

2026

Distribution System Plan

October 1, 2026



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Safe Harbor Statement

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Acknowledgements

PNM appreciates the organizations, customers, stakeholders, and individuals who contributed to the development of the 2026 Distribution System Plan. The PNM team thanks each participant for the time, experience, and perspectives provided throughout this process. These contributions helped PNM develop a more transparent and robust plan for maintaining a safe, reliable, resilient, and increasingly flexible distribution system as New Mexico's energy needs continue to evolve.

PNM especially recognizes the following contributions:

- The customers, community representatives, governmental entities, and other stakeholders who shared perspectives on reliability, affordability, resilience, electrification, distributed energy resources, wildfire risk, and the changing uses of the distribution system.
- PNM's Planning and Engineering teams, whose technical analyses, Ten-Year Distribution System Plans, contingency reviews, reconfiguration studies, detailed area studies, and hosting capacity assessments form the foundation of this DSP.
- PNM's Distribution Operations, Field Operations, System Control, Reliability, Asset Management, and Grid Modernization teams, whose operational experience, system data, and project implementation work informed the assessment of current conditions and future system capabilities.
- PNM's Customer Programs, Transportation Electrification, Energy Efficiency, Economic Development, Regulatory, Finance, Information Technology, Cybersecurity, Telecommunications, and Legal teams, which helped connect distribution planning with customer needs, regulatory requirements, emerging technologies, and prudent investment planning.

PNM appreciates the contributions of consultants, technical specialists, and vendors that provided analytical, modeling, technology, forecasting, and subject-matter support during development of the plan. This DSP reflects PNM's continued progress toward a more integrated planning approach that coordinates across planning areas and ensures alignment across PNM's long-range plans.

Integrated system planning is increasingly essential to efficiently and cost-effectively support load growth, economic development, electrification, distributed energy resources, grid modernization, and New Mexico's clean energy objectives while preserving safety, reliability, resilience, and affordability for customers. Modernizing the distribution system and preparing it for a changing energy future will require sustained collaboration.

PNM appreciates the collective effort that made this plan possible and looks forward to continued engagement as the DSP action plan is implemented and future planning cycles begin.

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Definitions and Acronyms

Table D-1 defines the principal technical, regulatory, planning, operational, and financial terms and acronyms used in this Distribution System Plan.

Table D-1: Definitions and Acronyms

Term or Acronym	Definition
ADMS	Advanced Distribution Management System; an integrated software platform supporting distribution monitoring, analysis, control, outage response, and optimization.
AFDC	US Department of Energy's Alternative Fuels Data Center
AMI	Advanced Metering Infrastructure: meters, communications, and data systems that enable interval usage data and two-way utility-customer communications.
AOP	Annual Operating Plan; PNM's planning and budgeting process for proposed capital and operating expenditures.
Area Study	A detailed engineering review of a cluster or defined geographic area that verifies a planning concern, evaluates alternatives, and establishes the recommended scope and timing of major projects.
ASAI	Average Service Availability Index: the proportion of time that electric service is available to the average customer during a reporting period.
CAIDI	Customer Average Interruption Duration Index; average restoration time per sustained customer interruption.
CAISO	California Independent System Operator; the regional transmission and wholesale market operator administering, among other services, the Extended Day-Ahead Market.
Cluster	A planning area within a division that groups substations and feeders that are geographically, electrically, or operationally related.
Commission	New Mexico Public Regulation Commission.
Community Solar	A solar facility whose output is allocated to subscribing customers through utility bill credits under New Mexico's community solar program. See NMSA 1978, Sections 62-16B-1 to -8; 17.9.573 NMAC; csnewmexico.com.
Contingency	An unplanned loss of a system element, such as a transformer or feeder, evaluated to determine whether load can be restored or served within applicable limits.

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DER	Distributed Energy Resource; distribution-connected generation, storage, controllable load, or other customer- or utility-sited resource capable of affecting system load or power-flow.
DERMS	Distributed Energy Resource Management System: a platform used to monitor, coordinate, forecast, or control distributed energy resources.
Detailed Area Study	An engineering study using feeder and substation models to evaluate normal and contingency performance, alternatives, sensitivities, costs, constructability, and recommended solutions.
DA	Distribution Automation: Communications, sensors, controls, and field devices that support remote or automated monitoring and operation of distribution equipment.
Distribution Planning	The process of forecasting needs and evaluating investments or operating strategies required to maintain safe, reliable, resilient, and affordable distribution service.
Distribution System	Facilities used to deliver electricity from substations to customers, including feeders, conductors, cables, transformers, switches, protection equipment, controls, and related assets.
Division	A broader PNM operating or planning area used to organize the Ten-Year Distribution System Plan and summarize needs across multiple clusters, substations, and feeders.
DNV Synergi Electric	Distribution-system modeling software used by PNM for power-flow, voltage, thermal, contingency, and hosting capacity analysis.
DSP	Distribution System Plan; PNM's forward-looking plan for distribution needs, investments, capabilities, and actions.
EDAM	Extended Day-Ahead Market; CAISO's regional day-ahead market framework for participating in Western balancing areas.
EIA	U.S. Energy Information Administration.
Energy Efficiency	Measures that reduce energy consumption while maintaining or improving the level of service provided.
EV	Electric Vehicle.
EVIO	Electric vehicles in operation.
Feeder	A distribution circuit that carries electricity from a substation to customers and distribution equipment within a defined service area.
FERC	Federal Energy Regulatory Commission.

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FLISR	Fault Location, Isolation, and Service Restoration - automated or remotely controlled functions that identify faults, isolate affected sections, and restore unaffected customers.
FOM	Front of the meter
GIS	Geographic Information System; a system for managing location, topology, connectivity, and attribute data for utility assets.
GMS	Grid Modernization Statute, NMSA 1978, Section 62-8-13.
Grid Modernization	Investments in communications, sensing, metering, automation, cybersecurity, data, and control capabilities that improve grid visibility, flexibility, reliability, resilience, and DER integration.
Gross Load	Underlying customer demand before the effect of customer-sited generation or other local resources is subtracted.
HCA	Hosting Capacity Analysis: engineering analysis of the amount of additional DER that can be interconnected without unacceptable thermal, voltage, protection, or operational impacts.
Hosting Capacity	The amount of additional DER that a feeder facility can safely accommodate under stated assumptions without violating applicable physical planning or operating limits.
IEEE	Institute of Electrical and Electronics Engineers.
IEEE 1366	IEEE standard providing definitions and guidance for electric distribution reliability indices and Major Event Days.
IEEE 1547	IEEE standard establishing interconnection and interoperability requirements for distributed energy resources connected to electric power systems.
Integrated Planning	Coordinated planning across distribution, transmission, resource, operational, customer, and financial functions using aligned forecasts, assumptions, and data.
IRP	Integrated Resource Plan: A long-term plan evaluating generation, storage, demand-side resources, and other supply alternatives needed to serve forecast load.
IVVO	Integrated Volt/VAR Optimization; coordinated control of voltage-regulating and reactive-power devices to maintain voltage and improve system efficiency.
kV	Kilovolt; one thousand volts.
kVA	Kilovolt-ampere; a unit of apparent electric power equal to one thousand volt-amperes.
kW	Kilowatt; a unit of real power equal to one thousand watts.

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kWh	Kilowatt-hour; a unit of energy equal to one kilowatt used or produced for one hour.
LDV	Light-duty vehicle.
Load Forecast	An estimate of future customer demand by time, location, and scenario for use in system planning.
Managed Charging	Control or coordination of EV charging to shift or limit load in response to customer, grid, or market conditions.
MED	Major Event Day; a day meeting the IEEE 1366 threshold for unusually severe reliability impacts and evaluated separately in reliability reporting.
Microgrid	A group of interconnected loads and energy resources within defined electrical boundaries that can operate as a coordinated system and, where designed, independently from the broader grid.
Minimum Daylight Load	The lowest distribution load during daylight hours, used in DER and hosting capacity analysis because it represents limited local demand available to absorb solar generation.
MVA	Megavolt-ampere; a unit of apparent electric power equal to one million volt-amperes.
MW	Megawatt; a unit of real power equal to one million watts.
MWh	Megawatt-hour; a unit of energy equal to one megawatt used or produced for one hour.
N-1	A planning condition representing the system's normal state minus one critical asset, such as a substation transformer or feeder.
Net Load	Load observed by the grid after the effect of customer-sited generation and other local resources is considered.
NMAC	New Mexico Administrative Code.
NMPRC	New Mexico Public Regulation Commission.
NMSA 1978	New Mexico Statutes Annotated 1978.
NMSU	New Mexico State University.
Non-Export	An operating mode in which a DER is configured to serve on-site load while limiting or preventing export to the utility system.
NWA	Non-Wires Alternative; a resource or operating strategy that can defer, reduce, or avoid a traditional distribution infrastructure project.
O&M	Operations and Maintenance.
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff; the FERC-jurisdictional tariff governing transmission and related interconnection services.

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OMS	Outage Management System; a system used to identify, manage, analyze, and report customer interruptions and restoration activity.
OH	Overhead Distribution: Distribution conductors and associated equipment installed above ground on poles or structures.
Peak Load	The highest level of electrical demand during a defined period or for a specified system element.
PNM	Public Service Company of New Mexico.
Power-flow	Engineering analysis of voltages, currents, power transfers, and equipment loading under defined system conditions.
Premises	A customer service location represented by a distribution meter or service point.
Protection Coordination	Selection and setting of protective devices so faults are detected and isolated safely while minimizing affected customers and equipment damage.
PSPS	Public Safety Power Shutoff; A planned de-energization used under defined conditions to reduce wildfire or other public safety risks.
PV	Photovoltaic; technology that converts sunlight directly into electricity.
QF	Qualifying Facility; a cogeneration or small power production facility meeting applicable federal criteria.
Reconfiguration Study	An engineering review used to determine whether a planning concern can be resolved through switching, load transfer, feeder ties, reconductoring, or other lower-cost system changes before larger capacity additions are developed.
Resilience	The ability to anticipate, withstand, adapt to, and recover from disruptive events affecting the distribution system.
Reverse Power-flow	Power-flow from distribution-connected generation toward a substation or upstream system, opposite the traditional direction of delivery to customers.
Rule 560	17.9.560 NMAC, the Commission's electric service standards rule.
Rule 568	17.9.568 NMAC, governing interconnection of generating facilities up to and including 10 MW.
Rule 570	17.9.570 NMAC, governing cogeneration, small power production, qualifying facilities, utility purchase and sales obligations, and related arrangements.
Rule 573	17.9.573 NMAC, the Community Solar Rule.
Rule 574	17.9.574 NMAC, governing utility applications to expand transportation electrification.

Rule 588	17.9.588 NMAC, the Grid Modernization Grant Program rule.
SAIDI	System Average Interruption Duration Index; average cumulative duration of sustained interruptions per customer during a reporting period.
SAIFI	System Average Interruption Frequency Index; average number of sustained interruptions experienced per customer during a reporting period.
SCADA	Supervisory Control and Data Acquisition; systems that provide remote monitoring, telemetry, alarms, and control of utility equipment.
SGIP	Small Generator Interconnection Procedures; FERC-jurisdictional procedures applicable to qualifying small-generator interconnection requests.
Substation	A facility that transforms voltage and connects transmission, subtransmission, or distribution circuits and related protection and control equipment.
Substation Outage Review	A focused N-1 review of a substation transformer outage to determine whether affected load can be restored through adjacent transformers, feeders, ties, and switching actions.
Telemetry	Remote measurement and communication of electrical or equipment data to utility systems.
Ten-Year Plan	Ten-Year Distribution System Plan; PNM's division-level capacity screening and budgeting report identifying potential needs and estimated timing over a ten-year horizon.
TEP	Transportation Electrification Plan
TIIR	Technical Interconnection and Interoperability Requirements applicable to DER equipment, controls, communications, and operation.
Transformer	Electrical equipment that changes voltage levels and transfers power between circuits.
UG	Underground Distribution: Distribution cables and associated equipment installed below ground.
UN	Utility Network: A GIS data model supporting utility asset connectivity, topology, network tracing, and integration with planning and operational systems.
Volt/VAR	Voltage and reactive-power management used to maintain acceptable voltage, power factor, and system efficiency.
VPP	Virtual Power Plant; a coordinated aggregation of distributed resources operated to provide load management, capacity, energy, or other grid services.
VVMS	Volt/VAR Management System; the system used to monitor and control selected voltage and reactive-power devices.
Wildfire Mitigation	Planning, operational, maintenance, and capital measures intended to reduce the likelihood or consequences of utility-related wildfire ignition and exposure.

Executive Summary

Public Service Company of New Mexico's 2026 Distribution System Plan provides a forward-looking framework for maintaining a safe, reliable, resilient, flexible, and affordable distribution system as customer needs and New Mexico's energy landscape evolve. The plan explains how PNM will continue serving more than 550,000 customers while accommodating load growth, economic development, transportation and building electrification, distributed energy resources, community solar, energy storage, and the State's transition toward carbon-free electricity. It also establishes the relationship between traditional distribution investments and the grid modernization capabilities needed to operate and plan an increasingly dynamic electric system.

PNM's distribution system includes approximately 197 energized substation transformers with 4,012.7 MVA of connected nameplate capacity, approximately 15,801 miles of overhead and underground distribution facilities, and approximately 560,000 customer premises. The system also supports more than 48,600 interconnected distributed energy resource installations totaling approximately 624.1 MW, primarily customer-sited solar. These resources provide important customer and clean-energy benefits but also create new planning and operational requirements involving reverse power-flow, voltage management, protection coordination, minimum-load conditions, hosting capacity, communications, and system visibility.

The plan describes a layered distribution planning process that begins with PNM's annual Ten-Year Distribution System Plan. This foundational study process evaluates transformer and feeder loading, load growth, contingency capability, known economic-development projects, and high-level distributed energy resource hosting capacity. Potential constraints are then examined through outage-contingency reviews, reconfiguration studies, detailed area studies, and feeder-level hosting capacity analyses. This progression allows PNM to first consider operating changes, load transfers, targeted upgrades, and non-wires alternatives before advancing larger capital projects. Detailed engineering studies ultimately establish the need, scope, timing, location, and cost of major distribution investments.

Over the next five years, PNM will continue to transition from primarily capacity-based planning toward a more integrated planning framework. A principal component of this transition is development of a consistent, location-specific load forecast that incorporates increasingly detailed information including organic growth, economic-development projects, customer-owned generation and storage, electric vehicles, building electrification, and flexible load. Forecasts broadly support plans across distribution, transmission, resource, operational, and financial planning using a common set of assumptions and data.

PNM's Commission-approved Grid Modernization Plan provides much of the technology foundation for PNM's energy transition and continued improvements to customer service and reliability. Investments in advanced metering infrastructure, telecommunications, distribution automation, an advanced distribution management system, fault location, isolation and service restoration, integrated Volt/VAR optimization, distributed energy resource management, cybersecurity, and improved network models will expand visibility and control across the distribution system. These capabilities are expected to improve outage detection and restoration, forecasting, hosting capacity analysis, operational flexibility, asset utilization, and the evaluation of non-wires alternatives. Grid modernization will complement—not replace—traditional investments such as new substations, transformer additions, feeder extensions, reconductoring, voltage-support equipment, wildfire mitigation, and asset replacement.

PNM 2026 Distribution System Plan

The plan also establishes a more systematic approach to comparing investment alternatives. PNM is testing and refining the Copperleaf decision-support platform to evaluate traditional infrastructure, grid modernization technologies, distributed resources, and other alternatives using consistent measures of cost, risk, reliability, resilience, safety, customer benefit, and strategic value. This framework will continue to improve investment prioritization, timing, transparency, and alignment with customer needs and regulatory objectives.

PNM's planning approach is governed by an extensive state and federal framework addressing utility service obligations, reliability, grid modernization, energy efficiency, transportation electrification, interconnection, community solar, distributed generation, wholesale market participation, and data sharing. The Distribution System Plan connects these requirements to practical planning decisions and identifies how distribution investments support New Mexico's renewable-energy, carbon-reduction, economic-development, and electrification objectives while maintaining affordability and operational reliability.

Stakeholder engagement is an integral part of PNM's planning processes. PNM's stakeholder engagement processes provide for public meetings, advance review of PNM's draft plans, formal stakeholder written comment periods, consideration of and responses by PNM, and discussion of revisions and unresolved issues before filing. This engagement continuously improves transparency, incorporates diverse perspectives, and creates a clear record of how stakeholder input informed the final plan.

The action plan focuses on implementing grid modernization, improving forecasting and data integration, refining hosting capacity and non-wires-alternative analyses, advancing targeted reliability and capacity projects, evaluating pilot programs and strategic partnerships, and developing metrics to measure results. Key areas of measurement include reliability, resilience, safety, DER integration, hosting capacity, operational visibility, project delivery, customer affordability, and progress toward integrated planning.

Overall, the 2026 Distribution System Plan establishes a practical path for maintaining reliability, modernizing PNM's distribution system, while also preserving disciplined engineering and investment review. Its central objective is to ensure that PNM can meet changing customer and policy needs through timely, cost-conscious, and technically sound investments that maintain safe and reliable service and create a more flexible platform for New Mexico's energy future.

1. State and Federal Statutory and Regulatory Landscape

1.1 Introduction

PNM's distribution system is governed by a broad set of New Mexico statutes, New Mexico Public Regulation Commission ("Commission" or "NMPRC") rules, federal rules and requirements, and Commission-approved tariffs and programs. Collectively, these requirements establish the legal and policy framework under which PNM plans, operates, maintains, modernizes, and expands its distribution system. They also guide how PNM collectively evaluates safety, reliability, affordability, interconnection, distributed energy resources, transportation electrification, energy efficiency, customer programs, and grid modernization investments.

State Requirements

1.2 Public Utility Act and Commission Jurisdiction

The New Mexico Public Utility Act provides the foundational regulatory framework for PNM's electric utility operations, including the obligation to provide safe, adequate, and reliable service at just and reasonable rates. Chapter 62 of the New Mexico Statutes governs electric, gas, and water utilities and includes provisions addressing public utility regulation, Commission authority, utility duties, rates, service obligations, hearings, enforcement, and related matters.

For distribution planning purposes, the Public Utility Act establishes the Commission's authority to review utility investments, rates, tariffs, service quality, and utility practices that affect customers. It also provides the statutory backdrop for Commission rules governing service standards, interconnection, renewable energy, energy efficiency, transportation electrification, community solar, and other programs that directly affect distribution system operations.

Accordingly, PNM's Distribution System Plan ("DSP") is designed to support the utility's core public service obligations by identifying prudent distribution investments needed to maintain safe and reliable service, respond to changing customer usage patterns, integrate distributed energy resources, support electrification, and enable achievement of state energy policy objectives in a manner that is operationally sound and cost-conscious.

1.3 Rule 560 Electric Service Standards

The Commission's electric service standards rule, 17.9.560 NMAC, applies to electric utilities operating in New Mexico that are subject to Commission jurisdiction under the Public Utility Act. The rule is intended to promote safe and adequate electric service, establish uniform and reasonable utility practices, and provide a basis for evaluating whether customer service demands and utility responses are reasonable.

This rule is directly relevant to distribution planning because it addresses utility practices related to records and reports, metering, customer relations, engineering, inspections and tests, quality of service, and safety. PNM's DSP therefore must consider distribution system investments and operational practices that support compliance with service quality, safety, metering, engineering, and customer service requirements as specified in 17.9.560 NMAC.

In practical terms, these standards inform PNM's planning for feeder capacity, voltage performance, outage prevention, equipment maintenance, customer connections, metering systems, and system restoration. They also provide a regulatory foundation for evaluating modernization investments, such as advanced distribution management systems, automated switching, communications, sensing, and advanced metering capabilities, are needed to maintain or improve the quality and reliability of service.

1.4 Grid Modernization Statute and Rule 588 Grid Modernization Grant Rule

New Mexico's grid modernization framework reflects the state's policy direction toward a more flexible, resilient, secure, efficient, and renewable-ready electric grid. The Grid Modernization Program was established by the Grid Modernization Roadmap Act of 2020, NMSA 1978, Sections 71-11-1 to -2, and is implemented in part through 17.9.588 NMAC, the Grid Modernization Grant Program.

To that end, PNM's Grid Modernization Plan was approved by the NMPRC in 2024 and includes a six-year, \$382.87 million investment to transform the utility's electric grid into a more resilient, reliable, efficient, and decarbonized system.¹ 2026 represents year two of PNM's Grid Modernization Plan implementation and it is a foundational implementation component of the DSP. While the DSP describes what distribution system capabilities are needed over the planning horizon, the Grid Modernization Plan provides many of the specific technologies, operational tools, and investments necessary to achieve those capabilities. The approved plan includes deployment of advanced metering infrastructure (AMI), an advanced distribution management system (ADMS) associated communications networks, cybersecurity enhancements, and distribution visibility improvements. This grid modernization is key in enabling DSP plans going forward.

Part of Rule 588 also includes a Grid Modernization Grant Program, which is intended to improve electric distribution and transmission infrastructure and make the grid more flexible and responsive to modern energy resources and demands. Although the grant program is administered for eligible entities such as municipalities, counties, state agencies, educational institutions, and Indian nations, tribes, and pueblos, it is relevant to PNM's distribution planning because grant-funded projects may interact with, depend on, or affect PNM's distribution system.

PNM's DSP therefore recognizes the importance of coordination with state, local, tribal, and educational entities pursuing grid modernization grants, particularly where those projects involve microgrids, distributed energy resources, resilience hubs, advanced metering, demand response, grid-edge technologies, or distribution-level renewable integration. This coordination can help ensure that public investments complement utility planning, avoid duplicative costs, and produce operational benefits for customers.

1.5 Efficient Use of Energy Act

The Efficient Use of Energy Act is codified in NMSA 1978, Sections 62-17-1 to -12. The Act addresses energy efficiency and load management programs, cost recovery, measurement and verification, self-directed programs, and integrated resource planning.

¹ See NMPRC Case No. 22-00058-UT.

The Efficient Use of Energy Act affects distribution planning because energy efficiency, demand response, and load management can reduce or defer distribution system needs, change peak demand patterns, and improve customer affordability. These programs can serve as non-wires alternatives where they are technically feasible, cost-effective, sufficiently locational, and dependable for planning purposes.

PNM's DSP should therefore incorporate energy efficiency and demand-side management into distribution forecasts, particularly feeders or substations where load growth may otherwise require capacity upgrades. The DSP should also evaluate whether targeted energy efficiency, demand response, managed charging, or other flexible load measures can reduce peak demands, mitigate localized constraints, and improve utilization of existing distribution assets.

1.6 Rule 574 Transportation Electrification Rule

New Mexico's transportation electrification requirements are implemented through 17.9.574 NMAC, "Applications to Expand Transportation Electrification." The rule applies to investor-owned electric utilities under Commission jurisdiction and implements NMSA 1978, Section 62-8-12. The stated objective of the rule is to implement transportation electrification applications and bring economic development and environmental benefits to New Mexico through expanded electrification of transportation modalities and infrastructure.

The rule requires public utilities to file three-year transportation electrification plans that may include investments, incentives, programs, rate designs, and expenditures reasonably expected to achieve the statutory goals. Required plan elements include strategies for low-income customers and underserved communities, multiple electric vehicle (EV) classes, customer participation estimates, multiple market segments, coordination with state or federal EV infrastructure planning, coordination with existing fuel providers, and key performance indicators.

The rule also requires annual progress reporting. For PNM, the first annual progress report was due June 1, 2024, with annual filings thereafter by June 1. Annual reports must include information such as estimated EV adoption, charging stations and ports, program participation, low-income participation, usage during on-peak and off-peak hours, program spending, estimated charging load in kW and kWh, geographic distribution of investments, load profiles, outreach activities, and data that may inform future measures to better understand EV charging impacts on the electric grid.

Transportation electrification is highly relevant to the DSP because EV adoption can create localized distribution impacts, especially where charging loads cluster on specific feeders, transformers, or substations. PNM's DSP must consider EV load forecasting, managed charging, rate design, transformer loading, feeder capacity, hosting capacity for charging infrastructure, public charging corridors, fleet electrification, low-income and underserved community access, and coordination between transportation electrification plans and distribution capital planning.

1.7 Rule 568 Interconnection Requirements for Generating Facilities up to 10 MW

The Commission's interconnection rule for facilities up to 10 MW (17.9.568 NMAC) governs the interconnection of generating facilities with a nameplate rating up to and including 10 MW that connects to a utility system. The rule applies to electric utilities in New Mexico that are subject to

Commission jurisdiction, including investor-owned utilities, rural electric cooperatives, and qualifying and non-qualifying facilities.

Rule 568 is central to distribution planning because it governs how customer-sited and third-party generation, including solar photovoltaic systems and energy storage, are reviewed for safe and reliable interconnection to the distribution system. The rule provides standards, procedures, and screening processes for interconnection requests and recognizes export capacity and energy storage operating modes when evaluating interconnection impacts.

The 2023 revisions to Rule 568 incorporated updated approaches for distributed energy resources, including provisions that evaluate systems based on the capacity designed to inject electricity into the utility system, rather than solely on installed nameplate capacity. The Interstate Renewable Energy Council described New Mexico's updated interconnection rules as reflecting national best practices for solar-plus-storage, smart inverters, and energy storage interconnection.

For DSP purposes, Rule 568 requires PNM to incorporate DER growth, interconnection queues, feeder hosting capacity, voltage impacts, protection settings, reverse power-flow, operational visibility, and energy storage operating profiles into distribution planning. The rule also reinforces the need for updated distribution models, transparent technical standards, process efficiency, and investment in grid capabilities that can safely accommodate increasing levels of DER adoption.

1.8 Rule 569 Interconnection Requirements for Generating Facilities Greater Than 10 MW

Rule 569 (17.9.569 NMAC) governs the interconnection of generating facilities with a rated capacity greater than 10 MW. Distribution planning activities include the evaluation of system capacity, reliability, power quality, protection requirements, and potential system upgrades necessary to accommodate large generation projects in a safe and reliable manner. Consistent with the objectives of Rule 569, PNM assesses the impacts of proposed interconnections on distribution facilities and coordinates with transmission planning, system operations, and engineering organizations to identify required modifications, cost estimates, and implementation timelines. These planning efforts help ensure that interconnection requests are processed in a transparent and technically sound manner while maintaining system reliability and supporting customer-driven generation development.

1.9 Rule 570 Governing Cogeneration and Small Power Production

Rule 570 (17.9.570 NMAC) provides a framework governing cogeneration facilities, qualifying facilities (QFs), distributed generation, net metering, utility purchase obligations, utility sales obligations, metering requirements, and associated contractual arrangements in New Mexico. The rule applies to electric utilities operating within New Mexico that are subject to the jurisdiction of the NMPRC. Its stated objectives include enabling the development of markets for power produced by qualifying facilities, establishing procedures for utility purchases and sales, supporting distributed generation deployment, and providing meaningful access to utility information necessary for project development. Additionally, DER interconnection and net metering in New Mexico are governed by New Mexico Public Regulation Commission rules,

including 17.9.570 NMAC (Interconnection of Distributed Generation), which establishes common interconnection requirements, screening processes, and timelines for qualifying facilities and renewable systems, and by technical standards such as IEEE 1547-2018, which provides uniform interconnection and interoperability criteria for DER connecting to electric power systems.

For a DSP, Rule 570 directly influences how distributed generation resources interconnect, operate, exchange energy with the grid, and must be considered in distribution system planning and investment decisions. DERs on PNM's system generally include generation, storage, and controllable load connected at the distribution level, such as rooftop solar, distribution-connected battery energy storage systems, community solar facilities, demand response-enabled devices, and other customer- and utility-sited assets.

Increasing DER penetration on PNM's distribution system is a key driver for the DSP. As DER installations grow, PNM must evaluate DER impacts in its load and generation forecasting, evaluate hosting capacity at the feeder and substation level, and consider DER-based solutions to emerging constraints alongside traditional distribution investments.

1.10 Rule 573 Community Solar Rule

The Community Solar Act, NMSA 1978, Sections 62-16B-1 to -8, was enacted in 2021 and established New Mexico's community solar program. The program allows qualified electric utility customers to subscribe to a community solar facility and receive bill credits associated with the subscriber's share of the facility's output.

The Commission's Community Solar Rule is codified at 17.9.573 NMAC and governs implementation of the program, including facility requirements, subscriber organization responsibilities, utility obligations, capacity allocations, bill credits, subscriber protections, and related administration. The Community Solar Rule became effective on October 22, 2024.

Community solar directly affects distribution planning because community solar facilities typically require distribution or substation-level interconnection review, feeder capacity analysis, voltage and protection assessment, and evaluation of whether sufficient local load exists to offset project generation. Recent reporting on proposed and advanced amendments to the Community Solar Rule indicates that utilities may have expanded responsibilities related to interconnection reporting, project review, enrollment, billing, and administration, and that utilities may evaluate whether local load is sufficient to accommodate project generation without transmitting electricity to another portion of the distribution system.

PNM's DSP should therefore account for community solar development by identifying likely interconnection locations, evaluating hosting capacity, coordinating with program administration, and considering whether distribution upgrades are needed to support selected projects. The DSP should also recognize that community solar can create localized operational needs, including voltage regulation, backfeed management, protection coordination, metering, data exchange, and billing system integration.

1.11 17.7.3 NMAC Integrated Resource Plans for Electric Utilities

17.7.3 NMAC is the New Mexico Public Regulation Commission's Integrated Resource Plans for Electric Utilities rule. It governs how investor-owned electric utilities such as PNM, SPS, and EPE develop, file, and implement their Integrated Resource Plans (IRPs). The rule's objective is to establish the requirements for preparation, filing, review, and acceptance of IRPs to identify the most cost-effective portfolio of resources needed to serve customers while ensuring just and reasonable rates. The current version also emphasizes transparency, early stakeholder participation, competitive evaluation of alternatives, and governs associated procurement processes.

The key requirements of the IRP Rule require preparation of a long-term plan evaluating expected customer demand, resource needs, and policy requirements over a planning period generally extending 20 years and is not limited to evaluating transmission-sited alternatives. Like the DSP, the IRP includes a stakeholder process and must identify and justify future plans that support reliability and policy compliance.

As part of PNM's 2026 IRP resource portfolio analysis, PNM evaluated a wide variety of alternative portfolios, considering:

- Supply-side resources, both transmission and distribution-sited
- Demand-side resources, demand response, and energy efficiency, primarily distribution-sited
- Renewable resources, transmission and distribution-sited
- Storage resources, transmission and distribution-sited
- Transmission alternatives

Both plans rely on PNM's load forecasts and other relevant company data, including assumptions regarding DER adoption, electrification, EV penetration, economic development, reliability, and resilience objectives, and planned or known system additions.

The IRP evaluates both transmission and distribution sited alternatives using a common planning and evaluation framework to ensure PNM is identifying the most efficient solutions to meet customer needs. The DSP provides the detailed distribution-level analysis needed to ensure reliability and it informs future IRPs by identifying DER options and potential. PNM will continue improving coordination among its state planning processes to promote efficient, aligned plans.

1.12 Rule 440 Extensions, System Improvements, Repairs or Replacements, Additions, and Cooperative Agreements Between or Among Utilities.

Rule 440 is 17.5.440 NMAC –The rule establishes the reporting and filing requirements for utilities when undertaking significant distribution or transmission system projects, including line extensions, system improvements, major repairs and replacements, additions, and certain cooperative agreements with other utilities. It also requires annual reporting of planned and completed projects and associated costs. The Company's distribution planning process supports

compliance with Rule 440 by identifying, evaluating, and documenting planned system extensions, system improvements, repairs, replacements, and additions necessary to maintain reliable electric service and meet customer growth. Distribution planning studies assess system needs, engineering feasibility, alternatives, reliability impacts, and estimated project costs to support required regulatory filings and reporting obligations. These activities ensure that capital investments are planned in a transparent and prudent manner while supporting long-term system reliability, resiliency, and customer service objectives.

Federal Requirements

1.13 Federal Energy Regulatory Commission (FERC)

A FERC-jurisdictional utility's distribution system is generally regulated by the state commission, but certain portions of the distribution system can become subject to FERC regulation when they are used to provide jurisdictional wholesale services, including generator interconnection service under the Small Generator Interconnection Procedures (SGIP).

1.13.1 FERC Small Generator Interconnection Procedures

In addition to state interconnection rules, certain interconnection requests may be governed by federally regulated interconnection procedures under the FERC, including the SGIP used for FERC-jurisdictional interconnections. PNM's solar interconnection reference materials identify the FERC-regulated SGIP process for interconnection requests greater than 10 MW or otherwise subject to FERC-regulated procedures.

The FERC SGIP process is relevant to distribution planning where a project is interconnected to facilities that are subject to FERC-jurisdictional service or where the interconnection request implicates wholesale sales or potential transmission service. PNM must therefore coordinate distribution planning with applicable FERC interconnection obligations, Open Access Transmission Tariff processes, affected system studies, and distribution-level technical reviews where projects have distribution implications.

For the DSP, this means that PNM's planning processes should maintain alignment between distribution interconnection studies, transmission planning, generation interconnection obligations, and DER forecasting. This is particularly important as increasing numbers of solar, storage, community solar, and hybrid facilities seek interconnection at locations that may create both local distribution impacts and broader transmission system implications. The SGIP and Rule 568 effectively create a nexus between federal and state requirements that do not totally align.

1.13.2 FERC Order 2222: DER Aggregation

FERC Order 2222 requires RTOs/ISOs to allow aggregated DERs, including batteries, distributed solar, EVs, demand response, and other distributed resources, to participate in wholesale energy, capacity, and ancillary service markets. The order removes barriers to DER aggregation and wholesale market participation in RTO and ISO footprints. While PNM is not a member of an RTO/ISO, it has received a federal grant to aid development of its own virtual power plant (VPP), which should mimic the benefits of FERC Order 2222

for PNM customers. Additionally, PNM's initiative to automate its hosting capacity analysis will also continue to provide foundational development needed for future support of aggregated DERs may be dispatched simultaneously as part of a wholesale market.

1.13.3 FERC Order 2023: Generator Interconnection Reform

FERC Order 2023 reformed generator interconnection procedures to reduce queue backlogs, increase transparency, and move toward a "first-ready, first-served" cluster-study process and was designed to accelerate deployment of generation and storage resources. While Order 2023 primarily addresses transmission-level interconnections, it will help unclog interconnection queues which will in turn accelerate development of resource and storage projects, many of which ultimately affect local substations and distribution facilities.

Like PNM's planned hosting capacity maps, Order 2023 requires transparency and system information around available capacity at the transmission level that builds on prior FERC data transparency managed through the PNM's OATT and OASIS site.

1.13.4 FERC Order 1920: Long-Term Regional Transmission Planning

Order 1920 requires transmission providers to conduct long-term regional transmission planning over a 20-year horizon, consider multiple future scenarios, evaluate broader benefits, and incorporate greater state participation in planning and cost allocation. A DSP should recognize that distribution planning can no longer occur independently of transmission planning. Long-term transmission expansion may create new load-serving substations and delivery points, affect local constraints, etc. Order 1920 requires consideration of long-term drivers such as electrification, data centers, manufacturing growth, and policy-driven resource changes, which are the same drivers that should inform DSP forecasts.

1.14 Discussion of Regional Markets on Distribution

A regional market such as the CAISO Extended Day-Ahead Market (EDAM) can create both opportunities and operational obligations for distribution-sited generator resource facilities in the future. EDAM expands day-ahead optimization across participating Western balancing areas, which can improve price transparency, renewable integration, resource commitment, and transmission utilization. For distribution-sited resources, the potential benefits include improved dispatch value, access to broader regional price signals, enhanced storage charging and discharging opportunities, and greater ability to support reliability through day-ahead scheduling. At the same time, participation will require expanded communications and supervisory control and data acquisition capabilities, along with forecasting, metering, telemetry, bidding, scheduling, settlement, and coordination with the distribution utility to ensure that wholesale market dispatch does not create local distribution reliability concerns. Distribution-sited resources may be valuable because they can respond to congestion, renewable variability, and net-load ramps, but they must be operated within interconnection limits, distribution constraints, state-jurisdictional retail requirements, and any applicable wholesale market registration rules.

1.15 Customer and Distribution System Data Sharing

PNM recognizes the importance of providing customers, stakeholders, and third parties with meaningful access to customer and distribution system information to support transparency, informed decision-making, distributed energy resource development, and participation in utility programs. At the same time, PNM must protect customer privacy, maintain cybersecurity, safeguard critical infrastructure information, and comply with applicable legal and regulatory requirements. Accordingly, PNM will evaluate requests for customer and distribution system data on a case-by-case basis, considering factors such as the intended use of the data, customer consent requirements, data sensitivity, system security implications, confidentiality obligations, and the resources required to compile and provide the requested information. PNM will continue to assess opportunities to expand appropriate data access and transparency while ensuring that data sharing practices remain consistent with customer privacy protections, operational security needs, and applicable regulatory requirements.

2. *Stakeholder Engagement Process*

2.1 Introduction

PNM developed this DSP through a structured stakeholder engagement process intended to promote transparency, facilitate meaningful participation, improve the quality of distribution system planning, and comply with the stakeholder engagement requirements established by the Commission. The process provided opportunities for stakeholders to understand the planning assumptions and methodologies underlying the DSP, review a draft plan prior to filing, submit written comments, propose alternative planning scenarios, and engage directly with PNM regarding proposed investments, programs, and planning initiatives.

Stakeholder participation served a significant role in identifying planning priorities, improving transparency regarding distribution system needs, and helping ensure that the DSP reflects a broad understanding of customer interests, emerging technologies, policy developments, and evolving distribution system requirements.

2.2 Stakeholder Engagement Objectives

The stakeholder engagement process was designed to provide stakeholders with a meaningful opportunity to review and comment on a draft DSP before filing, increase transparency regarding distribution planning assumptions, methodologies, and analytical inputs, solicit stakeholder perspectives regarding reliability, resilience, affordability, DERs, transportation electrification, grid modernization, and load growth, create a transparent record of stakeholder comments and PNM's responses, and most importantly to improve the quality of the DSP through collaborative dialogue and information sharing.

2.3 Stakeholder Outreach

PNM invited participation from a broad and diverse group of interested stakeholders, including:

- Commission Utility Division Staff
- Residential, commercial, industrial, and governmental customers

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- Consumer advocacy organizations
- Tribal governments and tribal representatives
- Environmental and community organizations
- Renewable energy and distributed energy resource developers
- Third-party aggregators and technology providers
- Local governments and economic development organizations
- Large commercial and industrial customers
- Other interested members of the public

Notice of public meetings and stakeholder materials were made available through PNM's public communication channels including a dedicated webpage <https://www.pnm.com/distributionsystemplan> and stakeholder distribution lists. Draft planning materials, presentations, stakeholder comments, responses, and supporting information were made publicly available to facilitate informed stakeholder participation.

2.4 First Public Meeting and Draft Plan Review

Consistent with Commission requirements, PNM conducted its first public stakeholder meeting at least sixty (60) days before filing this DSP, on July 31, 2026. The meeting was conducted via web conferencing to allow for broad attendance, and PNM published its draft DSP report for public review in advance of the meeting. PNM accepted both web form registration as well as email registrations for anyone who was unable to successfully complete the web form.

The purpose of the meeting was to present the draft DSP and provide stakeholders with sufficient information to understand the basis for the proposed plan. During the meeting, PNM reviewed:

- Welcome and Introductions
- Stakeholder Engagement and Timeline
- Regulatory Landscape
- Current Distribution System
- Distribution Planning Process and 10 Minute Break
- Vision for Distribution System
- Financial Information and Benefit-Cost Analysis
- Action Plan and Key Metrics
- Stakeholder Q&A and Feedback

The list of participants is provided in Appendix A.

PNM presented the underlying assumptions, data inputs, forecasts, and planning criteria at a level of detail intended to enable stakeholders to evaluate the draft plan and provide meaningful comments.

2.5 Stakeholder Comment Period

Following the first public meeting, stakeholders were provided a thirty (30) day period to submit written comments regarding the draft DSP.

Stakeholders were encouraged to provide comments concerning planning assumptions and methodologies, forecasts and system needs assessments, distribution system investment priorities, reliability and resilience considerations, DER integration strategies, hosting capacity analyses, grid modernization proposals, customer affordability impacts, demand-side management and flexible load opportunities, and alternative planning approaches and scenarios. All timely submitted comments were reviewed and considered during development of the final DSP.

PNM received a total of 34 comments and have addressed each of those formally in a comment tracking document, by responding directly to the stakeholder email and posting to the DSP website.

2.6 Responses to Stakeholder Comments

PNM prepared written responses to all timely stakeholder comments and made those responses available at least ten (10) days prior to the second public meeting.

The list of stakeholder questions and comments received during the stakeholder process and PNM's responses are provided in Appendix B.

Where stakeholder comments resulted in revisions to the DSP, those revisions were identified and incorporated into the updated draft presented at the second public meeting.

2.7 Second Public Meeting

Consistent with Commission requirements, PNM conducted its second public stakeholder meeting at least ten (10) days prior to filing this DSP and it was conducted on September 21, 2026. This meeting focused on Stakeholder feedback themes, and updates to the report.

The second meeting provided stakeholders with an opportunity to understand how their feedback was considered and incorporated into the final DSP.

2.8 Participation of Utility Division Staff

Consistent with Commission requirements, Utility Division Staff were invited to participate throughout the stakeholder engagement process.

Staff participation included attendance at stakeholder meetings, review of planning materials, and engagement on elements of the DSP.

2.9 Role of Third-Party Participants

PNM utilized third-party consultants and subject matter experts to support specific technical analyses associated with the development of the DSP. Consultant support included activities such as engineering analysis, forecasting, system studies, grid modernization assessments, hosting capacity evaluations, and other technical planning activities.

PNM retained responsibility for all planning decisions, analyses, conclusions, and the final DSP filing.

2.10 Major Issues Addressed During the Stakeholder Process

No major issues were identified, but Stakeholder discussions focused on a range of topics affecting distribution system planning, including:

- Electric Vehicles
- Asset condition and reliability
- Forecasting
- VPP
- Hosting Capacity
- Interconnection study methodology
- Education on customer benefits from Grid Modernization
- AMI
- Time of Day Rates

2.11 Issues Resolved Through Stakeholder Engagement

The stakeholder engagement process contributed to clarification of the items in Section 2.10.

Through stakeholder dialogue, PNM provided additional information and clarification that improved stakeholder understanding of the proposed DSP and supporting analyses and appreciated the participation of stakeholders to help enhance the final DSP product.

2.12 Issues Remaining Unresolved

The DSP Stakeholder engagement process involved a diverse range of stakeholders. Although several subjects were discussed, no major issues are unresolved. Since this is the first time PNM has prepared and presented a DSP, it appeared that stakeholders were thoughtfully considering all the information contained in the DSP. PNM appreciated their thoughtful review and intends to continue engagement on the DSP process in future planning cycles.

2.13 Compliance with Stakeholder Engagement Requirements

PNM believes the stakeholder engagement process described in this chapter satisfies all stakeholder engagement requirements established by the Commission. Specifically:

- A first public meeting was conducted at least sixty (60) days prior to filing the DSP.
- Stakeholders were provided with a thirty (30) day period to submit written comments.
- PNM provided responses to timely stakeholder comments at least ten (10) days before the second public meeting.
- A second public meeting was conducted at least ten (10) days prior to filing.
- Planning assumptions, methodologies, forecasts, and analytical inputs were presented with sufficient detail to support stakeholder understanding and participation.
- Utility Division Staff were invited to participate throughout the process.
- This DSP documents the stakeholder engagement process, the role of third-party participants, issues resolved during stakeholder engagement, and issues remaining unresolved.

PNM believes that the stakeholder engagement process materially improved the transparency, quality, and effectiveness of this DSP and provides a robust foundation for Commission review of the filing.

3. *Description of the Current Distribution System*

PNM's distribution system consists of substations, distribution substation transformers, overhead and underground primary circuits, distributed energy resources, monitoring and control equipment, and field devices used to deliver electric service to customers. This section establishes the current-system baseline used in PNM's distribution planning process and summarizes system capacity, circuit mileage, DER deployment, system visibility, and distribution operations.

PNM's distribution system uses a mix of primary distribution, and secondary distribution voltages, with the specific voltage depending on customer density, load size, and geographic location. The primary distribution voltages most used by PNM are 12.47 kV (12.47/7.2 kV grounded wye). While that is historically the most common distribution voltage on the PNM system, PNM's distribution system voltages vary primarily with more legacy installations. Additionally, PNM's current feeder capacity standard is generally approximately 10 MVA and each substation unit transformer typically has four feeders. Its unit transformers are typically 33 MVA and are designed to ensure that once constructed, they will be able to serve customer loads over a range of conditions and ensure continuity of service over time.

PNM's Distribution Standards group has established equipment and design bases for its system to ensure efficient design, maintenance, and equipment and materials sparing strategies across its system. These standards are updated from time to time, as determined necessary by PNM's Standards department.

3.1 Utility Service Territory Overview

PNM is a wholly owned subsidiary of TXNM Energy, Inc. based in Albuquerque, New Mexico. PNM is an electric utility that provides generation, transmission, and distribution service. In total, PNM serves more than 550,000 New Mexico residential and business customers in greater Albuquerque, Rio Rancho, Los Lunas and Belen, Santa Fe, Las Vegas, Alamogordo, Ruidoso, Silver City, Deming, Bayard, Lordsburg, and Clayton. PNM also serves the Tribal communities of the Tesuque, Cochiti, Santo Domingo, San Felipe, Santa Ana, Sandia, Isleta, and Laguna Pueblos located in New Mexico. As shown in Figure 3-1, PNM's electric service territory covers geographically diverse areas. Electric demand and energy usage varies based upon geography, customer mix, and climate.

Figure 3-1: PNM's Electric Service Territory Map



3.2 Total Distribution Substation Capacity

As of the date of filing this DSP, PNM operates 197 energized distribution substation transformers with a combined connected nameplate capacity of 4,012.7 MVA. Eighteen of these transformers are dedicated to specific customers. These transformers supply PNM's primary distribution system across Northern, Central, and Southern New Mexico. Table 3-1 summarizes the number and connected nameplate capacity of these transformers by area.

Table 3-1: Distribution Substation Transformer Capacity by Area

Area	Energized Substation Transformers	Connected Nameplate Capacity (MVA)
Northern New Mexico	39	475.8
Central New Mexico	128	3,169.4
Southern New Mexico	30	367.6
PNM total	197	4,012.7

3.3 Total Distribution Transformer Capacity

For purposes of this DSP, distribution transformer capacity is reported as the combined connected nameplate capacity of the energized substation transformers that supply PNM's primary distribution system. PNM's total distribution transformer capacity is 4,012,669 kVA.

3.4 Total miles of Overhead Distribution

The overhead distribution system consists of approximately 7,908 miles of overhead lines, including about 5,803 miles of primary overhead distribution and 2,105 miles of secondary overhead distribution.

3.5 Total Miles of Underground Distribution

The underground distribution system consists of approximately 7,893 miles of underground lines, including about 6,260 miles of primary underground distribution and 1,633 miles of secondary underground distribution.

3.6 Total Amount of DERs on the Distribution System

PNM's distribution system includes 48,635 interconnected distributed energy resource (DER) installations representing approximately 624.1 MW of installed capacity. Solar generation is the predominant DER technology, with 47,540 installations representing approximately 557.6 MW, excluding community solar. In addition, nine community solar projects totaling 42.75 MW are online. PNM also owns and operates two distribution-sited battery energy storage systems with a combined installed nameplate capacity of 12 MW. PNM intends to install five additional battery energy storage systems with a combined capacity of 30 MW, which are expected to be online in 2027. The remaining DERs include wind and natural gas technologies. DER deployment ranges from small customer-sited systems to larger distribution-connected facilities. Table 3-2 summarizes current DER deployment by technology. Appendix C includes PNM's DER interconnection queue status as of December 2025, the current DER deployment by technology and geographic dispersion, microgrid status, as well as the current electric vehicle market and electrical vehicle market projections.

Table 3-2: Distribution-Connected DER by Technology

Technology	Installations	Installed capacity (MW)
Solar (excluding Community Solar)	47,540	557.556
Community Solar	9	42.750
Customer Battery Energy Storage	1,041	9.706
PNM Distributed Sited Battery Energy Storage	2	12.000
Other DER*	43	2.074
PNM total	48,635	624.086

*Other DER's include Wind and Natural Gas

3.7 Total number of Distribution Premises

PNM serves approximately 550,000 premises.

PNM utilizes communicating meters that are interrogated remotely to support various customer programs; however as of today, PNM has no customers with two-way AMI meters. PNM plans to start deployment of AMI meters in Q4 2026 as part of its Grid Modernization Plan, discussed later in this DSP.

3.8 Percentage of Substations and Feeders with SCADA Monitoring, Controls

PNM's distribution system includes 197 distribution substations. Of these, 77 are System Control and Data Acquisition (SCADA) monitored and controlled, representing approximately 39.1 percent of the substations in the system. Where SCADA monitoring and control is lacking, a sum of the feeder data is typically used for substation load data.

PNM's distribution system includes 616 distribution feeders. Of these, 602 are SCADA monitored and controlled, representing approximately 97.7 percent of the feeders in the system. The remaining 14 feeders are designated for manual control and rely on circular chart data. Of the 14 that are manually controlled, PNM is in the process of updating 6 of the remaining feeders this year.

Table 3-3: SCADA Control Status

Control Status	Substations	Percentage
SCADA control	77	39.1%
Manual control	120	60.9%
	Feeders	
SCADA control	602	97.7%
Manual control	14	2.3%

3.8.1 System Visibility

System visibility is a critical component of the Distribution System Plan because it provides operators and Distribution Planning Engineers with real-time and historical insights into the performance, condition, and utilization of the electric distribution network. PNM uses its SCADA system at equipped substations and feeders to monitor system conditions and support distribution operations. SCADA provides real-time feeder-loading information to operating applications and remotely controlled equipment. Distinguishing SCADA-controlled and manually operated feeder positions allows operations personnel to identify control exceptions and coordinate system response. Whereas PNM has good visibility at the feeder head, visibility on the extent of the feeders is lacking. PNM uses SCADA control for SCADAmate switches and reclosers, and has some SCADA monitored voltage regulators, but most existing devices on the distribution feeders are locally controlled or manually operated with no remote visibility. SCADA control is limited

to opening and closing devices. Setting changes must be done in the field. Table 3-4 shows the approximate quantities of both underground and overhead devices with and without SCADA on the system.

Table 3-4: Distribution Line Device SCADA Status

	Switches	Voltage Regulators	Reclosers
SCADA monitoring	511	22	137
SCADA control	511	0	137
Local/Manual control	4140	79	205
Total	4651	101	342
Percent SCADA monitored	11.0 %	21.8 %	40.0 %

Grid Modernization gives PNM better visibility by installing more SCADA visible and controlled equipment for a more dynamically operated system.

PNM uses local and remote-controlled capacitors for power factor and voltage support. PNM has little visibility into the operational status of the local controlled capacitors. Where deployed, PNM presently uses the Volt/VAR Management System (VVMS) to control selected switched capacitor banks and support feeder and transmission power-factor performance. PNM's ability to maintain a consistent power factor is a result of installing radio-controlled capacitor banks that follow power factor targets established for the Albuquerque, East Mountain, Deming, Sandoval, Santa Fe, and Valencia divisions. Capacitors are switched on and off by the VVMS system that uses feeder KVAR data from our existing SCADA system to determine which capacitors are needed to meet the target power factor.

The VVMS system attempts to maintain a specific distribution system target power factor by switching 1200 KVAR and 1800 KVAR banks on and off as needed. Due to the size and location of banks, and loading on a given feeder, the actual power factor varies from the preset target. The VVMS system calculates the required VAR amount needed to meet the target power factor. The required capacitors are operated via a one-way radio signal that is transmitted every 10 minutes to accomplish switching. The VVMS system also tracks the status (tripped or closed) of each capacitor bank. If a command to switch a capacitor bank is issued and it does not result in the expected VAR change, the operation is automatically logged as a failure in a capacitor failure log. Distribution system operators monitor capacitor failure logs and initiate the necessary maintenance requests.

The VVMS system began operation in July 1997 and currently controls 526,800 KVAR of capacitor banks in the Albuquerque, East Mountain, Deming, Sandoval, Santa Fe, and Valencia divisions. Table 3-5 shows the approximate quantities of capacitors by control on the system.

Table 3-5: Capacitor Control Status

Control Status	Feeder Positions	Percentage of Capacitors
VVMS control	416	58.1 %
Fixed	257	35.9 %
Local control	43	6.0 %
Total	716	100.0 %

3.9 Summary of Reliability Metrics

PNM measures distribution-system reliability through its Outage Management System (OMS), including transmission outages that may affect distribution customers. The OMS integrates customer interruption reports with PNM's geographic information system to identify the first upstream interrupting device, calculate affected customers, and track partial and complete restoration. PNM applies the IEEE Standard 1366 to calculate reliability indices and identify Major Event Days (MEDs). Daily operational review and monthly data validation support data accuracy.

PNM monitors and tracks the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and Average Service Availability Index (ASAI). PNM reports this data throughout its organization but also regularly shares this data to the NMPRC. SAIDI measures average cumulative sustained interruption duration per customer; SAIFI measures average sustained interruptions per customer; CAIDI measures average restoration time per interrupted customer; and ASAI measures service availability. The indices exclude planned interruptions and are evaluated both including and excluding MEDs.

Table 3-6 summarizes PNM's systemwide results, excluding MEDs for 2021 through 2025. The totals include distribution, substation, and transmission interruptions that affect distribution customers.

Table 3-6: PNM System Reliability Indices Excluding Major Event Days, 2021-2025

Year	SAIDI (minutes per customer)	SAIFI (interruptions per customer)	CAIDI (minutes per interruption)
2021	86.22	0.742	116.12
2022	101.33	0.783	129.39
2023	92.17	0.726	127.01
2024	124.45	1.008	123.51
2025	116.51	0.868	134.30

In 2025, excluding MEDs, PNM's systemwide SAIDI was 116.51 minutes per customer, SAIFI was 0.868 interruptions per customer, CAIDI was 134.30 minutes per interruption, and ASAI was 99.9778 percent. Including MEDs, SAIDI was 125.10 minutes per customer, SAIFI was 0.937

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interruptions per customer, CAIDI was 133.49 minutes per interruption, and ASAI was 99.9762 percent. These results represent approximately 99.98 percent service availability and fewer than one sustained interruption per customer on average. Compared with 2024 results excluding MEDs, SAIDI and SAIFI decreased in 2025, while CAIDI increased.

PNM experienced one MED in 2025, a March 18 high-wind and tree event affecting the Albuquerque metropolitan and Santa Fe areas. The event affected 38,567 customers, all of whom were restored within 24 hours. Equipment was the largest contributor to interruption duration in 2025, led by primary cable faults, primary conductor slap, and crossarm issues. Power-supply events, lightning, and vegetation were also noted.

PNM screens distribution feeders with at least ten customers when feeder SAIDI or SAIFI is equal to or greater than the corresponding distribution-system value plus 300 percent, and tracks repeat results across years. PNM uses these results with outage causes, extended interruptions, asset condition, and operating information to risk-prioritize reliability investments to maintain customer reliability. This planning-level summary is additive to, and does not replace, reporting requirements in Docket No. 24-00246-UT.

3.9.1 Feeder-Level Reliability Performance

Tables 3-7 and 3-8 identify the feeders that exceeded the applicable feeder SAIDI and SAIFI screening thresholds in 2025. Highlighted rows identify feeders that exceeded the applicable threshold for two consecutive years. Only feeders serving at least 10 customers are included.

Table 3-7: 2025 Feeders Above SAIDI Threshold

2025 Distribution System SAIDI: 100.94 , Feeder SAIDI Threshold: 403.76, Total Feeders: 574							
2025 SAIDI Ranking	2024 SAIDI Ranking	Substation	Feeder ID	Location	Customers on Feeder	2025 SAIDI Value	Reason Above Threshold
1	N/A	MD #11	MD0012	Silver City	1556	3873	Fire Encroachment De-energization, Conductor Failure
2	N/A	CLIFF	CLIF12	Silver City	385	2065	Unknown/Not Found, Trees, Floater
3	N/A	BUCKMAN2	BUCK23	Santa Fe	207	1381	Dig-in, Animal Underground
4	N/A	CLIFF	CLIF11	Silver City	143	1376	Unknown/Not Found, Floater
5	2	COCHITI	COCH12	Santa Fe	313	1235	Lightning, OH Connector
6	N/A	SILVER CITY	SL0018	Silver City	1718	904	Floater. Unknown/Not Found
7	N/A	CAMEL TRACKS	CATR11	Santa Fe	28	824	Cable Fault(Primary)
8	5	GALLINAS	GALL11	Las Vegas	2248	769	PSPS, Floater, Lightning
9	N/A	SAN ANTONITO1	SNAN12	East Mountain	323	675	Trees
10	N/A	FORT MARCY	FOMA14	Santa Fe	1984	674	Lightning, Unknown/Not Found, Trees
11	1	COCHITI	COCH11	Santa Fe	602	656	Lightning
12	N/A	STATE PEN	STPE13	Santa Fe	2581	649	Reclosure Failure, Unknown/Not Found
13	22	STATE PEN	STPE12	Santa Fe	1916	592	Unknown/Not Found, Lightning, Cable Fault(Primary)
14	19	WAYNE2	WAYN24	ABQ NW	622	512	Trees, Conductor Down
15	N/A	ALAMOGORDO 1	A10002	Alamogordo	2057	511	Lightning, Other, Unknown/Not Found
16	4	LOS MORROS2	LSMO21	Valencia	141	465	Lightning
17	N/A	ALAMOGORDO 1	A10001	Alamogordo	3760	462	Crossarm, Trees
18	N/A	ZAMORA	ZAMO12	East Mountain	2203	443	ConductorSlap Primary, Lightning
19	N/A	BURRO MOUNTAIN	BM0160	Silver City	146	437	Unknown/Not Found
20	N/A	SOUTH PACHECO2	SOPA26	Santa Fe	1847	435	Dig-in, Bird
21	N/A	FOUR HILLS	FOHI11	ABQ SE	2694	408	Conductor Slap Primary, Lightning Arrestor, Cable Fault(Primary)

Table 3-8: 2025 Feeders Above SAIFI Threshold

2025 Distribution System SAIFI: 0.728, Feeder SAIFI Threshold: 2.912, Total Feeders: 574							
2025 SAIDI Ranking	2024 SAIFI Ranking	Substation	Feeder ID	Location	Customers on Feeder	2025 SAIFI Value	Reason Above Threshold
1	N/A	BUCKMAN2	BUCK23	Santa Fe	207	14.52	Dig-in, Animal Underground
2	N/A	CLIFF	CLIF12	Silver City	385	10.83	Unknown/Not Found, Lightning Arrestor, Trees
3	N/A	CLIFF	CLIF11	Silver City	143	8.36	Unknown/Not Found, Lightning Arrestor
4	N/A	MD #11	MD0012	Silver City	1556	6.25	Unknown/Not Found, Conductor Failure, Conductor Slap Primary
5	N/A	SILVER CITY	SL0018	Silver City	1718	6.05	Unknown/Not Found, Floater
6	N/A	STATE PEN	STPE13	Santa Fe	2581	5.56	Recloser Failure, Unknown/Not Found
7	N/A	FORT MARCY	FOMA14	Santa Fe	1984	5.31	Lightning, Unknown/Not Found, Overload
8	N/A	CAMEL TRACKS	CATR11	Santa Fe	28	4.82	Cable Fault(Primary)
9	9	SOUTH PACHECO2	SOPA26	Santa Fe	1847	3.98	Dig-in, Bird
10	N/A	ZAMORA	ZAMO12	East Mountain	2203	3.62	Conductor Slap Primary, Lightning
11	N/A	COCHITI	COCH12	Santa Fe	313	3.60	Lightning, Overhead Connector
12	N/A	ARRIBA	ARIB11	Las Vegas	1952	3.31	Unknown/Not Found, Lightning, Conductor Failure
13	2	LOS MORROS2	LSMO21	Valencia	141	3.21	Lightning
14	N/A	COLINAS	COLI13	Santa Fe	2750	3.17	Unknown/Not Found, Lightning Arrestor, Trees
15	N/A	ALAMOGORDO 1	A10002	Alamogordo	2057	3.15	Lightning, Unknown/Not Found, Other
16	5	WAYNE2	WAYN24	ABQ NW	622	3.13	Trees, Conductor Down
17	N/A	SAN ANTONITO1	SNAN12	East Mountain	323	3.05	Trees, Recloser Failure
18	N/A	RODEO	RODE13	Santa Fe	2891	3.04	Other, Unknown/Not Found
19	N/A	LAWRENCE	LAWR12	ABQ NE	1279	3.04	Conductor Slap Primary, Lightning
20	11	CLAREMONT	CLAR13	ABQ NE	1255	3.02	Trees, Balloon, Lightning

3.10 Major Areas of Distribution Planning Focus

Major areas of focus on PNM's distribution system are generally characterized by three major areas:

- 1) limited remaining capacity on feeders, transformers, substations, or other critical infrastructure,
- 2) legacy or aging infrastructure, and
- 3) emergent issues, such as equipment failure(s).

3.10.1 Capacity Limitations

Regarding capacity limitations, these constraints can arise from sustained load growth, concentrated customer development, electrification initiatives, or changing system usage patterns. Identifying and communicating these capacity limitations is a vital component of the Distribution System Plan, as it allows stakeholders to understand where infrastructure investments may be necessary to maintain reliability and support future economic development. PNM uses engineering analyses, load forecasts, and system visibility tools to identify constrained areas and prioritize investments that address current deficiencies and anticipated future needs.

3.10.2 Legacy or Aging Infrastructure

Regarding legacy or aging infrastructure, PNM monitors the age and condition of its equipment through inspections and use of an Asset Management Database system. PNM's environment generally supports long-term reliability of equipment given the mild weather and lack of natural disasters that other areas of the nation experience. That has allowed PNM to get very good, useful lives out of its investments, but even well-maintained equipment in mild weather conditions require upgrades. As such, PNM monitors asset age and tries to maximize equipment life but replace equipment before it can fail in the field.

The average age of Distribution Substation Transformers is about 39 years with the expected service life of about 50 years. About 35% of Distribution Substation assets are at or beyond their expected service life. Distribution infrastructure assets have a service life of about 40-75 years depending on the asset. About 15% of Distribution infrastructure assets are at or beyond their expected service life.

Examples of the most problematic aging or legacy infrastructure are live-front padmount transformers and switchgear, open-wire secondary installations, and pole and cable replacement(s). While there are other categories of distribution equipment age-related concerns, these are the most significant in PNM's system and as such, are addressed through regular risk prioritization and programmatic investments.

3.10.3 Emergent Conditions

The final category of issue is emergent conditions that occur as the result of a failure or accident. PNM periodically experiences equipment failures and/or cars hitting poles or other elements in the field. When this occurs, PNM generally treats it as an emergency condition and endeavors to repair the issue as promptly as safe and practicable.

3.11 Distribution Operations

PNM operates its distribution system using centralized monitoring and control together with remote field equipment and fixed or locally controlled devices. Distribution line capacitor banks provide voltage support and power-factor correction. Certain capacitor banks are fixed or locally controlled, while selected switched banks are remotely controlled through VVMS. The system uses real-time feeder-loading information and seasonal power-factor settings to determine switching needs. This operating approach allows PNM to apply remote control where communications and control equipment are installed while continuing to use local device control throughout the remainder of the system.

PNM currently operates its distribution system using a combination of centralized SCADA monitoring, selected remotely controlled field devices, VVMS, and locally controlled field equipment. While this operating model has provided safe and reliable service, visibility and controllability are not uniformly available across the distribution system. In many areas, operators have visibility primarily at substations, feeder breakers and selected feeder devices, while planning and operational decisions continue to rely on periodic engineering studies and limited field telemetry. PNM's Grid Modernization investments, as described in Section 5.2.1, are intended to significantly expand operational awareness and controllability beyond the substation

by deploying Advanced Metering Infrastructure (AMI), enhanced telecommunications networks, Distribution Automation (DA) devices, Advanced Distribution Management System (ADMS) applications, Integrated Volt/VAR Optimization (IVVO), Fault Location Isolation and Service Restoration (FLISR), and Distributed Energy Resource Management System (DERMS) functionality. Together, these investments will provide more granular feeder-level visibility, expanded monitoring of field equipment and customer load behavior, improved outage awareness, greater ability to remotely operate the distribution system, and enhanced integration of distributed energy resources. These capabilities will not only improve Distribution Operations but will also provide the data foundation necessary to support the evolving Distribution Planning processes described in Section 4, including improved forecasting, hosting capacity analysis, non-wires alternative evaluation, DER integration, and more targeted capital investment decisions.

4. *Distribution Planning Process*

PNM uses Distribution Planning to translate customer load, distributed energy resource activity, asset capability, operating constraints, and long-term service expectations into practical distribution system investments and operating strategies. This process is built around multiple related levels of review: the division-level Ten-Year Distribution System Plan, Substation Outage review, reconfiguration studies, detailed Area studies, Interconnection studies, and Hosting Capacity analysis for distributed generation and other distributed energy resources.

The Ten-Year Plan is the first step in PNM's Distribution Planning process and is completed annually. It includes a system level loading review and intentionally a high-level forecasted screening based on available capacity. It identifies potential substation transformers, feeder, outage restoration, and hosting capacity constraints, and is used to estimate when additional capacity or reliability projects may be needed over a forward-looking 10-year period. A detailed reconfiguration and/or detailed area study using Synergi Electric modeling then confirms whether a project is needed, whether operational or lower-cost alternatives can resolve the concern, the appropriate project scope, and the refined timing and cost estimate before a project is transitioned into design and construction.

This Distribution Planning process is continuously improving. PNM is moving from traditional load capacity planning toward a more integrated planning framework that considers Distributed Energy Resource (DER) penetration, customer-sited storage, transportation and building electrification, demand response, non-wires alternatives, and the automation needed to conduct more frequent feeder-level analysis. The section provides a more detailed insight into PNM's Distribution Planning process.

4.1 Planning Criteria

PNM applies planning criteria to evaluate whether the distribution system can reliably serve existing and forecasted customer load, maintain acceptable voltage, accommodate DER, and support restoration under substation transformer outage conditions. In accordance with good utility practice, PNM evaluates the outage of one substation transformer at a time and develops contingency switching plans to restore power to the outage area from an alternate substation source. The criteria are used consistently across division planning cluster studies, reconfiguration studies, and detailed area studies. The level of power-flow modeling complexity increases as an issue progresses from a high-level screening concern to a fully detailed engineering study.

At the screening level, the most visible trigger is the substation transformer loading criterion. PNM commonly screens normal transformers loading against an 80 percent peak loading threshold. When a transformer or cluster approaches or exceeds that threshold over the planning horizon, the condition is flagged for additional review. The 80 percent loading level is not intended to mean that equipment cannot operate above that level under all conditions; rather, it provides a key planning indicator that reliability and backup margin that helps preserve capacity for load growth, transfers, outage restoration of interconnected feeders, DER-related uncertainty, and operational flexibility, may be at risk in the near future.

Detailed studies apply a broader set of criteria. These include transformer normal and emergency ratings, feeder and conductor thermal limits, voltage criteria, contingency switching limits, and equipment standards. When potential solutions are developed, PNM also validates that the solution maintains acceptable performance under normal configuration, under contingency configuration, and under future load-growth or DER sensitivity conditions.

Table 4-1: Distribution Planning Criteria Used in PNM Planning Studies

Planning Criterion	Typical Threshold / Standard	Primary Planning Use
Substation transformer contingency loading	Should not exceed 90 percent of emergency rating during contingency operation.	Evaluates whether load can be restored or carried after loss of a transformer or other major element.
Substation transformer normal loading	Should not exceed 80 percent of normal rating during normal conditions.	Screening criteria for division plans and a primary trigger for additional capacity review.
Equipment, conductor, and cable loading	Should not exceed 100 percent of normal rating; planning solutions generally target conductor loading below 90 percent where practicable.	Used in detailed feeder, area study, and hosting capacity power-flow analysis.
New feeder construction	Maximum circuit ampacity for new feeder construction is generally 430 amps.	Maintains planning margin for new feeder projects and long-term operating flexibility.
Feeder contingency loading	Should not exceed 550 amps on the highest loaded phase for contingency planning; PNM operates a 600-amp standard system and phase amperage should not exceed 600 amps in any configuration.	Limits loading during temporary restoration and switching conditions.
Primary voltage - normal planning	Range A voltage criteria, typically 118.7 V minimum and 126 V maximum on a 120 V base.	Maintains acceptable steady-state customer voltage during normal configuration.
Primary voltage - contingency planning	Range B voltage criteria, typically 114.6 V minimum and 127 V maximum on a 120 V base.	Maintains acceptable voltage during contingency restoration.
Contingency switching	Planning studies typically limit contingency restoration to two normal switching steps and one supplemental switching step for a feeder outage scenario.	Ensures that proposed contingency plans are operationally realistic and not dependent on excessive switching complexity.

**The values summarized above are consistent with the planning criteria reflected in recent PNM area study resources and provide the technical basis for the planning process discussion.*

Planning criteria are applied in concert with engineering judgment. For example, a high-level division plan may identify that a cluster has sufficient aggregate emergency capacity for a loss-of-transformer scenario, but a detailed area study may still identify feeder-level voltage, thermal, or switching constraints that prevent all customers from being restored through available ties. Conversely, a transformer may be above the 80 percent screening threshold, but a more detailed review may show that a reconfiguration, load transfer, or already-planned project provides an acceptable path before a new major project is needed.

4.2 Terms Used in PNM's Distribution Planning Process

PNM organizes Distribution Planning around practical geographic areas so that system needs can be screened, studied, and communicated at the right level of detail. The planning process generally moves from the PNM service territory to a division, from a division to one or more clusters, and from a cluster to individual substations, feeders, and projects. Defining these terms early helps readers understand how the Ten-Year Plan, Substation Outage review, reconfiguration studies, area studies, and hosting capacity work fit together.

For clarity in this DSP, the following terms are defined in this section:

- **Division** - a broader operating or planning area used to organize the Ten-Year Plan and summarize needs across multiple substations, feeders, and planning clusters.
- **Cluster** - a smaller planning area within a division that groups substations and feeders that are geographically, electrically, or operationally related. Clusters help PNM evaluate local capacity, load-transfer, contingency, and hosting capacity needs at a practical planning scale.
- **Contingency (N-1)** - A Contingency (N-1) is a focused N-1 review of a single substation transformer outage for the next projected peak load season. N-1 means the normal state minus one critical asset such as a substation transformer or a feeder. The review evaluates whether the affected load can be restored by adjacent substations and feeders, considering available feeder ties, switching options, phase balancing, conductor and equipment ratings, voltage performance, and other operating limitations. This can also be referred to as a Substation Outage Review. The PNM Outage Contingency Application supports this review by organizing contingency restoration options and related feeder outage and switching information. If the review indicates that the outage cannot be managed through practical operating actions, the issue may be escalated to a Reconfiguration Study, Detailed Area Study, or capital project evaluation.
- **Reconfiguration Study** - a detailed engineering review of a cluster or other defined area to determine if an overloaded transformer or feeder can be alleviated with a lower cost distribution system reconfiguration and load transfer without adding new substation transformer capacity.
- **Area Study** - a detailed engineering review of a cluster or other defined area that cannot be resolved with a Reconfiguration Study. An area study verifies the high-level planning concern, evaluates and compares potential capacity solutions, and determines the scope and timing of major projects.

- **Ten-Year Distribution System Plan** - the division-level capacity screening and budgeting report that identifies potential capacity needs and estimated timing over the planning horizon. The Ten-Year Plan, or Ten-Year Plan, does not by itself finalize project scope, location, cost, or approval. Larger distribution feeder extensions or feeder upgrades are also included in the Ten-Year Plan if the anticipated cost classifies them as a large capital project.

Table 4-2: Relationship Between PNM Planning Review Levels

Planning level	Primary purpose	Typical outputs	How results are used
Ten-Year Plan	Screen the system by division and cluster using historical loading, forecast loading, area contingency capacity, DER information, and all known new-load inputs.	Transformer load forecasts, cluster summaries, high-level area contingency results, potential project timing, preliminary costs, and high-level hosting capacity indicators.	Identifies planning criteria for concerns and potential investments. Results are indicators and do not, by themselves, establish a final project scope.
Substation Outage Review/Contingency Study	Evaluate a single substation transformer outage can be successfully restored by adjacent feeders/substations	Phase balancing, potential feeder ties, switching actions, reconductoring, load transfers, voltage device changes, and other smaller-scope mitigations.	Provides operation plans for peak load outage solutions. When operational issues are found, the need is escalated to a more focused area study.
Reconfiguration / focused engineering review	Evaluate whether near-term operational actions can address a planning concern before a major capital project is proposed.	Potential feeder ties, switching actions, reconductoring, load transfers, voltage device changes, and other smaller-scope mitigations.	Documents whether operational fixes are feasible, durable, and sufficient. If not, the need is escalated to a detailed area study.
Detailed Area Study	Perform engineering analysis for a geographic area or planning cluster where system issues are significant or where a major project may be required.	Power-flow model results, normal and contingency performance, alternative solutions, sensitivity analysis, solution comparison, project descriptions, cost estimates, and schedule assumptions.	Confirms the need, scope, location, timing, and planning justification for major capacity or reliability investments.
Hosting Capacity Analysis	Evaluate the ability of feeders and related facilities to host additional DER without causing thermal, voltage, protection, or operational concerns.	Base-case hosting capacity, system improvement scenarios, sensitivity results, public-facing summary information, and DER integration insights.	Supports interconnection review, DER planning, grid modernization, and identification of hosting capacity improvement projects.

Figure 4-1 summarizes PNM's planning process. Each of these phases of PNM's distribution planning process are outlined in more detail below.

Figure 4-1: Distribution Planning Systematic Review from Service Territory to Project Transition



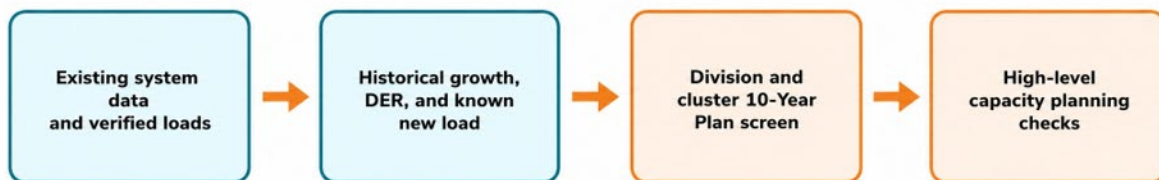
4.3 PNM's Ten-Year Planning Process

PNM's Ten-Year Plan is prepared by division and is used to identify high level load-growth trends, existing and forecasted capacity constraints, single-contingency exposure(s), hosting capacity limitations, and potential distribution projects over a Ten-Year planning horizon. The plans use Excel workbooks, SCADA load data, forecast assumptions, and reporting tables so that the Distribution Planning Engineers can compare needs across urban, suburban, rural, and geographically distinct planning areas.

The Ten-year Planning process is not intended to replace detailed engineering studies. Instead, it provides a consistent annual, first look across the system. When a potential need appears in a Ten-Year Plan, PNM uses additional engineering studies to confirm the scope, timing, cost, constructability, and operational value of any proposed solution. It also allows PNM to begin plans for land acquisition and other necessary permitting and sourcing activities so the issue can be timely resolved.

Figure 4-2 summarizes the Ten-Year Plan process at a high level. The process begins with SCADA load data and division/cluster setup, moves through forecast and screening reviews.

Figure 4-2: Overview of PNM's Ten-Year Distribution Planning Process



4.3.1 Distribution Capacity Planning

Distribution capacity planning is the first step in distribution system planning because the ability to serve load safely and reliably depends on the available capacity of substation transformers, feeders, conductors and feeder ties. The Ten-Year Plan process evaluates whether that capacity remains adequate as customer load grows, as load shifts among substations and feeders, as economic development projects are added, and as DER changes the load seen by the distribution system.

For each annual Ten-Year Plan cycle, Distribution Planning Engineers populate a Ten-Year Plan workbook with the most recent pertinent system data for the division and cluster being reviewed. The populated workbook is used to organize the most up-to-date version of the data described below and to generate the transformer forecasts, contingency indicators, hosting capacity indicators, and summary tables used for the high-level Ten-Year Plan screening.

The Ten-Year Plan begins with existing system data, including verified peak and minimum loads from available SCADA readings, transformer ratings, cluster assignments, DER and co-generation information, solar irradiance profile inputs, large PV assumptions, and residential PV data. Distribution Planning Engineers use the workbook to develop transformer and cluster load forecasts, capture known new load interconnections, incorporate proposed area study or forecast-evaluation projects, and evaluate contingency and hosting capacity indicators.

Table 4-3: Major Inputs and Outputs in the Ten-Year Plan Process

Ten-Year planning input or step	How it is used in the planning process
PNM verified peak/minimum load SCADA data	Establishes the existing loading baseline and supports both peak-load and minimum-daylight-load analysis.
Solar irradiance profile	Supports analysis of rooftop PV, large-scale PV, and coincident solar output assumptions.
Study start year, division, and cluster inputs	Defines the planning area and study horizon used to populate cluster tables and reporting summaries.
Five-year historical transformer loading	Provides the basis for applied transformer growth rates and the 10-year load forecast.
New load interconnections and economic development inputs	Adds known or expected customer loads to the forecast when a project is sufficiently defined.
Detailed Area and Reconfiguration studies performed with Synergi power-flow analysis and forecast-evaluation projects	Shows how previously proposed or newly identified projects would change transformer loading, load transfers, and cluster capacity.
N-1 contingency tables	Evaluates remaining area emergency capacity under existing system, future load, and project scenarios.
Hosting capacity section	Captures BESS, community solar, approved generation, and other data used for high-level hosting capacity indicators.

4.3.2 Planning by Division and Cluster in the Ten-Year Plan

Section 4.1 defines the planning criteria used throughout this document. Within the Ten-Year Plan process, the division and cluster structure allows PNM to apply common planning criteria while still reflecting local geography, customer density, feeder topology, load growth, DER penetration, and operating constraints.

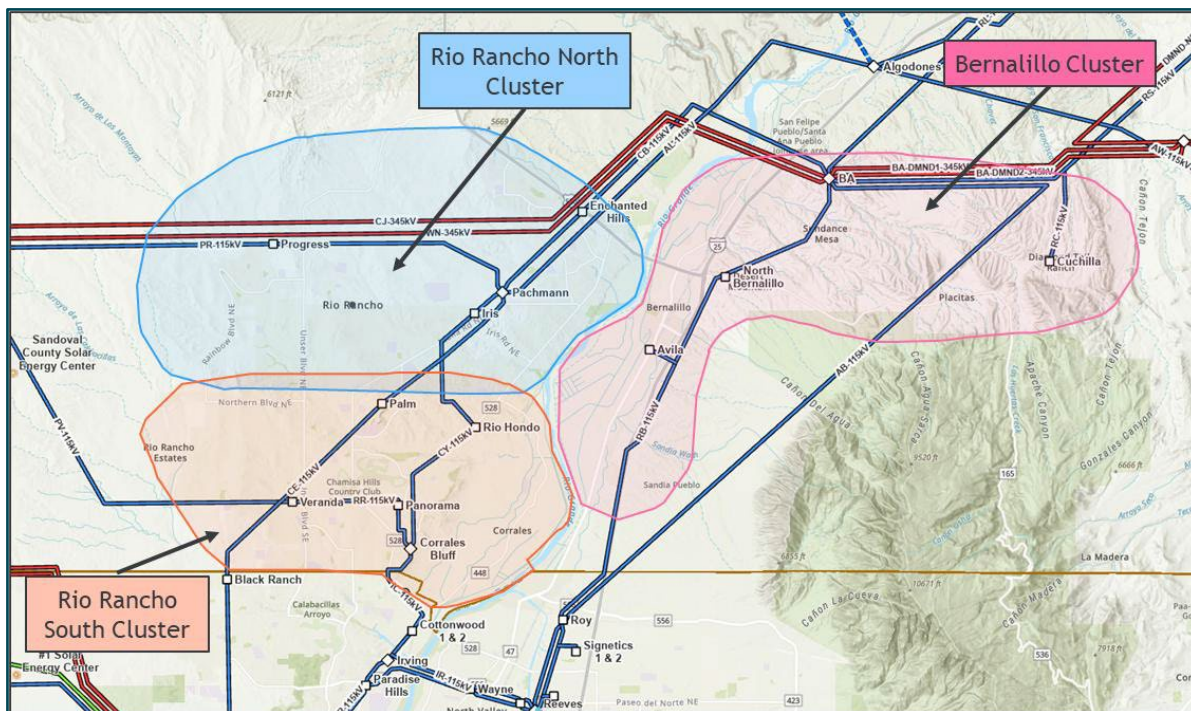
This approach is used across the 2026 Ten-Year Plan. Certain PNM divisions are divided into multiple functional clusters, such as the Albuquerque East Division with Northeast Heights, Montgomery Park, Coronado, and Foothills. Other divisions are smaller or more geographically compact and may be evaluated as a single cluster. In each case, the cluster provides a practical scale for evaluating transformer loading, feeder ties, contingency restoration, hosting capacity, and potential area study needs.

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The planning process applies the same capacity and reliability criteria to customers across divisions and clusters. PNM consistently applies its planning standards across its system, regardless of income ensuring no service differences in any community including underserved communities.

Figure 4-3 shows how a division is divided into multiple planning clusters.

