
Concourse	Yes	Yes	no	Install new DC monitor

Substation	Single station DC Supply	Alarm for low voltage?	Alarm for open circuit?	CAP
Craig	Yes	Yes	no	Install new DC monitor
Debuono	Yes	Yes	no	Install new DC monitor
Durango	Yes	Yes	no	Install new DC monitor
El Capitan	Yes	Yes	no	Install new DC monitor
Elkhorn	Yes	Yes	no	Install new DC monitor
Equestrian	Yes	Yes	no	Install new DC monitor
Excalibur	Yes	Yes	no	Install new DC monitor
Flamingo	Yes	Yes	no	Install new DC monitor
Ford	Yes	Yes	no	Install new DC monitor
Frias	Yes	Yes	no	Install new DC monitor
Garces	Yes	Yes	no	Install new DC monitor
Gas Pipeline	Yes	Yes	no	Install new DC monitor
Gilmore	Yes	Yes	no	Install new DC monitor
Grand Teton	Yes	Yes	no	Install new DC monitor
Green Valley	Yes	Yes	no	Install new DC monitor
Greenway	Yes	Yes	no	Install new DC monitor
Gypsum	Yes	Yes	no	Install new DC monitor
Haven	Yes	Yes	no	Install new DC monitor
Highland	Yes	Yes	no	Install new DC monitor
Hualapai	Yes	Yes	no	Install new DC monitor
Keehn	Yes	Yes	no	Install new DC monitor
Kidwell	Yes	Yes	no	Install new DC monitor
Lakes Las Vegas	Yes	Yes	no	Install new DC monitor
Larson	Yes	Yes	no	Install new DC monitor
Las Vegas Cogen	Yes	Yes	no	Install new DC monitor
Laughlin	Yes	Yes	no	Install new DC monitor
Leavitt	Yes	Yes	no	Install new DC monitor
Lewis	Yes	Yes	no	Install new DC monitor

Substation	Single station DC Supply	Alarm for low voltage?	Alarm for open circuit?	CAP
Lincoln	Yes	Yes	no	Install new DC monitor
Lindquist	Yes	Yes	no	Install new DC monitor
Lone Mountain	Yes	Yes	no	Install new DC monitor
Lynnwood	Yes	Yes	no	Install new DC monitor
Mayfair	Yes	Yes	no	Install new DC monitor
Michael Way	Yes	Yes	no	Install new DC monitor
Miller	Yes	Yes	no	Install new DC monitor
Mountains Edge	Yes	Yes	no	Install new DC monitor
MYS	Yes	Yes	no	Install new DC monitor
Nellis	Yes	Yes	no	Install new DC monitor
NSO	Yes	Yes	no	Install new DC monitor
North Las Vegas	Yes	Yes	no	Install new DC monitor
Oasis	Yes	Yes	no	Install new DC monitor
Oquendo	Yes	Yes	no	Install new DC monitor
Pabco	Yes	Yes	no	Install new DC monitor
Peace	Yes	Yes	no	Install new DC monitor
Pebble	Yes	Yes	no	Install new DC monitor
Polaris	Yes	Yes	no	Install new DC monitor
Procyon	Yes	Yes	no	Install new DC monitor
Quail	Yes	Yes	no	Install new DC monitor
Radar	Yes	Yes	no	Install new DC monitor
Railroad	Yes	Yes	no	Install new DC monitor
Redrock	Yes	Yes	no	Install new DC monitor
Regena	Yes	Yes	no	Install new DC monitor
Riley	Yes	Yes	no	Install new DC monitor
River Road	Yes	Yes	no	Install new DC monitor
Robindale	Yes	Yes	no	Install new DC monitor
Rochelle	Yes	Yes	no	Install new DC monitor

Substation	Single station DC Supply	Alarm for low voltage?	Alarm for open circuit?	CAP
Russell	Yes	Yes	no	Install new DC monitor
Sahara	Yes	Yes	no	Install new DC monitor
San Francisco	Yes	Yes	no	Install new DC monitor
Searchlight	Yes	Yes	no	Install new DC monitor
Shadow	Yes	Yes	no	Install new DC monitor
Sheep Mountain	Yes	Yes	no	Install new DC monitor
Skelton	Yes	Yes	no	Install new DC monitor
Sparta	Yes	Yes	no	Install new DC monitor
Speedway	Yes	Yes	no	Install new DC monitor
Spencer	Yes	Yes	no	Install new DC monitor
Strip	Yes	Yes	no	Install new DC monitor
Summerlin	Yes	Yes	no	Install new DC monitor
Sunpeak	Yes	Yes	no	Install new DC monitor
Sunrise	Yes	Yes	no	Install new DC monitor
Sunset	Yes	Yes	no	Install new DC monitor
Suzanne	Yes	Yes	no	Install new DC monitor
Swenson	Yes	Yes	no	Install new DC monitor
Tenaya	Yes	Yes	no	Install new DC monitor
Tomsik	yes	Yes	no	Install new DC monitor
Tonopah	Yes	Yes	no	Install new DC monitor
Tropical	Yes	Yes	no	Install new DC monitor
Truman	Yes	Yes	no	Install new DC monitor
Twin Buttes	Yes	Yes	no	Install new DC monitor
Vegas	Yes	Yes	no	Install new DC monitor
Venetian	Yes	Yes	no	Install new DC monitor
Village	Yes	Yes	no	Install new DC monitor
Warm Springs	Yes	Yes	no	Install new DC monitor
Washburn	Yes	Yes	no	Install new DC monitor

Substation	Single station DC Supply	Alarm for low voltage?	Alarm for open circuit?	CAP
Water Street	Yes	Yes	no	Install new DC monitor
Wigwam	Yes	Yes	no	Install new DC monitor
Wilson	Yes	Yes	no	Install new DC monitor

Footnote 13d. Control Circuitry (South)

Substation	Terminal	Element Name	CAP
Decatur 230kV	2303 line	TC	CAP is to move trips or BFR to TC2
Decatur 230kV	2305 line	TC	CAP is to move trips or BFR to TC2
Decatur 230kV	2306 line	TC	CAP is to move trips or BFR to TC2
Arden 138kV	3801 line	TC	CAP, replace breaker or wire in TC2
Pecos 138kV	138-12kV bus	87B/201-2	CAP dual 487B panel, relocate mod control to automation panel, upgrade automation panel if necessary
Pecos 138kV	3880 Cap Bank	50-51/280	CAP dual 351, partial bus diff panel
Pecos 138kV	3804 line	TC	CAP is to move trips or BFR to TC2
Pecos 138kV	3805 line	TC	CAP is to move trips or BFR to TC2
Pecos 138kV	3806 line	TC	CAP is to move trips or BFR to TC2
Pecos 138kV	3807 line	TC	CAP, replace breaker
Pecos 138kV	3808 line	TC	CAP, replace breaker
Pecos 138kV	3809 line	TC	CAP, replace breaker
Pecos 138kV	3810 line	TC	CAP is to move trips or BFR to TC2
Pecos 138kV	3813 line	TC	CAP is to move trips or BFR to TC2
Pecos 138kV	3814 line	TC	CAP is to move trips or BFR to TC2
Pecos 138kV	3815 line	TC	CAP is to move trips or BFR to TC2
Pecos 138kV	3817 line	TC	CAP is to move trips or BFR to TC2
Winterwood 138kV	3801 line	TC	CAP is use spare DC breakers for backup relays, replace breaker

Substation	Terminal	Element Name	CAP
Winterwood 138kV	3802 line	TC	CAP is use spare DC breakers for backup relays, replace breaker
Winterwood 138kV	3803 line	TC	CAP wire in BFR to TC2, split DC and have two breakers for each panel., double check there are available dc breaker positions
Winterwood 138kV	3804 line	TC	CAP is use spare DC breakers for backup relays, replace breaker
Winterwood 138kV	3805 line	TC	CAP is use spare DC breakers for backup relays, replace breaker
Winterwood 138kV	3806 line	TC	CAP wire in BFR to TC2, split DC and have two breakers for each panel., double check there are available dc breaker positions

#4002 Protection System Clearing Time Reduction

Summary:

Transient stability studies identified multiple contingencies that caused generators to go out of step, voltage dips at multiple busses or undamped oscillations due to long clearing times modelled in Transmission Planning's simulations. These identified issues can be mitigated by reducing the fault clearing time. This project requires multiples steps in order to determine the complete scope. The proposed project steps are outlined below:

- Review list of contingencies and clearing times with System Protection to determine if any modelled contingencies were modelled incorrectly. Any contingency with the modelled clearing time longer that the actual clearing time will be re-studied to determine if the actual lower clearing time would still cause any issues.
- A critical clearing time study will be performed by Transmission Planning for all contingencies identified in the transient stability study.
- System Protection will need to review the critical clearing times identified by Transmission Planning to determine the best course of action to meet the identified clearing times for each contingency. Actions may include:
    - Changing relay settings to trip within the required time
    - Replacement of electromechanical relays with microprocessor relays
    - Adding new communication aided tripping schemes

Project Status:

The clearing time reduction for the protection systems are performed on an as-needed basis depending on the results of the Transient Stability results. Projects are either initiated or relay settings changed as the correct scope for each contingency is identified.

Necessary, But Not NERC-Required

#1065 Mason Valley / Smith Valley 120kV Source

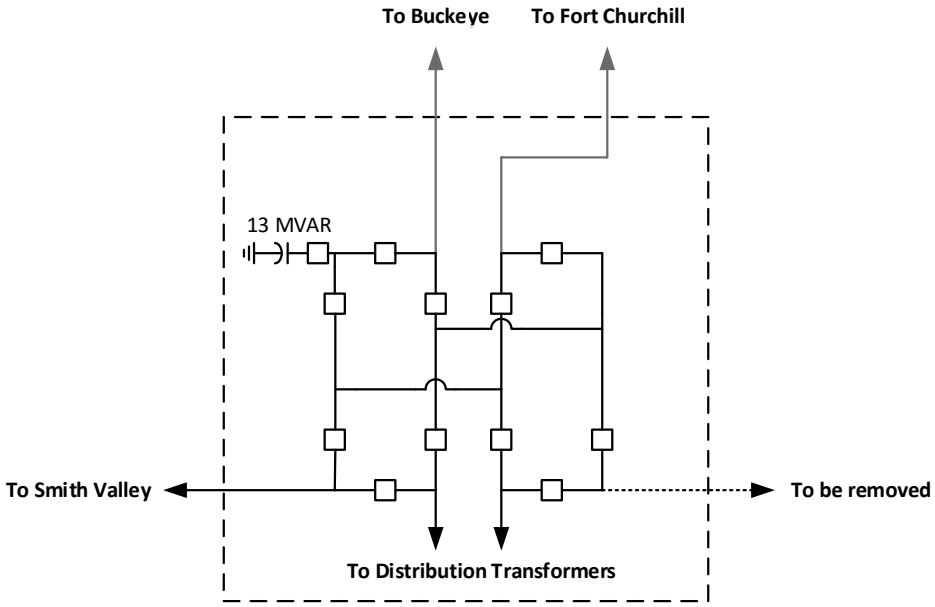
Summary:

Contingencies that isolate Mason Valley from Ft Churchill 120 kV significantly drops voltages in the Mason Valley and Smith Valley areas due to the disconnect of the 120 kV support provided by Fort Churchill. Proposed projects to add capacitor banks at Mason Valley and Smith Valley will help support the voltage in the area, but does not completely mitigate the voltage violations in the area. In order to completely mitigate the voltage violations, Mason Valley and Smith Valley substations must be converted to 120 kV.