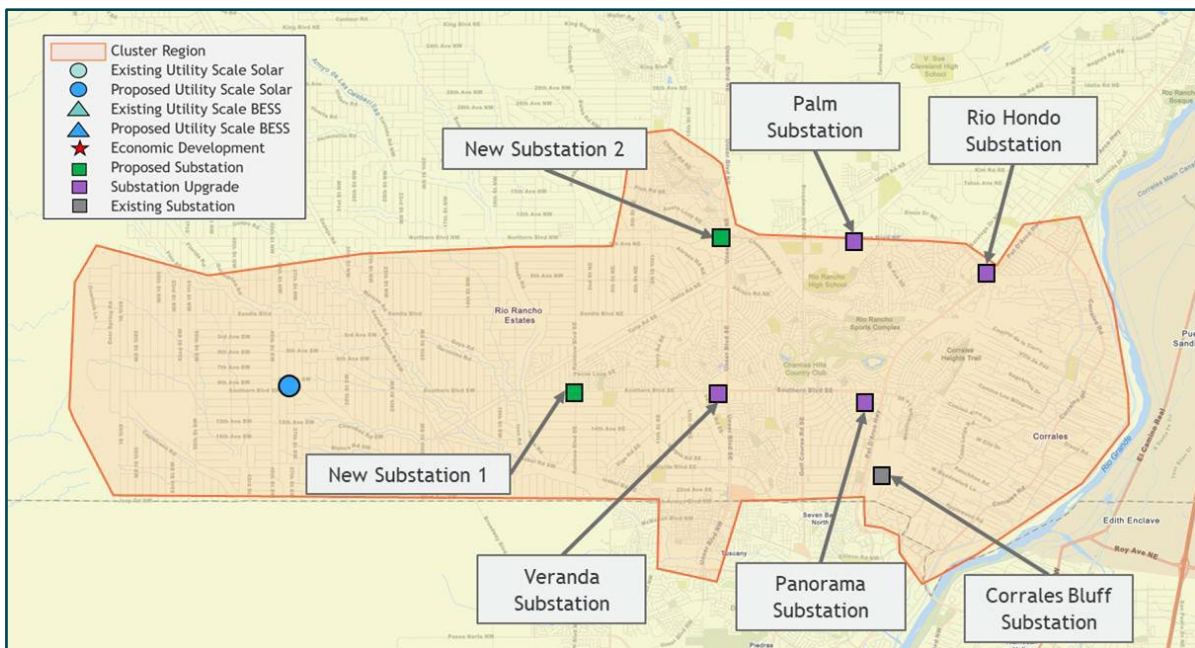
Figure 4-3: Example of a Division Divided into Planning Clusters - Sandoval Division



Source example: Sandoval Division 2026 Ten-Year Distribution System Plan. This figure is included to orient readers to the relationship between a division and clusters; it is not intended to replace detailed facility maps or engineering models.

Figure 4-4 then shows one cluster in greater detail, including the substations and proposed capacity additions that are evaluated as part of the planning process.

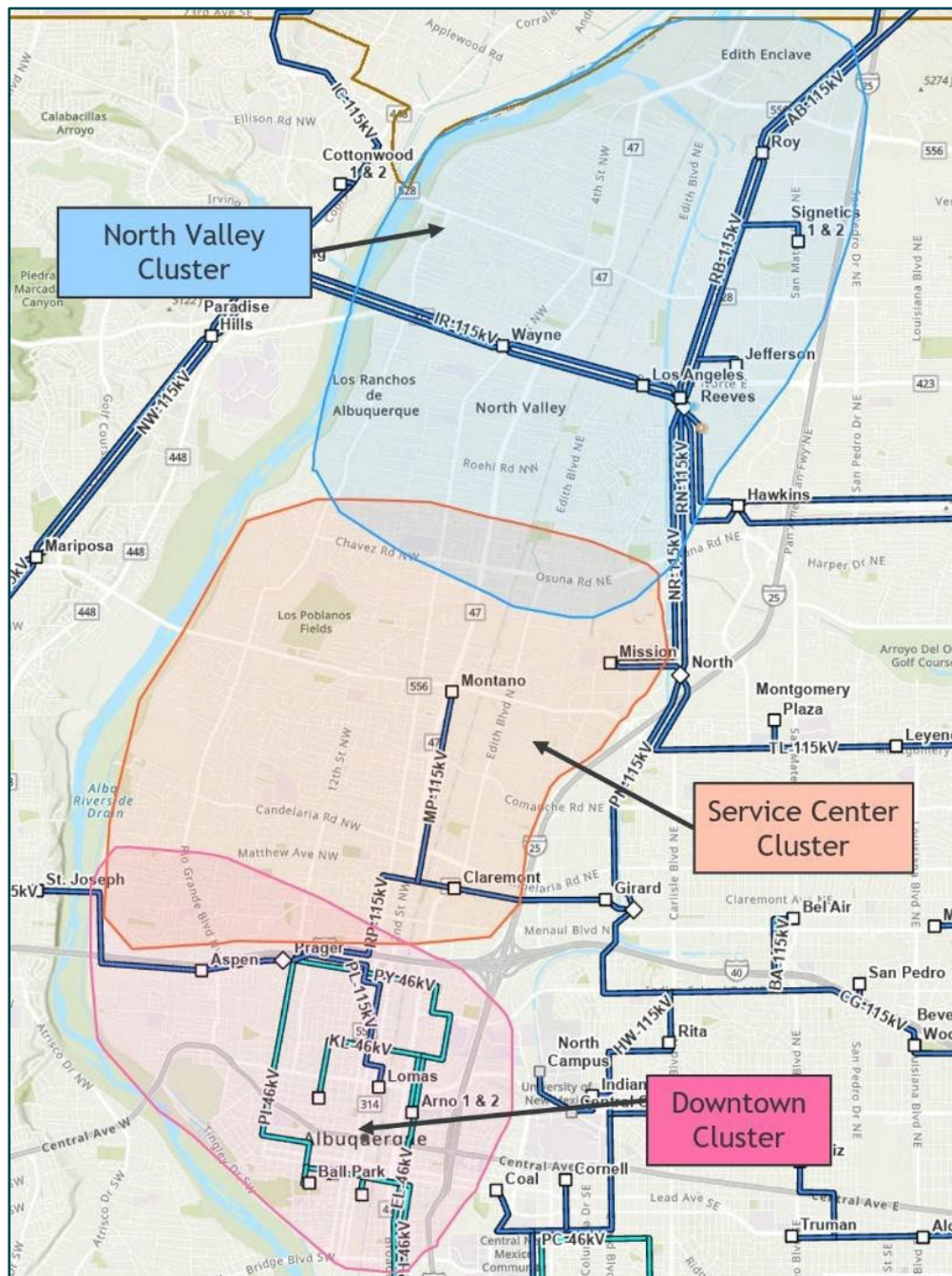
Figure 4-4: Example of a Cluster Used for Detailed Planning Review - Rio Rancho South Cluster



Source example: Sandoval Division 2026 Ten-Year Distribution System Plan, Rio Rancho South Cluster. This cluster is used later in Section 4 as a condensed example of how the Ten-Year Plan identifies planning triggers and how area study projects

Figure 4-5 provides a larger urban example from the Albuquerque Central Division to show that the same division/cluster framework applies in more complex areas of PNM's system. Together, these figures orient the reader before moving into forecasts, area studies, tools, load-altering considerations, and hosting capacity analysis.

Figure 4-5: Example of a Larger Urban Division Divided into Planning Clusters - Albuquerque Central Division



Source example: Albuquerque Central Division 2026 Ten-Year Distribution System Plan. This figure shows how North Valley, Service Center, and Downtown clusters are organized within a larger urban division.

With these terms defined, the rest of Section 4 describes the Ten-Year Plan screening process, detailed area studies, planning tools, load-altering considerations, and hosting capacity analysis that PNM uses to move from a high-level planning focus or concern to an actionable Distribution Planning recommendation.

4.3.3 Evolving Ten-Year Planning Process

System changes have triggered PNM's Ten-Year Plan process evolution from a primarily load capacity-focused process into a more integrated planning framework. Traditional capacity planning for load remains necessary, but it now must be coordinated with DER penetration, customer-side storage, community solar, transportation electrification, demand response, advanced metering, automation, and grid modernization capabilities to ensure continued public safety and customer reliability. Future Ten-Year Plan cycles can build on this existing process and incorporate improvements as better data and tools become available. For example, future plans may include more detailed feeder-level information and more detailed representations of resources such as EV charging, building electrification, rooftop solar, battery storage, and demand response that can change when and where load appears on the distribution system.

4.3.3.1 *Net Load and Gross Load*

The current Ten-Year Plan commonly evaluates substation transformer loading using net load. In the planning context, net load reflects the load observed by the grid after the effect of customer-sited behind-the-meter generation and other local generation is considered. This is important because rooftop PV and other DER can reduce the amount of load served through a transformer or feeder at certain times of the day. Gross load, by contrast, is the underlying customer demand before local generation reduces the load seen by the distribution system.

The Ten-Year Plan generally models rooftop PV as operating while large utility-scale PV systems are off for peak-season transformer loading. This approach is intended to simulate a high-load condition where large-scale PV generation may not be available or may not be coincident with the distribution peak. The distinction is important because relying only on net load can understate the capacity needed during low-solar-output, high-load, or large-PV-offline conditions. It can also affect DER planning because non-export inverters and customer-sited generation may mask load locally, reducing minimum daylight load and thereby changing the ability of a feeder to consume excess PV generation.

As the planning process necessarily becomes increasingly more complex and detailed, PNM expects to use both net-load and gross-load information where appropriate. Net-load analysis remains useful for equipment loading and actual system operation, while gross-load and scenario analysis help identify the risk that load may return to the grid when customer generation is unavailable, when inverter behavior changes, or when electrification adds new demand during different times of the day. Regardless, PNM must ensure its equipment abides by the laws of physics in all conditions and never unnecessarily risks safety or equipment failure for any reason.

4.3.3.2 Single-Contingency Analysis

The Ten-Year Plan includes a high-level single-contingency review, commonly focused on the loss of one substation transformer within a cluster. The review estimates whether the remaining transformers in the area have enough reserve capacity to restore the affected load. The contingency tables compare the area's rated emergency transformer capacity against existing and forecasted load and show whether additional capacity, load transfers, or a more detailed study may be required.

This high-level contingency review is an important screening tool, but it does not fully replace feeder-level contingency power-flow analysis.

4.3.3.3 High-Level Hosting Capacity Indicators in the Ten-Year Plan

The Ten-Year Plan includes high-level hosting capacity information to indicate where DER interconnections may be constrained or where future substation and feeder projects may improve DER flexibility. These indicators include approved generation, community solar expectations, BESS assumptions, and remaining transformer-level capacity, where available. They are planning indicators rather than final interconnection approvals. Individual DER projects must still follow the applicable interconnection review, screening, supplemental review, study, and approval process.

To show what this indicator looks like in the Ten-Year Plan, the following example uses the Las Vegas Cluster from the Las Vegas Division 2026 Ten-Year Distribution System Plan. This example was selected because it shows a clear planning signal: Arriba has significant existing generation, low remaining transformer-level hosting capacity, and high transformer utilization. The Las Vegas example provides the clearest single-table illustration of how the Ten-Year Plan flags transformer-level DER headroom concerns.

Table 4-4: Las Vegas Cluster High-Level Transformer Hosting Capacity Indicator, Ten-Year Plan Example

Transformer	Normal Rating MVA	Daytime Minimum Net Load MW	Total Transformer Generation MW	New Community Solar Projects MW	BESS MW	Estimated Remaining Hosting Capacity MW	% XFMR Utilization
ARRIBA	22.4	-17.7	20.3	0.0	0.0	2.1	91%
BACA	7.0	1.4	0.2	0.0	0.0	6.8	3%
GALLINAS	22.4	0.4	6.6	5.0	0.0	10.8	52%
Cluster Total	51.8	-15.9	27.2	5.0	0.0	19.6	62%

In this example, the Arriba transformer shows 20.3 MW of total transformer generation, 2.1 MW of remaining transformer-level hosting capacity, and 91% transformer utilization. That does not determine whether a specific generator can interconnect; rather, it flags the area for additional feeder-level analysis, interconnection review, or a hosting capacity improvement project if additional DER activity is expected.

To mitigate the hosting capacity constraint, the Las Vegas Ten-Year Plan identifies an ARIB11 hosting capacity improvement project to install a 6 MVA, 24 MWh BESS co-located with the San Miguel Solar Site, served by Arriba Feeder 11. This table should be read as an early planning indicator that points Distribution Planning Engineers to locations where detailed hosting capacity analysis may be needed.

The high-level Ten-Year Plan hosting capacity indicator should therefore be distinguished from the detailed hosting capacity analysis described later in Section 4.10. The Ten-Year Plan table provides a transformer-level planning screen; the detailed system impact study process evaluates feeder-level thermal, voltage, protection, operating, and interconnection constraints before a DER project can be approved.

4.3.3.4 Economic Development and Electrification Inputs

Known economic development projects are included in the ten-year forecast when the project is sufficiently defined with projected demand, expected timing, and the likely infrastructure such as the transformer and feeder needs. This allows the Ten-Year Plan to reflect new loads that could materially change capacity needs in a cluster.

Comprehensive electrification forecasting is still developing, so electrification is not formally included in the Ten-Year Plan currently. The current Ten-Year Plan primarily evaluates historical load growth, existing system loading, and known new load interconnections, while applying a projected load growth factor based on historical growth to determine capacity needs.

4.3.4 High-Level Transformer Load Forecast

The high-level transformer load forecast is PNM's first planning screen for identifying where distribution substation transformer and cluster capacity constraints may develop. The forecast is prepared through the Ten-Year Plan process and is intended to identify trends, overload risks, and locations where additional engineering review may be required. It is not intended to be the final engineering design, final project scope, final project cost estimate, or a stand-alone request for capital project approval.

PNM uses the high-level forecast to identify areas where the distribution system may approach or exceed planning criteria early enough for Distribution Planning Engineers to evaluate operational changes, load transfers, feeder reconfiguration, reconductoring, transformer upgrades, new substations, non-wires alternatives, or perform a detailed area study. The result of the annual Ten-Year Plan is an engineering indicator that drives the more detailed planning work described later in this section.

4.3.4.1 Forecast Methodology and Ten-year Planning Screen

Presently, the high-level forecast is based on historical transformer peak-load information, known load additions, anticipated economic-development load where information is available, and expected timing of proposed capacity projects. In the

Ten-Year Plan workbook, the cluster sheet uses five years of historical transformer loading to calculate an annualized growth rate for each transformer and produces a normal-configuration transformer forecast through the 10-year horizon. The process also allows known new load interconnections and proposed area study or forecast-evaluation projects to be reflected in the forecast.

Historical transformer peak-load data are reviewed by Distribution Planning Engineers as part of the Ten-Year Plan forecast development. If a historical peak appears to be caused by a temporary load transfer, outage condition, equipment change, abnormal operating configuration, or another non-representative event, that data point may be adjusted or excluded before the growth rate is selected. In this way, the Ten-Year Plan forecast is an engineering-reviewed screening forecast, not an automatic formula-based extrapolation from the most recent peak.

The forecast can be evaluated from both net-load and gross-load perspectives. Net load reflects actual metered load after the effect of generation that is operating at the time of the peak. Gross load is important where rooftop solar or large PV generation can mask underlying customer demand. In those areas, a low solar output day or a utility-scale PV outage can create operating risk even where net loading appears lower. The condensed tables below use the Sandoval Division Rio Rancho South Cluster net-load forecast as an example; the full Ten-Year Plan retains the annual forecast for each year of the study period.

PNM applies the high-level transformer load forecast screen as an engineering planning screen across its distribution system. The same planning criteria, including the 80 percent normal transformer loading screen, are applied to planning clusters without changing criteria due to customer class, income level, community status, or geography. The forecast does not lower service-quality expectations for low-income customers or underserved communities, and it does not use customer demographics as a basis to delay or avoid a capacity review. The high-level transformer load forecast screen is a uniform engineering screen that identifies where additional analysis is needed.

4.4 Sandoval Division / Rio Rancho South Cluster

The Sandoval Division example illustrates how the Ten-Year Plan process converts historical growth and projected load into a planning indicator. PNM organized the Sandoval Division into functional clusters, including Rio Rancho North, Rio Rancho South, and Bernalillo. The Rio Rancho South Cluster includes Corrales Bluff 1, Palm, Panorama, Rio Hondo, Veranda 1, and Veranda 2. The cluster has experienced significant load growth and was also evaluated through a detailed area study.

Table 4-5 condenses the Rio Rancho South normal-configuration transformer load forecast to three representative years: the starting year, the midpoint, and the end of the 10-year horizon. In the underlying Ten-Year Plan, the forecast is developed annually from 2025 through 2035. This condensed view shows the trend, the planning trigger, and the reason additional study is required without reproducing the entire workbook.

Table 4-5: Rio Rancho South Cluster Normal Configuration Transformer Load Forecast - Net Load, Condensed DSP View

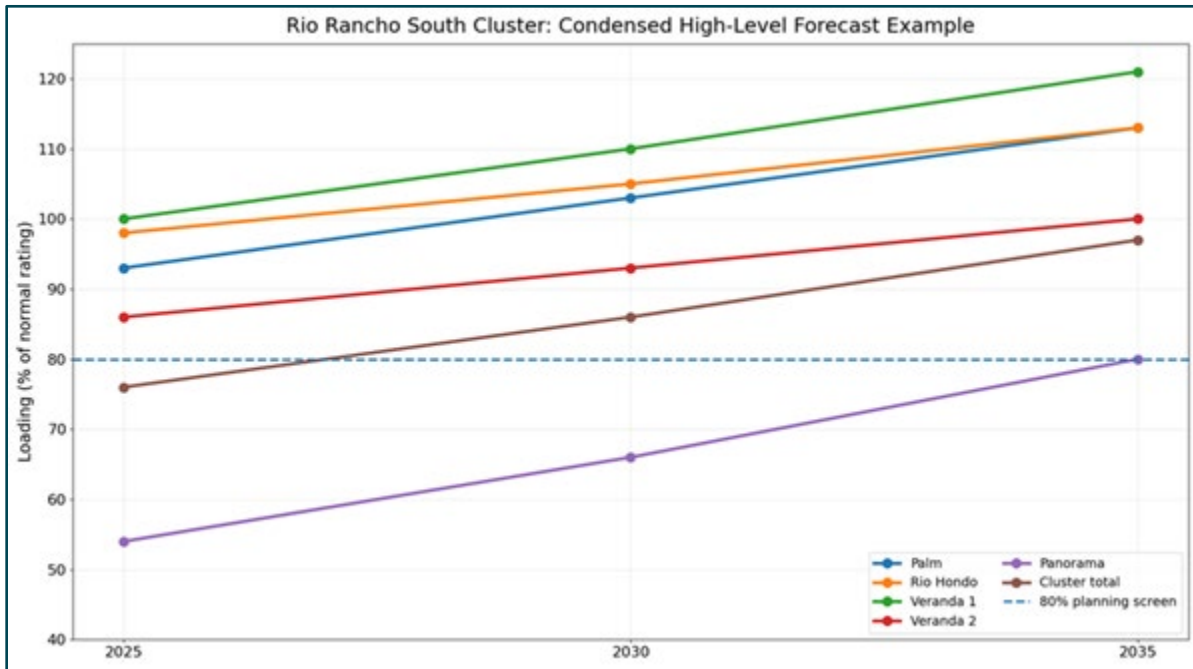
Transformer	2025	2030	2035	Planning interpretation
Corrales Bluff 1	37%	51%	69%	Below 80% throughout the forecast period.
Palm	93%	103%	113%	Above the normal 80% transformer planning criteria.
Panorama	54%	66%	80%	Reaches the 80% threshold by the end of the forecast period.
Rio Hondo	98%	105%	113%	Above the normal 80% transformer planning criteria.
Veranda 1	100%	110%	121%	Above the normal 80% transformer planning criteria.
Veranda 2	86%	93%	100%	Above the normal 80% transformer planning criterion and increasing.
Cluster total	76%	86%	97%	Cluster total exceeds 80% in the forecast period.

Source example: Sandoval Division 2026 Ten-Year Distribution System Plan, Rio Rancho South Cluster. The table is condensed to show the planning method and is not intended to replace the full annual Ten-Year Plan forecast.

The example shows why the high-level forecast is useful. Palm, Rio Hondo, Veranda 1, and Veranda 2 are above the 80 percent normal transformer planning criteria at the beginning of the forecast period; Panorama reaches the 80 percent threshold by the end of the period; and the cluster total rises above 80 percent during the 10-year horizon. That combination of individual transformer and cluster-level loading indicates that the area should not be evaluated only as isolated substations. The cluster should be reviewed as an operating area to determine whether load can be transferred, whether feeder ties are sufficient, and whether a detailed area study is needed.

The same information can also be viewed graphically. Figure 4-6 converts the condensed Rio Rancho South example into a trend view and shows how the 80 percent planning screen helps identify where additional planning review is needed.

Figure 4-6: Example forecast trend showing how high-level loading results flag additional planning review



Source example: Prepared from the condensed Rio Rancho South Cluster forecast table included in Section 4. The figure is illustrative and does not replace the full annual Ten-Year Plan forecast.

When a transformer or cluster approaches approximately 80 percent of normal rating, PNM treats the result as a planning trigger for additional review. The trigger does not itself approve a project or define the final project scope. It identifies a need to determine whether the concern can be addressed through operating changes, load transfers, feeder reconfiguration, smaller targeted improvements, non-wires alternatives, or a larger system improvement project determined by a detailed area study.

4.4.1 Completed Detailed Area Studies Modify the Forecast

A key purpose of the high-level forecast is to show the difference between an initial planning indicator and a more developed project scenario. After a detailed area study is completed, the Ten-Year Plan can incorporate the proposed transformer upgrades, new transformers, new substations, and associated load transfers. This allows PNM to show how the forecasted loading changes when the area study solution is reflected in the planning model.

For the Rio Rancho South example, the recent area study proposed upgrading non-standard transformers and adding two new 33.7 MVA substations. Table 4-6 summarizes the proposed capacity additions reflected in the updated 10-year forecast. Table 4-7 then shows the condensed forecast after the recent area study proposed projects are included.

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Table 4-6: Rio Rancho South Cluster recently proposed substation capacity additions

Project / transformer	Existing normal rating	System need / proposed year	Budget project year	Future normal rating
Veranda 1	22.4 MVA	2024	2032	33.7 MVA
Panorama	22.4 MVA	2024	2032	33.7 MVA
Rio Hondo	22.4 MVA	2024	2032	33.7 MVA
Palm	22.4 MVA	2024	2032	33.7 MVA
New Rio Rancho South 1	New	2027	2032	33.7 MVA
New Rio Rancho South 2	New	2027	2032	33.7 MVA

Table 4-7: Rio Rancho South Cluster Transformer Load Forecast with Recent Area study Proposed Projects - Net Load, Condensed DSP View

Transformer	2025	2030	2035	Planning interpretation
Corrales Bluff 1	37%	51%	79%	Higher after 2032 load transfers, but still below the 80% criteria.
Palm	93%	103%	58%	Reduced after proposed area study capacity additions and remains below 80%.
Panorama	54%	66%	66%	Reduced from the original forecast and remains below 80%.
Rio Hondo	98%	105%	56%	Reduced after proposed area study capacity additions.
Veranda 1	100%	110%	61%	Reduced after proposed area study capacity additions.
Veranda 2	86%	93%	45%	Reduced after proposed area study capacity additions.
New Rio Rancho South 1	0%	0%	45%	New capacity created in the proposed area study scenario.
New Rio Rancho South 2	0%	0%	45%	New capacity created in the proposed area study scenario.
Cluster total	76%	86%	57%	Cluster returns below the 80% screening threshold after proposed projects.

Source example: Sandoval Division 2026 Ten Year Distribution System Plan. These tables are included to show the planning method and not to request project approval through Section 4 alone.

The comparison between Table 4-5 and Table 4-7 shows how the planning process is iterative. The initial high-level transformer load forecast identifies an area where several transformers and the cluster total exceed the 80 percent planning screen. The detailed area study then evaluates the area with more precise engineering analysis and identifies a combination of transformer upgrades, new substations, new feeders, and load transfers. When those proposed projects are added back into the 10-year forecast, the cluster returns below the 80 percent screening threshold by the end of the forecast period.

This does not mean that the high-level forecast is a substitute for the area study. Instead, it shows how the two planning layers work together. The Ten-Year Plan identifies the likely need and timing. The area study confirms technical feasibility, evaluates normal and contingency power-flow performance, compares solution alternatives, and develops a more precise project scope. After the area study is complete, the forecast is updated so PNM can track whether the proposed projects are expected to restore planning margin over the 10-year horizon.

Where a high-level transformer load forecast identifies a need that is not already addressed by a completed area study or active project, the Ten-Year Plan may show a newly proposed forecast-evaluation project. Those projects should be treated as indicators of what could help the system satisfy planning criteria under the Ten-Year Plan assumptions. They are not final design decisions, final locations, final cost estimates, or self-executing approvals. For the Rio Rancho South example, the recent area study projects resolve the high-level forecast violations in the Ten-Year Plan scenario, so no additional Ten-Year Plan - only load-forecast evaluation project was identified for that cluster. In other clusters, newly proposed Ten-Year Plan projects should trigger project-development review and, where appropriate, a detailed area study.

4.4.1.1 Cluster Analysis and Escalation to Detailed Study

Cluster analysis is used because a single transformer forecast does not always show the full operating need. A transformer may appear constrained while neighboring transformer capacity, feeder ties, or load-transfer paths are insufficient to provide practical relief. Conversely, a transformer's load may be below 80 percent of its normal rating, but the cluster may still have limited contingency capability or limited ability to serve future growth. For that reason, the Ten-Year Plan process evaluates each cluster for normal load-serving capacity, single-transformer contingency performance, and high-level DER hosting capacity.

A cluster-level proposed project in the Ten-Year Plan should therefore be read as a planning indicator. It shows where additional capacity could improve performance and where the system may need a detailed area study to confirm the exact capacity investment, location, feeder buildout, load-transfer plan, and construction timing. The detailed study may confirm the Ten-Year Plan concept, revise it, reject it, or replace it with a different solution after power-flow, contingency, sensitivity, operability, and constructability review.

This escalation path is consistent with PNM's area study approach. The Ten-Year Plan identifies the overload or planning-margin concern; reconfiguration and smaller operational alternatives are considered where feasible; and if those options do not provide a durable solution, a detailed area study evaluates transformer upgrades, new substations, feeder rebuilds, and other alternatives. The area study is the appropriate place to confirm whether the capital investment, exact location, and detailed scope are justified.

4.4.2 Cluster High-Level Analysis for Hosting Capacity

The Ten-Year Plan also includes a high-level hosting capacity indicator at the cluster and transformer level. This indicator is useful because load growth and DER growth affect the same distribution equipment. In the Ten-Year Plan Excel Workbook cluster sheet, PNM reviews transformer-level load, existing generation, new community-solar projects, BESS additions where applicable, and remaining transformer hosting capacity. The result gives Distribution Planning Engineers an early view of how DER activity may interact with load-serving capacity.

This table should be read as a transformer-level planning indicator and not as a gross-load hosting capacity analysis, feeder-level hosting capacity determination, or interconnection result. It uses available Ten-Year Plan planning inputs to show where DER activity may affect transformer-level headroom and where additional feeder-level analysis may be needed.

Table 4-8: Rio Rancho South Cluster High-Level Transformer Hosting Capacity Indicator, Condensed DSP View

Transformer	Normal rating MVA	Daytime Minimum Net load MW	Total generation MW	Net community solar MW	Estimated Remaining HC MW	% XFMR utilization
Corrales Bluff 1	33.7	1.7	2.1	0.0	31.5	6%
Palm	22.4	1.2	6.9	0.0	15.5	31%
Panorama	22.4	2.6	3.1	0.0	19.3	14%
Rio Hondo	22.4	2.2	8.0	0.0	14.4	36%
Veranda 1	22.4	5.6	5.5	0.0	16.9	24%
Veranda 2	33.7	1.0	9.9	5.0	18.8	44%
Cluster total	156.9	14.3	35.5	5.0	116.5	26%

Source example: Sandoval Division 2026 Ten Year Distribution System Plan, Rio Rancho South Cluster hosting capacity evaluation. This is a high-level transformer indicator and should not be read as feeder-level interconnection approval. Remaining HC MW is a transformer-level planning-screening indicator based on information available in the Ten-Year Plan; it does not represent available feeder-level hosting capacity or approval for a specific DER interconnection.

The high-level Ten-Year Plan hosting capacity indicator should be distinguished from the detailed hosting capacity analysis described later in Section 4.10. The Ten-Year Plan indicator can show where transformer-level headroom appears to exist, but it does not determine whether a specific DER project can interconnect at a specific location on a

feeder. Feeder conductor ratings, voltage regulation, protection settings, reverse power flow, minimum daylight load, inverter behavior, queued projects, and exact point of interconnection must be evaluated through detailed hosting capacity analysis or an interconnection study.

In detailed hosting capacity analysis and interconnection studies, PNM will consider actual DER output as accurately as it can be represented with available data and engineering assumptions. Where actual DER telemetry, historical output, or project-specific operating data is available, PNM will use that information to inform the model. Where direct output data is not available, PNM will use the best available DER project data, approved and queued generation information, solar irradiance profiles, inverter and export assumptions, BESS operating assumptions where applicable, and minimum-daylight-load conditions.

4.5 Ten-Year Plan Interpretation

In summary, the Ten-Year Plan is the first step in PNM's Distribution Planning process. It identifies where growth, DER activity, or operating risk may create future planning criteria violations; it applies the same engineering screens across the system; it uses cluster analysis to understand broader area needs; and it points Distribution Planning Engineers toward detailed area studies or hosting capacity studies when the high-level screen shows a need for additional review. The Ten-Year Plan supports planning transparency and budgeting discussions, but final capital project scope, cost, location, and implementation timing should be supported by detailed engineering study and the appropriate regulatory and budgeting processes.

4.6 Reconfiguration Study

A Reconfiguration Study is the first engineering step of a Detailed Area Study, even when the review is brief. PNM uses this step after the Ten-Year Plan, Substation Outage Review, or another planning review identifies a potential capacity, reliability, contingency, or operating concern. The purpose is to determine whether the issue can be resolved through lower-cost distribution reconfiguration, load transfers, or targeted system improvements before larger substation or feeder capacity additions are developed.

The review uses Synergi feeder models to simulate power-flow to evaluate feeder configuration, normally open ties, load transfers among adjacent feeders or substations, phase balancing, targeted conductor or cable upgrades, new or modified feeder ties, switching plans, voltage device changes, protection considerations, available emergency capacity, N-1/single-contingency restoration needs, feeder-outage constraints, customer impacts, and operational complexity.

If a practical and sustainable lower-cost solution is identified, PNM may document the recommended reconfiguration, operating plan, or targeted improvement for implementation. If reconfiguration is not sufficient, the issue proceeds to the broader Detailed Area Study process for evaluation of larger alternatives, scope, timing, and cost.

4.7 Detailed Area Study

A detailed Area study is performed when high-level planning results indicate that a geographic area or planning cluster requires more detailed engineering evaluation. The trigger may be transformer loading above the planning criterion, insufficient contingency capacity, recurring voltage or feeder loading concerns, limited restoration options, DER hosting capacity constraints, or a combination of these issues. Area studies are intended to identify long-term solutions rather than temporary feeder fixes.

The Area study process uses Synergi feeder models to simulate power-flow and begins by confirming the capacity need and reviewing whether the existing system can be operated differently to resolve the concern. This review may include near-term reconfiguration, feeder ties, switching, reconductoring, voltage device changes, load transfers, or other operational adjustments. If these options are not sufficient, the area study develops and compares more substantial alternatives such as transformer upgrades, new substations, major feeder rebuilds, additional switching points, voltage regulators, capacitor banks.

4.7.1 Area Study Examples

Two recent PNM Area studies, the Montano and Claremont Area Study and the Rio Hondo Palm Area Study, illustrate the level of detail expected when a planning concern moves beyond the ten-year screening stage. Modern area studies generally include an existing-system assessment, model-year definition, load allocation, capacity analysis, normal-configuration power-flow analysis, contingency analysis, near-term reconfiguration review, long-term solution alternatives, sensitivity analysis, solution assessment, and a recommended solution. The studies also document planning criteria, construction standards, equipment assumptions, switching steps, and cost or schedule considerations needed to support project transition.

These studies show how PNM progresses from a screening concern to specific engineering recommendations. Figure 4-7 is a geographic example for the Rio Hondo Palm study. The area map shows how several substations and surrounding feeders are grouped into one practical area for detailed engineering review.

Figure 4-7: Example detailed area study geography - Rio Hondo Palm Study Area

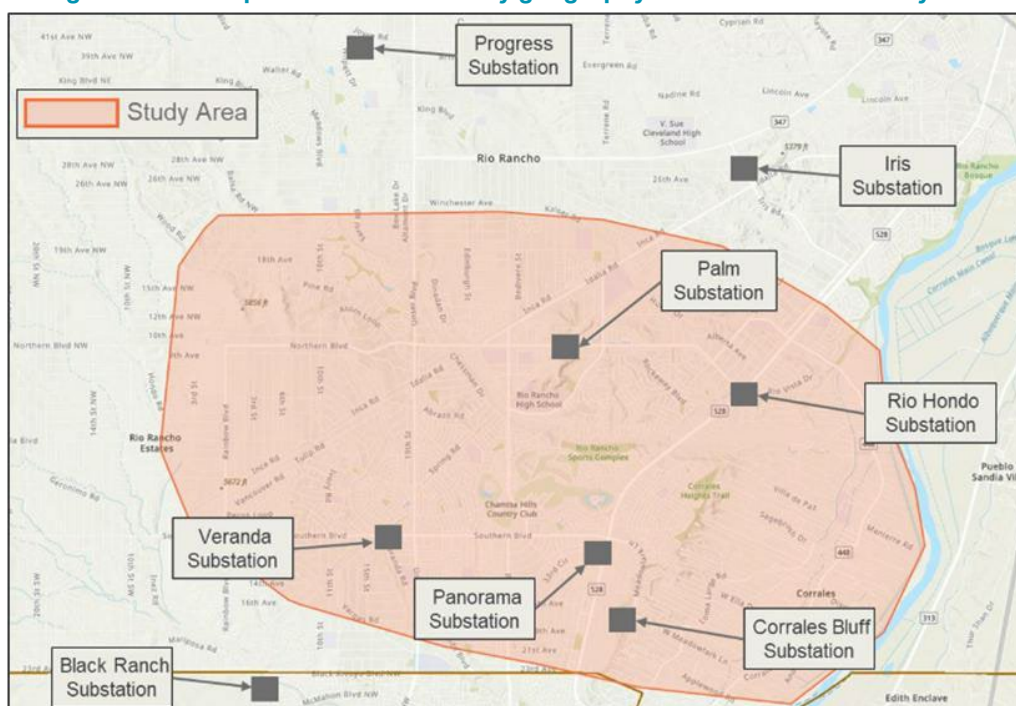


Figure 4-8 illustrates how alternative solutions are framed in an area study. In this example, the Montano and Claremont area study presents three capacity alternatives that were evaluated after both substations were identified as being at or near their capacity limits, and after reviewing nearby substations for contingency support options. Alternative 1 proposes upgrading the existing transformers at both Montano and Claremont. Alternative 2 includes upgrading Montano and expanding Claremont by both upgrading its existing transformer and adding a second 33.7 MVA transformer. Alternative 3 involves upgrading both Montano and Claremont while also constructing a new substation near the intersection of 2nd Street and Osuna Road. The study ultimately recommended Alternative 2 as the preferred technical solution because it provided additional feeder capacity closer to the area of need and demonstrated the best performance under current conditions, contingency scenarios, and long-term planning requirements.

Figure 4-8: Example of detailed area study alternatives - Montano and Claremont capacity solutions



Source example: Montano and Claremont Area Study. The DSP uses this figure to illustrate the area study process, not to request approval of a specific project through this section alone.

4.8 Detailed Study Content Compared with the Ten-Year Plan

The 10-Year Distribution System Plan and the detailed area study serve different purposes. The Ten-Year Plan identifies the existing state of the distribution system where a problem may exist and estimates when a project may be needed. The detailed Area study uses Synergi feeder models with power-flow analysis to confirm the problem, test alternatives, evaluate operating constraints, and defines a preferred solution with enough engineering support to inform project transition, budgeting, and potential regulatory review.

Table 4-9: Difference between the Ten-Year Plan and a detailed area study

Topic	10-Year Distribution System Plan	Detailed Area Study
Primary purpose	High-level screening, forecast review, and budget planning by division and cluster.	Engineering validation with Synergi power-flow analysis and solution development for a defined study area.
Modeling detail	Transformer-level and cluster-level capacity review, with high-level contingency and hosting capacity indicators.	Detailed feeder and substation models with normal, contingency, reconfiguration, and sensitivity cases.
Capacity analysis	Identifies transformers or clusters approaching or exceeding the 80% planning criterion.	Confirms the capacity need, evaluates load allocation, and tests whether capacity can be delivered through the feeder network.
Existing system power-flow	No power-flow modeling.	Evaluates thermal loading, voltage performance, protection-related constraints, and operating limits.
Near-term reconfiguration	May identify load transfers or general mitigation concepts.	Tests switching, feeder ties, reconductoring, and operational changes before recommending major capital projects.
Solution development	Lists recent area study projects, forecast-evaluation projects, or proposed projects as indicators.	Develops viable alternatives, compares them, and documents why a recommended solution is preferred.
Contingency analysis	Screens aggregate emergency capacity for loss-of-transformer scenarios.	Tests detailed contingency switching paths, feeder loading, voltage performance, and restoration feasibility.
Use in project approval	Supports identification, prioritization, and timing for inclusion in the 6-10 year planning horizon; not sufficient by itself for major project approval.	Provides the technical basis for project transition, recommended timing, detailed design, cost refinement, and regulatory approval.

A complete detailed area study typically includes the following analysis sequence:

- Build or validate the existing system power-flow models for the relevant study year and operating conditions.
- Evaluate the existing normal configuration and document thermal, voltage, and equipment-loading violations.
- Confirm the capacity, voltage, reliability, contingency, or hosting capacity concern identified by the Ten-Year Plan or by operations.
- Evaluate near-term reconfiguration potential, including feeder ties, switching plans, reconductoring, load transfers, voltage devices, and operational constraints.
- Develop multiple viable solutions when a major capital project appears necessary.
- Perform detailed solution analysis under normal configuration, contingency configuration, and load-growth or DER sensitivity conditions.
- Compare solutions based on technical performance, constructability, customer impact, operational flexibility, cost, timing, risk, and future expandability.
- Recommend a preferred solution and identify the next steps for project transition, timing, budget coordination, engineering design, permitting, and stakeholder or regulatory review as applicable.

Because area studies are more detailed than the Ten-Year Plan, they are the appropriate place to confirm the exact capacity investment, project location, scope, equipment configuration, and timing.

4.8.1 2026 Ten-Year Plan Capacity Results

PNM's 2026 Ten-Year Plan has been updated with 2025 load data. Tables 4-10 through 4-21 represent the state of loading from the 2025 load and forecasted through 2035 on each substation transformer per Division. These evaluation results are used to identify existing loading and load growth trends. Areas shown in green are below 60% loading, yellow are areas greater than 60% but less than the 80% loading planning criteria and red is loading greater than 80%. Red areas indicate that a more detailed power-flow study is necessary to determine a solution.

Table 4-10: Alamogordo Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Alamogordo	Alamogordo #1 Middle	46.7											
Alamogordo	Alamogordo #1 North	20.0											
Alamogordo	Alamogordo #1 South	46.7											
Alamogordo	Tularosa	22.4											

A detailed Area Study has been completed to address the area denoted in red. See Table 4-22 for Summary of Study results.

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Table 4-11: Albuquerque Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Downtown	ARNO 1	11.2											
Downtown	ARNO 2	14.0											
Downtown	ASPEN	22.4											
Downtown	BALL PARK	5.0											
Service Center	CLAREMONT	22.4											
Downtown	HAZELDINE	4.7											
Downtown	IRON ST 1	22.0											
Downtown	IRON ST 2	22.4											
North Valley	JEFFERSON	14.0											
Downtown	KELEHER	6.3											
Downtown	LOMAS	37.3											
North Valley	LOS ANGELES	14.0											
Service Center	MISSION 1	33.7											
Service Center	MISSION 2	33.7											
Service Center	MONTANO	22.4											
Downtown	PRAGER	33.7											
North Valley	REEVES	22.4											
North Valley	ROYS	33.7											
North Valley	SIGNETICS 1	41.7											
North Valley	SIGNETICS 2	41.7											
North Valley	WAYNE 1	33.7											
North Valley	WAYNE 2	33.7											
Montgomery Park	BEL AIR	22.4											
Coronado	BEVERLY WOOD	14.0											
Foothills	EASTRIDGE	22.4											
Foothills	EMBUDO	22.4											
Montgomery Park	GIRARD	20.0											
Northeast Heights	HAMILTON 1	22.4											
Northeast Heights	HAMILTON 2	22.4											
Montgomery Park	HAWKINS 1	22.4											
Montgomery Park	HAWKINS 2	33.7											
Coronado	INEZ	14.0											
Foothills	JUAN TABO	22.4											
Foothills	LAWRENCE	22.4											
Coronado	LEYENDECKER	33.7											
Coronado	MENAU	33.7											
Montgomery Park	MONTGOMERY P	33.7											
Foothills	MORRIS	33.7											

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Table 4-11: Albuquerque Division System Normal Configuration Forecast (continued)

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Montgomery Park	NORTH 1	22.4											
Montgomery Park	NORTH 2	22.4											
Foothills	PRINCESS JEANNE	22.4											
Coronado	SAN PEDRO	33.7											
Coronado	THOMAS	22.4											
Northeast Heights	TRAMWAY	22.4											
Coronado	WINROCK	22.4											
Northeast Heights	WYOMING	33.7											
University	ALCAZAR	22.4											
Airport	COAL	22.4											
Airport	CORNELL	22.4											
Sandia	FOUR HILLS	22.4											
University	INDIAN HOSPITAL	22.4											
Sandia	INNOVATION	33.7											
Sandia	LENKURT	22.4											
Mesa Del Sol	LOUDEN HILLS	33.7											
University	ORTIZ	22.4											
University	RITA	14.0											
Mesa Del Sol	SEWER PLANT	33.7											
Mesa Del Sol	STUDIO	33.7											
University	TRUMAN	22.4											
Airport	WESMECO	33.7											
Airport	SAGEBRUSH 1	22.4											
Airport	SAGEBRUSH 2	22.4											
South Valley	ANDERSON	10.5											
Paradise Hills	BLACK RANCH	33.7											
Central	CENTRAL	22.4											
Paradise Hills	COTTONWOOD 1	33.7											
Paradise Hills	COTTONWOOD 2	33.7											
West Mesa	LA MORADA	33.7											
Petroglyph	LOST HORIZON	33.7											
Paradise Hills	MARIPOSA	22.4											
Paradise Hills	PARADISE HILLS	22.4											
Petroglyph	PETROGLYPH 1	33.7											
Paradise Hills	SCENIC	33.7											
South Valley	SNOW VISTA	33.7											
South Valley	SOUTH COORS	22.4											
West Mesa	ST JOSEPH	22.4											
West Mesa	UNSER	33.7											
Central	VOLCANO 1	33.7											
Central	VOLCANO 2	33.7											

A detailed Area Study has been completed to address the area denoted in red for Claremont, Montano, Central, Hamilton, Tramway, Anderson, Scenic, Paradise Hills, South Coors and Snow Vista Substations. See Table 4-22 for Summary of Study results.

Table 4-12: Clayton Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Clayton	VAN BUREN 1	10.5											
Clayton	VAN BUREN 2	6.3											
Clayton	VAN BUREN 4	7.5											

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Table 4-13: Deming Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Deming	DEMING EAST	9.4											
Deming	DEMING WEST	9.4											
Deming	GOLD	22.4											
Deming	HERMANES	20.0											
Deming	HONDALE	14.0											

Table 4-14: East Mountain Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
East Mountain	SAN ANTONITO 1	6.3											
East Mountain	SAN ANTONITO 2	6.3											
East Mountain	TIJERAS	14.0											
East Mountain	ZAMORA	22.4											
East Mountain	MANZANITA 1	15.0											
East Mountain	MANZANITA 2	15.0											

Table 4-15: Las Vegas Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Las Vegas	ARRIBA	22.4											
Las Vegas	BACA	7.0											
Las Vegas	GALLINAS	22.4											

A detailed Area Study has been completed to address the area denoted in red. See Table 4-22 for Summary of Study results.

Table 4-16: Lordsburg Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Lordsburg	LORDBURG T1-NORTH	7.5											
Lordsburg	LORDBURG T2-SOUTH	7.5											

Table 4-17: Ruidoso Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Ruidoso	GAVILAN NORTH	9.4											
Ruidoso	GAVILAN SOUTH	9.4											
Ruidoso	HOLLYWOOD NORTH	12.5											
Ruidoso	HOLLYWOOD SOUTH	7.5											

A detailed Area Study has been completed to address the area denoted in red. See Table 4-22 for Summary of Study results.

Table 4-18: Sandoval Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bernalillo	ALGODONES 1	12.5											
Bernalillo	ALGODONES 2	7.0											
Bernalillo	AVILA	20.0											
Rio Rancho South	CORRALES BLUFF 1	33.7											
Bernalillo	CUCHILLA	14.0											
Rio Rancho North	ENCHANTED HILLS	22.4											
Rio Rancho North	IRIS	33.7											
Bernalillo	NORTH BERNALILLO	15.0											
Rio Rancho North	PACHMANN 1	33.7											
Rio Rancho South	PALM	22.4											
Rio Rancho South	PANORAMA	22.4											
Rio Rancho North	PROGRESS	33.7											
Rio Rancho South	RIO HONDO	22.4											
Rio Rancho South	VERANDA 1	22.4											
Rio Rancho South	VERANDA 2	33.7											

A detailed Area Study has been completed to address the area denoted in red for Palm, Rio Hondo and Veranda Substations. See Table 4-22 for Summary of Study results.

Table 4-19: Santa Fe Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
North Santa Fe	ALIRE	7.0											
West Santa Fe	BECKNER	22.4											
North Santa Fe	BUCKMAN 1	7.0											
North Santa Fe	BUCKMAN 2	22.4											
North Santa Fe	CAJA DEL RIO	33.7											
West Santa Fe	CAMEL TRACKS	10.5											
North Santa Fe	CAPITOL	3.8											
Cochiti	COCHITI	7.0											
South Santa Fe	COLINAS	14.0											
South Santa Fe	EL DORADO	22.4											
North Santa Fe	FORT MARCY	22.4											
North Santa Fe	HALONA	4.8											
North Santa Fe	HICKOX	4.7											
Cochiti	KAISER	1.5											
Cochiti	KEWA	14.0											
Cochiti	LA BAJADA	1.0											
North Santa Fe	MANHATTAN	7.0											
North Santa Fe	MEJIA	22.4											
East Santa Fe	MIGUEL LUJAN	22.4											
East Santa Fe	PECOS	7.0											
North Santa Fe	PERALTA	6.3											
North Santa Fe	POWER PLANT	6.3											
East Santa Fe	RODEO	22.4											
East Santa Fe	SOUTH PACHECO 1	22.4											
East Santa Fe	SOUTH PACHECO 2	22.4											
West Santa Fe	STATE PEN	14.0											
East Santa Fe	WARNER	10.5											
East Santa Fe	ZAFARANO	33.7											

A detailed Area Study has been completed to address the area denoted in red for Beckner and State Pen Substations.

See Table 4-22 for Summary of Study results. A detailed Area Study has been completed to address the area denoted in red. See Table 4-22 for Summary of Study results.

Table 4-20: Silver City Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
West Silver City	BURRO MOUNTAIN	0.4											
West Silver City	CLIFF 1	1.5											
West Silver City	CLIFF 2	1.5											
East Silver City	MD11	14.0											
West Silver City	NORTH SILVER T1-NORTH	22.4											
West Silver City	SILVER CITY T1-NORTH	22.4											
West Silver City	SILVER CITY T2-SOUTH	9.4											
West Silver City	TYRONE T1	3.8											

Table 4-21: Valencia Division System Normal Configuration Forecast

Cluster	Substation Transformer	Existing Normal Rating MVA	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Pueblo	BOSQUE FARMS	33.7											
Meadow Lake	COLLEGE	22.4											
Meadow Lake	EL CERRO	14.0											
Belen	FIRST STREET	22.4											
Pueblo	ISLETA	7.0											
Belen	JARALES	22.4											
West Los Lunas	LOS CHAVEZ	14.0											
West Los Lunas	LOS LUNAS	6.3											
West Los Lunas	LOS MORROS 1	22.4											
West Los Lunas	LOS MORROS 2	22.4											
Meadow Lake	MANZANO	14.0											
Pueblo	PALACE	14.0											
West Los Lunas	ST CECILIA	22.4											
Belen	TOME	12.6											

A detailed Area Study has been completed to address the area denoted in red for Los Morros Substation.

Table 4-22 shows the studies that resulted from PNM's Distribution Planning Process starting with the Ten-Year Plan screen to a detailed area study.

Table 4-22: Projects Identified Through PNM's Distribution Planning Study Process

Study	Problem	Solution	Need Date
Alamogordo Area Study	Inadequate transformer capacity to support the area load for an outage of either the Middle or South transformers.	Build a new substation in southern Alamogordo with two 33.7 MVA transformers.	2026
Las Vegas Area Study	Baca Substation Transformer Replacement for imminent failure	Install a new substation transformer at the Valencia Switching Station	2025
Paradise Hills Area Study	Heavily loaded Black Ranch, Cottonwood II, Mariposa, Paradise Hills, and Scenic substation transformers.	Paradise Hills transformer upgrade and new	Black Ranch II – 2027; Paradise Hills I Upgrade – 2028

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Table 4-22: Projects Identified Through PNM's Distribution Planning Study Process

		Paradise Hills, Black Ranch, and Scenic transformers installed at existing substations.	Paradise Hills II – 2028; Scenic Unit II - 2029
South Coors Area Study	Heavily loaded South Coors transformer and Snow Vista feeders.	New Snow Vista II and upgrade of South Coors and Anderson transformers	Snow Vista II – 2026 Anderson Upgrade – 2027 South Coors Upgrade – 2029
North Albuquerque Acres Area Study	Heavily loaded Hamilton II and Tramway transformers and Signetics and Hamilton One feeders.	New substation with two new transformers and upgrade Hamilton units one and two and Tramway	New NAA substation with two new transformers – 2017 Hamilton One Upgrade – 2030 Hamilton II Upgrade – 2031 Tramway Upgrade - 2026
Ruidoso Area Study	Heavily loaded Gavilan North and Hollywood South transformers. Also not adequate capacity to support an outage of the Hollywood North transformer.	New Ruidoso substation. Replacement of two Gavilan transformers with one 33.7 MVA transformer. Replacement of two Hollywood transformers with one 33.7 MVA transformer.	New substation – 2026 New Gavilan transformer – 2027 New Hollywood transformer – 2029
Central Area Study	Central transformer load above the 80% planning criteria and inadequate capacity for loss of Volcano I and Volcano II transformers.	Upgrade Central	Central Upgrade – 2026 New Volcano III - 2027
Montano Claremont Area Study	Heavily loaded Claremont and Montano substation transformers	New Claremont II and upgrade of existing Claremont unit and Montano transformers.	Claremont Transformer upgrade – 2024 Montano Transformer upgrade – 2028 New Claremont II - 2027
Palm Rio Hondo Area Study	Heavily loaded Palm and Rio Hondo transformers.	Two new substations and upgrade the Rio Hondo, Veranda I, Palm, and Panorama transformers.	Rio Hondo upgrade – 2027 New Rio Rancho South Substation I - 2028 New Rio Rancho South Substation II - 2028 Veranda I upgrade – 2028 Panorama upgrade – 2029 Palm upgrade – 2029
West Los Lunas Area Study	Inadequate capacity for an outage of Los Morros unit I.	New substation transformer at existing Rattlesnake switching station	New Rattlesnake transformer – 2027
Santa Fe West Reconfiguration Study	Heavily loaded State Pen transformer and Beckner Substation feeders.	Two new feeder ties, Caja Del Rio to Beckner, and Camel Tracks to State Pen.	2021
Santa Fe West Area Study	Heavily loaded State Pen transformer and Beckner Substation feeders.	Beckner Unit Two, State Pen transformer upgrade.	Beckner upgrade – 2023 State Pen upgrade - 2023

4.8.2 Far Northeast Heights Area

The far northeast heights area of Albuquerque (the majority of which is unincorporated Bernalillo County), including the neighborhoods such as North Albuquerque Acres and Sandia Heights, are currently experiencing significant distribution capacity constraints, with portions of the system operating at or near PNM's safe operating limits.

Area studies performed for the area concluded that the existing substation and feeder infrastructure serving the area lacks sufficient capacity to reliably accommodate current loads much less continued customer load growth and maintain acceptable operating conditions under contingency scenarios. Modeling results identified deficiencies related to transformer loading, feeder performance, customer voltage levels, and system restoration capability.

To address these concerns, the study recommends the immediate construction of a new substation, including two 33.7 MVA transformers and associated feeder infrastructure, to alleviate existing operations and planning criteria violations, increase operational flexibility, and provide the capacity necessary to support future customer growth and maintain long-term system reliability in the area. This substation will also allow PNM to restore the backup capability to the adjacent area substations that are currently carrying transferred load despite there being no planned maintenance or equipment out of service. The study identified further upgrades at Tramway and Hamilton substations in the area as well.

This reliability need has existed for many years and unfortunately remains unresolved. PNM has repeatedly sought local approval to build the necessary infrastructure, has conducted extensive community engagement, and has relied on independent engineering and siting studies to ensure unbiased third-party expert evaluations. Despite that record, the local process has not produced an approval that allows PNM to construct the facilities needed to maintain safe and reliable service. The result is that PNM is now requesting customers in that area to conserve energy during certain days and times in order to reduce load to protect transformers and feeders from overload conditions to avoid outages and damage to equipment. Overloading the equipment causes damage and increases the risk of equipment failure. If the equipment fails under high load, it could take longer to fix the equipment and restore power to the area.

Reserve capacity, meaning the difference between a transformer's or feeder's actual loading and its normal or emergency rating, is what allows PNM to transfer customer load from a facility that has experienced an outage onto adjacent, healthy facilities while the original equipment is repaired or replaced. Where adequate reserve capacity exists, PNM can typically restore most or all affected customers relatively quickly through switching alone. Where reserve capacity is inadequate, as is currently the case for two substations in the Albuquerque far northeast heights area, PNM's ability to transfer load is constrained, and full restoration may not be possible without exceeding safe equipment loading limits. In that situation, PNM must choose between accepting an elevated risk of equipment damage or failure by overloading adjacent facilities, or leaving some number of customers without service for a longer period until the original equipment can be

repaired or replaced. Additional substation and feeder capacity, such as that provided by the proposed North Albuquerque Acres Substation, restores an adequate reserve margin and gives PNM meaningfully more options to promptly restore customers following a contingency.

Customer loads from this area continue to be transferred with multiple cascading transfers to adjacent substations and beyond to offload the two far northeast heights substations and feeders as a temporary measure to ensure continued service as long as possible. However, it is creating additional risk in the greater surrounding areas as it is reducing their ability to provide planned backup for their adjacent areas until a permanent solution can be implemented.

4.9 Operational Studies

4.9.1 Operational Outage Contingency Planning

Operational outage contingency planning is an annual operational study performed in preparation for the next peak season. PNM generally begins the annual review in the Fall, around October 1, after the summer system peak. The process begins with reviewing and cleansing peak feeder and transformer SCADA data. The cleansing looks for false peaks due to operational load transfers and bad data. It also looks for differences greater than 10% of the previous year for outlying causes. The resulting peak data provides the basis for developing outage contingency plans for the following peak season and supports other distribution planning activities for the following year. Although operational in focus, the results also inform the longer-term capacity planning process described in this DSP.

PNM uses the operational outage contingency review to evaluate how the distribution system could be operated when one major distribution component is assumed to be unavailable. As defined in Section 4.2, this condition is commonly referred to as a single contingency or N-1 condition. PNM's routine distribution review is generally centered on the assumed unavailability of one substation transformer for the next projected peak load season. The review evaluates the ability of adjacent feeders and substations to serve affected load while remaining within the applicable planning criteria described in Section 4.1.

A substation transformer may be unavailable because of planned maintenance or unplanned equipment failure. The review is a planning stress test; it is not a prediction that a particular transformer will fail. It also does not mean that service would continue without an initial interruption. Its purpose is to determine whether and to what extent affected load can be restored through available switching and transfer paths, and to identify operating actions or system improvements before a projected limitation becomes more significant.

4.9.2 Relationship to the Ten Year Plan

The Ten-Year Plan provides the high level single contingency screen described in Section 4.3.3.2. That screen compares the aggregate emergency capacity of the remaining transformers in a cluster with existing and forecasted load. The operational

outage contingency review is a detailed Synergi modeling study that provides the next level of analysis: it evaluates whether the feeder network can physically deliver the available backup capacity to the affected area through practical switching and load transfers.

This distinction is important because available transformer capacity alone does not establish that restoration is feasible. A cluster may show sufficient aggregate backup capacity but still have a limiting feeder getaway, conductor, cable, protection setting, voltage condition, phase imbalance, insufficient feeder ties, or impractical switching sequence. Conversely, the focused review may identify a practical transfer arrangement that is not apparent from the aggregate screen. The review therefore connects the Ten-Year Plan indicator to an operating plan, a targeted improvement, or a more detailed engineering study.

4.9.3 Study Inputs and Assumptions

PNM develops the Operational Contingency Planning study model using the best information reasonably available for the area being reviewed. Typical inputs include verified feeder loading, applicable load growth assumptions, known significant load additions or transfers, the current and planned system configuration, transformer and feeder equipment ratings, feeder ties and switch status, conductor and cable ratings along potential transfer paths, protection and control device limitations, and voltage control equipment. The study model reflects the applicable seasonal peak condition and the system configuration expected for the projected next year peak study period.

PNM uses its internally developed Outage Contingency Application as the central repository for feeder and transformer peak readings and the contingency plans developed by Distribution Planning Engineers. The documented information is available for operational use by PNM's Distribution Operations Center and supports subsequent distribution planning studies, including area studies. PNM also documents daylight minimum and daylight maximum readings in the Outage Contingency Application for use in hosting capacity analyses and DER interconnection screens and studies.

Available feeder SCADA data establishes the peak condition used for load allocation in the Synergi model. Because the SCADA reading is a net measurement at the substation or feeder, rooftop solar operating at that hour is already reflected in the power supplied through the feeder. In Synergi, PNM separately represents the rooftop solar output using an area specific median irradiance curve for the selected hour and season. The curve estimates the percentage of aggregate installed rooftop solar capacity expected to be producing at that time. The model represents customer demand, feeder loading, and expected rooftop solar output for the same seasonal peak hour without counting the solar contribution twice.

4.9.4 Evaluation Process and Planning Criteria

In plain terms, if Transformer A is assumed to be unavailable, PNM evaluates whether normally open ties can be used to serve the affected area from Transformers B and C. The Distribution Planning Engineer checks the significant equipment along those transfer

paths to verify that thermal loading, voltage, protection, phase balance, and switching remain within the applicable contingency criteria. If full restoration is not feasible within those criteria, PNM identifies the practical restoration capability and any remaining system limitation requiring operational or capital mitigation. Emergency ratings are used for the temporary contingency condition and do not replace the normal ratings used for routine operation.

4.9.5 Results, Corrective Actions, and Escalation

If the affected load can be transferred within the applicable criteria, PNM documents the restoration arrangement, the switching assumptions, and any important operating limitations. If the transfer is not feasible or leaves insufficient margin, PNM evaluates practical corrective actions, generally beginning with less complex operational or targeted measures before advancing larger capacity additions. Potential actions may include:

- Changing feeder open points or the switching sequence, transferring load to another feeder, or rebalancing load to improve phase balance.
- Verifying applicable equipment ratings and protection settings, or adding or modifying voltage control equipment where appropriate.
- Adding or modifying switches and feeder ties, or upgrading a limiting feeder getaway, conductor, cable, or other transfer path equipment.
- Adding or upgrading a feeder to a higher rating, including use of an available substation feeder position where feasible.
- Upgrading a substation transformer to increase capacity or developing a new substation source when smaller measures are not sufficient.

Consistent with the planning process described elsewhere in this DSP, PNM may also consider an alternative that does not require traditional wires infrastructure when the resource can be located at the constrained area, is controllable or otherwise dependable during the relevant contingency period, and can satisfy the same loading, voltage, protection, and operating requirements. The preferred response considers technical performance, durability, constructability, customer impact, cost, schedule, forecast load growth, DER conditions, and operational flexibility.

A concern that can be addressed through a practical switching change or targeted improvement may proceed through a Reconfiguration Study. If those measures are not sufficient, the concern advances to a Detailed Area Study, where PNM evaluates larger alternatives and refines the recommended scope, location, cost, timing, constructability, and long-term performance.

4.9.6 Interpretation and Limitations

A single contingency review represents one assumed equipment outage under a specified load forecast and system configuration. It does not, by itself, evaluate every possible sequence of events or the simultaneous loss of multiple system elements.

The study evaluates restoration capability; it is not a guarantee that customers will experience no interruption or that all affected load can be restored in every actual event. Actual restoration can be affected by the location and nature of the equipment damage that caused the outage, the availability of feeder ties and other equipment, actual customer load and DER output, field safety requirements, and the operating condition of the surrounding system at the time of the outage.

When full restoration is not feasible within the applicable criteria, the Distribution Planning Engineer identifies the limiting facility or transfer path and the operational or capital mitigation needed to address the limitation. In this way, operational outage contingency planning connects the Ten-Year Plan's high level contingency indicator to a practical restoration strategy or a justified system improvement.

4.10 Tools Used

PNM uses several established, reliable industry-standard modeling tools to perform the analyses required for its distribution planning studies. Each tool is outlined in more detail below.

4.10.1 Primary Power-flow Modeling Software

PNM's primary modeling tool is DNV Synergi Electric modeling software. It is one of the most widely used distribution planning and analysis software platforms in North America. Utilities use it to model, analyze, and plan the distribution system, including substations, feeders, voltage regulators, capacitor banks, distributed energy resources (DERs), and customer loads. Synergi provides a detailed electrical model of PNM's distribution system that allows Distribution Planning Engineers to evaluate existing and forecasted operating conditions, identify capacity constraints, assess reliability and resilience, analyze distributed energy resource impacts, and determine the timing and scope of distribution infrastructure investments needed to maintain safe and reliable electric service. Detailed area studies and hosting capacity studies are completed using the DNV Synergi Electric software, which is used to model, analyze and optimize electrical distribution circuits.

Publicly available information is available on the DNV website <https://www.dnv.com/services/synergi-electric/> and in the Synergi Electric brochure in Appendix D. However, proprietary product documentation (manuals, technical references, etc.) cannot be shared publicly or with any third party as per PNM's Synergi licensing.

4.10.2 Distribution Equipment Rating Evaluation Software

PNM's Distribution Standards Department uses Eaton's CYMCAP to evaluate ampacities for underground cable. PNM's cable ratings differ from published manufacturers' ratings because the manufacturers' variables such as earth thermal resistivity and ambient temperature are not valid for use in the New Mexico environment. They also differ because they are published for steady state limits. PNM evaluates the ampacity using a load curve and performing a transient analysis because feeders experience a daily load cycle that varies during the day. The transient analysis assesses the maximum permissible current a cable can sustain over a specific period without damaging the cable materials.

PNM's Strategic Asset Management Department uses EPRI's PTLoad to evaluate the substation transformer operating temperatures and ratings. PNM uses a 4-hour rating for emergency loading. Both normal and emergency transformer ratings are calculated in accordance with ANSI/IEEE Standard C57.91-2011 Loading guide.

4.10.3 Other Distribution Planning Tools

Some of the additional tools that Distribution Planning uses are shown in Table 4-23.

Table 4-23: Planning tools and data sources used in the Distribution Planning process

Tool or Data Source	Primary Use in Distribution Planning process	Outputs / Planning Value	Key Limitations or Maturation Need
Ten-Year Plan Excel Workbook	Develop division and cluster forecasts, load-transfer scenarios, N-1 contingency tables, project summaries, and high-level hosting capacity indicators.	Consistent screening across divisions; supports budget timing and identification of potential projects.	High-level tool; results require detailed engineering validation before major capital decisions.
PNM Outage Contingency Application	Provides verified peak loads, minimum loads, and transformer loading data for forecast and contingency analysis.	Establishes the baseline for net-load and minimum-daylight-load planning.	Data quality, timing, and telemetry coverage affect forecast accuracy and model validation.
SCADA Report	Provides the raw load data from which the peak and minimum load data is derived.	Establishes the base load information for PNM's Outage Contingency Application.	Data must be cleansed for load transfers and invalid readings.
Synergi Electric Distribution Power-Flow Model	Performs detailed power-flow, voltage, thermal, contingency, and hosting capacity analysis.	Provides feeder-level validation, line-section results, heat maps, and engineering support for area studies and DER analysis.	Model accuracy depends on GIS topology, equipment data, load allocation, settings, and regular data maintenance.
PNM Electric Web Viewer	Provides feeder topology, asset location, equipment attributes, and connectivity information.	Supports model building, map-based review, and future automation of feeder-level analysis.	Needs continued alignment with planning models and field as-built data.
Cascade / Equipment Settings Records	Provides device settings and equipment information needed for protection-aware modeling and feeder automation.	Supports improved modeling of reclosers, fuses, regulators, capacitor banks, switches, and TIIR-related functionality.	Requires clear workflow for entry, verification, and synchronization with planning models.
AOP / Capital Planning and Copperleaf or Equivalent Prioritization Tools	Coordinates project timing, budget status, transition, prioritization, and benefit-cost inputs after planning identifies a need.	Connects planning recommendations to capital budgeting, prioritization, and action planning.	Financial approval, prioritization, and benefit-cost analysis are addressed in later DSP sections and are not duplicated in Section 4.

The DSP order requirements call for information and manuals for modeling software used. Section 4 summarizes the primary modeling approach at a planning-methodology level. More detailed user manuals, model documentation, version information, and assumptions can be provided or referenced in appendices as applicable, while avoiding release of sensitive model files, protection settings, cybersecurity-sensitive information, or detailed facility maps that require management, Legal, Regulatory, or Operations review.

4.11 Load Altering Considerations

Load-altering considerations are increasingly important to Distribution Planning Engineers because customer demand is no longer shaped only by traditional load growth. Demand response, energy efficiency, transportation electrification, building electrification, DER, storage, microgrids, EV charging, and non-wires alternatives can materially change both peak load and minimum daylight load. These resources may reduce the need for a traditional project in some cases, but they may also create new planning complexities if they change load shape, reduce local load during solar production hours, create reverse power-flow, or concentrate new load at constrained locations. PNM is responsible for ensuring equipment limits are adhered to, so this complexity is important to understand and ensure has been adequately considered.

Within the overall Distribution Planning process, load-altering considerations are evaluated at various levels of detail depending on the planning activity. The Ten-Year Plan provides the initial systemwide screening using known load additions, available DER information, and high-level forecast assumptions. Substation Outage Reviews, Reconfiguration Studies, Detailed Area Studies, Hosting Capacity Analysis, interconnection studies, and other feeder-level reviews provide more detailed location-specific reviews when a potential load-altering resource may affect a feeder, transformer, cluster, contingency condition, or DER interconnection constraint.

4.11.1 Demand Response and Demand-Side Management

Demand response and demand-side management can reduce peak load, shift usage away from constrained hours, or help manage localized feeder or transformer constraints. For Distribution Planning purposes, these resources are most useful when they are locationally targeted, measurable, durable, and available during the specific hours when the distribution constraint occurs. A broad system-level demand reduction may not defer a distribution project if the constrained transformer, feeder, or cluster does not receive enough coincident load reduction. PNM presently operates the demand response program system wide and not locationally.

In the current Distribution Planning process, the Ten-Year Plan may identify candidate locations where these resources could be useful, while Reconfiguration Studies, Detailed Area Studies, and other feeder-level reviews are needed to determine whether a specific resource is sufficient to defer, reduce, or avoid a traditional capacity project. PNM is continuing to develop methods to incorporate demand response and demand-side management into feeder-level and cluster-level forecasts.

As PNM's forecasting and scenario-development methods mature, avoided-cost information and IRP assumptions may also help inform how load-altering resources are evaluated in future DSP cycles, as discussed further in Section 5.

4.11.2 Assessment of Electrification-Related Load

Transportation and building electrification can increase distribution load and can also shift the time of peak demand. EV charging, fleet electrification, building electrification, and new industrial or commercial electric loads may create localized transformers or feeder

constraints even if the system-level load forecast appears manageable. Distribution Planning should therefore consider both the magnitude of electrification load and where and when that load is expected to occur.

In the current Distribution Planning process, known electrification projects, new load interconnections, and economic development loads are included when sufficient information is available. Broader electrification forecasting is still developing and will be refined through coordination with transportation electrification planning, customer program data, AMI and SCADA data, managed charging assumptions, economic development information, and detailed feeder or area studies.

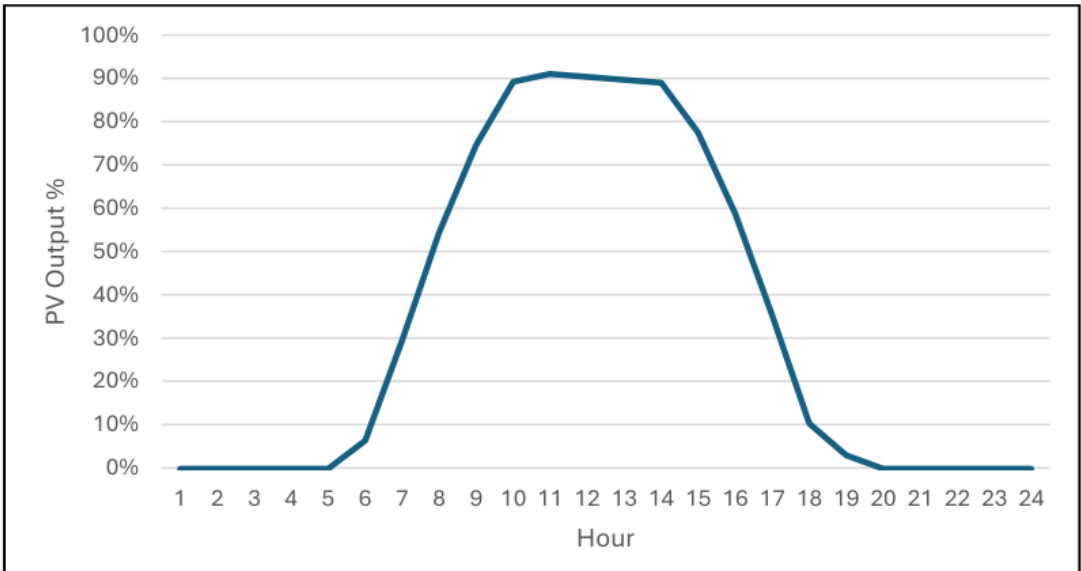
4.11.3 DER, Storage, Microgrids, and EVs

DER, customer storage, utility-scale or distribution-connected BESS, microgrids, and EVs affect both gross load and net load. Solar generation can reduce the net load served by the distribution system during daylight hours, but it may not be available during system peak or during low-solar-output conditions. During low solar-output conditions the distribution system must be able to serve the gross load without exceeding equipment ratings. This can occur when large DER system is offline for maintenance or for cloud cover that rapidly decreases solar output. Customer storage may reduce peak load if it discharges at the right time, but it can also increase load while charging. EV charging can add new load and may create new evening or overnight peaks, depending on customer behavior and managed charging programs.

These resources also affect hosting capacity. Minimum daylight gross load is important because local customer demand can consume excess PV generation. If customer generation or non-export inverter-controlled systems serve load locally, the load seen by the feeder can decrease during daylight hours. That can reduce the amount of excess PV generation the feeder can absorb and can increase the risk of high voltage, thermal, or protection concerns on high-PV feeders. Conversely, BESS can improve hosting capacity when operated to consume excess PV generation during daylight hours and discharge during peak or other beneficial periods.

Figure 4-9 provides a simple example of why time-of-day conditions matter. Solar output is not constant over the day, so the planning concern may be different during evening peak, minimum daylight load, cloudy periods, or large-PV-offline conditions.

Figure 4-9: Example PV output profile used to explain time-dependent DER planning considerations



Source example: Rule 568 Hosting Capacity Improvement Solutions Report. The figure illustrates why DER analysis must consider time-dependent solar output and minimum-daylight-load conditions.

4.11.4 Non-Wires Alternatives Considerations

Non-wires alternatives are resources or operating strategies that can defer, reduce, or avoid a traditional distribution infrastructure project. Potential non-wires alternatives include targeted demand response, energy efficiency, managed EV charging, customer or utility storage, DERMS-enabled control, virtual power plants, voltage optimization, and targeted DER or microgrid solutions.

PNM is starting to evaluate non-wires alternatives when the resource can meet the same planning need within the required timeframe and with comparable reliability, resilience, operating control, and customer impact. The evaluation considers whether the resource is available at the exact constrained location, whether it can be dispatched or safely or reliably be depended upon during the relevant hours, whether it satisfies contingency and voltage criteria, whether communications and cybersecurity requirements are feasible, and whether the cost and implementation timeline are competitive with a traditional project.

In PNM’s Rule 568 Hosting Capacity Improvement Solutions Study, completed August 23, 2024, PNM compared BESS solutions to traditional wired solutions to increase hosting capacity and continues to evaluate these and more traditional solutions based on costs-effectiveness and engineering viability to ensure customers receive the best and most cost effective solutions to system issues.

4.11.5 Summary of Load Altering Considerations

Table 4-24 is a summary of the load altering alternatives and their potential benefits and risks.

Table 4-24: Load Altering Considerations for Distribution Planning

Load-Altering Consideration	Potential Planning Benefit	Potential Planning Risk / Data Need
Demand Response / Demand-Side Management	Can reduce or shift peak demand and may defer a localized capacity project if targeted to the constrained area.	Requires feeder- or cluster-level participation data, dispatch certainty, persistence, and measurement/verification.
Transportation Electrification	Managed charging may shift load away from constrained hours and support more efficient asset use.	Unmanaged charging can create localized feeder, transformer, or service transformer overloads. Forecasting must identify location and timing.
Building Electrification	Can support policy goals and reduce customer emissions when planned with adequate distribution capacity.	May increase winter or evening peaks and require new forecasting methods beyond historical summer peak assumptions.
Rooftop PV and Distributed Generation	Can reduce net load during daylight hours and support customer clean-energy goals.	May reduce minimum daylight load, create reverse power-flow, and increase voltage, thermal, or protection concerns.
Battery Energy Storage	Can charge during excess PV conditions, discharge during constrained peak periods, improve hosting capacity, and provide operational flexibility.	Benefits depend on charge/discharge control, communications, availability, siting, interconnection limits, and cost recovery.
Microgrids and Virtual Power Plants	Can provide localized resilience and flexible capacity when coordinated with distribution operations.	Requires clear operating mode, islanding protection, DERMS/communications capability, and coordination with protection and restoration plans.
Feeder Automation / Reconfiguration	Can improve restoration and use existing capacity more effectively.	Does not solve all capacity problems and must still satisfy thermal, voltage, protection, and switching criteria.

4.12 Distributed Energy Resource Interconnection Review and Planning

PNM's distribution system accommodates customer owned, third party, and utility owned distributed energy resources, including solar generation and energy storage. Sections 1.7-1.10 and 1.13 summarizes the Rules that PNM follows to review and analyze new interconnections to the Distribution System. Section 3.6 summarizes the amount and type of DER presently connected to the distribution system, Section 4.11.5 discusses DER in load forecasting and system modeling, and Section 4.13 describes hosting capacity analysis. This section explains the project specific review used to determine whether, where, and under what conditions a proposed DER may interconnect safely and reliably.

Interconnection capability is location specific. Results depend on the proposed point of interconnection, facility size, export capacity, technology, operating mode, existing and queued generation, customer load, equipment capability, and the normal and contingency configurations of the surrounding system. Hosting capacity information and an optional pre-application report can help customers evaluate a location, but neither one reserves capacity or constitutes approval of a specific interconnection request.

4.12.1 Interconnection Review Paths and Thresholds

Rule 568 provides several review paths based on size of the system. The path establishes the initial level of analysis; it does not predetermine whether the project will be approved or whether modifications will be required. Not every project proceeds through every stage.

Table 4-25: Principal Interconnection Review Paths

Review Path	Basic Applicability And Purpose
Simplified Process	Certified inverter-based facilities with a nameplate rating of 50 kW or less and an export capacity of 25 kW or less, subject to the applicable screens.
Fast Track Process	Facilities with a nameplate rating up to 5 MW, subject to export limits based on line voltage, line capacity, and distance from the substation, and subject to the applicable screens.
Supplemental Review	Facilities that do not pass one or more applicable Simplified or Fast Track screens and elect additional engineering evaluation to determine whether they can interconnect without a detailed study. The review evaluates minimum gross load, voltage and power quality, and safety and reliability.
Detailed Study Process	Facilities of 10 MW or less that do not qualify for, or do not pass through, the simplified process, Fast Track process, or supplemental review.
Case Specific Process	Facilities greater than 10 MW under Rule 569 when state jurisdiction applies. FERC SGIP procedures may apply to interconnections under FERC jurisdiction.

Most of PNMs interconnection applications are submitted through Rule 568 and the Simplified process. If an application does not fail any of the technical screens, it moves to permission to operate. Applications that request interconnection to a feeder that is already experiencing reverse power flow will fail Screen 3 due to the aggregate export capacity that may not exceed one hundred percent of relevant minimum load. Where a feeder already has reverse power flow at relevant minimum load any new connections, no matter the export level, will cause minimum load to decrease further. Any application that fails Screen 3 must go through a supplemental review or detailed study. Therefore, PNM has seen a large increase in Supplemental Reviews due to Screen 3 which is now based on 100 percent of minimum load instead of a percentage of peak load.

For Fast Track eligibility, the facility nameplate rating may not exceed 5 MW and the proposed export capacity must remain below the applicable threshold shown in Table 4-26. The higher threshold applies only when the point of interconnection is on a main distribution line rated above 600 amperes and is within 2.5 circuit miles of the substation. Since PNM's system is rated at 600 amperes in most locations, and PNM's distribution

voltages are typically less than 14 kV, the maximum size to be considered for Fast Track is usually 2 MW. There are only 3 feeders in the PNM service area that are rated greater than 600 amperes, and 5 feeders rated at 600 amperes that are operating at a distribution voltage greater than 14 kV. The largest system that can be considered on these feeders is 3 MW.

Table 4-26: Rule 568 Fast Track Export Eligibility Limits

Line Voltage	Export Capacity Must Be Less Than
5 kV or less	500 kW
Greater than 5 kV through 14 kV	2 MW generally; 3 MW when the higher threshold conditions are met
Greater than 14 kV through 30 kV	3 MW generally; 4 MW when the higher threshold conditions are met
Greater than 30 kV through 69 kV	4 MW generally; 5 MW when the higher threshold conditions are met

The thresholds above determine eligibility for a review path. They are not automatic statements of available capacity. A project that is eligible for Fast Track review must still pass the applicable technical screens or proceed through an allowed next step. Similarly to the Simplified process, applications that request interconnection to a feeder that is already experiencing reverse power flow, will fail Screen 2 due to the aggregate export capacity that may not exceed one hundred percent of relevant minimum load instead of a percentage of peak load. Any application that fails Screen 2, usually goes directly to supplemental review.

4.12.2 Optional Pre-Application

A potential applicant may request an optional pre-application report before submitting an interconnection application. For Community Solar applications, under Rule 573, a pre-application report is a required document. Using information already available to PNM, the report may identify the likely serving feeder and substation, feeder voltage, distance to the substation, existing and queued export capacity, peak and minimum load information, number of protective and voltage regulating devices, limiting conductor ratings, and other known constraints. The report is informational and nonbinding. It is a snapshot of the data at the time. It does not consider other pre-application reports as part of the queue for capacity. It does not reserve capacity, establish queue position, or guarantee interconnection.

4.12.3 Supplemental Review

Supplemental review applies three broader evaluations: minimum gross load, voltage and power quality, and safety and reliability. For solar facilities without storage, Rule 568 uses the applicable daytime minimum load period defined by the rule; other generation is evaluated using absolute minimum load. The review also considers whether voltage regulation can be maintained, whether voltage fluctuations and harmonics remain within applicable limits, whether the project reduces operational flexibility, and whether switching or transfer of the affected line section could create loading or voltage concerns.

Using Synergi modeling and power flow analysis, the review documents the existing system condition, the proposed project condition, the incremental change caused by the project, and the technical basis for any required modification. This comparison prevents a preexisting system condition from being presented as though it were caused by the proposed DER, while still identifying a condition that the project would create or materially worsen.

4.12.4 Detailed or System Impact Study

When an application is larger than the Fast Track process allows, or when screening is not sufficient to establish that the project can interconnect safely and reliably, the detailed study process provides progressively more specific analysis.

For detailed feeder studies, the Distribution Planning Engineer develops baseline Synergi models of the existing system at peak and minimum load timeframes and compares the results of the baseline power flow analysis to the model with the proposed project added to the model. If the project includes battery storage, the timeframe modeled for minimum is absolute minimum instead of Daylight minimum. The distribution system is evaluated with and without the new project for both normal and contingent configurations at peak and minimum load timeframes. The analysis is performed with the technical considerations shown in Table 4-27 in mind. If system operating violations are identified due to the new project, system improvements to alleviate the violations are modeled and tested as part of the analysis and documented in the report along with preliminary cost estimates and construction timelines to implement the system improvements and complete the interconnection.

Potential solutions may include metering changes, fuse or relay setting changes, replacement or addition of protective equipment, conductor or cable upgrades, voltage regulation or control changes, substation transformer upgrades, feeder reconfiguration, a dedicated feeder, or coordination of upstream system improvements. The appropriate solutions are project and location specific.

Table 4-27: Principal Technical Considerations

Consideration	Purpose of the Evaluation
Voltage and power quality	Evaluate high and low voltage, voltage changes, balance, regulator and capacitor coordination, flicker, and harmonics.
Thermal and equipment capability	Evaluate conductors, cables, substation transformers, protective devices, and other affected equipment under applicable operating conditions.
Reverse power flow and export	Determine the direction and magnitude of power flow during minimum load and other relevant conditions and verify that affected equipment can operate with bidirectional flow.
Protection and safety	Evaluate fault current, interrupting capability, relay, recloser and fuse coordination, anti islanding performance, grounding, disconnection, and reconnection requirements.
Operations and reliability	Evaluate switching configurations for contingency transfers, operational flexibility, isolation and restoration requirements, metering, monitoring, and control needs.
Upstream and affected systems	Determine whether a distribution connected facility requires additional review or coordination with a transmission provider or another affected system.

The Distribution Planning Engineer documents the assumptions, the existing system condition, the proposed project condition, and the incremental effect associated with the interconnection. The study result is specific to the approved equipment, controls, export capacity, and point of interconnection. A material change to those characteristics may require additional evaluation.

4.12.5 Facilities study

This study converts the system impact study conclusions into the engineering design, equipment procurement, construction scope, and actual cost estimate needed to implement the interconnection. Once design and costs are finalized, the interconnection agreement can be developed for the customer to continue to interconnect.

4.12.6 Community Solar and Cumulative DER Impacts

Under Rule 573, in the first phase of Community Solar, PNM was allocated 125 MW out of a statewide capacity cap of 200 MW. PNM initially received 29 ranked projects ranging from 1.665 MW to 5 MW. Later in the process PNM also received a tribal project of 6.42 MW in addition to the original cap of 125 MW for a total of 130.82 MW as shown in Table 4-28.

Table 4-28: PNM Community Solar at Start of Program

Division	Original Substation	Original Feeder	Application System Size (MW)	Notes
Alamogordo	Alamo South	A10083	3.5	Existing 5 MW solar on feeder
		A10089	5	
Albuquerque	Scenic	Scenic 11	5	
Clayton	Van Buren T4	Van Buren 43	5	
Deming	Hermanas	Hermanas 11	3.33	
		Hermanas 14	4.255	
	Hondale	Hondale 11	9.665	2 projects
		Hondale 12	4.625	Existing 9 MW solar on feeder
Las Vegas	Gallinas	Gallinas 12	5	Existing 5 MW solar on feeder
Lordsburg	Lordsburg South	LD1000	5	
	Lordsburg North	LD318	5.415	2 projects
Sandoval	Avila	Avila 11	6.42	
	Veranda	Veranda 22	5	
Santa Fe	Colinas	Colinas 11	5	
Silver City	Silver City South	SL0017	7.25	
Tularosa	Tularosa	Tularosa 12	2.75	
		Tularosa 13	9.75	2 projects
		Tularosa 14	7.375	2 projects
Valencia	El Cerro	El Cerro 11	11.485	3 projects plus existing 9.3 MW solar on feeder
	First Street	First Street 13	5	
	Jarales	Jarales 11	5	Existing 10 MW on substation
	Manzano	Manzano 12	5	
	Tome	Tome 11	5	Existing 10 MW on substation
Grand Total			130.82	

4.12.7 Community Solar Challenges and Ongoing Concerns

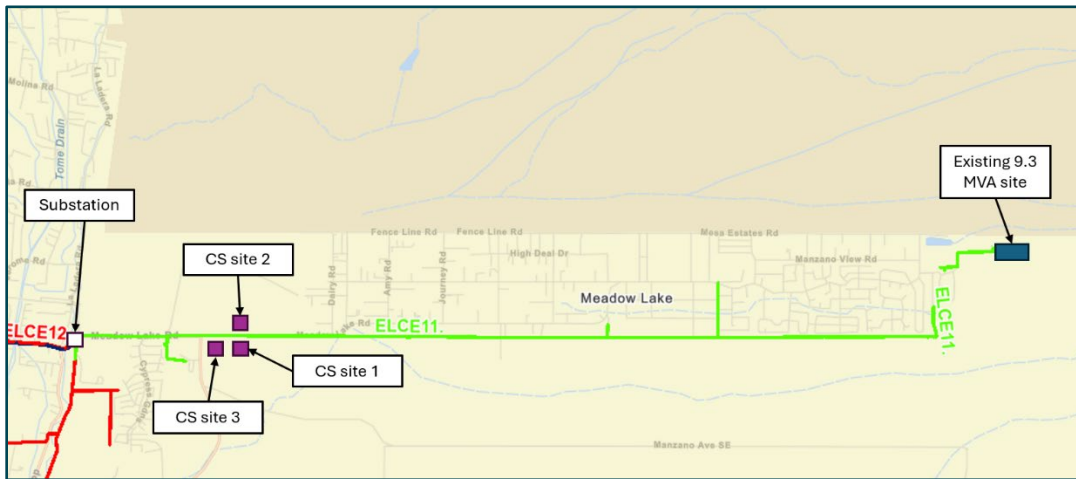
As Table 4-28 shows, several Community Solar projects were selected to interconnect to the same feeder or substation without considering the results for overall capacity shown in the required pre-application report. A pre-application report may have indicated there was some capacity remaining, but in some cases, there was not enough for multiple projects on the same feeder or substation. Additionally, there were some cases where there were existing large solar sites on the nearest feeder, which also impacted the amount of additional distributed generation that could be connected. The cumulative impacts created study challenges. Where multiple projects were selected to be on the same feeder or substation transformer, multiple scenarios had to be analyzed in case a prior ranked project were to withdraw. If a prior ranked project were to withdraw the projects following would need to know the impacts for their system improvements and cost estimates.

In practical terms, the first project in an area might be able to interconnect with limited modifications, while later projects can encounter a constraint created by the combined export of existing and queued facilities. This applies to both utility scale systems and residential/commercial systems. Each additional project may require an export limit, an alternative point of interconnection, protection or voltage control changes, feeder reconfiguration, feeder upgrades or broader system upgrades including substation transformer upgrades. Expanding hosting capacity can require material investment, and PNM must maintain safe and reliable service for all customers while evaluating those alternatives.

For example, for the Deming Division, three projects were selected to interconnect to the Hondale Substation, two on Hondale Feeder 11 (total of 9.7 MW) and one on Hondale Feeder 12 (4.7 MW). The pre-application reports for all three showed that the Hondale Substation transformer was only rated 14 MVA and that there was 9.3 MVA of existing generation interconnected. The pre-application reports for feeder 11 showed that the feeder rating was 6.5 MVA and there was only approximately 2.6-3.3 MVA of overall capacity remaining at the POI due to either the existing generation on the substation transformer, 50% of the feeder rating limit imposed at the time the report was prepared, and limiting conductor size between the POI and the substation. The report for feeder 12 showed 0 MVA available due to the existing generation on the feeder. All three pre-applications were completed through PNM's SGIP process prior to the new Rule 568 release. Without the 50% of the feeder limitation (which was removed in later pre-applications due to the new Rule 568) the overall limitation on Hondale feeder 12 was shown in the reports to be 4.7 MVA. As shown in Table 4-28, a total of 9.665 MVA was selected to interconnect on Hondale 11, which exceeded the rating of the feeder and the remaining capacity on the substation transformer. With the third project, the total amount selected to interconnect to the Hondale Substation was 14.29 MVA, which exceeded the substation transformer rating without considering the existing 9.3 MVA of generation. Major upgrades to the PNM system, such as the substation transformer upgrade, were identified for all three projects selected to connect to this substation. There were no other feeders close to the selected sites to find alternative sources for interconnection to minimize the costs. The first project requested a smaller size and was restudied for interconnection, resulting in not having to pay for the substation transformer upgrade, passing that cost to the following two.

For the Valencia Division, three projects were selected to interconnect to the El Cerro Substation transformer adjacent to the El Cerro Feeder 11. The three projects selected were in close proximity to each other and the feeder already had a 9.3 MVA Solar site interconnected to it. A single feeder in the PNM system cannot accommodate 20.785 MVA of generation (11.485 MVA of Community Solar and 9.3 MVA existing). Neither could the El Cerro Substation Transformer because of its 14 MVA rating.

Figure 4-10: Community Solar Site selected for interconnection to El Cerro Substation



The pre-application reports for all three projects showed that the El Cerro Substation transformer was rated 14 MVA and that there was 10-10.1 MVA of existing generation interconnected, with 9-9.3 MVA of that on the El Cerro Feeder 11. All reports showed 0 MVA available due to the existing generation on the feeder with approximately 3.9-4.0 available on the substation transformer. A substation transformer upgrade and major line extensions were needed to interconnect any of the projects. The first project requested a smaller size and was restudied for interconnection, resulting in connecting to El Cerro Feeder 12 and not having to pay for the substation transformer upgrade, passing that cost to the following two. The second project requested interconnecting to the next closest feeder, on the Manzano substation, which increased the line extension cost, but alleviated the need to pay for upgrading the substation transformer. The third project requested information about capacity on the neighboring feeder as well, but due to the second project connecting to it and another Community Solar project connecting to it, it also had limited capacity and a substation transformer upgrade would have been needed regardless of which substation it connected to. The third project withdrew from the program.

Another issue identified during the System Impact Study was for the Clayton Division. During the review for reverse power flow, it was determined that the PNM customer load in the Clayton Division would not prevent reverse power flow from the Community Solar site into the transmission system. Clayton is an isolated area in the PNM system where PNM purchases network integration transmission service from Tri-State Generation and Transmission Association, Inc. (Tri-State) and pays a facility usage charge to serve PNM's retail load in Clayton. PNM will need to acquire additional transmission service from Tri-state to transmit the solar power from the Community Solar site to PNM's central and northern load centers. As described in the Deming and Valencia examples above, the first projects in the queue for interconnection where the substation transformer needed to be upgraded, downsized their system size to remove the upgrade cost from their cost to interconnect. This transferred the upgrade cost to the following projects or future customers. To compound on that, in the Valencia Division, a community solar project applied to interconnect to the Tome Feeder 11 with a 5 MW system and the SIS

recommended an upgrade to the substation transformer. To avoid the upgrade cost, and to maximize their system output size, they requested to interconnect 3.4 MW to be able to utilize the BESS capacity that had been recently added to the Tome Feeder 12. The BESS was added to Tome Feeder 12 to increase hosting capacity on that feeder, which also increased the hosting capacity on the substation transformer. With the new reduced system size, the hosting capacity gained by the BESS has now been allocated, restricting further interconnection on the entire substation and all feeders, and shifts the substation transformer upgrade cost to a future generation interconnection customer(s), which could be a behind the meter residential customer.

The present status of Community Solar Phase I with all the requested changes and withdrawals is shown in Table 4-29. This table does not reflect two new waitlist projects that are currently still in the application completeness review. With these new projects, the total Community Solar generation for PNM is about 130 MW. Much of the shifting capacity allocation and restudy time could have been avoided if the available capacity shown in the pre-applications would have been utilized to select the Community Solar projects.

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Table 4-29: PNM Community Solar as of September 2026

Division	Final Substation	Final Feeder	Sum of Final Program System Size (MW)	Notes
Alamogordo	Alamo South	A10083	3.5	Existing 5 MW solar on feeder
		A10089	5	
Clayton	Van Buren T1	Van Buren 12	5	Interconnection point had to change from 4.16kV to a 12.47kV feeder, had transmission issues
Deming	Gold	Gold 11	2.1	
	Hermanas	Hermanas 11	3.33	
		Hermanas 14	4.255	
	Hondale	Hondale 11	8.665	2 projects, Sub Transformer upgrade
		New Hondale 13	4.625	Due to existing 9 MW solar on original feeder, feeder was split into two, Sub Transformer upgrade
Las Vegas	Gallinas	New Gallinas Feeder 14	5	Due to existing 5 MW solar on original feeder, feeder was split into two
Lordsburg	Lordsburg North	LD1000	5	
	Lordsburg South	LD0318	5.415	2 projects
Sandoval	Avila	Avila 11	5	
	Enchanted Hills	Enchanted Hills 13	5	Project in Albu, was replaced by this one, original POI was on Progress 13. Feeder open point was changed due to a protection concern which moved this to new feeder.
	Veranda	Veranda 22	5	
Santa Fe	Colinas	Colinas 11	5	
Silver City	Silver City South	SL0017	5	2 projects caused the need for substation transformer upgrade, second one withdrew
Tularosa	Tularosa	Tularosa 12	2.75	
		Tularosa 13	9.75	2 projects
		Tularosa 14	7.375	2 projects
Valencia	El Cerro	El Cerro 12	3	3 projects plus existing 9.3 MW solar on feeder caused Substation upgrade and new feeders. One system had to reduce size, one changed interconnection point to another feeder/substation and third one withdrew.
	First Street	First Street 13	5	
	Jarales	Jarales 11	5	Existing 10 MW on substation
	Manzano	Manzano 12	8.6	
	Tome	Tome 11	3.4	Existing 10 MW on substation, BESS
Grand Total			121.765	

4.13 Hosting Capacity Analysis

Hosting Capacity Analysis evaluates how much additional DER can be interconnected to a feeder or related distribution facility without causing unacceptable thermal loading, voltage performance, protection, or other operating concerns. Hosting capacity is unfortunately not a static number. It changes as customer load changes, DER is added, equipment is upgraded, switching configurations change, large PV output changes, or operating constraints are identified. For that reason, hosting capacity analysis must be treated as both a planning tool and an interconnection-support tool, not as an automatic approval for any specific project that seeks to connect to the grid or interact with the grid.

PNM has performed hosting capacity work using Synergi through Rule 568 studies and through the high-level hosting capacity review embedded in the 10-Year Distribution System Plans. This section summarizes methodology, major findings, study evolution, public availability, and future automation plans.

4.13.1 Present Feeder by Feeder Hosting Capacity

As of today, all of PNM's feeders can host customer-sited installations. As described in the Ten-Year Plan process, PNM's present high level hosting capacity review compares the aggregate of connected distributed energy resources to the feeder rating to determine an estimated hosting capacity. This information in conjunction with measured net daytime minimum loads is used to produce an interconnection map that is posted on the pnm.com website for customer interconnections. The map highlights feeder areas in red if the area does not have hosting capacity and yellow if the feeder has existing reverse power-flow during minimum daytime load, which shows that the aggregate amount of distributed energy resources is larger than the remaining feeder load. Areas denoted in yellow indicate that there is hosting capacity available, however, requires a supplemental review pursuant to Rule 568 interconnection application minimum load screen as requiring a more detailed evaluation. PNM's interconnection map gets updated on a quarterly basis at minimum.

4.13.2 First Phase Hosting Capacity Analysis Study

PNM's first Rule 568 Hosting Capacity study, completed on May 22, 2024,² evaluated 30 PNM feeders to understand the actual distribution-system limits for hosting additional PV generation. The study consisted of 18 feeders that PNM considered at PV saturation (aggregate DER exceeds 90% of feeder rating), six at high PV saturation (aggregate DER causes minimum daylight load to be less than zero but aggregate DER not exceeding 90% of feeder rating) and six at low PV saturation (no reverse power-flow), all identified by the high-level review explained in section 4.8.1. The study used Synergi's Incremental hosting capacity analysis and power flow simulations to determine remaining hosting capacity more technically. Minimum daylight load was used as a key basis because PV-related hosting constraints are most likely when customer load is low and there is less local demand to consume excess generation. The analysis evaluated three principal scenarios for each selected feeder: base-case hosting capacity, hosting capacity with system improvements, and a non-export inverter control sensitivity.

The base-case scenario evaluated the existing distribution system feeders, including

² NMPRC Case No. 23-00072-UT, Public Service Company of New Mexico's Hosting Capacity Analysis Study (May 23, 2024)

equipment ratings, protective device settings, voltage constraints, and other operational limitations to determine remaining hosting capacity. The system-improvements scenario evaluated potential investments such as conductor and cable upgrades, protective equipment upgrades, new equipment, BESS, and adjustments to existing inverter settings at large PV facilities to increase hosting capacity. The non-export inverter sensitivity evaluated the impact of customer systems serving on-site load locally and thereby reducing minimum daylight load available to absorb existing PV generation.

Figure 4-11 shows why feeder-level analysis is needed. Transformer or feeder-level headroom can be useful as an early indicator, but actual DER hosting capacity depends on the specific line sections, voltage devices, conductor limits, protection settings, and point of interconnection on a feeder. Figure 4-11 shows the available hosting capacity on one Tularosa feeder by categories depicted by color. The study showed that the maximum available capacity on this Tularosa feeder near the Tularosa Substation was 6.19 MW (shown in blue), but only 0.5-1.0 MW of available hosting capacity further down the circuit (shown in red).

Figure 4-11: Example feeder hosting capacity heat map showing location-specific feeder constraints



Source example: Rule 568 Hosting Capacity Analysis Report. This figure is included as a conceptual example of feeder-level hosting capacity results and is not an interconnection approval.

The study also confirmed a key planning concept for high-PV feeders: when connected generation capacity exceeds 90 percent of feeder rating and has reverse power-flow at minimum daytime load, the feeder is considered at solar saturation for planning purposes and additional PV interconnections may require detailed review before they can be safely interconnected. The study results showed that there was remaining hosting capacity on most of the feeders. The study recommended that PNM develop a plan to regularly perform hosting capacity updates, prioritizing the high-PV feeders, and continue to improve Synergi model automation so hosting capacity analysis can be updated more efficiently over time because the Synergi model building process is a manual data-intensive process. The study also concluded that non-export DER systems would further reduce minimum daytime load, increasing reverse power-flow. If reverse power-flow increases on high PV saturated feeders, thermal loading violations and/or voltage violations could result.

Table 4-30: Rule 568 Hosting Capacity Refresh Concept by PV Penetration Level

PV penetration level	Recommended hosting capacity refresh concept	Planning implication
0% to 30%	No routine refresh need identified.	Review through normal planning or interconnection processes unless specific concerns arise.
30% to 60%	Refresh approximately every 24 months.	Monitor feeders where PV penetration is increasing, and voltage-management needs may begin to appear.
60% to 90%	Refresh approximately every 12 months.	Evaluate feeder ratings, targeted conductor upgrades, and emerging thermal or voltage constraints.
90% and above	Refresh approximately every 6 months.	High-PV feeders require more frequent review, supplemental interconnection scrutiny, and potential system improvements.

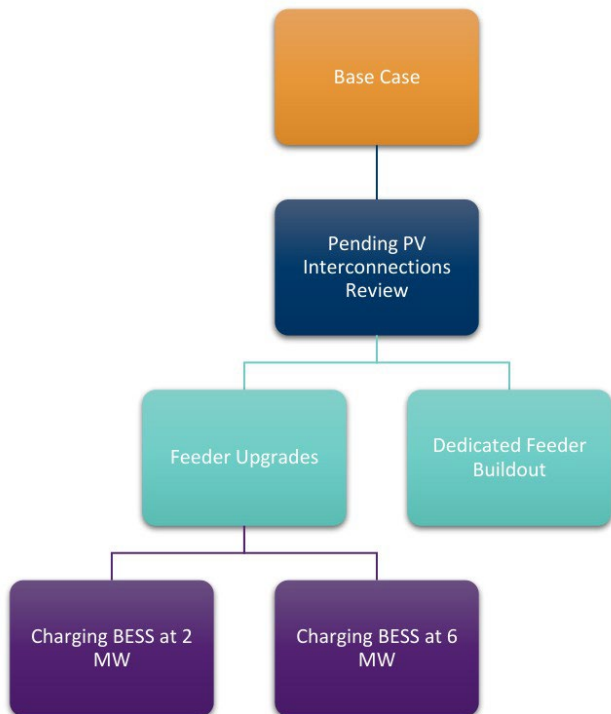
4.13.3 Second Phase Hosting Capacity Analysis Study

PNM's second Rule 568 hosting capacity study work, done in collaboration with DOE, NREL and NMPRC staff, completed August 23, 2024,³ further evaluated improvement solutions for the 18 PV-saturated feeders. Of the 18 PV saturated feeders, 13 of 18 had pending customers on hold. This second study reviewed pending customer PV interconnections, modeled whether those interconnections could proceed without system impacts, and evaluated capital project alternatives that could increase hosting capacity. Improvement alternatives included feeder upgrades, feeder upgrades with BESS charging at various levels, BESS without feeder upgrades for selected cases, and dedicated feeder buildout to existing large-scale PV sites.

Figure 4-12 shows the logic used to move from a base-case hosting capacity result to pending-PV review and then to potential improvement solutions. This demonstrates the distinction between high-level planning indicators and feeder-specific interconnection or improvement analysis.

³NMPRC Case No. 23-00072-UT, Public Service Company of New Mexico's Amended Motion for Extension of Variances from Rule 17.9.568 of the New Mexico Administrative Code (Aug. 23, 2024) at Attachment A

Figure 4-12: Hosting Capacity Analysis and Capital Project Evaluation Approach



Source example: Rule 568 Hosting Capacity Improvement Solutions Report. The figure is included to summarize the analysis sequence at a high level.

Figure 4-13 summarizes the primary hosting capacity improvement solution types evaluated in PNM's Rule 568 hosting capacity work. This visual helps explain why hosting capacity planning may identify operational, feeder-upgrade, BESS, or dedicated-feeder concepts rather than a single standard solution.

Figure 4-13: Hosting Capacity Improvement Solutions Evaluated in Rule 568 Planning Work

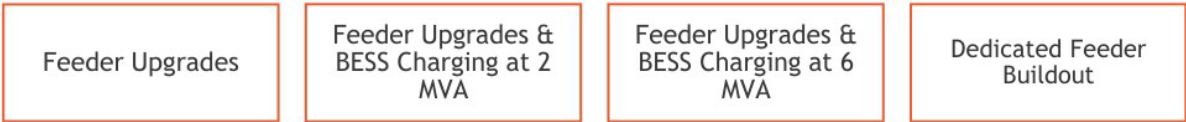
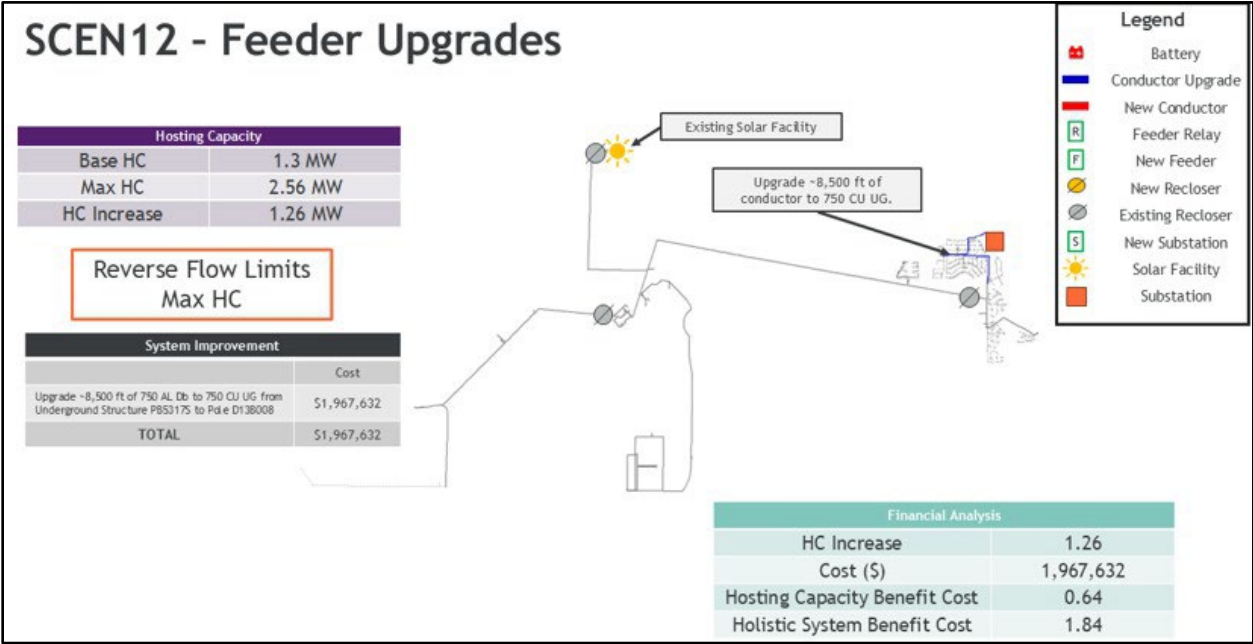


Figure 4-14 provides a location-specific example of a hosting capacity traditional feeder upgrade project. It illustrates how a feeder-specific project can be identified to increase DER hosting capacity on a constrained feeder while maintaining a clear relationship to the serving substation and existing solar resource.

Figure 4-14: Example Location-Specific Hosting Capacity Improvement Project - Scenic Feeder 12

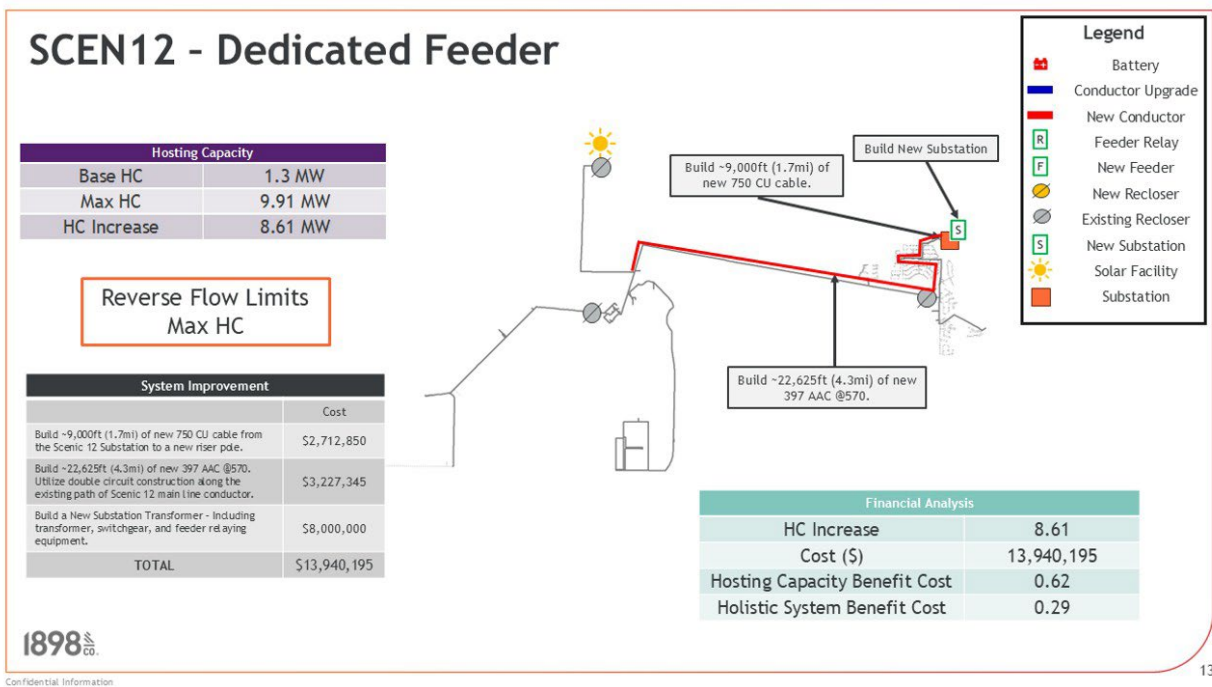


Source example: Rule 568 Hosting Capacity Improvement Solutions Report. The DSP presents the solution types at a planning-methodology level.

The second phase of hosting capacity analysis showed that different solutions provide different planning value. Feeder upgrades can unlock incremental hosting capacity and may be useful for near-term customer interconnections, but they may provide only a marginal increase where feeders are already built near PNM standard ratings. BESS can increase minimum daylight gross load by charging during periods of excess PV generation, thereby improving hosting capacity, and potentially providing additional system benefits. Dedicated feeder buildout often provides the greatest hosting capacity increase, but it can require substation upgrades, and coordination with transmission or substation constraints. Solutions must each be evaluated based on their increased hosting capacity to cost ratios.

This phase is summarized at a portfolio and methodology level. The study report explains the types of solutions evaluated and the resulting planning insights. Detailed feeder-by-feeder constraints, exact weak points, protection concerns, and preliminary cost estimates are included, and Figure 4-15 provides a second improvement example from the Rule 568 hosting capacity improvement solution work. The figure shows how a dedicated feeder, cost information, and resulting hosting capacity increases can be presented together for project screening and comparison.

Figure 4-15: Hosting Capacity Improvement Alternative Option Considered



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Table 4-31: Example of Combined Community-Solar and Traditional System Upgrades Used to Increase Hosting Capacity

Hosting Capacity Improvement Option	Planning Function	Important Considerations
Feeder upgrades	Increase feeder rating and improve the ability to carry additional generation or load.	May include conductor, cable, protection, voltage device, or switching upgrades. Benefits may be limited if the feeder is already at maximum standard ratings.
BESS charging during PV production hours	Increases minimum daylight gross load and consumes excess PV generation, improving hosting capacity.	Requires appropriate operation, control, communications, interconnection review, and cost recovery.
Dedicated feeder buildout	Moves large PV generation or creates a dedicated path that can unlock additional hosting capacity.	May provide large hosting capacity increases, but can require new substation transformers, switchgear, feeders, and coordination with upstream system constraints.
Voltage management and inverter settings	Mitigates voltage rise and improves operating performance on high-PV feeders.	Requires careful coordination with customer equipment, utility voltage devices, and interconnection rules.
Protection upgrades	Maintains protection sensitivity and coordination as DER penetration increases.	Requires accurate device settings, fault analysis, and field implementation.

Out of the 18 feeders studied, 13 had pending customers. This report confirmed that there was additional hosting capacity on 11 out of the 13 after the pending customer systems were analyzed as interconnected. Those customers were contacted and allowed to interconnect. Two feeders were determined not to have any hosting capacity remaining due to thermal limits and customers remained on hold until system improvements were completed. As of July 2026, all system improvements identified in this study for the two feeders have been completed and all PNM feeders can now host customer-sited installations pending Rule 568 supplemental review due to existing reverse power-flow.

4.13.4 Third Phase Hosting Capacity Analysis Study

PNM has continued work with a third phase hosting capacity analysis study as part of a continued effort to review hosting capacity constraints and refine feeder hosting capacity improvement system benefits. This phase addresses the original 18 feeders at PV saturation and 9 additional feeders due to proposed community solar projects. The study compared system improvement costs of increase in hosting capacity relative to the system improvement cost for a more holistic cost benefit approach. The holistic benefit approach included other system benefits in addition to the increase in capacity to weigh against project cost. It included additional benefits via value models within our Copperleaf investment tool. This study is in Appendix E and the updated feeder hosting capacity results for these 27 feeders is in Appendix F.

The study demonstrated that the nine feeders with Community Solar sites still have remaining hosting capacity, but the hosting capacity was reduced because of the Community Solar installations' significant size compared to the feeder rating. The importance of this third study is that it confirms that hosting capacity analysis must be completed as a recurring Distribution Planning function rather than a one-time study to ensure ongoing reliability and safety of the grid. As PNM integrates community solar projects, receives new DER applications, updates GIS and model data, and constructs new distribution projects, hosting capacity results will need to be refreshed and reconciled with interconnection review, distribution capacity planning, area studies, and grid modernization tools.

4.13.5 Hosting Capacity Updates

For feeders with high PV penetration or known hosting capacity constraints, PNM expects hosting capacity updates to remain an ongoing planning activity. The Rule 568 Hosting Capacity studies that PNM has completed to date, support more frequent analysis for high-PV saturated feeders. Hosting Capacity mapping update frequency depends on feeder PV penetration, model readiness, data quality, available resources, automation capability, and regulatory direction. PNM's current process to date has been largely a manual data collection and engineering process.

Ongoing updates need to consider changes in feeder configuration, new DER interconnections, queued DER projects, community solar additions, customer load

changes, BESS operation, equipment upgrades, protection settings, and system operating practices. The results are coordinated with the interconnection process so that developers and customers have useful planning information while still understanding that

individual projects require point-of-interconnection-specific review. Automation is the key way to ensure long-term sustainability.

PNM will continue to update the interconnection map on a regular basis as new customer and Community Solar interconnections directly affect the available hosting capacity on PNM's distribution system.

4.13.6 Progress Toward Fully Automated Feeder-by-Feeder Analysis

PNM is working toward more automated feeder-by-feeder hosting capacity analysis. The current process is still engineering- and data-intensive to create the individual Synergi feeder models for the analysis. Accurate automated hosting capacity analysis requires current GIS Utility Network data, validated Synergi feeder models, updated equipment ratings, verified settings from systems such as Cascade, reliable load and DER data, and the ability to model inverter operation, export limits, TIIR functionality, and BESS operating modes.

PNM is implementing the necessary foundational data and software required elements to fully automate its distribution hosting capacity analysis and associated public maps as outlined in PNM's Grid Mod Plan. PNM's more detailed analysis will show hosting capacity ranges on an even more granular feeder line section basis to improve efficiency for future DER interconnections. That process is on-going for all feeders and will be completed before the end of 2028. The Grid Mod Plan identified hosting capacity to be fully automated during years 2-4 (i.e., 2026-2028) in three phases. Phase one is automation of base case development and Synergi model optimization. Phase two includes the ability to forecast future feeder loading to accommodate longer-term planning horizons for customers. Phase three incorporates automatic updates to the system's hosting capacity analysis to make more current information available on a public-facing portal.

As of June 1, 2026, PNM has successfully completed multiple critical foundational efforts to more regularly perform hosting capacity analysis for customers. Those include implementation of the multi-year geographic information system (GIS) Utility Network upgrade, and installation of a software integration link between the distribution planning tool, Synergi, to PNM's asset management database (Cascade) for automatic population of equipment voltage regulation settings for automated feeder modeling. PNM is currently completing user acceptance validation to ensure the proper functionality and verify that the automated feeder model data population is accurate for use in the future automated hosting capacity analysis. This will allow automatic pulls of DER data by type, improving modeling of inverter operation and export amount, modeling technical interconnection and interoperability requirements (TIIR) functionality, and testing the Synergi data-lake automated function to complete hosting capacity analysis on selected feeders identified as being at full capacity.

PNM sought independent third-party validation from an outside engineering and technical services firm of its hosting capacity automation as outlined in its Grid Mod plan. Automation will allow full system analysis to be completed automatically and is on track to be completed on schedule from commencement with the foundational elements that are now in place. A scalable feeder-by-feeder process requires more than publishing existing study results. PNM will also be able to build and refresh feeder models in bulk, validate system topology and equipment data on a more real-time basis, confirm customers loads and DER inputs, incorporate protection and device settings, model inverter behavior and export limits, and account for all potential battery energy storage system (“BESS”) operating modes. Additional linkages to Cascade, SCADA, Profiler (MV-90 customer meter load data), protection databases, DER data sources, and other source systems are expected to continue as this process matures.

Of note, more frequent manual updates are still necessary, as hosting capacity changes when load or generation changes on the feeder. Additionally, to ensure integrity of the distribution system for all customers, PNM must also consider loading on its substation transformer(s). When new customer load is

added, hosting capacity increases and when large solar facilities connect, hosting capacity generally decreases. In the case of Community Solar Phase I, hosting capacity can quickly change. As an example, one developer initially applied to connect to Tome Feeder 11 with a 5 MW system and was recommended to upgrade the substation transformer. With the recommended substation transformer upgrade, hosting capacity would have remained on the Tome Feeder 11 and on the adjacent feeders 12 and 13. The Tome Feeder 12 had recently been upgraded with a BESS at an existing 10 MVA solar site to increase hosting capacity on the Tome Feeder 12. The developer requested and reapplied to reduce their system size to

3.4 MVA which relieved them of the substation transformer upgrade. This alternate system size has now restricted the hosting capacity on the substation transformer, shifting the required upgrade to a future customer(s).

PNM expects to deploy automation in stages. The near-term focus is on model readiness, automated model-build validation, data-quality checks, DER data classification by type and operating mode, data-lake automated hosting capacity analysis testing on selected constrained feeders, and internal review of results before broader use. PNM expects that initial public-facing hosting capacity maps or similar results could be developed over approximately a two- to three-year period as outlined in PNM’s Grid Mod plan.

Table 4-32: Progress Toward Automated Feeder-By-Feeder Hosting Capacity Analysis

Roadmap Item	Planning Purpose	DSP Treatment
Feeders identified as at PV saturation	Provides current engineering heat-map style results for the feeders identified at PV saturation and demonstrates how feeder-level thermal, voltage, and line-section constraints are evaluated.	Current technical foundation for feeder-level HCA; future implementation of public feeder-by-feeder hosting capacity map.
GIS / Utility Network upgrade	Improves the quality of the distribution system topology and asset data used to build and validate feeder models.	Foundational data improvement supporting future automated analysis. Utility Network go-live enabled the next stage of automated model-building.
Synergi and Cascade linkage	Improves the ability to incorporate equipment voltage regulation settings and device data into planning Synergi models.	Model accuracy depends on distribution equipment settings and asset data. Additional linkages to Cascade, protection databases, and related source systems will continue to improve model quality.
DER data by type	Allows the model to distinguish rooftop PV, community solar, large PV, BESS, microgrids, and other DER.	Necessary for feeder-level and technology-specific hosting capacity results.
Inverter operation and export modeling	Improves evaluation of non-export, limited-export, Volt/VAR, and other inverter functions.	This is a key improvement for accurate net-load, minimum-daylight-load, and HCA analysis.
TIIR modeling	Supports more accurate interconnection and operational analysis where technical interconnection requirements affect DER operation.	Part of the next generation of DER and hosting capacity modeling.
Profiler load and generation data linkage	Improves the ability to model minimum daylight load, large PV output, coincident customer load, and other time-dependent inputs.	Supports more repeatable and current feeder-level HCA results as automation matures.
Synergi Data-lake automated HCA pilot	Tests automation on selected feeders that are at capacity or otherwise constrained.	Verification step before broad feeder-by-feeder rollout. Model-build results must be checked and validated before they are used for systemwide or public-facing purposes.
Refresh cadence by PV penetration	Prioritizes higher-PV feeders for more frequent review because hosting capacity changes more quickly where DER penetration is high.	Rule 568 framework supports more frequent review for higher-PV feeders and helps PNM focus automation and engineering review where it is most needed.
Public maps or public-facing results	Improves transparency for customers, developers, and stakeholders.	Public-facing results at an appropriate level once data quality, security, and regulatory review are complete. Results should include an effective date, methodology limitations, appropriate ranges, and a clear statement that maps are planning guidance rather than interconnection approval.
Two- to three-year public-facing map direction	Provides an indicative planning horizon for moving from selected-feeder studies and internal validation toward initial public-facing hosting capacity maps or similar results.	Future objective dependent on model readiness, automation, data quality, cybersecurity review, stakeholder input, regulatory direction, and implementation resources.

5. *Vision For an Evolving Distribution System*

PNM's vision for the distribution system is to develop a safe, reliable, resilient, and increasingly intelligent electric grid that serves as one of the foundational elements supporting New Mexico's carbon-free energy

future. The distribution system must continue to provide high-quality service to customers while enabling economic growth, support electrification of transportation and buildings, and integrate increasing levels of DERs, including solar generation, battery storage, and electric vehicles. Through a balanced combination of traditional infrastructure investments and advanced grid modernization technologies, PNM seeks to transform the distribution system into a more connected, data-driven, and flexible network capable of managing dynamic, two-way power flows and responding to changing customer needs, while ensuring the historic reliability customers know they can count on to power their homes and businesses. This vision emphasizes prudent investment, operational efficiency, affordability, and customer value while supporting the State's transition toward a carbon-free electric system.

This vision includes continued system integration so that consistent data is used in all of PNM's planning processes including Integrated Resource Planning, Transmission System Planning, Distribution System Planning, corporate load forecasting, Financial Planning as well as Distribution Operations.

Ultimately, PNM's vision is to create a distribution system that is prepared not only for today's needs, but for tomorrow's opportunities—a system that delivers safe, reliable, resilient, and affordable electric service while serving as an enabling platform for innovation, customer choice, and the State's long-term energy objectives. This vision serves as the guiding principle for the Distribution System Plan and informs the investments, analyses, and the Action Plan presented in the DSP.

5.1 **Current Data**

Distribution Planning's current distribution load forecasting methodology is based primarily on historical transformer loading trends, verified SCADA load data, known customer load additions, and identified economic development projects. Distribution Planning Engineers review five years of historical loading data for each transformer, develop annualized growth rates, and project loading conditions over a ten-year planning horizon. While distributed energy resources and known load modifications are considered where information is available, broader forecasts associated with transportation electrification, building electrification, flexible load, and advanced DER adoption are still under development. Accordingly, PNM is transitioning toward a more integrated forecasting framework that will provide increasingly location-specific forecasts capable of supporting distribution, transmission, and resource planning using a common set of assumptions and data.

5.2 **Five-Year Load Forecast**

PNM's vision for the five-year load forecast is to provide a transparent, data-driven, geographically detailed, and forward-looking assessment of future electric demand that serves as the foundation for distribution system planning and investment decisions. The forecast should enable PNM to anticipate where and when customer needs are expected to evolve, identify emerging system constraints before they affect reliability, and support the timely development of infrastructure and operational solutions necessary to maintain safe, reliable, resilient, and affordable electric service.

PNM 2026 Distribution System Plan

This vision recognizes that the electric system is undergoing significant transformation driven by economic development, customer growth, transportation and building electrification, distributed energy resources, energy storage, and changing patterns of energy use. As these factors continue to reshape the distribution system, the load forecast must extend beyond traditional estimates of energy consumption and provide a comprehensive view of how future demand may impact substations, feeders, transformers, and local areas throughout the system.

PNM further envisions the five-year forecast as an adaptive planning tool that acknowledges uncertainty while providing actionable insight. Rather than attempting to predict a single future outcome, the forecast should support the evaluation of multiple planning scenarios, improve understanding of potential risk

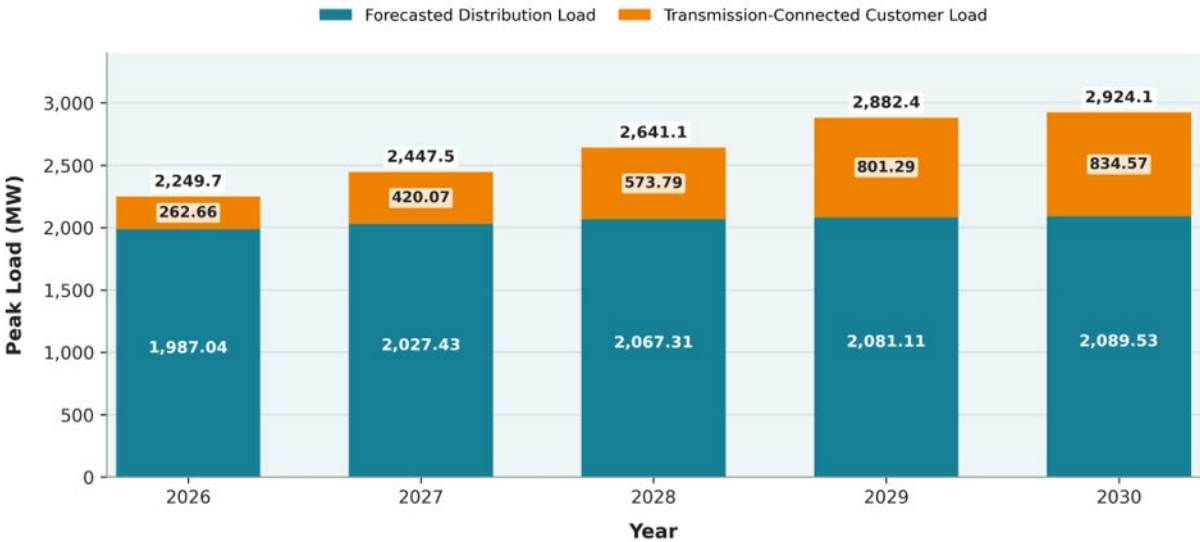
and opportunities, and inform decisions that remain prudent across a range of future conditions. In this way, the forecast becomes a critical link between evolving customer needs and the investments required to meet those needs efficiently and cost-effectively.

Ultimately, PNM's vision is for the five-year load forecast to be a living planning framework that integrates emerging trends, evolving technologies, and changing customer expectations into a repeatable decision-making process. By providing a clear understanding of future system conditions, the forecast supports proactive distribution planning, guides grid modernization efforts, and helps ensure that PNM can continue delivering reliable and affordable service while supporting New Mexico's long-term economic, electrification, and energy objectives.

5.3 Improved Forecasting and Scenario Development

Figure 5-1 represents PNM’s forecasted distribution and transmission customer load for 2026-2030, relevant to the total system load forecast as presently prepared for the IRP process.

Figure 5-1: PNM’s Five-Year Load Forecast



PNM believes that the basis for consistent and integrated planning begins with a corporate level load forecast that takes into consideration organic new load growth, customer-owned DER, transportation electrification, building electrification, and large economic development. There are now methodologies available that allows the forecast to be developed in a bottoms-up fashion so that locational forecasts for DERs, economic development, electrification etc., can be rolled up and diversified so that it can be used for system level planning such as Integrated Resource and Transmission Planning, but can also be used for feeder and distribution substation planning. PNM has been actively working to consolidate its forecasting efforts into developing a bottoms-up corporate forecast.

For the Distribution System Plan, the methodology used in the recent Avoided Cost Study for PNM's 2026 Energy Efficiency filing (Docket No. 26-0000074), represents a transition from traditional top-down forecasting toward an integrated planning framework that combines load forecasting, DER forecasting, electrification forecasting, and avoided-cost valuation into a unified planning process. PNM's vision is to leverage increasingly granular data and advanced forecasting techniques so that avoided-cost analysis can help identify non-wires alternatives, improve capital planning decisions, and support a more flexible, data-driven distribution system. The same forecasting framework can be used to evaluate scenarios involving high electrification, increased customer-owned solar, energy storage adoption, and other emerging grid conditions.

5.4 Scenario Rationale

Forecast scenarios will help PNM evaluate how different future conditions could affect the distribution system and ensure that investment decisions remain appropriate under a range of plausible outcomes. Rather than relying on a single forecast, PNM is moving towards using scenarios to examine how different assumptions regarding customer growth, distributed energy resources, electrification, energy storage adoption, and other emerging trends may influence future system needs. This approach allows PNM to better understand potential risks, identify opportunities, and develop investment strategies that remain effective even as actual conditions evolve over time.

5.5 Modeling Sensitivities

PNM's forecast modeling sensitivities will be used to test the distribution system against the major uncertainties that could affect future infrastructure needs, including load growth, economic development, high PV penetration, electrification, customer storage adoption, flexible load, and the difference between gross and net load. These sensitivities will allow PNM to evaluate how changing customer behavior, distributed energy resources, electric vehicles, building electrification, and storage may affect peak load minimum daylight load, hosting capacity, reverse power-flow, and the timing of future distribution investments. By examining these sensitivities, PNM can better identify investments that are robust across multiple potential futures while maintaining safety, reliability, resilience, affordability, and flexibility for customers.

5.6 Impacts of Results on Projections of Peak and Minimum Loads

The high electrification sensitivity is expected to increase peak demand across portions of the distribution system, as transportation electrification, building electrification, and new electric technologies increase overall electricity consumption. Electrification may also shift the timing of peak demand and create localized impacts on feeders, transformers, and substations where

adoption becomes concentrated. These impacts could accelerate the need for capacity-related investments in certain areas of the system.

The high photovoltaic (PV) penetration sensitivity is expected to further reduce daytime net load and minimum daylight load on many feeders. While increased solar adoption may reduce measured system load during periods of solar production, it may also increase reverse power-flow, reduce the amount of local load available to absorb generation, and create additional hosting-capacity, voltage-management, and protection-coordination challenges. PNM therefore evaluates both peak-load and minimum-daylight-load conditions when assessing future system needs.

The high storage adoption sensitivity may mitigate some peak-load growth by allowing customers to shift energy consumption and reduce demand during constrained periods. Battery storage can also improve hosting capacity by charging during periods of excess solar generation and discharging during higher-load periods. However, the benefits depend on storage location, operating characteristics, and customer behavior, which introduces planning uncertainty.

Overall, the results of these scenario analyses are expected to improve PNM's understanding of future distribution system conditions, support more informed infrastructure planning, identify areas where hosting-capacity limitations may emerge, evaluate the potential value of non-wires alternatives, and help prioritize investments that remain effective across a broad range of possible future outcomes. By evaluating both peak-load and minimum-load impacts, PNM can better position the distribution system to maintain safety, reliability, resilience, affordability, and flexibility as customer needs and technologies continue to evolve.

5.6.1 Public-Facing Automated Hosting Capacity Maps

Automation for bulk feeder building is required for systematic hosting capacity analysis. The ArcGIS Utility Network upgrade was implemented in May 2026. The remainder of 2026 is being used to validate the GIS data and the linkages to the Synergi power-flow software to ensure the modeling data are accurate. PNM is planning to work on automated model building and hosting capacity analysis in early 2027. This will require further software enhancements with DNV, the developer of Synergi. Also further linking to Cascade, Profiler, Protection database will be ongoing etc.

5.7 Grid Mod Plan Summary

PNM's Grid Modernization ("Grid Mod") Plan represents the operational and technological foundation supporting the Company's vision for a more resilient, reliable, flexible, and intelligent distribution system. While traditional infrastructure investments remain critical, the Grid Mod Plan introduces advanced technologies and operational capabilities that allow the distribution system to evolve in response to changing customer needs, increasing electrification, distributed energy resources (DERs), community solar, energy storage, and growing reliability expectations.

5.7.1 Overview

PNM's Grid Modernization vision for the next five years is to create the operational, data, communications, and analytical foundation needed to support the evolving Distribution Planning process described in Section 4 of this Distribution System Plan. Section 4

explains that PNM's Distribution Planning process is transitioning from a primarily capacity-focused planning framework toward a more integrated process that considers DER penetration, customer-sited storage, transportation and building electrification, demand response, non-wires alternatives, hosting capacity, and more frequent feeder-level analysis. Grid Modernization is one of the principal means by which PNM will enable that transition.

The purpose of Grid Modernization in this DSP is not simply to list modern technologies. Rather, Grid Modernization provides the field data, system visibility, communications capability, control functionality, and operational intelligence needed to improve how PNM identifies distribution constraints, evaluates alternatives, prioritizes capital investments, integrates DERs, and coordinates Distribution Planning with Distribution Operations. Over the next five years, PNM expects Grid Modernization investments to improve the quality and timeliness of the data used in the Ten-Year Distribution System Plan, detailed area studies, hosting capacity analysis, contingency review, DER integration studies, and evaluation of non-wires alternatives.

PNM's Grid Modernization efforts began through the filing of NMPRC Case No. 22-00058-UT under the State's Grid Modernization Statute, NMSA 1978, Section 62-8-13. The Grid Modernization program supports equitable access to a modern electric grid, including the implementation of Advanced Metering Infrastructure, communications upgrades, Distribution Automation, ADMS, DERMS, IVVM, FLISR, and related data and modeling improvements. These capabilities directly support the Distribution Planning objectives described earlier in this DSP by improving system visibility, supporting more granular forecasting, enabling feeder-level analysis, and providing additional tools to evaluate alternatives to traditional infrastructure expansion.

5.7.1.1 Advanced Metering Infrastructure (AMI)

AMI consists of automated meters, communication infrastructure, and back-office software which will support many of the goals within the Distribution System Plan as well as PNM's Grid Modernization Plan. Advanced digital meters will be able to measure multiple electrical parameters at premises and send those data points directly over communication paths back to PNM back-office software. The AMI head end software will collect those measurements and can send the data internally to systems to create customer billing, grid operating software such as distribution management systems or distributed energy resource management systems (DERMS), or data warehouses to be utilized in planning studies or hosting capacity analysis.

Current billing meters provide 12 data points per year, each consisting of approximately 30 days of aggregated data with no ability to discern peaks or valleys in usage that can be utilized to support infrastructure planning. This level of granularity does not provide the data needed for modern complex planning needs. Additionally, most current meters will only provide kilowatt hours utilized over the billing month. New advanced meters will be able to provide data on 15-minute intervals to support situational awareness of needed for the more complex planning

studies as well as supporting more complex rate designs that can incentivize utilization of energy in better alignment with system load and generation needs. In addition to kilowatt hours, the meters will be able to provide kilowatt demand and Voltage to alert system operators to instances where there are trending problems that need to be addressed through distribution automation (described later in this section) or alert to trends that will feed planning studies.

The meters will also have the capability for customers to choose to participate in potential future programs to communicate with customer devices such as demand response resources or smart inverters.

This communication supports some of the capabilities previously described in the Distribution System Plan where PNM is unable to coordinate with customer resources such as EV charging or distributed storage to directly support grid balancing.

5.7.1.2 Communications Upgrades, Future SCADA Upgrades

PNM is executing a comprehensive communications network modernization program to replace aging telecommunications infrastructure and establish the high-speed, secure, and resilient communications foundation required to support advanced grid operations. Historically, portions of the distribution communications network were designed primarily to support limited SCADA telemetry and serial communications. As Grid Modernization initiatives introduce significantly greater volumes of operational data and advanced control functionality, additional communications capacity, reliability, and network resiliency are required to support future operational requirements.

During the planning horizon, PNM intends to continue migrating from legacy communications technologies toward a modern packet-based network architecture capable of supporting Advanced Metering Infrastructure (AMI), Distribution Automation (DA), Advanced Distribution Management System (ADMS) applications, Distributed Energy Resource Management System (DERMS) functionality, operational analytics, and future grid-edge technologies. These investments include upgrading wide-area communications infrastructure, expanding fiber-based connectivity, enhancing backhaul capabilities, implementing field area networking solutions, and improving communications diversity for critical operational facilities.

This communications modernization effort ties directly to Distribution Planning because better communications enable more useful operational data. Section 4 describes how planning currently relies on SCADA data, Ten-Year Plan workbooks, Synergi models, GIS information, equipment settings, DER data, and hosting capacity studies. Communications upgrades improve the ability to collect and use feeder telemetry, device status, voltage data, outage information, and field-device data that can eventually improve the accuracy of planning models and the quality of planning decisions.

The communications program also helps address the distinction raised regarding SCADA visibility. A high percentage of substation feeder breakers may have SCADA

control, but Distribution Automation requires visibility and control beyond the feeder main breaker. DA applies to devices along the feeder, including reclosers, switches, sectionalizing devices, sensors, regulators, capacitor banks, and other field equipment. The need for communications upgrades is therefore not eliminated by existing feeder-breaker SCADA availability; rather, additional communications capability is required to extend visibility and control deeper into the distribution system where planning constraints, restoration opportunities, voltage issues, and DER impacts occur.

5.7.1.3 Distribution Automation

Distribution Automation (DA) is a key component of PNM's Grid Modernization strategy and is intended to improve reliability, resiliency, operational awareness, and distribution system efficiency while providing a foundation for future ADMS capabilities. The Distribution Automation program includes deployment of intelligent field devices, remote monitoring equipment, remote switching capabilities, feeder automation technologies, and associated communications infrastructure across targeted portions of the distribution system.

During the planning horizon, PNM expects to continue strategically deploying automation technologies on selected distribution feeders to improve fault detection, outage isolation, system restoration, and operational flexibility. Automation devices will provide enhanced visibility into feeder conditions while enabling operators to remotely monitor and control portions of the distribution system under both normal and contingency operating conditions. These capabilities will help reduce outage durations, improve restoration performance, and provide additional operational flexibility during emergency events and planned switching activities.

From a Distribution Planning perspective, DA helps close the gap between high-level planning assumptions and actual feeder conditions. Section 4 emphasizes that the Ten-Year Plan is a screening tool and that detailed area studies are needed to evaluate feeder ties, switching plans, voltage performance, load transfers, thermal constraints, and operating limits. DA provides the field infrastructure and telemetry that can help Distribution Planning Engineers and operators understand whether switching alternatives, load transfers, and feeder reconfigurations are practical under real system conditions.

5.7.1.4 Advanced Distribution Management System

PNM has signed a contract with Schneider Electric to implement EcoStruxure ADMS, a unified platform that integrates SCADA, distribution management, outage management, and advanced network applications on a single data model. The current implementation plan includes Release 1 for DSCADA and OMS Lite targeted for a 2028 go-live; Release 2 for DERMS and Release 4 for Base DMS and Advanced Applications, including IVVO and FLISR, targeted for a 2028 go-live; and Release 3 for OMS Full, including Field Crew Management, Mobile, Storm Mode, Workforce

Management, System Operations Management, and wildfire-related functionality, targeted for a 2029 go-live.

ADMS is important to the DSP because it creates a stronger connection between Distribution Planning and Distribution Operations. Section 4 describes how planning currently moves from high-level Ten-Year Plan screening to detailed area studies and hosting capacity analysis. ADMS will provide a more integrated operational platform that can use the distribution network model, SCADA data, AMI integration, field-device data, outage information, DER information, and advanced applications to improve operational awareness and inform future planning cycles.

As ADMS capabilities mature, PNM expects to improve how planning assumptions are validated against real operating conditions. For example, ADMS can support improved understanding of switching configurations, feeder loading, outage restoration performance, voltage conditions, and the operational feasibility of load transfers. This information can then be used to improve subsequent Ten-Year Plan cycles, detailed area studies, hosting capacity evaluations, and non-wires alternative assessments.

5.7.1.5 Integrated Volt/VAR Management

Integrated Volt/VAR Management, or IVVM, is included within ADMS Release 4 and is targeted for go-live in 2028 concurrent with ADMS Release 2 for DERMS. Within the EcoStruxure ADMS platform, IVVM supports conservation voltage reduction, peak demand management, and active power loss minimization by using analytics and control algorithms to optimize feeder voltage and reactive power.

IVVM connects to Distribution Planning because voltage performance is one of the planning criteria evaluated in detailed area studies and hosting capacity analysis. Section 4 describes how detailed studies evaluate voltage criteria, contingency performance, DER sensitivity, and feeder-level operating constraints. IVVM can provide an operational tool to manage voltage more dynamically where the required monitoring, communications, controllable devices, and model accuracy are available.

Over time, IVVM may also support non-wires alternatives and improved asset utilization by reducing losses, improving voltage profiles, and helping manage the impact of DERs on feeder voltage. The current draft also notes that, as DERMS is deployed, PNM expects to leverage dispatchable DER to support IVVM objectives, including monitoring voltage at DER points of interconnection and using DERs to supply or absorb real and reactive power in response to voltage conditions.

5.7.1.6 Distribution Energy Response Management System

DERMS is included within ADMS Release 2, targeted for a 2028 go-live concurrent with ADMS Release 4. DERMS is expected to provide monitoring, dispatch, and orchestration of DERs and aggregations, including visibility into DER performance, voltage monitoring at DER points of interconnection, and control signals for real power, reactive power, and demand response across front-of-the-meter and eligible behind-the-meter resources.

DERMS is directly tied to the Distribution Planning issues described throughout the DSP. Section 4 identifies DER penetration, storage, electrification, minimum daylight load, hosting capacity, inverter behavior, and non-wires alternatives as important planning considerations. DERMS provides a future operational framework for coordinating DERs in a way that can support local distribution constraints, voltage conditions, hosting capacity, and potentially non-wires alternatives.

PNM expects to begin with utility-owned DERs that already have RTUs and SCADA connectivity, such as distribution-connected solar facilities and distribution battery energy storage systems. Over time, PNM expects to evaluate additional DER integration either directly or through aggregators. PNM's proposed VPP Enablement project under the DOE GRIP program, discussed in Section 6.6, is intended, if funded, to build upon DERMS capabilities by creating DER aggregations that can provide grid services and participate as virtual power plants.

5.7.1.7 Fault Location, Isolation, and Service Restoration

Fault Location, Isolation, and Service Restoration, or FLISR, is included within ADMS Release 4 and is targeted for a 2028 go-live concurrent with ADMS Release 2. FLISR uses data from field devices, communications networks, and the ADMS network model to detect faults, locate the faulted section, isolate the affected portion of the feeder, and restore service to customers on healthy sections, where safe and feasible.

FLISR ties directly to Distribution Planning because restoration capability, feeder ties, switching complexity, and contingency restoration are recurring themes in Section 4. The DSP explains that the Ten-Year Plan provides high-level contingency indicators, while detailed area studies evaluate feeder-level switching, voltage performance, thermal loading, and restoration feasibility. FLISR provides an operational capability that can improve the effectiveness of those planning concepts by enabling faster and more coordinated restoration on feeders that have the required automation, communications, model accuracy, and operating procedures.

As PNM deploys FLISR, the benefits will depend on the availability of DA devices, communications connectivity, accurate network models, and integration with ADMS. For that reason, FLISR should be presented as an outcome enabled by the combined Grid Modernization portfolio rather than as an isolated software function. The current draft notes that FLISR will initially operate on a subset of feeders equipped with DA and SCADA connectivity, including the 55 feeders targeted for DA deployment in 2026–2027, with additional feeders enabled over time.

5.7.2 Status of Pilot Programs

PNM is evaluating, on a preliminary basis, including a Front-of-Meter (FOM) battery deployment pilot program as part of the VPP Project discussed in Section 6.6.

5.7.3 Utilities Roadmap

PNM's grid modernization roadmap is designed to deliver multiple customer and system benefits through a phased deployment of operational technology, communications infrastructure, advanced analytics, and distributed energy resource integration capabilities. Rather than relying solely on traditional infrastructure expansion, grid modernization investments provide tools that allow existing distribution facilities to be used more effectively and support a broader range of customer energy resources.

5.7.3.1 Reliability

Grid modernization technologies will improve reliability by reducing outage duration, improving outage awareness, and increasing operational flexibility. Distribution Automation and FLISR technologies will allow portions of the system to be isolated and restored more quickly following outages. Enhanced communications systems, SCADA integration, AMI outage notifications, and future ADMS capabilities will provide operators with improved situational awareness during both normal and contingency conditions.

Improved system visibility also supports Distribution Planning by enabling more accurate identification of capacity constraints, load transfer opportunities, and feeder operating conditions, leading to better-informed capital investment decisions.

5.7.3.2 Resilience

Grid modernization investments enhance resilience by providing operators with improved visibility, remote control capability, and greater flexibility during abnormal system conditions. Communications upgrades, automation devices, and advanced operational applications help support faster restoration, more effective contingency response, and improved system adaptability during extreme weather events or other disruptive events.

As DERs, battery storage systems, and potential microgrid applications increase across the distribution system, DERMS and related technologies will provide a framework to integrate these resources while maintaining reliable system operations. These technologies can improve the ability of distributed resources to support local loads and system needs during constrained operating conditions.

5.7.3.3 Greenhouse Gas Reduction and Clean Energy Integration

Grid modernization investments also support New Mexico's clean energy and decarbonization objectives by increasing the distribution system's ability to accommodate customer-sited solar, community solar projects, battery storage systems, electric vehicles, and other distributed energy technologies.

Hosting capacity analysis, DER integration tools, advanced inverter management capabilities, and future DERMS functionality will help maximize the utilization of existing distribution infrastructure while reducing barriers to DER adoption. Advanced monitoring, forecasting, and planning capabilities will also support higher penetrations of renewable energy resources without compromising safety or reliability.

The roadmap therefore links grid modernization investments directly to reliability improvements, resilience enhancements, and the ability to support the continued transition toward a cleaner and more distributed electric system.

5.7.4 Utility Maximization of Customer Benefits

PNM's approach to grid modernization emphasizes not only deployment of innovative technologies but also maximizing the value of previous investments through integration, expanded use cases, and operational improvements. Existing grid modernization assets provide a foundation that can be leveraged to support future Distribution Planning, system operations, customer programs, and DER integration activities.

Advanced Metering Infrastructure serves as a foundational technology for multiple grid modernization objectives. AMI improves visibility into customer usage patterns, supports outage identification and restoration activities, enables more accurate operational analysis, and provides data that can improve forecasting and planning processes. As electrification, DER adoption, and customer participation programs continue to expand, AMI data will become increasingly important for understanding feeder-level load behavior and improving planning assumptions.

Similarly, prior investments in SCADA systems, communications infrastructure, GIS modernization, Utility Network implementation, hosting capacity studies, and distribution modeling platforms are being integrated into a more comprehensive planning and operational framework. These systems provide the data foundation necessary for advanced applications such as automated hosting capacity analysis, DER integration studies, improved forecasting methods, and future ADMS and DERMS functionality.

PNM also expects to maximize customer benefits by using these investments to improve the effectiveness of existing infrastructure. Better visibility and analytics can help identify opportunities to defer traditional infrastructure upgrades, improve asset utilization, accelerate outage restoration, and support customer adoption of technologies such as rooftop solar, battery storage, electric vehicles, and other distributed energy resources.

Over time, the integration of AMI, communications networks, SCADA, GIS, Utility Network, Synergi modeling, automation, and DER management capabilities will allow PNM to create a more connected and data-driven distribution system that delivers measurable reliability, resilience, and customer-service benefits while supporting the evolving needs of customers.

5.8 Wildfire Risk and Mitigations Including Public Safety Power Shutoff

The PNM Wildfire Team works with internal stakeholders to annually review, revise, and file a Wildfire Mitigation Plan (WMP), Public Safety Power Shutoff Plan (PSPS), and a Wildfire and Vegetation Management and Infrastructure Maintenance Expense Report to the NMPRC. The Wildfire Mitigation Plan contains project and program information that support ongoing wildfire risk mitigation in High Fire Risk Areas (HFRAs). The WMP reports on risk mitigation activities completed in the prior calendar year and offers some forward-looking information on the upcoming year's projects/programs. This report shares PNM's wildfire mitigation and risk reduction philosophy through strategically prioritized grid investments in high-risk areas. This targeted investment approach supports more immediate mitigation needs, while establishing longer-term cyclical programs. Examples of HFRA specific cyclical programs might include vegetation management, asset health assessments-remediation activities, and hardware replacements and/or upgrades that support a zero-ignition goal and philosophy. The WMP is an evolving document that drives PNM to continuously improve its system reliability, reduce wildfire risks, and keep pace with technology evolutions that support customer access to safe, reliable, and affordable, energy. Nearer-term project specific information is detailed in the WMP.

The PSPS is the company's process and plan to proactively de-energize lines in impacted HFRA(s), if/when there is a high wildfire risk, as indicated by risk modeling tools tailored to PNM's electric grid. It also details the layered communications process for: outreach, education, and PSPS awareness pushed to customers, from PNM. The WMP and PSPS are filed together by April 1.

Currently, PNM continues to approach wildfire risk mitigation investments by focusing on:

- Ignition Prevention & System Hardening: Examples include - strategic undergrounding, PSPS, Wildfire Safety Mode (WSM) [system settings], vegetation clearance, installation of lightning arrestors, bird guarding, covered wire, and other technology and infrastructure installs/upgrades,
- Risk Informed – Data Driven Mitigation Activities: Mitigation activities occur in HFRAs based on project metrics, asset health and performance data, risk spend efficiency adjusted for changing climate risks and outcomes of PNM's ongoing grid hardening and resilience projects/programs,
- Operational and System Resilience: Ongoing system upgrades, advanced system monitoring, informed risk modeling with asset and vegetation ingests to inform system and climate risks to meet challenges of evolving climate risks,
- Community Outreach, Education, and Engagement: Goal is to have all PNM customers aware of wildfire safety projects, programs, and plans to support community safety.

The full WMP, PSPS, and annual financial filing are found at [insert NMPRC link(s) to these items].
Technology Advancements:

Over the next five to ten years, PNM strives to increasingly leverage technology advancements and move successful pilot projects into programs for hyperlocal situational awareness, real-time

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system-health and status insights that not only inform, but are able to, optimize PSPS activities to reduce potential impacts to customers and communities. This could mean strategically prioritized investments in HFRA that use smart grid technologies, enabled by expanding telecommunications capabilities to drive SCADA-enabled hardware installations, protective devices, enhance real-time decision making, and responsibly use AI-ML with human validators to:

- Measurably reduce ignitions and wildfire risk
- Minimize the number and scope of potential de-energizations
- Reduce the time to re-energization
- Provide 24/7 real-time situational awareness, system health metrics, and use smart devices for virtual mitigation activities
- Provide actionable data and strategies to effectively reduce risks from assets, vegetation, or other
- Suggest system setting changes in real-time and take action to reduce/avoid service disruptions and/or reduce risk to the system when certain PNM-identified thresholds are met

Today, smart devices can relay real-time asset health, status information, and take appropriate human-validated action. However, these devices necessitate a robust telecommunications backbone across the energy grid, or at the very least, throughout identified HFRA, to enable remote system activities, predictive analytics, and a future state—self-monitored and self-healing system, with human validation. This future state will be available when ADMS is fully implemented.

In addition to ADMS and smart device adoption throughout the system, PNM is starting an in-house drone program with beyond visual line of sight (BVLOS) capability, for blue-sky asset health inspections, pre and post event situational awareness and restoration support. Drones may be piloted as well as semi-permanently situated units at strategic locations for autonomous-programmed inspection routines. This high-quality visual data collection would lend itself to accurate vegetation assessments, asset health inspections, additional QA/QC, oversight of contractors, and future project planning. With trackable metrics over time, risk-reducing activities are measured and adjusted. Investments can be reprioritized and/or augmented dependent upon historical and collected data, and precise-targeted vegetation and an asset health management system can be continually refined for optimized risk reduction, cost efficiency, and customer benefit.

Years 1-5 in HFRA:

- Establish prioritized telecommunications rollout
- Subsegment HFRA into smaller operational areas and create a program to install necessary hardware and upgrades to:
 - Provide asset health, current state/status

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- Prioritize installation of segmentation devices, reclosers, fuses, covered wire
- Establish prioritized wildlife corridors within HFRAs for rollout of ignition mitigation hardware installs (avian, lightning, etc.)
- Study unique locations for cost-benefit analysis of strategic undergrounding
- Pilot visual learning model to review past LiDAR, drone, satellite data for vegetation remediation, growth projections, and asset health information
- Establish data governance process/policies
- Establish wildfire system setting timeframes for SCADA and non-SCADA enabled devices
- Build tracking mechanisms for WSM and SAIDI/CAIDI reporting
- Collaborate with Tribal, state, federal, and local partners for further understanding of statewide critical infrastructure and access and functional needs population
- Partner with federal, state, Tribal, and local forestry partners to amplify forest-health activities to mitigate wildfire risk and promote tree-forest health
- Collaborate with federal, state, local, and Tribal partners on emergency planning and community response to continually improve safety outcomes
- Investigate 2-way, multi-lingual communication notification alerts to customers if/when a PSPS is contemplated
- Augment PNM-owned mesonet and ignition detection capability via cameras and collaborate with first responders to share data
- Continue to use data-metrics refine wildfire risk, historical climatology, near-term extreme climate risks to re-evaluate WF program focus and strategic investments
- Pilot GridWare-Gridscope/other line sensor technology for real-time reporting, fault detection, environmental monitoring
- Pilot New Mexico State University's (NMSU) efforts to develop and scale ignition detection camera technology
- Build out PNM drone program: Human-piloted, and autonomous – programmed semi-permanent installation (Drone in a Box – DIAB)
- Study and Pilot: Weather station height variance - (PNM currently has 66 weather stations installed at 20 feet)
- Establish cyclical data collection: LiDAR, satellite, drone, video capture, photos
- Establish and collect 3D point-cloud data-rendering of T&D system throughout HFRA (vegetation and assets)

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- Analyze 3D data collection for vegetation and asset remediation plan for prioritized and cyclical resolution
- Establish cyclical pole assessment, treatment, and remediation program
- Establish cyclical vegetation clearance assessment and remediation schedule
 - annual adjustments for invasive species, fire, and flood threats
- Establish covered wire program with prioritization and installation timeline
- Establish prioritized fire wrap installation program
- Investigate-establish preventative fire-retardant program (for dispatch prior to potential PSPS event to support strategic poles/areas' resilience)
- Conduct additional protection studies for the Transmission system
- Implement lifecycle asset health management system for HFRA T&D poles, hardware, and vegetation
 - Layer asset information into risk modeling and risk spend efficiency calculations
 - Layer project and program information into risk modeling and risk spend efficiency-calculations
 - Resolve disaggregated data streams and optimize workflows for unified project and program planning and field operations via holistic data collection, management, and workflows
 - Establish real-time asset situational awareness dashboard for data analysis and decision-making

5.9 Distribution Engineering Asset Management (poles, switchgear, etc.)

Engineering Teams work in conjunction with Line Operations to determine what emergent assets need replacement. All other asset replacements fall under 5.5.

5.10 Distribution Engineering Programs

PNM is working on several programs to improve reliability. The programs are set up on a two-year cycle each consisting of engineering/design/scope the first year and construction the second year. When the new cycle begins the engineering/design will overlap the construction of the previous cycle. This ensures that PNM always has scope and can execute construction within budget parameters. The programs are as follows:

5.10.1 Open Wire Secondary (OWS) Upgrades:

PNM is committed to improving the reliability of the electric grid by replacing aging, multi-wired bare 600V secondary lines with insulated bundle wire. PNM evaluates which OWS to replace due to the number of outages and age. The most common outages are due to vegetation and annealed lines that slap. PNM's practice is to remove as much OWS by

performing thorough load calculations to meet current and future power demands, adding transformers and covered triplex wire. For all new secondary installations, covered wire is our standard.

5.10.2 Live-Front Replacements and Upgrades

PNM is committed to improving the reliability of the electric grid by replacing live front pad mounted transformers and switchgears with dead front pad mounted equipment. Live front means that equipment has exposed energized parts inside, such as a live front switchgear has energized, exposed switch bays and fuse bays. Due to these exposed parts, some of these devices have been compromised by vermin and thus causing a lengthy outage (avg 7+hrs). The identified vermin compromised equipment will be replaced with dead front pad mounted equipment. Dead front is a more modern design that means that there will not be any exposed energized parts providing additional employee lineman safety when accessing the equipment and installation from vermin compromise. For all new pad mounted transformers and switchgear installations, a dead front is the modern PNM standard.

5.10.3 Distribution Looping (Redundant Service)

PNM is committed to improving the reliability of the electric grid by identifying and addressing problematic radial feeders in the underground distribution system. These radials lack redundant power supplies, leaving customers at increased risk of outages in the event of a cable fault or equipment failure, when compared with a redundant, looped design.

Looped distribution feeder system design benefits include: 1) Improved service reliability: looping radials to include a redundant feed significantly enhances the reliability of power delivery to PNM customers. 2) Reduced outages and faster restoration times. If a cable fault or termination failure occurs, customers on the redundant, looped design will not experience prolonged periods without power when compared to the redundant feed. This minimizes the duration of outages and ensures a more reliable electricity experience. 3) Efficient cable replacement by installing all new conductors, located within conduit, allows crews to replace faulty cables more efficiently, further reducing outage durations. 4) Improved Safety for Crews and Customers. Faults that require more complex repairs will be thoroughly evaluated by engineers to ensure a safe working environment for our crews. Additionally, the ability to switch to the redundant feed allows for power restoration to customers while repairs are underway.

For all new underground systems that serve more than one customer, looping is the current PNM standard. There are instances where a radial underground feed is a standard and that only applies to a dedicated service to the customer or business with multi-tenants.

5.10.4 Smart Device Replace and Upgrade

PNM is committed to improving the reliability of the electric grid by replacing outdated and obsolete 3-phase dynamic protective devices and manual switches with intelligent reclosers and switches with Supervisory Controlled and Data Acquisition (SCADA)

systems. These intelligent reclosers and switches provide greater protection and reliability to the distribution system while providing the Distribution Operations Center with the ability to control the devices when needed for any situation, routine switching, and outage restoration. The modernized reclosers will provide enhanced protection and valuable data on the electric system to aid PNM in operating a more resilient and reliable electrical system.

5.10.5 Lightning Mitigation

PNM is committed to improving the reliability of the electric grid by mitigating outages and damage to system equipment, caused by lightning strikes. It is necessary to reduce exposure to equipment and conductor over long distances, that does not allow for the grounding of high voltages caused by lightning. Our current standard is being evaluated from four lightning arrestor stations per mile to eight per mile and install single-phase reclosers where necessary.

5.10.6 Cable Replacement Program

PNM is committed to improving the reliability of the electric grid by replacing aging underground distribution lines. This project is driven by the need to proactively address aging infrastructure within our underground distribution system. By replacing these components before they fail, we can minimize the risk of outages and ensure long-term service reliability for our customers. The scope of the project includes inspection, assessments, designs, materials, and construction across various areas in the PNM's service territory.

5.10.7 Structural Replacement Program

PNM is committed to improving the reliability of the electric grid by replacing distribution poles due to their age, size, condition, or any other criteria deemed appropriate by engineers or linemen. This could

also include the replacements of any other assets as necessary that are on the pole(s). PNM is also in the process of developing a cyclical cycle pole inspection program.

5.10.8 Structural Replacement Program in HFRA

PNM is committed to improving the reliability of the electric grid by replacing distribution poles due to their age, size, condition, or any other criteria deemed appropriate by engineers or linemen due to the new wildfire standards that were created in 2025. This could also include the replacements of any other assets as necessary that are on the pole(s). PNM is also in the process of developing a cyclical cycle pole inspection program for HFRA that will be different from the number 7 above.

5.10.9 Wildfire Mitigation

In 2025, PNM updated its distribution design standards applicable to High Fire Risk Areas, for new builds and/or rebuilds. The updated standards were developed to mitigate or lower the risk of a wildfire being started by PNM facilities. PNM will extend facilities through new line extensions, and the engineering group will comply with the new wildfire standards. With existing facilities, PNM will change out facilities like poles, crossarms,

cutouts, arresters, reclosers etc to meet the new wildfire standard. In addition, PNM has increased the required easement for our facilities in HFRA. For 1-phase lines, PNM requires a 15-foot-wide easement and for 3-phase lines, PNM requires a 30-foot-wide easement.

5.10.10 Telecom for Distribution

PNM is committed to improving the reliability of the electric grid by installing new fiber optic or by adding more radio devices that allow our smart devices to communicate and be controlled by DOC Operations. New fiber is being installed in HFRA's due to lack of radio signal; this will allow DOC to instantly change settings based on PSPS events. All feeder rebuilds will have new fiber installed. Grid Modernization will be installing new fiber and radio devices for their projects related to Distribution Automation. All Community Solar projects will have fiber or radio installed for those projects. With the addition of fiber and radio, it will allow DOC to communicate with these devices and be able to switch around how power might flow to restore power quicker to customers.

5.10.11 Feeder Rebuild

PNM is committed to improving the reliability of the electric grid by rebuilding our backbone feeders to meet current standards. PNM evaluates our worst performing feeders on a 3–5-year average, average age of the feeder, and customer count. These factors help decide which feeders we will rebuild. These feeders have aging infrastructure, capacity issues, and reliability issues. We are upgrading our poles, conductors, feeder getaways, equipment and adding more protective devices.

5.10.12 Distribution Relay Replacements

PNM is committed to improving the reliability of the electric grid by improving the operation of the distribution protection systems. Improved protection operation improves reliability by providing quicker isolation during a fault, reducing the risk of misoperation of equipment, and reducing the risk of widespread outages exacerbated by failure of equipment to operate. PNM is doing this by replacing obsolete electromechanical and solid-state relays with modern microprocessor relays, installed with redundancy, effectiveness, and maintainability in mind.

This integrated approach supports more informed decision-making and long-term planning effectiveness.

5.11 Distribution System Plan Policy Alignment

5.11.1 Safe, Reliable, and Resilient Service Remains the Foundation

PNM's DSP prioritizes maintaining a safe, reliable, and resilient distribution system while planning for future changes in customer demand and technology adoption.

Reliability and public safety remain core planning objectives as the grid evolves.

5.11.2 Support for New Mexico's Clean Energy Transition

The DSP prepares the distribution system to accommodate increasing levels of distributed energy resources, including rooftop solar, battery storage, and electric vehicles.

The plan supports the State's transition toward a carbon-free electric system while maintaining reliable service.

5.11.3 Transportation Electrification Readiness

PNM's planning process considers expected growth in transportation and building electrification.

The DSP evaluates future infrastructure needs so customers can adopt modern technologies without compromising system performance.

5.11.4 Energy Efficiency

The DSP supports modeling energy efficiency through proposed advanced forecasting.

5.11.5 Grid Modernization and Innovation

The DSP supports the deployment of advanced technologies that improve visibility, operational flexibility, and system efficiency.

Modernization investments are intended to help manage increasingly dynamic, two-way power flows and changing customer needs.

5.11.6 Affordability and Prudent Investment

The DSP emphasizes prudent investment, operational efficiency, affordability, and customer value.

Planning decisions are intended to balance customer benefits with cost-effective infrastructure investments.

5.11.7 Integrated Planning and Data Consistency

The DSP promotes consistent data and coordination across planning processes, including distribution planning and other utility planning functions.

This integrated approach supports more informed decision-making and long-term planning effectiveness.

5.11.8 Compliance with NMPRC Distribution Planning Requirements

The DSP is structured to address the Commission's distribution planning framework, including system assessment, forecasting, DER integration, stakeholder engagement, reliability, resilience, and future investment planning.