Project Scope:

Mason Valley and Smith Valley substations are currently energized at 63 kV but both substations were built to 120 kV specifications. The transmission line between Smith Valley and Mason Valley was constructed to 120 kV specifications, along with the transmission lines for the first 2.5 miles leaving Mason Valley.

To fully convert Mason Valley and Smith Valley substations to 120 kV, the #124 Buckeye – Walker River line should be folded into Mason Valley. The line route can follow the existing #601 line between Mason Valley and Silver Springs (~6 miles). The Silver Springs terminal of the #601 line can be removed following the conversion of Mason Valley. To maintain a 63 kV tie back to Brunswick, the Mason Valley #638 line terminal and the #636 line terminal will be removed and those two lines will be connected ~2.5 miles North of Mason Valley creating a Buckeye – Fort Churchill 63 kV line



Mason Valley 60 kV

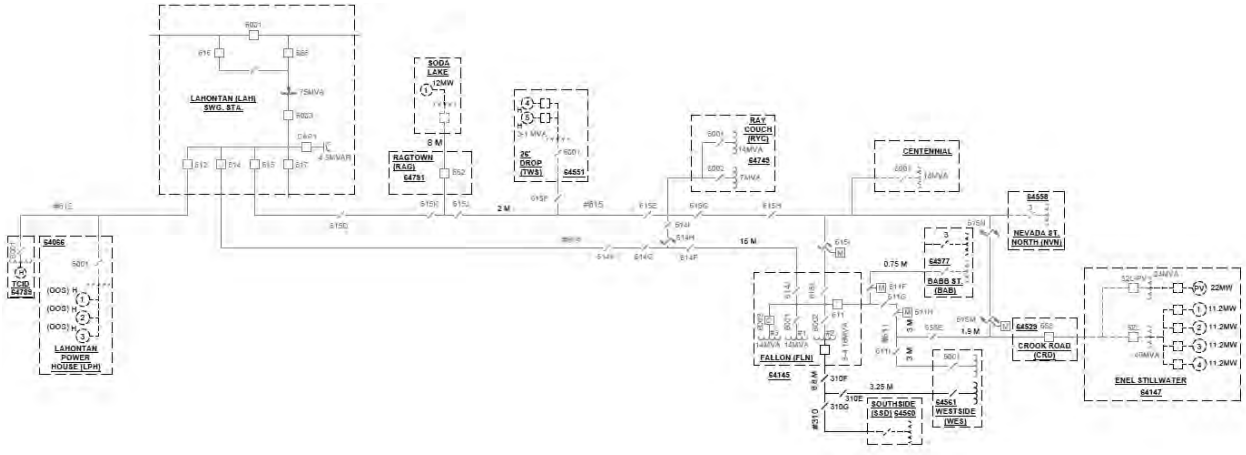

Remove #601 line back to Silver Springs
Mason Valley Wildlife Management Area
Proposed line route for #124 Line Fold
Ogden Drilling
Walker River Bowmen Archery Club
Walker River
Tie #636 and #638 lines together
Visualeyes Photography By Ashley Rae
ANACONDA
YERINGTON
Weed Heights
Dini's Lucky Club Casino
BRIDGE STREET
Yerington
Existing line built to 120 kV Specs
Night in the Country Music Festival
MASON VALLEY
MASON VALLEY
Image © 2025 Airbus
Google Earth

Appendix A

#1099 Fallon 120 kV Source

Summary:

Loss of the Eagle 120/63kV transformer, or Stillwater Generation, may cause the 63kV system voltage to drop below 90% in the Lahontan pocket, and around Eagle 63kV.



Project Scope:

To improve the voltage in the Fallon load pocket, two upgrades were identified.

Mitigation 1: Installation of a Mobile 18 MVAR staged capacitor bank at Fallon 63 kV substation

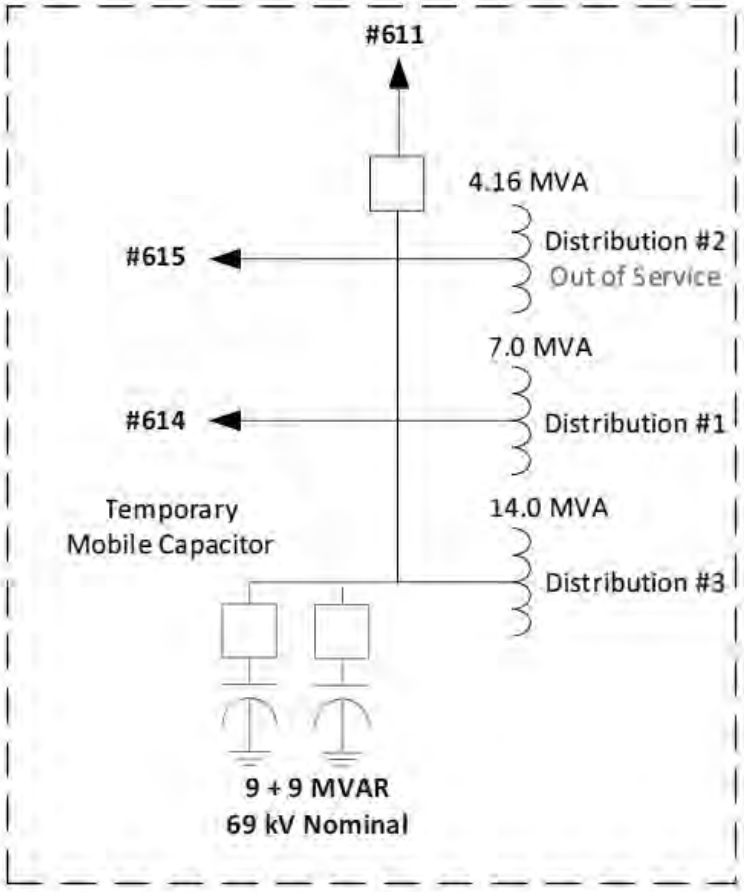
Mitigation 2: Construction of the Greenwave 120/63 kV substation to include one 24 MVAR switched capacitor bank at 120 kV, a 12 MVAR and 15 MVAR switched capacitor bank at 63 kV, one 75 MVA 120/63 kV transformer and a new Eagle – Greenwave 120 kV line.