6. Investment Plans

6.1 Historical Distribution Capital and O&M Costs (≥3 Years)

Historical capital is outlined directly below:

Table 6-1: Three-Year Historical Capital Costs

Capital Category	2023 Historical Capital Spend	2024 Historical Capital Spend	2025 Historical Capital Spend	2023-2025 Historical Capital Spend
Asset Management	\$ 141,629,748	\$ 114,231,711	\$ 155,839,166	\$ 411,700,624
Customer Programs	\$ 103,892,428	\$ 66,659,684	\$ 98,960,271	\$ 269,512,383
Economic Development	\$ 12,711	\$ 1	\$ 10,000,354	\$ 10,013,126
Grid Mod	-	\$ 5,359,104	\$ 30,817,750	\$ 36,176,854
Distribution Planning	\$ 41,945,781	\$ 53,281,577	\$ 19,321,638	\$ 114,548,996
Other	\$ (232,429)	\$ 922,865	\$ 4,494,395	\$ 5,184,831
Total estimated capital spend	\$ 287,248,298	\$ 240,454,942	\$ 319,433,575	\$ 847,136,815

Historical distribution O&M is outlined directly below:

Table 6-2: Three-Year Historical O&M Costs

	2023 Historical O&M Spend	2024 Historical O&M Spend	2025 Historical O&M Spend	2023-2025 Historical O&M Spend
Historical O&M	\$ 33,269,256	\$ 32,871,612	\$ 35,860,363	\$ 102,001,231

6.2 Projected capital and O&M costs (≥5 years)

Projected capital is outlined directly below:

Table 6-3: Five-Year Projected Capital Costs

Rate Case Category	2027 Estimated Capital Spend	2028 Estimated Capital Spend	2029 Estimated Capital Spend	2030 Estimated Capital Spend	2031 Estimated Capital Spend	2027-31 Estimated Capital Spend
Asset Management	\$ 103,521,553	\$ 137,342,977	\$ 131,066,708	\$ 141,525,982	\$ 162,509,231	\$ 675,966,450
Buildings	\$ 1,150,395	\$ 758,866	\$ 785,321	\$ 785,284	\$ 800,948	\$ 4,280,815
Customer Programs	\$ 71,352,131	\$ 84,495,857	\$ 81,587,361	\$ 88,453,260	\$ 87,858,893	\$ 413,747,502
Economic Development	\$ 13,475,307	\$ -	\$ -	\$ -	\$ -	\$ 13,475,307
Grid Mod	\$ 112,017,742	\$ 96,631,262	\$ 45,732,084	\$ 32,902,948	\$ 4,559,130	\$ 291,843,166
Transmission and Distribution Planning	\$ 49,010,056	\$ 83,467,712	\$ 53,270,391	\$ 95,793,615	\$ 49,834,982	\$ 331,376,756
Wildfire Mitigation	\$ 15,570,369	\$ 37,312,090	\$ 31,511,354	\$ 35,493,722	\$ 36,077,430	\$ 155,964,965
Total estimated capital spend	\$ 366,097,553	\$ 440,008,764	\$ 343,953,218	\$ 394,954,811	\$ 341,640,615	\$ 1,886,654,961

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The 2027-2031 Projected capital budget shown above is subject to change as system conditions evolve. The Grid Mod budget will be updated going forward as the program continues over its projected 11-year rollout.

For purposes of capital planning, the following Categories are used to define investment areas of focus:

- Asset Management programs on the T&D systems are aimed at improving overall T&D system reliability, incorporating security, ensuring regulatory compliance, and positing the T&D system to meet future customer demands. They include jointly owned projects, blankets, and other regular equipment replacement programs.
- Customer Program investments are those that are required to support new service delivery, customer programs such as EV programs, facility relocation for customer needs, streetlights and private area lighting, electrification, and energy efficiency programs.
- Economic development investments support new economic development customer load service and facilities.
- Grid Modernization is the program PNM utilizes to modernize its distribution system and includes investments outlined in its Grid Mod filings.
- Transmission and Distribution Planning investments are derived from planning studies and these projects fulfill the requirement to provide safe and reliable services. They can include capacity expansions, or other improvements required to serve customer load.
- Wildfire Mitigation supports improvement of wildfire risk through system and equipment resilience initiatives.

Projected distribution O&M is outlined directly below:

Table 6-4: Five-Year Projected O&M Costs

	2026 Forecasted O&M Spend	2027 Forecasted O&M Spend	2028 Forecasted O&M Spend	2029 Forecasted O&M Spend	2030 Forecasted O&M Spend	2026-2030 Forecasted O&M Spend
Forecasted O&M	\$ 40,191,575	\$ 51,557,301	\$ 53,200,476	\$ 54,913,261	\$ 58,927,571	\$ 258,790,185

The 2027-2031 projected distribution O&M budget is not provided yet due to the timing of final approval. This includes labor and inspections and regular and emergency maintenance of PNM's system.

6.3 Cost Drivers and Investment Timelines

The primary drivers of PNM's future distribution investments are expected load growth, economic development, electrification, increasing penetration of distributed energy resources, aging infrastructure replacement, grid modernization, and resilience requirements. Consistent with the Distribution System Plan framework, PNM evaluates these needs over a five-year planning horizon while maintaining a longer-term view. Investments are prioritized to maintain safe and

reliable service, accommodate emerging customer technologies, and support the evolving needs of New Mexico's electric system.

6.4 Regulatory Approval and Cost Recovery Framework

At this time, PNM is not seeking Commission approval of the investments identified in this DSP, nor is it requesting cost recovery for the projects, programs, or expenditures described herein. The filing is intended to inform stakeholders and the New Mexico Public Regulation Commission ("NMPRC") of PNM's long-term distribution planning processes, system challenges, and potential investment priorities.

As distribution system planning continues to evolve and as customer expectations for reliability, resiliency, affordability, and grid modernization increase, PNM is evaluating whether future DSP filings should be submitted for Commission approval and accompanied by a Distribution System Rate Rider or similar recovery mechanism for NMPRC consideration. Such an approach could create a more structured and transparent framework for reviewing, prioritizing, and implementing distribution system investments over a multi-year planning horizon. An approved DSP would provide greater visibility into PNM's distribution system needs and planned investments, allowing stakeholders to evaluate proposed projects in the context of broader system objectives and long-term customer benefits.

PNM believes that aligning distribution planning with a forward-looking cost recovery mechanism could improve the efficiency and predictability of distribution infrastructure investment. Distribution systems across the country are facing increasing demands associated with aging infrastructure replacement, population and economic growth, electrification, increasing customer expectations for service quality, distributed generation interconnection, load growth from emerging industries, grid resilience improvements, and wildfire risk mitigation. Addressing these challenges often requires sustained investment programs that extend beyond a single rate case cycle. A Commission-approved planning and recovery framework would help ensure that necessary projects are identified, evaluated, and prioritized through a transparent regulatory process while allowing investments to proceed on a timeframe that better aligns with customer and system needs.

In addition, a Distribution System Rate Rider could reduce regulatory lag associated with the recovery of prudent distribution investments. By providing a timelier mechanism for recovering capital investments placed into service, such a framework could support the deployment of projects needed to maintain reliability, accommodate customer growth, expand hosting capacity for distributed energy resources, enhance system resilience, and address evolving operational risks. Timely investment recovery can also improve capital planning efficiency and provide greater certainty regarding funding for long-term infrastructure programs.

From a stakeholder perspective, an approved DSP and associated recovery mechanism would increase transparency and accountability by clearly identifying proposed investments, expected benefits, implementation schedules, and estimated costs. It would also create a regular forum for stakeholder engagement regarding distribution system needs and priorities, helping ensure that limited capital resources are directed toward projects that provide the greatest value to customers. Through this approach, PNM could better balance affordability considerations with

the need to maintain a safe, reliable, resilient, and modern electric distribution system capable of supporting New Mexico's evolving energy and economic development objectives.

Accordingly, while this filing does not seek approval of specific investments or cost recovery, PNM views the DSP as an important first step toward establishing a more comprehensive distribution planning framework that promotes transparency, stakeholder engagement, prudent investment, and the long-term reliability and resiliency of the electric distribution system.

6.5 Grid Modernization Statute vs. Ordinary-Course Investment Delineation

PNM distinguishes GMS investments from ordinary-course distribution investments based on the primary purpose of the investment. GMS investments generally provide advanced communications, monitoring, automation, control, cybersecurity, and data-management capabilities that enhance visibility, operational awareness, DER integration, and system flexibility. Ordinary-course investments, by contrast, represent the traditional infrastructure, capacity, reliability, safety, wildfire mitigation, and asset-replacement projects necessary to provide electric service. While these investment categories are distinct, they are complementary. Grid modernization investments enhance PNM's ability to plan, operate, and optimize the distribution system, while ordinary-course investments continue to provide the physical infrastructure necessary to reliably deliver electricity to customers.

6.6 Potential State or Federal Funding

PNM applied for a U.S. Department of Energy (DOE) grant in 2024 for a Virtual Power Plant (VPP) Enablement project under the DOE's Grid Resilience and Innovative Partnerships (GRIP) program, Topic Area 2 (Smart Grid Grants). As proposed, the project sought \$35.6 million in DOE funding, allocated across several scope categories, including VPP software solution development, behind-the-meter device installation and deployment, system integration services, and demand response aggregator services.

The project is also expected to evaluate FOM battery deployments as a solution which could provide an additional tool for addressing feeder or substation-level constraints in locations where a traditional utility-owned distribution BESS installation may not be sited economically or where site availability is limited. FOM battery systems of this type are sited on the distribution feeder and configured on the utility side of the customer's meter, allowing PNM to dispatch them directly as a grid asset rather than as a customer-controlled behind-the-meter resource. In addition to providing dispatchable capacity that can support overloaded feeders or substations at the system level, these systems can also be configured to disconnect the residence from the distribution system during an outage and continue supplying that residence from the battery, providing the customer with a degree of uninterrupted power during utility outages.

PNM and DOE have not yet completed contract negotiations, and PNM does not have a definitive, executed award at this time. PNM anticipates that the final project scope will differ from the original proposal as negotiations continue, in part because certain activities originally contemplated as cost-share have progressed during the award delay and because system needs have continued to evolve, including identification of feeders or substations that may now be better candidates for project deployment. PNM cannot represent the project's final funding level, scope, or schedule with certainty at this time. PNM does not have any potential state funding opportunities at this time.

7. *Benefit-Cost Analysis – Copperleaf*

Copperleaf is a tool that PNM has invested in and continues to refine the value models that establish the project benefit scoring priority.

7.1 **Comparison Of Proposed Grid Modernization and Advanced Grid Technology Investments with Traditional Distribution Investment Alternatives Over the Next Five Years**

PNM's distribution system planning approach is evolving from one that relies primarily on traditional infrastructure expansion toward a framework that combines conventional distribution investments with advanced grid technologies, operational technologies, and data-driven planning tools. Traditional distribution investments—including new substations, transformer additions, feeder extensions, conductor upgrades, voltage-support equipment, and system replacement programs—will continue to be necessary to address customer growth, asset replacement needs, reliability requirements, and safety obligations. However, Grid Modernization investments provide additional tools that can improve visibility, operational flexibility, and asset utilization, allowing PNM to evaluate a broader range of solutions before constructing new infrastructure.

Over the next five years, PNM expects Grid Modernization technologies to complement—not replace—traditional distribution investments. Technologies such as AMI, telecommunications upgrades, Distribution Automation, ADMS, FLISR, IVVO, DERMS, Utility Network, advanced forecasting tools, and hosting capacity analytics will provide operational and planning information that was not previously available at scale. These capabilities improve PNM's ability to identify localized constraints, evaluate operational alternatives, understand actual feeder loading conditions, analyze distributed energy resource impacts, and prioritize capital investments more effectively.

In many situations, traditional infrastructure solutions will remain the preferred option. For example, when customer growth exceeds available transformer capacity, new substations, transformer additions, feeder expansions, or conductor upgrades are necessary to maintain compliance with planning criteria and reliability requirements. Grid Modernization technologies do not eliminate the need for these investments; rather, they improve PNM's ability to identify the appropriate scope, timing, and location of those investments.

Grid Modernization technologies may also provide alternatives that defer or reduce the amount of traditional infrastructure required. Distribution Automation and FLISR can improve utilization of existing feeder configurations through enhanced switching capabilities and faster restoration. ADMS applications provide improved system visibility and operational awareness that may enable Distribution Planning Engineers and operators to identify load-transfer opportunities or operational alternatives before major capital projects are constructed. Utility Network and advanced distribution models improve engineering analysis and allow planning studies to be performed using more accurate and current system information.

As distributed energy resources, battery storage systems, electrification, and community solar continue to grow, technologies such as hosting capacity analysis, DERMS, and advanced forecasting tools will improve PNM's ability to evaluate non-wires alternatives alongside traditional infrastructure investments. In appropriate circumstances, customer-sited resources, utility-owned

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battery storage systems, voltage optimization, demand response programs, managed EV charging, or targeted distribution automation investments may provide a cost-effective supplement to traditional distribution upgrades while maintaining reliability and operational flexibility.

PNM expects a significant long-term benefit of Grid Modernization investments to be the integration of Distribution Planning and Distribution Operations. AMI, communications upgrades, Utility Network, Distribution Automation, ADMS, DERMS, and advanced analytics will provide Distribution Planning Engineers and operators with a common set of data and operational tools. This integrated environment will improve forecasting, enhance system visibility, support DER integration, improve outage response, enable more accurate hosting capacity analysis, and help ensure that future capital investments are directed toward the areas of greatest customer benefits.

Accordingly, PNM views Grid Modernization and traditional distribution investments as complementary components of a single strategy. Traditional infrastructure projects will continue to provide the physical capacity, reliability, and safety improvements required to serve customers, while Grid Modernization investments provide the data, communication, control, and analytical capabilities needed to maximize the value of those assets and support the evolving needs of the distribution system.

Table 7-1: Distribution Needs and Alternative Investment Matrix

Distribution Need	Traditional Investment Alternative	Grid Modernization Alternative or Enabler	Expected Customer Benefit
Capacity Constraints	New substation, transformer addition, feeder buildout	Enhanced forecasting, AMI analytics, operational load transfers, DERMS, battery storage	Better investment timing and improved asset utilization
Reliability Improvement	Additional switching devices, looping, feeder rebuilds	DA, FLISR, ADMS, improved communications	Reduced outage duration and faster restoration
Voltage Management	Capacitor banks, voltage regulators	IVVO, DERMS-enabled Volt/VAR support	Improved voltage quality and reduced losses
DER Integration	Traditional feeder upgrades	Hosting Capacity Analysis, DERMS, Utility Network, advanced modeling	Faster DER integration and improved system visibility
Planning Accuracy	Engineering studies based primarily on historical loading	AMI interval data, Utility Network, ADMS, advanced forecasting	Improved capital investment decisions
Resilience	Additional infrastructure redundancy	Communications modernization, DA, ADMS, FLISR, DERMS	Enhanced operational flexibility and emergency response

8. Action Plan

8.1 Prioritized List of Investments, Expenditures, And Activities

Action: PNM will pursue the following distribution investments in the near-term to ensure on-going distribution system reliability. PNM will continuously monitor and make any adjustments to priority as system or customer needs change.

In addition to the projects outlined in the Grid Mod Plan in Section 5.7, the Wildfire Mitigation and Distribution Asset Management Programs described in Sections 5.8 – 5.10, the Distribution Engineering Asset and Transmission & Distribution Planning departments will pursue specific projects as outlined below:

- *Build three new Distribution Substations, with a total expansion of 5 transformers*
- *Upgrade eleven Distribution Substations, with a total expansion of 12 transformers*
- *Six Distribution Feeder rebuild/upgrade projects*
- *Four new Feeder tie projects*

Background: Pursuant to PNM's Ten-Year Plan and other supporting studies, the identified projects address PNM system and customer needs on a prioritized basis and in coordination with interdependent plans outlined in detail in the body of this report.

8.2 Automated Hosting Capacity Capability

Action: PNM will complete its Grid Mod effort to automate its hosting capacity analysis and ensure that analysis is provided on a public-facing platform for use by customers and other stakeholders. PNM will continue to complete the necessary foundational data and software required elements in accordance with the details outlined in PNM's Grid Modernization Plan.

Background: PNM's Grid Mod Plan identified hosting capacity to be fully automated during years 2-4 of the effort (i.e., 2026 through 2028), in three phases. PNM will continue to pursue these necessary steps to build a fully sustainable, automated solution for customers and will continue to provide regular updates using more manual processes until the automation is completed.

8.3 DOE Grant Projects (Pilot)

Action: PNM will continue to pursue finalization of the DOE Grant to support a VPP pilot on PNM's system.

Background: The intent of the VPP project is to pilot solution(s) that will help expand PNM's ability to identify, connect, and dispatch additional DERs, so that those systems can be operated more effectively, once available. As proposed, the project would pursue this goal through multiple workstreams. The proposed end-of-project goals included attaining capacity coordinated with PNM's DERMS, FLISR, and IVVM capabilities as those become available. See Section 6.6 for discussion regarding PNM's potential VPP pilot project.

8.4 Strategic Partnerships

Action: PNM will continue to collaborate with the following strategic partners on R&D related types of projects and/or studies, in alignment with the investment and system prioritizations noted in 8.1 above.

Background: PNM's strategic partnerships currently include:

- 1) NMSU,
- 2) Sandia National Laboratories,
- 3) Lawrence Berkeley National Laboratory,
- 4) 1898 & Co.,
- 5) U.S. Department of Energy (DOE).

As part of its Grid Modernization Program, PNM will continue to collaborate with the following strategic partners:

- 1) West Monroe,
- 2) Black & Veatch.

8.5 Future Distribution System Plan Approaches and Funding Mechanisms

Action: PNM will explore its approach to future DSPs including opportunities to improve the reporting and regulatory approaches, such as seeking future NMPRC approvals for such plan(s). PNM will also explore the concept of a Distribution System Rate Rider. Each concept will be considered in the context of customer service benefits or advantages when determining a proposed path forward.

Background: PNM is submitting this DSP as an informational filing to provide transparency regarding the current condition of its distribution system, anticipated future needs, outline the investments needed to maintain reliability, address legacy or aging infrastructure, support customer growth, enable distributed energy resource integration, and advance broader public policy objectives. As such, PNM is not currently seeking either approval of or cost recovery for the distribution plan investment outlined herein.

Going forward, PNM believes, due to the increased demand, the need to make improvements at a pace customers are seeking, and to timely respond to the significant rise in distribution demands, it prudent to explore the potential to seek NMPRC approval for a DSP in the future.

Additionally, 6.4 having an NMPRC approved DSP and Distribution System Rate Rider may be useful tools to ensure distribution projects, like the ones described in this plan, would be transparent to stakeholders on a longer-term basis and appropriately prioritized and funded. A Distribution System Rate Rider would also allow PNM to respond to increasing need to address aging infrastructure, system expansion due to more prevalent new growth, hosting capacity

improvements, and wildfire risk mitigation. A transparent, approved DSP and associated Distribution System Rate Rider provide PNM with a mechanism to timely recover distribution project investments without significant regulatory lag associated with rate reviews.

9. *Key DSP Metrics*

For a Distribution System Plan, PNM will track a balanced set of reliability, resilience, capacity, DER integration, customer, safety, and financial metrics that demonstrate whether distribution investments are delivering measurable benefits to customers and supporting New Mexico's policy objectives. The metrics should be transparent, repeatable, and aligned with utility and state planning objectives.

9.1 Reliability Metrics

These measures demonstrate whether the distribution system is providing dependable electric service.

- SAIDI (System Average Interruption Duration Index): Average outage duration per customer.
- SAIFI (System Average Interruption Frequency Index): Average number of outages per customer.
- CAIDI (Customer Average Interruption Duration Index): Average restoration time per outage.
- Circuit reliability performance: Number of circuits performing below established reliability targets.
- ASAI (Average Service Availability Index): Percentage of time an electric service is available over a year.

Measure of Success: Reduction in outage frequency and duration over time, particularly on poor performing circuits.

9.2 System Capacity and Load Growth Metrics

These metrics track whether the distribution system can accommodate future growth.

- Peak loading of substations and feeders.
- Number of substations operating above defined planning thresholds (e.g., 80% or 90% of firm normal/emergency capacity).
- Number of overloaded distribution feeders.
- Economic development interconnection requests accommodated.

Measure of Success: Fewer constrained facilities and timely accommodation of customer growth without degradation in reliability.

9.3 DER and Hosting Capacity Metrics

These metrics support New Mexico's clean energy and distributed generation objectives.

- Total distributed generation interconnected (MW).
- Annual distributed generation applications received and processed.
- Average interconnection processing time.
- Hosting capacity by feeder (available after 2028).
- Percentage of feeders with published hosting capacity information.
- Number of distribution upgrades driven by DER interconnections.
- Energy storage interconnected to the distribution system (MW/MWh).

Measure of Success: Increased hosting capacity, reduced interconnection timelines, and fewer customer interconnection constraints.

9.4 Asset Health and Aging Infrastructure Metrics

These metrics track long-term system condition:

- Condition assessment scores for major asset classes.
- Number of open-wire secondary and other hazardous conditions corrected.

Measure of Success: Reduction in high-risk aging infrastructure and asset failure rates.

9.5 Customer Experience Metrics

These metrics measure outcomes from the customer's perspective.

- I. Customer satisfaction survey results.
- II. New service connection timelines.
- III. Interconnection application processing times.

Measure of Success: Improved customer satisfaction and more timely service delivery.

9.6 Grid Modernization Metrics

Grid modernization metrics are outlined in the Grid Mod filing and are summarized in the figure below:

Figure 9-1: Grid Modernization Metrics Summary

Grid Modernization Implementation Plan (Years 1–6)						
	Y1	Y2	Y3	Y4	Y5	Y6
	2025	2026	2027	2028	2029	2030
Customer Empowerment	Advanced Metering Infrastructure (AMI) — Head-End System, Meter Data Management System, Network & Meter Deployment					
	Customer Information & Analytics — Customer Identity and Access Management (CIAM), Customer Energy Management Platform (CEMP) & Mobile App					
			Green Button Connect My Data			
Distribution Operations Enhancements	Distribution Automation — Planning, Design & Device Deployment					
		ADMS & DERMS (SCADA, OMS, DMS, and advanced apps for FLISR and IVVM)				
			Integrated Volt/VAR Management (IVVM) — Device Deployment			
			Distribution Planning & Engineering — Interconnection & DER Forecast Tools, Hosting Capacity Tools			
Supporting Services	Cybersecurity					
	Data Management & Architecture — TIBCO Middleware / Data Warehouse					
		Network Model Management / Connectivity Model / GIS Integration				
	Telecommunications — WAN/DWDM & FAN Expansion					
	Program Oversight — Program Management, Architecture, Engineering & Change Management					

APPENDICES

Appendix A

2026 DSP Stakeholder Lists

1 Stakeholder outreach list

PNM invited participation from the following organizations:

- 350 New Mexico
- ABCWUA
- ABQCore Neighborhood Association
- Ameren – Lucky Corridor
- Bernalillo County Attorney
- Bernalillo County Economic Development
- Black Mesa Casino
- Boem, Kurtz and Lowry Law
- CABQ
- City of Lordsburg Economic Development
- City of Santa Fe
- Clean Energy Coalition of Santa Fe County
- Coalition for Clean Affordable Energy
- Coalition for Community Solar Access
- Cochiti Pueblo
- EDD
- El Paso Electric
- EMNRD
- Goschke Energy Advisors
- Gould Law Firm
- GridLab
- Hall Estill Law
- IEEE
- Indian Pueblos Marketing Inc
- Institute of American Indian Arts
- Interwest Energy Alliance
- Isleta Casino Hotel Convention Center
- Isleta Pueblo
- Laguna Route 66 Casino
- Legal Solutions of NM
- Mescalero Apache Tribe
- META
- Modrall Sperling Law Firm

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- New Mexico Gas Co.
- New Mexico Partnership
- NM Affordable Reliable Energy Alliance
- NM DOJ
- NM Economic Development Department
- NM Institute of Mining and Technology
- NMPRC
- NM Representative
- NM RETA
- NM State Land Office
- Prosperity Works
- Renewable Energy Industries of NM
- Rio Rancho Chamber of Commerce
- RMI
- San Felipe Pueblo
- Sandia Casino
- Sandia National Labs
- Sandia Pueblo
- Sandoval County Economic Development Department
- Sandoval Economic Alliance
- Santa Ana Pueblo
- Santa Ana Star Casino Hotel
- Santa Fe Economic Development Division
- Santa Fe Indian School
- Santo Domingo Health Center
- Santo Domingo Pueblo
- Senate Energy and Natural Resources Committee
- Sierra Club
- Southwest Research and. Information Center
- Southwestern Indian Polytechnic Institute
- Southwestern Power Group
- Stelzner Law
- SWEEP
- Tesuque Casino
- Third Act NM
- Village of Los Lunas, Economic Development Division
- Walmart
- Western Environmental Law Center
- WRA
- Xcel Energy

Appendix A

2 Stakeholder Presentation July 31, 2026

List of organizations that had representation at the presentation on July 31, 2026:

- 350 New Mexico
- City of Albuquerque
- Community Solar Access
- El Paso Electric
- Energy Conservation and Management
- Goschke Energy Advisors
- New Mexico Gas Company
- New Mexico Renewable Energy Transmission Authority
- New Mexico Representative Southwest Energy Efficiency Project
- NMPRC
- PNM Customer
- Pueblo of Tesuque
- REIA
- Sandia National Laboratories
- Sandia Pueblo
- SFPHA
- SPS
- The Gould Law Firm
- Velarde & Yar
- Western Resource Advocates

3 Stakeholder Presentation September 21, 2026

List of organizations that had representation at the presentation on September 21, 2026.

- City of Albuquerque
- Community Solar Access
- El Paso Electric
- Grid Alternatives
- NMPRC
- PNM Customer
- Sandia National Laboratories



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Stakeholder Questions and Comments

August 1, 2026-August 31, 2026

PNM would like to thank all stakeholders who submitted questions and comments.

Q: Just now I opened the link you sent, and at first thought it was the same draft as had been distributed on July 31. However, when I compared the 2 documents, it appears the earlier one, was just the first 95 pages, and the version sent today has 436 pages. I tried to compare them, and came up with this understanding: The first 95 pages may be essentially the same--I did not do a page by page comparison, and the 8/14/2026 distributed version includes hundreds of Appendix

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pages. Please confirm or point me to where I should look for differences. The new draft is all I found attached, so where is the Table of Questions with the PNM responses?

A: Your understanding is correct. The July 31 version included the draft DSP narrative, while the August 14 version includes the same draft along with additional appendices and supporting materials, which account for the increase in page count.

The stakeholder questions and PNM responses are posted separately from the draft DSP and are available on the DSP stakeholder website.

Q: First and most importantly, explain how AMI customer data is protected during transmission, storage, and analysis. Given recent utility database breaches and the unauthorized use of user data to train AI or for other purposes, specifically address how meter locations, customer identities, and customer activity are safeguarded.

A: Please see cyber security controls we filed as part of testimony in the AMI case in 2022 on pages 21-27: <https://www.txnmenenergy.com/~media/Files/P/PNM-Resources/rates-and-filings/PNM%20Grid%20Mod/8%20Direct%20Testimony%20of%20Jonathan%20C%20Hawkins.pdf>

(Alternate response can be simply providing the text - PNM maintains a comprehensive cybersecurity program to address the risks associated with malicious software attacks. The cybersecurity program is designed to protect PNM computers, servers, business applications and data, and high value networks from unauthorized access and control from both external and internal threats. The cybersecurity threat landscape constantly evolves and expands, and it is critical to continuously improve PNM's defense posture through investments in technology, improvements in cybersecurity processes, and collaboration with law enforcement, regulatory and industry resources. PNM's guiding security philosophy is to simplify, secure, and standardize where possible to provide a reliable, resilient, and redundant environment to mitigate risk across the enterprise and define PNM's security strategy. PNM uses a risk-based process aligned with the National Institute of Standards and Technology ("NIST") Cybersecurity Framework ("CSF") Core Functions to manage security threats. The CSF defines the five core functions as follows:

- Identify – Identify threats and inform the enterprise as a key part of the end-to-end intelligence program.
- Protect – Stop would-be intruders from infiltrating and entering protected systems.
- Detect – Effectively detect and deter cyber threats via monitoring tools and other analytics.
- Respond – Assess, contain, and mitigate damages from compromising events by utilizing tools, a trained workforce, and other resources.
- Recover – Return systems to normal and understand how to protect and assess vulnerabilities in the system. All-hazards based recovery capabilities apply to all threats.

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By applying this organizing foundation, PNM positions itself to protect its networks and assets based upon the risk to the business and customers. PNM has defined and implemented the CSF using industry standards and best practices. These objectives support PNM's goal to provide reliable electric service to customers. Computer security will remain a major concern for PNM for both the short and long term, as malicious software and intrusions continue to become more sophisticated. The actors are changing and increasingly have the skills to employ stealth techniques over time that attempt to evade and disable current detection mechanisms. As such, PNM continuously assesses its cybersecurity program to help evaluate, prioritize, and improve security capabilities to protect against cybersecurity threats.

PNM has comprehensive policies and processes that will be followed during procurement, design, and operation of any cyber asset associated with grid modernization. Applicable processes include the following:

- Identifying, prioritizing, and assessing supplier's and other third-party providers' systems, components, and services using a supply chain security risk assessment process; Other third parties include the parties that work with PNM's existing suppliers.
- Protecting network integrity (e.g., network segregation, network segmentation);
- Authenticating users, devices, and other assets commensurate with the risk of the transaction (e.g., individuals' security and privacy risks and other organizational risks) or applying mitigating controls;
- Protecting data-at-rest commensurate with its classification;
- Protecting data-in-transit commensurate with its classification;
- Verifying software, drivers, firmware, and information integrity with integrity checking mechanisms;
- Implementing configuration change control processes;
- Protecting, monitoring, and restricting access to communications and control networks;
- Ensuring no device will be connected to the network without authority to operate and an appropriate set of protective software;
- Establishing and monitoring a baseline of network and system operations and configuration
- Assessing suppliers and third-party partners to evaluate the security of their programs prior to contractual obligation. A baseline of normal user activity is established and monitored. Personnel and account activity are monitored to detect potential security of their programs prior to contractual obligation.

These processes will help PNM implement a risk-based approach to protecting its grid modernization-related cyber assets.

To protect customer confidentiality, PNM is adopting the U.S. Department of Energy's DataGuard Energy Data Privacy Program ("DataGuard") code of conduct to implement customer-facing technologies. The key tenets of the DataGuard code include:

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- Consumer Notice and Awareness: Customers should be given prior notice about privacy-related policies and practices.
- Customer Choice and Consent: Customers should have a degree of control over access to their own customer data.
- Customer Data Access and Participation: Customers should have access to their own customer data and should have the ability to participate in its maintenance.
- Integrity and Security: Customer data should be as accurate as reasonably possible and secured against unauthorized access.
- Self-Enforcement Management and Redress: Enforcement mechanisms should be in place to ensure compliance with the foregoing principles.

Since its launch in 2012, DataGuard has become an established industry best practice. PNM will use the DataGuard voluntary code of conduct within the policies, processes, and procedures that will need to be developed to govern and operate the new data systems associated with the AMI system. In addition, PNM's customer-facing systems will conform to the U.S. National Institute of Standards and Technology's "Guide to Protecting the Confidentiality of Personally Identifiable Information" (Publication NIST SP 800-122).)

Q: Explain expected benefits to PNM from the GMP and AMI, e.g., cost savings via electronic meter reading, Demand Response impact on short and long term system management, etc.

A: A cost/benefit analysis was performed when PNM filed the application for Grid Modernization in 2022. Please see the testimony of James Shields, Exhibit JWS-2 (CBA) for additional information. The information studied for AMI begins on page A-11.

<https://www.txnenergy.com/~media/Files/P/PNM-Resources/rates-and-filings/PNM%20Grid%20Mod/CBA/James%20W%20Shields.pdf>

Q: Explain expected benefits to customers from GMP and AMI. E.g., Would rates be lowered a) to reflect the savings from electronic meter reading, or b) lower fuel costs as solar/wind replace fossil fuels? How might power be made more affordable through these two programs?

A: A cost/benefit analysis was performed when PNM filed the application for Grid Modernization in 2022. Please see the testimony of James Shields, Exhibit JWS-2 (CBA) for additional information. Savings from electronic meter reading were included in the analysis as were costs associated with capacity and carbon offset estimated benefits but not directly fuel cost savings.

<https://www.txnenergy.com/~media/Files/P/PNM-Resources/rates-and-filings/PNM%20Grid%20Mod/CBA/James%20W%20Shields.pdf>

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Q: Reconcile the contradicting information between the GMP FAQ sheet that states [p7] in answer to the Top Question: “No. PNM will not control your daily energy use in your home or business,” with the 2026 IRP draft, e.g., Section 8.1 Demand Response [p171 ff] and similar, that clearly describe circumstances that the two-way AMI meters could connect to Direct Load Control [DCL] devices engaged with Peak Saver and Power Saver program extensions, as well as on customer-owned battery storage, hot water heaters, thermostats, EV charging times, etc.

A: The GMP FAQ sheet is incorrect for possible future capabilities for customer programs and is being corrected. PNM could have some capability for customer device control facilitated by the AMI system provided a customer opts into a program that allowed that control and customer devices are technically enabled to receive those commands. PNM’s existing Peak Shaver or Power Saver programs are programs that may be good candidates to utilizing the AMI system as opposed to the direct communication technology being utilized today, as an example. While the AMI platform supports such capabilities, PNM still has both technology and customer program components to develop to enable such programs.

Q: Provide citations or links to studies that show how AMI adoption has changed customer usage behavior related to TOD and TOU. What metrics were used? Were changes achieved that sufficiently lowered demand on the generating system?

A: PNM included the annual TOD reports in Docket 26-0000069 Second Annual Grid Modernization filing. The 2025 Impact Analysis report is included as Exhibit HMP-4 to the Direct Testimony of Heidi M. Pitts. The 2025 TOD Pilot Program Evaluation report is included as Exhibit HMP-1 (Supplemental) to the Supplemental Testimony of Heidi M. Pitts. Finally, PNM's presentation on the results from its baseline survey on customer awareness of energy usage reports is provided as Exhibit HMP-2 for the Direct Testimony of Heidi M. Pitts. The TOD pilot is still in the pilot stage with approximately 2,200 residential customers. The 2025 Impact Analysis report showed a statistically significant reduction in summer on-peak period energy usage. PNM will continue to evaluate the pilot and propose modifications in the next general rate case as progress is made towards default TOD rates for residential customers.

Q: Explain the replacement schedules and timelines PNM uses to replace and upgrade older equipment?

A: These projects don’t go unresolved usually. The outages in La Cienaga started with a snow storm and tree issues that were mitigated. The recent outages were do to cable faults which are being mitigated now. PNM evaluates outages consistently and tracks repeat outages and makes sure we can come up with projects to increase either reliability or resilience in these areas to make sure they don't become a continuous problem.

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Q: Does PNM have TOD rates in effect that apply to all customers? If yes, how much savings do customers receive when using power in lower cost TOD rate periods.

A: All customer classes except the lighting (Rate 6 Private Lighting and Rate 20 Streetlighting) and Rate 36B Special Services Contract have a TOD pilot rate option on their rate schedules. The ability to save money on energy bills depends on customers' energy usage and the ability to shift or reduce usage during on-peak hours. For instance, in the summer, the on-peak to off-peak energy ratio is 4:1 and in the non-summer the on-peak to off-peak energy rate is 2.5:1 for the residential TOD pilot. For the commercial classes, summer energy rate ratios-- on-peak to super off-peak is 4:1 and off-peak to super off-peak is 2.5:1. Non-summer energy rate ratios-- on-peak to super off-peak is 2.5:1 and off-peak to super off-peak is 1.5:1.

Q: What metrics are used to track TOU?

A: PNM assumes that this question is about Time-of-Day (TOD) rates not the Time-of-Use (TOU) rates. PNM has two annual analysis reports that measure customer satisfaction and load impact for the residential TOD pilot. PNM has also developed a survey to track how customers are using the TOD emails and energy insights dashboard.

Q: What incentives are offered to encourage customers to change their TOU behavior?

A: PNM assumes that this question is about Time-of-Day (TOD) rates not the Time-of-Use (TOU) rates. Higher energy rates during on-peak periods provide a pricing incentive to shift usage to lower cost off-peak or super off-peak periods.

Q: What other accommodations might be built into the PNM system for customers who cannot take advantage of TOD rates?

A: PNM plans to propose modifying the residential TOD pilot to include the super-off-peak period (8:00am to 5:00pm Monday-Friday year round) in its next rate case. This will provide more opportunities for customers to save on their energy bills. However, as stated in PNM's original Grid Modernization application, the intent of the TOD rate structure is to lower the costs that the utility must incur to serve customers.

Q: Must customers be enrolled in special programs to benefit when they use power during lower TOD rate periods?

A: Customers can take service on the TOD pilot without needing to be enrolled in any program. A customer with an electric vehicle can take service on the residential TOD pilot or the residential

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Whole House Electric Vehicle (WHEV) pilot rate but cannot participate in both pilots because they are on separate rate schedules.

Q: What is the average age of the PNM transformers and other distribution grid infrastructure?

A: The average age of Distribution Substation Transformers is about 39 years with an expected service life of about 50 years. About 35% of Distribution Substation assets are past their expected service life. Distribution infrastructure assets have a service life of about 40-75 years depending on the asset. About 15% of Distribution infrastructure assets are past their expected service life.

Q: Key aspects of the plan's forward-looking sections were not made available to stakeholders prior to or during the defined comment period. Specifically:

- **Projected capital and operating costs.** Section 6.2 states in its entirety that PNM will update the section prior to the September 21, 2026, meeting. Exhibit A 3(f)(ii) requires projected costs for at least five years.

A: This will be provided in the final report.

- **Five-year load forecast.** Section 5.2 describes what a load forecast should aspire to be. It does not include forecast. Exhibit A 4(f)(ii) requires a forecast.

A: PNM's five-year system load forecast has been added to the report.

- **Scenarios and sensitivities.** Sections 5.3 through 5.6 are written prospectively throughout. No scenario or sensitivity has been run for stakeholders to respond to. Exhibit A 4(f)(iii)–(v) requires scenario with defined peak impact analyses and other attributes.

A: Presently, PNM does not do multiple forecast scenarios or specific sensitivities in the Distribution Planning Process. As described in Sections 5.3 and 5.4, this is what PNM is potentially evaluating for the future.

- **Prioritized list of investments.** Section 8.1 consists of the placeholder text “**Future**.” Exhibit A 7(a) requires this list.

A: This will be provided in the final report.

- **DER, battery storage, and microgrid appendices.** Appendices 10.1 through 10.3 reproduce the Exhibit A requirement text and state “To be added prior to final report.” These items are required in Exhibit A 3(b), 3(g)(i), 3(g)(ii), 3(g)(v), 3(g)(vi).

A: This will be provided in the final report.

Q: In addition to the missing items above, ECAM requests feeder-level analysis of low-income customers, underserved communities, and service quality (Exhibit A 2(g)(i)–(ii)).

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Exhibit A 2(g) requires, on a feeder-by-feeder basis, discussion of low-income customers and underserved communities and evaluation of differences in service quality. The draft responds by stating that PNM applies uniform planning criteria regardless of income, community status, or geography, and that there are accordingly no service differences in any community. This does not answer the Order's requirement. Uniform planning criteria are an input to the planning process. Differences in service quality are an output of the system as built and operated.

ECAM notes that it would be useful for the filed DSP to include:

- Feeder-level reliability performance, including SAIDI, SAIFI, and predominant outage cause, with identification of feeders meeting PNM's worst-performing screen and those meeting it in consecutive years.
- An overlay of low-income and energy-burdened customer concentration against that feeder-level reliability performance and against available hosting capacity headroom.
- Where localized service quality deficiencies are identified, the measures PNM proposes to correct them and the schedule for doing so.

ECAM notes that this overlay is useful to the State's program offerings and offers to work with PNM on the data conventions used to define energy burden. This data is important as low-income communities are less able to respond and recover from outage events. These communities also face disproportionate exposure to service outages.

A: Feeder-level reliability performance for feeders that exceed the threshold will be added to the final report.

PNM's income-qualified energy efficiency efforts include income-qualified specific programs – the Income-Qualified Easy Savings Kit, Income-Qualified Home Energy Checkup, and Energy Smart programs. They also includes largely market rate programs that also serve a portion of the income qualified market segment such as the Home Works, Residential Products, New Home Construction, and Multifamily programs. While PNM has these types of programs, the distribution planning processes focuses on technical aspects and not socioeconomic status. The planning process equally applies the same capacity and reliability criteria to all customers across divisions and clusters. PNM consistently applies its planning standards across its system, regardless of income ensuring no service differences in any community including underserved communities. The process does not lower service-quality expectations for low-income customers or underserved communities, and it does not use customer demographics as a basis to delay or avoid a capacity review. PNM has no evidence that low-income communities in our service territory face disproportionate exposure to service outages.

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Q: Data and plan to access TOU rate benefits of AMI (Exhibit A 3(g)(vii), 4(e)).

Exhibit A 4(e) requires a description of how the utility will maximize the customer benefits of previous grid modernizing investments, including automated metering technology. Exhibit A 3(g)(vii) requires a status update for existing grid-mod related rate design pilots. PNM's direct testimony in Docket No. 22-00058-UT identified time-of-use rate implementation as one of the main AMI benefits.

ECAM believes the filed DSP would benefit from including a dated roadmap from meter deployment to TOU rate availability, identifying when time-varying rates would be proposed, the design under consideration including whether it would be opt-in or opt-out, the treatment of low-income customers, and any shadow-billing or transition period. ECAM further requests that the plan discuss on-going grid-modernization-leveraged rate design pilots (with program data collected so far) or state that none exist and explain why.

A: PNM provides annual updates to the TOD pilot in the annual Grid Modernization filings. In the Second Annual Grid Mod filing (Docket 26-0000069), PNM provided a Roadmap to Default TOD rates in the Direct Testimony of Heidi M. Pitts and the residential TOD pilot load impact analysis report as PNM Exhibit HMP-4 to the same testimony. PNM also provided the second annual evaluation report, the TOD Pilot Program Evaluation Year 2 in her Supplemental Testimony. The Roadmap to Default TOD provides the steps over two general rate cases to arrive at the point where PNM proposes default TOD for all residential customers. Rate Schedule 1A Residential will be the opt-out rate schedule for residential customers. PNM witness Pitts's testimony also discusses the logical next steps after TOD rates and provides a table comparing PNM's peer utilities residential rate options (PNM Exhibit HMP-5). With regards to low-income customers, in the next general rate case PNM plans to file a low-income discounted customer charge proposal that will be available to low-income customers regardless of which residential rate schedule they take service on.

Q: Better visibility into the 10-year load forecasting methodology

ECAM believes the plan would benefit from better visibility into the 10-year forecasting methodology explained in section 4.3.4.1. Specifically, we'd like to know how many transformer loading forecasts are manually adjusted each year during the engineering screen and what percent of total transformer loading forecasts each year are manually adjusted.

ECAM is also curious how PNM accounts for data quirks that may skew load growth rates. For instance, section 4.3.4.1 describes the peak loading forecast as essentially using a 5-year moving average to forecast the next year's peak loading before engineering adjustments. If, for the sake of argument, every house connected to a specific transformer purchased an EV during the prior year, this would skew the annual year-over-year demand growth rate applied by the forecast. Yet, this year would clearly be an outlier. How does PNM account for skewed growth rates in the manual

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adjustment process? Are there quantitative examples illustrating how engineers calculate the adjustments used to modify forecasts?

A: PNM reviews the SCADA data for each substation annually. PNM eliminates false peaks due to load transfers and bad data by eliminating the bad data from the load transfer timeframe, choosing the next available peak. Where loads have increased or decreased more than 10% from the prior year, PNM reviews to see if the cause can be identified. Then for growth projections, the five-year historical peaks are used to calculate an annualized average growth rate. This should minimize any single year spike or decrease. Regarding the EV charging example given; EV charging typically occurs off peak. It should not affect the peak load forecast since PNM's system typically peaks during the late afternoon. However, peaks are reviewed annually so should the EV load cause a consistent change to the transformer peak, it would be seen in the following year review. If it was an outlier peak reading, the following year peak would decrease. Since the 10-year forecast is a long-term planning tool, a one-year outlier in data will not greatly affect the outcome of a single annual 10-year review.

Q: Contingency for virtual power plant project (Exhibit A 2(g)(iii)).

Section 6.6 states that PNM has applied for approximately \$35.6 million under the DOE GRIP program for a virtual power plant project. It also states that PNM cannot represent the project's final funding level, scope, or schedule.

Within the plan's five-year window, it appears VPP deployment at PNM depends on a grant that may not close and on the DERMs release scheduled for 2028. Yet close to 692.6 megawatts of DER are interconnected to PNM's system today, including roughly 38.7 megawatts of customer battery storage across 1,041 installations, none of which is currently available to the system as a dispatchable resource.

ECAM requests that the filed DSP state what PNM will do to advance DER utilization if the award is not executed or is executed at materially reduced scope.

A: PNM's plan to advance DER utilization does not solely depend on the DOE GRIP award closing. As described in Section 5.7.1.6, ADMS Release 2 (DERMS), targeted for go-live in 2028, will be deployed under PNM's contract with Schneider Electric and will proceed on this schedule regardless of the outcome of the VPP grant. At DERMS go-live, PNM intends to have integrated a number of the larger DER assets that already have SCADA hardware in place, with a proven path forward to continue integrating the remaining assets in this category over time.

The VPP grant project is intended to address residential and commercial DER that currently lack the on-site communications hardware needed to integrate with DERMS. If the DOE award is not executed, or is executed at materially reduced scope, PNM will continue to assess its ability to develop cost-effective VPP projects that can benefit customers, subject to any necessary

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Commission approvals and cost recovery.

In addition, there is a possibility that up to \$25 million will be made available for utility infrastructure targeting a pilot project for virtual power plant ("VPP") and utility-controlled demand management, subject to Commission approval of the program and of the proposed indirect acquisition of PNM by Blackstone Infrastructure. These funds are separate from the DOE award and could be used to either supplement DER aggregation efforts if the DOE grant is executed, or to help support a similar effort if the DOE grant is not executed or is materially reduced in scope.

Q: Integrated System Planning Exhibit A8(a) encourages utilities to strengthen integration between distribution system planning and integrated resource planning by aligning data, assumptions, and forecasts across both processes. Sections 1.11 and 5.3 of the Draft Plan describe movement toward a common corporate bottom-up forecast and reference the methodology used in the Avoided Cost Study in Docket No. UT 26-0000072.

ECAM supports this direction and requests a crosswalk identifying which specific assumptions (load growth, DER adoption, electric vehicle penetration, electrification, and economic development) are shared with the 2026 Integrated Resource Plan and the Avoided Cost Study, and where and why they diverge.

A: While certain assumptions in the Avoided Cost Study and the 2026 Integrated Resource Plan are currently based on different planning perspectives and timelines, PNM is advancing efforts to align these analyses through an integrated system planning approach, as discussed in Section 5.3.

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DER in the PNM Distribution System

1 Interconnection Queue Data

Below is the Interconnection Application Queue Status for 2025. PNM does not have the interconnection cost on a feeder-by-feeder basis.

Interconnection Application Status of Queues

1st Half

January 1, 2025 – June 30, 2025

Queue Name	Number in Queue
Completeness Review	2,905
Simplified Review	1,706
FastTrack Review	26
Supplemental Review	139
Feasibility Study	0
System Impact Study	2
Facilities Study	3
Inspections/Meter Set	1,473

2nd Half

July 1, 2025 – December 31, 2025

Queue Name	Number in Queue
Completeness Review	2,560
Simplified Review	2,043
FastTrack Review	37
Supplemental Review	524
Feasibility Study	0
System Impact Study	0
Facilities Study	2
Inspections/Meter Set	1,736

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2 Current DER and Battery Storage

SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
ALAMOGORDO 1	A10001	1789.56	35.72
	A10002	1240.79	11.04
	A10003	2034.76	5
	A10011	1636.67	5
	A10012	10395.51	7.68
	A10083	8136.09	15.36
	A10089	2992.45	35.72
ALAMOGORDO 1 Total		28225.84	115.52
ALCAZAR	ALCA11	475.51	
	ALCA12	668.25	
	ALCA13	422.22	15
	ALCA14	209.21	
ALCAZAR Total		1775.19	15
ALGODONES	ALGO11	10.00	
	ALGO21	191.29	
ALGODONES Total		201.29	
ALIRE	ALIR11	536.80	15.34
	ALIR12	1024.70	
ALIRE Total		1561.50	15.34
ANDERSON	ANDE11	816.61	
	ANDE12	295.65	
	ANDE13	324.70	15
ANDERSON Total		1436.96	15
ARNO	ARNO11	79.66	
	ARNO13	83.30	
	ARNO24	223.31	
	ARNO26	170.81	
ARNO Total		557.08	
ARRIBA	ARIB11	10359.54	
ARRIBA Total		10359.54	
ASPEN	ASPE11	733.53	5
	ASPE12	928.19	288.84
	ASPE13	848.96	3.84
	ASPE14	1642.30	
ASPEN Total		4152.98	297.68
AVILA	AVIL11	828.50	10
	AVIL12	641.06	

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SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
AVILA Total		1469.56	10
BACA	BACA12	203.01	
BACA Total		203.01	
BALL PARK	BLPA11	160.85	
	BLPA14	54.41	
BALL PARK Total		215.26	
BECKNER	BECK11	424.26	7.08
	BECK12	865.60	
	BECK13	2253.29	10
	BECK14	287.04	25
BECKNER Total		3830.19	42.08
BEL AIR	BLAR11	87.30	
	BLAR12	490.89	
	BLAR13	102.30	
	BLAR14	573.04	
BEL AIR Total		1253.54	
BEVERLY WOOD	BVWO11	584.23	
	BVWO13	539.56	5.12
BEVERLY WOOD Total		1123.79	5.12
BLACK RANCH	BLRA11	2627.48	22.08
	BLRA12	690.93	
	BLRA13	1758.01	7.08
	BLRA14	2844.19	567.5
BLACK RANCH Total		7920.61	596.66
BOSQUE FARMS	BOSQ11	435.66	16.5
	BOSQ12	534.47	3.84
BOSQUE FARMS Total		970.14	20.34
BUCKMAN	BUCK21	1937.50	
	BUCK22	1129.10	
	BUCK23	620.37	23.04
BUCKMAN Total		3686.97	23.04
BURRO MOUNTAIN	BM0160	94.54	14.68
BURRO MOUNTAIN Total		94.54	14.68
CAJA DEL RIO	CDRI11	1038.00	
	CDRI13	1076.97	122.68
CAJA DEL RIO Total		2114.97	122.68
CAMEL TRACKS	CATR11	1170.00	
	CATR13	38.27	
CAMEL TRACKS Total		1208.27	
CENTRAL	CENT11	933.06	

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SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
	CENT12	1024.65	
	CENT13	914.90	233
	CENT14	649.81	
CENTRAL Total		3522.41	233
CLAREMONT	CLAR11	18.20	
	CLAR12	182.24	
	CLAR13	429.99	
	CLAR14	1159.63	21.5
CLAREMONT Total		1790.06	21.5
CLIFF	CLIF11	11.16	
	CLIF12	95.50	5
CLIFF Total		106.66	5
COAL	COAL11	584.28	
	COAL12	918.65	
	COAL13	4.00	
	COAL14	70.77	
COAL Total		1577.71	
COCHITI	COCH11	167.13	
	COCH12	65.40	
COCHITI Total		232.53	
COLINAS	COLI11	1126.42	41.52
	COLI13	3006.60	86.5
COLINAS Total		4133.02	128.02
COLLEGE	COLL11	1432.82	10
	COLL12	9319.51	
	COLL13	427.22	
	COLL14	9999.00	
COLLEGE Total		21178.55	10
CORNELL	CORN11	617.81	14.16
	CORN12	12.24	
	CORN13	248.28	11.52
	CORN14	1045.42	20.36
CORNELL Total		1923.73	46.04
CORRALES BLUFF	COBL11	342.32	
	COBL12	1801.65	49.9
CORRALES BLUFF Total		2143.97	49.9
COTTONWOOD	COTT11	1209.86	30
	COTT14	55.50	
	COTT22	2058.18	4
	COTT23	941.34	15.36

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SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
	COTT24	729.35	15
COTTONWOOD Total		4994.24	64.36
DEMING EAST	DEME12	695.28	10
DEMING EAST Total		695.28	10
DEMING WEST	DEMW11	45.48	
	DEMW13	274.62	
DEMING WEST Total		320.10	
EASTRIDGE	EAST11	1274.11	12.68
	EAST12	1542.12	5.12
	EAST13	939.69	
	EAST14	600.66	7.68
EASTRIDGE Total		4356.59	25.48
EL CERRO	ELCE11	9289.05	
	ELCE12	1008.51	20.84
	ELCE13	403.48	
EL CERRO Total		10701.04	20.84
ELDORADO	ELDO11	1255.00	25.36
	ELDO12	604.36	15
ELDORADO Total		1859.36	40.36
EMBUDO	EMBU11	1182.81	29.58
	EMBU12	919.74	5
	EMBU13	756.80	21.5
	EMBU14	537.76	5
EMBUDO Total		3397.11	61.08
ENCHANTED HILLS	ENHI11	624.62	5
	ENHI12	316.81	
	ENHI13	739.30	3.84
	ENHI14	1927.04	15
ENCHANTED HILLS Total		3607.77	23.84
FIRST STREET	FIST11	800.87	
	FIST12	524.60	5
	FIST13	879.94	
	FIST14	152.33	
FIRST STREET Total		2357.74	5
FORT MARCY	FOMA11	96.54	
	FOMA12	200.00	
	FOMA13	2382.61	188.64
	FOMA14	2261.24	155.72
FORT MARCY Total		4940.39	344.36
FOUR HILLS	FOHI11	543.37	

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SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
	FOHI12	946.64	25.24
	FOHI13	928.69	23
	FOHI14	631.12	25
FOUR HILLS Total		3049.82	73.24
GALLINAS	GALL11	422.77	4.8
	GALL12	190.68	
GALLINAS Total		613.44	4.8
GAVILAN	GA0000	142.30	
	GA0010	49.80	
	GA0030	197.70	35.72
GAVILAN Total		389.80	35.72
GIRARD	GIRA11	221.70	
	GIRA12	189.48	
	GIRA13	39.38	
	GIRA14	9.00	
GIRARD Total		459.56	
GOLD	GOLD11	1468.94	12.68
	GOLD12	305.77	
	GOLD13	302.59	
GOLD Total		2077.30	12.68
HALONA	HALO11	242.89	38.84
	HALO14	372.58	
HALONA Total		615.47	38.84
HAMILTON	HAMI11	1058.68	
	HAMI12	251.32	
	HAMI13	1985.30	10
	HAMI14	771.91	21
	HAMI21	427.08	
	HAMI22	2848.65	123.98
	HAMI23	911.48	31.52
	HAMI24	188.00	
HAMILTON Total		8442.42	186.5
HAWKINS	HAWK11	100.00	
	HAWK12	33.14	
	HAWK13	42.08	
	HAWK14	100.00	
	HAWK21	3468.44	
	HAWK22	323.97	
	HAWK23	65.38	
	HAWK24	523.23	

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SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
HAWKINS Total		4656.23	
HAZELDINE	HAZE11	28.10	
	HAZE12	161.50	
HAZELDINE Total		189.60	
HERMANAS	HERM11	460.74	
	HERM12	712.92	5
	HERM13	1577.76	
	HERM14	39.20	
HERMANAS Total		2790.63	5
HICKOX	HICK11	85.67	
	HICK12	44.38	
HICKOX Total		130.05	
HOLLYWOOD	HO0123	92.89	
	HO0126	190.24	8.84
HOLLYWOOD Total		283.13	8.84
HONDALE	HOND11	222.43	3.84
	HOND12	9145.13	
HONDALE Total		9367.56	3.84
INDIAN HOSPITAL	INHO12	561.34	28.12
	INHO13	342.33	
	INHO14	1336.12	5
INDIAN HOSPITAL Total		2239.79	33.12
INEZ	INEZ12	221.81	10
	INEZ13	977.26	
INEZ Total		1199.07	10
INNOVATION	INNO11	698.54	
	INNO12	2898.71	16.5
	INNO13	577.87	
INNOVATION Total		4175.12	16.5
IRIS	IRIS11	2850.84	15
	IRIS12	372.57	
	IRIS13	2089.86	25
	IRIS14	1447.24	
IRIS Total		6760.51	40
ISLETA	ISLE11	11.93	
	ISLE12	271.63	3.6
ISLETA Total		283.56	3.6
JARALES	JARA11	445.66	
	JARA12	10064.30	
	JARA13	41.10	

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SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
JARALES Total		10551.06	
JUAN TABO	JUTA11	579.30	13.84
	JUTA12	879.92	
	JUTA13	223.38	
	JUTA14	421.08	
JUAN TABO Total		2103.68	13.84
KELEHER	KELE11	160.71	
	KELE12	45.88	10
KELEHER Total		206.59	10
KEWA	KEWA11	146.52	
KEWA Total		146.52	
LA MORADA	LAMO11	3661.88	28.02
	LAMO12	1450.71	5
	LAMO13	813.83	11.28
	LAMO14	778.93	5
LA MORADA Total		6705.35	49.3
LAWRENCE	LAWR11	648.85	16.51
	LAWR12	282.60	3.6
	LAWR13	982.72	40.36
	LAWR14	210.80	26.5
LAWRENCE Total		2124.98	86.97
LENKURT	LENK11	762.96	
	LENK12	229.50	
	LENK13	369.01	5
	LENK14	266.95	
LENKURT Total		1628.42	5
LEYENDECKER	LEYE11	304.43	
	LEYE12	461.16	
	LEYE13	646.01	
	LEYE14	490.14	
LEYENDECKER Total		1901.74	
LOMAS	LOMA12	166.50	125
	LOMA15	413.46	
	LOMA16	325.34	
LOMAS Total		905.31	125
LORDSBURG	LD0318	319.10	
	LD1000	786.40	
LORDSBURG Total		1105.50	
LOS ANGELES	LSAN12	129.36	
LOS ANGELES Total		129.36	

APPENDIX C

SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
LOS CHAVEZ	LSCH11	124.37	
	LSCH12	1119.82	54.56
LOS CHAVEZ Total		1244.19	54.56
LOS LUNAS	LSLU11	538.03	7.08
LOS LUNAS Total		538.03	7.08
LOS MORROS	LSMO12	10234.94	
	LSMO13	225.20	
	LSMO21	9032.83	
	LSMO22	723.18	17
	LSMO23	1131.81	21.5
	LSMO24	1687.19	7.68
LOS MORROS Total		23035.14	46.18
LOST HORIZON	LOHO11	6.40	
	LOHO12	10027.10	
	LOHO13	11368.80	
	LOHO14	9999.00	
LOST HORIZON Total		31401.30	
LOUDEN HILLS	LOHI11	145.39	3.84
	LOHI12	474.43	
LOUDEN HILLS Total		619.82	3.84
MANHATTEN	MANH12	126.80	
MANHATTEN Total		126.80	
MANZANO	MANZ11	759.69	20
	MANZ12	543.88	
	MANZ13	1152.36	
MANZANO Total		2455.93	20
MARIPOSA	MARI11	570.31	32.68
	MARI12	594.40	
	MARI13	500.64	
	MARI14	1383.84	17.68
MARIPOSA Total		3049.19	50.36
MARQUEZ	MARQ11	8000.00	
MARQUEZ Total		8000.00	
MD #1	MD0011	616.56	3.84
	MD0012	538.98	42.24
	MD0013	36.47	
	MD0014	105.90	
MD #1 Total		1297.91	46.08
MEJIA	MEJI11	1698.66	169.68
	MEJI12	889.29	22.44

APPENDIX C

SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
	MEJI13	143.49	3.84
	MEJI14	1346.44	30
MEJIA Total		4077.87	225.96
MENAU	MENA11	573.79	
	MENA12	499.84	5
	MENA13	909.35	3.84
	MENA15	55.32	6.4
MENAU Total		2038.30	15.24
MIGUEL LUJAN	MILU11	418.68	
	MILU12	723.80	36.52
	MILU13	1125.74	5.12
	MILU14	1099.05	16.52
MIGUEL LUJAN Total		3367.27	58.16
MISSION	MISS11	1000.00	
	MISS12	610.00	
	MISS13	271.76	
	MISS21	2054.30	
	MISS22	2950.40	
	MISS23	439.43	
	MISS24	1107.65	
MISSION Total		8433.53	
MONTANO	MONT11	1043.89	
	MONT12	695.94	11.5
	MONT13	558.01	
	MONT14	871.17	
MONTANO Total		3169.02	11.5
MONTGOMERY PLAZA	MOPL11	7.60	
	MOPL12	1361.59	15
	MOPL13	98.11	
	MOPL14	280.57	
MONTGOMERY PLAZA Total		1747.88	15
MORRIS	MORR11	809.74	
	MORR12	1109.25	
	MORR13	711.35	
	MORR14	91.05	
	MORR15	221.00	
	MORR16	486.63	10
MORRIS Total		3429.02	10
NORTH	NORT11	216.20	

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SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
	NORT12	59.70	
	NORT13	18.00	
	NORT14	445.00	
	NORT24	57.90	
NORTH Total		796.80	
NORTH BERNALILLO	NOBE11	589.49	10
	NOBE13	3079.34	187.9
NORTH BERNALILLO Total		3668.82	197.9
NORTH SILVER CITY	NS1061	1203.43	31.52
	NS1065	645.45	16.52
NORTH SILVER CITY Total		1848.88	48.04
ORTIZ	ORTI11	348.80	
	ORTI12	262.91	5
	ORTI13	474.79	
	ORTI14	121.82	5
ORTIZ Total		1208.32	10
PACHMANN	PCMN11	1060.23	5
	PCMN12	1500.51	11.5
	PCMN13	1082.91	10
	PCMN14	1515.12	18.84
PACHMANN Total		5158.76	45.34
PALACE	PALA13	570.00	
PALACE Total		570.00	
PALM	PALM11	2235.22	25
	PALM12	1493.14	
	PALM14	2423.87	22.68
PALM Total		6152.23	47.68
PANORAMA	PANO11	933.64	16
	PANO12	694.06	18.84
	PANO13	1093.86	15.01
PANORAMA Total		2721.56	49.85
PARADISE HILLS	PAHI12	761.07	
	PAHI13	1729.00	23.96
	PAHI14	2113.13	24.2
PARADISE HILLS Total		4603.20	48.16
PECOS	PECO11	801.06	10
	PECO12	1174.25	96.52
PECOS Total		1975.30	106.52
PERALTA	PERA11	345.88	
PERALTA Total		345.88	

APPENDIX C

SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
PETROGLYPH	PGYH11	1875.00	1003.5
PETROGLYPH Total		1875.00	1003.5
POWER PLANT	POPL12	138.69	
	POPL13	6.29	
POWER PLANT Total		144.98	
PRAGER	PRAG11	122.10	
	PRAG12	2152.73	50.4
	PRAG13	202.90	
	PRAG14	393.92	
PRAGER Total		2871.65	50.4
PRINCESS JEANNE	PRJE11	1000.18	8.84
	PRJE12	498.94	
	PRJE13	949.20	
	PRJE14	973.62	
PRINCESS JEANNE Total		3421.94	8.84
PROGRESS	PROG11	1639.02	10
	PROG12	2048.74	8.84
	PROG13	10140.08	
	PROG14	158.40	
PROGRESS Total		13986.24	18.84
REEVES	REEV11	363.01	5
	REEV13	568.86	
	REEV14	180.10	
REEVES Total		1111.97	5
RIO HONDO	RIHO12	2612.24	
	RIHO13	3067.05	55.69
	RIHO14	1354.38	12.68
RIO HONDO Total		7033.68	68.37
RITA	RITA12	1396.91	31.52
	RITA13	1416.80	
RITA Total		2813.71	31.52
RODEO	RODE11	924.40	10
	RODE12	1846.60	75.7
	RODE13	2374.69	44.2
	RODE14	46.14	
RODEO Total		5191.85	129.9
ROY	ROYS12	98.07	
	ROYS13	147.16	
ROY Total		245.23	
SAGEBRUSH	SAGE11	149.10	

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SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
	SAGE12	675.00	
	SAGE13	1134.00	
	SAGE14	185.94	
	SAGE21	44.35	
	SAGE22	1150.00	
	SAGE23	226.51	
SAGEBRUSH Total		3564.90	
SAN ANTONITO	SNAN12	256.76	
	SNAN21	714.29	17.68
	SNAN22	1091.10	42.36
SAN ANTONITO Total		2062.15	60.04
SAN PEDRO	SNPE12	751.00	11.5
	SNPE13	48.70	
	SNPE14	440.90	
SAN PEDRO Total		1240.59	11.5
SCENIC	SCEN11	1738.96	3.84
	SCEN12	11136.98	17.68
	SCEN13	911.26	
	SCEN14	2356.83	12.68
SCENIC Total		16144.03	34.2
SEWER PLANT	SEPL11	1234.75	
	SEPL13	999.00	
	SEPL14	214.43	
SEWER PLANT Total		2448.17	
SIGNETICS	SIGN21	69.17	
	SIGN22	681.95	
	SIGN23	881.07	10
	SIGN26	3182.81	63.04
SIGNETICS Total		4815.00	73.04
SILVER CITY	SL0010	1022.69	28.04
	SL0016	189.73	3.84
	SL0017	828.20	34.2
	SL0018	1513.65	25
SILVER CITY Total		3554.27	91.08
SNOW VISTA	SNVI11	1808.98	5
	SNVI12	1371.23	10
	SNVI13	3308.78	1346.4
	SNVI14	960.78	
SNOW VISTA Total		7449.78	1361.4
SOUTH COORS	SOCO11	1467.89	10

APPENDIX C

SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
	SOCO12	16973.98	
	SOCO13	916.04	
	SOCO14	1339.06	13.84
SOUTH COORS Total		20696.97	23.84
SOUTH PACHECO	SOPA11	1666.74	6.4
	SOPA13	953.86	21.44
	SOPA26	2019.29	57.68
	SOPA27	2420.85	250
SOUTH PACHECO Total		7060.73	335.52
ST. CECILIA	STCE11	224.00	
	STCE12	534.13	
	STCE13	959.70	6
ST. CECILIA Total		1717.83	6
ST. JOSEPH	STJO11	1423.47	48
	STJO12	571.74	
	STJO13	202.16	
	STJO14	85.11	
ST. JOSEPH Total		2282.47	48
STATE PEN	STPE11	374.31	
	STPE12	10318.69	
	STPE13	2282.29	62.59
STATE PEN Total		12975.29	62.59
STUDIO	STUD11	2218.60	
	STUD14	4609.92	765
STUDIO Total		6828.52	765
THOMAS	THOM11	870.56	15
	THOM12	366.79	
	THOM13	735.41	5
	THOM14	561.91	
THOMAS Total		2534.67	20
TIJERAS	TIJE11	675.54	7.08
	TIJE12	1003.11	24.08
	TIJE13	336.17	10
TIJERAS Total		2014.82	41.16
TOME	TOME11	36.08	
	TOME12	16732.50	10
	TOME13	260.89	20
TOME Total		17029.47	30
TRAMWAY	TRAM11	2676.46	65.36
	TRAM12	579.96	11.52

APPENDIX C

SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
	TRAM13	447.51	12.78
	TRAM14	1914.21	15
TRAMWAY Total		5618.14	104.66
TRUMAN	TRUM12	166.76	
	TRUM13	3657.84	
	TRUM14	1521.14	15
TRUMAN Total		5345.74	15
TULAROSA	TULA12	519.98	
	TULA13	371.80	
	TULA14	175.87	
TULAROSA Total		1067.65	
TYRONE	TY0395	34.30	
	TY0517	214.84	
TYRONE Total		249.14	
UNSER	UNSE11	1411.25	15
	UNSE12	1937.83	10
	UNSE13	629.61	5
	UNSE14	286.48	
UNSER Total		4265.17	30
VAN BUREN	VNBU12	6.40	
	VNBU41	5.62	
	VNBU42	22.20	
	VNBU43	69.40	
VAN BUREN Total		103.62	
VERANDA	VERA11	3184.22	17.68
	VERA13	1437.34	
	VERA14	384.26	
	VERA21	1308.22	12.68
	VERA22	3357.14	3.84
	VERA23	1281.78	15.34
	VERA24	2452.08	
VERANDA Total		13405.04	49.54
VOLCANO	VOLC11	435.05	
	VOLC12	1038.77	
	VOLC13	242.32	5
	VOLC14	856.69	
	VOLC21	1200.30	120.1
	VOLC22	495.91	
	VOLC23	1927.42	
	VOLC24	1077.18	

APPENDIX C

SUBSTATION	FEEDER	Total Inverter Nameplate AC kW Connected	Total ESS AC kW Connected
VOLCANO Total		7273.63	125.1
WARNER	WARN12	1558.35	12.68
WARNER Total		1558.35	12.68
WAYNE	WAYN12	1184.14	3.84
	WAYN13	697.27	30
	WAYN14	438.47	
	WAYN22	449.21	
	WAYN23	1017.76	34.68
	WAYN24	695.19	
WAYNE Total		4482.04	68.52
WESMECO	WESM11	493.51	
	WESM13	760.90	
	WESM14	613.15	627
WESMECO Total		1867.57	627
WINROCK	WINR11	754.08	7.68
	WINR12	347.89	
	WINR13	1342.40	
	WINR15	243.50	
WINROCK Total		2687.87	7.68
WYOMING	WYOM11	781.99	7.68
	WYOM12	414.02	3.84
	WYOM13	1141.53	
	WYOM14	1241.29	13.84
WYOMING Total		3578.84	25.36
ZAFARANO	ZAFA11	104.79	10
	ZAFA12	367.44	
	ZAFA13	1302.83	
	ZAFA14	246.70	
ZAFARANO Total		2021.76	10
ZAMORA	ZAMO11	349.86	5
	ZAMO12	2053.39	83.7
ZAMORA Total		2403.25	88.7
Grand Total		557555.67	9706.14

3 Microgrids

PNM has one Microgrid Interconnected

Santa Fe Community College 2.38 MW; “One-Off Pilot” in cooperation with the College for teaching curriculum associated with renewable energy, power engineering and experimentation. Commissioned on 12/12/2025.

APPENDIX C

4 Electric Vehicles

4.1 Current Electric Vehicle Market and Electric Vehicle Market Projections

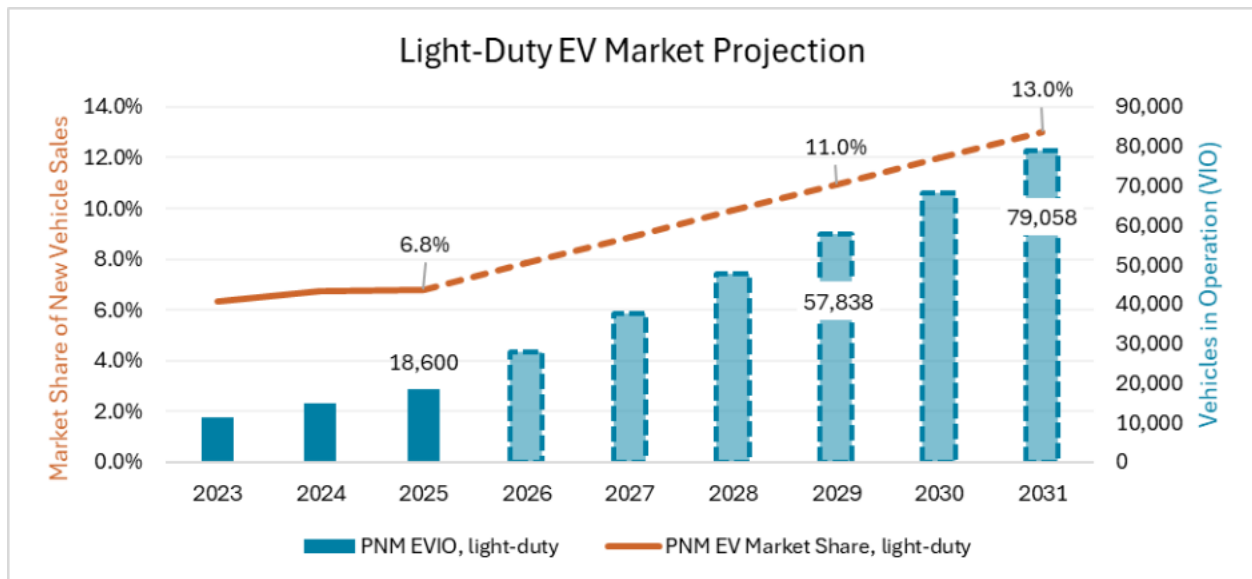
Electric vehicle technologies have progressed significantly since the 2024-2026 TEP was filed in June 2023, but the market for electric transportation is uncertain. On the national level and in PNM's service territory, the rate of growth in EV adoption has fluctuated significantly month-to-month over the past several years due to a variety of factors, including macroeconomic conditions and federal policy decisions such as the rollback of the federal EV purchase tax credit in September 2025.

Two of the most common measures of EV adoption are the market share of new vehicle sales and the number of electric vehicles in operation (EVIO). Market share is a leading indicator that quantifies the popularity of EVs among consumers in the market for a new vehicle, while EVIO is a lagging indicator which provides context for how the total on-road vehicle fleet has changed in composition over time as new vehicles enter the fleet and old vehicles age out. When PNM filed its 2022-2023 TEP in December 2021, the light-duty vehicle (LDV) EV market share in PNM's service territory was less than 3%. In 2025, LDV EV market share averaged 6.8% for the full year, and single-month market share peaked at 9.0% in September 2025 in advance of the expiration of the federal EV purchase tax credit. Based on PNM's analysis of proprietary data from the Electric Power Research Institute (EPRI), month-to-month EV market share in PNM's service territory has averaged about one percentage point higher than the New Mexico statewide EV market share, and about two percentage points lower than the US national EV market share. By the end of 2025, LDV EVIO in PNM's service territory exceeded 18,500 vehicles, a significant increase from fewer than 6,000 vehicles recorded at the end of 2021.

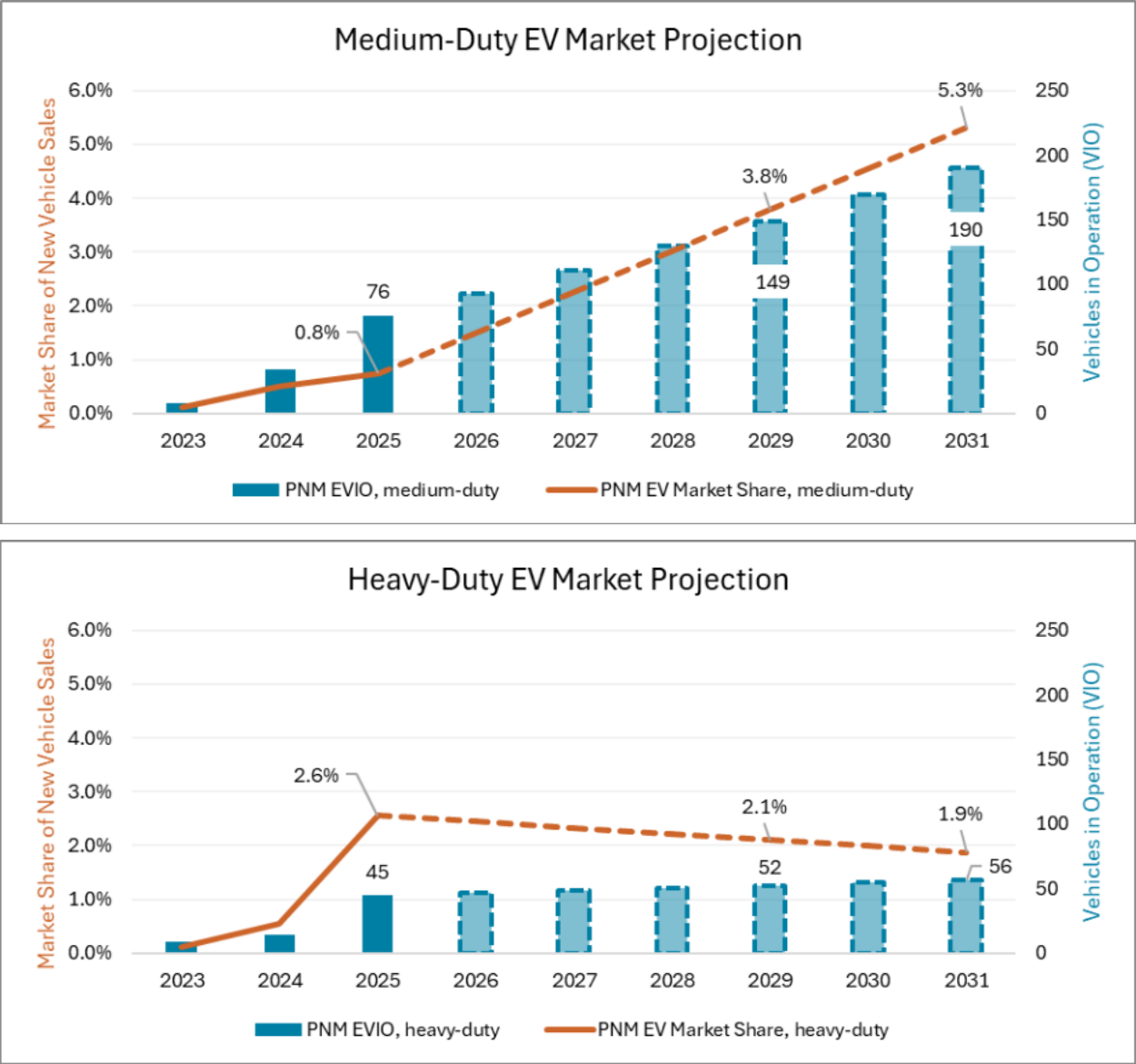
The table and charts below provide additional detail regarding estimated historical EV adoption metrics in PNM's service territory and projected adoption over the three-year plan (2027-2029) and the additional two-year planning outlook (2030-2031), listed by light-duty, medium-duty, and heavy-duty EV classes, pursuant to 17.9.574.11(D)(1) NMAC. Light-duty data for 2023-2025 are sourced from an EPRI analysis of Experian Data, 2026, and are rounded to hundreds. Medium-duty and heavy-duty vehicle data for 2023-2025 are sourced from Atlas Public Policy's [EvaluateNM](#) data portal. Data for 2026 – 2031 are based on PNM's model of EV adoption, informed by projections made by the U.S. Energy Information Administration (EIA) in the 2026 Annual Energy Outlook (AEO2026) Alternative Transportation case. To project EV market conditions in PNM's service territory, we began with PNM's historical metrics and projected that we would match the national EV market share and EV share of VIO by 2045 as projected by EIA.

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	Light-duty EV market share	Light-duty EVIO	Medium-duty EV market share	Medium-duty EVIO	Heavy-duty EV market share	Heavy-duty EVIO
2023	6.3%	11,400	0.1%	8	0.1%	10
2024	6.7%	14,900	0.5%	34	0.6%	15
2025	6.8%	18,600	0.8%	76	2.6%	45
2026	7.8%	28,094	1.5%	93	2.4%	47
2027	8.9%	37,747	2.3%	111	2.3%	48
2028	9.9%	47,664	3.0%	130	2.2%	50
2029	11.0%	57,838	3.8%	149	2.1%	52
2030	12.0%	68,316	4.5%	169	2.0%	54
2031	13.0%	79,058	5.3%	190	1.9%	56



APPENDIX C



4.2 Current and Projected Number and Capacity of Public EV Charging Stations

PNM does not have visibility to the total number and nameplate capacity of public charging stations across its service territory; however, PNM has developed a projection (below) of the number of public charging stations necessary to adequately support the adoption of transportation electrification consistent with EV adoption forecast provided above. The US Department of Energy’s Alternative Fuels Data Center (AFDC) maintains a record of the count of alternative fueling stations by state. This data can be downloaded on demand from the AFDC’s [Data Download tool](#), and PNM has provided an export of this dataset, as of May 26, 2026.

An [analysis](#) performed by the Alliance for Automotive Innovation with data acquired from S&P Global Mobility and the U.S. Department of Energy’s Alternative Fuels Data Center shows that as of December 31, 2025, New Mexico was ranked 18th in the United States (50 states plus the District of Columbia) as measured by the ratio of registered light-duty EVs to non-residential, public EV charging ports (EVs per

APPENDIX C

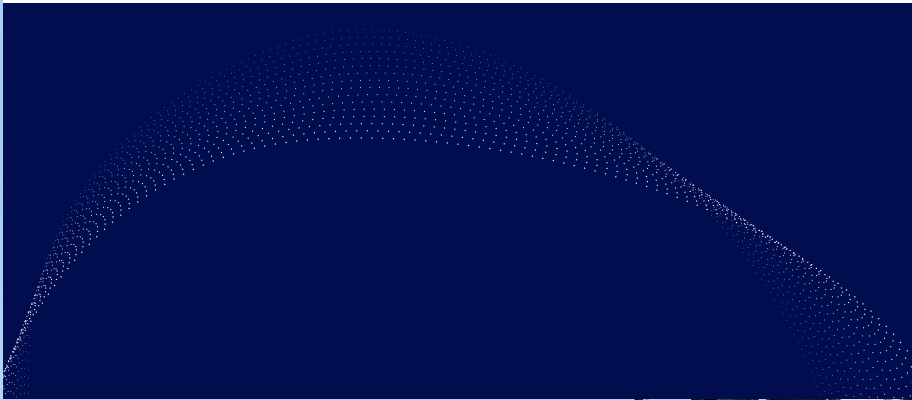
public charging port) with 21 EVs per public charging port. New Mexico needs to attain a ratio of 17 EVs per public charging port to move into the top quartile of states as ranked by this metric. Based on proprietary data from EPRI and public data from Atlas Public Policy's [EvaluateNM](#) data portal, as of December 31, 2025, in PNM's service territory there were 29 EVs per public charging port (18,600 EVs to 645 public charging ports). To meet the goal ratio of 17 EVs per public charging port in our service territory by 2029, when we project that approximately 57,800 light-duty EVs will be in operation, PNM anticipates the need for an additional 2,757 public charging ports to be installed in our service territory. PNM anticipates that the proposed 2027-2029 Transportation Electrification Program, as described in Case No. 26-0000115, may incentivize the installation of an estimated 20% of the market need within PNM's service territory via incentives, which is anticipated to provide enough support to persuade those who might otherwise be disincentivized by the upfront costs to install EVSE and to encourage the deployment of private capital in pursuit of transportation electrification.

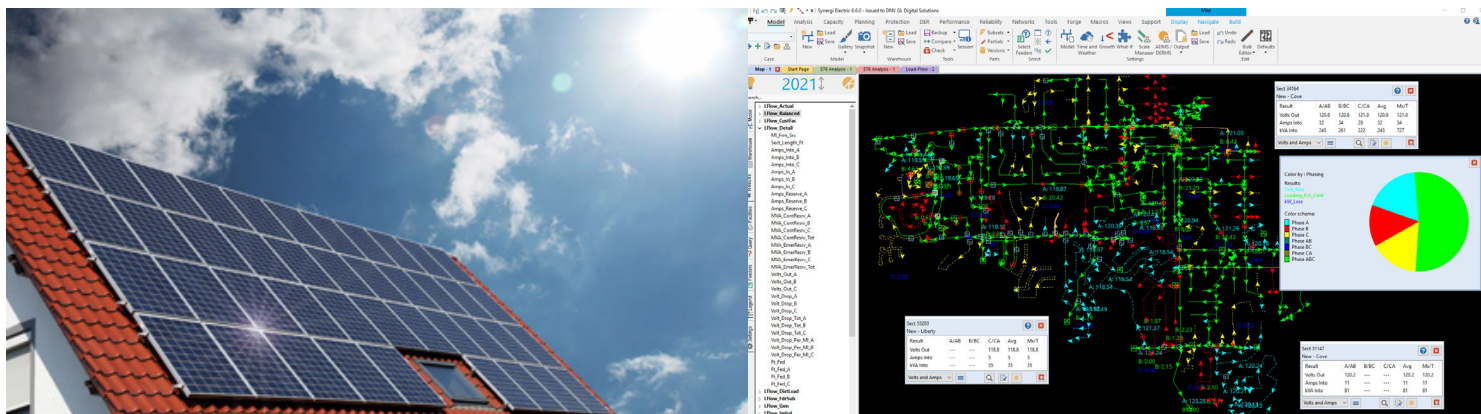


WHEN TRUST MATTERS

SYNERGI ELECTRIC

Distribution planning and circuit analysis for the electric grid





Synergi Electric is a comprehensive circuit analysis and modelling software program for power distribution engineers. Synergi Electric models the power system, including detailed loads and generation, from substation to customer.

Advanced modelling solution

Power distribution companies are facing ever increasing challenges to provide safe, reliable and cost-effective energy solutions. Regulations, distributed generation, new technologies and extreme weather events necessitate advanced modelling solutions such as Synergi Electric. Power engineers require software systems that are flexible, comprehensive and tightly integrated to the corporate asset databases. Synergi Electric provides you with the intelligence you need to make decisions that drive business performance, safety and reliability, while mitigating risk.

Synergi Electric has a wide variety of tools and engineering applications integrated into a single model and database. With Synergi Electric you can better understand the performance of your system through different perspectives and analysis results in various functional areas.

Analysis tools for planning

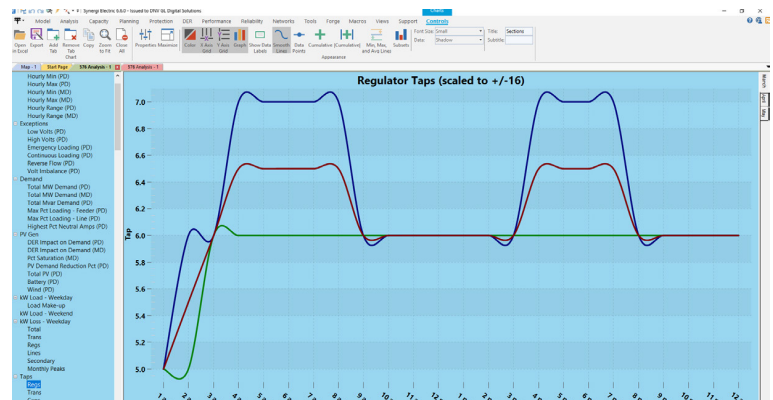
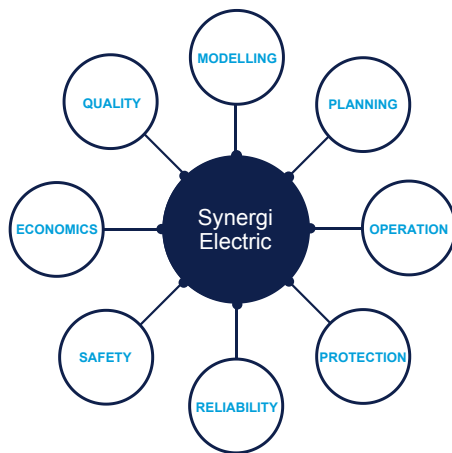
Synergi Electric incorporates a full suite of analysis tools to perform short and long-term planning studies. Its customer class modelling and weather modelling comprise of a solid basis for diurnal or daily load modelling. Demand levels, voltages, loading and spare capacity can be evaluated each hour of every day over 12 months or 10 years. Synergi Electric analyses determine if the distribution system will adequately meet the utility's design and operation criteria. Synergi Electric models the base year plus 10 years forward, including tools for load allocation, phase balancing, capacitor placement, PV placement and load balancing.

Renewables and Distributed Energy Resources (DER)

Models for PV and wind generation are easy to set up in Synergi Electric. Load-flow, fault analysis, hosting capacity and time-series analyses evaluate the impact of these generators. Time and weather conditions are modelled in Synergi Electric to represent real world output of PV generators, combined with detailed load models that provide the most accurate representation of your distribution system. Synergi Electric also models large battery energy storage systems and a variety of control models.

KEY BENEFITS OF SYNERGI ELECTRIC

- A complete framework of power analysis tools in a single model and user interface
- Multi-year analysis reporting provides engineers an efficient view for short-range and long-range planning
- Time series analysis has been added to address the variabilities in load and generation on high penetration PV circuits
- Python scripting builds script routines to automate analysis
- Data handling in Synergi Electric is efficient and open, leveraging structured query language for importing external data sources
- COM Solver provides a programming platform to support client-specific analysis applications and automate planning and operations analysis functions
- Publish model results to the web, DXF, GIS, MS Excel, SharePoint or a dashboard



System Protection

Synergi Electric provides an advanced modelling environment for over-current protective devices and allows engineers to quickly evaluate and manage the extensive and complex protection schemes for hundreds or thousands of distribution feeders. Synergi Electric includes numerous fault applications, including Fault Flow, Fault Voltage, Fault Sequence, PV Fault and Fault Location Analysis. Fault location analysis assists you in quickly troubleshooting outages by accurately predicting the location of fault events and momentary outages. Fault location can be performed manually or automated with Python scripting or our Electric Solver. Synergi Electric also performs Arc flash hazard analysis based on the IEEE 1584 standard

Synergi Electric includes a time current curve explorer where engineers can model their protective devices in the model without requiring separate data stores. Curves for over 15,000 devices are included in the product.

Load growth, customer behaviour, switching configurations and changing facilities are all part of the environment in Synergi Electric and important to protection studies. The Synergi Electric coordination evaluation engine is based on an expert system and a detailed set of over 80 user-defined rules and margins.

Reliability analysis

Reliability metrics are indicators of the value that customers realize through their utility service and are a key concern for power distribution engineers. Outage events are brought into Synergi Electric where they are correlated and used to calculate the performance indices of the base system. You can see root causes of reliability problems, the impact of new or relocated reclosers and switches and evaluate mitigation strategies, such as tree trimming or animal guards. The Synergi Electric reliability simulation is run on the same model and data as all other simulations. While making changes to protection, switching, and loading, you can evaluate the impact of your proposed changes on reliability.

Power quality engineers will find useful tools in Synergi Electric in performing harmonic analysis. Analysis of harmonic curves and total harmonic distortion are native tools in Synergi Electric. Analysis of the loss of a feeder/circuit is simple and automated in Synergi Electric with the contingency switching tool. Synergi Electric has a full suite of tools for capacity planning including: switch assessment, throw-over analysis, optimal switching, load transfer analysis, switch plan analysis, auto-transfer analysis, outage pick up, load at risk, and feeder tie path analysis.

10 GOOD REASONS FOR CHOOSING SYNERGI ELECTRIC

1. Middlelink Analyze distribution models from the substation to the retail customer within a real world spatially correct mapping environment
2. Integrate load and DER forecasts into data models and perform multi-year analysis
3. Perform Hosting Capacity Analysis, supporting DER including PV, storage and microgrids, model PV & batteries and screen PV
4. Includes detailed load modelling: diurnal load curves, customer classes, spot loads, distributed loads, EVs, growth options
5. Run load flow analysis: 8760, multi-year and quasi steady state load flow
6. Protect critical equipment and improve reliability with a full suite of tools for coordinating protective devices and evaluating system reliability
7. Analyze networks and looped systems
8. Develop and validate contingency switching plans and find the best possible switching configuration for your system
9. Automate planning studies and operations analysis functions and run batch analysis
10. Take advantage of data integration tools to import GIS data, customer meter data (AMR/AMI) and SCADA and integration services with enterprise systems and processes.



Data services (data integration and automation) and Solver

Synergi Electric provides tools to integrate with external data sources. Geographic Information Systems (GIS) can be used to develop distribution system models in Synergi as well as automated model build processes, which ensure that the user always has a current model of their distribution system. Additional data sources can be used to further enhance the model build, such as:

- The Customer Management Module (CMM) provides a link to the utility's billing system, improving the accuracy of load allocation in the model and allowing customer classes to be included
- Advanced Metering Infrastructure (AMI) can be used to import a specific loading condition from a known date and time
- Middlelink and Model Forge tools can be used to interface with records of distributed generation, improving accuracy of hosting capacity and impact studies
- Results from load forecasting studies can be imported to Synergi Electric using the Forecast tool, further enhancing the model for multi-year analysis.

DNV's Consulting team has helped many utilities to implement these processes, providing a fully customized model build solution with all data required for distribution engineers to carry out their analyses.

Synergi Electric Viewer

The product provides the option of deploying of a model view-only license. Synergi Electric Viewer allows data technicians to QA/QC models and work with data without having a full copy of Synergi Electric. Viewer has the same data and view capabilities without load flow or other analysis features.

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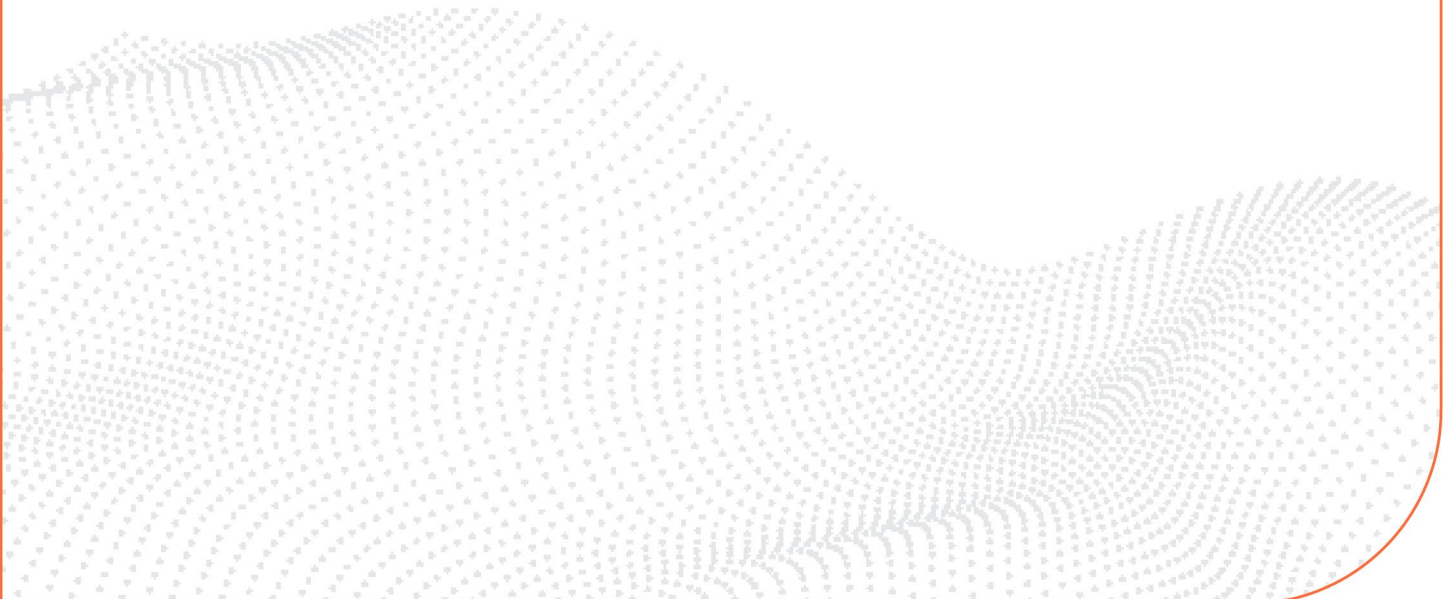
RULE 568 HOSTING CAPACITY IMPROVEMENT SOLUTIONS - DRAFT

PUBLIC SERVICE COMPANY OF NEW MEXICO

PROJECT NO. 171847

REVISION 2

June 24, 2025



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1.0 Executive Summary

Photovoltaic (PV) penetration is growing within the Public Service Company of New Mexico (PNM or the Company) system. High PV penetration can present benefits but can also result in challenges for operating and maintaining the distribution system. In response to rule 568, PNM was granted partial variance in NMPRC Order 23-00072-UT-2023-06-14 to conduct studies to evaluate PNM's technical concerns regarding Variance requests 1, 2, and 3. As ordered, PNM worked with the Department of Energy (DOE) and the National Renewable Energy Laboratory (NREL) to design the pilot study. The purpose of the pilot study was to better understand the actual limits on distribution feeders for hosting new PV generation, given the levels of PV penetration PNM is experiencing, and identify potential solutions to increase the hosting capacity on the PV-saturated feeders. That report¹ was submitted to the NMPRC on May 23, 2024.

In this report, after understanding the limitations of distribution feeders, multiple hosting capacity improvement solutions were evaluated for a total of 27 feeders, 18 PV-saturated feeders and nine feeders with approved community solar project interconnections. The types of hosting capacity improvement solutions that were evaluated are shown in Figure 1-1. A financial analysis was then performed to understand the value of each solution and ultimately recommend a portfolio of hosting capacity improvement projects.

Figure 1-1: Hosting Capacity Improvement Solutions Evaluated



1.1 Pending Customer PV Interconnection Analysis

As of January 1, 2024, 13 of the 18 PV-saturated feeders had pending customer PV interconnections. Based on the results of the first hosting capacity study report, it was determined that many of the PV-saturated feeders had remaining hosting capacity. For 11 of the 13 feeders evaluated, all pending PV customers modeled can successfully interconnect without any system improvements. With the proposed hosting capacity improvement solutions constructed, all pending customer PV can successfully interconnect through August 19, 2024.

Going forward, all applications on PV-saturated feeders will follow the Rule 568 screening process. Since these feeders have reverse power flow at minimum load times, they will fail the 100% of

¹Rule 568 Hosting Capacity Analysis Report
https://edocket.prc.nm.gov/AspSoft/HandlerDocument.ashx?document_id=1233550

minimum load screen and require supplemental review. Under supplemental review, each application will be studied to see if there is remaining hosting capacity to safely interconnect.

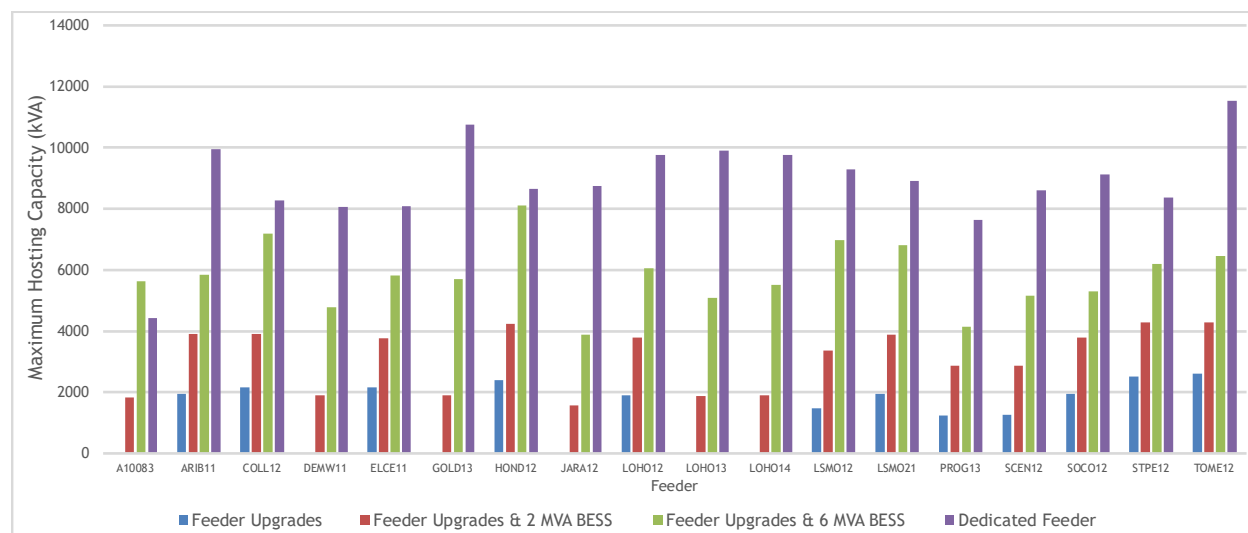
1.2 Community Solar Feeder Analysis

Nine feeders with approved large-scale solar projects were assessed to evaluate the hosting capacity available after the solar facilities were interconnected. Naturally, the hosting capacity for each feeder was reduced as each solar facility was energized. While ample hosting capacity remained for most of these feeders, system improvement scenarios were evaluated to assess the cost and benefit of each of the hosting capacity improvements.

1.3 Hosting Capacity Improvement Solutions Analysis

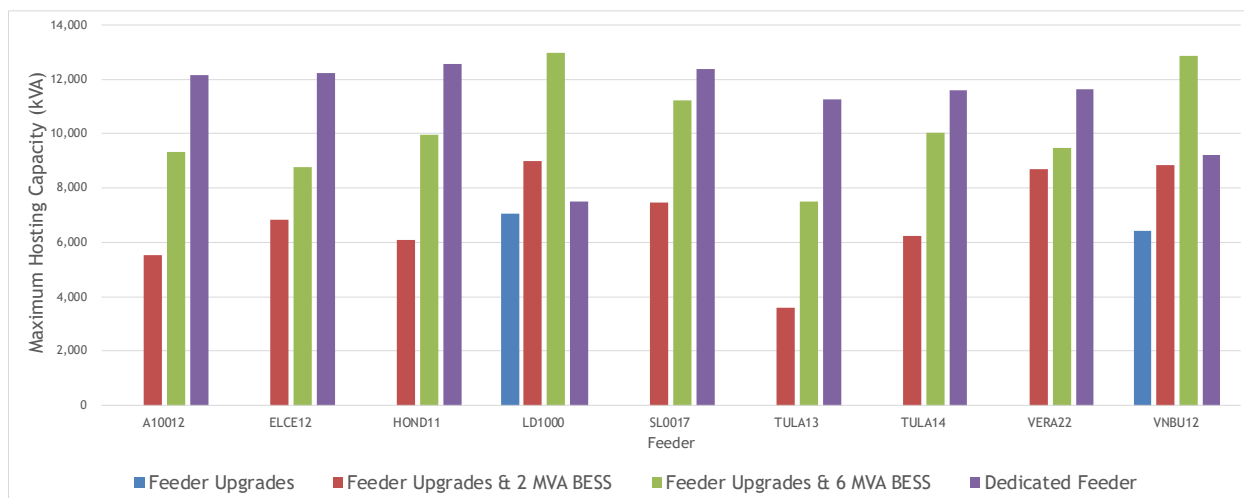
All capital project solutions investigated for the 18 PV-saturated feeders and nine community solar feeders resulted in an increase in hosting capacity. However, the increase in hosting capacity varied across the feeder and was influenced by several factors. The dedicated feeder buildout scenario most often provided the greatest increase in hosting capacity, while feeder upgrades generally provided a marginal increase in hosting capacity. For some of the feeders, upgrades were not applicable because the feeder is presently built to the maximum PNM standard ratings, and no increase in hosting capacity is shown for that scenario. Figure 1-2 shows the Synergi analysis hosting capacity increase for each capital project alternative relative to the base case model results for the 18 PV-saturated feeders. Figure 1-3 shows the same analysis for the nine community solar feeders.

Figure 1-2: PV-Saturated Feeders - Hosting Capacity Increase Per Solution Results



Note: An absent vertical bar indicates that the hosting capacity increase was not applicable for the given scenario.

Figure 1-3: Community Solar Feeders - Hosting Capacity Increase per Solution Results



Note: An absent vertical bar indicates that the hosting capacity increase was not applicable for the given scenario.

1.4 Financial Analysis of Solutions

Two perspectives were used to evaluate all hosting capacity improvement solutions. These perspectives differ by valuing hosting capacity improvement alone or considering the overall system benefits provided by the solution.

Hosting Capacity Benefit Cost - solutions were scored based only on the increase in hosting capacity relative to the cost. This perspective does not consider the overall system benefits provided by each solution.

The left side of Table 1-1 and Table 1-2 presents the portfolio of capital project solutions that scored the highest using the hosting capacity benefit-cost perspective. Feeder upgrades or dedicated feeder buildouts were the types of solutions that scored the highest using the hosting capacity benefit-cost perspective.

Holistic System Benefit Cost - solutions were scored based on the value provided by the new PV generation enabled by hosting capacity and by overall system benefits. The complete value of BESS to the PNM system was more holistically considered from this perspective, as battery storage can improve distribution feeder hosting capacity as well as provide transmission system benefits. See Section 2.5 for further explanation of the value models used for this analysis.

The right side of Table 1-1 and Table 1-2 presents the portfolio of hosting capacity improvement solutions that scored the highest using a holistic system benefit-cost perspective. Considering this holistic value perspective, the 6 MVA BESS solution scored highest for most feeders. However, feeder upgrades in addition to the BESS were not recommended in all instances due to high costs.

Table 1-1: PV-Saturated Feeders Hosting Capacity Analysis Results

Hosting Capacity Benefit Cost Portfolio				
Feeder	Capital Project Category	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)
A10083	Dedicated Feeder	4,427	\$2,595,082	1.71
ARIB11	Feeder Upgrades	1,090	\$174,850	6.23
COLL12	Feeder Upgrades	1,020	\$211,994	4.81
DEMW11	Dedicated Feeder	8,073	\$8,756,768	0.92
ELCE11	Dedicated Feeder	8,091	\$11,902,457	0.68
GOLD13	Dedicated Feeder	10,743	\$1,286,828	8.35
HOND12	Feeder Upgrades	2,389	\$383,946	6.22
JARA12	Dedicated Feeder	8,742	\$4,040,940	2.16
LOHO12	Dedicated Feeder	9,758	\$3,744,957	2.61
LOHO13	Dedicated Feeder	9,898	\$4,131,806	2.40
LOHO14	Dedicated Feeder	9,759	\$3,704,661	2.63
LSMO12	Feeder Upgrades	1,469	\$46,562	31.56
LSMO21	Feeder Upgrades	1,944	\$174,590	11.13
PROG13	Dedicated Feeder	7,647	\$18,415,494	0.42
SCEN12	Dedicated Feeder	8,608	\$14,097,893	0.61
SOCO12	Dedicated Feeder	9,126	\$9,224,026	0.99
STPE12	Feeder Upgrades	2,517	\$2,275,192	1.11
TOME12	Feeder Upgrades	2,620	\$60,570	43.26
Total	-	107,921	\$85,288,614	-

Holistic System Benefit Cost Portfolio				
Feeder	Capital Project Category	Net Hosting Capacity Increase kVA	Capital Project Cost	Holistic Financial Benefit Cost Ratio Score
A10083	6 MVA BESS	5,637	\$14,350,000	1.88
ARIB11	Feeder Upgrades	1,090	\$174,850	6.64
COLL12	Feeder Upgrades	1,020	\$211,994	5.13
DEMW11	Feeder Upgrades & 6 MVA BESS	4,794	\$14,693,013	1.79
ELCE11	6 MVA BESS	2,531	\$14,350,000	2.92
GOLD13	Dedicated Feeder	10,743	\$1,286,828	8.90
HOND12	Feeder Upgrades	2,389	\$383,946	6.63
JARA12	Dedicated Feeder	8,742	\$4,040,940	2.31
LOHO12	Dedicated Feeder	9,758	\$3,744,957	2.78
LOHO13	Dedicated Feeder	9,898	\$4,131,806	2.55
LOHO14	Dedicated Feeder	9,759	\$3,704,661	2.81
LSMO12	Feeder Upgrades	1,469	\$46,562	33.64
LSMO21	Feeder Upgrades	1,944	\$174,590	11.87
PROG13	6 MVA BESS	2,425	\$14,350,000	2.16
SCEN12	6 MVA BESS	3,183	\$14,350,000	3.08
SOCO12	Feeder Upgrades & 6 MVA BESS	5,291	\$26,403,358	1.10
STPE12	Feeder Upgrades & 6 MVA BESS	6,207	\$16,625,192	1.69
TOME12	Feeder Upgrades	2,620	\$60,570	46.11
Total	-	89,502	\$133,083,266	-

Table 1-2: Community Solar Feeders Hosting Capacity Analysis Results

Hosting Capacity Benefit Cost Portfolio				
Feeder	Capital Project Category	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)
A10012	Dedicated Feeder	8,384	12,613,746	0.66
ELCE12	Dedicated Feeder	7,315	8,297,200	0.88
HOND11	Dedicated Feeder	8,326	4,574,152	1.82
LD1000	Feeder Upgrades	4,169	8,000,000	0.52
SL0017	Dedicated Feeder	6,634	12,339,062	0.54
TULA13	Dedicated Feeder	9,589	6,684,780	1.43
TULA14	Dedicated Feeder	7,271	6,391,436	1.14
VERA22	Dedicated Feeder	4,724	13,740,883	0.34
VNBU12	Dedicated Feeder	4,948	8,335,134	0.59
Total	-	61,360	\$80,976,394	-

Holistic System Benefit Cost Portfolio				
Feeder	Capital Project Category	Net Hosting Capacity Increase kVA	Capital Project Cost	Holistic Financial Benefit Cost Ratio Score
A10012	6 MVA BESS	5,577	\$14,350,000	1.79
ELCE12	6 MVA BESS	3,848	\$14,350,000	1.69
HOND11	Dedicated Feeder	8,326	\$4,574,152	1.85
LD1000	Feeder Upgrades & 6 MVA BESS	10,085	\$22,350,000	1.41
SL0017	6 MVA BESS	5,488	\$14,350,000	1.79
TULA13	6 MVA BESS	5,809	\$14,350,000	1.81
TULA14	6 MVA BESS	5,710	\$14,350,000	1.80
VERA22	6 MVA BESS	2,560	\$14,350,000	1.62
VNBU12	Feeder Upgrades & 6 MVA BESS	8,584	\$22,647,200	1.22
Total	-	55,987	\$135,671,352	-

1.5 Portfolio of Recommended Capital Project Solutions

Table 1-3 and Table 1-4 provide the recommended portfolio of capital project solutions to improve hosting capacity on the PV-saturated feeders while also providing the greatest value to PNM customers. Engineering judgement, in combination with the two-perspective financial analysis contained in the tables above, was used to determine this proposed solution portfolio.

In selecting this portfolio, the BESS solutions were considered valuable because of the hosting capacity increase on the local distribution feeder, but also because of the ability to avoid investments in other parts of the system. PNM foresees battery storage as a need to move forward in the clean energy transition. By building BESS on these distribution feeders, less battery storage must be constructed on the transmission system. While the dedicated feeder buildout solution typically resulted in the greatest hosting capacity increase for distribution feeders, these investments provide no benefit to other parts of the overall PNM system, which can also become constrained as PV levels rise. The transmission system can be constrained during times of low load and high PV generation. Even after performing dedicated feeder buildouts, additional transmission system upgrades could be required in certain areas, which would significantly impact the cost of upgrades to improve PNM's overall system hosting capacity. BESS solutions located in proximity to PV generation can reduce PV generation power flow on the transmission system and improve transmission congestion in lieu of transmission upgrades.

PNM plans to prioritize the feeder upgrades in the near term to unlock incremental hosting capacity quickly and enable more customers to connect their new PV systems successfully. The proposed 6 MVA BESS systems can be constructed as PV penetration levels rise locally to improve feeder hosting capacity, or BESS systems can be constructed to obtain the overall system benefits captured in the holistic system benefit analysis. Timelines are provided for the individual projects in Table 1-3 below. Where feeder upgrades and a 6 MVA BESS are proposed, the first timeline is for the feeder upgrades only. The second timeline is for the BESS construction. The timeline to construct the overall portfolio will be greater than three years, as it will be subject to budget allocations.

For Jarales Feeder 12 (JARA12), a dedicated feeder solution scored the highest for the benefit-cost analysis. A dedicated feeder would require a significant amount of double-circuit buildout and could be difficult to construct. A 6 MVA BESS is recommended as it will be more feasible to construct and provide system benefits in addition to improving hosting capacity. The feeder upgrade solution scored the highest for the benefit-cost analysis for ARIB11, COLL12, HOND12, LSMO12, and LSMO21. However, feeder upgrades result in a marginal increase in hosting capacity. To further increase hosting capacity on these feeders, a 6 MVA BESS is also recommended after feeder upgrades are performed.

Table 1-3: PV-Saturated Feeders Hosting Capacity Improvement Solutions Portfolio

Feeder	Capital Project Solution Category	Increase in Hosting Capacity kVA	Capital Project Cost	Construction Timeline
A10083	6 MVA BESS	5,637	\$14,350,000	3 Years
ARIB11	Feeder Upgrades & 6 MVA BESS	5,842	\$14,524,850	1 Year / 3 Years
COLL12	Feeder Upgrades & 6 MVA BESS	7,187	\$14,501,149	1 Year / 3 Years
DEMW11**	Feeder Upgrades & 6 MVA BESS	4,794	\$14,892,473	1 Year / 3 Years
ELCE11	6 MVA BESS	2,531	\$14,350,000	3 Years
GOLD13**	Dedicated Feeder	10,743	\$1,286,828	1 Year
HOND12	Feeder Upgrades & 6 MVA BESS	8,116	\$14,733,946	1 Year / 3 Years
JARA12	6 MVA BESS	3,897	\$14,350,000	3 Years
LOHO12	Dedicated Feeder	9,758	\$3,744,957	3 Years
LOHO13	Dedicated Feeder	9,898	\$4,131,806	3 Years
LOHO14	Dedicated Feeder	9,760	\$3,704,661	3 Years
LSMO12	Feeder Upgrades & 6 MVA BESS	6,980	\$14,396,562	1 Year / 3 Years
LSMO21	Feeder Upgrades & 6 MVA BESS	6,802	\$14,524,590	1 Year / 3 Years
PROG13	6 MVA BESS	2,425	\$14,350,000	3 Years
SCEN12	6 MVA BESS	3,183	\$14,350,000	3 Years
SOCO12*	Feeder Upgrades & 6 MVA BESS	5,291	-	Installed
STPE12	Feeder Upgrades & 6 MVA BESS	6,207	\$16,625,192	1 Year / 3 Years
TOME12*	6 MVA BESS	6,460	-	Installed
-	-	115,511	188,817,014	-

*SOCO12 & TOME12 were selected for the Phase I BESS installations and have been installed. Phase I selection was based on different criteria. The feeder upgrades only solution scored highest for these feeders because it provided the least cost alternative to provide an increase in hosting capacity. The 6 MVA BESS that is installed provides more hosting capacity for future customer interconnections.

**For DEMW11 and GOLD13, the SGIA has not been constructed. The proposed capital project solution would not be constructed unless the SGIA moves forward with construction, or if pending customers are not able to connect to the PNM system without system improvements being built.

For El Cerro Feeder 12 (ELCE12), a 6 MVA BESS scored the highest for the benefit-cost analysis. A BESS would provide many benefits, but a battery is already recommended for El Cerro Feeder 11 to support the Meadow Lake Solar facility. To diversify the system improvements in this area, a dedicated feeder is recommended that will result in the upgrade of the El Cerro Substation. For Veranda Feeder 22 (VERA22), a 6 MVA BESS scored the highest for the benefit-cost analysis. However, the Veranda Substation is heavily loaded, and the new load serving capacity is limited. A dedicated feeder solution is proposed for VERA22 because substation upgrades to enable a dedicated feeder would also increase the load serving capacity in the area. Future iterations of this financial analysis will better represent the value of increasing load serving capacity.

Table 1-4: Community Solar Feeders Hosting Capacity Improvement Solutions Portfolio

Feeder	Capital Project Solution Category	Increase in Hosting Capacity kVA	Capital Project Cost	Construction Timeline
A10012	6 MVA BESS	5,577	\$14,350,000	3 Years
ELCE12	Dedicated Feeder	7,315	\$8,297,200	3 Years
HOND11	Dedicated Feeder	8,326	\$4,574,152	1 Year / 3 Years
LD1000	Feeder Upgrades & 6 MVA BESS	10,085	\$22,350,000	1 Year / 3 Years
SL0017	6 MVA BESS	5,488	\$14,350,000	1 Year / 3 Years
TULA13	6 MVA BESS	5,809	\$14,350,000	3 Years
TULA14	6 MVA BESS	5,710	\$14,350,000	3 Years
VERA22	Dedicated Feeder	4,724	\$13,740,883	3 Years
VNBU12	Feeder Upgrades & 6 MVA BESS	8,584	\$22,647,200	1 Year / 3 Years
-	-	61,618	129,009,435	-

2.0 Inputs and Assumptions

Several distribution feeders within the PNM system already have large amounts of interconnected PV generation. High PV penetration can present challenges for operating and maintaining the distribution system. The purpose of this evaluation was to understand the cost of various hosting capacity improvement solutions and the value of these projects. As in PNM’s previous report, Rule 568 Hosting Capacity Study Analysis Study - Final, dated May 22, 2024, and filed with the NMPRC on May 23, 2024, Synergi Electric is the modeling tool PNM uses for its Distribution System Planning Analysis. This same tool was used for the evaluation of Hosting Capacity solutions in this study. As stated in the previous report, several inputs and assumptions are required to build and prepare distribution feeder models for analysis. These assumptions are described in Section 2 of PNM’s previous report. Only new assumptions required for this evaluation are discussed in this report.

2.1 PV-Saturated Feeders

PNM evaluated 18 distribution feeders classified as at PV saturation, where generation capacity exceeds 90% of the feeder rating. Presently, when a feeder is classified as at PV saturation, new interconnection requests are placed on hold until further study can be performed, and if necessary, system upgrades can be constructed. Table 2-1 shows the 18 distribution feeders with the associated region identified.

Table 2-1: PNM Feeders at PV Saturation

Feeder	Region
A10083	Alamogordo
ARIB11	Santa Fe
COLL12	Albuquerque
DEMW11	Deming
ELCE11	Albuquerque
GOLD13	Deming
HOND12	Deming
JARA12	Albuquerque
LOHO12	Albuquerque
LOHO13	Albuquerque
LOHO14	Albuquerque
LSMO12	Albuquerque
LSMO21	Albuquerque
PROG13	Albuquerque
SCEN12	Albuquerque
SOCO12	Albuquerque
STPE12	Santa Fe
TOME12	Albuquerque

2.2 Community Solar Program/Additional Feeders

PNM evaluated eight distribution feeders that will be at/near PV saturation once Community Solar Program projects are constructed and energized. Alamogordo Feeder 12 (A10012) has a large PV system in operation and similar high levels of PV penetration, so it was included in this analysis. Table 2-2 shows the nine distribution feeders with the associated region and number of projects identified.

Table 2-2: Community Solar Program Feeders

Feeder	Community Solar Projects	Region
A10012	.*	Alamogordo
ELCE12	2	Valencia
HOND11	2	Deming
LD1000	1	Lordsburg
SL0017	1	Silver City
TULA13	1	Alamogordo
TULA14	2	Alamogordo
VNBU12	1	Clayton
VERA22	1	Sandoval

*Note: Feeder A10012 has a 7.5 MVA PV facility in operation and is near PV saturation.

2.3 Pending Customer PV Interconnections for PV-saturated Feeders

Presently, customers requesting to interconnect to feeders at PV saturation have been placed on hold until further study can be performed. Pending PV interconnections, as of January 1st, 2024, are summarized in Table 2-3. Prior to evaluating solutions to increase hosting capacity, these pending PV interconnections were modeled, and power flow analysis performed to determine if these customers could successfully interconnect to the PNM system without causing any negative system impacts. Section 3.2.2 shows the analysis performed to identify which pending customer PV interconnections can be successfully connected to the PNM system without any feeder modifications.

Table 2-3: Pending Customer PV Interconnections as of January 1, 2024

Feeder	Number of Pending Interconnections	Pending Interconnection Capacity kVA (AC)
A10083	4	30
COLL12	2	11
ELCE11	19	107
HOND12	22	125
JARA12	3	18
LOHO12	2	13
LSMO12	17	72
LSMO21	3	22
PROG13	58	330
SCEN12	35	225
SOCO12	55	371
STPE12	23	1,137
TOME12	29	174
Total	270	2,635

2.3.1 Pending Customers PV Interconnections in 2024

Since January 1, 2024, seven additional customers have applied to interconnect new PV systems on these PV-saturated feeders. These customers were again placed on hold since the evaluation documented in this report was already underway. Table 2-4 shows the pending customer PV interconnections as of August 19, 2024. Once the hosting capacity solution was determined for these PV-saturated feeders and applied to the planning model, the pending customer PV interconnections were modeled to confirm successful interconnection.

Table 2-4: 2024 Pending Customer PV Interconnections Between 1/1/2024 and 8/19/2024

Feeder	Number of additional Pending Interconnections	Pending Interconnection Capacity kVA (AC)
ARIB11	1	6
COLL12	1	5
HOND12	3	25
SCEN12	1	6
SOCO12	1	9
Total	7	51

2.4 Hosting Capacity Planning Criteria and Considerations

Thermal loading and voltage are the main criteria that influence hosting capacity analysis within the Synergi software platform. PNM standard planning criteria were applied to this hosting capacity analysis and are listed in detail in Section 2 of PNM's first hosting capacity report.

Various system improvements were evaluated for each feeder to improve hosting capacity limits. For select feeders, battery energy storage was also evaluated to understand the impact on hosting capacity where large-scale solar facilities are presently operating.

2.4.1 Distribution Feeder DER Inverter Limit

PNM published a DER integration plan² that outlined their approach to increasing hosting capacity on distribution feeders. This report also discusses a PV inverter penetration limit of 150% of the feeder rating. For distribution feeders to achieve this level of PV penetration, system upgrades and BESS are generally required to regulate power flow on the feeder and avoid thermal or voltage violations. This PV inverter penetration limit was incorporated into this evaluation so that hosting capacity was not overstated for distribution feeders after various types of system improvements were applied.

2.4.2 DER Integration Plan - Anticipated Capital Improvements

The previous report recommends changes to PNM's initial DER Integration Plan. In Sections 1.2.2 and 9.5, the report recommends that at 60% PV penetration, feeder upgrades should be performed to bring a distribution feeder to the current PNM standard rating. Next, the report stated that at 80% PV penetration, BESS systems should be constructed to continue increasing the hosting capacity of feeders. If this updated DER integration plan had been in place while PV penetration levels rose on these PV-saturated feeders, hosting capacity improvement projects could have been constructed as needed to avoid delaying new customer PV interconnections. However, because these feeders are already beyond 90% PV penetration, a detailed evaluation of each feeder was required. Going forward, the updated DER integration plan will provide criteria for upgrades on feeders as the total generation rises.

2.4.3 System Improvements Standard Equipment

Table 2-5 shows the standard equipment sizes and configurations that are commonly used for planning studies at PNM. Equipment and conductor upgrades were investigated within this evaluation to understand if certain upgrades could improve a distribution feeder's hosting capacity limits.

² https://edocket.prc.nm.gov/AspSoft/HandlerDocument.ashx?document_id=1226661

Table 2-5: System Improvement Upgrades

System Improvement	Standard Size
Lateral Conductor Upgrade	#2 ACSR or 2/0 ACSR
Main Line Conductor Upgrade	397 AAC @ 570
Lateral Cable Upgrade	1/0 AL
Main Line Cable Upgrade	750 CU or 750 AL
New Capacitor Bank	1,200 kVAR Switched
New Voltage Regulator	501 kVA
New Switch Overhead	SCADA Control Pole Top Switch
New Underground Switch	Various SCADA Controlled PME Configurations

2.4.4 Battery Energy Storage Systems

BESS is another solution for improving hosting capacity on a distribution feeder operated and optimized by PNM for this benefit. Battery storage can consume excess PV generation on a distribution feeder and thereby increase the minimum daylight gross load. Battery storage may be an option for improving hosting capacity for feeders that are at PV saturation, after feeder upgrades have maximized the hosting capacity they can support. Table 2-6 shows the two scenarios of battery storage system specifications used for this evaluation. First, a 6 MW battery will be installed with a charge rate of 2 MW, representing a control scheme where the battery can charge for an extended amount of time during daytime hours. Second, a 6 MW battery will be installed with a charge rate of 6 MW using the full capability of the equipment, but this battery can only charge continuously for four hours at this rate. It is anticipated that a BESS installation operating to full capability may require additional investment into communications infrastructure to monitor power flow and customer service voltage more accurately on the feeder.

Table 2-6: BESS Operation Scenarios

Battery	Rating	Operational Charge Rate	Energy Storage
BESS Scenario 1	6 MW	2 MW	24 MW Hours
BESS Scenario 2	6 MW	6 MW	24 MW Hours

2.5 Copperleaf - Value Models

Copperleaf is a decision analytics tool primarily used for asset investment planning and management, particularly in asset-intensive industries such as energy, utilities, and infrastructure. It helps organizations maximize capital efficiency, manage asset risk, and achieve environmental, social, and governance (ESG) goals by providing a comprehensive platform for making data-driven investment decisions. Overall, Copperleaf's solutions are designed to help organizations navigate complex investment decisions by providing a unified platform that aligns financial, environmental, and community objectives. To obtain robust results, a utility must

thoughtfully develop various “value models” which are a way of capturing the whole value of a potential investment. Since this is a new tool for PNM, it is anticipated that refining the inputs to Copperleaf will be an iterative process as PNM gains more experience using it.

Various models within Copperleaf were used to assess the benefits of each investment solution evaluated. The focus of this evaluation was to determine the appropriate projects to increase hosting capacity on distribution feeders and provide the greatest total benefit to customers. The following list shows the value models utilized within Copperleaf for this evaluation, which are further discussed in the sections below.

- Capital Project Cost
- Expected Life of Asset
- New Distributed PV Generation Benefit
- Increase in Load Serving Capacity
- Evening Hours BESS Capacity/Capacity Over Risk Hours
- BESS Energy Supplied to the System
- Energy Arbitrage
- Avoided Curtailment (Contractual Take or Pay)
- Public Perception for Improving Hosting Capacity

2.5.1 Capital Project Cost

For each evaluated alternative, a class 4 (2025 estimated dollars) cost estimate was performed. The alternative cost is categorized as a negative value within Copperleaf. Quantified benefits from the other value models are summed up to determine if the anticipated benefits exceed the upfront investment cost of the alternative.

2.5.2 Expected Life of Asset

Traditional distribution system upgrades typically have a 30-year expected life. The traditional feeder upgrades and dedicated feeder buildout solutions were evaluated with this 30-year expected life. However, BESS assets are anticipated to have a shorter 20-year expected life. After 20 years, PNM anticipates that BESS facilities may need to be repowered and require significant investments to maintain the required performance. Within Copperleaf, a 30-year expected life was modeled for all investment solutions. If a BESS were included in a hosting capacity improvement solution, the cost of repowering the BESS in 20 years was included in the Copperleaf analysis. The BESS cost was prorated by 50% in year 20, which resulted in the total cost of BESS solutions being 1.5 times the initial investment cost with a 20-year expected life. The expected life of the asset was not incorporated into Copperleaf for previous hosting capacity efforts. This is a new addition to the Copperleaf modeling.

2.5.3 New Distributed PV Generation Benefit

An avoided cost calculator was developed to identify the economic benefit that PV generation provides to the PNM system by deferring capital costs associated with traditional system improvements and distribution equipment maintenance. The calculator is based on the 2024

Distributed Energy Resources Avoided Cost Calculator³ created for the California Public Utilities Commission. Several PNM system reports containing peak load information, equipment ratings, area solar irradiance profiles, and existing or planned PV generation were used as inputs to calculate the monetary benefit of a kW of DER on the system for deferring capacity improvement upgrades. The Avoided Cost calculator is shown in Figure 2-1. This avoided cost calculator approach is a new method for this update of the hosting capacity report.

Figure 2-1: Avoided Cost Calculator Results

		Feeder	Transformer
[1]	Actual Overloads	26	26
[2]	DER Removed Overloads	33	35
[3]	Actual Overloads (kW)	34,553	67,087
[4]	DER Removed Overloads (kW)	46,204	120,566
[5]	Estimated Overload Capacity Deferred by DER (kW)	11,651	53,479
[6]	DER - Deferrable Capital Investments (\$)	\$ 3,500,000	\$ 72,000,000
[7]	Distribution deferral value (\$/kW of DER installed)	\$ 300.40	\$ 1,346.32
[8]	Marginal Distribution Cost Factor (WACC Debt Component) %	3.72%	3.72%
[9]	Capacity Deferral Value (\$/kW of DER installed - yr)	\$ 11.17	\$ 50.08
[10]	Total Benefit (\$/kW)	\$61.26	

Notes:

- [1] The number of transformers and feeders in the PNM system that show overloads using the loading information reported in the PNM 2024 Actual Peak Reads report.
- [2] The number of transformers and feeders in the PNM system that show overloads using the loading information reported in the PNM 2024 Actual Peak Reads report, if DER were removed.

³ See Pages 89 – 91

2024 Distributed Energy Resources Avoided Cost Calculator Documentation

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2024-acc-documentation-v1b_clean_posted_nowm.pdf

- [3] The total amount of kilowatts across feeders or transformers by which the observed overload exceeds the equipment ratings.
- [4] The total amount of kilowatts across feeders or transformers by which the observed overloads would exceed the equipment ratings if DER were removed.
- [5] The amount of overloads in kW that is deferred by the DER. This value is calculated by subtracting the kW Actual Overloads from the DER Removed Overloads.

$$[4] - [3] = [5]$$

- [6] The amount is the cost of capital investments required to mitigate equipment overload issues currently being deferred by DER. This amount is calculated by multiplying the number of feeders or transformers that are observed to have overloads deferred by DER by an estimated cost to upgrade the feeder or transformer. The sum of \$500,000 is used to estimate the upgrade costs for a feeder, and \$8,000,000 is used for a transformer upgrade.

$$([2] - [1]) * \text{Cost of Upgrade} = [6]$$

- [7] The amount is the monetary benefit of a kW of DER. It is calculated by the ratio of deferred capital investment costs against the estimated overload capacity by DER.

$$[6] / [5] = [7]$$

- [8] WACC

- [9] The amount is calculated by multiplying the distribution deferral value by the marginal distribution cost factor.

$$[7] * [8] = [9]$$

- [10] The total monetary benefit of each kW of DER is calculated by combining the capacity deferral values for both the feeder and the transformer.

2.5.4 Increase in Load Serving Capacity

Several of the solutions to increase hosting capacity in this evaluation included substation and feeder upgrades. For these scenarios, system improvements would enable PNM to serve more customer load in addition to customer PV generation. However, for most of the feeders evaluated, the existing PNM system does not have difficulty with load serving capacity. If there is no load serving capacity challenge for a feeder, \$0 of benefit was attributed to load serving capacity increases. Some feeders in the evaluation do have limited ability to serve new load. If the feeder is heavily loaded or located near areas of economic development, some value should be attributed to the project. At the time of this evaluation, PNM does not have a monetary value determined for increased load serving capacity. In future iterations, PNM desires to include this benefit in the financial analysis of future projects.

2.5.5 Evening Hours BESS Capacity/Capacity Over Risk Hours

PNM must manage the power system to ensure that sufficient power is available to customers throughout each day. PNM must also plan for adequate generation to meet its system peak, which

traditionally occurs in the early afternoon. However, due to large amounts of PV generation on its system, PNM has seen a shift in its peak to the evening hours. PV generation can produce large amounts of power coincident with solar irradiance. The result is that PNM receives a large amount of PV generation during the middle of the day, but as the sun sets in the evening, customer power demand can remain high, and PNM must use other generation sources to continue serving the load. Solutions that increase hosting capacity using a battery system will allow PNM to charge this resource during daylight hours from excess PV generation and then deliver the energy during the evening hours when additional peaking capacity is needed to continue serving customers. Installing BESS on the PNM system will provide value by shifting excess renewable PV generation from the peak daylight hours to the evening hours.

If BESS is installed on distribution feeders, PNM would be able to avoid some investments in these types of resources on the transmission system. The avoided cost of \$140/kW/Year was used to quantify the benefit of BESS for providing peaking capacity to the PNM system and is based on recent RFP efforts and was updated in this version of the report. For a 6,000 kW BESS, the yearly monetary benefit was calculated to be \$840,000 ($\$140 \times 6,000 \text{ kW}$) for providing this generation capacity service during evening hours. For hosting capacity increase solutions that did not involve constructing a BESS, \$0 of value was recorded for BESS capacity.

2.5.6 BESS Energy Supplied to the System

A BESS provides a resource for energy storage to the PNM system. Energy storage for recent BESS projects has been valued at \$50/MWh. These distribution BESS applications are anticipated to operate with one full cycle per day for 365 days per year. For a 6 MW battery with 24 MWh of storage, the yearly value for energy supplied to the system was estimated to be \$438,000 ($\$50 \times 365 \text{ days} \times 24 \text{ MWh}$). For hosting capacity increase solutions that did not involve constructing a BESS, \$0 of value was recorded for BESS energy supplied to the system.

2.5.7 Energy Arbitrage

Energy arbitrage is a strategy that involves purchasing energy at a low price and selling back into the market at a higher price. Solutions that increase hosting capacity on distribution feeders using a BESS also provide the opportunity to participate in energy arbitrage. As the needs of the distribution feeder change throughout each day/season, PNM can use a BESS to charge from excess PV generation or grid power to capture the benefit of storing energy when prices are low and then selling to the market as energy prices increase. The monetary value assumed for energy arbitrage

in this evaluation was equal to \$41,000 per MW per year of BESS capacity⁴. For a 6 MW BESS, the yearly monetary benefit was estimated to be \$250,000 (\$41,000 * 6 MW). For hosting capacity solutions that did not involve constructing a BESS, \$0 of value was recorded for energy arbitrage.

2.5.8 Avoided Curtailment (Contractual Take or Pay)

PNM purchases power from many large wind/solar generators interconnected to the transmission system. Contracts with these power producers require that PNM take all power generated or pay the producer to curtail. During times of low customer demand but high output from renewable sources, PNM must pay the producers to curtail or sell the power at discounted rates to nearby utilities. Installing BESS on the PNM electric system will allow PNM to charge the batteries during times of high renewable energy production, but low customer demand. Charging these batteries will help PNM to avoid curtailing renewable energy sources while enabling a dispatchable resource on a distribution feeder. PNM has estimated a \$10,000 yearly benefit from a 6 MW 4-hour BESS for limiting curtailment of renewable energy production on the transmission system. This constant benefit each year for curtailment is an update in this version of the report. For capital project solutions that did not involve constructing a BESS, \$0 of value was recorded for avoided curtailment.

2.5.9 Public Perception for Improving Hosting Capacity

PNM customers desire to interconnect new PV generators to feeders at PV saturation. Each hosting capacity improvement solution represents an action by PNM to enable the interconnection of customer PV. These solutions also represent PNM's response to supporting the clean energy transition. A qualitative value model was used to represent the benefit to capital projects that correct the issue of PNM customers being unable to interconnect new PV generation to feeders at PV saturation. A more significant consequence value was attributed to distribution feeders with a higher number of pending customer PV interconnections. For feeders with minimal/no pending customer PV interconnections, a reduced consequence value was applied. Among all feeders analyzed, a 30% consistent probability of an event was used to scale the public perception value.

⁴ See pages 9-10 direct testimony of Lucas McIntosh

<https://www.txnmenenergy.com/~media/Files/P/PNM-Resources/rates-and-filings/PNM%20CCN%20Application%20for%2012%20MW%20Battery%20Storage/2023-05-03-PNM%20Direct%20Testimony%20of%20Lucas%20McIntosh.pdf>

3.0 Hosting Capacity Analysis - Feeders at PV Saturation

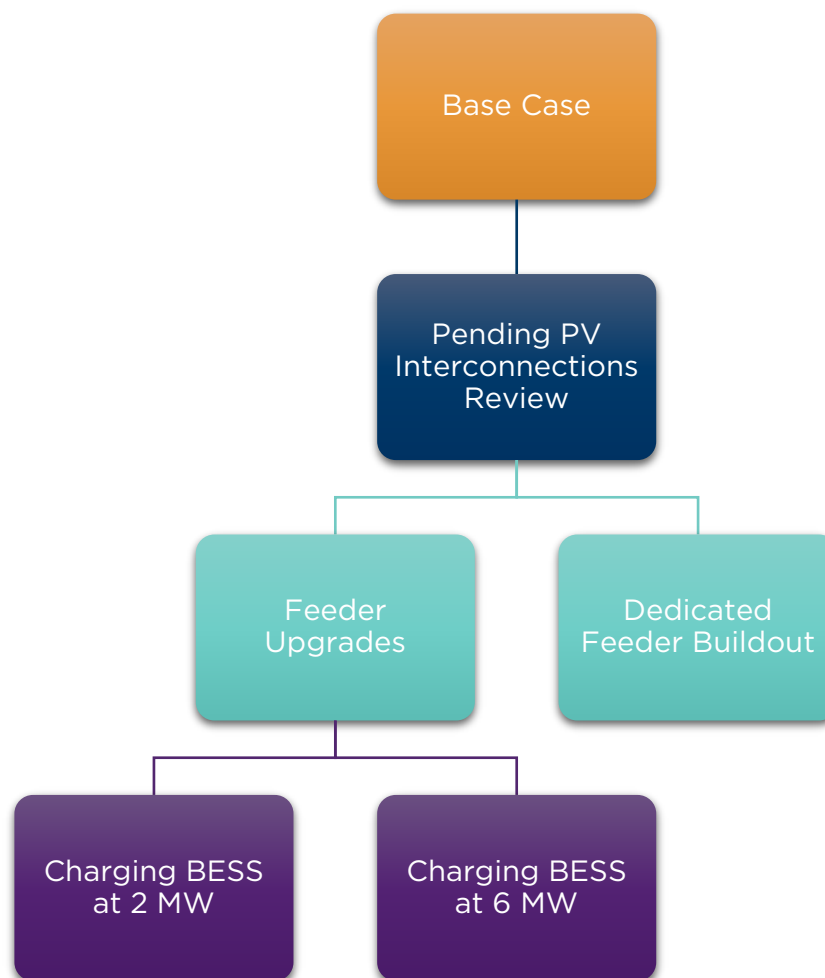
3.1 Hosting Capacity Improvement Solutions Evaluation Approach - Feeders at PV Saturation

Synergi's incremental Hosting capacity analysis and power flow simulations were used to understand the capability of existing distribution feeders to host new PV generation. This analysis was performed and documented within the first hosting capacity study report. The existing capability was established, then pending PV interconnections as of January 1, 2024, were modeled to determine if customer interconnections that were on hold due to high PV penetration levels could successfully interconnect to the PNM system. Once pending PV interconnections were modeled, various solutions to increase hosting capacity were evaluated. A Class 5 cost estimate was performed for each hosting capacity improvement solution evaluated. With the hosting capacity improvement identified and the cost estimate documented, a financial analysis was performed to determine the recommended capital project portfolio for these 18 feeders.

3.1.1 Hosting Capacity Analysis and Capital Project Solutions

PNM has 18 feeders at PV saturation that were analyzed for this evaluation. Minimum daylight load was the basis for this analysis to understand the limits of the system when there is the least amount of customer load on the feeder to consume PV generation. There are five specific scenarios that were evaluated for each distribution feeder: base case hosting capacity with queued customer solar (if applicable), hosting capacity with feeder upgrades, hosting capacity with system improvements and a 6 MW battery operating at 2 MW or 6 MW, and a dedicated feeder built to serve the existing large-scale solar facility. The scenarios are outlined below in Figure 3-1.

Figure 3-1: Hosting Capacity Analysis and Capital Projects Approach



The process is delineated as follows and explains the significant steps of the analysis:

Step 1 - Base Case Hosting Capacity Analysis

1. Document the current system capability.
2. Identify any existing planning criteria violations.

Step 2 - Pending PV Interconnections Review

1. If applicable, model pending customer PV interconnections as of January 1, 2024, and perform power flow simulation.
2. Review the power flow results to determine if any new planning criteria violations occurred with the modeled pending customer PV interconnections.
3. If no planning criteria violations are observed, pending customer PV interconnections should be approved for interconnection.
4. Perform hosting capacity analysis to determine the remaining hosting capacity after interconnecting pending PV projects.
5. All pending PV interconnections remain in the model for the following steps.

Step 3 - Feeder Upgrades

1. Construct capital projects in the feeder model to increase hosting capacity, such as conductor upgrades, protective device upgrades, new equipment, etc.
2. Perform hosting capacity analysis and document the new system capability with the capital projects in place.

Step 4 - Feeder Upgrades and Charging BESS at 2 MVA

1. Construct a BESS co-located with the existing large PV system set to charge at 2 MVA.
2. Perform hosting capacity analysis and document the new system capability with the Feeder Upgrades in place and BESS charging at 2 MVA.

Step 5 - Feeder Upgrades and Charging BESS at 6 MVA

1. Construct a BESS co-located with the existing large PV system set to charge at 6 MVA.
2. Perform hosting capacity analysis and document the new system capability with the Feeder Upgrades in place and BESS charging at 6 MVA.

Step 6 - Build a Dedicated Feeder to Existing Large-Scale PV Site

1. Identify the substation upgrades and conductor buildout required to construct a dedicated feeder to the existing large PV site.
2. Move the existing large PV system to a new dedicated feeder.
3. No upgrades performed for the existing feeder that serves PNM customers.
4. Perform hosting capacity analysis for the existing feeder that serves PNM customers and document the new system capability with the large PV system moved to a dedicated feeder.

Step 7 - Review Pending Customer PV Interconnections in 2024

1. If applicable, pending customer PV interconnections as of August 19, 2024, new PV projects were modeled within the base case model.
2. Review power flow results to determine if any new planning criteria violations occurred with pending customer PV interconnections modeled within the base case model.
3. If no planning criteria violations are observed, pending customer PV interconnections should be approved for interconnection.

3.1.2 Hosting Capacity Improvement Solutions Cost Estimate

Capital projects identified during the power flow analysis were estimated using a class 4 (2025 estimated dollars) estimate approach. Detailed engineering and design will refine the cost estimate later. However, recent cost data were utilized and applied in this evaluation for larger capital projects like BESS installations and substation upgrades.

3.1.2.1 BESS Construction Cost Estimate

PNM recently constructed two battery systems on distribution feeders sized at 6 MW with 24 MWh of storage. The installation cost of each system was \$14.3M. These recent actual costs were utilized as an estimate for future BESS systems. To enable more functionality for the battery, it is anticipated that PNM will need to install additional communications and relaying infrastructure so

that power flow and voltage on the feeder can be monitored more accurately. For scenarios where 6 MW charging was evaluated, an additional cost of \$50,000 for this communications infrastructure was included.

3.1.2.2 Substation Upgrades to Enable Dedicated Feeder Construction Cost Estimate

Fully built-out substations presently serve many of the feeders evaluated. Traditionally, PNM builds substation transformers with an associated switchgear that contains four feeder breaker compartments. If all existing substation feeder breaker compartments are utilized, building out a dedicated feeder will require significant upgrades, and in many cases, require a new substation transformer and switchgear. Recent cost estimates from the Community Solar Program were used to estimate the substation upgrades necessary to build a new dedicated feeder to a large PV site. Based on recent engineering designs, the cost for a new substation transformer and switchgear was estimated at \$8M.

3.1.3 Financial Analysis

Two perspectives were used to evaluate all solutions to improve hosting capacity on PV-saturated feeders. These perspectives differ by valuing hosting capacity improvement alone, versus considering the overall system benefits, including transmission and distribution system benefits.

Hosting Capacity Benefit Cost - solutions were scored based only on the increase in hosting capacity relative to the cost. This perspective does not consider the overall system benefits provided by each solution.

Holistic Financial Benefit Cost - solutions were scored based on the value provided from new PV generation enabled by hosting capacity and by overall system benefits. The complete value of BESS to the PNM system was more holistically considered from this perspective. See Section 2.5 for further explanation of the value models used for this financial benefit cost analysis.

3.2 Hosting Capacity Improvement Solutions Analysis - Feeders at PV Saturation

Table 3-1 shows the 18 feeders that were identified at/near PV saturation for this evaluation. The feeder rating utilization is calculated by comparing the total approved PV capacity, using an installed generation report and pending SGIA interconnections, against the feeder rating. Several feeders have approved PV capacity beyond the feeder rating identified by a feeder utilization greater than 100% and are colored red. Various system improvements were evaluated in this section to improve the hosting capacity of these feeders.

Table 3-1: Feeders at PV Saturation

Feeder	Region	Feeder Rating kVA	Total Approved PV Capacity kVA	Feeder Rating Utilization %
A10083	Alamogordo	11,663	10,705*	92%
ARIB11	Santa Fe	9,331	10,115	108%
COLL12	Albuquerque	11231	9294	83%
DEMW11	Deming	9,370	8,304	89%
ELCE11	Albuquerque	9,288	9,295	100%
GOLD13	Deming	12,429	11,333	91%
HOND12	Deming	10,039	9,154	91%
JARA12	Albuquerque	11,231	10,068	90%
LOHO12	Albuquerque	9,288	10,249	110%
LOHO13	Albuquerque	9,288	9,036	97%
LOHO14	Albuquerque	9,288	10,006	108%
LSMO12	Albuquerque	11,231	12,223	109%
LSMO21	Albuquerque	11,231	10,000	89%
PROG13	Albuquerque	9,936	9,741	98%
SCEN12	Albuquerque	9,936	10,834	109%
SOCO12	Albuquerque	9,288	10,737	116%
STPE12	Santa Fe	8,208	10,372	126%
TOME12	Albuquerque	9,288	10,575	114%

*The total approved PV capacity for A10083 includes a recently studied 3,500 kVA Community Solar Program project.

3.2.1 Base Case Hosting Capacity Analysis

Initial base case models were created for 18 feeders at solar saturation using the process outlined in Section 2 of PNM's first Hosting Capacity report. Table 3-2 shows the Synergi calculated results observed for each feeder based on the existing PNM system. Synergi Minimum Daylight Load (MDL) is the feeder meter's lowest kW reading during daylight hours. Synergi maximum hosting capacity represents the amount of additional PV generation that could be interconnected if placed at an optimal location, which is most often near the substation where equipment ratings are highest. Maximum thermal and voltage observations are documented as well. For these feeders at PV saturation, many are experiencing maximum voltage and/or maximum conductor loading near the planning criteria limits and are colored yellow. For LSMO12, STPE12, and TOME12, thermal loading violations were observed in the base case model (colored red) and indicate there is no remaining

hosting capacity for these feeders. System improvements must be performed for these three feeders before any new PV generation can be successfully interconnected.

Table 3-2: Synergi Base Case Hosting Capacity Results

Feeder	Feeder Rating kVA	Synergi Existing Gen kVA	Synergi MDL kW	Synergi MDL kVA	Synergi MDGL kVA	Synergi Max Voltage	Synergi Max Load %	Synergi Maximum Hosting Capacity kVA
A10083	11,663	9,973	-7,959	8,043	1,478	125.0	95.5	3,675
ARIB11	9,331	10,326	-8,188	8,188	2,121	123.4	89.0	1,099
COLL12	9,072	9,150	-8,297	8,702	372	125.5	96.0	781
DEMW11	10,278	8,304	-8,062	8,070	83	125.3	91.8	1,308
ELCE11	9,288	9,257	-6,954	7,668	1,300	124.4	97.0	2,019
GOLD13	12,429	11,272	-10,292	10,315	730	125.7	81.1	2,139
HOND12	10,039	9,153	-8,561	9,565	267	125.0	86.0	1,352
JARA12	11,231	10,063	-7,944	8,843	848	124.4	96.6	3,269
LOHO12	9,288	10,004	-8,260	8,263	1,660	124.9	86.0	1,060
LOHO13	11,231	12,073	-10,962	11,157	528	123.7	98.0	267
LOHO14	11,231	9,999	-9,616	9,684	529	124.6	86.0	1,616
LSMO12	9,288	10,216	-9,682	9,753	431	125.4	106.0	Thermal Violation
LSMO21	9,288	9,032	-7,944	8,001	848	123.4	97.0	1,272
PROG13	9,936	9,610	-6,367	6,373	1,909	125.3	97.0	3,255
SCEN12	9,936	10,728	-8,421	9,641	1,075	122.7	97.0	1,297
SOCO12	9,288	10,708	-7,707	8,484	2,347	123.0	97.0	1,224
STPE12	8,208	10,066	-7,839	8,703	1,770	124.3	112.0	Thermal Violation
TOME12	9,288	10,698	-8,442	8,624	1,800	123.2	110.0	Thermal Violation

Note: Negative MDL kW indicates reverse power flow on the feeder.

3.2.1.1 Feeders with Max Thermal Loading Violations

Feeders LSMO12, STEP12 and TOME12 showed thermal criteria violations when performing the base case power flow analysis. System improvements are required to mitigate this violation of planning criteria and the risk of equipment failure that can result from use above normal ratings. Due to the thermal violations observed, zero hosting capacity remains for these feeders. Once system improvements are constructed to resolve these thermal violations, some hosting capacity will be enabled on each distribution feeder.

3.2.1.2 Feeders with Max Voltage Near Planning Criteria

Seven feeders within this evaluation experienced maximum voltage near the planning criteria of 126 V and are colored yellow in Table 3-2. High PV penetration can result in a voltage rise on distribution feeders. The generation location on the feeder, conductor sizes, and other factors will influence the voltage rise resulting from PV generation. Mitigation efforts can be performed to regulate voltage by installing new equipment, adjusting the settings of PV inverters, and using BESS to control power flow. Although none of the feeders experienced high voltage violations in

the base case hosting capacity scenario, high voltage violations must be monitored for distribution feeders as PV penetration increases.

3.2.2 Pending Customer PV Interconnections Review

Several of the feeders had pending customer PV interconnections before this study. See Table 2-3 in Section 2.2 for the number of pending customer PV interconnections and the total capacity. If the remaining hosting capacity was observed for a distribution feeder in PNM's first Hosting Capacity study, all pending interconnections shown in Table 2-3 were modeled, and power flow analysis was performed to determine if all planning criteria were still maintained. Table 3-3 shows the summary power flow results and remaining hosting capacity after modeling the pending PV interconnections shown in Table 2-3. Feeders without pending customer PV interconnections are not shown in the table below.

Table 3-3: Synergi Power Flow Analysis with Pending PV Interconnections Modeled

Feeder	Feeder Rating kVA	Synergi Existing Gen kVA	Pending PV kVA	Synergi Maximum Voltage V	Synergi Maximum Load %	Synergi Maximum Hosting Capacity kVA	Pending PV Customers Can Interconnect?
A10083	11,663	9,973	30	125.0	95.5	3,703	N/A
COLL12	9,072	9,161	11	125.6	96.1	781	Yes
ELCE11	9,288	9,257	107	124.6	96.7	2,019	Yes
HOND12	10,039	9,153	125	125	86	1,352	Yes
JARA12	11,231	10,081	18	124.4	96.6	3,269	Yes
LOHO12	9,288	10,017	13	124.9	86	1,060	Yes
LSMO12	9,288	10,288	72	125.4	106	Thermal Violation	No
LSMO21	9,288	9,040	22	123.4	96.6	1,272	Yes
PROG13	9,936	9,931	330	125.4	96.3	3,255	Yes
SCEN12	9,936	10,948	225	122.8	98.9	1,297	Yes
SOCO12	9,288	11,063	371	123.5	98.2	1,224	Yes
STPE12	8,208	11,175	1,137	124.7	124.6	Thermal Violation	No
TOME12	9,288	10,852	174	123.2	111.6	Thermal Violation	Yes*

*A 6 MVA BESS was recently installed on TOME12. With this BESS in place, the existing thermal violation has been mitigated, and all pending PV projects can successfully interconnect.

3.2.2.1 Feeders Where Pending PV Projects Can Interconnect

If no planning criteria violations were observed after modeling pending PV interconnections, these customers can be allowed to interconnect to the PNM system. All pending PV customers modeled can interconnect without system improvements on 11 of the 13 feeders evaluated. This would result in 230 new projects interconnecting and an increase of 1,391 kVA in PV capacity. For these 11 feeders, some hosting capacity remains after modeling pending customer PV interconnections and indicates the potential to successfully interconnect more PV to these feeders without experiencing planning criteria violations.

3.2.2.2 Feeders Where Pending PV Projects Cannot Interconnect

Feeders LSMO12 and STPE12 showed thermal criteria violations when performing the base case power flow analysis. Planning criteria violations would be exacerbated if pending PV interconnections were allowed on these feeders. Pending customer PV interconnections on these feeders must not be approved until system improvements can be constructed to mitigate existing planning criteria violations and increase the available hosting capacity for these feeders.

3.2.3 Feeder Upgrades

Traditional conductor and equipment upgrades could bring the feeders up to the current PNM standard rating for many of these feeders at PV saturation. Table 3-4 shows the summary of results and indicates the number of system improvements evaluated for each feeder. Each feeder was individually assessed to determine the appropriate system improvements to increase hosting capacity. The Synergi maximum hosting capacity value represents the remaining hosting capacity, assuming all pending PV customers are interconnected to the respective feeder, if applicable. All feeders show remaining hosting capacity with feeder upgrades applied. Some feeders have already been constructed to the maximum PNM standard ratings. The feeder upgrade scenario did not apply to these feeders.

Table 3-4: Feeder Upgrades Summary Results

Feeder	Feeder Rating kVA	Feeder Cable Upgrade Mi	Main Line Conductor Upgrade Mi	Protective Device Upgrade Units	New Equipment Units	Synergi Maximum Hosting Capacity kVA
A10083	11,663	-	-	-	-	3,675
ARIB11	11,231	0	0	1	0	2,100*
COLL12	11,231	0.1	0	0	0	1,800*
DEMW11	12,429	0.03	0.63	0	0	1,280**
ELCE11	11,231	0.03	0	0	0	4,178
GOLD13	12,429	-	-	-	-	2,139
HOND12	12,429	0.08	3.2	0	0	2,390
JARA12	11,231	-	-	-	-	3,269
LOHO12	11,231	0	0	1	0	2,960
LOHO13	11,231	-	-	-	-	267
LOHO14	11,231	-	-	-	-	1,616
LSMO12	11,231	0	1.17	0	0	1,469
LSMO21	11,231	0	1.17	0	0	3,216
PROG13	11,231	0.16	5.26	0	0	4,506
SCEN12	11,231	0	1.61	0	0	2,559
SOCO12	11,231	0.03	.09	0	0	3,167
STPE12	11,231	0.42	5.24	0	0	2,520
TOME12	11,231	0.03	0	0	0	2,620

*The Ariba Substation and College Substation transformers have high PV penetration. The substation transformer limits the maximum hosting capacity after feeder upgrades are performed.

** The Deming West Substation transformer is more limiting to hosting capacity than the feeder rating. After feeder upgrades are performed, losses decrease on the feeder, but power flow through the transformer increases, so the hosting capacity decreases by a small amount.

3.2.3.1 Conductor Upgrades to Improve Feeder Rating

The maximum standard PNM feeder construction utilizes 750 CU cable for underground construction, rated for 520 Amps, and 397 AAC conductor for overhead construction, rated for 570 Amps. A distribution feeder constructed with these conductors/cables typically will have a normal rating of 11.2 MVA and an emergency rating of 13 MVA with a nominal system voltage of 12.47 kV_{LL}. PNM does operate in some regions at a nominal system voltage of 13.8 kV_{LL}. This higher nominal voltage results in a normal rating of 12.5 MVA and an emergency rating of 14.3 MVA. These emergency ratings result from the system design based on 600-amp rated equipment. Emergency capacity is reserved for contingency switching and power restoration.

The Alamogordo South, Gold, Jarales, and Lost Horizon Substation feeders contained in this feeder set could not be upgraded to improve the feeder rating, and feeder upgrades were not applicable. Lost Horizon, Gold, and Jarales feeders are newer and were constructed to the present maximum standards. Alamogordo Feeder A10083 was purchased from another utility provider with a conductor rated higher than the maximum PNM standard. As PNM continues to expand its system, they are working to construct new feeders to the maximum PNM standard, where possible, to mitigate the cost of future upgrades to increase the capacity of the feeder.

3.2.3.2 Protection Upgrades

As PV generation increases on a distribution feeder, system protection schemes are impacted. Desensitization of protection schemes can occur as new PV generation sources are distributed throughout the feeder. Reclosers and other sectionalizing devices protect distribution feeders from faults and limit the impact on customers. Additional protective devices were included in the feeder upgrade analysis to mitigate potential desensitization concerns anticipated on distribution feeders as PV penetration increases.

3.2.4 Feeder Upgrades and Charging BESS at 2 MVA / 6 MVA

Feeder upgrades can bring all distribution feeders at PV saturation to current PNM construction standards and maximum feeder rating. By increasing the feeder rating, hosting capacity was observed to increase. However, once the maximum feeder rating is achieved, no other feeder upgrades can be performed to increase the maximum hosting capacity. Charging a BESS from PV generation is one solution to increase further hosting capacity on a distribution feeder. Charging the BESS from PV generation can regulate the power flow on the feeder during times when there is minimal customer demand, but large amounts of solar generation. Using a BESS to manage power flow on the distribution feeder can help mitigate potential thermal and voltage violations resulting from PV generation.

Two different BESS charge rates were studied in this evaluation. The 2 MVA charge rate represents a simple control scheme where the 24 MWh BESS charges at a low rate for an extended time. This lower charge rate will ensure that the BESS can charge up to 12 hours during the day. The 6 MVA charge rate represents a more dynamic control scheme where the BESS charges at its full capability during peak solar production to enable more PV generation on the distribution feeder. However, if the BESS charges at 6 MVA, it can only sustain this charge rate continuously for up to 4

hours daily. PNM will need to continue monitoring the energy component of BESS solutions. The BESS charge rate may need to vary throughout the day to manage power flow on the distribution feeder while not filling the BESS too quickly to maintain enough storage to last through the solar day. Table 3-5 shows the summary results for all feeders at PV saturation evaluated.

Table 3-5: BESS Charging Hosting Capacity Results with Feeder Upgrades

Feeder	Feeder Rating kVA	New Protective Device Units	Synergi Maximum Hosting Capacity with 2 MVA Charging kVA	Synergi Maximum Hosting Capacity with 6 MVA Charging kVA
A10083	11,231	0	5,501	9,312
ARIB11	11,231	1	5,011	6,941
COLL12	11,231	0	4,698	7,968
DEMW11	12,429	0	3,208	6,102
ELCE11	11,231	0	5,786	7,844
GOLD13	12,429	0	4,037	7,838
HOND12	12,429	0	5,603	9,468
JARA12	11,231	0	4,846	7,166
LOHO12	11,231	1	4,853	7,111
LOHO13	11,231	0	2,157	5,346
LOHO14	11,231	0	3,512	7,129
LSMO12	11,231	0	3,373	6,980
LSMO21	11,231	0	5,161	8,074
PROG13	11,231	0	6,120	7,391
SCEN12	11,231	0	4,179	6,453
SOCO12	11,231	0	5,012	6,515
STPE12	11,231	0	4,289	6,207
TOME12	11,231	0	4,299	6,460

3.2.4.1 BESS Charging at 2 MVA / 6 MVA without Feeder Upgrades

For distribution feeders where significant amounts of feeder upgrades were identified, an additional scenario was analyzed to determine if a BESS alone would provide increased hosting capacity while limiting the amount of capital investment. Only a small subset of the distribution feeders studied were evaluated without feeder upgrades applied. For this subset of feeders, the existing large-scale PV facility was located further away from the substation.

Table 3-6: Hosting Capacity Results with BESS Charging and no Feeder Upgrades

Feeder	Feeder Rating kVA	New Protective Device Units	Synergi Maximum Hosting Capacity with 2 MVA Charging kVA	Synergi Maximum Hosting Capacity with 6 MVA Charging kVA
ELCE11	9,288	0	3,630	4,550
PROG13	9,936	0	4,850	5,680
SCEN12	8,208	0	2,910	4,480
STPE12	9,288	0	1,280	1,600

3.2.4.2 Distribution Feeder Inverter Capacity Limit

PNM's DER integration plan indicates a PV penetration limit of 150% of the feeder rating. This planning criterion is intended to provide another milestone for distribution feeders where further study and evaluation would be required to understand the implications of allowing PV penetration higher than 150% of the feeder rating. PNM's concern is that the distribution system could become more difficult to operate and maintain power quality for customers as local generation levels exceed local consumption by a significant amount.

For a distribution feeder upgraded to the standard PNM rating of 11.2 MVA, a PV penetration limit of 150% of the feeder rating would allow for up to 16.8 MVA of interconnected PV capacity. In some instances, the hosting capacity results presented in the table above were limited to align with this planning criterion.

3.2.4.3 Protection Upgrades with BESS

For these scenarios, additional protective devices that will be necessary when installing BESS on certain distribution feeders were identified. Adding BESS resources to a distribution feeder allows for better regulation of feeder power flow and increased hosting capacity. However, BESS is also a source of generation when discharging and can complicate protection schemes if both existing PV and the BESS feed into a fault. Reclosers and other sectionalizing devices can be used to protect distribution feeders from faults and limit the impact on customers.

3.2.5 Build a Dedicated Feeder to Existing Large-Scale PV Sites

Many utilities around the country construct dedicated distribution feeders to large-scale PV facilities. This practice has resulted in higher upfront interconnection costs but has simplified the distribution system operation and planning efforts. Historically, PNM has interconnected large-scale PV facilities to shared distribution feeders. This practice has resulted in challenges to interconnect new customer PV generation to the PNM system. A dedicated feeder scenario was evaluated to identify the hosting capacity benefit to PNM customers by moving these large-scale PV sites to a new dedicated feeder. Table 3-7 shows the summary results of this dedicated feeder buildout scenario.

Table 3-7: Dedicated Feeder Buildout Results

Existing Feeder	Existing Feeder Rating kVA	Substation Upgrade Required?	Feeder Cable Buildout Mi	Main Line Conductor Mi	Synergi Maximum Hosting Capacity kVA (For Existing Feeder)
A10083	11,663	No	0.13	5.3	8,102
ARIB11	9,331	Yes	0.05	0.15	11,061
COLL12	9,072	Yes	0.25	7.1	9,063
DEMW11	10,278	Yes	0.03	0.5	9,380
ELCE11	9,288	Yes	0.02	8.6	10,110
GOLD13	12,429	No	0.07	1.8	12,882
HOND12	10,039	Yes	0.08	3.0	9,994
JARA12	11,231	No	0.04	7.6	12,011
LOHO12	9,288	Yes	0.05	1.8	10,818
LOHO13	11,231	Yes	0.19	2.7	10,165
LOHO14	11,231	Yes	0.03	1.7	11,376
LSMO12	9,288	Yes	0.06	1.2	9,296
LSMO21	9,288	Yes	0.09	0.7	10,196
PROG13	9,936	Yes	3	6.9	10,901
SCEN12	9,936	Yes	1.7	4.3	9,906
SOCO12	9,288	Yes	0.03	2.2	10,350
STPE12	8,208	Yes	0.43	3.4	8,367
TOME12	9,288	Yes	0.3	4.9	11,537

3.2.5.1 Substation Upgrades

Upstream infrastructure must be in place to build a new dedicated feeder for the existing large-scale PV facilities. At the Jarales and Gold substations, there was a vacant position in the substation switchgear that was ready for a new feeder buildout. The capital improvements to build the new dedicated feeder were significantly lower in this situation. For 15 feeders studied, substation upgrades were required to enable the buildout of a new distribution feeder. Each substation is unique, and the capital needed to build a new distribution feeder varies. Some of the

necessary upgrades were to replace a substation switchgear, upgrade the existing substation transformer to the new PNM standard size, or even construct a new substation because the existing substation has no room for expansion/upgrade. Substation upgrades can require long-lead equipment, significant engineering and design work, land acquisition, and significant cost.

3.2.5.2 Additional Load Serving Benefit

For 15 of the feeders evaluated, a substation upgrade was required to enable the buildout of a new distribution feeder to serve an existing large-scale PV facility. While upgrading a substation transformer or constructing a new substation transformer is a significant capital project, it also provides an additional opportunity to serve the load. Substation transformers are shared between 2-4 distribution feeders. If a new substation or expansion of an existing substation is required to build a new dedicated feeder to serve the existing large-scale PV, additional feeders could be constructed to serve economic development or traditional customer load. However, it is essential to note that while these PV-saturated feeders are limited in the ability to host new PV generation, all feeders in this evaluation have some remaining load-serving capacity. Typically, the areas of PNM's system experiencing significant economic development interest are not where feeders are at PV saturation.

3.2.6 Hosting Capacity Improvement Observations

Table 3-8 shows the maximum hosting capacity observed for feeders at PV saturation for each scenario evaluated. The base case evaluation observed limited hosting capacity for these saturated feeders. System improvements were shown to increase the maximum hosting capacity by increasing feeder ratings and/or installing a BESS that charges from excess PV generation. Building a dedicated feeder to the existing large-scale PV facilities generally unlocked the most hosting capacity for existing distribution feeders. Figure 3-2 visually shows the maximum hosting capacity results.