Substation One Lines

NVEnergy	Fallon 63 kV Substation	11/14/2024

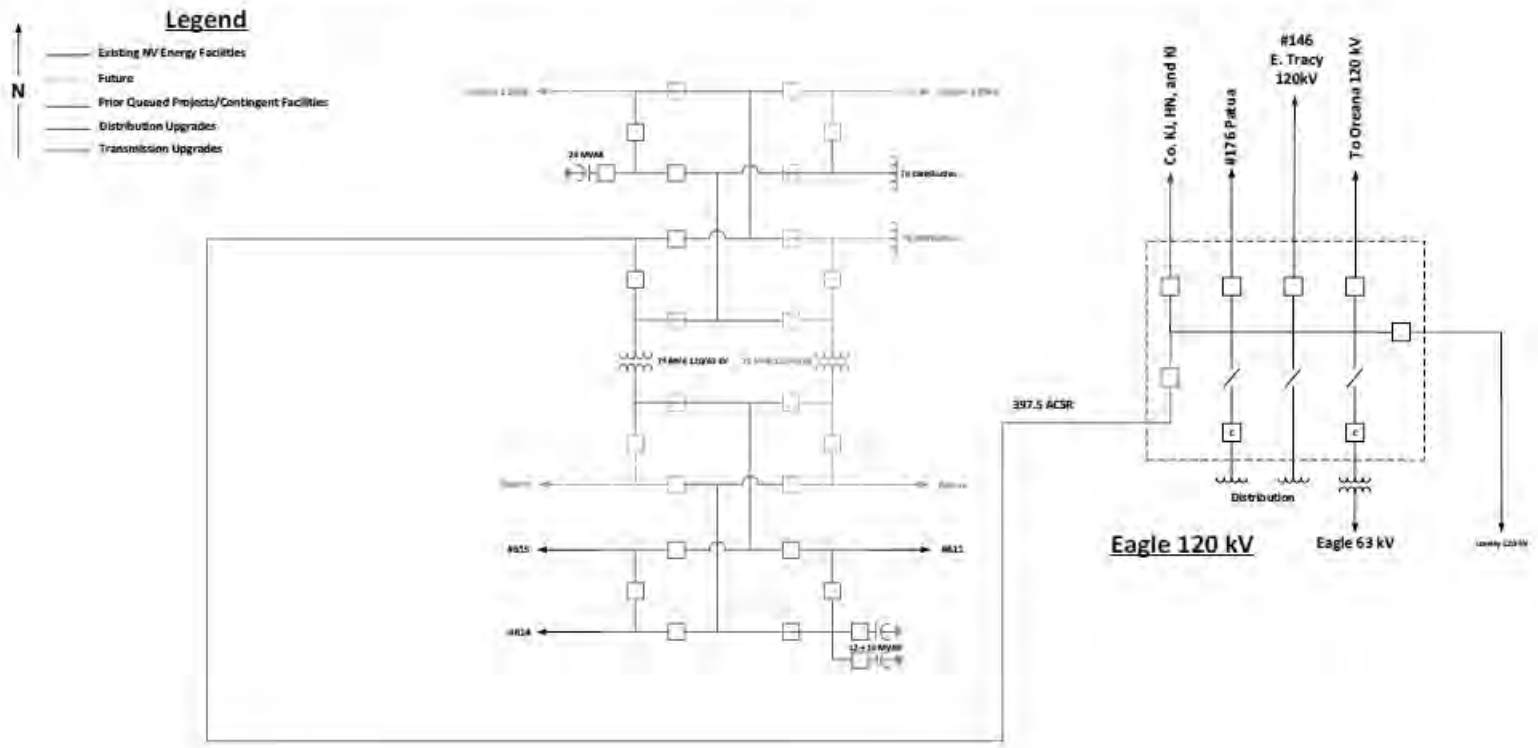
Legend

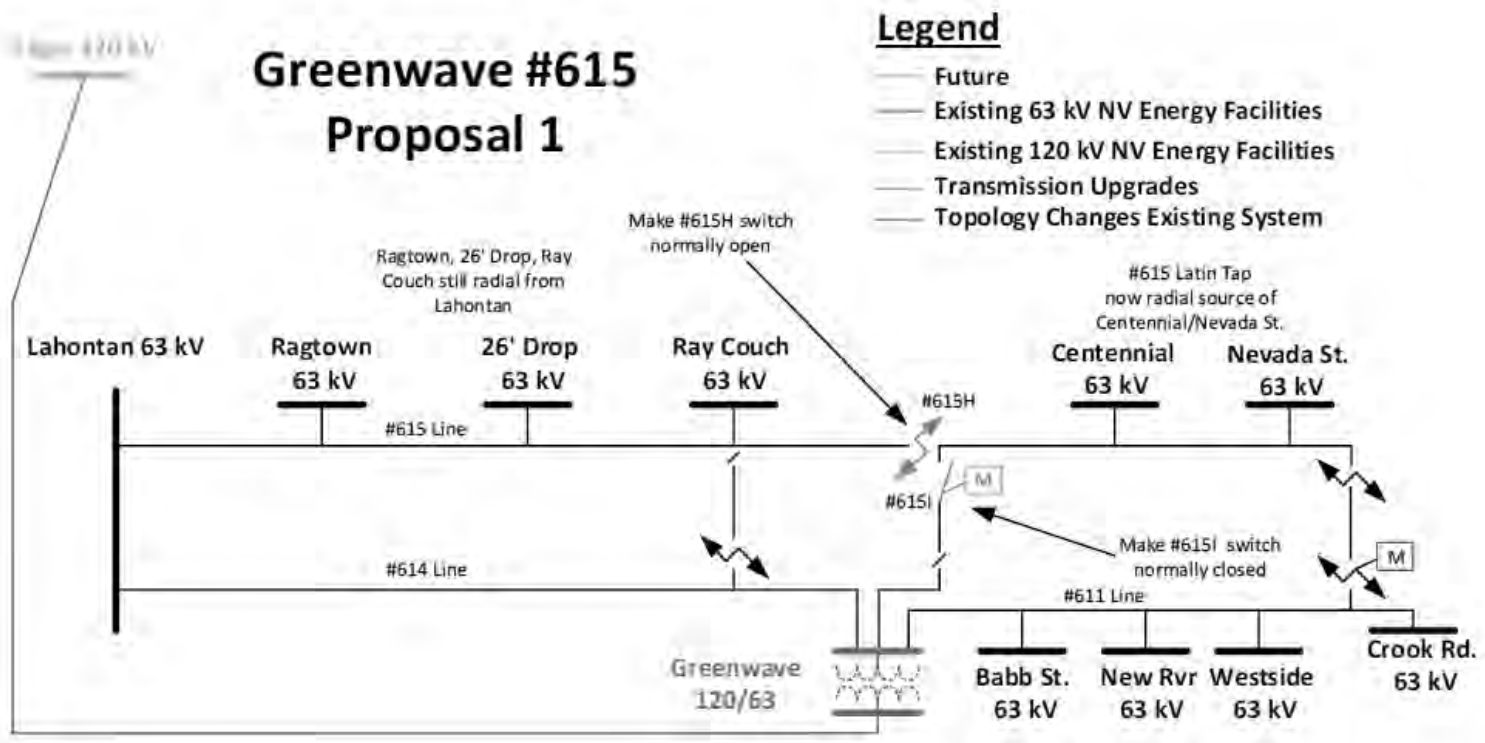
- Future
- Existing NV Energy Facilities
- Transmission Upgrades



Mitigation 1: Installation of Mobile Cap Bank at Fallon Substation

NVEnergy	Fallon OAP Eagle and Greenwave Substations	3/5/2025




Greenwave #615
Proposal 1
Legend
Future
Existing 63 kV NV Energy Facilities
Existing 120 kV NV Energy Facilities
Transmission Upgrades
Topology Changes Existing System
Make #615H switch normally open
Ragtown, 26' Drop, Ray Couch still radial from Lahontan
#615 Latin Tap now radial source of Centennial/Nevada St.
Lahontan 63 kV
Ragtown 63 kV
26' Drop 63 kV
Ray Couch 63 kV
Centennial 63 kV
Nevada St. 63 kV
#615H
#615 Line
#615I
M
Make #615I switch normally closed
#614 Line
#611 Line
Greenwave 120/63
Babb St. 63 kV
New Rvr 63 kV
Westside 63 kV
Crook Rd. 63 kV

NVEnergy

#1110 #670 Buckeye – Heybourne 63 kV Line Uprate

Summary:

There are multiple P1 and P4 events in the Carson load pocket that result in overloads of various 120 kV and 63 kV elements along with low voltage in the area. A P1 event either the Brunswick or Buckeye 120/60 kV Transformers, or various P4 and P6 events involving those transformers, can overload the underlying 60 kV system and lead to low voltage in the 60 kV system. These contingencies combined with planned load growth in the area, require multiple projects to mitigate all planned violations in the area. The Carson Valley Optimized Area Plan (OAP) was issued to address existing issues and also support planned load growth in the area.

Multiple projects were identified in the Carson Valley OAP. This scope includes:

- Buckeye Substation Rebuild (CAP #1076)
- Pinenut 120 kV Conversion (CAP #1121)
- Move Minden load to Muller and/or Buckeye substation
    - This is a distribution project that requires a second 120/12.5 kV transformer at Muller or a 120/12.5 kV transformer at the rebuilt Buckeye substation.
- Reconductor the #670 Buckeye – Heybourne 63 kV line

The addition of these projects will solve the immediate voltage and flow violations identified in the planning cases. The following projects were identified in the Carson Valley OAP as being needed as loads increase. The timing of these projects will be identified in the annual Transmission Planning Assessment depending on the load values

- Install a second 20 MVAR 120 kV Capacitor Bank at Brunswick
- Install a second 20 MVAR 120 kV Capacitor Bank at Buckeye
- Install a 20 MVAR 120 kV Capacitor Bank at Overland
- Reconductor the #109 Overland – Overland Tap to 954 ACSR

Project Scope:

To mitigate this problem, the 2/0 ACSR and 4/0 ACSR conductor on the #670 Buckeye – Heybourne 63 kV line should be reconductored with 795 ACSR conductor, approximately 8.29 miles. All substation equipment at Heybourne is rated appropriately. No equipment will need to be replaced at those locations. The breaker jumpers and disconnect switches for the Buckeye 670 will need to be confirmed and updated as needed to the correct rating.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle
N	63	HVD	No		#670	1	Heybourne / Minden Tap	3.51	QUAIL	2 / 0	ACSR	1
N	63	HVD	No		#670	2	Heybourne / Minden Tap	0.23		1750	AAC,UG	1
N	63	HVD	No		#670	3	Heybourne / Minden Tap	2.44	QUAIL	2 / 0	ACSR	1
N	63	HVD	No		#670	4	Minden Tap / Buckeye	2.31	PENGUIN	4 / 0	ACSR	1
N	63	HVD	No		#670	5	Minden Tap / Buckeye	0.73	ARBUTUS	795	AAC	1
N	63	HVD	No		#670	6	Minden Tap / Buckeye	0.03	PENGUIN	4 / 0	ACSR	1

NVEnergy

Appendix A

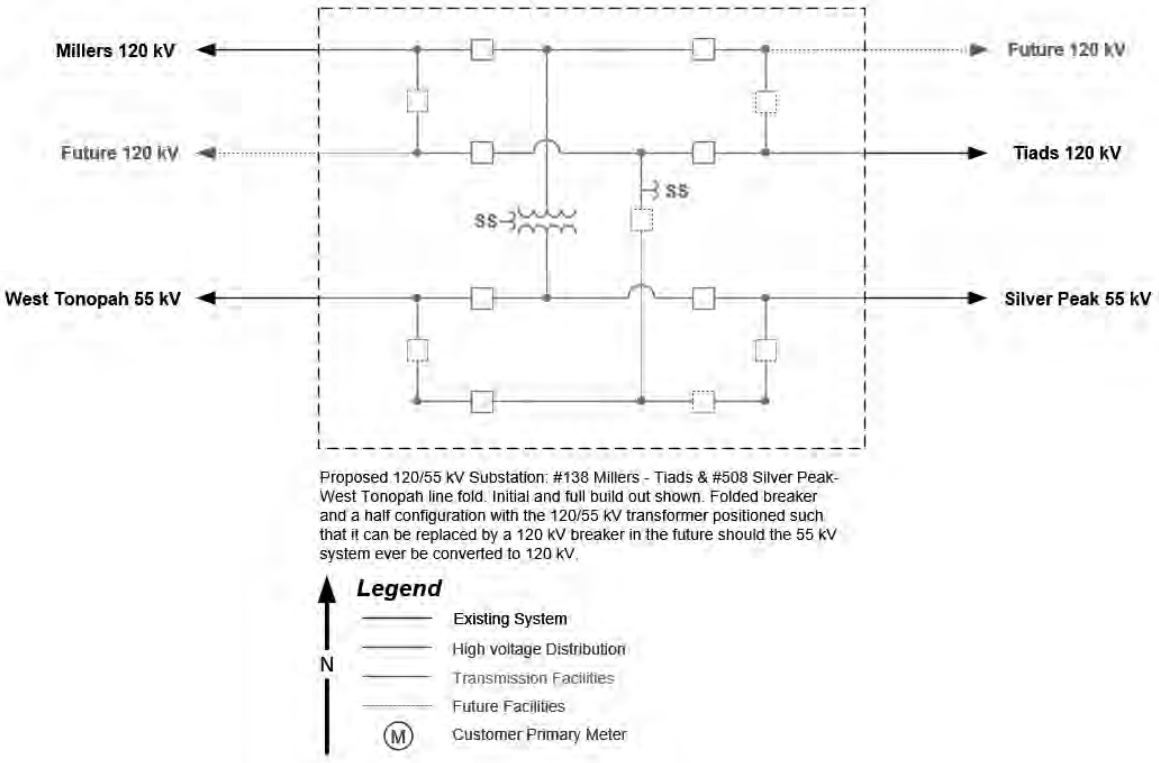
#1112 Tonopah 120/60 kV Transformer addition

Summary:

Loss of the Silver Peak #501 or #502 lines during summer peak can cause overloads of the Millers 120/55 kV transformer as well as low voltage in the Tonopah area.

Project Scope:

A new 120 kV transformer is required in the Tonopah load pocket in order to mitigate low voltages in the Tonopah area. The #138 Millers – Tiads 120 kV line and the #508 Silver Peak – West Tonopah 57.5 kV line will both be folded into a new Siebert substation with will also include a 120/57.5 kV transformer.



Proposed 120/55 kV Substation: #138 Millers - Tiads & #508 Silver Peak-West Tonopah line fold. Initial and full build out shown. Folded breaker and a half configuration with the 120/55 kV transformer positioned such that it can be replaced by a 120 kV breaker in the future should the 55 kV system ever be converted to 120 kV.

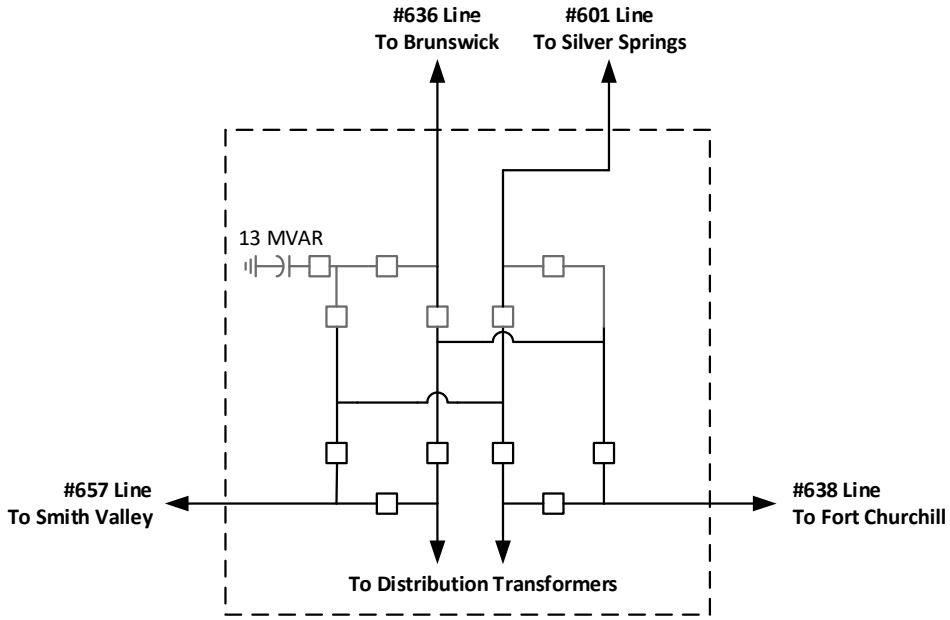
#1119 Addition of Cap Banks at Mason Valley/Smith Valley.

Summary:

Contingencies that isolate Mason Valley from Ft Churchill 120 kV significantly drops voltages in the Mason Valley and Smith Valley areas due to the disconnect of the 120 kV support provided by Fort Churchill.

Project Scope:

To help with low voltages, it is recommended that a 13 MVAr capacitor bank be installed at Mason Valley. The addition of the capacitor bank will require Mason Valley to be converted to a breaker and a half configuration. This will require the addition of six new breakers. A 3.6 MVAr capacitor bank may also be required at Smith Valley. This capacitor bank is dependent on the timing of CAP #1065 – Mason Valley / Smith Valley 120 kV conversion.



Mason Valley 60 kV

NVEnergy

#2068 Arden - Oquendo 69kV Uprate

Summary:

A P6 event (N-1-1) consisting of the Decatur – Oquendo 69 kV line and either the Flamingo – MGM 69 kV line or the Excalibur – MGM 69 kV line, will overload the Arden – Oquendo 69 kV line by as much as 220% of the current line rating. The voltage at Oquendo, Flamingo and the MGM can also drop to 0.78 pu voltage during this same contingency.

The Excalibur – MGM 69 kV line and the Flamingo – MGM 69 kV line both consist of underground cable. Failure of a cable on either of these lines can result in a long outage until the cable is replaced. While this cable is out, a P1 of the Decatur – Oquendo 69 kV line will produce the overloads and voltage violations listed above. Load shedding is allowed but will require shedding load on the Las Vegas Strip. This is not a viable mitigation due to the very long duration of underground line outages.

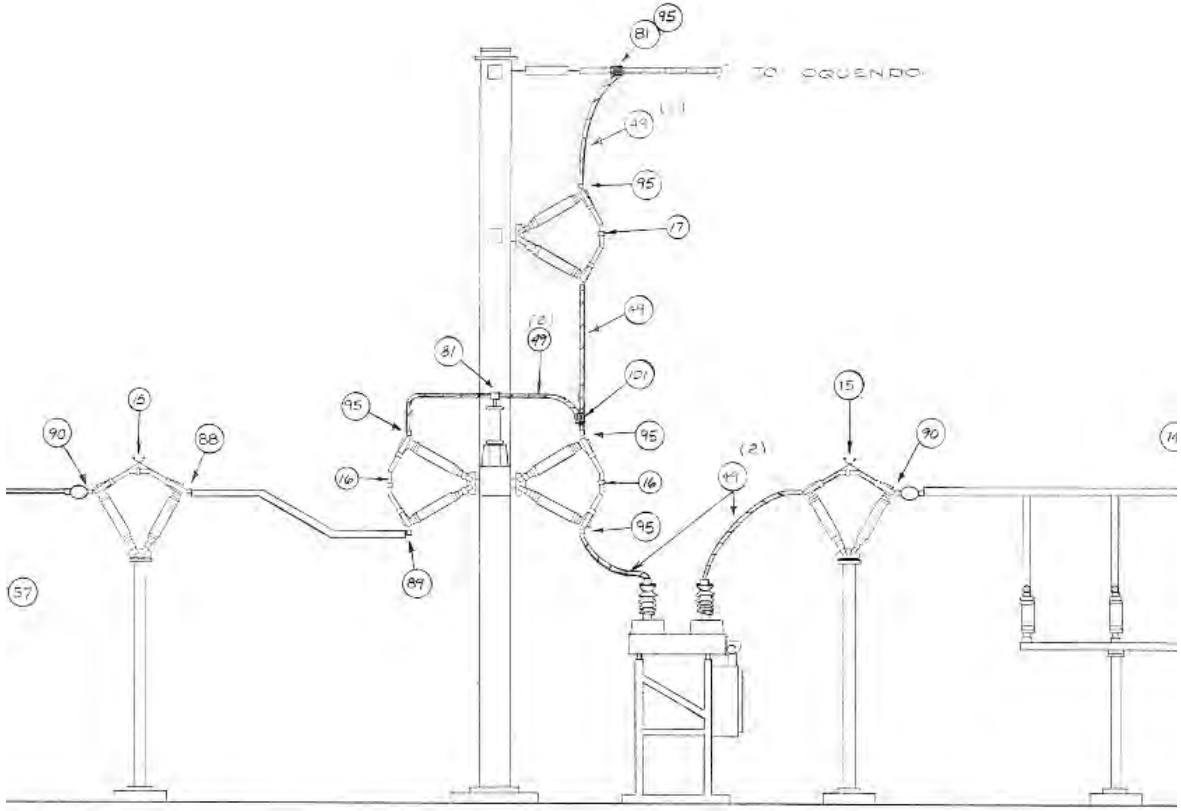
Project Scope:

The Arden – Oquendo 69 kV line should be reconductored with 1026 ACCC conductor, approximately 7.41 miles. At Arden, the line drops will need to be replaced with 2-954 AAC conductor to match the line conductor and the 6901-02L disconnect switch will need to be replaced with a 2000 A switch. At Oquendo, the line drops, breaker jumpers and jumpers to the main bus will need to be replaced with 2-954 AAC conductor to match the line rating. The breaker disconnect switches will need to be replaced with a 2000 A switch.

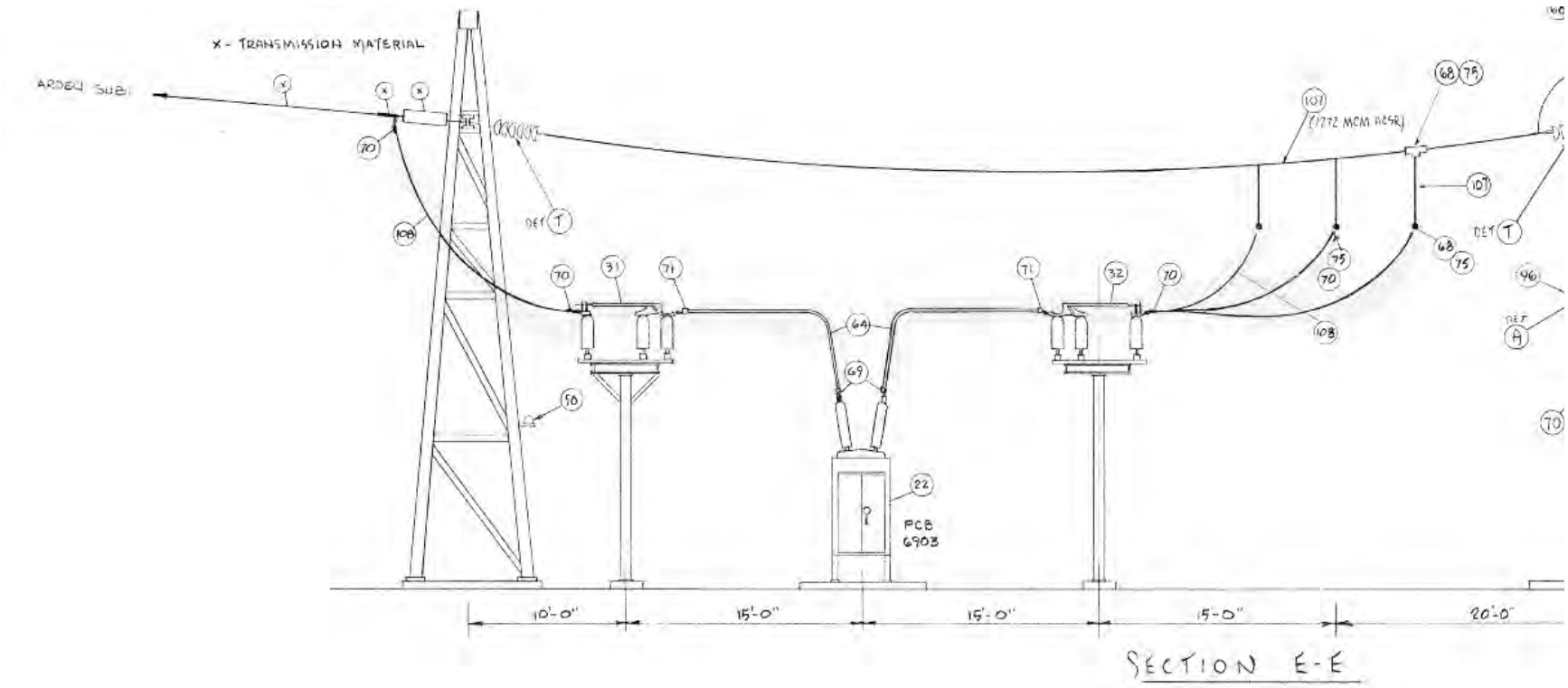
A second 24 MVAR capacitor bank will be required at Oquendo to mitigate the low voltage violations.

Regio	kV	FERC Class, Order 888	Non-NVE	Short Line ID	Sec ID	Line	Region 1	Region 2	Old NEVP Nam	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°	Conductor MOT (°F)
S	69	T		AD-OQ-69-1	1	Arden - Oquendo	Las Vegas		Arden - (	7.41	LINNET	336	ACSR	1	212	250	212

All conductor on the Arden – Oquendo 69 kV line needs to be replaced with 1026 ACCC conductor.