Figure 3-2: Maximum Synergi Hosting Capacity Results

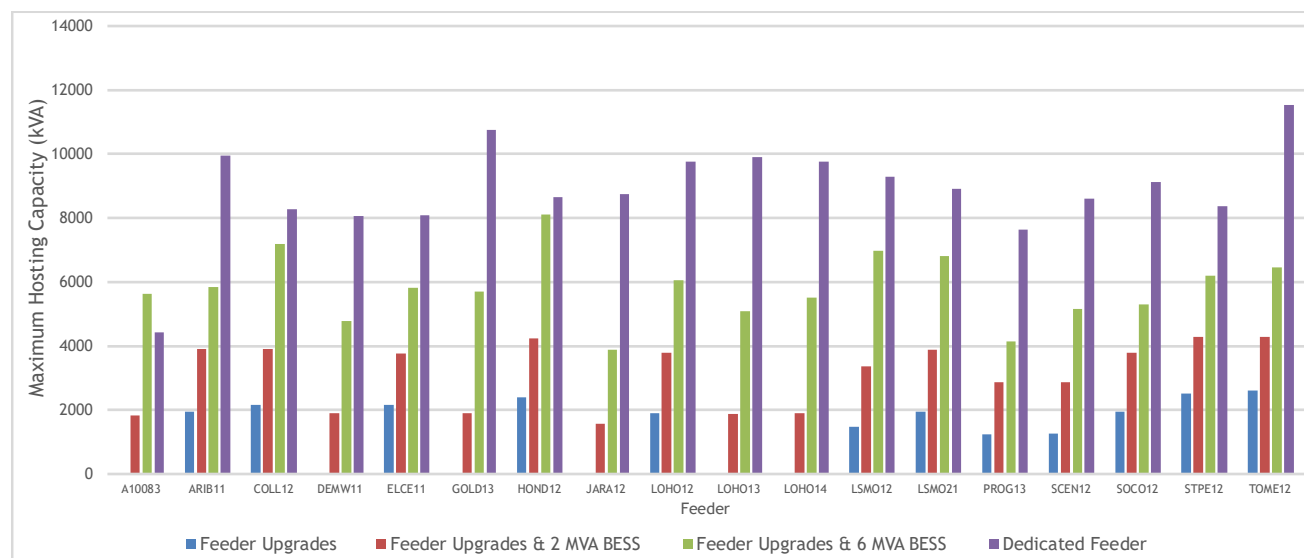


Table 3-8: Maximum Synergi Hosting Capacity Results Summary

Feeder	Base Case Synergi Max Hosting Capacity kVA	Feeder Upgrades Synergi Max Hosting Capacity kVA	2 MVA BESS Charging Synergi Max Hosting Capacity kVA	6 MVA BESS Charging Synergi Max Hosting Capacity kVA	Dedicated Feeder Buildout Synergi Max Hosting Capacity kVA
A10083	3,703	3,675	5,501	9,312	8,102
ARIB11	1,099	2,100*	5,011	6,941	11,061
COLL12	781	1,800*	4,698	7,968	9,063
DEW11	1,308	1,280**	3,208	6,102	9,380
ELCE11	2,019	4,179	5,786	7,844	10,110
GOLD13	2,139	2,139	4,037	7,838	12,882
HOND12	1,352	3,741	5,603	9,468	9,994
JARA12	3,269	3,269	4,846	7,166	12,011
LOHO12	1,060	2,961	4,853	7,111	10,818
LOHO13	267	267	2,157	5,346	10,165
LOHO14	1,616	1,616	3,512	7,129	11,376
LSMO12	Thermal Violation	1,469	3,373	6,980	9,296
LSMO21	1,272	3,216	5,161	8,074	10,196
PROG13	3,255	4,506	6,120	7,391	10,901
SCEN12	1,297	2,559	4,179	6,453	9,906
SOCO12	1,224	3,167	5,012	6,515	10,350
STPE12	Thermal Violation	2,517	4,289	6,207	8,367
TOME12	Thermal Violation	2,620	4,299	6,460	11,537

*The Ariba Substation and College Substation transformers have high PV penetration. The substation transformer limits the maximum hosting capacity after feeder upgrades are performed.

**The Deming West Substation transformer is more limiting to hosting capacity than the feeder rating. After feeder upgrades are performed, losses decrease on the feeder, but power flow through the transformer increases, so the hosting capacity decreases by a small amount.

3.3 Financial Analysis - Feeders at PV saturation

Two perspectives were used to evaluate all hosting capacity improvement solutions on PV-saturated feeders. These perspectives differ by the value attributed to hosting capacity improvement and other associated system benefits related to the evaluated solutions.

3.3.1 Feeder Upgrades

Feeder Upgrades primarily target conductor and cable upgrades to bring each distribution feeder to the maximum PNM standard rating. The capital project costs varied greatly as the configuration of each distribution feeder also influenced the number of conductors and equipment upgrades. Table 3-9 shows the financial analysis results for the feeder upgrade solution. Feeder upgrades were not applicable to all feeders at PV saturation. If the feeder is already constructed to the maximum PNM ratings, no hosting capacity increase or benefit-cost scoring was provided.

Table 3-9: Feeder Upgrades Financial Analysis Results

Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
A10083	3,675	3,675	N/A	-	-	-
ARIB11	1,099	3,043	1,944	\$174,850	6.23	6.64
COLL12	781	2,936	2,155	\$211,994	4.81	5.13
DEMW11	1,308	1,277	-31*	\$343,013	-	-
ELCE11	2,019	4,179	2,160	\$4,502,143	0.48	0.51
GOLD13	2,139	2,139	N/A	-	-	-
HOND12	1,352	3,741	2,389	\$383,946	6.22	6.63
JARA12	3,269	3,269	N/A	-	-	-
LOHO12	1,060	2,961	1,901	\$174,850	10.87	11.59
LOHO13	267	267	N/A	-	-	-
LOHO14	1,616	1,616	N/A	-	-	-
LSMO12	Thermal Violation	1,469	1,469	\$46,562	31.55	33.64
LSMO21	1,272	3,216	1,944	\$174,590	11.13	11.87
PROG13	3,255	4,506	1,252	\$7,164,255	0.17	0.19
SCEN12	1,297	2,559	1,262	\$3,904,518	0.32	0.34
SOCO12	1,224	3,167	1,943	\$12,053,358	0.16	0.17
STPE12	Thermal Violation	2,517	2,517	\$2,275,192	1.11	1.18
TOME12	Thermal Violation	2,620	2,620	\$60,570	43.26	46.11

* The Deming West Substation transformer is more limiting to hosting capacity than the feeder rating. After feeder upgrades are performed, losses decrease on the feeder but power flow through the transformer increases, so the hosting capacity decreased by a small amount.

3.3.2 Feeder Upgrades and BESS Charging at 2 MVA

The cost of this capital project alternative was significant due to the investment in the battery system. First, all feeders were evaluated with the BESS and applicable feeder upgrades to provide the greatest increase in hosting capacity. For some of the feeders, upgrades were significant and drove up the total project cost. In these instances, 1898 & Co. also evaluated constructing only the BESS and not the feeder upgrades. Table 3-10 shows the financial analysis results for the feeder upgrades and 2 MVA BESS charging solution.

Table 3-10: Feeder Upgrades and BESS Charging at 2 MVA Financial Analysis Results

Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
A10083*	-	-	-	-	-	-
ARIB11	1,099	5,011	3,912	\$14,474,850	0.27	1.04
COLL12	781	4,698	3,917	\$14,511,994	0.27	1.04
DEMW11	1,308	3,208	1,901	\$14,643,013	0.13	0.91
ELCE11	2,019	5,786	3,768	\$18,802,143	0.20	0.83
GOLD13*	-	-	-	-	-	-
HOND12	1,352	5,603	4,251	\$14,683,946	0.29	1.05
JARA12*	-	-	-	-	0.11	0.91
LOHO12	1,060	4,853	3,793	\$14,474,850	0.26	1.03
LOHO13*	-	-	-	-	-	-
LOHO14*	-	-	-	-	-	-
LSMO12	Thermal Violation	3,373	3,373	\$14,346,562	0.24	1.02
LSMO21	1,272	5,161	3,888	\$14,474,590	0.27	1.04
PROG13	3,255	6,120	2,866	\$21,464,255	0.13	0.70
SCEN12	1,297	4,179	2,882	\$18,204,518	0.16	0.81
SOCO12	1,224	5,012	3,788	\$26,353,358	0.14	0.62
STPE12	Thermal Violation	4,289	4,289	\$16,575,192	0.26	0.95
TOME12	Thermal Violation	4,299	4,299	\$14,360,570	0.30	1.07

*This feeder is already built to the maximum PNM standard rating. Results for the 2 MVA BESS only solution are shown in the next table.

3.3.2.1 BESS Charging at 2 MVA without Feeder Upgrades

Four feeders required significant upgrades to increase their ratings. These feeders were also evaluated to determine if only the BESS was constructed, and no other improvements were performed. The benefit-cost ratio scores did improve with the lower overall project cost. Five of the feeders evaluated are already built to the maximum PNM standard ratings. For these five feeders, analysis was performed with only the BESS upgrades. Table 3-11 shows the financial analysis results for the 2 MVA BESS charging solution without feeder upgrades.

Table 3-11: BESS Charging at 2 MVA without Feeder Upgrades Financial Analysis Results

Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic Financial Benefit Cost Ratio Score
A10083	3,675	5,501	1,826	\$14,300,000	0.13	0.92
ELCE11	2,019	3,630	1,611	\$14,300,000	0.11	1.57
GOLD13	2,139	4,037	1,899	\$14,300,000	0.13	0.93
JARA12	3,269	4,846	1,577	\$14,300,000	0.11	0.91
LOHO13	267	2,157	1,890	\$14,300,000	0.13	0.93
LOHO14	1,616	3,512	1,895	\$14,300,000	0.13	0.93
PROG13	3,255	4,850	1,595	\$14,300,000	0.11	1.17
SCEN12	1,297	2,910	1,613	\$14,300,000	0.11	1.62
STPE12	Thermal Violation	1,280	1,280	\$14,300,000	0.09	1.54

3.3.3 Feeder Upgrades with BESS Charging at 6 MVA

The cost of this capital project alternative was significant due to the investment in the battery system. First, all feeders were evaluated with the BESS and Feeder Upgrades. For some of the feeders, feeder upgrades were significant and drove up the total project cost. In these instances, 1898 & Co. also evaluated the benefit-cost ratio of constructing only the BESS and not the feeder upgrades. Table 3-12 shows the financial analysis results for the feeder upgrades and 6 MVA BESS charging solution.

Table 3-12: Feeder Upgrades with BESS Charging at 6 MVA Financial Analysis Results

Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
A10083*	-	-	-	-	-	-
ARIB11	1,099	6,941	5,842	14,524,850	0.40	1.87
COLL12	781	7,968	7,187	14,561,994	0.49	1.95
DEMW11	1,308	6,102	4,794	14,693,013	0.33	1.79
ELCE11	2,019	7,844	5,825	18,852,143	0.31	1.17
GOLD13*	-	-	-	-	-	-
HOND12	1,352	9,468	8,116	14,733,946	0.55	1.99
JARA12*	-	-	-	-	-	-
LOHO12	1,060	7,111	6,051	14,524,850	0.42	1.89
LOHO13*	-	-	-	-	-	-
LOHO14*	-	-	-	-	-	-
LSMO12	Thermal Violation	6,980	6,980	14,396,562	0.48	1.96
LSMO21	1,272	8,074	6,801	14,524,590	0.47	1.93
PROG13	3,255	7,391	4,137	21,514,255	0.19	1.23
SCEN12	1,297	6,453	5,156	18,254,518	0.28	1.51
SOCO12	1,224	6,515	5,291	26,403,358	0.20	1.10
STPE12	Thermal Violation	6,207	6,207	16,625,192	0.37	1.69
TOME12	Thermal Violation	6,460	6,460	14,410,570	0.45	1.92

*This feeder is already built to the maximum PNM standard rating. Results for the 6 MVA BESS only solution are shown in the next table.

3.3.3.1 BESS Charging at 6 MVA without Feeder Upgrades

Significant feeder upgrades were required to increase the rating for the four feeders. These feeders were also evaluated to determine if only the BESS was constructed and no other feeder upgrades were made. The benefit-cost ratio scores did improve with the lower overall project cost. Table 3-13 shows the financial analysis results for the 6 MVA BESS charging solution without feeder upgrades.

Table 3-13: BESS Charging at 6 MVA without Feeder Upgrades Financial Analysis Results

Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
A10083	3,675	9,312	5,637	\$14,350,000	0.39	1.88
ELCE11	2,019	4,550	2,531	\$14,350,000	0.18	2.92
GOLD13	2,139	7,838	5,699	\$14,350,000	0.40	1.88
JARA12	3,269	7,166	3,897	\$14,350,000	0.27	1.53
LOHO13	267	5,346	5,079	\$14,350,000	0.35	1.85
LOHO14	1,616	7,128	5,512	\$14,350,000	0.38	1.87
PROG13	3,255	5,680	2,425	\$14,350,000	0.17	2.16
SCEN12	1,297	4,480	3,183	\$14,350,000	0.22	3.08
STPE12	Thermal Violation	1,600	1,600	\$14,350,000	0.11	2.17

3.3.4 Dedicated Feeder Buildout

Most feeders evaluated must include a substation transformer upgrade or a new substation transformer to successfully build out a new dedicated feeder and improve hosting capacity in the area. The capital project costs were impacted by the amount of conductor buildout required, which varied based on the distance of existing solar facilities from the substation. Also, some cost sharing of substation upgrades can be experienced among the Lost Horizon Substation feeders and the Los Morros Substation feeders. Table 3-14 shows the financial analysis results for the dedicated feeder buildout solution.

Table 3-14: Dedicated Feeder Buildout Financial Analysis

Existing Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic Financial Benefit Cost Ratio Score
A10083	3,675	8,102	4,427	\$2,595,082	1.71	1.82
ARIB11	1,099	11,061	9,961	\$8,357,645	1.19	1.27
COLL12	781	9,063	8,283	\$11,503,202	0.72	0.77
DEMW11	1,308	9,380	8,073	\$8,756,768	0.92	0.98
ELCE11	2,019	10,110	8,091	\$11,902,457	0.68	0.72
GOLD13	2,139	12,882	10,743	\$1,286,828	8.35	8.90
HOND12	1,352	9,994	8,642	\$9,679,126	0.89	5.49
JARA12	3,269	12,011	8,742	\$4,040,940	2.16	2.31
LOHO12	1,060	10,818	9,758	\$3,744,957	2.61	2.78
LOHO13	267	10,165	9,898	\$4,131,806	2.40	2.55
LOHO14	1,616	11,376	9,759	\$3,704,661	2.63	2.81
LSMO12	Thermal Violation	9,296	9,296	\$4,777,065	1.95	2.07
LSMO21	1,272	10,196	8,924	\$4,593,086	1.94	2.07
PROG13	3,255	10,901	7,647	\$18,415,494	0.42	0.44
SCEN12	1,297	9,906	8,608	\$14,097,893	0.61	0.65
SOCO12	1,224	10,350	9,126	\$9,224,026	0.99	1.05
STPE12	Thermal Violation	8,367	8,367	\$10,647,470	0.79	0.84
TOME12	Thermal Violation	11,537	11,537	\$10,392,631	1.11	1.18

3.3.5 Capital Project Portfolios

Two separate portfolios were determined based on the two benefit-cost perspectives that were scored for this evaluation. Table 3-15 represents the highest-scoring solutions portfolio based on hosting capacity improvement relative to the cost perspective and the holistic financial benefit-cost perspective.

The dedicated feeder buildout or feeder upgrade solutions scored highest from the hosting capacity improvement perspective, relative to the cost, as these were solutions that provided the greatest increase to hosting capacity for a lower cost. This portfolio would result in a total

investment of six new substation transformers to enable the buildout of eight distributed feeders. Feeder upgrades that scored highest typically required small investments but only resulted in marginal increases in hosting capacity. Additional upgrades would be required in the future to further increase hosting capacity beyond the marginal feeder upgrade increase.

The holistic financial analysis considered the other benefits provided by a BESS installation in addition to increasing hosting capacity. This holistic perspective resulted in the 6 MVA BESS solution scoring highest for each feeder in most cases. However, feeder upgrades were not desirable for some feeders because of the high cost. For additional feeders, feeder upgrades are not applicable because they are presently constructed to the maximum standard. Feeder upgrades scored the highest for six of the feeders evaluated. Feeder upgrades provide a marginal increase to hosting capacity, which will allow customers to interconnect new PV in the near term, but as PV penetration continues to increase, additional solutions will be required. A 6 MVA BESS could be added to enable more customer PV generation, as PV penetration levels necessitate. This portfolio represents six 6 MVA BESS installations within the PNM distribution system, totaling 36 MVA of capacity and 144 MWH of energy storage.

Table 3-15: PV-Saturated Feeders Hosting Capacity Analysis Results

Hosting Capacity Benefit Cost Portfolio					Holistic System Benefit Cost Portfolio				
Feeder	Capital Project Category	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Feeder	Capital Project Category	Net Hosting Capacity Increase kVA	Capital Project Cost	Holistic Financial Benefit Cost Ratio Score
A10083	Dedicated Feeder	4,427	\$2,595,082	1.71	A10083	6 MVA BESS	5,637	\$14,350,000	1.88
ARIB11	Feeder Upgrades	1,090	\$174,850	6.23	ARIB11	Feeder Upgrades	1,090	\$174,850	6.64
COLL12	Feeder Upgrades	1,020	\$211,994	4.81	COLL12	Feeder Upgrades	1,020	\$211,994	5.13
DEMW11	Dedicated Feeder	8,073	\$8,756,768	0.92	DEMW11	Feeder Upgrades & 6 MVA BESS	4,794	\$14,693,013	1.79
ELCE11	Dedicated Feeder	8,091	\$11,902,457	0.68	ELCE11	6 MVA BESS	2,531	\$14,350,000	2.92
GOLD13	Dedicated Feeder	10,743	\$1,286,828	8.35	GOLD13	Dedicated Feeder	10,743	\$1,286,828	8.90
HOND12	Feeder Upgrades	2,389	\$383,946	6.22	HOND12	Feeder Upgrades	2,389	\$383,946	6.63
JARA12	Dedicated Feeder	8,742	\$4,040,940	2.16	JARA12	Dedicated Feeder	8,742	\$4,040,940	2.31
LOHO12	Dedicated Feeder	9,758	\$3,744,957	2.61	LOHO12	Dedicated Feeder	9,758	\$3,744,957	2.78
LOHO13	Dedicated Feeder	9,898	\$4,131,806	2.40	LOHO13	Dedicated Feeder	9,898	\$4,131,806	2.55
LOHO14	Dedicated Feeder	9,759	\$3,704,661	2.63	LOHO14	Dedicated Feeder	9,759	\$3,704,661	2.81
LSMO12	Feeder Upgrades	1,469	\$46,562	31.56	LSMO12	Feeder Upgrades	1,469	\$46,562	33.64
LSMO21	Feeder Upgrades	1,944	\$174,590	11.13	LSMO21	Feeder Upgrades	1,944	\$174,590	11.87
PROG13	Dedicated Feeder	7,647	\$18,415,494	0.42	PROG13	6 MVA BESS	2,425	\$14,350,000	2.16
SCEN12	Dedicated Feeder	8,608	\$14,097,893	0.61	SCEN12	6 MVA BESS	3,183	\$14,350,000	3.08
SOCO12	Dedicated Feeder	9,126	\$9,224,026	0.99	SOCO12	Feeder Upgrades & 6 MVA BESS	5,291	\$26,403,358	1.10
STPE12	Feeder Upgrades	2,517	\$2,275,192	1.11	STPE12	Feeder Upgrades & 6 MVA BESS	6,207	\$16,625,192	1.69
TOME12	Feeder Upgrades	2,620	\$60,570	43.26	TOME12	Feeder Upgrades	2,620	\$60,570	46.11
Total	-	107,921	\$85,288,614	-	Total	-	89,502	\$133,083,266	-

4.0 Hosting Capacity Analysis - Community Solar Program Feeders

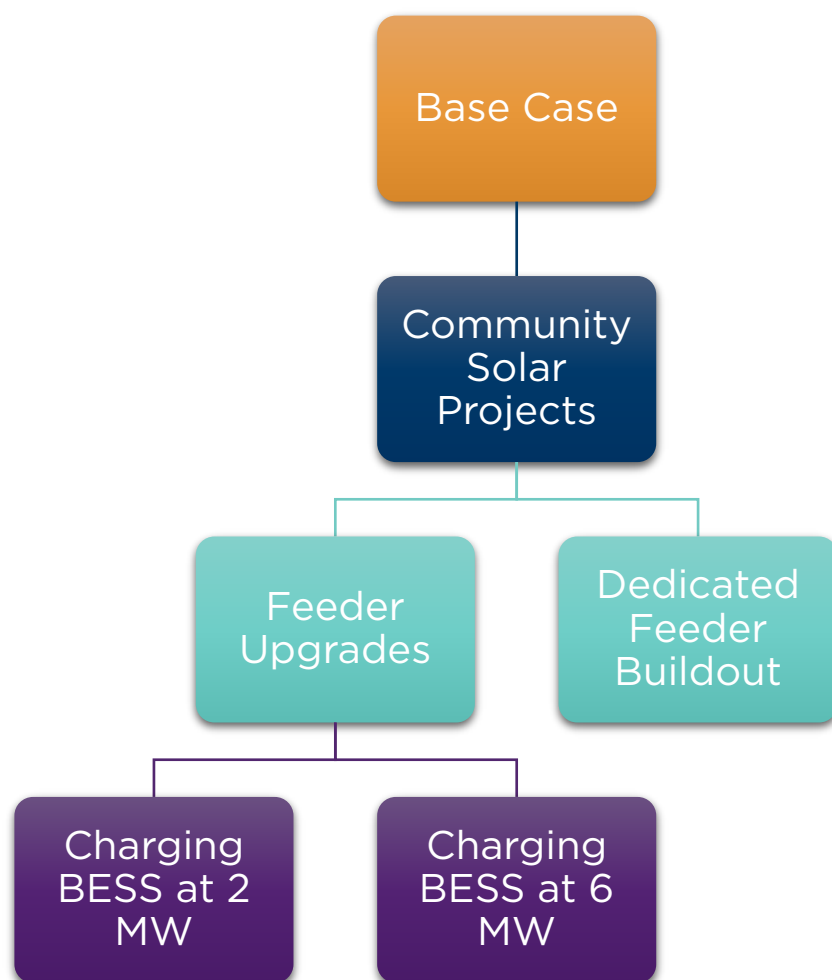
4.1 Hosting Capacity Improvement Solutions Evaluation Approach - Community Solar Projects

For the nine additional PNM feeders listed in Table 2-2, the existing hosting capacity was established using Synergi's incremental hosting capacity analysis and power flow simulations. Next, the community solar project improvements were added to the model. Once the model captured all upgrades necessary for the community solar project to interconnect, various solutions to increase hosting capacity were evaluated. A Class 4 cost estimate was performed for each hosting capacity improvement solution evaluated. With the hosting capacity improvement identified and the cost estimate documented, a financial analysis was performed to determine the recommended capital project portfolio for these nine feeders.

4.1.1 Hosting Capacity Analysis and Capital Project Solutions

PNM has nine feeders with pending Community Solar projects that were analyzed for this evaluation. Minimum daylight load was the basis for this analysis to understand the limits of the system when there is the least amount of customer load on the feeder to consume PV generation. There are six specific scenarios that were evaluated for each distribution feeder: base case hosting capacity, hosting capacity with Community Solar Projects and improvements, hosting capacity with community solar project improvements and additional traditional system improvements, hosting capacity with community solar project improvements and a 6 MW battery operating at 2 MW or 6 MW, and a dedicated feeder built to serve the existing large-scale solar facilities. The scenarios are outlined below in Figure 4-1.

Figure 4-1: Hosting Capacity Analysis and Capital Projects Approach - Community Solar Projects



The process is delineated as follows and explains the major steps of the analysis:

Step 1 - Base Case Hosting Capacity Analysis

1. Document the current system capability.

Step 2 - Community Solar Project

1. Perform a hosting capacity analysis to determine the remaining hosting capacity after interconnecting Community solar projects and applying the system improvements required by the System Impact Study.

Step 3 -Community Solar Project and Feeder Upgrades

1. Construct additional capital projects in the feeder model to increase hosting capacity after the Community solar project and required System Impact Study system improvements are included, such as conductor upgrades, protective device upgrades, new equipment, etc.
2. Perform hosting capacity analysis and document the new system capability with the capital projects in place.

Step 4 - Community Solar Project, Feeder Upgrades and Charging BESS at 2 MVA

1. Construct a BESS co-located with the added Community Solar PV system set to charge at 2 MVA.
2. Perform hosting capacity analysis and document the new system capability with the Community Solar Project in place and BESS charging at 2 MVA.

Step 5 - Community Solar Project, Feeder Upgrades and Charging BESS at 6 MVA

3. Construct a BESS co-located with the added Community Solar PV system set to charge at 6 MVA.
4. Perform hosting capacity analysis and document the new system capability with the Community Solar Project in place and BESS charging at 6 MVA.

Step 6 - Build a Dedicated Feeder to Community Solar PV Site

1. Identify the substation upgrades and conductor buildout required to construct a dedicated feeder to the Community Solar PV site.
2. Move the Community Solar PV system to a new dedicated feeder.
3. No upgrades performed for the existing feeder that serves PNM customers.
4. Perform hosting capacity analysis for the existing feeder that serves PNM customers and document the new system capability with the Community Solar PV system moved to a dedicated feeder.

4.1.2 Financial Analysis

Two perspectives were used to evaluate all solutions to improve hosting capacity on PV-saturated feeders. These perspectives differ by valuing hosting capacity improvement alone rather than considering the overall system benefits, including both transmission and distribution system benefits.

4.2 Hosting Capacity Improvement Solutions Analysis - Community Solar Projects

Table 4-1 shows the nine feeders that were identified to have approved community solar projects. The feeder ratings were updated with new ratings after the community solar project improvements were applied. The feeder rating utilization is calculated by comparing the total approved PV capacity, using an installed generation report, plus the maximum output of each community solar project, against the feeder rating. Various system improvements were evaluated in this section to improve the hosting capacity of these feeders.

Table 4-1: Community Solar Project Feeders

Feeder	Region	Feeder Rating kVA	Approved PV Capacity kVA	Community Solar Projects	Community Solar Project Size kVA	Feeder Rating Utilization %
A10012	Alamogordo	11,663	9,030	1*	1,500*	90%
ELCE12	Valencia	11,231	1,104	2	7,485	76%
HOND11	Deming	12,429	251	2	8,650	72%
LD1000	Lordsburg	7,192	942	1	5,000	82%
SL0017	Silver City	12,959	931	1	7,250	63%
TULA13	Tularosa	11,231	402	1	9,750	90%
TULA14	Tularosa	11,231	189	2	7,375	67%
VERA22	Sandoval	11,231	2,811	1	5,000	78%
VNBU12	Clayton	9,287	6	1	5,000	53%

*Note: Feeder A10012 Project is a 1.5MVA SGIA.

4.2.1 Base Case Hosting Capacity Analysis

Using the process outlined in Section 2 of PNM's first Hosting Capacity report, initial base case models were created for the nine feeders identified as having approved community solar projects. Table 4-2 shows the Synergi calculated results observed for each feeder based on the existing PNM system. All the feeders are observed to have ample hosting capacity and should allow interconnections of the community solar projects, barring small conductor, protection equipment, and transformer capacity constraints.

Table 4-2: Synergi Base Case Hosting Capacity Results

Feeder	Feeder Rating kVA	Synergi Existing Gen kVA	Synergi MDL kW	Synergi MDL kVA	Synergi MDGL kVA	Synergi Max Voltage	Synergi Max Load %	Synergi Maximum Hosting Capacity kVA
A10012	11,663	10,074	-7,928	8,664	2,489	125.0	77.4	3,753
ELCE12	9,071	872	1,005	1,030	2,392	122.4	41.2	11,503
HOND11	6,454	170	116	117	280	122.1	2.4	6,569
LD1000	7,192	659	522	579	1,160	125.6	18.3	7,714
SL0017	9,331	834	711	795	1,551	125.3	10.3	11,014
TULA13	5,832	329	35	130	365	125.1	2.6	5,867
TULA14	5,832	151	354	429	506	125.1	15.1	6,185
VERA22	11,231	2,811	391	610	3,698	124.1	11.9	11,621
VNBU12	4,428	6	147	179	188	122.0	4.0	4,575

Note: Negative MDL kW indicates reverse power flow on the feeder.

4.2.1.1 Feeders with Max Voltage Near Planning Criteria

Five feeders within this evaluation experienced maximum voltage above 125 V, but did not exceed the planning criteria. The generation location on the feeder, conductor sizes, and other factors will influence the voltage rise that can result from PV generation.

4.2.2 Community Solar Project Implementation

The Community Solar Program projects triggered system improvements that needed to be completed before the solar facility's interconnection; these improvements were applied in the models. A power flow analysis was performed to determine whether all planning criteria were maintained. Table 4-3 summarizes the power flow results and the remaining hosting capacity after the interconnection of the community solar projects. All feeders are observed to experience reverse power flow during the minimum daytime loading. After the interconnections of the Community Solar Program projects, some hosting capacity remains for all feeders.

Table 4-3: Synergi Power Flow Analysis with Community Solar Project Interconnections Modeled

Feeder	Feeder Rating kVA	Synergi Existing Gen kVA	Synergi MDL kW	Synergi MDL kVA	Synergi MDGL kVA	Synergi Max Voltage	Synergi Max Load %	Synergi Maximum Hosting Capacity kVA
A10012	11,663	10,074	-7,928	8,664	2,489	125.0	77.4	3,753
ELCE12	11,231	8,372	-6,308	6,418	2,394	124.1	58.9	4,923
HOND11	12,429	8,895	-8,211	8,300	285	124.9	79.6	4,218
LD1000	7,192	5,687	-4,609	4,628	1,003	125.5	41.4	2,888
SL0017	12,959	8,122	-5,999	6,136	1,549	125.5	57.3	5,741
TULA13	11,231	10,261	-9,552	9,632	365	125.4	82.5	1,678
TULA14	11,231	7,846	-6,916	6,923	507	125.4	74.4	4,314
VERA22	11,231	7,793	-4,334	4,365	3,722	125.3	79.5	6,897
VNBU12	9,287	5,009	-4,801	4,818	188	123.1	80.6	4,271

Note: Negative MDL kW indicates reverse power flow on the feeder.

4.2.2.1 Feeders with Max Voltage Near Planning Criteria

Six feeders within this evaluation experienced a maximum voltage above 125 V, but did not exceed the planning criteria. Four of the six feeders experienced a voltage increase once the community solar projects were interconnected compared to the base case scenario.

4.2.3 Community Solar Projects and Feeder Upgrades

The Community Solar Program projects system improvements brought six out of the nine feeders up to the PNM standard. Feeders Lordsburg 1000 and Van Buren 12 still have room to improve through traditional system improvements. Both feeders have nonstandard transformers that did not need to be upgraded for the Community Solar Projects to interconnect successfully. Additionally, the Van Buren 12 feeder getaway was upgraded to 750 AL UG cable during the Community Solar Program system improvement because that was sufficient to interconnect the project successfully. This feeder getaway could be upgraded to 750 CU UG cable for further hosting capacity improvement.

Table 4-4 Shows the summary of results and indicates the amount/type of system improvements evaluated for each feeder. Each feeder was individually assessed to determine the appropriate system improvements to increase hosting capacity. Due to their low ratings, the substation transformers for feeders Lordsburg 1000 and Van Buren 12 are the main limiting factors for the

hosting capacity available. These transformers must be upgraded to raise the feeder ratings to the maximum PNM standard for Lordsburg 1000 and Van Buren 12. Hondale Feeder 11 (HOND11) only required a small amount of conductor upgrade to raise the feeder rating. The remaining feeders in this group have already been constructed to the maximum PNM standard ratings. The feeder upgrade scenario did not apply to these feeders.

Table 4-4: Feeder Upgrades Summary Results

Feeder	Feeder Rating kVA	Feeder Cable Upgrade Mi	New Transformer Units	Synergi Maximum Hosting Capacity kVA
HOND11	12,429	0.05	-	4,220
LD1000	11,231	-	1	7,060
VNBU12	11,231	0.02	1	6,430

4.2.4 Community Solar Projects and Charging BESS at 2 MVA / 6 MVA

The feeder upgrades discussed in the previous section can bring all community solar feeders to current PNM construction standards and maximum feeder rating. Next, two different BESS charge rates were evaluated for each distribution feeder to document the increase in hosting capacity. Table 4-5 shows the summary results for all community solar feeders evaluated.

Table 4-5: BESS Charging Hosting Capacity Results with Community Solar Projects

Feeder	Feeder Rating kVA	Synergi Maximum Hosting Capacity with 2 MVA Charging kVA	Synergi Maximum Hosting Capacity with 6 MVA Charging kVA
A10012	12,959	5,548	9,331
ELCE12	11,231	6,827	8,771
HOND11	12,429	6,085	9,969
LD1000	11,231	8,994	12,973
SL0017	12,959	7,470	11,229
TULA13	11,231	3,588	7,487
TULA14	11,231	6,253	10,024
VERA22	11,231	8,707	9,457
VNBU12	11,231	8,836	12,854

4.2.5 Build a Dedicated Feeder to Existing Large-Scale PV Sites

A dedicated feeder scenario was last evaluated to identify the hosting capacity benefit to PNM customers by moving these Community Solar projects to a new dedicated feeder. Some feeders contain multiple Community Solar projects. So, all community solar facilities allocated to the feeder analyzed were moved to the same dedicated feeder. Table 4-6 shows the summary results of this dedicated feeder buildout scenario.

Table 4-6: Dedicated Feeder Buildout Results

Existing Feeder	Existing Feeder Rating kVA	Substation Upgrade Required?	Feeder Cable Buildout Mi	Main Line Conductor Mi	Synergi Maximum Hosting Capacity kVA (For Existing Feeder)
A10012	12,959	Yes	0.03	5.30	12,137
ELCE12	11,231	Yes	0.02	-	12,238
HOND11	12,429	No	0.05	5.09	12,544
LD1000	7,192	Yes	0.11	0.72	7,485
SL0017	12,959	Yes	-	6.45	12,375
TULA13	11,231	Yes*	0.02	2.77	11,267
TULA14	11,231	Yes*	0.02	2.4	11,585
VERA22	11,231	Yes	0.03	6.5	11,621
VNBU12	9,287	Yes	0.02	0.09	9,219

*The Tularosa feeders TULA13 and TULA14 will share a new substation transformer.

4.2.6 Hosting Capacity Improvement Observations

Table 4-7 shows the maximum hosting capacity observed for the community solar feeders for each scenario evaluated. Ample hosting capacity was observed for these community solar feeders in the base case evaluation. System improvements were shown to increase the maximum hosting capacity by increasing feeder ratings and/or installing a BESS that charges from excess PV generation. Building a dedicated feeder to the community solar facilities generally unlocked the most hosting capacity for existing distribution feeders. Figure 4-2 visually shows the maximum hosting capacity results.

Figure 4-2: Maximum Synergi Hosting Capacity Results - Community Solar Feeders

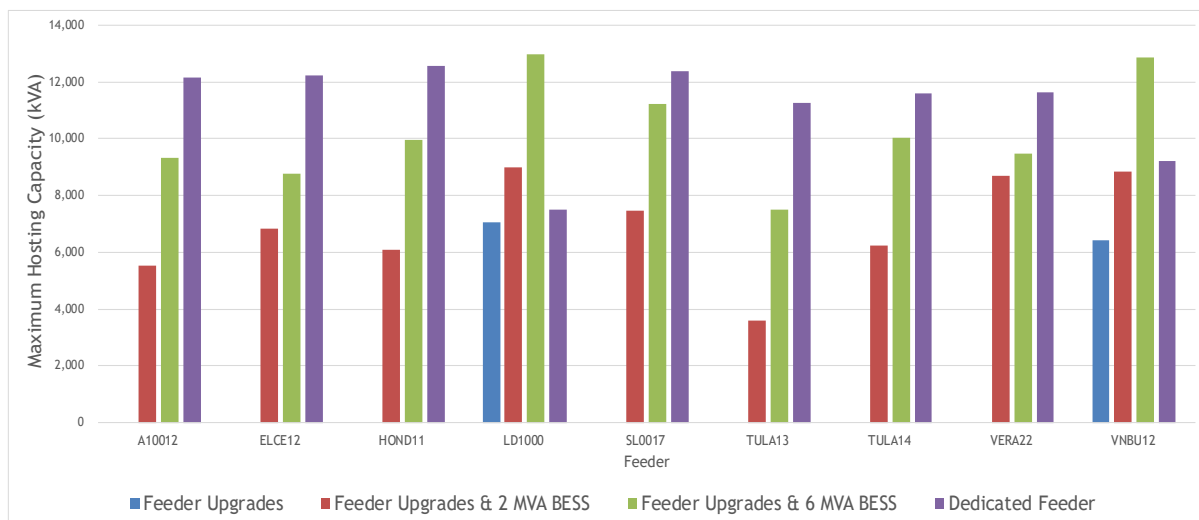


Table 4-7: Maximum Synergi Hosting Capacity Results Summary

Feeder	Base Case Synergi Max Hosting Capacity kVA	Com. Solar Interconnections Synergi Max Hosting Capacity kVA	Feeder Upgrades Synergi Max Hosting Capacity kVA	2 MVA BESS Charging Synergi Max Hosting Capacity kVA	6 MVA BESS Charging Synergi Max Hosting Capacity kVA	Dedicated Feeder Buildout Synergi Max Hosting Capacity kVA
A10012	3,753	-	-	5,548	9,331	12,137
ELCE12	11,503	4,923	-	6,827	8,771	12,238
HOND11	6,569	4,218	-	6,085	9,969	12,544
LD1000	7,714	2,888	7,056	8,994	12,973	7,485
SL0017	11,014	5,741	-	7,470	11,229	12,375
TULA13	5,867	1,678	-	3,588	7,487	11,267
TULA14	6,185	4,314	-	6,253	10,024	11,585
VERA22	11,621	6,897	-	8,707	9,457	11,621
VNBU12	4,575	4,271	6,430	8,836	12,854	9,219

Note: A dash represents a scenario that was not applicable to the feeder.

4.3 Financial Analysis - Community Solar Projects

Two perspectives were used to evaluate all hosting capacity improvement solutions on PV-saturated feeders. These perspectives differ by the value attributed to hosting capacity improvement and other associated system benefits related to the evaluated solutions.

4.3.1 Feeder Upgrades

Feeder Upgrades primarily target nonstandard transformer sizes and cable upgrades to bring each distribution feeder to the maximum PNM standard rating. Table 3-9 shows the financial analysis results for the feeder upgrade solution. Feeder upgrades were not applicable to all community solar project feeders. If the feeder is already constructed to the maximum PNM ratings, no hosting capacity increase or benefit-cost scoring was provided. Feeders LD1000 and VNBU12 both required upgrading the substation transformer to improve the feeder rating to the maximum PNM standard.

Table 4-8: Feeder Upgrades Financial Analysis Results

Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
HOND11*	4,218	4,218	0	23,880	0.00	0
LD1000	2,888	7,057	4,169	8,000,000	0.52	0.53
VNBU12	4,271	6,430	2,160	8,297,200	0.26	0.61

* The Feeder HOND11 project does not increase the available hosting capacity but rather increases the spread of hosting capacity.

4.3.2 Feeder Upgrades and BESS Charging at 2 MVA

The cost of this capital project alternative was significant due to the investment in the battery system. All feeders were evaluated with the BESS and applicable feeder upgrades to provide the greatest increase in hosting capacity. For feeders LD1000 and VNBU12, the substation transformer upgrades, in addition to the BESS installation, drove up the total project cost. Table 4-9 shows the financial analysis results for the feeder upgrades and 2 MVA BESS charging solution.

Table 4-9: Feeder Upgrades and BESS Charging at 2 MVA Financial Analysis Results

Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
A10012	3,753	5,548	1,795	14,300,000	0.13	0.88
ELCE12	4,923	6,827	1,904	14,300,000	0.13	0.89
HOND11	4,218	6,085	1,868	14,323,880	0.13	0.88
LD1000	2,888	8,994	6,106	22,300,000	0.27	0.78
SL0017	5,741	7,470	1,729	14,300,000	0.12	0.88
TULA13	1,678	3,588	1,910	14,300,000	0.13	0.89
TULA14	4,314	6,253	1,939	14,300,000	0.14	0.89
VERA22	6,897	8,707	1,810	14,300,000	0.13	0.88
VNBU12	4,271	8,836	4,566	22,597,200	0.20	0.71

4.3.3 Feeder Upgrades with BESS Charging at 6 MVA

The cost of this capital project alternative was significant due to the investment in the battery system. First, all feeders were evaluated with the BESS and Feeder Upgrades. For feeders LD1000 and VNBU12, the substation transformer upgrades, in addition to the BESS installation, drove up the total project cost. Table 4-10 shows the financial analysis results for the feeder upgrades and 6 MVA BESS charging solution.

Table 4-10: Feeder Upgrades with BESS Charging at 6 MVA Financial Analysis Results

Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
A10012	3,753	9,331	5,577	14,350,000	0.39	1.79
ELCE12	4,923	8,771	3,848	14,350,000	0.27	1.69
HOND11	4,218	9,969	5,752	14,373,880	0.40	1.8
LD1000	2,888	12,973	10,085	22,350,000	0.45	1.41
SL0017	5,741	11,229	5,488	14,350,000	0.38	1.79
TULA13	1,678	7,487	5,809	14,350,000	0.40	1.81
TULA14	4,314	10,024	5,710	14,350,000	0.40	1.8
VERA22	6,897	9,457	2,560	14,350,000	0.18	1.62
VNBU12	4,271	12,854	8,584	22,647,200	0.38	1.22

4.3.4 Dedicated Feeder Buildout

Most feeders evaluated must include a substation transformer upgrade or a new substation transformer to successfully build out a new dedicated feeder to improve hosting capacity in the area. The capital project costs were impacted by the amount of conductor buildout required, which varied based on the distance of existing solar facilities from the substation. Also, some cost sharing of substation upgrades can be experienced among the Tularosa Substation feeders. Table 4-11 shows the financial analysis results for the dedicated feeder buildout solution.

Table 4-11: Dedicated Feeder Buildout Financial Analysis

Existing Feeder	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic Financial Benefit Cost Ratio Score
A10012	3,753	12,137	8,384	12,613,746	0.66	0.68
ELCE12	4,923	12,238	7,315	8,297,200	0.88	0.90
HOND11	4,218	12,544	8,326	4,574,152	1.82	1.85
LD1000	2,888	7,485	4,597	8,902,054	0.52	0.46
SL0017	5,741	12,375	6,634	12,339,062	0.54	0.55
TULA13	1,678	11,267	9,589	6,684,780	1.43	1.46
TULA14	4,314	11,585	7,271	6,391,436	1.14	1.16
VERA22	6,897	11,621	4,724	13,740,883	0.34	0.35
VNBU12	4,271	9,219	4,948	8,335,134	0.59	0.60

4.3.5 Capital Project Portfolios

Two separate portfolios were determined based on the two benefit-cost perspectives that were scored for this evaluation. Table 4-12 represents the highest-scoring solutions portfolio based on hosting capacity improvement relative to the cost perspective and the holistic financial benefit-cost perspective.

The dedicated feeder buildout or feeder upgrade solutions scored highest from the hosting capacity improvement relative to cost perspective as these were solutions that provided the greatest increase to hosting capacity for a lower cost. This portfolio would result in a total investment of six new substation transformers to enable the buildout of seven distributed feeders. Feeders TULA13 and TULA14 share the cost of a new transformer.

The holistic financial analysis considered the other benefits provided by a BESS installation in addition to increasing hosting capacity. This holistic perspective resulted in the 6 MVA BESS solution scoring highest for each feeder in most cases. This portfolio represents eight 6 MVA BESS installations within the PNM distribution system totaling 48 MVA of capacity and 192 MWH of energy storage.

Table 4-12: Community Solar Feeders Hosting Capacity Analysis Results

Hosting Capacity Benefit Cost Portfolio				
Feeder	Capital Project Category	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)
A10012	Dedicated Feeder	8,384	12,613,746	0.66
ELCE12	Dedicated Feeder	7,315	8,297,200	0.88
HOND11	Dedicated Feeder	8,326	4,574,152	1.82
LD1000	Feeder Upgrades	4,169	8,000,000	0.52
SL0017	Dedicated Feeder	6,634	12,339,062	0.54
TULA13	Dedicated Feeder	9,589	6,684,780	1.43
TULA14	Dedicated Feeder	7,271	6,391,436	1.14
VERA22	Dedicated Feeder	4,724	13,740,883	0.34
VNBU12	Dedicated Feeder	4,948	8,335,134	0.59
Total	-	61,360	\$80,976,394	-

Holistic System Benefit Cost Portfolio				
Feeder	Capital Project Category	Net Hosting Capacity Increase kVA	Capital Project Cost	Holistic Financial Benefit Cost Ratio Score
A10012	6 MVA BESS	5,577	\$14,350,000	1.79
ELCE12	6 MVA BESS	3,848	\$14,350,000	1.69
HOND11	Dedicated Feeder	8,326	\$4,574,152	1.85
LD1000	Feeder Upgrades & 6 MVA BESS	10,085	\$22,350,000	1.41
SL0017	6 MVA BESS	5,488	\$14,350,000	1.79
TULA13	6 MVA BESS	5,809	\$14,350,000	1.81
TULA14	6 MVA BESS	5,710	\$14,350,000	1.80
VERA22	6 MVA BESS	2,560	\$14,350,000	1.62
VNBU12	Feeder Upgrades & 6 MVA BESS	8,584	\$22,647,200	1.22
Total	-	55,987	\$135,671,352	-

5.0 Conclusion

Photovoltaic (PV) penetration is growing within the Public Service Company of New Mexico (PNM or the Company) system. High PV penetration can present benefits but can also result in challenges for operating and maintaining the distribution system. In response to rule 568, PNM was granted partial variance in NMPRC Order 23-00072-UT-2023-06-14 to conduct studies to evaluate PNM's technical concerns regarding Variance requests 1, 2, and 3. As ordered, PNM worked with the Department of Energy (DOE) and the National Renewable Energy Laboratory (NREL) to design the pilot study. The purpose of this pilot study was to better understand the actual limits on distribution feeders for hosting new PV generation, given the levels of PV penetration PNM is experiencing. That report⁵ was submitted to the NMPRC on May 23, 2024.

In this report, after understanding the limitations of distribution feeders, multiple hosting capacity improvement solutions were evaluated for 18 of PNM's PV-saturated feeders. The types of hosting capacity improvement solutions that were evaluated are shown in Figure 5-1. A financial analysis was then performed to understand the value of each solution and ultimately recommend a portfolio of hosting capacity improvement projects for these PV-saturated feeders.

Figure 5-1: Hosting Capacity Improvement Solutions Evaluated



5.1 Pending Customer PV Interconnection Analysis

As of January 1, 2024, 13 of the 18 PV-saturated feeders had pending customer PV interconnections. Based on the results of the first hosting capacity study report, it was determined that there was remaining hosting capacity on many of the PV-saturated feeders. 1898 & Co. modeled the pending PV projects to determine if the distribution feeder could successfully host all pending customer PV projects as of January 1, 2024. For 11 of the 13 feeders evaluated, the pending PV customers modeled can successfully interconnect without any system improvements. This will result in 230 new PV interconnections and an increase of 1,391 kVA in customer-owned PV capacity. Existing thermal violations were observed on LSMO12 and STPE12, which must be mitigated through system improvements before pending PV interconnections can

⁵ Rule 568 Hosting Capacity Analysis Report
https://edocket.prc.nm.gov/AspSoft/HandlerDocument.ashx?document_id=1233550

successfully interconnect. The hosting capacity improvement solutions proposed in this report for these two feeders will allow the pending PV customers to interconnect successfully to LSM012 and STPE12.

As of August 19, 2024, there are 7 pending customer PV interconnections resulting in 51 kVA of capacity that have been placed on hold since January 1, 2024. All these additional pending customer PV interconnections have been modeled on PV-saturated feeders with the proposed hosting capacity improvement solutions in place. With hosting capacity improvement solutions in place, all pending customer PV projects through August 19, 2024, can successfully interconnect.

Going forward, all applications on PV-saturated feeders will follow the Rule 568 screening process. Since these feeders have reverse power flow at minimum load times, they will fail the 100% of minimum load screen and require supplemental review. Under supplemental review, each application will be studied to see if there is remaining hosting capacity to safely interconnect the project. If it is determined that improvements are required, but that these improvements are within the recommended solutions provided in this report, the customers can be placed on hold until the recommended solutions for the PV-saturated feeders are implemented.

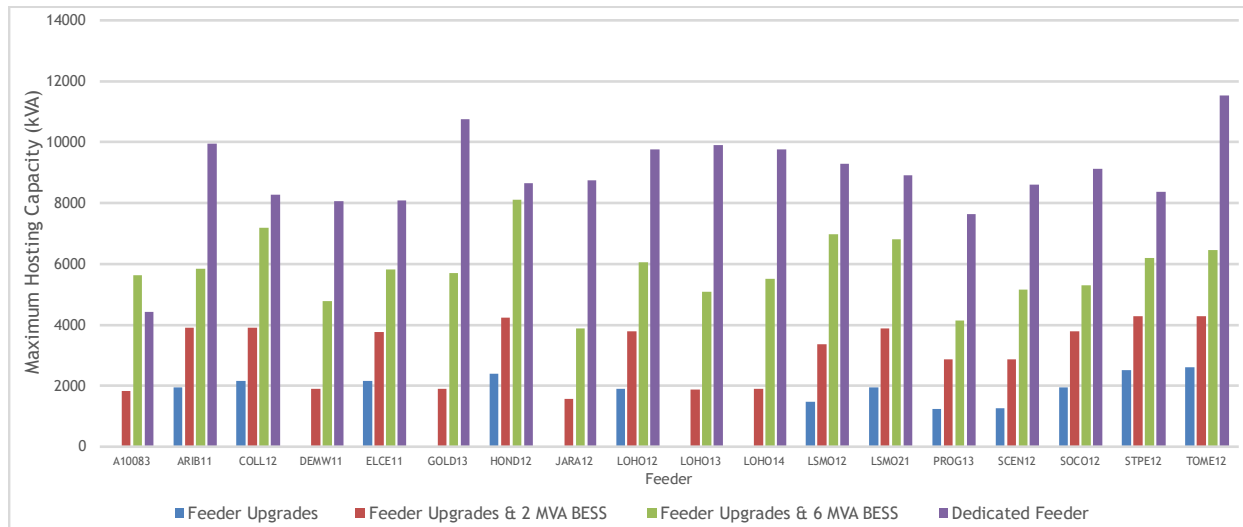
5.2 Community Solar Feeder Analysis

Nine feeders with approved large-scale solar projects were assessed to evaluate the hosting capacity available after the solar facilities were interconnected. Naturally, the hosting capacity for each feeder was reduced as each solar facility was energized. While ample hosting capacity remained for most of the feeders, system improvement scenarios were evaluated to assess the cost per benefit of each of the hosting capacity improvements.

5.3 Hosting Capacity Improvement Solutions Analysis

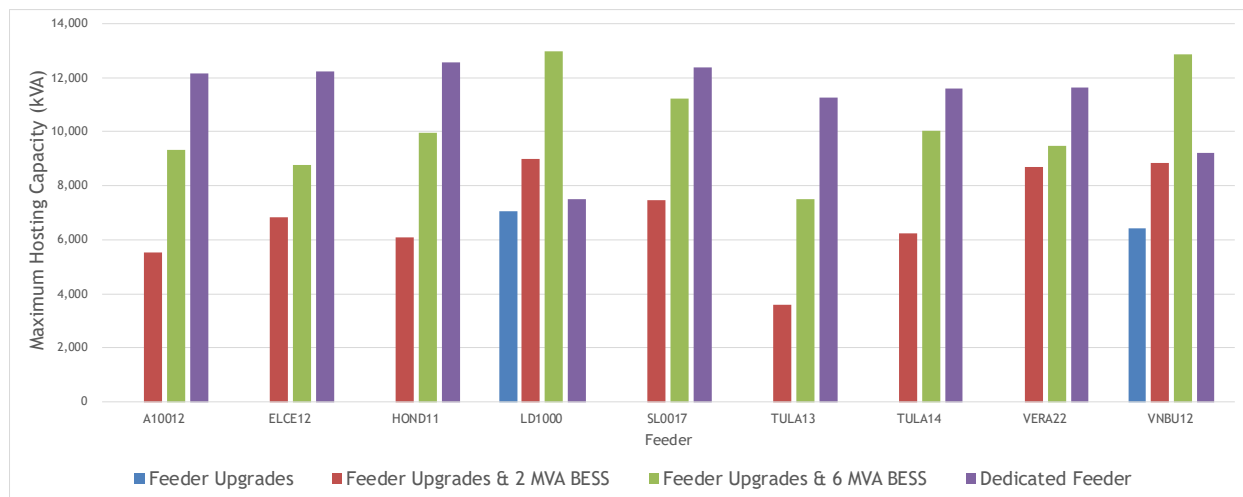
All capital project solutions investigated for the 18 PV-saturated feeders and nine community solar feeders resulted in an increase in hosting capacity. However, the increase in hosting capacity varied across the feeder and was influenced by several factors. The dedicated feeder buildout scenario most often provided the greatest increase in hosting capacity, while feeder upgrades generally provided a marginal increase in hosting capacity. For some of the feeders, upgrades were not applicable because the feeder is presently built to the maximum PNM standard ratings, and no increase in hosting capacity is shown for that scenario. Figure 5-2 and Figure 5-3 shows the Synergi analysis hosting capacity increase for each capital project alternative relative to the base case model results.

Figure 5-2: PV-saturated Feeders - Hosting Capacity Increase per Solution Results



Note: An absent vertical bar indicates that the hosting capacity increase was not applicable for the given scenario.

Figure 5-3: Community Solar Feeders - Hosting Capacity Increase per Solution Results



Note: An absent vertical bar indicates that the hosting capacity increase was not applicable for the given scenario.

5.4 Portfolio of Recommended Capital Project Solutions

Table 5-1 and Table 5-2 provide the recommended portfolio of capital project solutions to improve hosting capacity on the study feeders while also providing the greatest value to PNM customers. Engineering judgement, in combination with the two-perspective financial analysis, was used to determine this proposed solution portfolio.

In selecting this portfolio of solutions, the BESS solutions were considered valuable because of the hosting capacity increase on the local distribution feeder, but also because of the ability to avoid investments in other parts of the system. PNM foresees battery storage as a need moving forward in the clean energy transition. By building BESS on these distribution feeders, less battery storage must be constructed on the transmission system. While the dedicated feeder buildout solution typically resulted in the greatest hosting capacity increase for distribution feeders, these investments provide no benefit to other parts of the overall PNM system, which can also become constrained as PV levels rise. The transmission system can be constrained during times of low load and high PV generation. Even after performing dedicated feeder buildouts, additional transmission system upgrades could be required in certain areas, which would significantly impact the cost of upgrades to improve PNM's overall system hosting capacity. BESS solutions located in proximity to PV generation can reduce PV generation power flow on the transmission system and improve transmission congestion in lieu of transmission upgrades.

PNM plans to prioritize the feeder upgrades in the near term to unlock incremental hosting capacity quickly and enable more customers to connect their new PV systems successfully. The proposed 6 MVA BESS systems can be constructed as PV penetration levels rise locally to improve feeder hosting capacity, or BESS systems can be constructed to obtain the overall system benefits captured in the holistic system benefit analysis. Timelines are provided for the individual projects in Table 5-1 below. Where feeder upgrades and a 6 MVA BESS are proposed, the first timeline is for the feeder upgrades only. The second timeline is for the BESS construction. The timeline to construct the overall portfolio will be greater than three years as it will be subject to budget allocations.

For Jarales Feeder 12 (JARA12), a dedicated feeder solution scored the highest for the benefit-cost analysis. A dedicated feeder would require a significant amount of double-circuit buildout and could be difficult to construct. A 6 MVA BESS is recommended as it will be more feasible to construct and provide system benefits in addition to improving hosting capacity.

The feeder upgrade solution scored the highest for the benefit-cost analysis for ARIB11, COLL12, HOND12, LSMO12, and LSMO21. However, feeder upgrades result in a marginal increase in hosting capacity. To further increase hosting capacity on these feeders, a 6 MVA BESS is also recommended after feeder upgrades are performed.

Table 5-1: Hosting Capacity Improvement Solutions Portfolio

Feeder	Capital Project Solution Category	Increase in Hosting Capacity kVA	Capital Project Cost	Construction Timeline
A10083	6 MVA BESS	5,637	\$14,350,000	3 Years
ARIB11	Feeder Upgrades & 6 MVA BESS	5,842	\$14,524,850	1 Year / 3 Years
COLL12	Feeder Upgrades & 6 MVA BESS	7,187	\$14,501,149	1 Year / 3 Years
DEMW11**	Feeder Upgrades & 6 MVA BESS	4,794	\$14,892,473	1 Year / 3 Years
ELCE11	6 MVA BESS	2,531	\$14,350,000	3 Years
GOLD13**	Dedicated Feeder	10,743	\$1,286,828	1 Year
HOND12	Feeder Upgrades & 6 MVA BESS	8,116	\$14,733,946	1 Year / 3 Years
JARA12	6 MVA BESS	3,897	\$14,350,000	3 Years
LOHO12	Dedicated Feeder	9,758	\$3,744,957	3 Years
LOHO13	Dedicated Feeder	9,898	\$4,131,806	3 Years
LOHO14	Dedicated Feeder	9,760	\$3,704,661	3 Years
LSMO12	Feeder Upgrades & 6 MVA BESS	6,980	\$14,396,562	1 Year / 3 Years
LSMO21	Feeder Upgrades & 6 MVA BESS	6,802	\$14,524,590	1 Year / 3 Years
PROG13	6 MVA BESS	2,425	\$14,350,000	3 Years
SCEN12	6 MVA BESS	3,183	\$14,350,000	3 Years
SOCO12*	Feeder Upgrades & 6 MVA BESS	5,291	-	Installed
STPE12	Feeder Upgrades & 6 MVA BESS	6,207	\$16,625,192	1 Year / 3 Years
TOME12*	6 MVA BESS	6,460	-	Installed
-	-	115,511	188,817,014	-

*SOCO12 & TOME12 were selected for the Phase I BESS installations and are installed. Phase I selection was based on different criteria. The feeder upgrades only solution scored highest for these feeders because it provided a least cost alternative to provide an increase in hosting capacity. The 6 MVA BESS that is installed provides more hosting capacity for future customer interconnections.

**For DEMW11 & GOLD13, the SGIA has not been constructed. The proposed capital project solution would not be constructed unless the SGIA moves forward with construction, or if pending customers are not able to connect to the PNM system without system improvements built.

For El Cerro Feeder 12 (ELCE12), a 6 MVA BESS scored the highest for the benefit-cost analysis. A BESS would provide many system benefits, but a battery is already recommended for El Cerro Feeder 11 to support the Meadow Lake Solar facility. To diversify the system improvements in this area, a dedicated feeder is recommended that will require the upgrade of the El Cerro Substation. For Veranda Feeder 22 (VERA22), a 6 MVA BESS scored the highest for the benefit-cost analysis. However, the Veranda Substation is heavily loaded, and the new load serving capacity is limited. A dedicated feeder solution is proposed for VERA22 because substation upgrades to enable a dedicated feeder would also increase the load serving capacity in the area.

Table 5-2: Community Solar Feeders Hosting Capacity Improvement Solutions Portfolio

Feeder	Capital Project Solution Category	Increase in Hosting Capacity kVA	Capital Project Cost	Construction Timeline
A10012	6 MVA BESS	5,577	\$14,350,000	3 Years
ELCE12	Dedicated Feeder	7,315	\$8,297,200	3 Years
HOND11	Dedicated Feeder	8,326	\$4,574,152	1 Year / 3 Years
LD1000	Feeder Upgrades & 6 MVA BESS	10,085	\$22,350,000	1 Year / 3 Years
SL0017	6 MVA BESS	5,488	\$14,350,000	1 Year / 3 Years
TULA13	6 MVA BESS	5,809	\$14,350,000	3 Years
TULA14	6 MVA BESS	5,710	\$14,350,000	3 Years
VERA22	Dedicated Feeder	4,724	\$13,740,883	3 Years
VNBU12	Feeder Upgrades & 6 MVA BESS	8,584	\$22,647,200	1 Year / 3 Years
-	-	61,618	129,009,435	-

6.0 Appendix - Feeder Analysis

6.1 PV Saturated Feeder Analysis

A10083 Analysis



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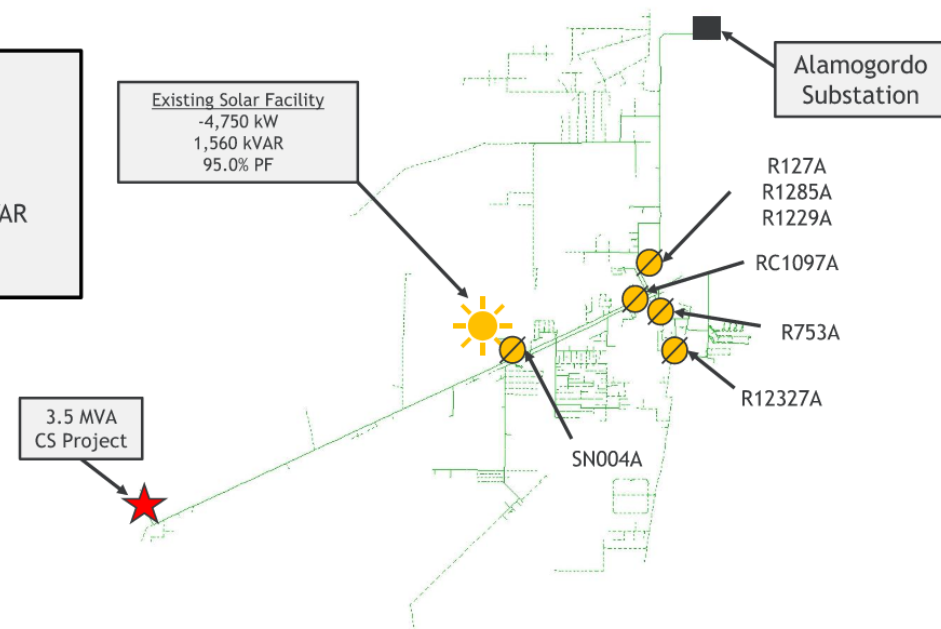
A10083 - Feeder Overview

Feeder Data

- Feeder Rating: 11,663 kVA
- Existing Generation: 9,973 kVA
- Minimum Daylight Load: -7,959 kW
- Minimum Daylight Gross Load: 1,282 kW / 736 kVAR
- Substation LTC Setpoint: 125 V
- Primary Voltage: 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	A10083 Breaker	600
Recloser	R1229A	140
Recloser	R12327A	200
Recloser	R127A	140
Recloser	R1285A	140
Recloser	RC1097A	300
Recloser	SN004A	600



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-7,959	1,159	8,043	-99	358	360	354	122.4	125.0	96



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A10083 - Feeder Overview with Queued Solar as of 1-1-24

Feeder Data

- Feeder Rating: 11,663 kVA
- Existing Generation: 9,973 kVA
- Minimum Daylight Load: -7,959 kW
- Minimum Daylight Gross Load: 1,282 kW / 736 kVAR
- Substation LTC Setpoint: 125 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: 4
- Total Queued AC Inverter Nameplate: 30 kW

Protection & Equipment Pickup/Ratings

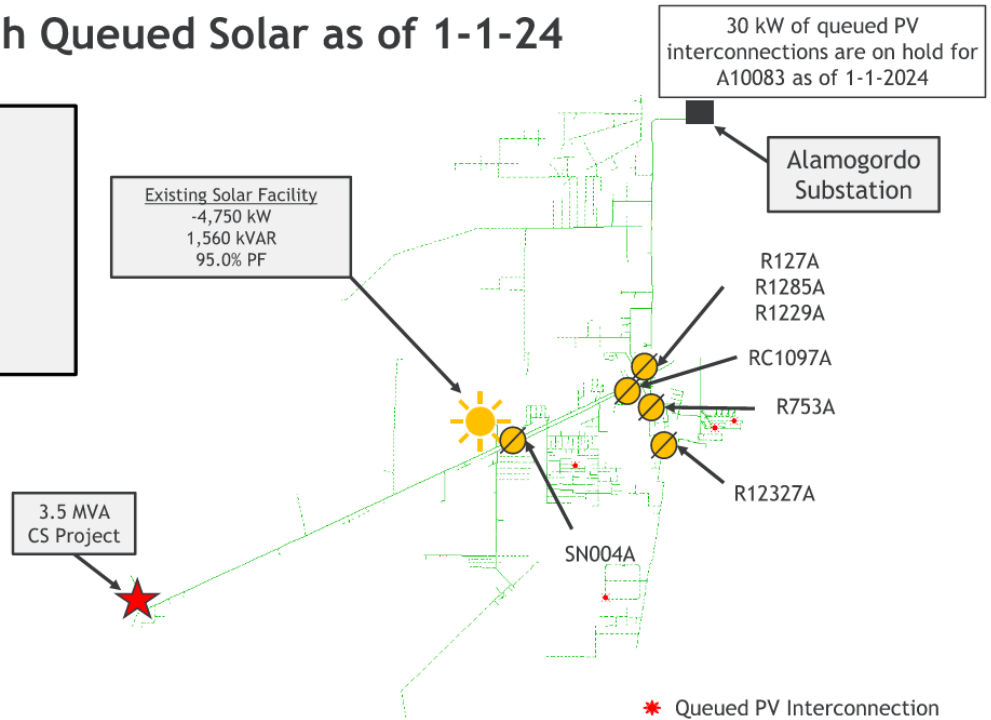
Device	Name	Pick Up Rating (A)
Breaker	A10083 Breaker	600
Recloser	R1229A	140
Recloser	R12327A	200
Recloser	R127A	140
Recloser	R1285A	140
Recloser	RC1097A	300
Recloser	SN004A	600



The feeder can serve queued PV interconnection requests without violations.

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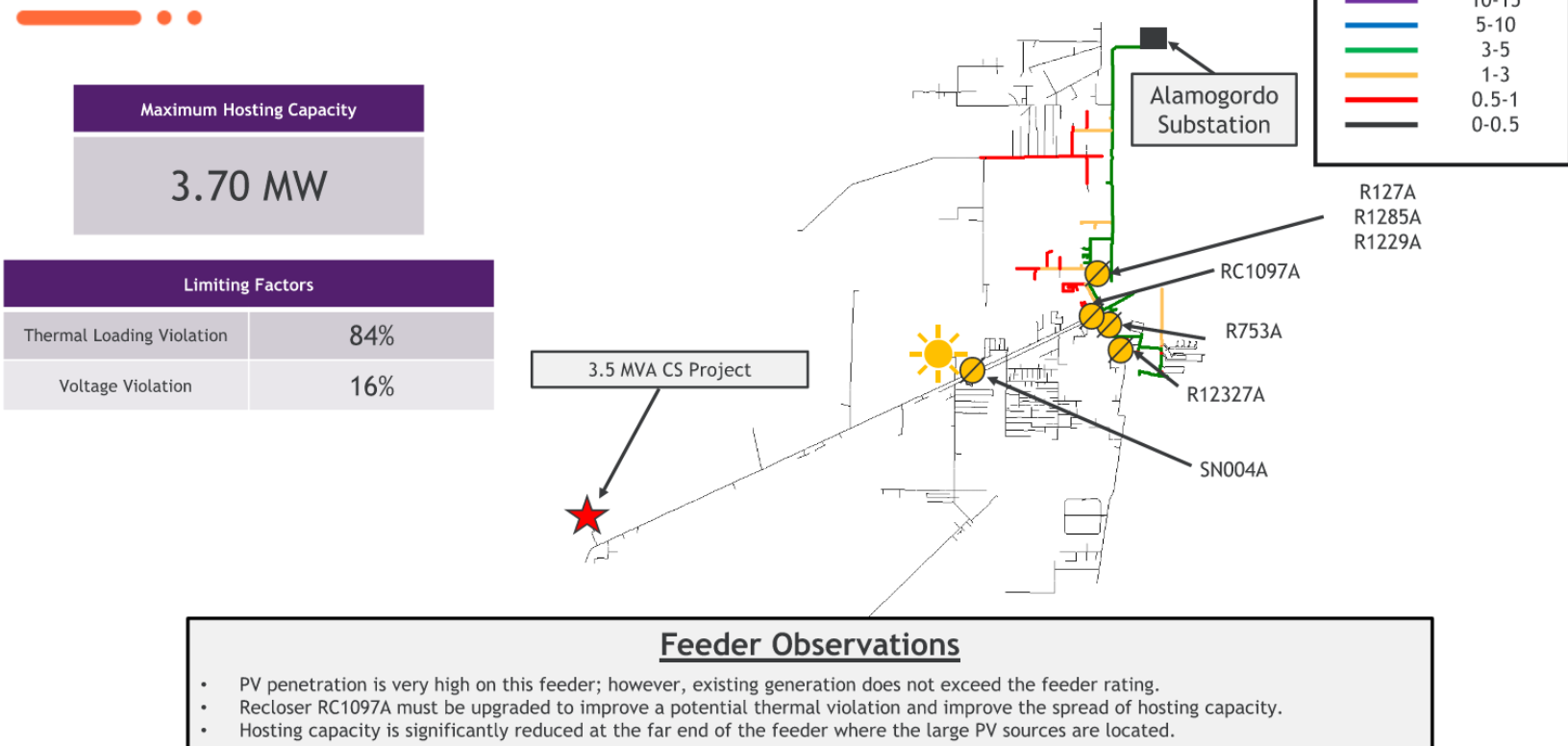
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Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-7,986	1,169	8,071	-99	359	361	356	122.4	125.0	95

A10083 - Maximum Hosting Capacity Base Case With Queued PV



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A10083 - Feeder Upgrades

Hosting Capacity	
Base HC	3.68 MW
Max HC	3.68 MW
HC Increase	0 MW

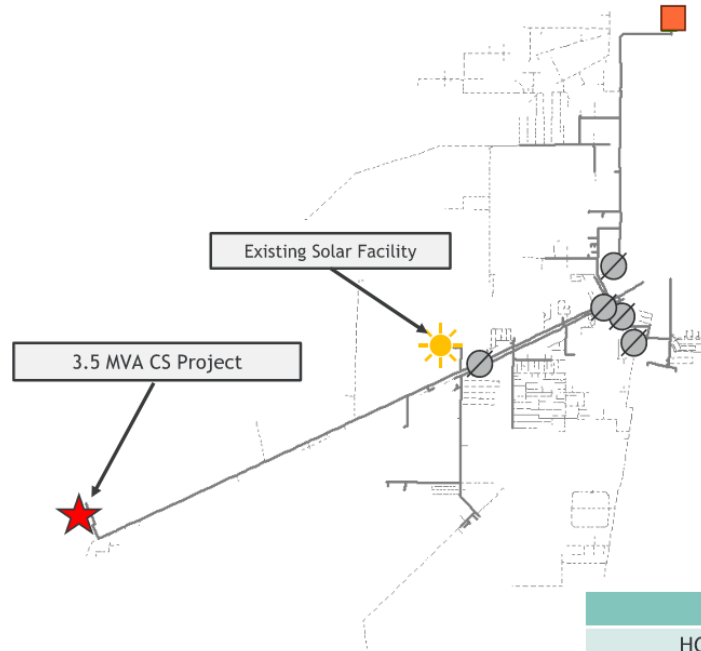
Reverse Flow Limits
Max HC

System Improvement	
N/A	Cost
TOTAL	\$0

No feeder upgrades are applicable for this scenario.



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Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

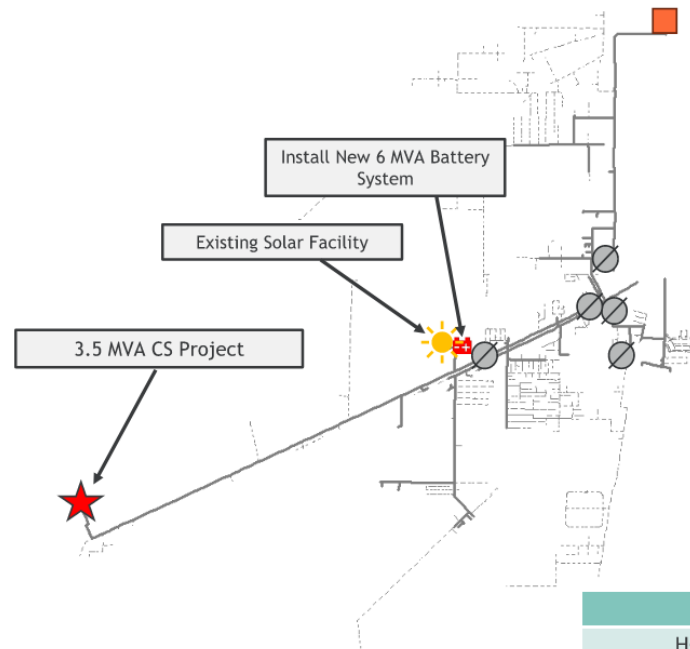
Financial Analysis	
HC Increase	0 MW
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-

A10083 - 2 MVA BESS Only

Hosting Capacity	
Base HC	3.68 MW
Max HC	5.5 MW
HC Increase	1.82 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,300,000



Financial Analysis	
HC Increase	1.82 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.92

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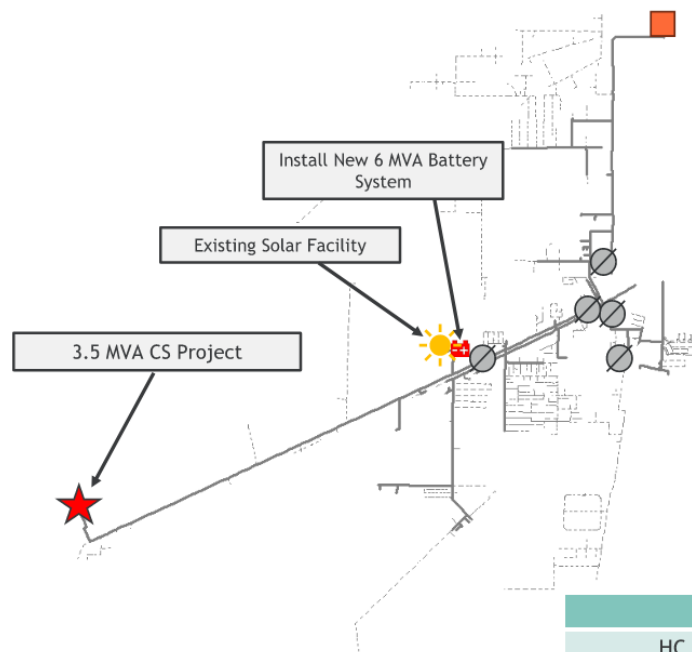
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A10083 - 6 MVA BESS Only

Hosting Capacity	
Base HC	3.68 MW
Max HC	9.31 MW
HC Increase	5.63 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,350,000



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	5.63 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.39
Holistic System Benefit Cost	1.88

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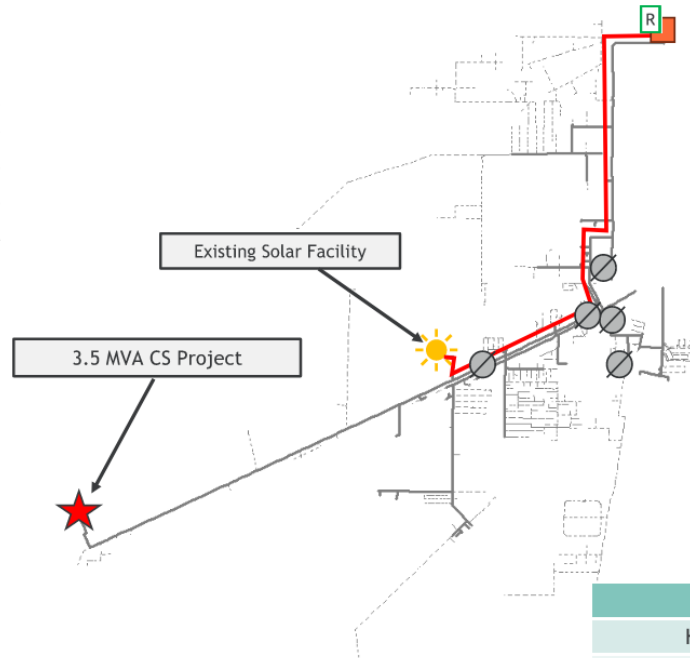
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A10083 - Dedicated Feeder

Hosting Capacity	
Base HC	3.68 MW
Max HC	8.1 MW
HC Increase	4.42 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~700ft of new 397 AAC @ 570 from the new Alamogordo Feeder to a new riser pole.	\$2,595,082
Build ~5.3 miles of new 397 AAC @ 570. Utilize double circuit construction along the existing path of A10083 feeder main line conductor.	
Expand the Alamogordo Substation bus and install new feeder breaker and relay for the New Feeder.	
TOTAL	\$2,595,082



Financial Analysis	
HC Increase	4.42 MW
Cost (\$)	2,595,082
Hosting Capacity Benefit Cost	1.71
Holistic System Benefit Cost	1.82



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A10083 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades*	-	-	-	-	-	-
Feeder Upgrade* with 2 MVA BESS	-	-	-	-	-	-
2 MVA BESS Only	3,675	5,501	1,826	\$14,300,000	0.13	0.92
Feeder Upgrades* with 6 MVA BESS	-	-	-	-	-	-
6 MVA BESS Only	3,675	9,312	5,637	\$14,350,000	0.39	1.88
Dedicated Feeder	3,675	8,101	4,426	\$2,595,082	1.71	1.82

*This scenario was not applicable for this analysis.



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ARIB11 Analysis



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ARIB11 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,188	56	8,188	100	371	375	363	120.6	123.4	89.0

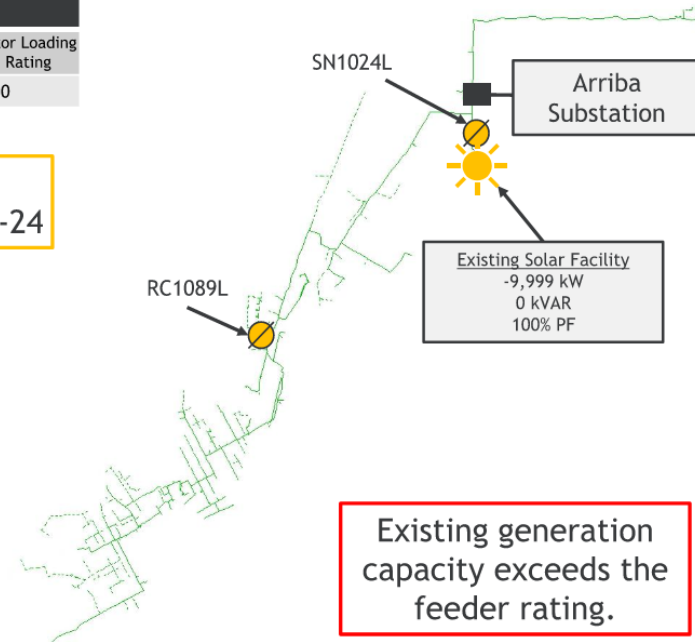
Protection Devices

Device	Name	Pick Up Rating (A)
Breaker	ARIB11 Breaker	480
Recloser	SN1024L	515
Recloser	RC1089L	350

No Pending PV Customers as of 1-1-24

Feeder Data

- Feeder Rating: 9,331 kVA
- Existing Generation: 10,326 kVA
- Minimum Daylight Load: -8,188 kW
- Minimum Daylight Gross Load: 2,062 kW / 500 kVAR
- Substation LTC Setpoint: 123 V
- Primary Voltage: 12.47 kV



ARIB11 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity

1.10 MW

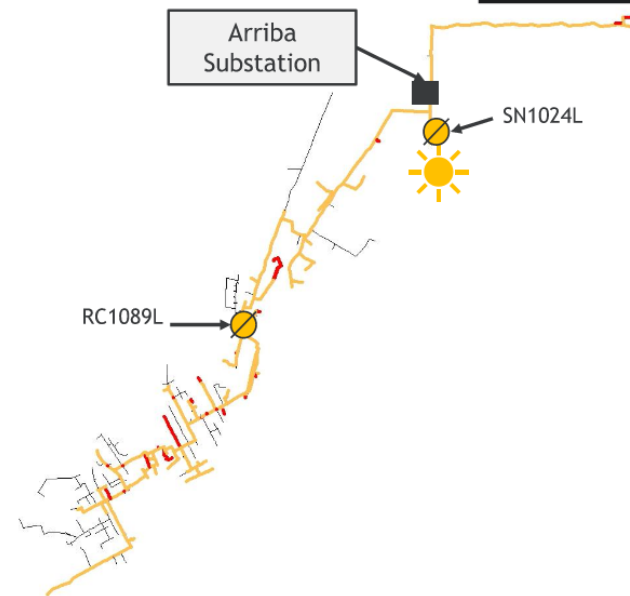
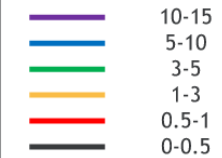
Limiting Factors

Thermal Loading Violation	92%
Voltage Violation	8%

Feeder Observations

- The feeder relay rating of 480 Amps limits the hosting capacity of this feeder. Upgrading the feeder relay would unlock additional hosting capacity.