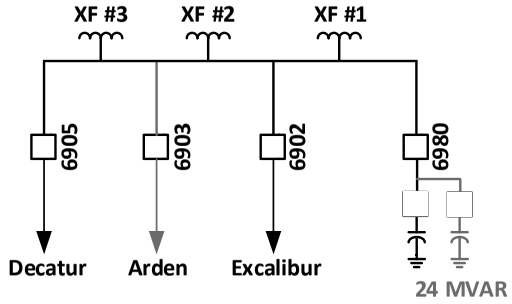


Arden line terminal. 954 AAC conductor in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The 6901-02L disconnect switch needs to be replaced with a 2000 A switch.



Oquendo line terminal. Line drops and breaker jumpers in the substation needs to be replaced with 2-954 AAC or equivalent to match new line rating. The 6903 breaker disconnect switches needs to be replaced with a 2000 A switch.

NVEnergy	Oquendo 69kV Substation	4/10/2025



Line drop, jumpers, and switches to be replaced with 2,000A equipment

NVEnergy

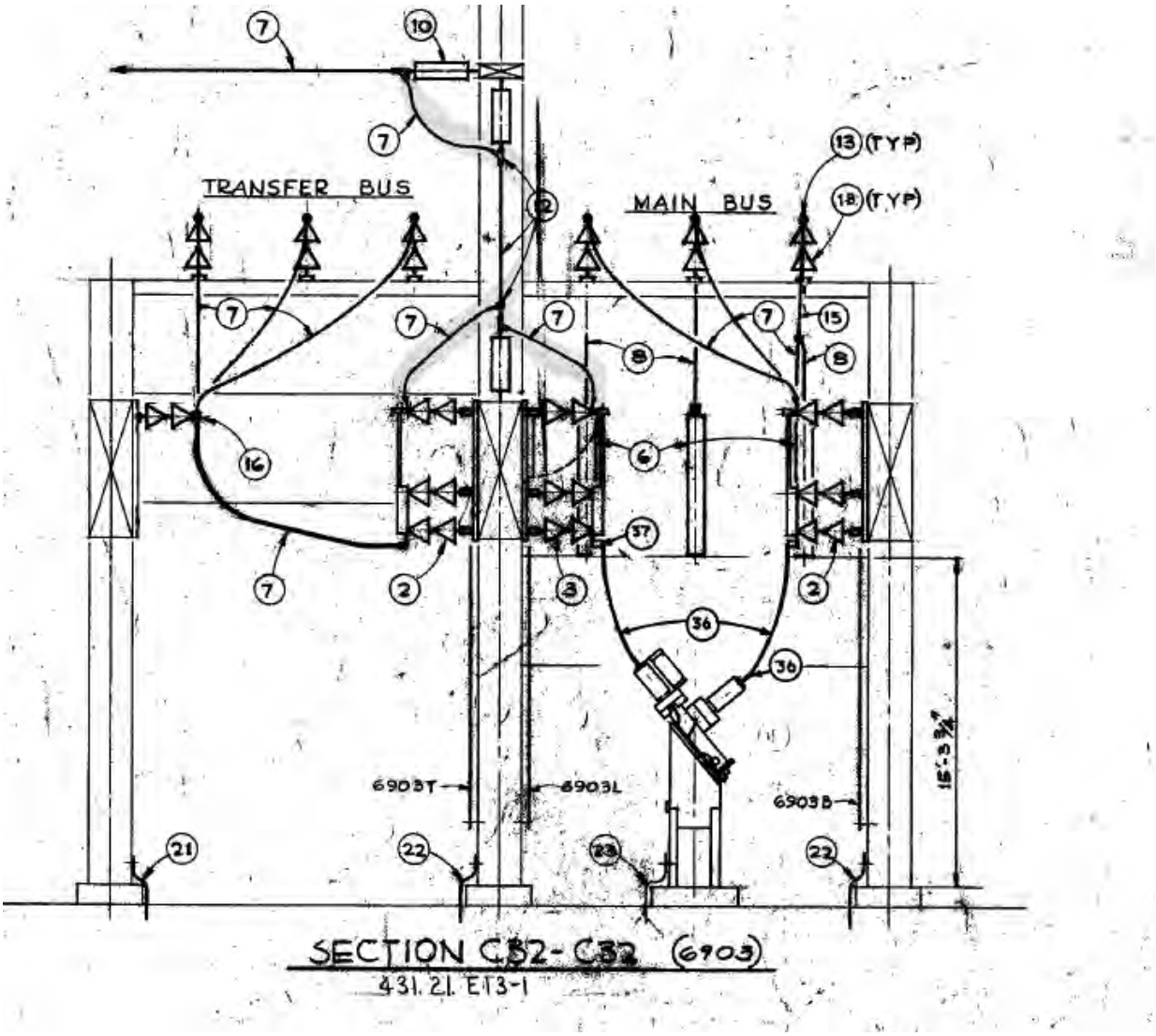
#2079 Mayfair – San Francisco 69 kV line Uprate

Summary:

Multiple P4 and P6 contingencies involving the loss of both 230kV sources to Clark and Equestrian 69kV, or any contingency involving the P2 at the Clark – Hacienda - Lamb - Pearl - San Francisco line (Open at Clark) causes an overload at the Mayfair – San Francisco line up to 15%.

Project Scope:

The Mayfair – San Francisco 69 kV line should be reconductored with 954 ACSR conductor, approximately 1.35 miles.



Mayfair line terminal. The line drops in the substation need to be confirmed and replaced with 954 AAC to match the line conductor if necessary.

No updates are necessary at San Francisco substation.

#2082 Mayfair 69 kV Line Drop Replacement

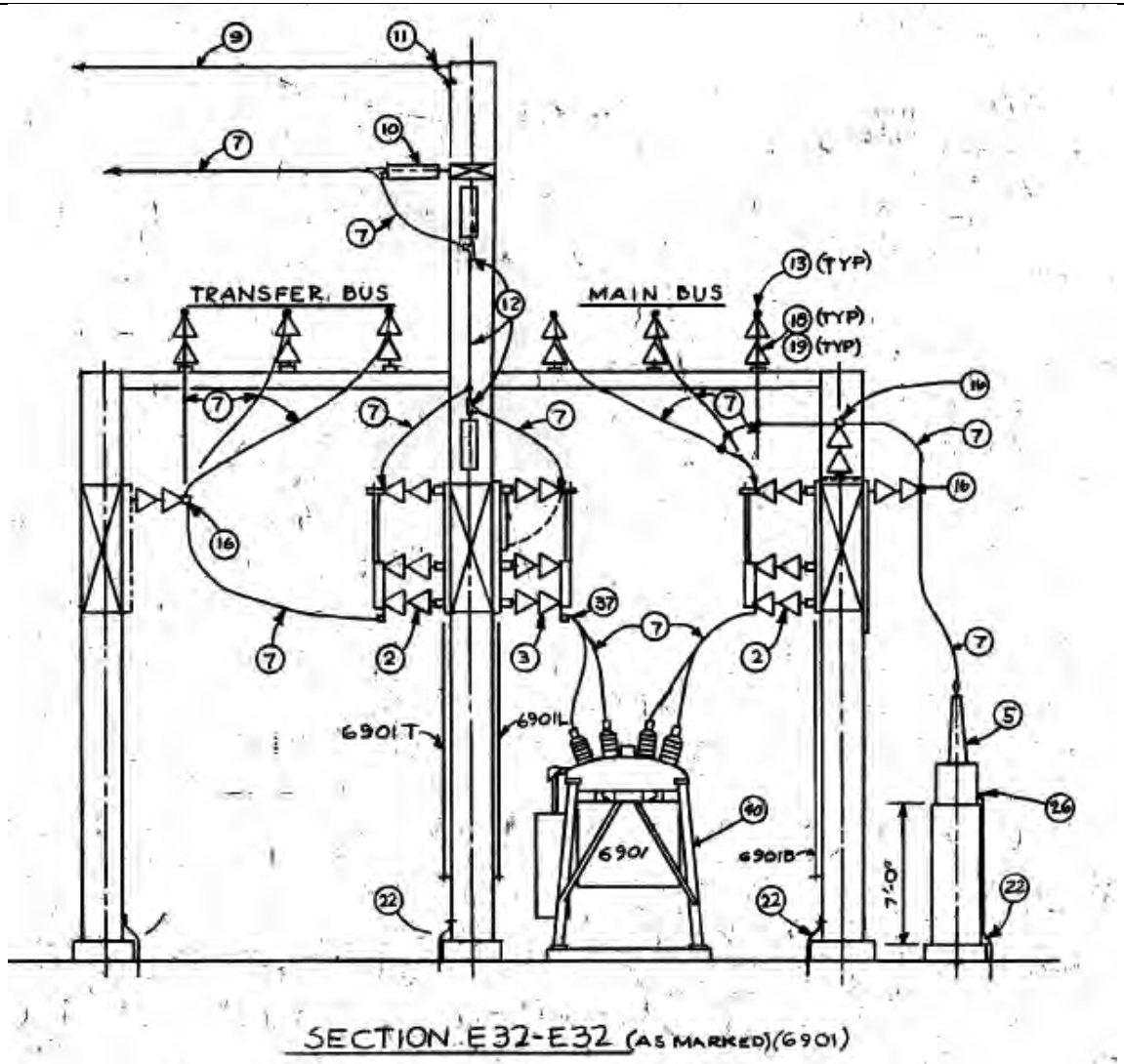
Summary:

A P6 contingency involving the loss of the Artesian – Winterwood and the Pecos – Lincoln line causes a loss of a 138 kV source to Artisan and Lincoln. This causes the underlying 69 kV system to feed Artisan, making an overload at the Garces – Mayfair line up to 10%. A P6 contingency involving the Clark – San Francisco and San Francisco – Winterwood 69 kV lines can overload the Artesian – Mayfair 69 kV line by up to 119% of its rating

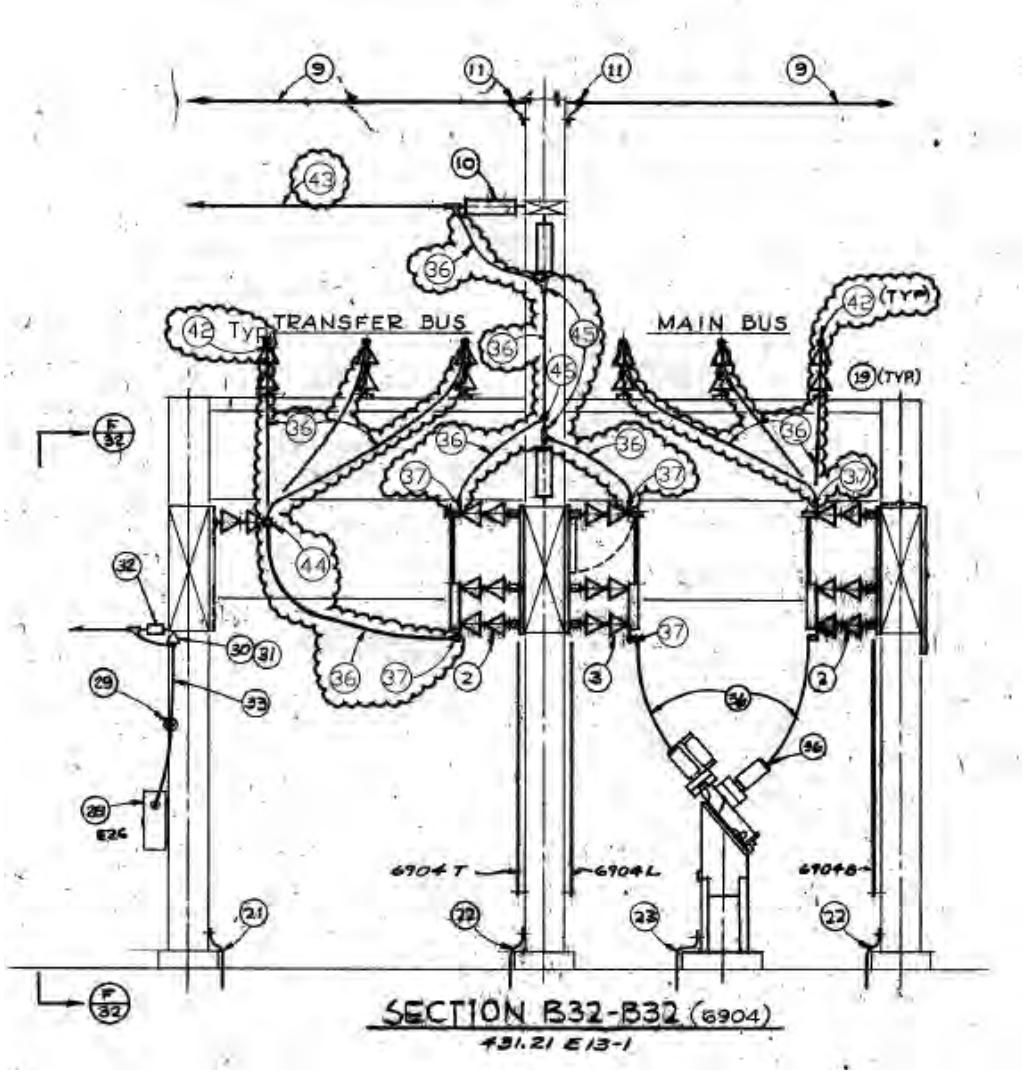
Project Scope:

The Artesian – Mayfair 69 kV line is limited by the line drops at Mayfair. The line drops are 636 ACSR while the rest of the line is using 954 ACSR. Replacing the line drops at Mayfair on the Artesian – Mayfair 69 kV line will increase the rating to the line conductor and mitigate the overload

The Garces – Mayfair 69 kV line is limited by the line drops at Mayfair and the Mayfair 6904 breaker jumpers. The line drops and jumpers are using 954 AAC while the rest of the line is using 954 ACSS. Replacing the line drops and jumpers at Mayfair will increase the line rating to 1200 A (limited to the disconnect switches at Mayfair and Garces which will increase the line rating enough to mitigate the overload.



Mayfair 6901 breaker. The line drops were field verified to be 636 AAC or ACSR. The highlighted sections need to be replaced with 954 AAC conductor to match the line



Mayfair 6904 breaker. The line drops and breaker jumpers were field verified to be 954 AAC. The highlighted sections need to be replaced with 2-954 AAC conductor to match the line.

#2084 San Francisco 6905 breaker replacement

Summary:

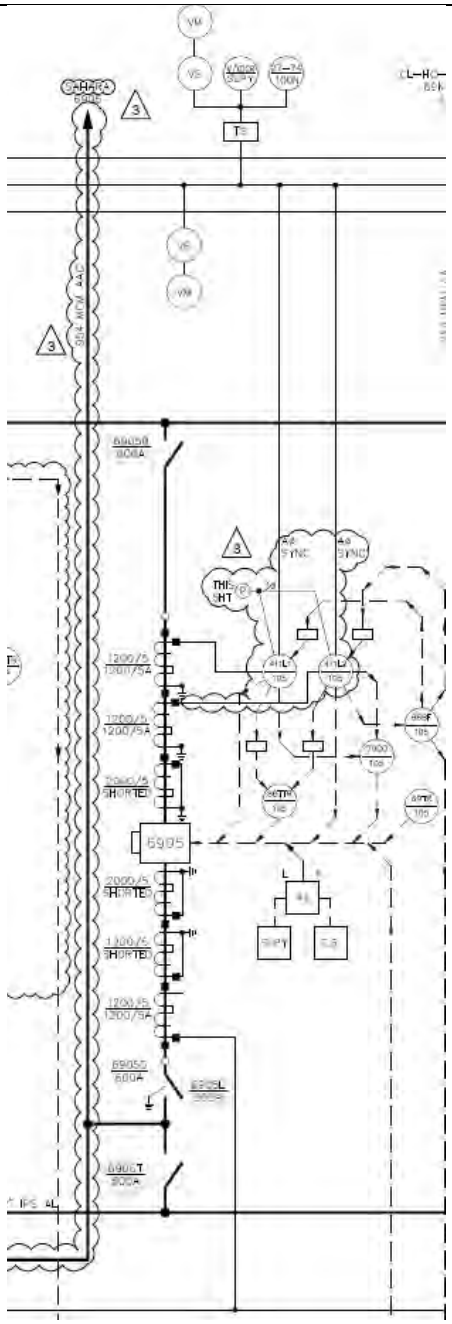
A P1 event consisting of the Sahara – Winterwood 69kV line will cause the Sahara – San Francisco 69 kV line to exceed its current rating by 101% in 2028.

Project Scope:

The San Francisco 6905T, 6905L, and 6905B disconnect switches should be replaced with 2000A rated switches. The SF 6905 breaker jumpers should be replaced with 2-954 AAC jumpers to match the higher rated switches and the breaker rating. The line drop at San Francisco should be replaced with 1-954AAC to match the line conductor.

NVEnergy

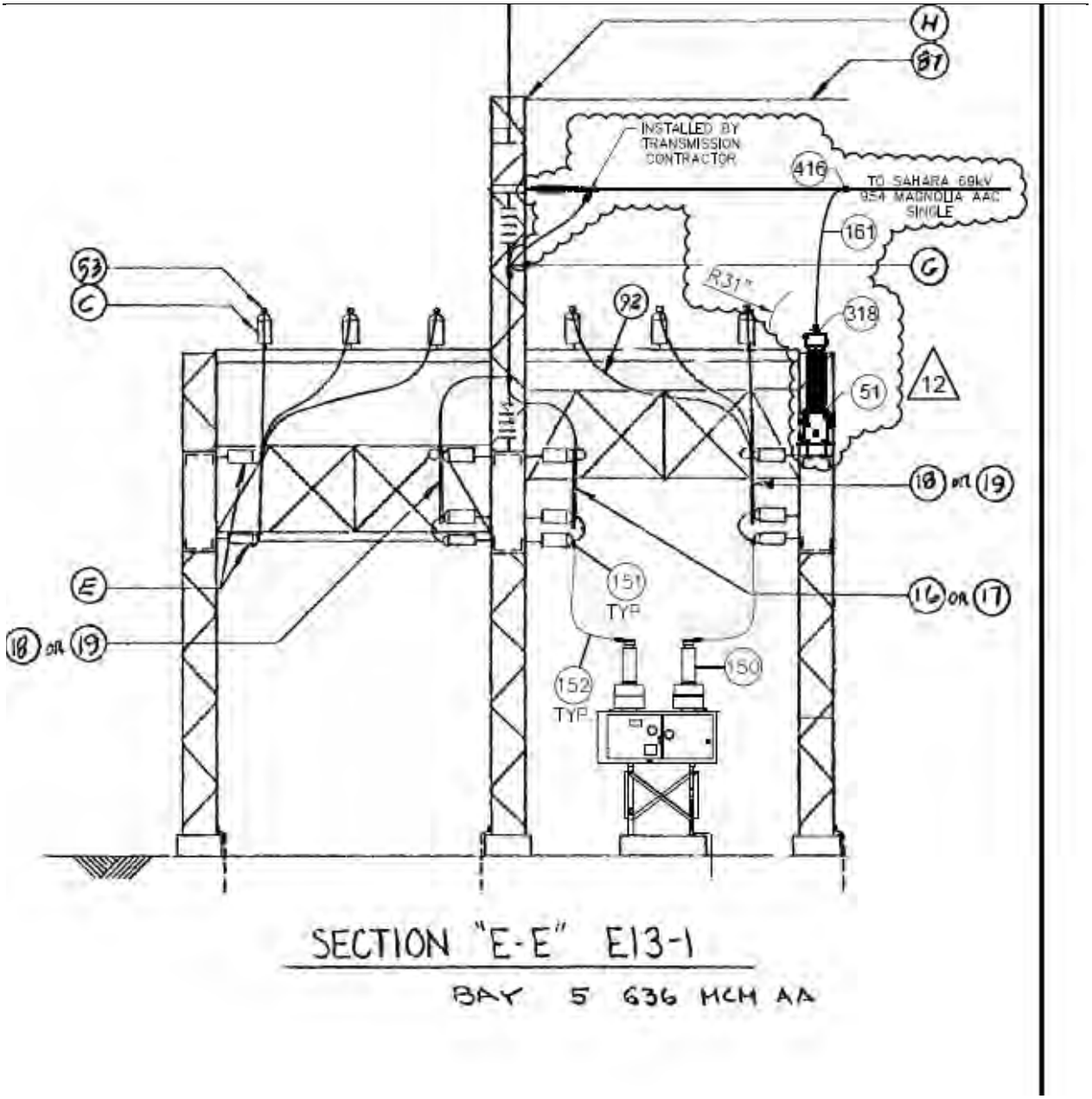
Appendix A



San Francisco 6905 one line. Disconnect switches should be replaced with a minimum rating of 1200A.e

NVEnergy

Appendix A



San Francisco 6905 plan view. The line drops and breaker jumpers should be replaced with 2-954 AAC.

#2086 Miller – North Las Vegas 69 kV Uprate

Summary:

A P1 event consisting of the Lincoln – Artesian 138 kV line and the Pecos – Lincoln 138 kV line will cause the Miller – North Las Vegas 69 kV line to exceed its current rating by 101% starting in 2024 and as high as 106% by 2028.

The current rating will exceed by up to 118% by 2033 for a P4 event consisting of breaker failures of Lincoln #3801 and #3802, or the Pecos #3805 and #3806.