Hosting Capacity (MW)



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ARIB11 - Feeder Upgrades

Hosting Capacity	
Base HC	1.1 MW
Max HC	3.04 MW
HC Increase	1.94 MW

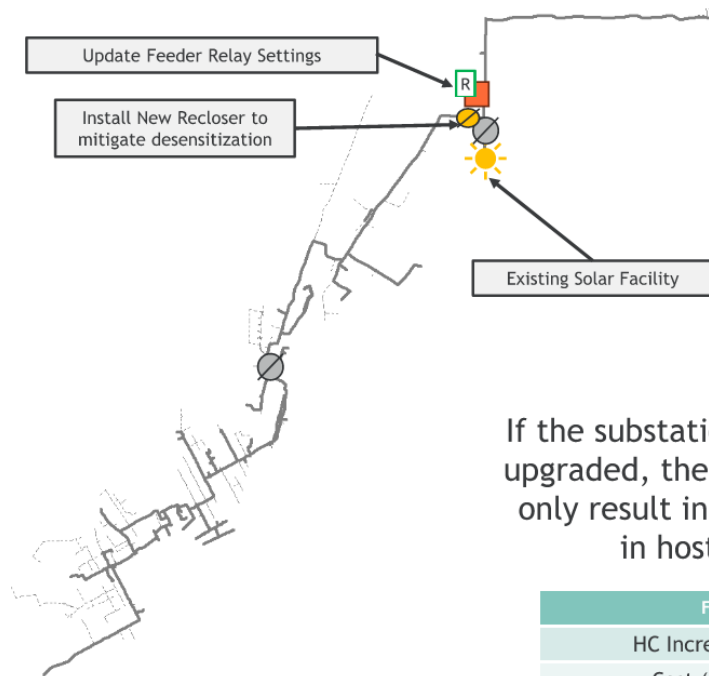
Arriba XFMR Capacity - 2.1MW
Actual HC Increase - 1.09 MW

System Improvement	
	Cost
Update Feeder Relay Settings	\$174,850
Install new recloser to protect line feeding to the west.	
TOTAL	\$174,850

Reverse Flow Limits
Max HC



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Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

If the substation transformer is not upgraded, the feeder upgrades will only result in a marginal increase in hosting capacity.

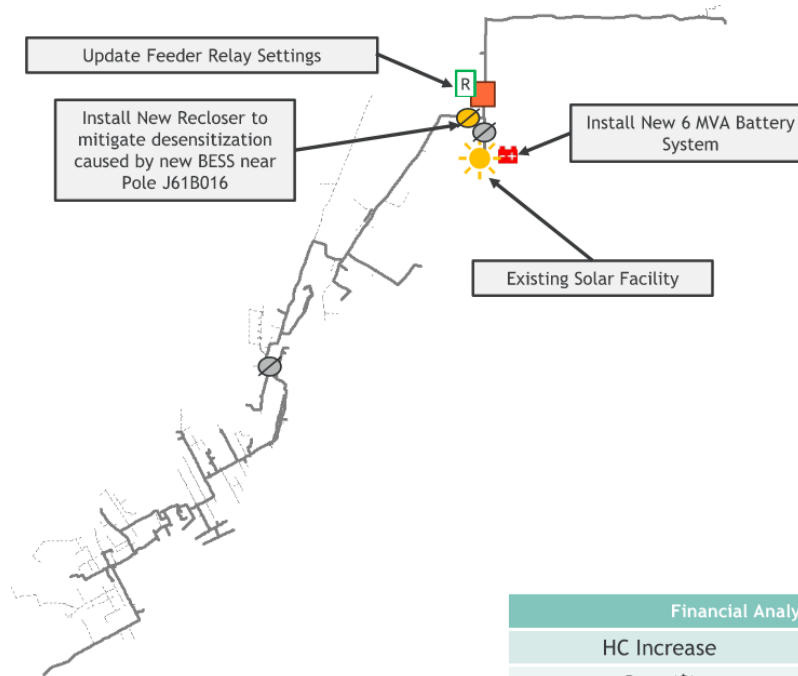
Financial Analysis	
HC Increase	1.09 MW
Cost (\$)	174,850
Hosting Capacity Benefit Cost	6.23
Holistic System Benefit Cost	6.64

ARIB11 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	1.1 MW
Max HC	5.01 MW
HC Increase	3.91 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
Install new recloser to protect line feeding to the west.	\$174,850
Update Feeder Relay Settings	
TOTAL	\$14,474,850



Financial Analysis	
HC Increase	3.91 MW
Cost (\$)	14,474,850
Hosting Capacity Benefit Cost	0.27
Holistic System Benefit Cost	1.04



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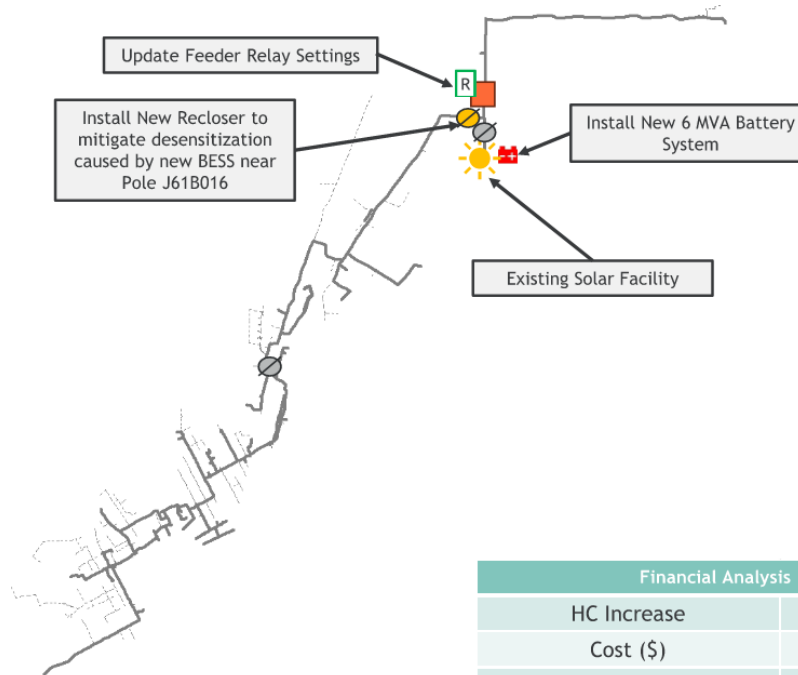
14

ARIB11 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	1.1 MW
Max HC	6.94 MW
HC Increase	5.84 MW

Thermal Loading
Limits Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
Install new recloser to protect line feeding to the west.	\$174,850
Update Feeder Relay Settings	
TOTAL	\$14,524,850



Financial Analysis	
HC Increase	5.84 MW
Cost (\$)	14,524,850
Hosting Capacity Benefit Cost	0.40
Holistic System Benefit Cost	1.87



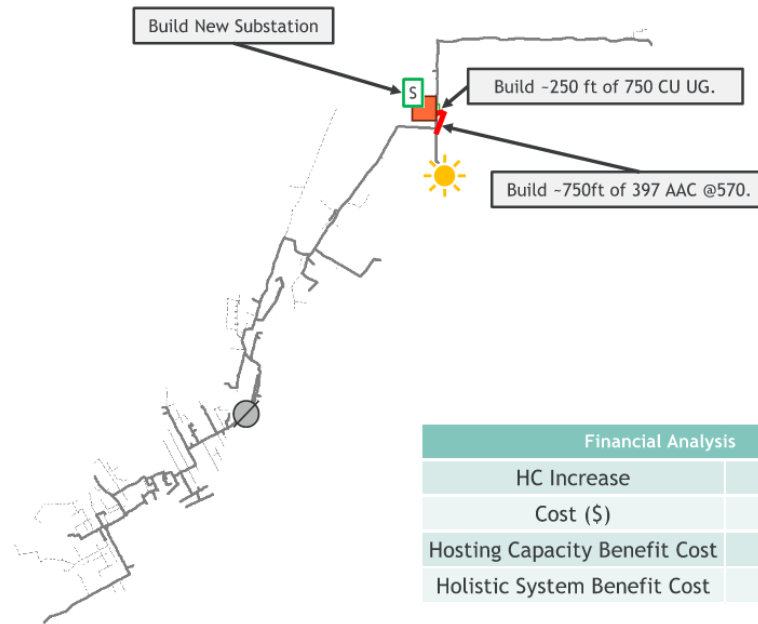
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ARIB11 - Dedicated Feeder

Hosting Capacity	
Base HC	1.1 MW
Max HC	11.06 MW
HC Increase	9.96 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~250ft of new 750 CU cable from the new Arriba Feeder to a new riser pole.	
Build ~750ft of new 397 AAC @ 570. Utilize double circuit construction along the existing path of Arriba 11 feeder main line conductor.	\$357,645
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$8,357,645



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	9.96 MW
Cost (\$)	8,357,645
Hosting Capacity Benefit Cost	1.19
Holistic System Benefit Cost	1.27



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ARIB11 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	1,099	2,100	1,090	\$174,850	6.23	6.64
Feeder Upgrades with 2 MVA BESS	1,099	5,010	3,911	\$14,474,850	0.27	1.04
2 MVA BESS Only*	-	-	-	-	-	-
Feeder Upgrades with 6 MVA BESS	1,099	6,940	5,841	\$14,524,850	0.40	1.87
6 MVA BESS Only*	-	-	-	-	-	-
Dedicated Feeder	1,099	11,060	9,960	\$8,357,645	1.19	1.27

*This scenario was not applicable to this analysis.



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ARIB11 - Feeder Overview with Queued Solar as of 8-19-2024

Base Case Load Flow Analysis (Minimum daylight Load)									
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,194	56	8,194	100	371	375	364	120.7	123.4	86.57

Protection Devices		
Device	Name	Pick Up Rating (A)
Breaker	ARIB11 Breaker	480
Recloser	SN1024L	515
Recloser	RC1089L	350

6 kW Pending PV Customers as of 8-19-24

Feeder Data

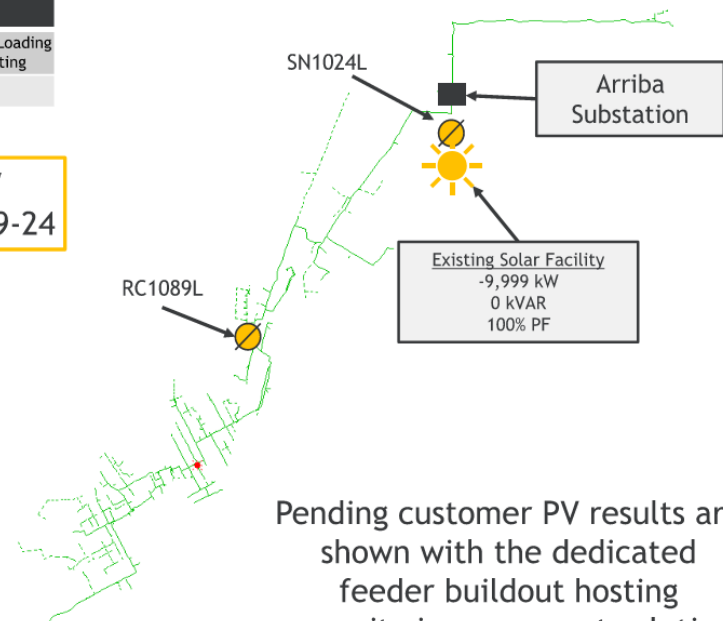
- Feeder Rating: **9,331 kVA**
- Existing Generation: **10,332 kVA**
- Minimum Daylight Load: -8,194 kW
- Minimum Daylight Gross Load: 2,062 kW / 500 kVAR
- Substation LTC Setpoint: 123 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **1**
- Total Queued AC Inverter Nameplate: **6 kW**

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The feeder can serve queued PV interconnection requests without violations.

* Queued PV Interconnection



Pending customer PV results are shown with the dedicated feeder buildout hosting capacity improvement solution modeled.

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COLL12 Analysis



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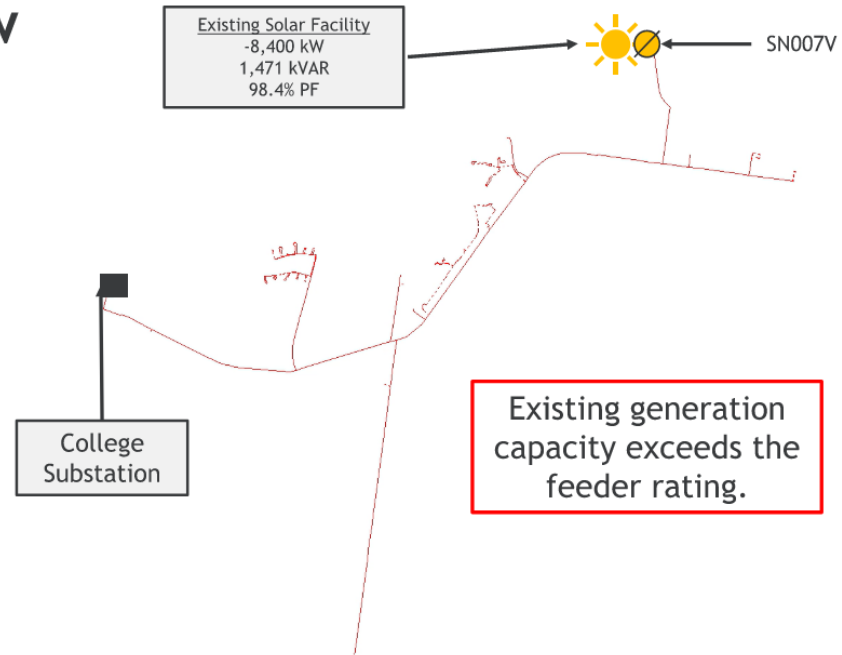
COLL12 - Feeder Overview

Feeder Data

- Feeder Rating: **9,072 kVA**
- Existing Generation: **9,150 kVA**
- daylight Minimum Load: -8,297 kW
- daylight Minimum Gross Load: 284 kW / -241 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	COLL12 Breaker	600
Recloser	SN007V	425



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,297	2,662	8,702	-95	404	387	399	122.0	125.5	96.0

COLL12 - Feeder Overview with Queued Solar as of 1-1-2024

Feeder Data

- Feeder Rating: **9,072 kVA**
- Existing Generation: **9,161 kVA**
- Minimum Daylight Load: -8,307 kW
- Minimum Daylight Gross Load: 284 kW / -241 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **2**
- Total Queued AC Inverter Nameplate: **11 kW**

Protection & Equipment Pickup/Ratings

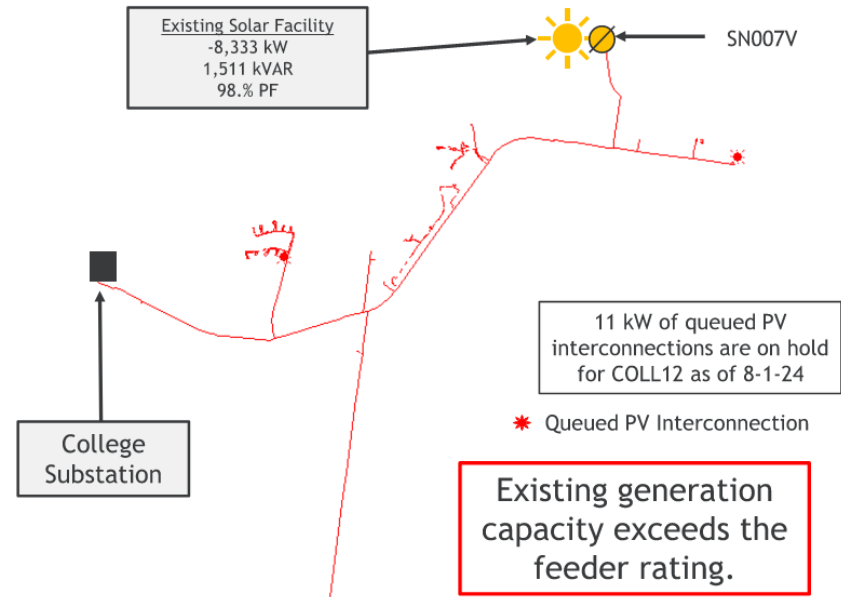
Device	Name	Pick Up Rating (A)
Breaker	COLL12 Breaker	600
Recloser	SN007V	425



The feeder can serve queued PV interconnection requests without violations.

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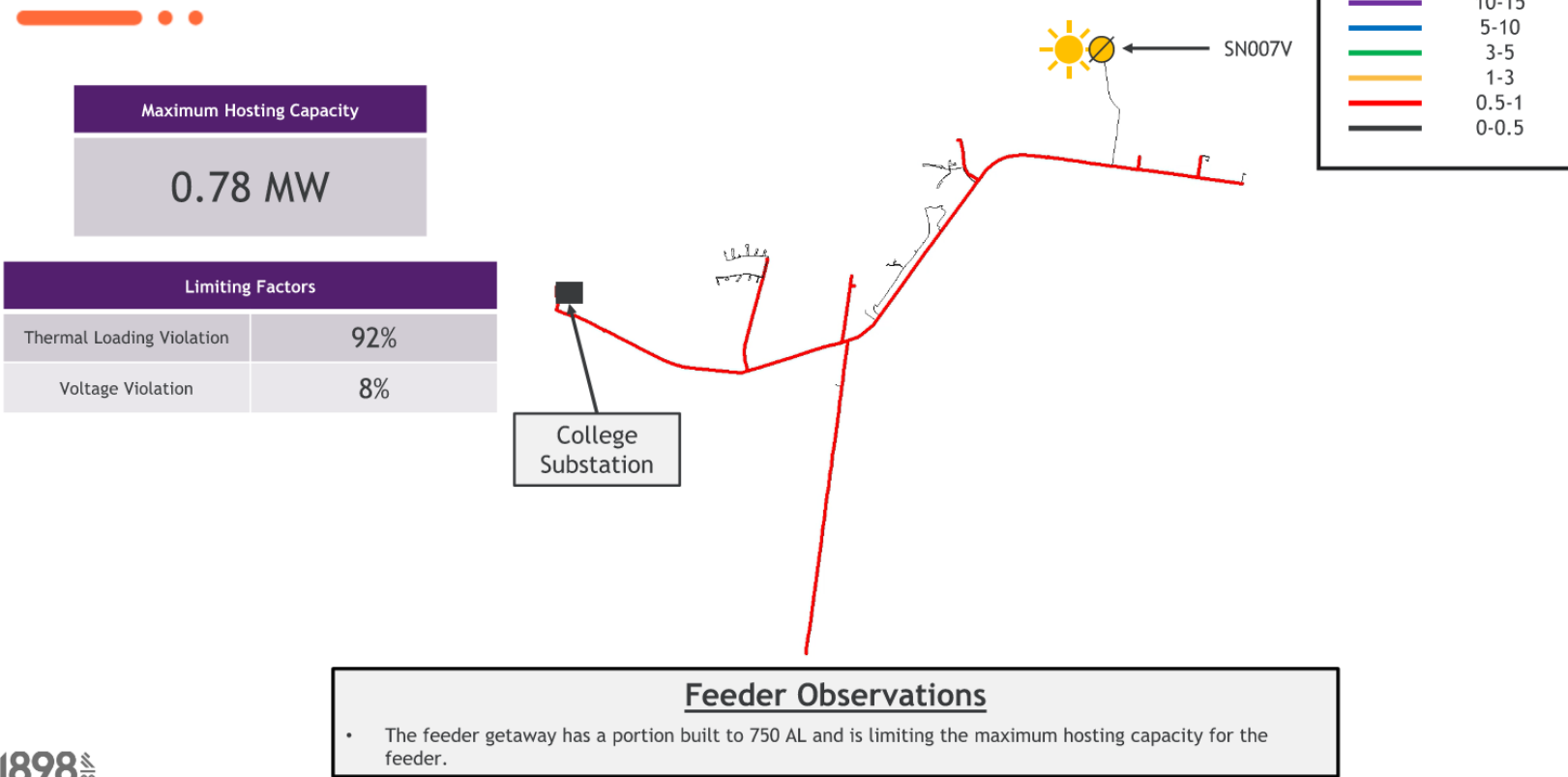
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Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,307	2,624	8,712	-95	404	387	400	122.0	125.6	96.1

COLL12 - Maximum Hosting Capacity Base Case w/ Queued PV

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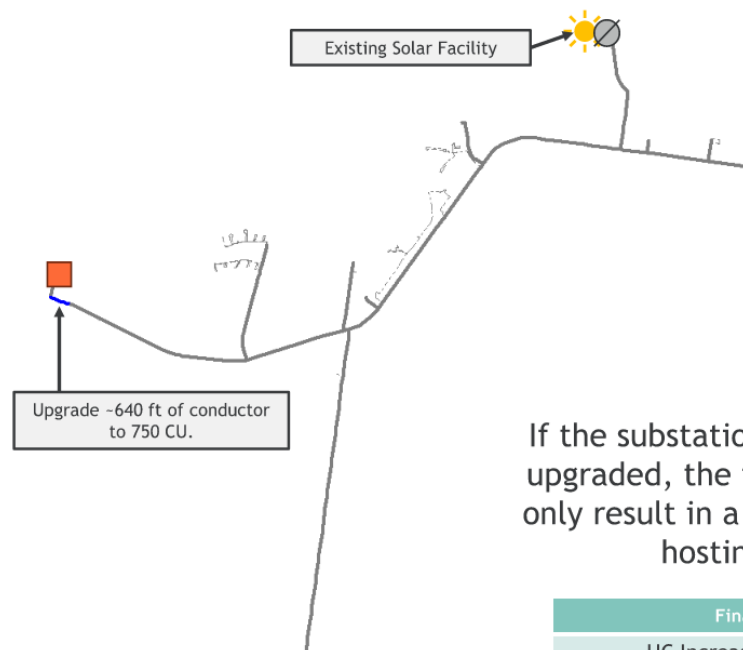
COLL12 - Feeder Upgrades

Hosting Capacity	
Base HC	0.78 MW
Max HC	2.94 MW
HC Increase	2.16 MW

College XFMR Capacity - 1.8 MW
Actual HC Increase - 1.02 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade -640 ft of 750 AL UG to 750 CU UG from South of College Substation to Pole E33A031.	\$211,994
TOTAL	\$211,994



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

If the substation transformer is not upgraded, the feeder upgrades will only result in a marginal increase in hosting capacity.

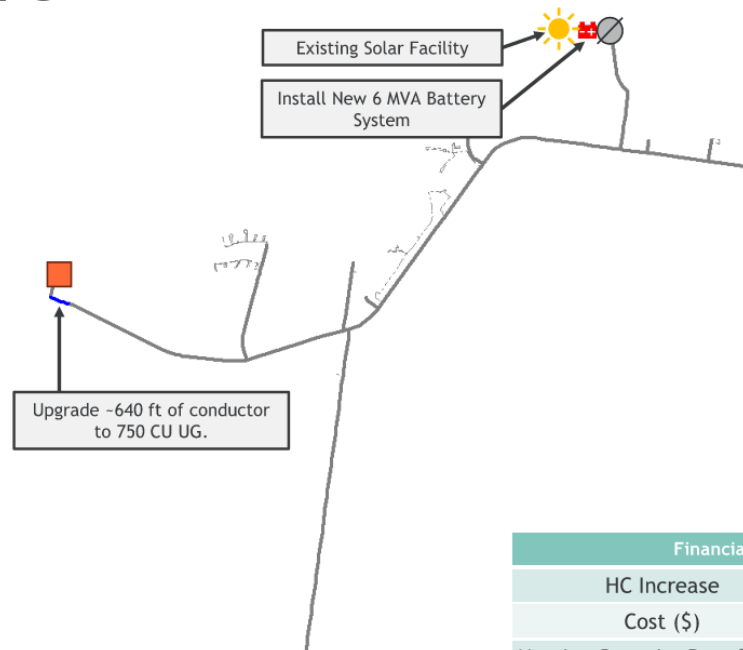
Financial Analysis	
HC Increase	1.02 MW
Cost (\$)	211,994
Hosting Capacity Benefit Cost	4.81
Holistic System Benefit Cost	5.13

COLL12 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	0.78 MW
Max HC	4.7 MW
HC Increase	3.92 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~640 ft of 750 AL UG to 750 CU UG from South of College Substation to Pole E33A031	\$211,994
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,511,994



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

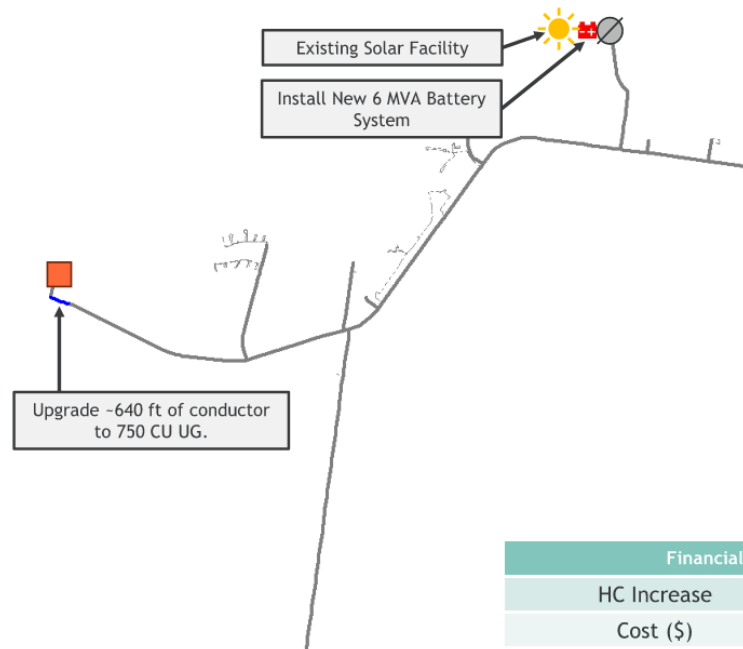
Financial Analysis	
HC Increase	3.92 MW
Cost (\$)	14,511,994
Hosting Capacity Benefit Cost	0.27
Holistic System Benefit Cost	1.04

COLL12 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	0.78 MW
Max HC	7.97 MW
HC Increase	7.19 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Upgrade ~640 ft of 750 AL UG to 750 CU UG from South of College Substation to Pole E33A031	\$211,994
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,561,994



Financial Analysis	
HC Increase	7.19 MW
Cost (\$)	14,561,994
Hosting Capacity Benefit Cost	0.49
Holistic System Benefit Cost	1.95



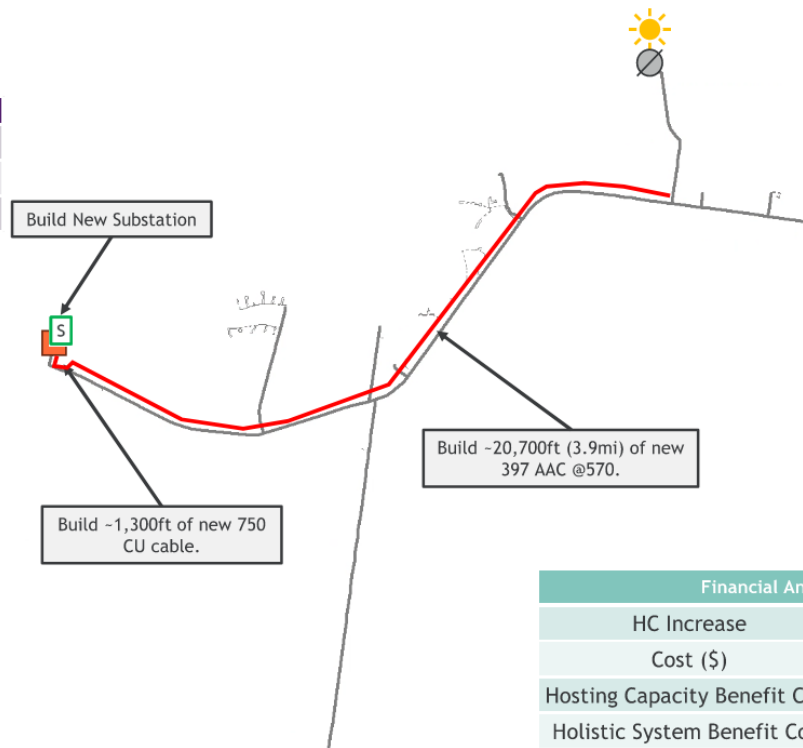
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COLL12 - Dedicated Feeder

Hosting Capacity	
Base HC	0.78 MW
Max HC	9.06 MW
HC Increase	8.28 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~1,300ft of new 750 CU cable from the New College Substation to a new riser pole.	\$3,503,202
Build ~36,300ft (7.1mi) of new 397 AAC @570. Utilize double circuit construction along the existing path of College 12 main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$11,503,202



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	8.28 MW
Cost (\$)	11,503,202
Hosting Capacity Benefit Cost	0.72
Holistic System Benefit Cost	0.77

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COLL12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	781	1,800	1,020	\$211,994	4.81	5.13
Feeder Upgrades with 2 MVA BESS	781	4,698	3,917	\$14,511,994	0.27	1.04
2 MVA BESS Only*	-	-	-	-	-	-
Feeder Upgrades with 6 MVA BESS	781	7,968	7,187	\$14,561,994	0.49	1.95
6 MVA BESS Only*	-	-	-	-	-	-
Dedicated Feeder	781	9,063	8,282	\$11,503,202	0.72	0.77

*This scenario was not applicable to this analysis.



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COLL12 - Feeder Overview with Queued Solar as of 8-19-2024

Feeder Data

- Feeder Rating: **9,072 kVA**
- Existing Generation: **9,161 kVA**
- Minimum Daylight Load: -8,312 kW
- Minimum Daylight Gross Load: 284 kW / -241 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **3**
- Total Queued AC Inverter Nameplate: **17 kW**

Protection & Equipment Pickup/Ratings

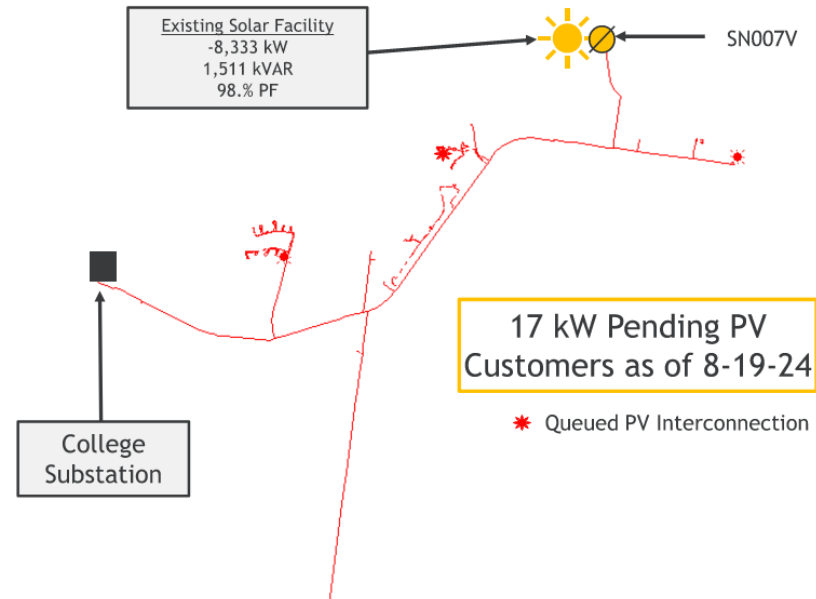
Device	Name	Pick Up Rating (A)
Breaker	COLL12 Breaker	600
Recloser	SN007V	425



The feeder can serve queued PV interconnection requests without violations.

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Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,312	2,625	8,717	-95	404	387	400	122.0	125.1	96.1

DEM W11 Analysis



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DEMW11 - Feeder Overview

The transformer rating is more limiting than the feeder rating for DEMW11.

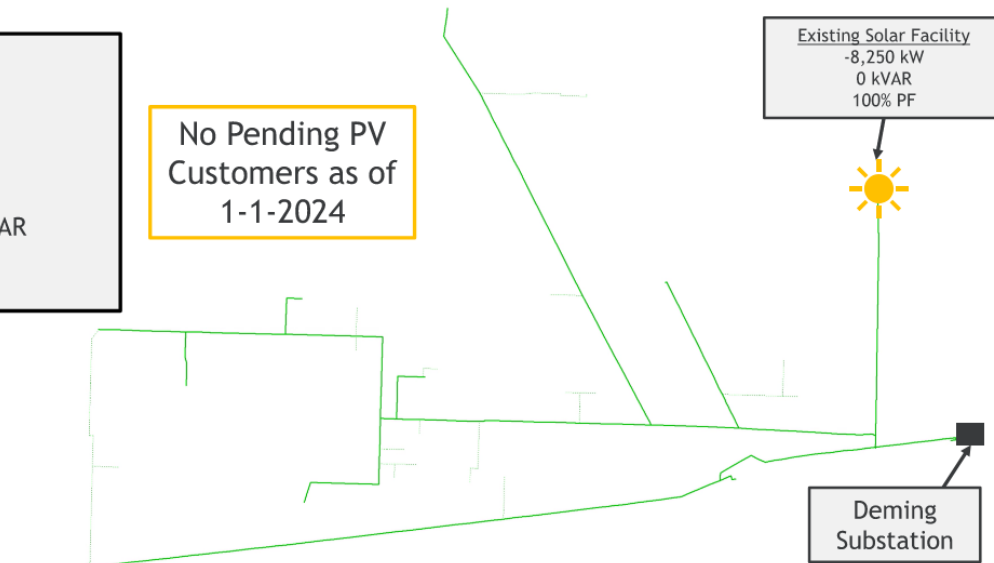
Feeder Data

- Feeder Rating: **10,278 kVA**
- Transformer Rating: **9,370 kVA**
- Existing Generation: 8,304 kVA
- Minimum Daylight Load: -8,062 kW
- Minimum Daylight Gross Load: 83 kW / -10 kVAR
- Substation LTC Setpoint: 123 V
- Primary Voltage: 13.8 kV

No Pending PV Customers as of 1-1-2024

Protection & Equipment Pickup/Ratings		
Device	Name	Pick Up Rating (A)
Breaker	DEM11 Breaker	600

8,250 kVA solar facility shown in the figure is an approved SGIA interconnection that has not been constructed yet. The system improvements identified in the impact study have been modeled to show the hosting capacity performance of the feeder once all system improvements have been constructed that are necessary for interconnecting this project.



Base Case Load Flow Analysis (Minimum daylight Load)

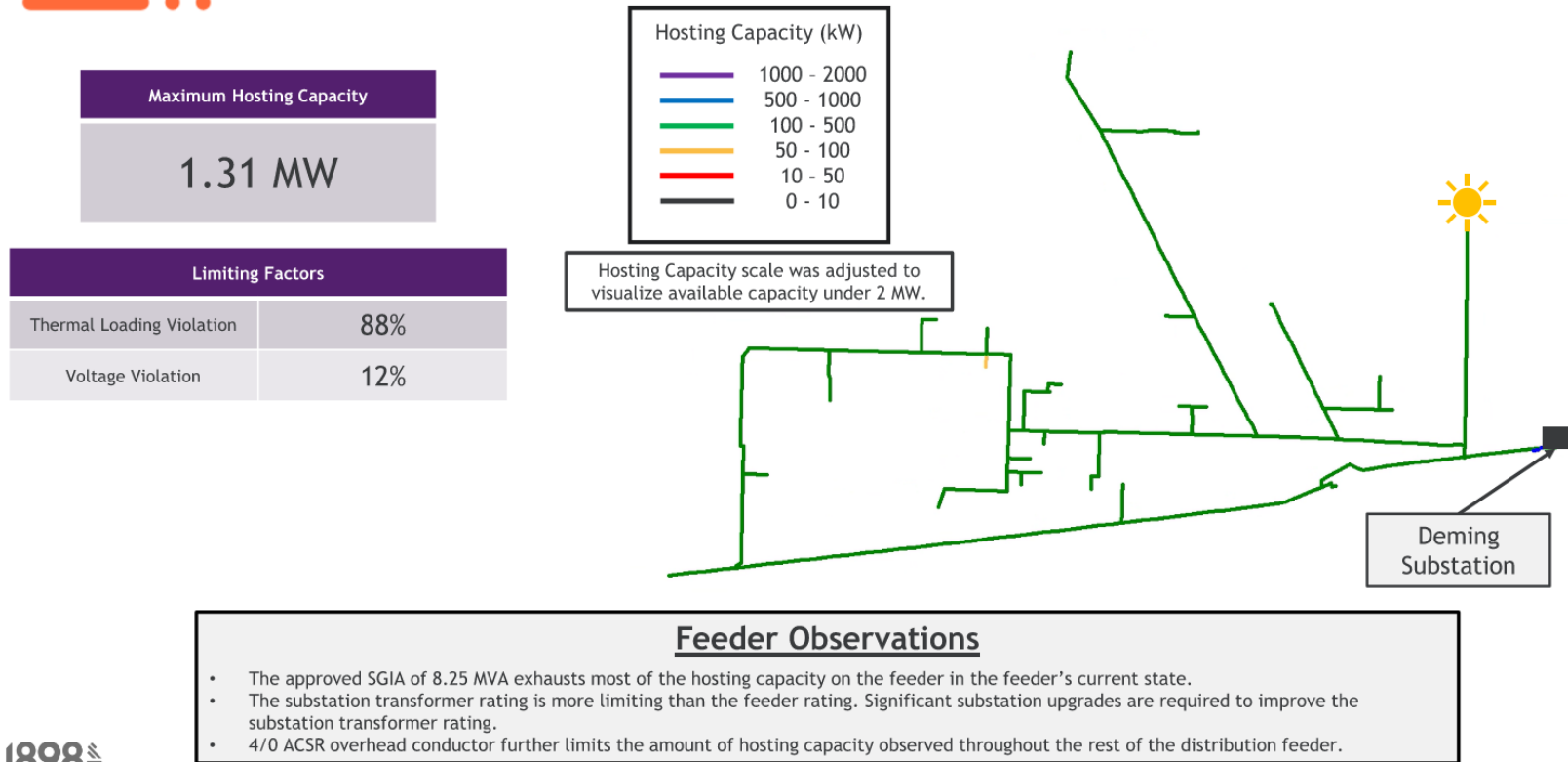
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,062	348	8,070	-100	330	328	331	123.0	125.3	92

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DEMW11 - Maximum Hosting Capacity Base Case



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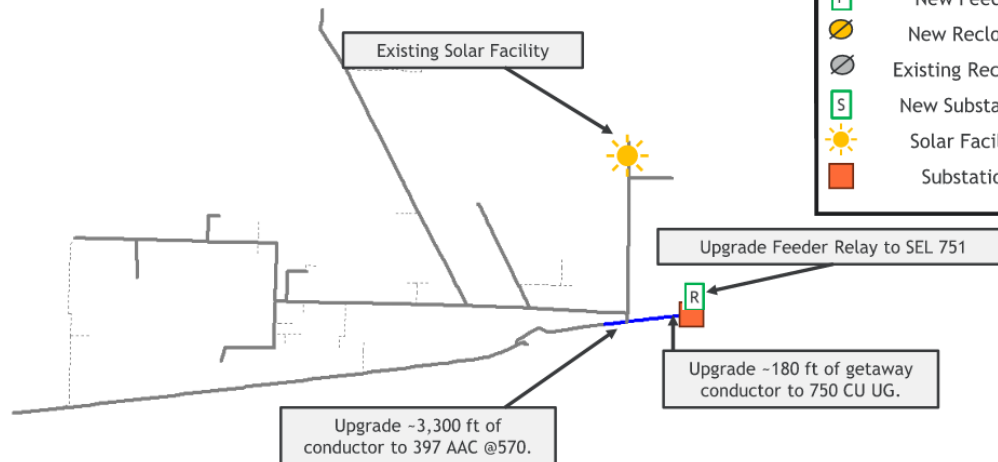
DEMW11 - Feeder Upgrades

Hosting Capacity	
Base HC	1.31 MW
Max HC	1.28 MW
HC Increase	-0.03 MW

Reverse Flow Limits
Max HC

System Improvement	Cost
Upgrade ~180 ft of 750 AL UG to 750 CU UG from Deming West Substation to Pole H73C514	\$343,013
Upgrade ~3,300 ft of 4/0 ACSR to 397 AAC @570 from Pole H73C514 to Pole G73D116	
Upgrade Feeder relay setting	
TOTAL	\$343,013

Hosting capacity decreased after constructing feeder upgrades. The overall hosting capacity constraint, which is the substation transformer, is not improved with feeder upgrades. The losses on the feeder decrease with new conductor but the power flow through the transformer increases. Reduced losses resulted in slightly less hosting capacity.



Financial Analysis	
HC Increase	-0.03 MW
Cost (\$)	343,013
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-



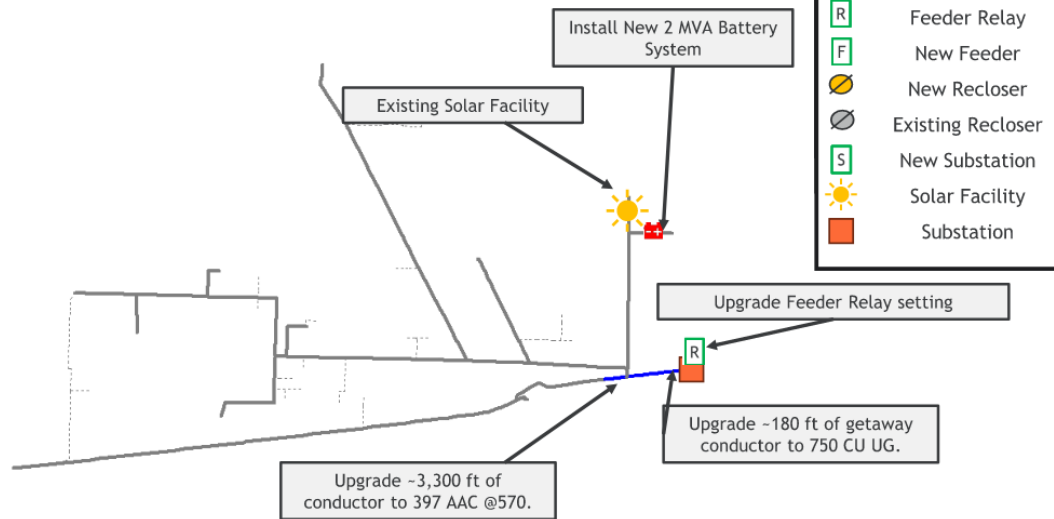
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DEMW11 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	1.31 MW
Max HC	3.21 MW
HC Increase	1.9 MW

Reverse Flow Limits
Max HC

System Improvement	Cost
Upgrade ~180 ft of 750 AL UG to 750 CU UG from Deming West Substation to Pole H73C514	\$343,013
Upgrade ~3,300 ft of 4/0 ACSR to 397 AAC @570 from Pole H73C514 to Pole G73D116	
Upgrade Feeder relay setting	
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,643,013



Financial Analysis	
HC Increase	1.9 MW
Cost (\$)	14,643,013
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.91



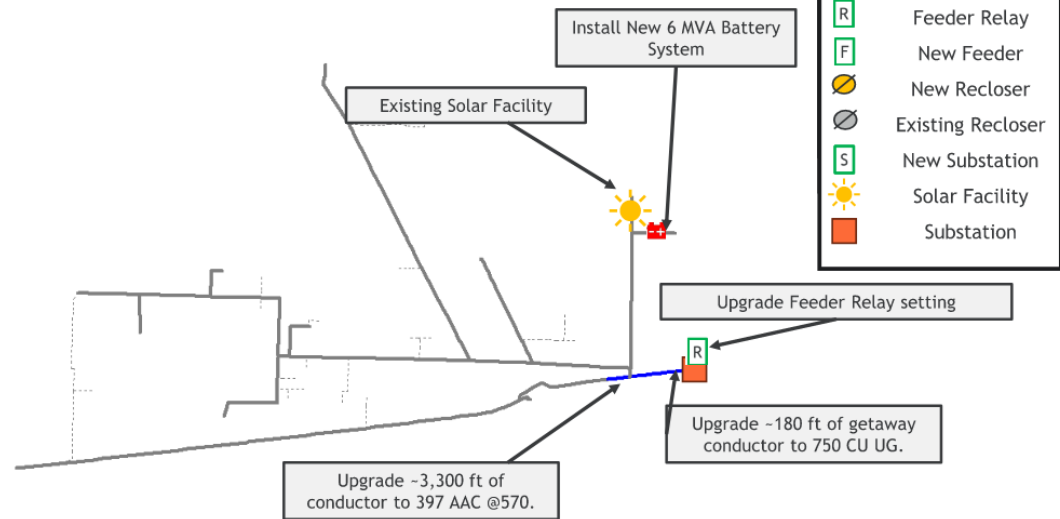
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DEMW11 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	1.31 MW
Max HC	6.1 MW
HC Increase	4.79 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Upgrade ~180 ft of 750 AL UG to 750 CU UG from Deming West Substation to Pole H73C514	\$343,013
Upgrade ~3,300 ft of 4/0 ACSR to 397 AAC @570 from Pole H73C514 to Pole G73D116	
Upgrade Feeder relay setting	
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,693,013



Financial Analysis	
HC Increase	4.79 MW
Cost (\$)	14,693,013
Hosting Capacity Benefit Cost	0.33
Holistic System Benefit Cost	1.79



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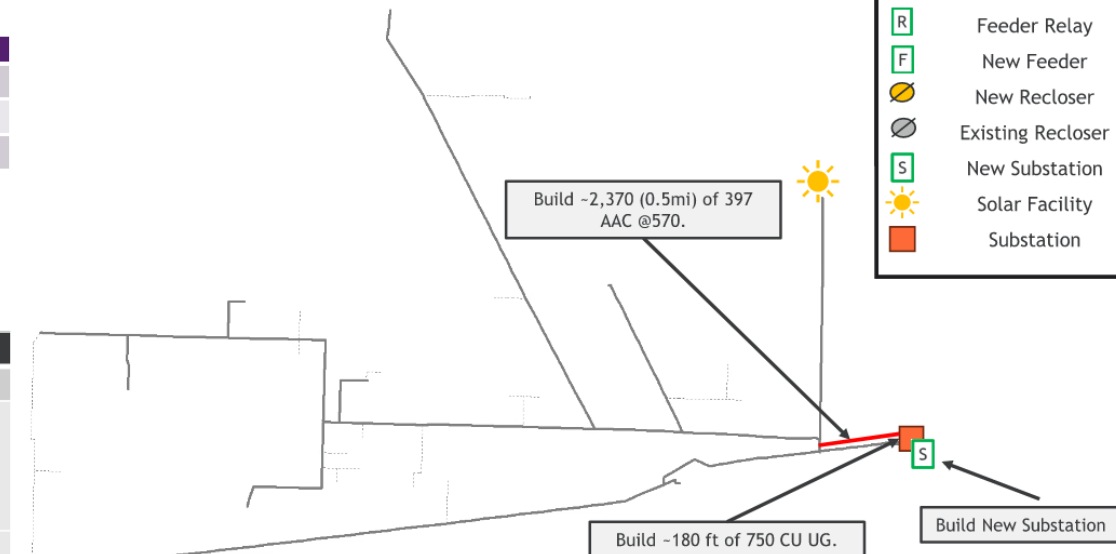
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DEMW11 - Dedicated Feeder

Hosting Capacity	
Base HC	1.31 MW
Max HC	9.38 MW
HC Increase	8.07 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~180ft of new 750 CU UG cable from the New Deming West Substation to a new riser pole.	
Build ~2,370ft (0.5mi) of new 397 AAC @ 570. Utilize double circuit construction along the existing path of Deming West 11 feeder main line conductor.	\$756,768
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$8,756,768



Financial Analysis	
HC Increase	8.07 MW
Cost (\$)	8,756,768
Hosting Capacity Benefit Cost	0.92
Holistic System Benefit Cost	0.98



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DEM11 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	1,308	1,280	-28*	\$343,013	-	-
Feeder Upgrades with 2 MVA BESS	1,308	3,208	1,900	\$14,643,013	0.13	0.91
2 MVA BESS Only**	-	-	-	-	-	-
Feeder Upgrades with 6 MVA BESS	1,308	6,102	4,794	\$14,693,013	0.33	1.79
6 MVA BESS Only**	-	-	-	-	-	-
Dedicated Feeder	1,308	9,380	8,072	\$8,756,768	0.92	0.98

*Deming West Substation transformer is more limiting to hosting capacity than the feeder rating. Feeder upgrades would not remove the substation transformer constraint. After feeder upgrades are performed, losses would decrease on the feeder and the maximum hosting capacity decreased by a small amount.

**This scenario was not applicable to this analysis.



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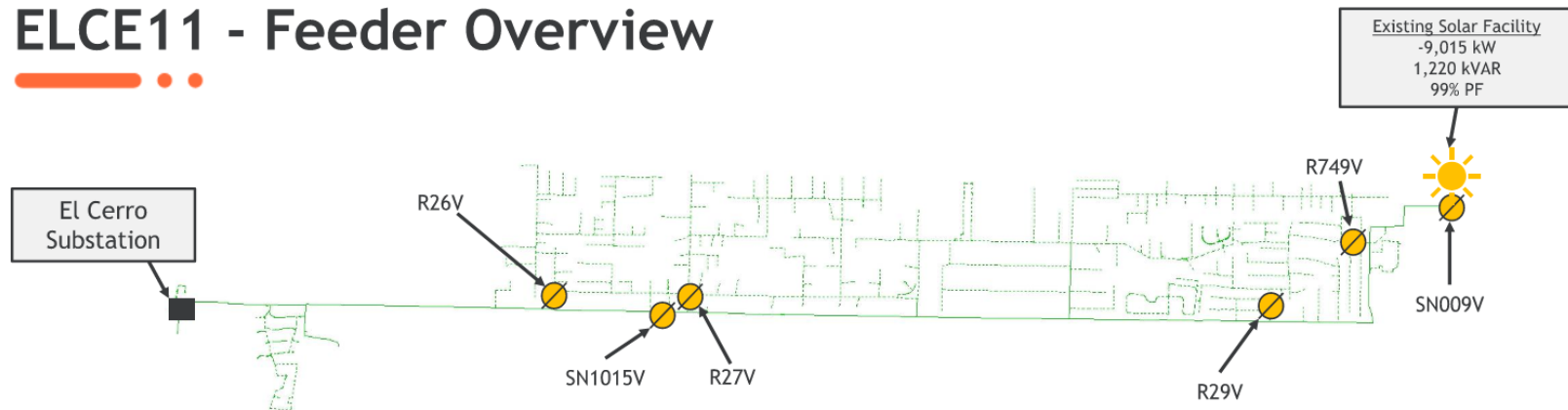
ELCE11 Analysis



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ELCE11 - Feeder Overview



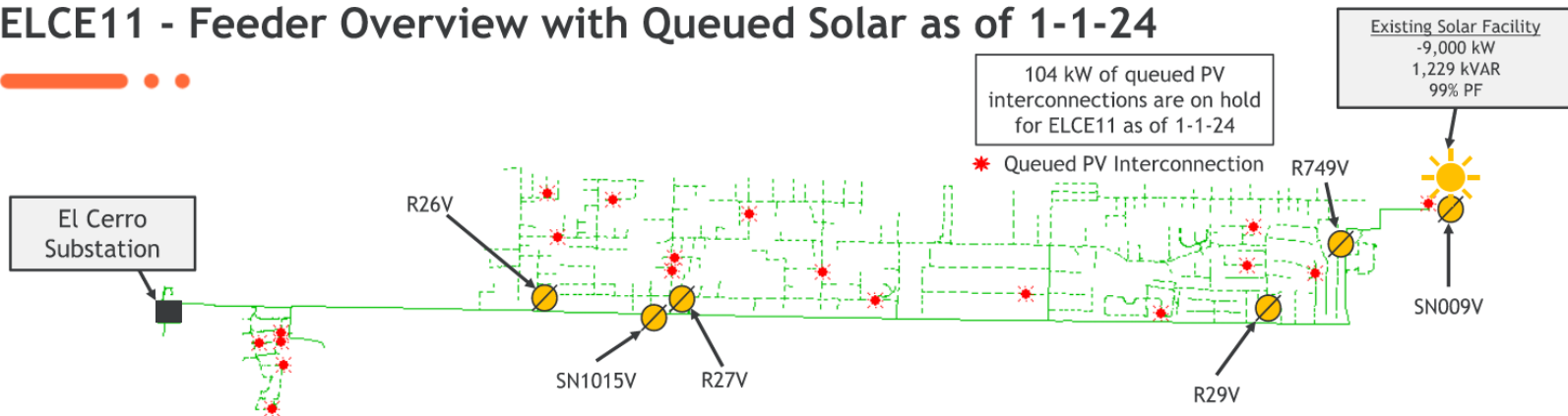
Protection & Equipment Pickup/Ratings		
Device	Name	Pick Up Rating (A)
Breaker	ELCE11 Breaker	540
Recloser	R26V	100
Recloser	R27V	100
Recloser	R29V	200
Recloser	R749V	200
Recloser	SN009V	600
Recloser	SN1015V	600

Base Case Load Flow Analysis (Minimum daylight Load)									
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-6,954	3,232	7,668	-91	345	350	352	120.6	124.4	97.0

Feeder Data

- Feeder Rating: 9,288 kVA
- Existing Generation: 9,257 kVA
- Minimum Daylight Load: -6,954 kW
- Minimum Daylight Gross Load: 1,288 kW / 180 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV

ELCE11 - Feeder Overview with Queued Solar as of 1-1-24



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-7,039	3,254	7,755	-91	347	356	356	120.8	124.6	96.7

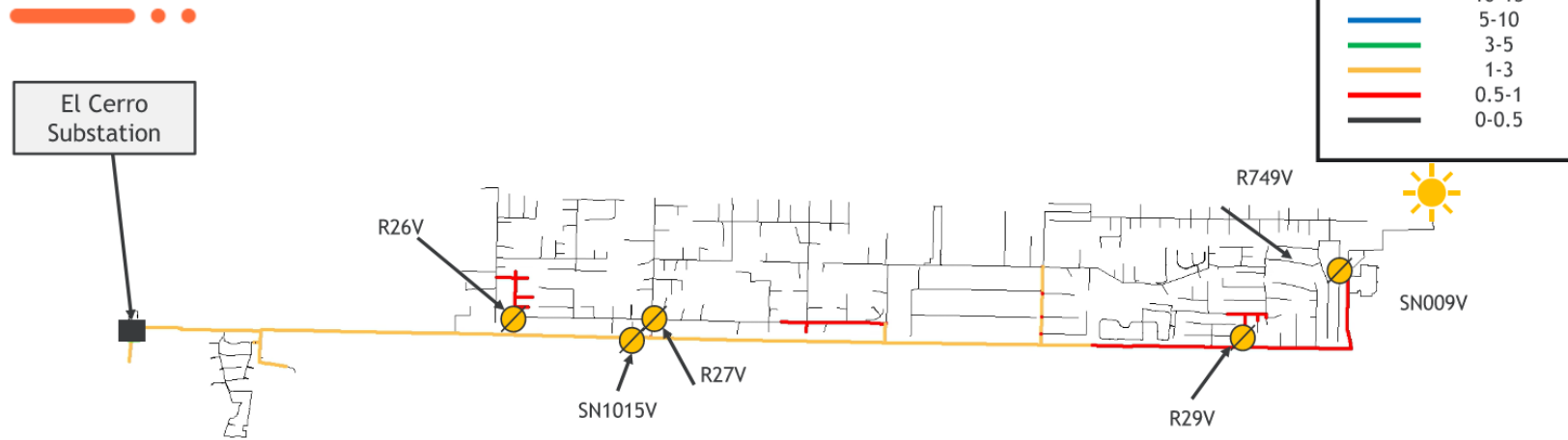


The feeder can serve queued PV interconnection requests without violations.

Feeder Data

- Feeder Rating: 9,288 kVA
- Existing Generation: 9,284 kVA
- Minimum Daylight Load: -7,039 kW
- Minimum Daylight Gross Load: 1,288 kW / 180 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **19**
- Total Queued AC Inverter Nameplate: **104 kW**

ELCE11 - Maximum Hosting Capacity Base Case w/ Queued PV



Maximum Hosting Capacity
2.02 MW

Limiting Factors	
Thermal Loading Violation	78%
Voltage Violation	22%

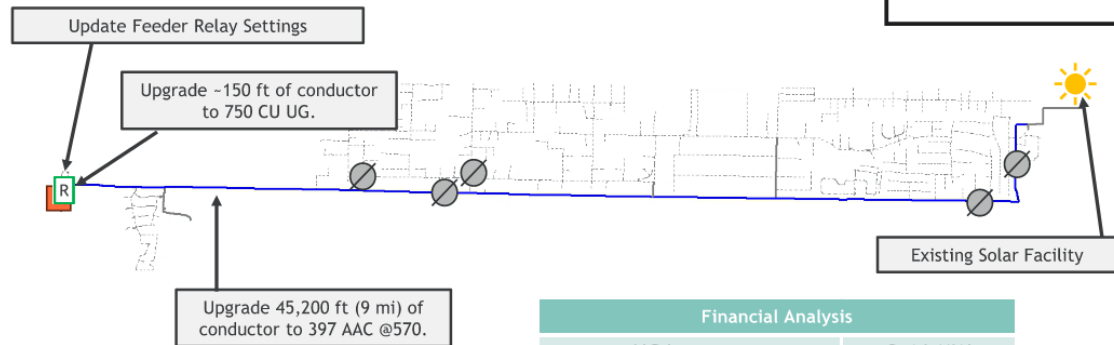
- Feeder Observations**
- 750 AL sections of the feeder getaway is the limiting factor for the maximum hosting capacity. Conductor upgrade to 750 CU would increase the feeder rating and maximum hosting capacity.
 - Volt-VAR control from the existing large-scale PV facility is helping to regulate voltage and limit the number of voltage violations observed while performing hosting capacity analysis.

ELCE11 - Feeder Upgrades

Hosting Capacity	
Base HC	2.02 MW
Max HC	4.18 MW
HC Increase	2.16 MW

Reverse Flow Limits
Max HC

System Improvement	Cost
Upgrade 45,200ft (9mi) 397 AAC (old standard) to 397 AAC @570 from Pole E29D367 to near Pole I29C061	\$4,502,143
Upgrade ~150 ft feeder getaway cable from 750 AL to 750 CU from El Cerro Substation to Pole E29D367	
Update Feeder Relay Settings	
TOTAL	\$4,502,143



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	2.16 MW
Cost (\$)	4,502,143
Hosting Capacity Benefit Cost	0.48
Holistic System Benefit Cost	0.51

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ELCE11 - Feeder Upgrades & 2 MVA BESS

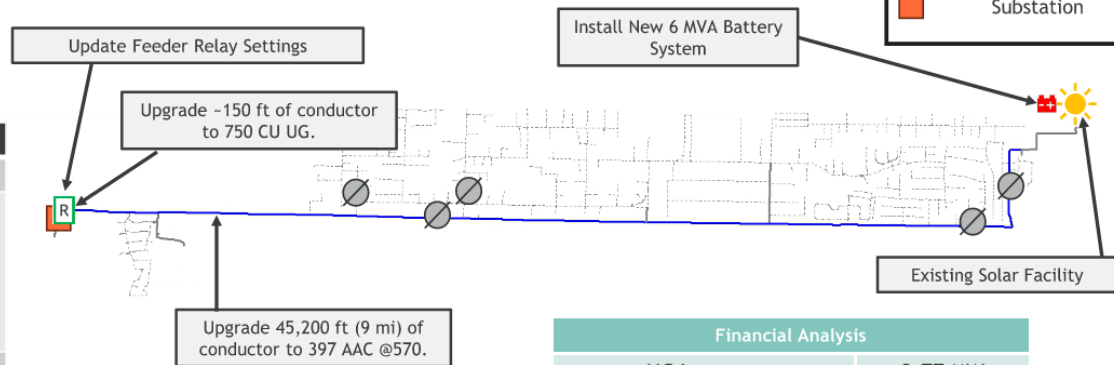
Hosting Capacity	
Base HC	2.02 MW
Max HC	5.79 MW
HC Increase	3.77 MW

Reverse Flow Limits
Max HC

System Improvement	Cost
Upgrade 45,200ft (9mi) 397 AAC (old standard) to 397 AAC @570 from Pole E29D367 to near Pole I29C061	\$4,502,143
Upgrade ~150 ft feeder getaway cable from 750 AL to 750 CU from El Cerro Substation to Pole E29D367	
Update Feeder Relay Settings	
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$18,802,143

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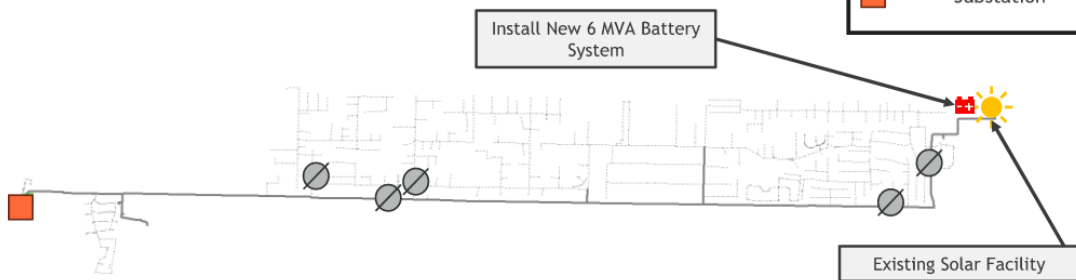
Financial Analysis	
HC Increase	3.77 MW
Cost (\$)	18,802,143
Hosting Capacity Benefit Cost	0.20
Holistic System Benefit Cost	0.83

ELCE11 - 2 MVA BESS Only

Hosting Capacity	
Base HC	2.02 MW
Max HC	3.63 MW
HC Increase	1.61 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,300,000



Financial Analysis	
Hosting Capacity Increase (MW)	1.61
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.11
Holistic System Benefit Cost	1.57

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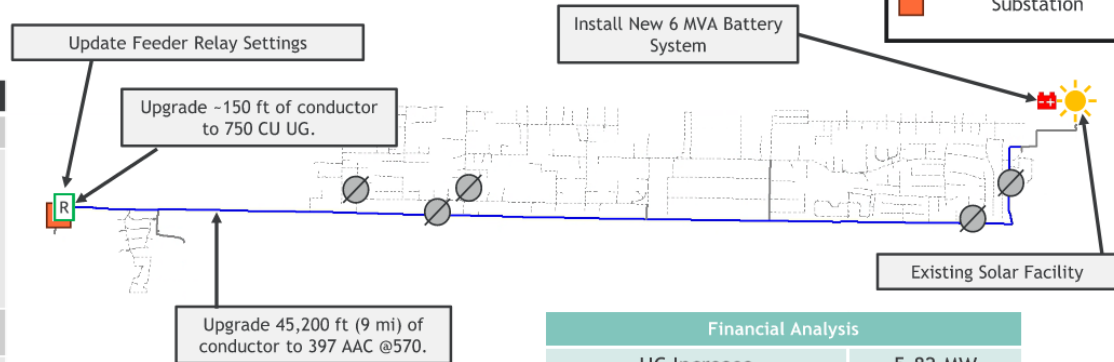
44

ELCE11 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	2.02 MW
Max HC	7.84 MW
HC Increase	5.82 MW

Thermal Loading Limits
Max HC

System Improvement	Cost
Upgrade 45,200ft (9mi) 397 AAC (old standard) to 397 AAC @570 from Pole E29D367 to near Pole I29C061	\$4,502,143
Upgrade ~150 ft feeder getaway cable from 750 AL to 750 CU from El Cerro Substation to Pole E29D367	
Update Feeder Relay Settings	
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$18,852,143



Financial Analysis	
HC Increase	5.82 MW
Cost (\$)	18,852,143
Hosting Capacity Benefit Cost	0.31
Holistic System Benefit Cost	1.17



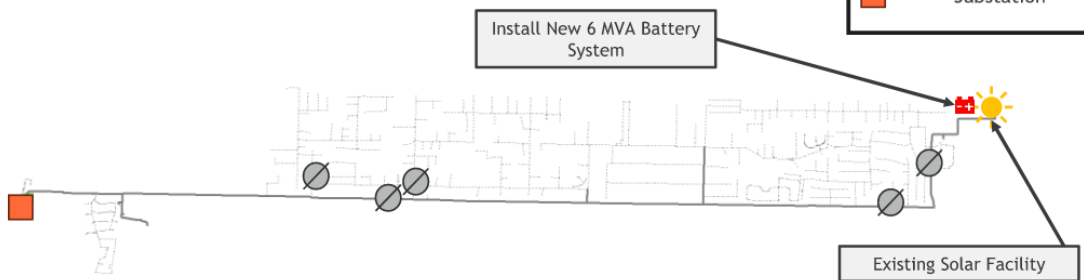
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ELCE11 - 6 MVA BESS Only

Hosting Capacity	
Base HC	2.02 MW
Max HC	4.55 MW
HC Increase	2.53 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,350,000



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

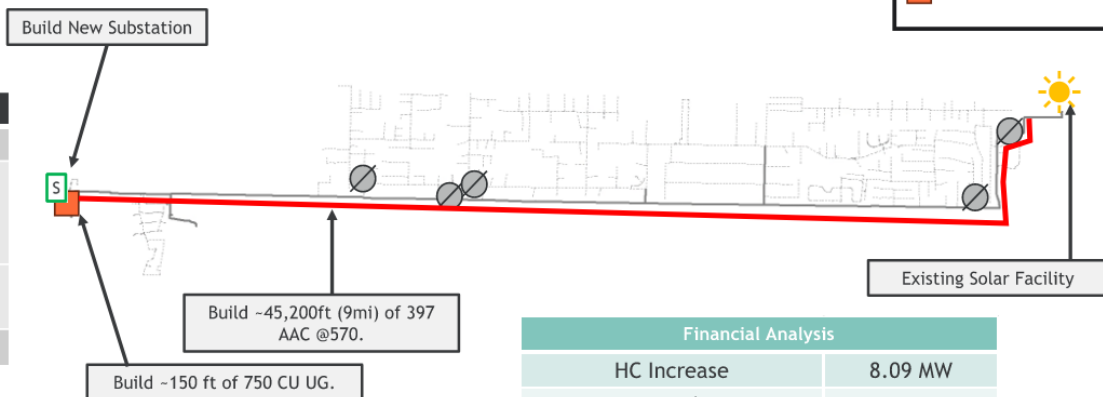
Financial Analysis	
Hosting Capacity Increase (MW)	2.53
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.18
Holistic System Benefit Cost	2.92

ELCE11 - Dedicated Feeder

Hosting Capacity	
Base HC	2.02 MW
Max HC	10.11 MW
HC Increase	8.09 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~150ft of new 750 CU UG.	
Build ~45,200ft of new 397 AAC@ 570. Utilize double circuit construction along the existing path of El Cerro Feeder 11 main line conductor.	\$3,902,457
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$11,902,457



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	8.09 MW
Cost (\$)	11,902,457
Hosting Capacity Benefit Cost	0.68
Holistic System Benefit Cost	0.72

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ELCE11 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	2,019	4,178	2,159	\$4,502,143	0.48	0.51
Feeder Upgrades with 2 MVA BESS	2,019	5,787	3,768	\$18,802,143	0.20	0.83
2 MVA BESS	2,019	3,630	1,611	\$14,300,000	0.11	1.57
Feeder Upgrades with 6 MVA BESS	2,019	7,844	5,825	\$18,852,143	0.31	1.17
6 MVA BESS	2,019	4,550	2,531	\$14,350,000	0.18	2.92
Dedicated Feeder	2,019	10,110	8,091	\$11,902,457	0.68	0.72



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GOLD13 Analysis



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GOLD13 - Feeder Overview

Gold Feeder 13 is in the Deming, NM area. This area is operated at 13.8 kV.

No Pending PV Customers
as of 1-1-2024

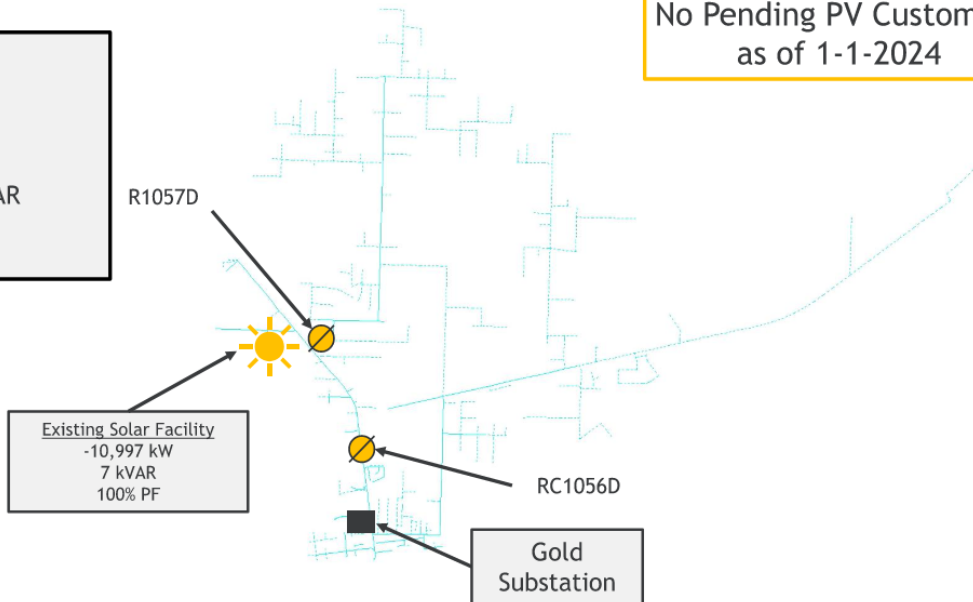
Feeder Data

- Feeder Rating: 12,429 kVA
- Existing Generation: 11,272 kVA
- Minimum Daylight Load: -10,292 kW
- Minimum Daylight Gross Load: 729 kW / 28 kVAR
- Substation LTC Setpoint: 123 V
- Primary Voltage: **13.8 kV**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	GOLD13 Breaker	600
Recloser	R1057D	600
Recloser	RC1056D	600

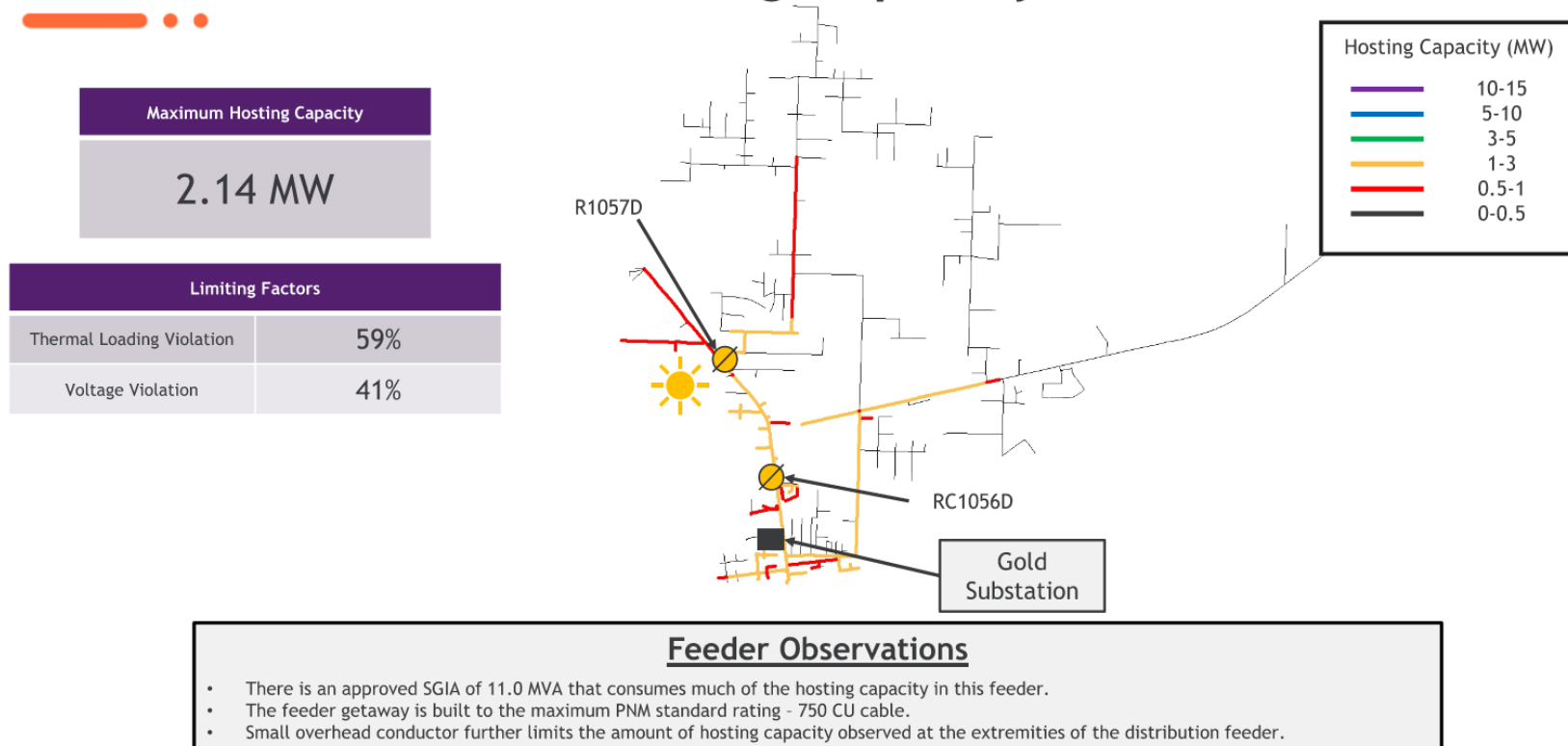
11,000 kVA solar facility shown in the figure is an approved SGIA interconnection that has not been constructed yet. The system improvements identified in the impact study have been modeled to show the hosting capacity performance of the feeder once all system improvements have been constructed that are necessary for interconnecting this project.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-10,292	692	10,315	-100	420	422	421	122.4	125.7	81

GOLD13 - Maximum Hosting Capacity Base Case



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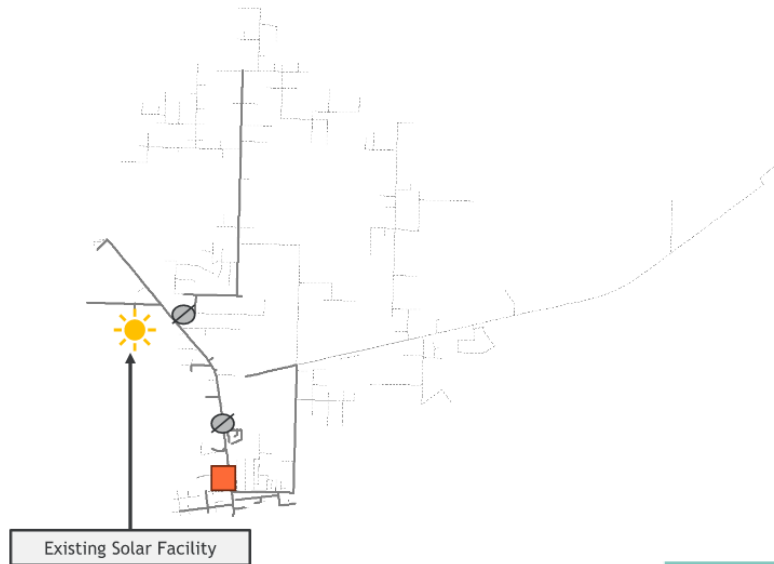
51

GOLD13 - Feeder Upgrades

Hosting Capacity	
Base HC	2.14 MW
Max HC	2.14 MW
HC Increase	0 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
No traditional system upgrades are applicable. The feeder is built to the maximum PNM conductor and equipment standards.	\$0
TOTAL	\$0



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
Hosting Capacity Increase (MW)	0
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-

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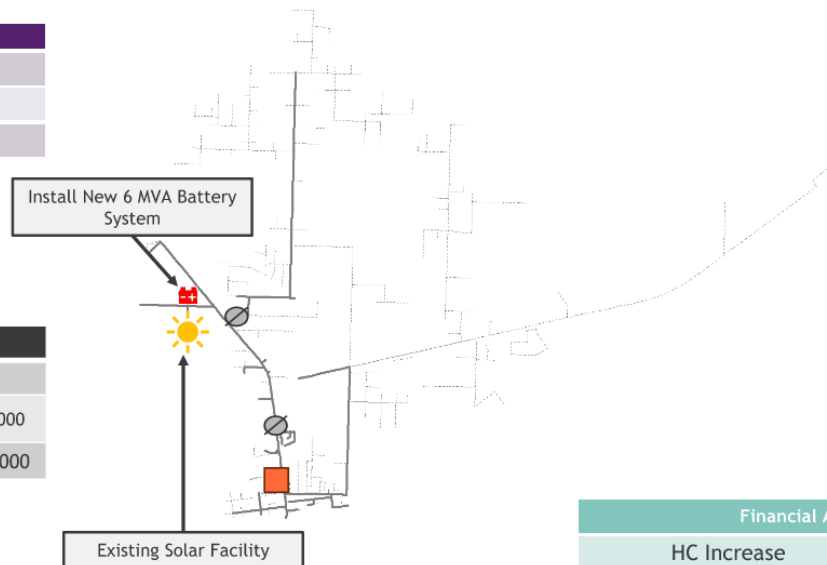
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GOLD13 - 2 MVA BESS Only

Hosting Capacity	
Base HC	2.14 MW
Max HC	4.04 MW
HC Increase	1.9 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,300,000



Financial Analysis	
HC Increase	1.9 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.93



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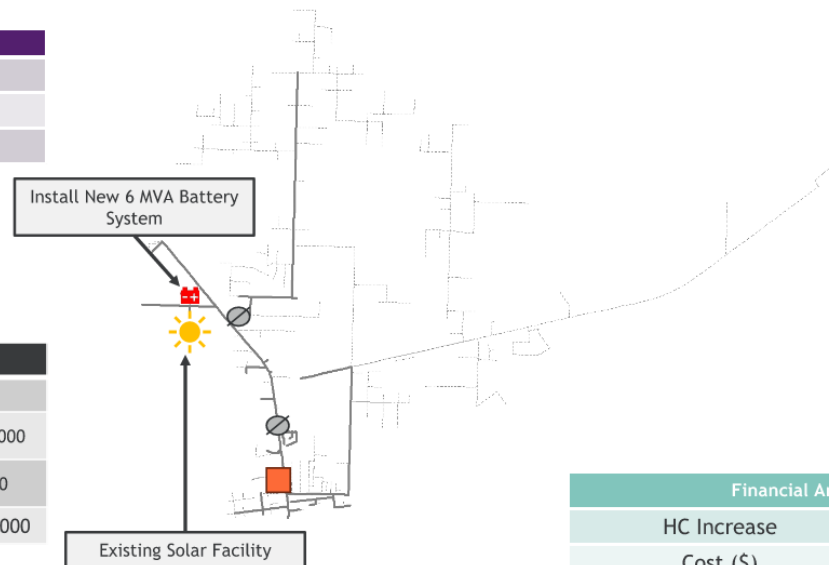
53

GOLD13 - 6 MVA BESS Only

Hosting Capacity	
Base HC	2.14 MW
Max HC	7.84 MW
HC Increase	5.7 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,350,000



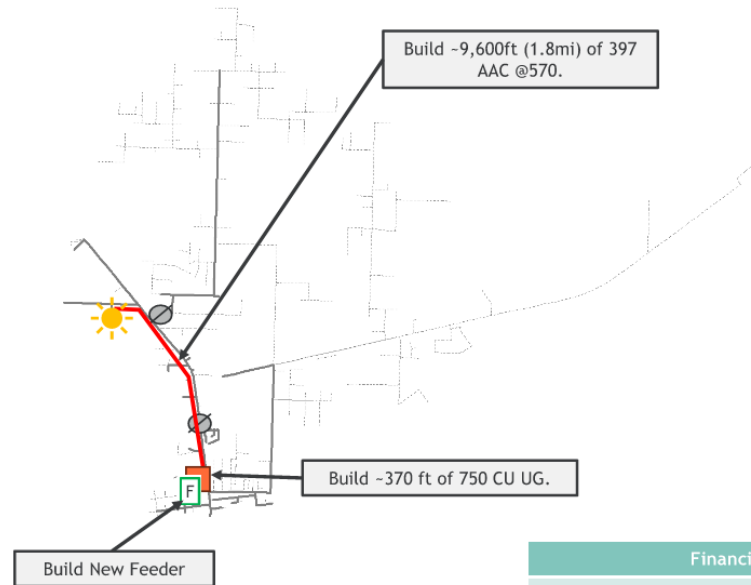
Financial Analysis	
HC Increase	5.7 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.40
Holistic System Benefit Cost	1.88

GOLD13 - Dedicated Feeder

Hosting Capacity	
Base HC	2.14 MW
Max HC	12.88 MW
HC Increase	10.74 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~370 ft of new 750 CU UG cable from the New Gold Feeder to a new riser pole.	\$1,286,828
Build ~9,600 ft of new 397 AAC @ 570. Utilize double circuit construction along the existing path of Gold 13 feeder main line conductor.	
Install Breaker and SEL 751 Relay for the New Feeder.	
TOTAL	\$1,286,828



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	10.74 MW
Cost (\$)	1,286,828
Hosting Capacity Benefit Cost	8.35
Holistic System Benefit Cost	8.90



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GOLD13 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades*	-	-	-	-	-	-
Feeder Upgrades with 2 MVA BESS*	-	-	-	-	-	-
2 MVA BESS Only	2,139	4,037	1,898	\$14,300,000	0.13	0.93
Feeder Upgrades with 6 MVA BESS*	-	-	-	-	-	-
6 MVA BESS Only	2,139	7,838	5,699	\$14,350,000	0.40	1.88
Dedicated Feeder	2,139	12,882	10,743	\$1,286,828	8.35	8.90

*This scenario was not applicable to this analysis.