A P6 event consisting of Artesian – Winterwood 138 kV followed by Pecos – Lincoln 138 kV, Basic – Boulder City – Mead 230 kV line followed by Equestrian 230/69 kV transformer outage, Clark East – Basic B 230 kV line followed by Equestrian 230/69 kV transformer outage, and Clark Power Block 1 causes the Miller – North Las Vegas 69 kV line to exceed its current rating by up to 130% from 2024 to 2033.

Project Scope:

The NLV – Millers 69 kV line has a LiDAR MOT value of 225 deg F. The clearance violations on the line will need to be mitigated to increase the MOT to 392 deg F. This will increase the line rating to 1792 Amps.

The line drops at both Miller and North Las Vegas need to be confirmed as well. If the line drops are 954 AAC, then they will need to be replaced with 2-954 AAC conductor

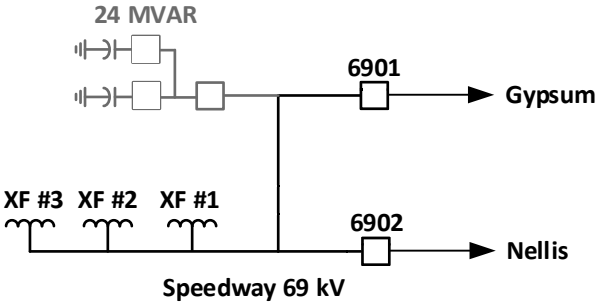
#2100 Speedway and Gypsum Capacitor Bank Additions

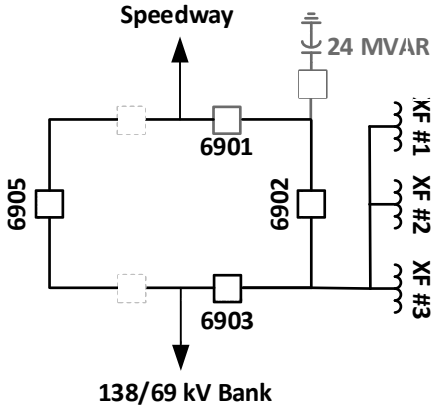
Summary:

Multiple P1 events including the loss of the Nellis – Carey 69 kV line, the Pecos – Gypsum 138 kV line, and the Gypsum 138/69 kV Bank, and P4 events that involve the loss of the above elements can cause low voltage in the 69 kV system. These contingencies can lead to voltage as low as 0.84 pu by 2026 and 0.776 pu by 2030.

Project Scope:

To help with low voltages, two 24 MVAR capacitor banks should be installed at Speedway substation and one 24 MVAR capacitor bank is required at Gypsum substation.





Gypsum
69 kV

#2101 Goat 230/69 kV Substation and Goat – Speedway 69 kV Line Uprate

Summary:

Multiple P1 events including the loss of the Nellis – Carey 69 kV line, the Pecos – Gypsum 138 kV line, and the Gypsum 138/69 kV Bank, and P4 events that involve the loss of the above elements can cause The Nellis – Carey 69 kV line, the Nellis – Speedway 69 kV line, and the Gypsum – Speedway line. A second 69 kV source is required in the area to mitigate contingencies tripping one of the existing sources to that 69 kV load pocket.

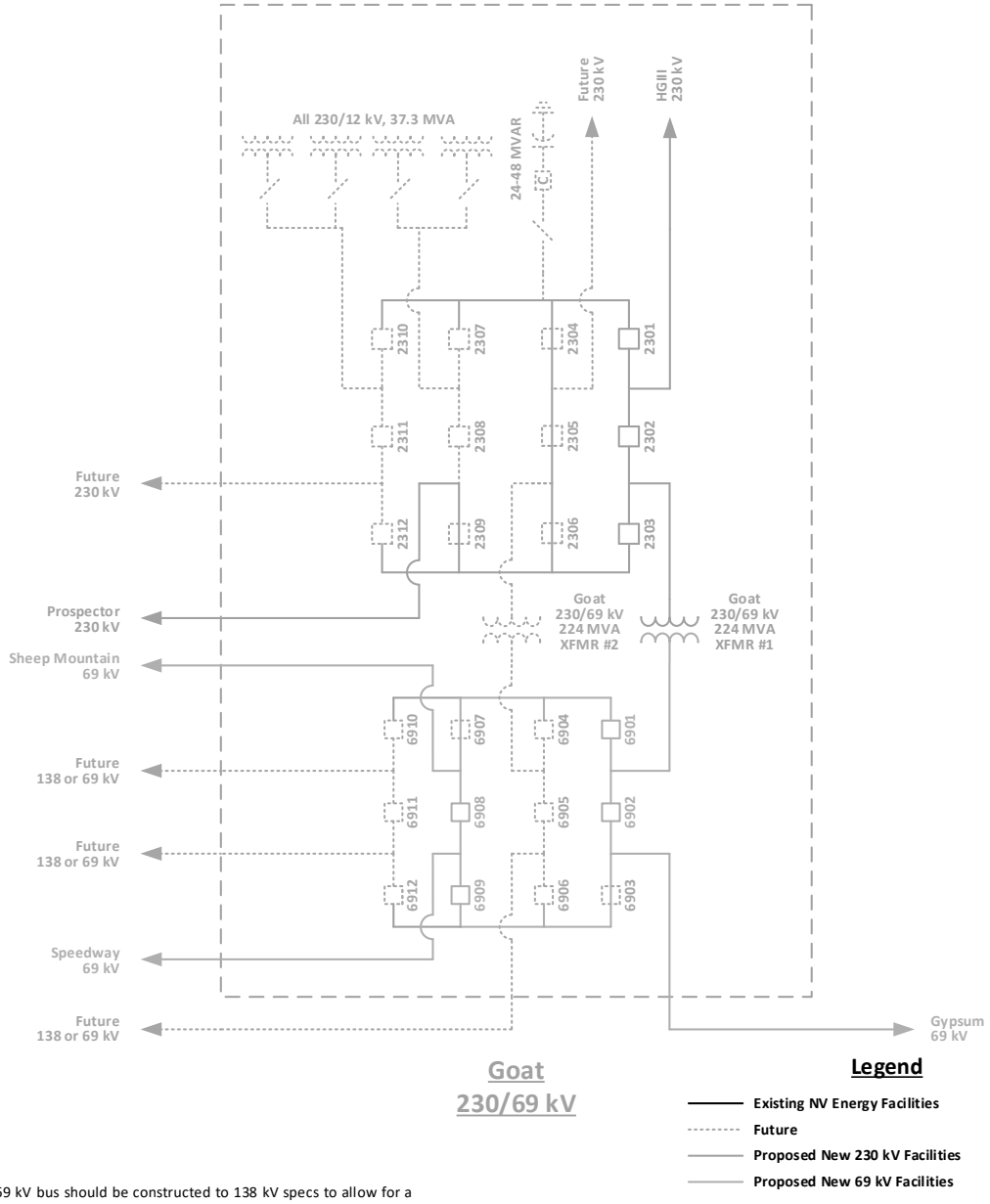
Project Scope:

To mitigate these overloads and add a new source in the area, the Goat 230 kV substation will be required. The original plan for Goat was to convert the 69 kV system to 138 kV and install a 230/138 kV transformer at Goat. Until that system can be fully converted, a 230/69 kV transformer should be installed to support the area. All components of Goat substation should be constructed to 138 kV specs to support the conversion at a later date. After the addition of the Goat 230/69 kV substation, the Goat – Speedway 69 kV line can exceed its ratings for certain contingencies. This line should be reconductored with 1026 ACCC, approximately 6.44 miles. The line drops at Speedway will need to be replaced with 2-954 AAC conductor to match the line conductor.

NVEnergy

Appendix A

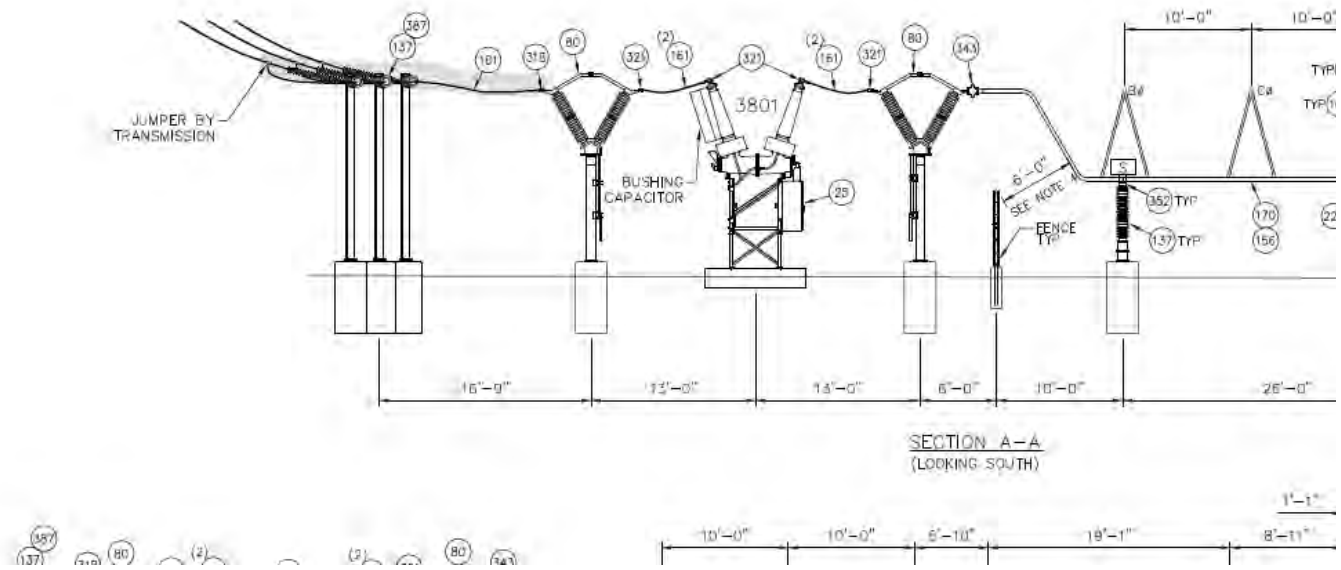
NVEnergy	Goat 230/138/12 kV	12/17/2025



Note:
1. The 69 kV bus should be constructed to 138 kV specs to allow for a conversion of the 69 kV lines at a later date.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F	Conductor MOT (°F)
S	69	T	No		GYP-SMS-SPD-69-1	3	Gypsum Tap - Speedway	6.44	CARDINAL	954	ACSR	1			212

All conductor on the Goat – Speedway 69 kV line needs to be replaced with 1026 ACCC conductor (~6.44 miles).



Speedway line terminal. Line drop in the substation needs to be replaced with 2-954 AAC or equivalent to match the new line rating.

#2108 Lake Las Vegas – Mead 69 kV Line Uprate

Summary:

A P1 event of the Equestrian – Lake Las Vegas 69 kV line, the Equestrian 230/69 kV Transformer or a P4 event (breaker fail) at Equestrian that trips those elements will overload the Lake Las Vegas – Mead 69 kV line by as much as 103.4 % of the current line rating by 2030 and 168.9% by 2035.

Project Scope:

To mitigate this problem, the Lake Las Vegas – Mead 69 kV line should be reconductored with 954 ACSR conductor, approximately 16.71 miles. All substation equipment at both Mead and Lake Las Vegas are rated appropriately. No equipment will need to be replaced at those locations.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F	Conductor MOT (°F)
S	69	T	No		LLV-MD-69-1	1	Lake Las Vegas - X20430	1.99	CARDINAL	954	ACSR	1		212	212
S	69	T	No		LLV-MD-69-1	2	X20430 - Mead	16.71	CU4/0AWG-7	4 / 0	CU	1	167		167

All 4/0 copper conductor on the Lake Las Vegas – Mead 69 kV line needs to be replaced with 954 ACSR conductor.

#2109 Equestrian – Lake Las Vegas 69 kV Line Uprate

Summary:

A P1 event of the Lake Las Vegas – Mead 69 kV line, or a P4 event (breaker fail) at Equestrian or Mead that trips those elements will overload the Equestrian – Lake Las Vegas 69 kV line by as much as 105.2 % of the current line rating by 2030 and 153.5% by 2035.

Project Scope:

To mitigate this problem, the 4/0 copper conductor on the Equestrian – Lake Las Vegas 69 kV line should be reconductored with 954 ACSR conductor, approximately 0.17 miles. All substation equipment at both Equestrian and Lake Las Vegas are rated appropriately. No equipment will need to be replaced at those locations.

Regio	kV	FERC Class, Order 888	BES	Non-NVE	Short Line ID	Sec ID	Line	Length (Miles)	Ratekit Name	KCM or AW	Type	No. in Bundle	DOT (°F)	LiDAR MOT (°F	Conductor MOT (°F)
S	69	T	No		EQU-LLV-69-1	1	Equestrian - X24368	2.46	CARDINAL	954	ACSR	1			212
S	69	T	No		EQU-LLV-69-1	2	X20430 - X24368	0.17	CU4/0AWG-7	4 / 0	CU	1		167	167
S	69	T	No		EQU-LLV-69-1	3	X20430 - Lake Las Vegas	2.04	CARDINAL	954	ACSR	1			212

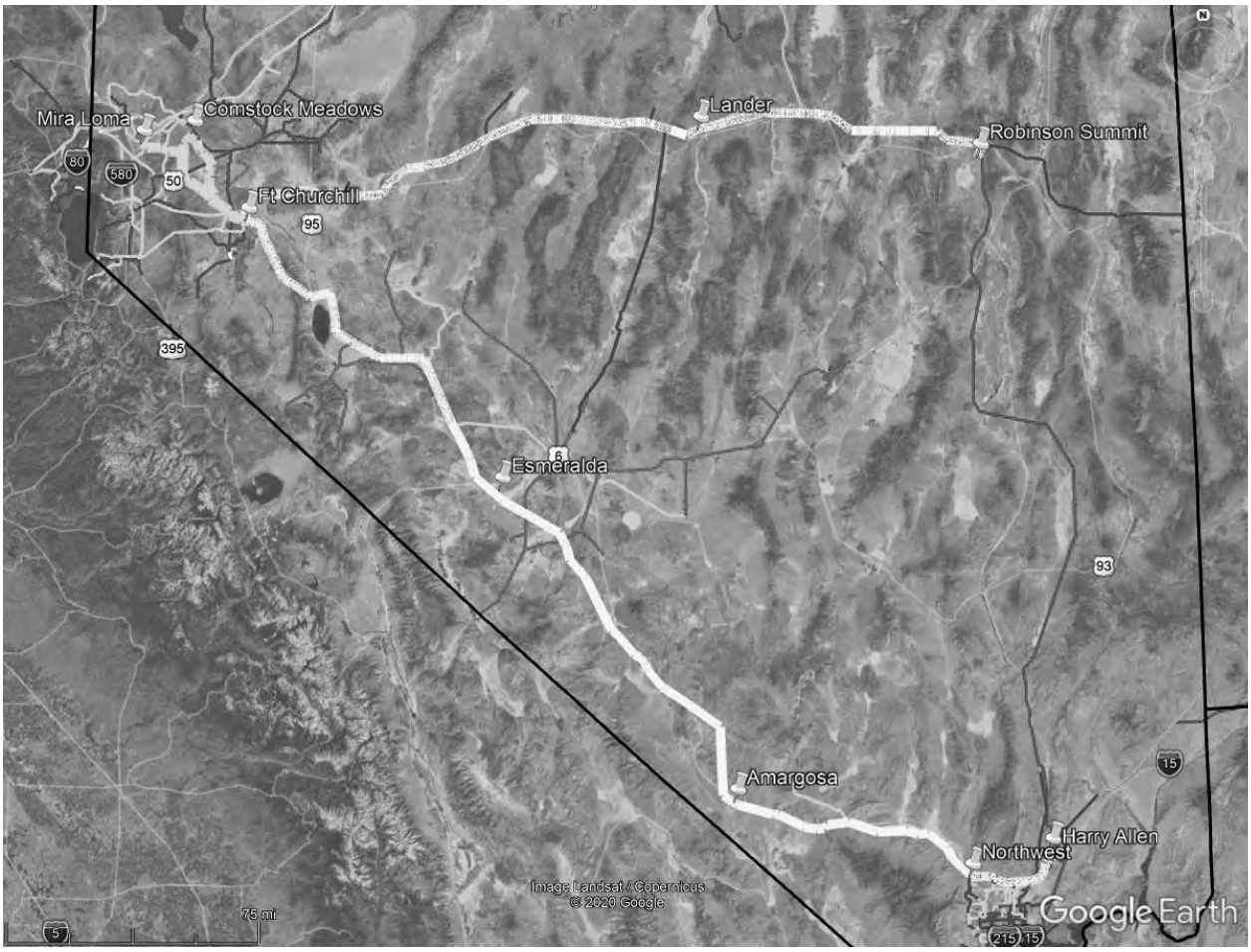
All 4/0 copper conductor on the Equestrian – Lake Las Vegas 69 kV line needs to be replaced with 954 ACSR conductor.

Additional Projects

Greenlink

In order to meet the growing demand for both native load and network customers for NV Energy North, Transmission Planning has identified two projects, Greenlink North and Green link West, to increase the import capability. These projects will also provide increased access to renewables as they provide access to BLM Solar Energy Zones

Greenlink West consists of two 500 kV line segments; a Harry Allen – Northwest 500 kV line (~32 miles) and a Fort Churchill – Northwest 500 kV line (~325 miles). Greenlink North consists of a 500 kV line from Fort Churchill – Robinson Summit. Along with the new transmission, Fort Churchill will be rebuilt as a new 500/345/230/120 kV substation. The 345 kV lines include a Fort Churchill – Mira Loma 345 kV line (~52 miles) and two 345 kV lines from Comstock Meadows – Fort Churchill (~55 miles each).



In-Service

The below projects are now in-service and were fully described in previous NERC assessments. Please refer to prior NERC annual assessments for full descriptions.

- Harry Allen - 525/230kV XFMR Installation
- Mead - River Road 69kV Line Uprate
- North Valley Road 345kV 75MVAR Capacitor
- Mira Loma 345kV 75MVAR Capacitor
- Winnemucca 2nd 120/60kV XFMR Installation
- Oreana 2nd 120/60kV XFMR Installation
- Grass Valley 120kV Conversion
- Crescent Dunes Tonopah Solar Reserve Generation RAS
- Carlin Trend Under-Voltage Load Shed
- Millers - Candelaria 120kV
- Falcon 345/120kV Transformer Addition
- Frontier 230kV Relay Loadability
- Reno Area UVLS RAS
- Eagle - Oreana #118 120kV RAS
- Ft Churchill 120/230kV XFMR RAS
- #2307 Transfer Trip
- Brunswick Substation Rebuild with a breaker-and-a-half scheme
- Garces - Mayfair 69kV Line Uprate
- Greg St - Glendale 120kV Uprate
- Winnemucca & Oreana 120 kV UVLS
- Frontier Breaker Addition and Re-Terminate 2308 Line
- North Valley Road – Penny's Tap 120 kV Uprate
- Dove – East Tracy 120 kV Uprate
- Robinson – Gonder 345 kV Uprate (Wave Traps)
- McDonald 230/138 kV Transformer & Arden – McDonald 230 kV Uprate
- Cortez South Pipeline 2.12 MVar Capacitors
- Emerson – Carson 120 kV Line Uprate
- Valmy - Midpoint 345kV Wave Trap Uprate
- 1094 North Valley Road 345-125kV 2 Uprate
- Valmy 345-125kV #3 Transformer Uprate
- Mira Loma Transformer Uprate
- Glendale – Valley Road 120kV Uprate
- Bannock Capacitor Bank
- Bell Creek Capacitor Bank
- Burnham – Ford 138 kV Fold into Pebble
- Liberty Plan Stages 1 and 2
- Lindquist – AWT – Winterwood 69 kV Uprate
- Equestrian – Balboa 69 kV Uprate
- Sunrise 138/69 kV Bank Addition

- Humboldt – Eight Mile #137 120 kV Upgrades / Eight Mile Creek RAS Modifications
- Miller substation second 138 kV source

Alternative Plans / On Hold

Below is a list of projects which are alternatives to a current CAP or projects which have been identified in prior studies, but the need for these project were not identified in newer studies. These projects have been placed on hold until the need for these projects are identified again

- CAP #1113: #122 Brunswick – Fort Churchill 120 kV Line Uprate
- CAP #1118: Reconductor #635 Line from Glenbrook Tap – Heybourne
- CAP #1222: #117 North Valmy – Winnemucca 120 kV Line Uprate
- CAP #2044 Winterwood 2nd 138/69 kV Xfmr and 2nd 230/138 kV Xfmr Installation
- CAP #2071: Winterwood – Sahara 69 kV Line Uprate
- CAP #2072: Hacienda – Lamb 69 kV Line Uprate
- CAP #2078: Cabana – Winterwood 138 kV Line Uprate
- CAP #2087: Winterwood – Sloan 69 kV Line Uprate
- CAP #2088: Washington – Winterwood 69 kV Line Uprate
- CAP #2089: Clark – Surge Pond Tap 69 kV Line Uprate
- CAP #2093: DeBuono – Sloan 69 kV Line Uprate
- CAP #2095: Leavitt – Miller 138 kV Line Uprate
- CAP #2097: Decatur – McDonald 230 kV Line Uprate
- CAP #101: Mission 69 kV Cap Bank

Cancelled

Below is a list of projects which were cancelled.

- Silver Lake 40MVAR 120kV Capacitor (Replaced with Peavine Substation)