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HOND12 Analysis



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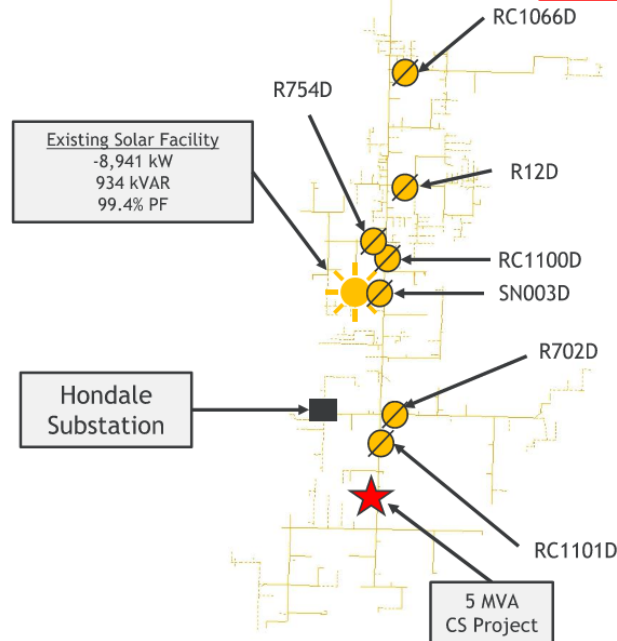
HOND12 - Feeder Overview

Feeder Data

- Feeder Rating: 10,039 kVA
- Existing Generation: 9,153 kVA
- Minimum Daylight Load: -8,561 kW
- Minimum Daylight Gross Load: 242 kW / -112 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: **13.8 kV**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	HOND12 Breaker	480
Recloser	R12D	140
Recloser	R702D	140
Recloser	R754D	150
Recloser	R1066D	70
Recloser	RC1100D	100
Recloser	RC1101D	150
Recloser	SN003D	450



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,561	-277	8,565	100	343	357	352	122.0	125.0	86.0

HOND12 - Feeder Overview with Queued Solar as of 1-1-24

Feeder Data

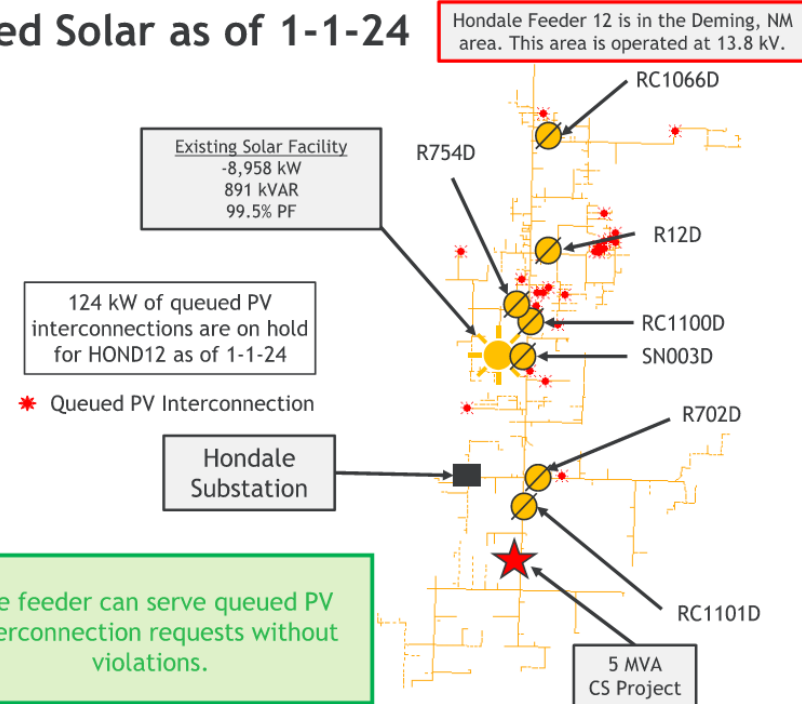
- Feeder Rating: 10,039 kVA
- Existing Generation: 9,234 kVA
- Minimum Daylight Load: -8,679 kW
- Minimum Daylight Gross Load: 242 kW / -112 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: **13.8 kV**
- Queued Solar Projects: **22**
- Total Queued AC Inverter Nameplate: **125 kW**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	HOND12 Breaker	480
Recloser	R12D	140
Recloser	R702D	140
Recloser	R754D	150
Recloser	R1066D	70
Recloser	RC1100D	100
Recloser	RC1101D	150
Recloser	SN003D	450

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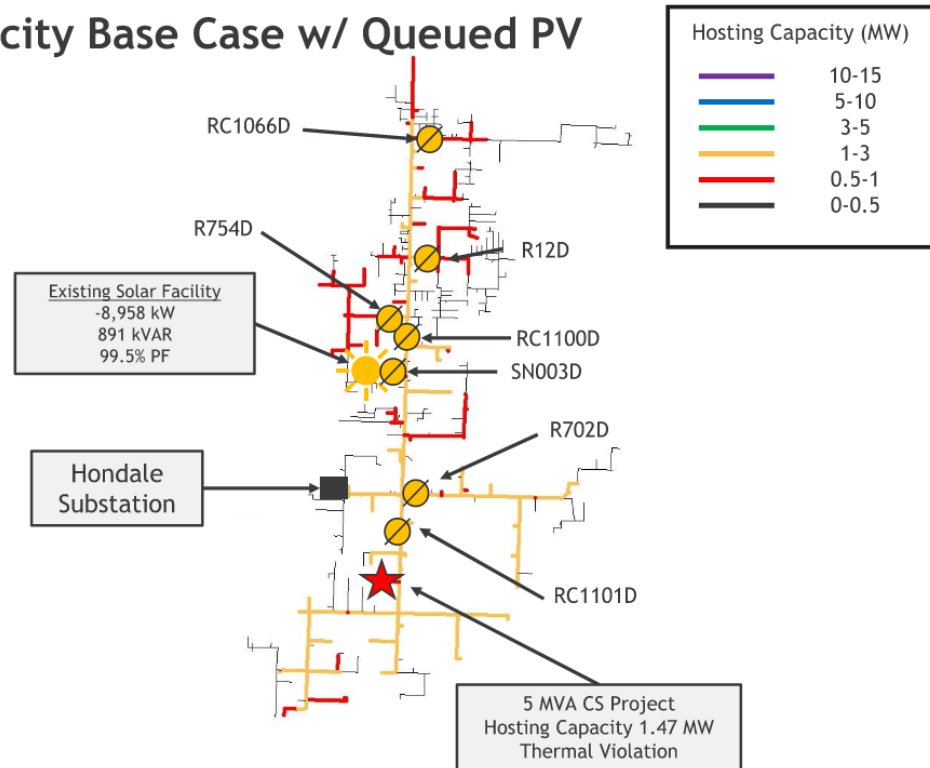


Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,679	-258	8,682	100	354	361	353	122.0	125.0	86.0

HOND12 - Maximum Hosting Capacity Base Case w/ Queued PV

Maximum Hosting Capacity	
1.35 MW	
Limiting Factors	
Thermal Loading Violation	59%
Voltage Violation	41%



Feeder Observations

- The feeder getaway is 750 AL UG and 397 AAC conductor rated for 430 Amps is limiting the hosting capacity for HOND12.

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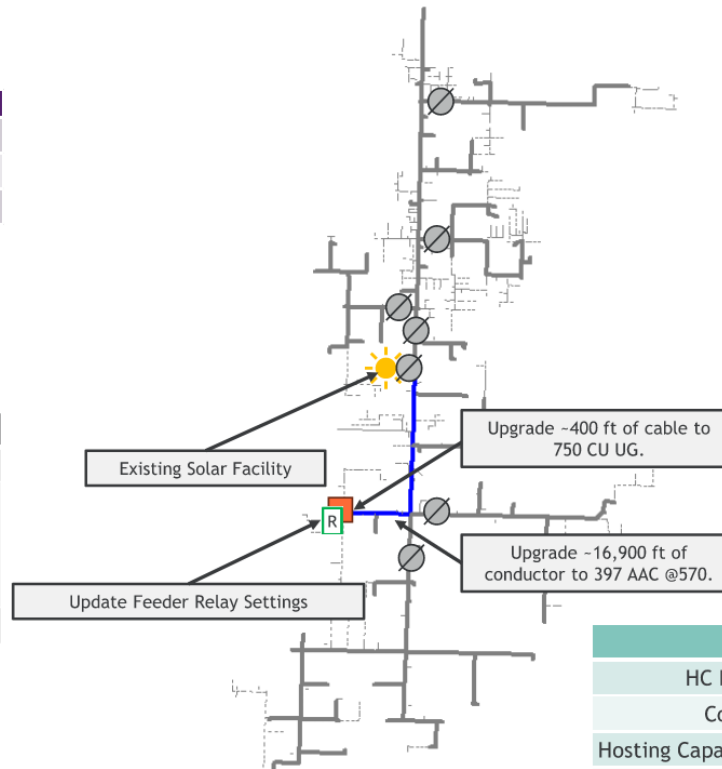
60

HOND12 - Feeder Upgrades

Hosting Capacity	
Base HC	1.35 MW
Max HC	3.74 MW
HC Increase	2.39 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~400 ft of 750 AL UG to 750 CU UG from Hondale 12 Substation to Pole G79D002.	\$383,946
Upgrade ~16,900 ft of 397 AAC to 397 AAC @570 from Pole G79D002 to near Pole H78A002.	
Update Feeder Relay Settings	
TOTAL	\$383,946



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	2.39 MW
Cost (\$)	383,946
Hosting Capacity Benefit Cost	6.22
Holistic System Benefit Cost	6.63

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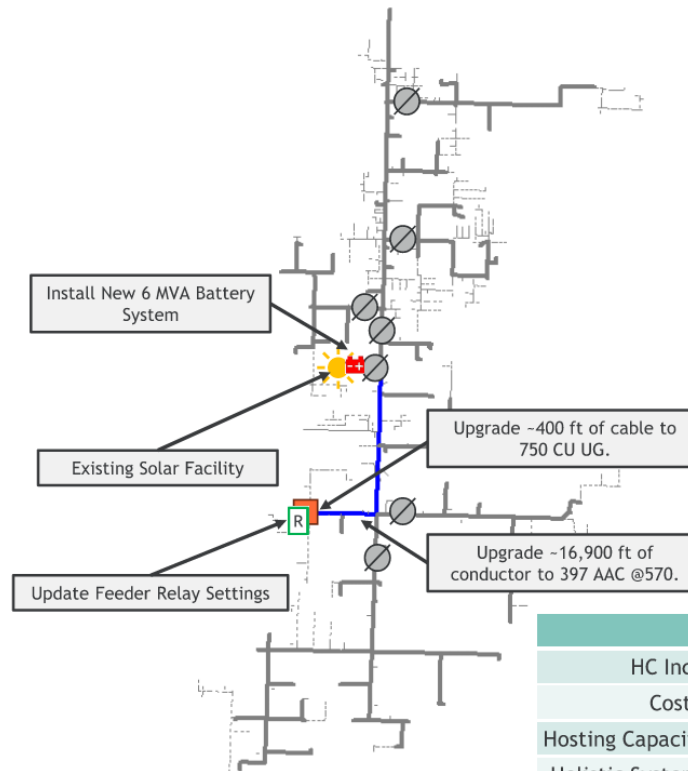
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HOND12 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	1.35 MW
Max HC	5.6 MW
HC Increase	4.25 MW

Reverse Flow Limits
Max HC

System Improvement	Cost
Upgrade ~400 ft of 750 AL UG to 750 CU UG from Hondale 12 Substation to Pole G79D002.	\$383,946
Upgrade ~16,900 ft of 397 AAC to 397 AAC @570 from Pole G79D002 to near Pole H78A002.	
Update Feeder Relay Settings	
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,683,946



Financial Analysis	
HC Increase	4.25 MW
Cost (\$)	14,683,946
Hosting Capacity Benefit Cost	0.29
Holistic System Benefit Cost	1.05

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HOND12 - Feeder Upgrades & 6 MVA BESS

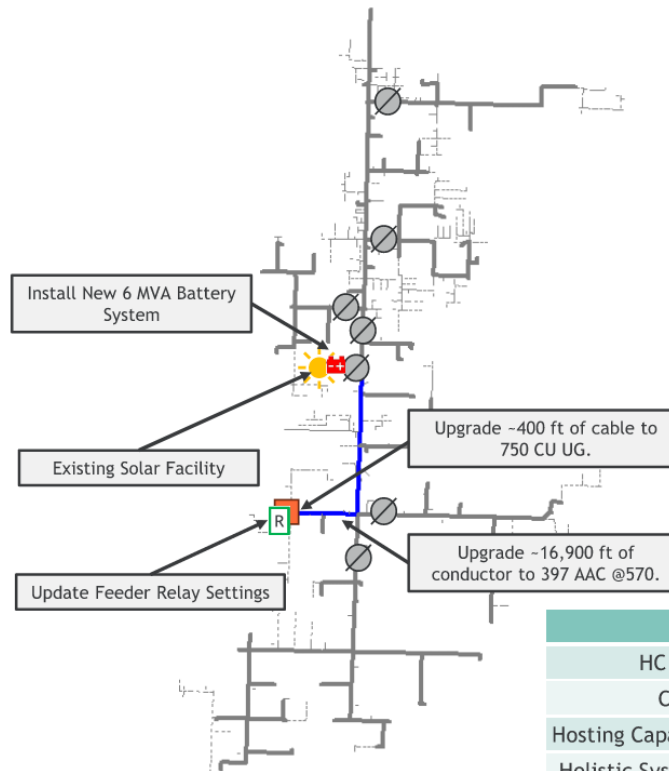
Hosting Capacity	
Base HC	1.35 MW
Max HC	9.47 MW
HC Increase	8.12 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~400 ft of 750 AL UG to 750 CU UG from Hondale 12 Substation to Pole G79D002	\$383,946
Upgrade ~16,900 ft of 397 AAC to 397 AAC @570 from Pole G79D002 to near Pole H78A002	
Update Feeder Relay Settings	
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,733,946



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Financial Analysis	
HC Increase	8.12 MW
Cost (\$)	14,733,946
Hosting Capacity Benefit Cost	0.55
Holistic System Benefit Cost	1.99

HOND12 - Dedicated Feeder

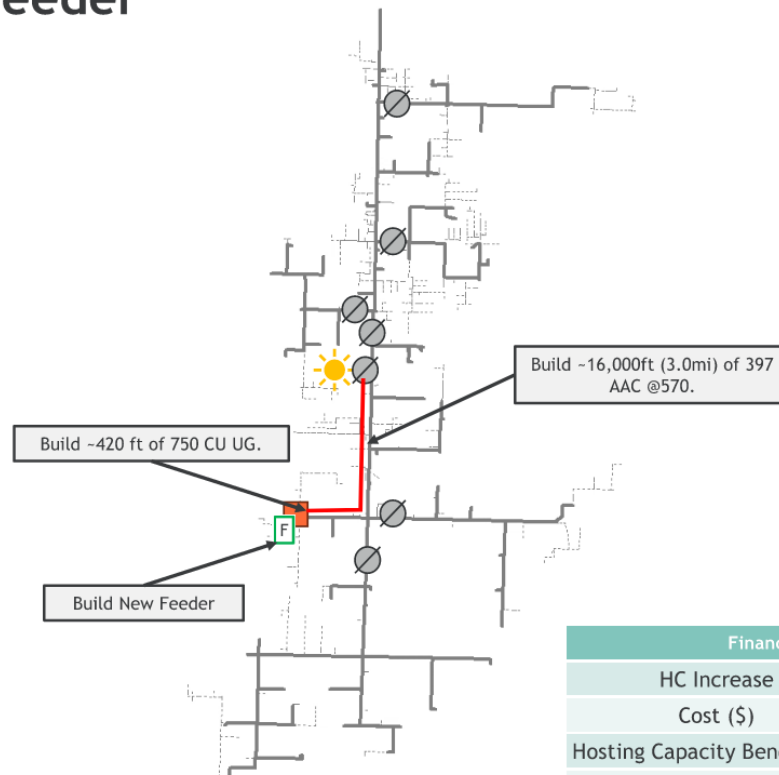
Hosting Capacity	
Base HC	1.35 MW
Max HC	9.99 MW
HC Increase	8.64 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~420ft of new 750 CU cable from the New Hondale Feeder to a new riser pole.	\$1,679,126
Build ~16,000ft of new 397 AAC @ 570. Utilize double circuit construction along the existing path of HOND12 13 feeder main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$9,679,126



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Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	8.64 MW
Cost (\$)	9,679,126
Hosting Capacity Benefit Cost	0.89
Holistic System Benefit Cost	5.49

HOND12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	1,352	3,740	2,390	\$383,946	6.22	6.63
Feeder Upgrades with 2 MVA BESS	1,352	5,603	4,251	\$14,683,946	0.29	1.05
2 MVA BESS Only*	-	-	-	-	-	-
Feeder Upgrades with 6 MVA BESS	1,352	9,468	8,116	\$14,733,946	0.55	1.99
6 MVA BESS Only*	-	-	-	-	-	-
Dedicated Feeder	1,352	9,994	8,642	\$9,679,126	0.89	5.49

*This scenario was not applicable to this analysis.



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HOND12 - Feeder Overview with Queued Solar as of 8-19-24

Feeder Data

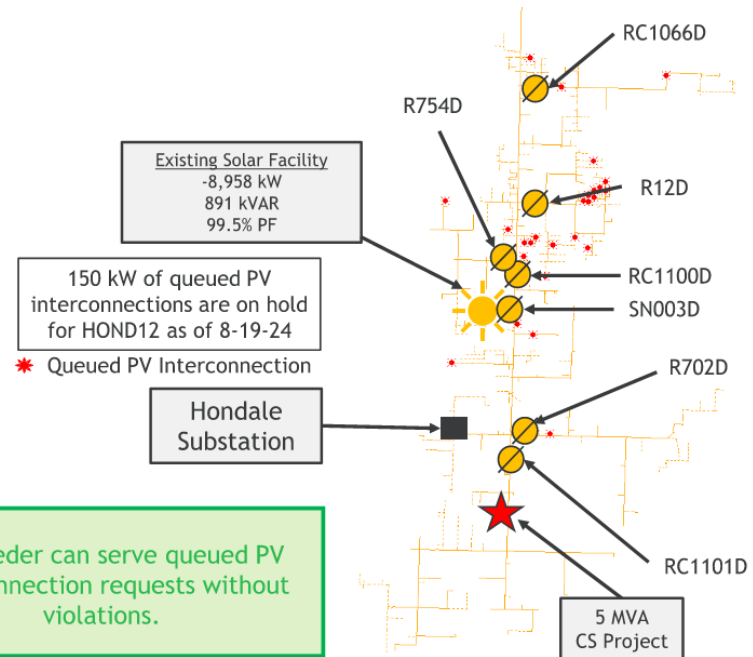
- Feeder Rating: 10,039 kVA
- Existing Generation: 9,268 kVA
- Minimum Daylight Load: -8,702 kW
- Minimum Daylight Gross Load: 242 kW / -112 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: **13.8 kV**
- Queued Solar Projects: **25**
- Total Queued AC Inverter Nameplate: **150 kW**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	HOND12 Breaker	480
Recloser	R12D	140
Recloser	R702D	140
Recloser	R754D	150
Recloser	R1066D	70
Recloser	RC1100D	100
Recloser	RC1101D	150
Recloser	SN003D	450

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Hondale Feeder 12 is in the Deming, NM area. This area is operated at 13.8 kV.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,702	-254	8,706	100	354	362	358	122.0	125.0	86.24

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JARA12 Analysis



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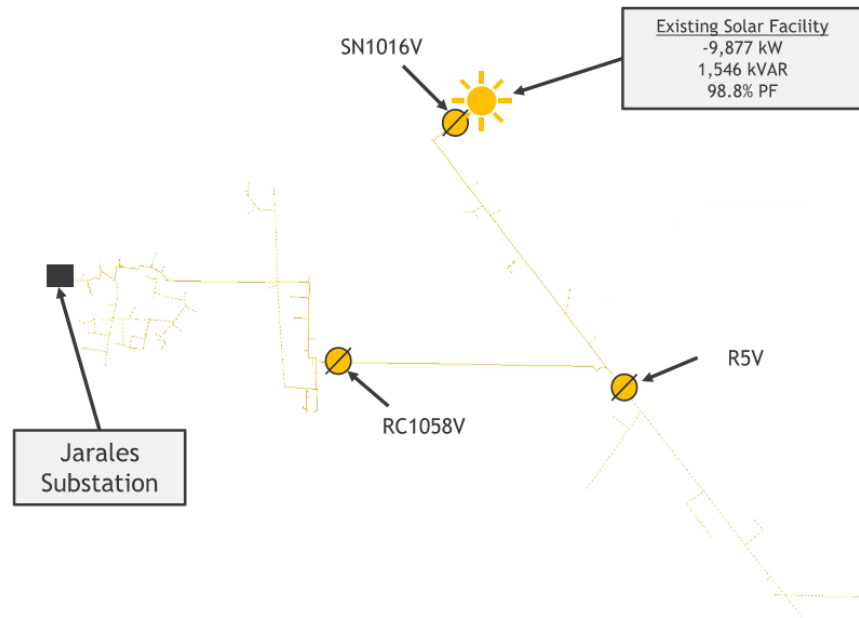
JARA12 - Feeder Overview

Feeder Data

- Feeder Rating: 11,231 kVA
- Existing Generation: 10,063 kVA
- Minimum Daylight Load: -7,944 kW
- Minimum Daylight Gross Load: 848 kW / -3 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	JARA12 Breaker	600
Recloser	R5V	100
Recloser	RC1058V	225
Recloser	SN1016V	500



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-7,944	3,885	8,843	-90	416	405	387	119.7	124.8	97

JARA12 - Feeder Overview with Queued Solar as of 1-1-2024

Feeder Data

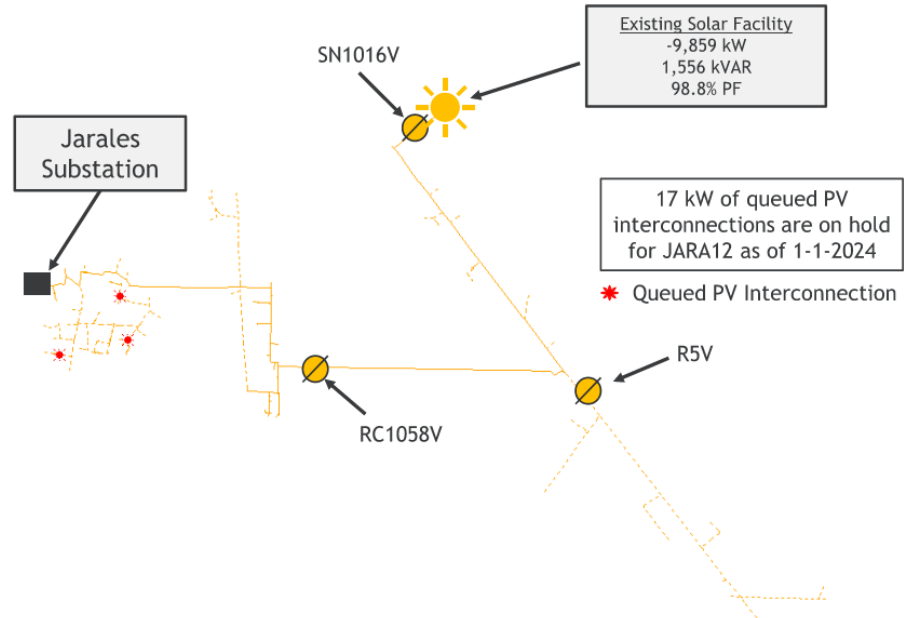
- Feeder Rating: 11,231 kVA
- Existing Generation: 10,081 kVA
- Minimum Daylight Load: -7,947 kW
- Minimum Daylight Gross Load: 848 kW / -3 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **3**
- Total Queued AC Inverter Nameplate: **17 kW**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	JARA12 Breaker	600
Recloser	R5V	100
Recloser	RC1058V	225
Recloser	SN1016V	500



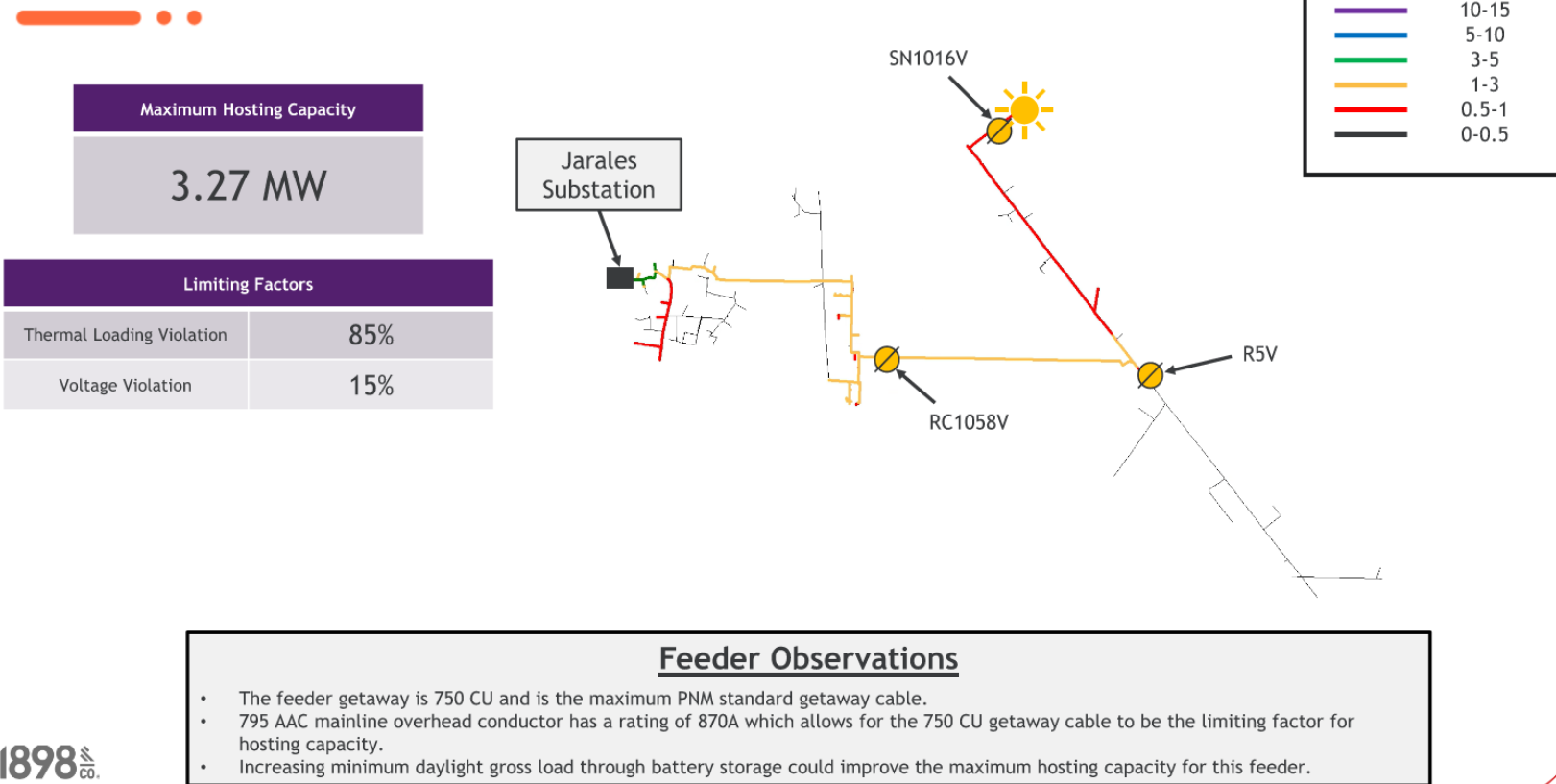
The feeder can serve queued PV interconnection requests without violations.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-7,947	3,886	8,846	-90	415	405	389	119.9	124.7	97

JARA12 - Maximum Hosting Capacity Base Case w/ Queued PV



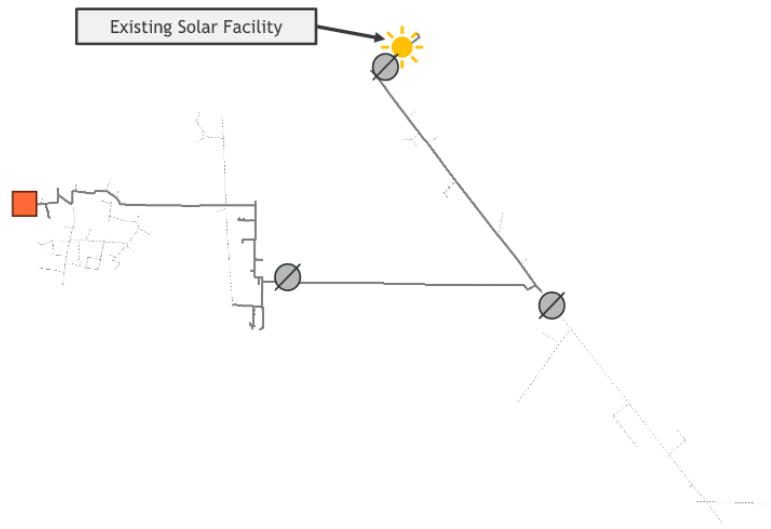
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JARA12 - Feeder Upgrades

Hosting Capacity	
Base HC	3.27 MW
Max HC	3.27 MW
HC Increase	0 MW

System Improvement	
	Cost
No feeder upgrades were applicable. This feeder is already built to the maximum PNM standard ratings.	\$0
TOTAL	\$0



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

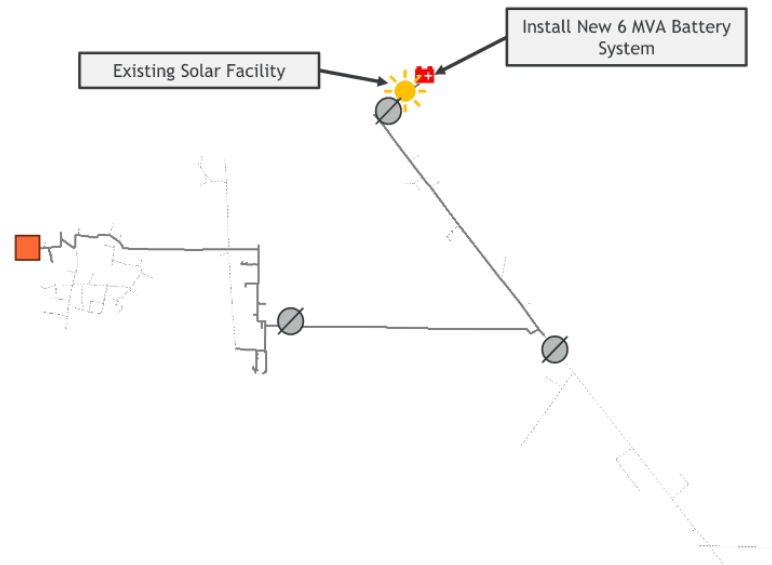
Financial Analysis	
Hosting Capacity Increase (MW)	0
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-

JARA12 - 2 MVA BESS Only

Hosting Capacity	
Base HC	3.27 MW
Max HC	4.85 MW
HC Increase	1.58 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,300,000



Financial Analysis	
HC Increase	1.58 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.11
Holistic System Benefit Cost	0.91

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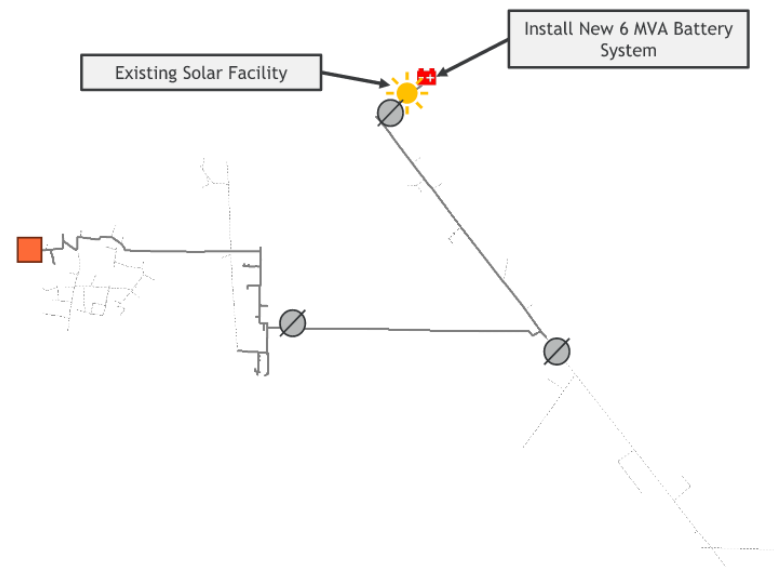
72

JARA12 - 6 MVA BESS Only

Hosting Capacity	
Base HC	3.27 MW
Max HC	7.17 MW
HC Increase	3.9 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,350,000



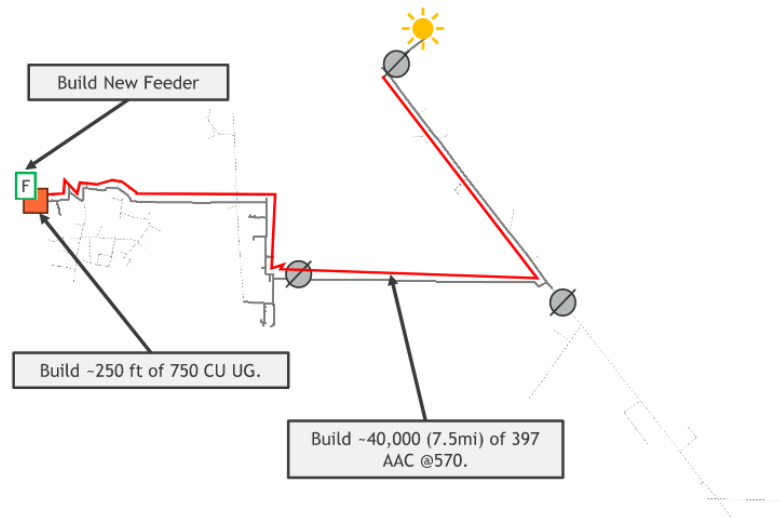
Financial Analysis	
HC Increase	3.9 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.27
Holistic System Benefit Cost	1.53

JARA12 - Dedicated Feeder

Hosting Capacity	
Base HC	3.27 MW
Max HC	12.01 MW
HC Increase	8.74 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~200ft of new 750 CU cable from the Jarales 11 Substation to a new riser pole.	\$4,040,940
Build ~40,000ft (7.5mi) of new 397 AAC @ 570. Utilize double circuit construction along the existing path of Jarales 12 feeder main line conductor.	
Install Breaker and SEL 751 Relay for the New Feeder.	
TOTAL	\$4,040,940



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	8.74 MW
Cost (\$)	4,040,940
Hosting Capacity Benefit Cost	2.16
Holistic System Benefit Cost	2.31

JARA12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades*	-	-	-	-	-	-
Feeder Upgrades with 2 MVA BESS*	-	-	-	-	-	-
2 MVA BESS Only	3,269	4,846	1,577	\$14,300,000	0.11	0.94
Feeder Upgrades with 6 MVA BESS*	-	-	-	-	-	-
6 MVA BESS Only	3,269	7,166	3,897	\$14,350,000	0.27	1.53
Dedicated Feeder	3,269	12,011	8,742	\$4,040,940	2.16	2.31

*This scenario was not applicable to this analysis.



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LOHO12 Analysis

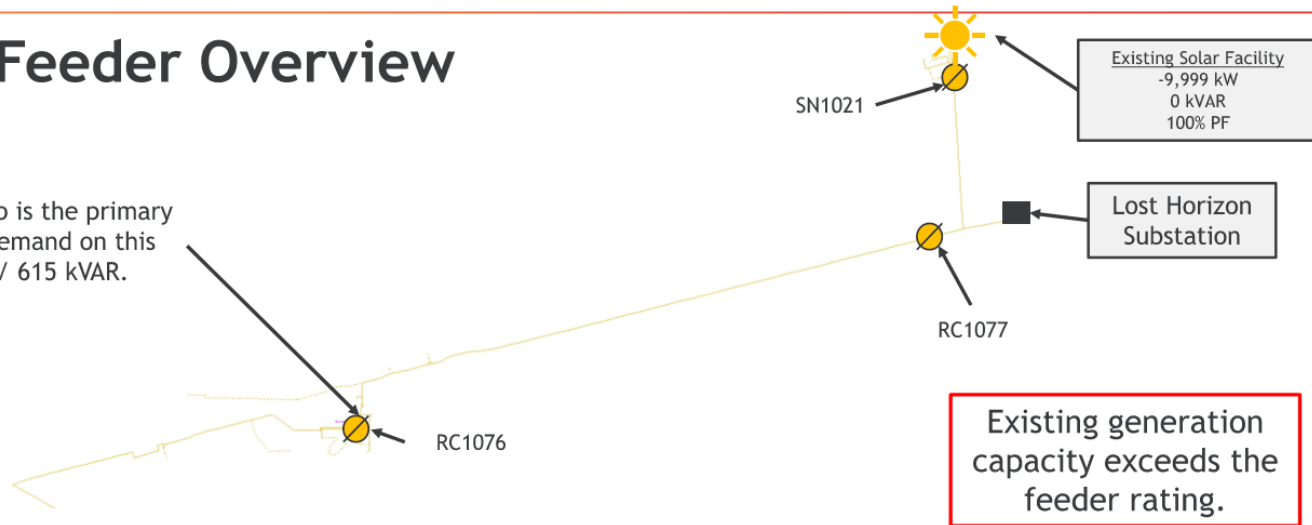


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LOHO12 - Feeder Overview

Laguna Route 66 Casino is the primary source of customer demand on this feeder - 1,233 kW / 615 kVAR.



Protection & Equipment Pickup/Ratings		
Device	Name	Pick Up Rating (A)
Breaker	LOHO12 Breaker	480
Recloser	RC1076	70
Recloser	RC1077	400
Recloser	SN1021	600

Base Case Load Flow Analysis (Minimum daylight Load)									
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,258	268	8,263	-100	380	372	377	120.0	124.9	86.0

Feeder Data

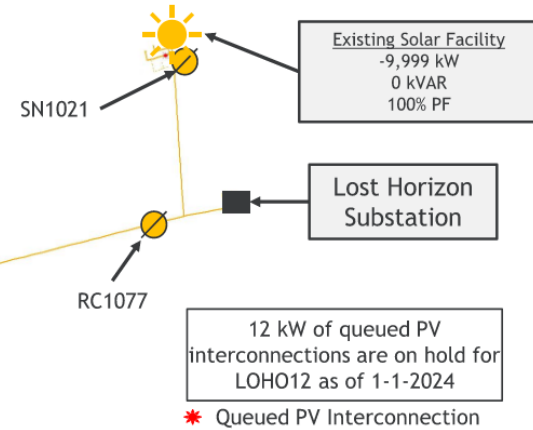
- Feeder Rating: **9,288 kVA**
- Existing Generation: **10,004 kVA**
- Minimum Daylight Load: -8,260 kW
- Minimum Daylight Gross Load: 1,459 kW / 791 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV

LOHO12 - Feeder Overview with Queued Solar as of 1-1-2024

Protection & Equipment Pickup/Ratings		
Device	Name	Pick Up Rating (A)
Breaker	LOHO12 Breaker	480
Recloser	RC1076	70
Recloser	RC1077	400
Recloser	SN1021	600

Existing generation capacity exceeds the feeder rating.

Laguna Route 66 Casino is the primary source of customer demand on this feeder - 1,233 kW / 615 kVAR.



Feeder Data

- Feeder Rating: **9,288 kVA**
- Existing Generation: **10,017 kVA**
- Minimum Daylight Load: -8,272 kW
- Minimum Daylight Gross Load: 1,447 kW / 784 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **2**
- Total Queued AC Inverter Nameplate: **12 kW**

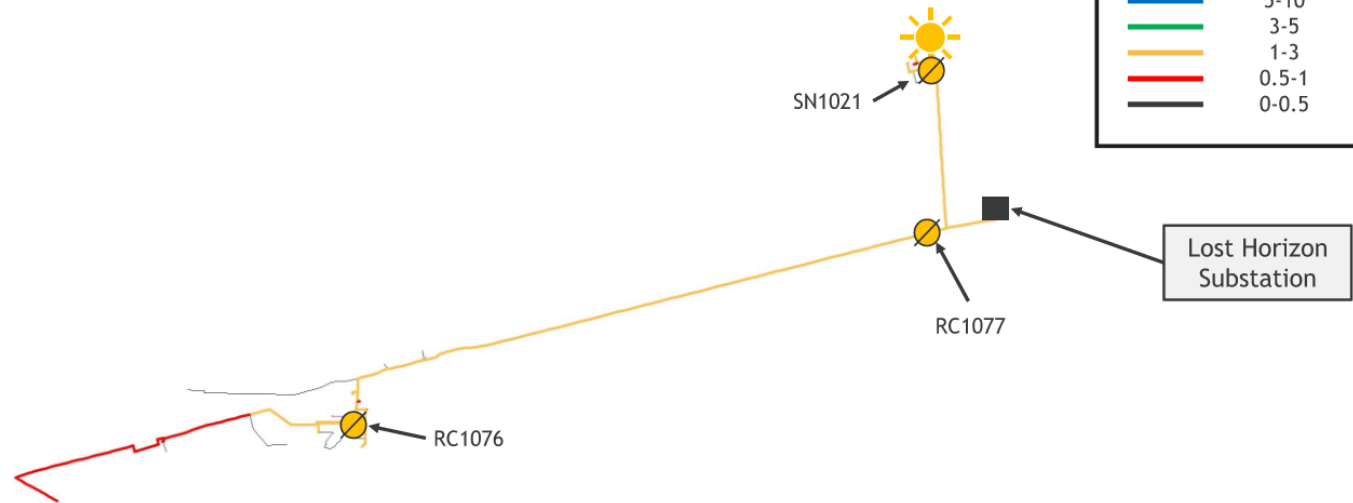
Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,272	269	8,276	-100	380	374	377	120.0	124.9	86.0



The feeder can serve queued PV interconnection requests without violations.

LOHO12 - Maximum Hosting Capacity Base Case w/ Queued PV



Maximum Hosting Capacity
1.06 MW

Limiting Factors	
Thermal Loading Violation	78%
Voltage Violation	22%

Feeder Observations
- Feeder getaway is built to 750 CU which is the maximum PNM standard getaway cable. - The pickup of the feeder relay (480 Amps) is limiting the hosting capacity of the feeder. - Enabling directional settings for the existing SEL 751 relay would increase hosting capacity.



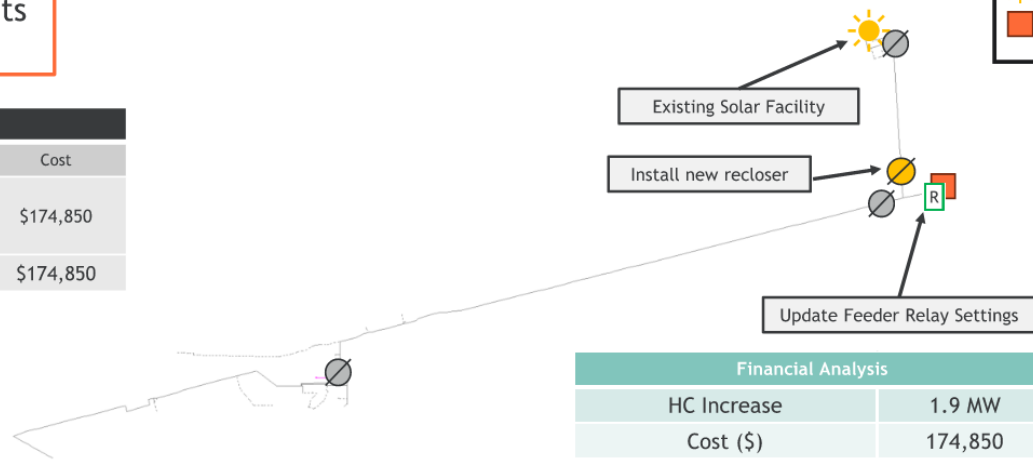
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LOH012 - Feeder Upgrades

Hosting Capacity	
Base HC	1.06 MW
Max HC	2.96 MW
HC Increase	1.9 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Update Feeder Relay Settings	
Install new Recloser to mitigate EOL fault desensitization.	\$174,850
TOTAL	\$174,850



Financial Analysis	
HC Increase	1.9 MW
Cost (\$)	174,850
Hosting Capacity Benefit Cost	10.87
Holistic System Benefit Cost	11.59

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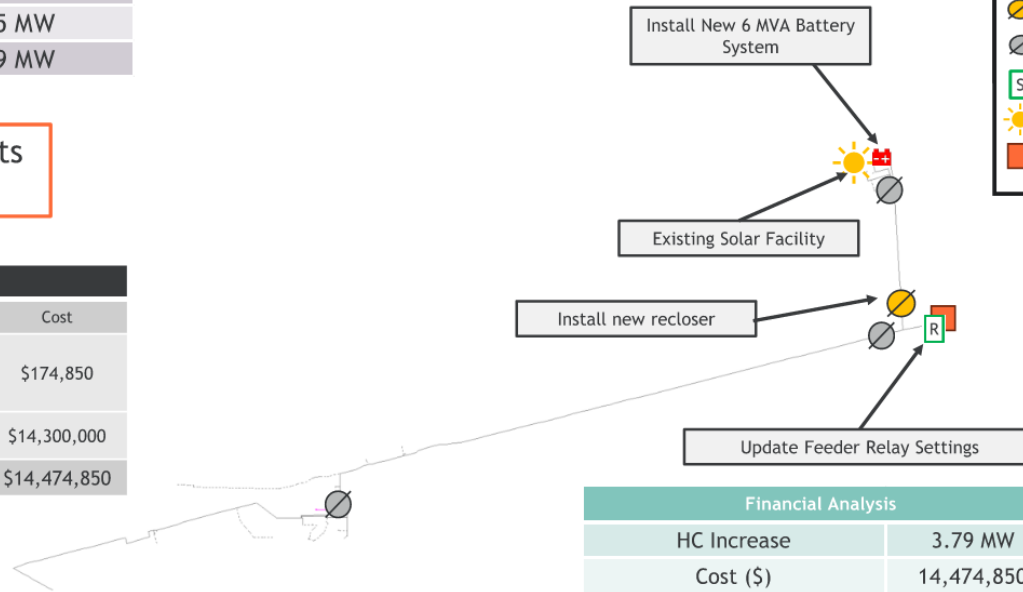
80

LOH012 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	1.06 MW
Max HC	4.85 MW
HC Increase	3.79 MW

Reverse Flow Limits
Max HC

System Improvement	Cost
Update Feeder Relay Settings	\$174,850
Install new recloser to mitigate potential EOL desensitization.	
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,474,850



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	3.79 MW
Cost (\$)	14,474,850
Hosting Capacity Benefit Cost	0.26
Holistic System Benefit Cost	1.03



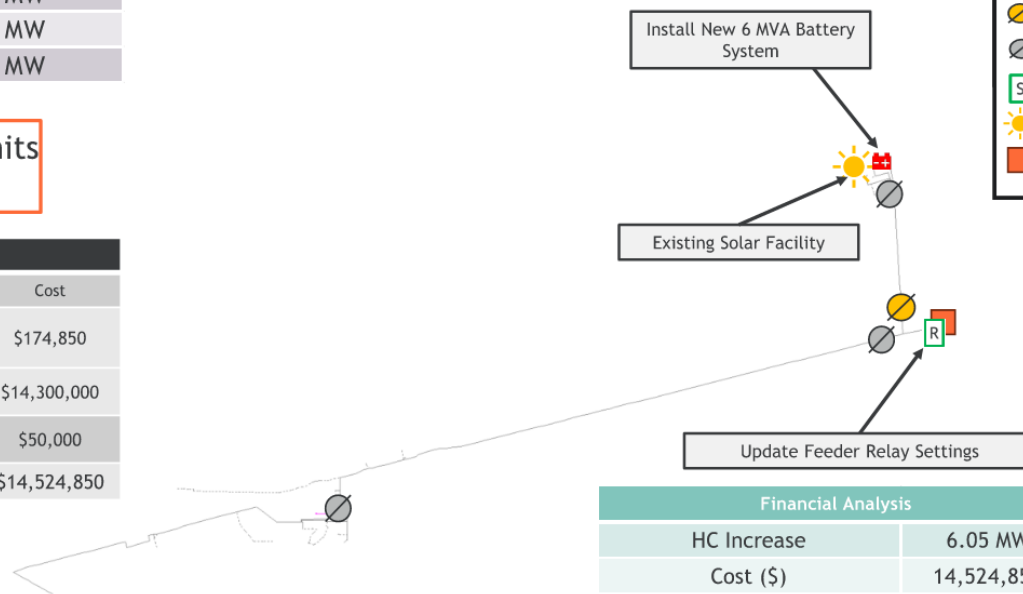
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LOH012 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	1.06 MW
Max HC	7.11 MW
HC Increase	6.05 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Update Feeder Relay Settings	\$174,850
New Recloser	
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,524,850



Financial Analysis	
HC Increase	6.05 MW
Cost (\$)	14,524,850
Hosting Capacity Benefit Cost	0.42
Holistic System Benefit Cost	1.89

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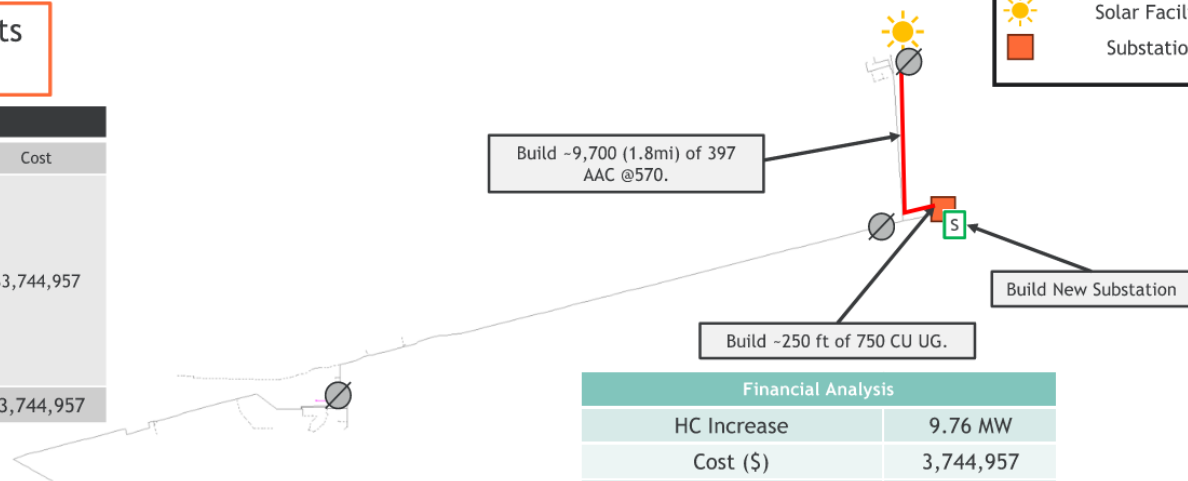
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LOHO12 - Dedicated Feeder

Hosting Capacity	
Base HC	1.06 MW
Max HC	10.82 MW
HC Increase	9.76 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~250ft of new 750 CU cable from the New Lost Horizon Substation to a new riser pole.	\$3,744,957
Build ~9,700ft (1.8mi) of new 397 AAC @ 570. Utilize double circuit construction along the existing path of Lost Horizon 12 feeder main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment. Cost shared with the other Lost Horizon Substation feeders (3 total feeders)	
TOTAL	\$3,744,957



Financial Analysis	
HC Increase	9.76 MW
Cost (\$)	3,744,957
Hosting Capacity Benefit Cost	2.61
Holistic System Benefit Cost	2.78

Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

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LOHO12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	1,060	2,960	1,900	\$174,850	10.87	11.59
Feeder Upgrades with 2 MVA BESS	1,060	4,853	3,793	\$14,474,850	0.26	1.03
2 MVA BESS Only*	-	-	-	-	-	-
Feeder Upgrades with 6 MVA BESS	1,060	7,110	6,050	\$14,524,850	0.42	1.89
6 MVA BESS Only*	-	-	-	-	-	-
Dedicated Feeder	1,060	10,818	9,758	\$3,744,957	2.61	2.78

*This scenario was not applicable to this analysis.



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LOHO13 Analysis



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LOHO13 - Feeder Overview

Feeder Data

- Feeder Rating: **11,231 kVA**
- Existing Generation: **12,073 kVA**
- daylight Minimum Load: -10,962 kW
- daylight Minimum Gross Load: 527 kW / 34 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	LOHO13 Breaker	660
Recloser	SN1014	550
Recloser	R766	140

LOHO13 historically has exceeded the feeder rating due to excess PV generation. Inverter settings were adjusted in the field to reduce power factor and mitigate potential overloads.

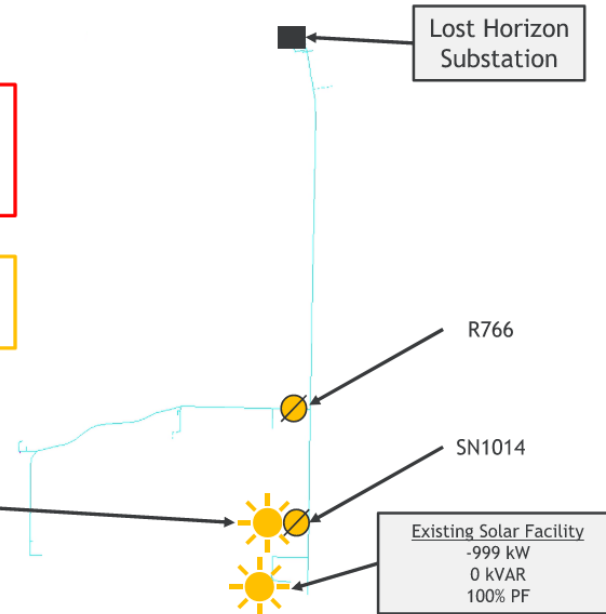


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Existing generation capacity exceeds the feeder rating.

No Pending PV Customers

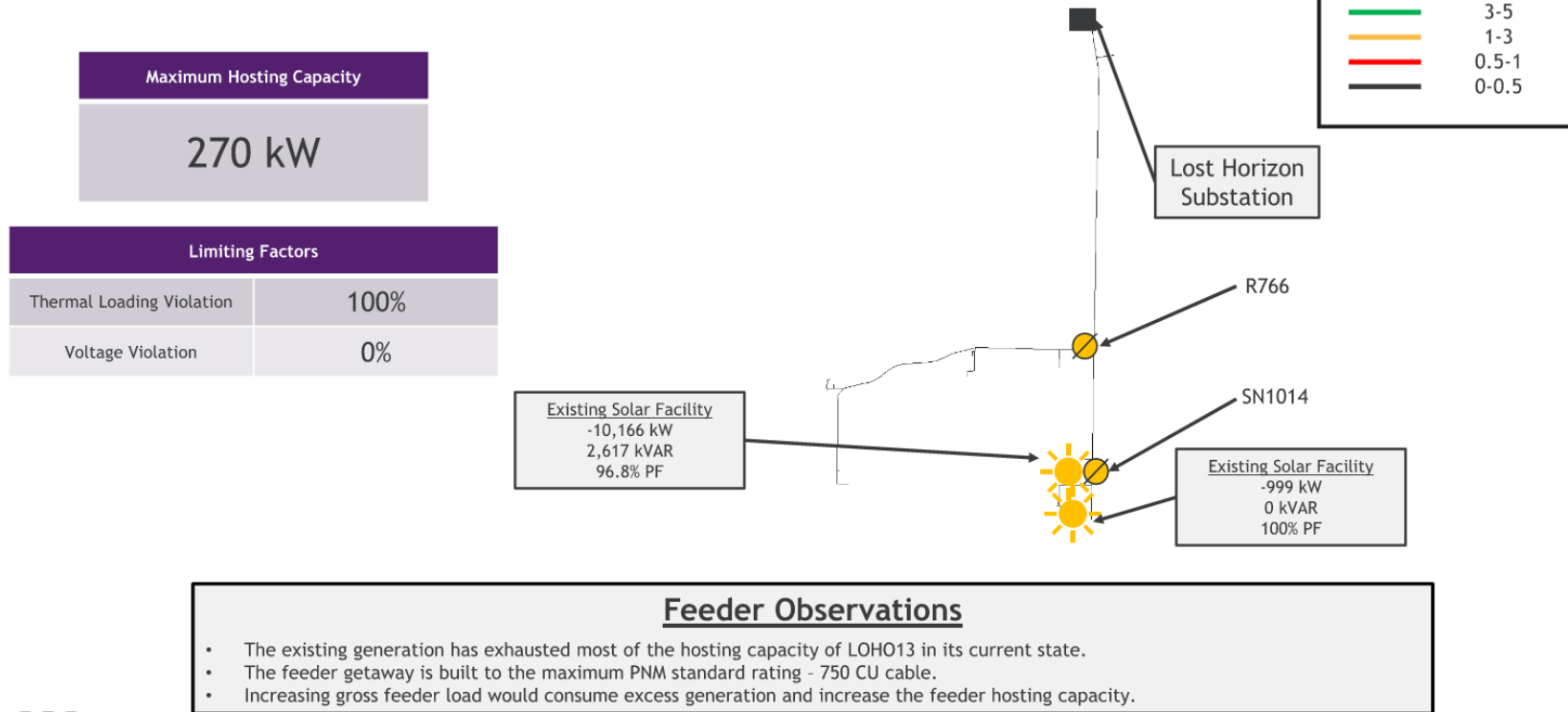
Existing Solar Facility
-10,157 kW
2,646 kVAR
96.8% PF



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-10,962	2,075	11,157	-98	506	508	510	122.0	123.7	98.0

LOHO13 - Maximum Hosting Capacity Base Case

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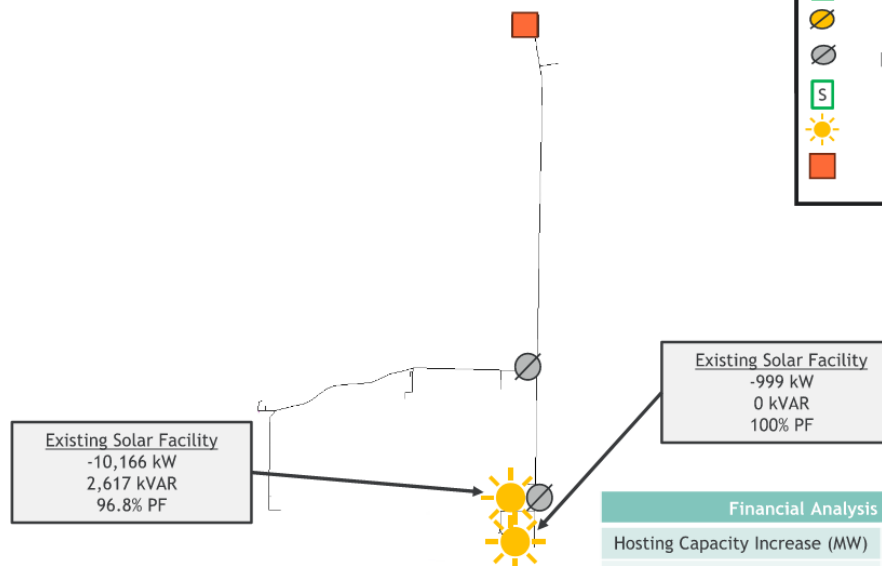
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LOHO13 - Feeder Upgrades

Hosting Capacity	
Base HC	0.27 MW
Max HC	0.27 MW
HC Increase	0 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
No traditional system upgrades are applicable. The feeder is built to the maximum PNM conductor and equipment standards.	\$0
TOTAL	\$0



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
Hosting Capacity Increase (MW)	0
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-

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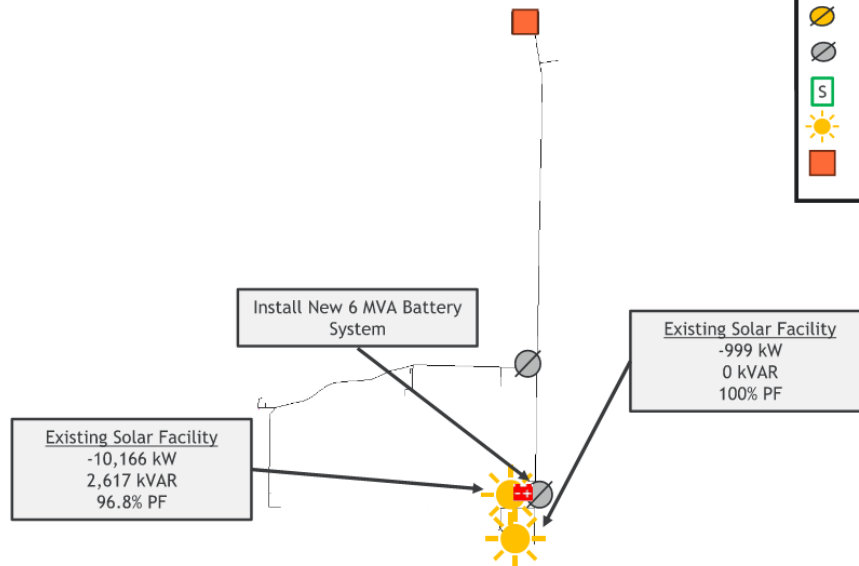
LOHO13 - 2 MVA BESS Only

Hosting Capacity	
Base HC	0.27 MW
Max HC	2.16 MW
HC Increase	1.89 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,300,000

Financial Analysis	
HC Increase	1.89 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.93



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LOHO13 - 6 MVA BESS Only

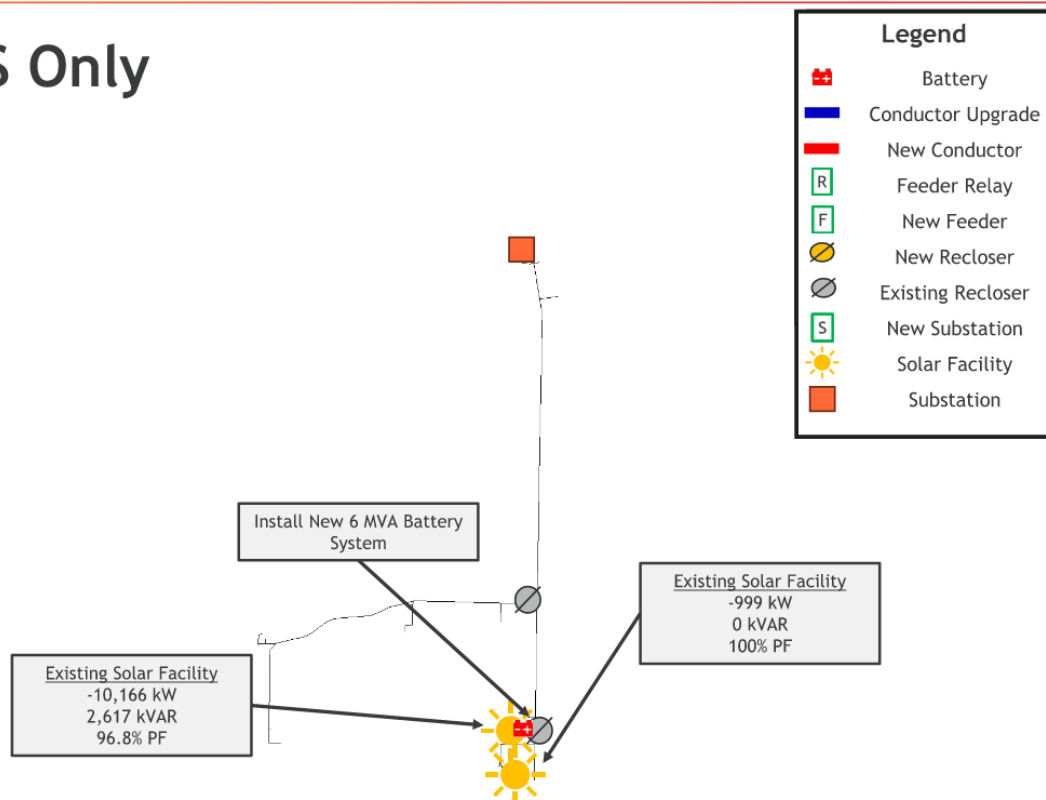
Hosting Capacity	
Base HC	0.27 MW
Max HC	5.35 MW
HC Increase	5.08 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,350,000

Financial Analysis	
HC Increase	5.08 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.35
Holistic System Benefit Cost	1.85

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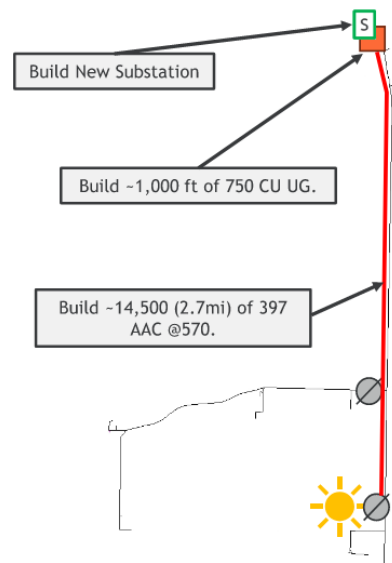
90

LOHO13 - Dedicated Feeder

Hosting Capacity	
Base HC	0.27 MW
Max HC	10.16 MW
HC Increase	9.89 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~1,000ft of new 750 CU cable from the New Lost Horizon Substation to a new riser pole.	\$4,131,806
Build ~14,500ft (2.7mi) of new 397 AAC @ 570. Utilize double circuit construction along the existing path of Lost Horizon 13 feeder main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment. Cost shared with the other Lost Horizon Substation feeders (3 total feeders)	
TOTAL	\$4,131,806



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Benefit Cost Ratio	
HC Increase	9.89 MW
Cost (\$)	4,131,806
Holistic System Benefit Cost	2.55
Hosting Capacity Benefit Cost	2.40



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LOHO13 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades*	-	-	-	-	-	-
Feeder Upgrades with 2 MVA BESS*	-	-	-	-	-	-
2 MVA BESS Only	267	2,157	1,890	\$14,300,000	0.13	0.93
Feeder Upgrades with 6 MVA BESS*	-	-	-	-	-	-
6 MVA BESS Only	267	5,346	5,079	\$14,350,000	0.35	1.85
Dedicated Feeder	267	10,165	9,898	\$4,131,806	2.40	2.55

*This scenario was not applicable to this analysis.



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LOHO14 Analysis



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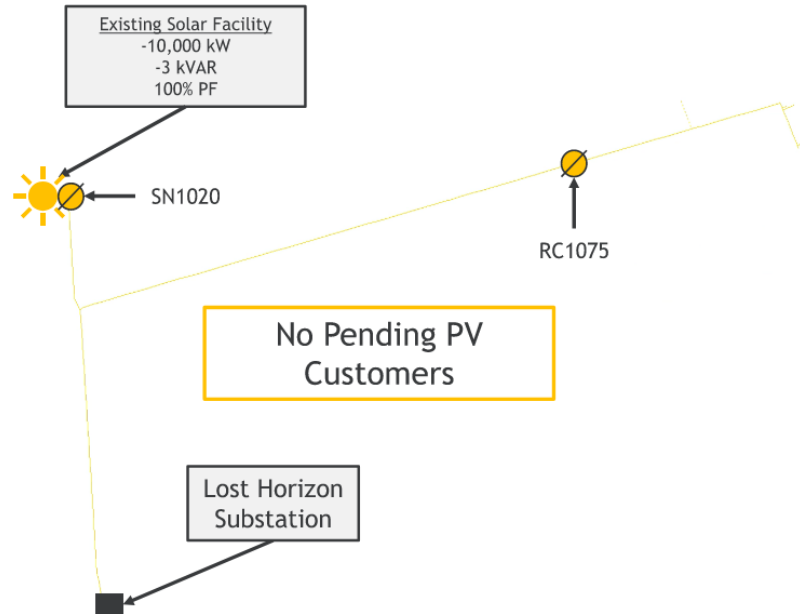
LOHO14 - Feeder Overview

Feeder Data

- Feeder Rating: 11,231 kVA
- Existing Generation: 9,999 kVA
- daylight Minimum Load: -9,616 kW
- daylight Minimum Gross Load: 136 kW / 511 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV

Protection & Equipment Pickup/Ratings

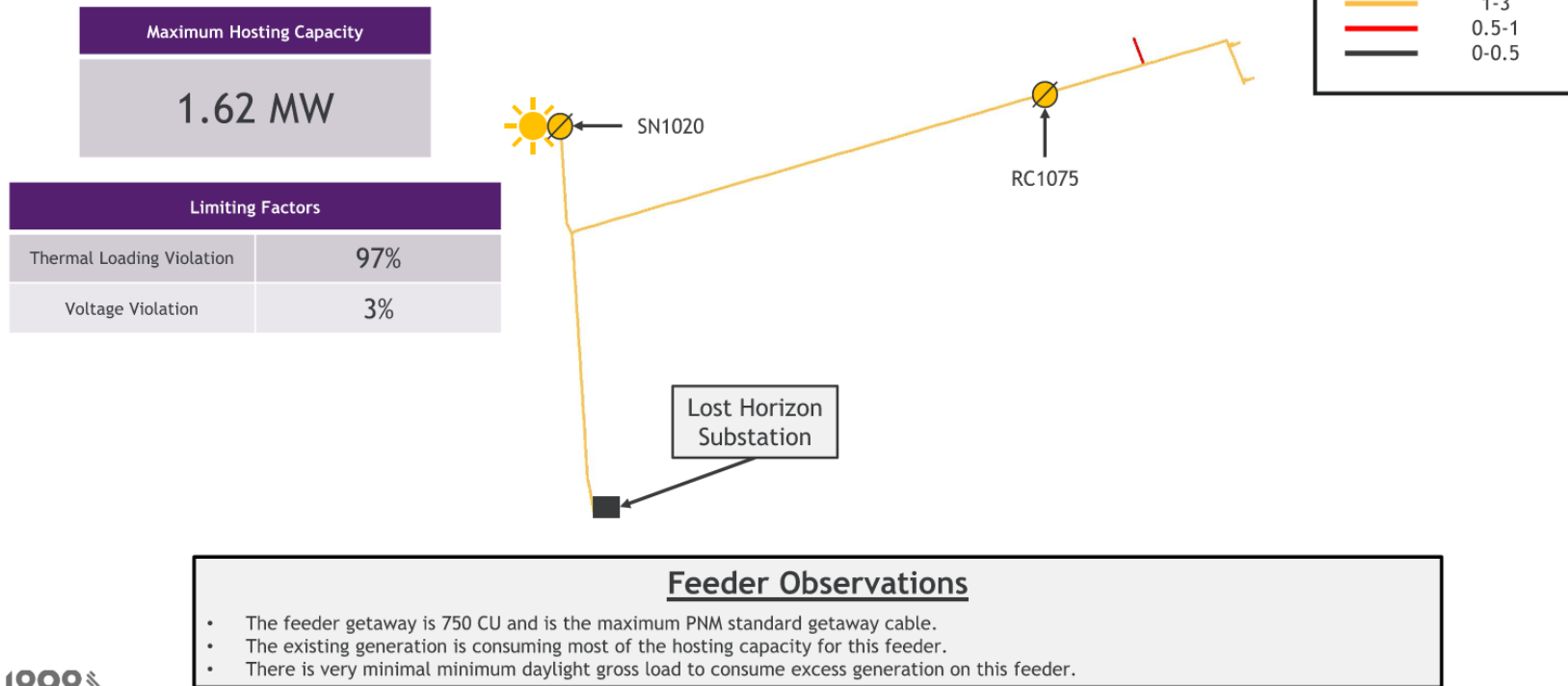
Device	Name	Pick Up Rating (A)
Breaker	LOHO14 Breaker	600
Recloser	RC1075	500
Recloser	SN1020V	600



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-9,616	1,146	9,684	-99	445	432	446	122.0	124.6	86

LOHO14 - Maximum Hosting Capacity Base Case



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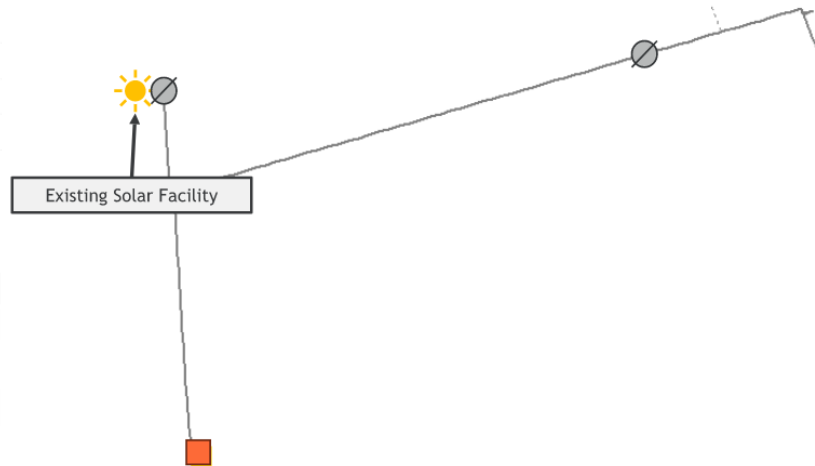
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LOH014 - Feeder Upgrades

Hosting Capacity	
Base HC	1.62 MW
Max HC	1.62 MW
HC Increase	0 MW

System Improvement	
	Cost
No traditional system improvements were necessary	\$0
TOTAL	\$0



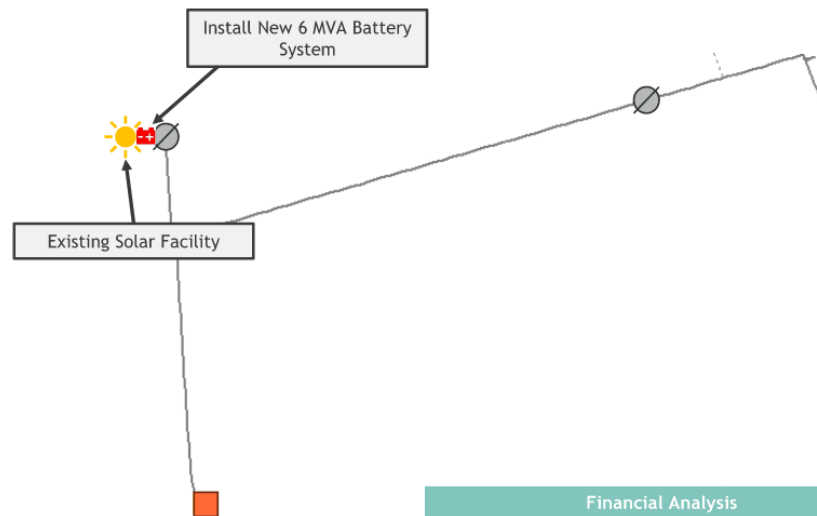
Financial Analysis	
HC Increase	0
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-

LOHO14 - 2 MVA BESS Only

Hosting Capacity	
Base HC	1.62 MW
Max HC	3.51 MW
HC Increase	1.89 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,300,000



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

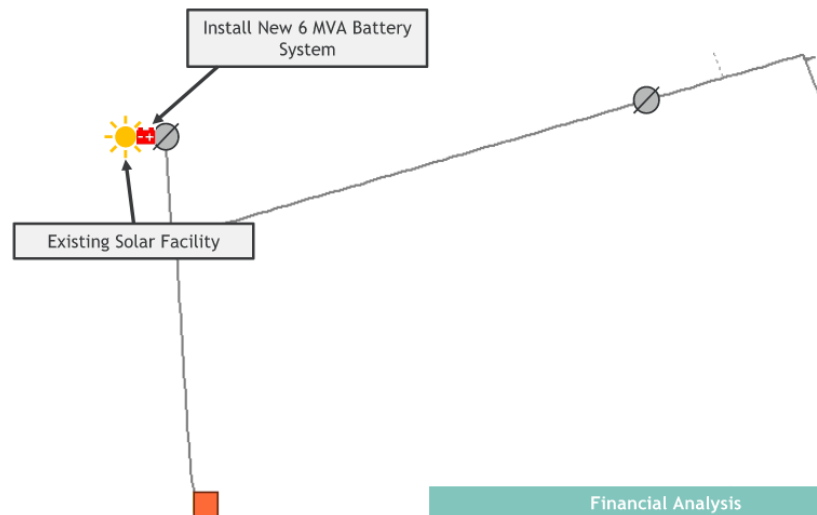
Financial Analysis	
HC Increase	1.89
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.93

LOHO14 - 6 MVA BESS Only

Hosting Capacity	
Base HC	1.62 MW
Max HC	7.13 MW
HC Increase	5.51 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,350,000



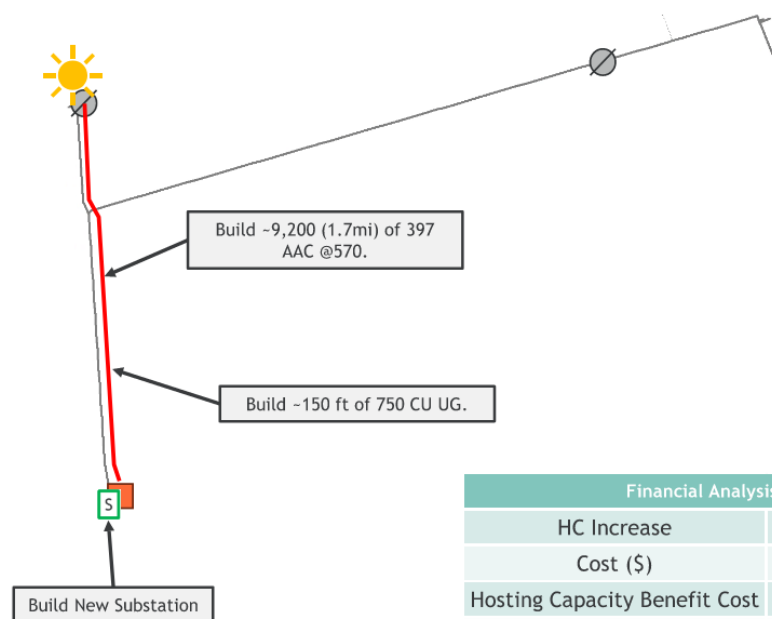
Financial Analysis	
HC Increase	5.51
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.38
Holistic System Benefit Cost	1.87

LOH014 - Dedicated Feeder

Hosting Capacity	
Base HC	1.62 MW
Max HC	11.38 MW
HC Increase	9.76 MW

Reverse Flow Limits
Max HC

System Improvement	Cost
Build ~150ft of new 750 CU cable from the New Lost Horizon Substation to a new riser pole.	\$3,704,661
Build ~9,200ft (1.7mi) of new 397 AAC @ 570. Utilize double circuit construction along the existing path of Lost Horizon 14 feeder main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment. Cost shared with the other Lost Horizon Substation feeders (3 total feeders)	
TOTAL	\$3,704,661



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	9.76
Cost (\$)	3,704,661
Hosting Capacity Benefit Cost	2.63
Holistic System Benefit Cost	2.81

LOHO14 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades*	-	-	-	-	-	-
Feeder Upgrades with 2 MVA BESS*	-	-	-	-	-	-
2 MVA BESS Only	1,616	3,512	1,896	\$14,300,000	0.13	0.93
Feeder Upgrades with 6 MVA BESS*	-	-	-	-	-	-
6 MVA BESS Only	1,616	7,128	5,512	\$14,350,000	0.38	1.87
Dedicated Feeder	1,616	11,376	9,760	\$3,704,661	2.63	2.81

*This scenario was not applicable to this analysis.



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LSMO12 Analysis



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LSMO12 - Feeder Overview

Existing generation capacity exceeds the feeder rating.

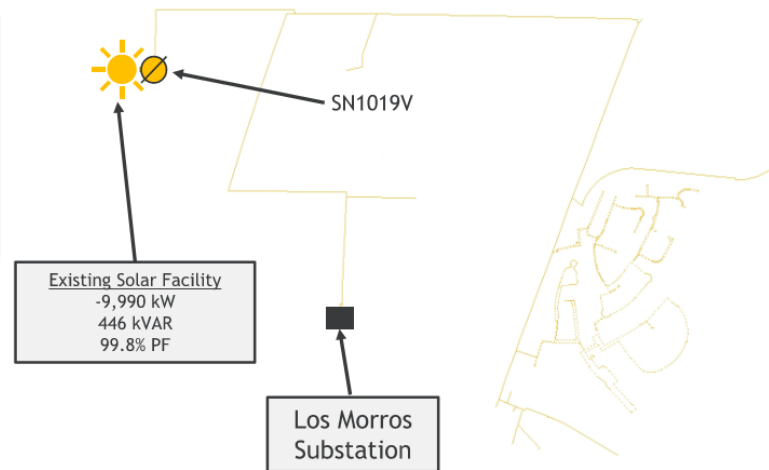
Feeder Data

- Feeder Rating: **9,288 kVA**
- Existing Generation: **10,216 kVA**
- Minimum Daylight Load: -9,682 kW
- Minimum Daylight Gross Load: 307 kW / 302 kVAR
- Substation LTC Setpoint: 123 V
- Primary Voltage: 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	LOMO12 Breaker	480
Recloser	SN1019V	600

LSMO12 feeder could operate beyond the normal feeder rating if all generation is operating at 100% output coincident with minimum daylight load. This represents risk to the PNM system.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-9,682	1,177	9,753	-99	439	449	434	123.0	125.4	106.0

LSMO12 - Feeder Overview with Queued Solar

Feeder Data

- Feeder Rating: **9,288 kVA**
- Existing Generation: **10,288 kVA**
- Minimum Daylight Load: -9,751 kW
- Minimum Daylight Gross Load: 307 kW / 302 kVAR
- Substation LTC Setpoint: 123 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **17**
- Total Queued AC Inverter Nameplate: **71 kW**

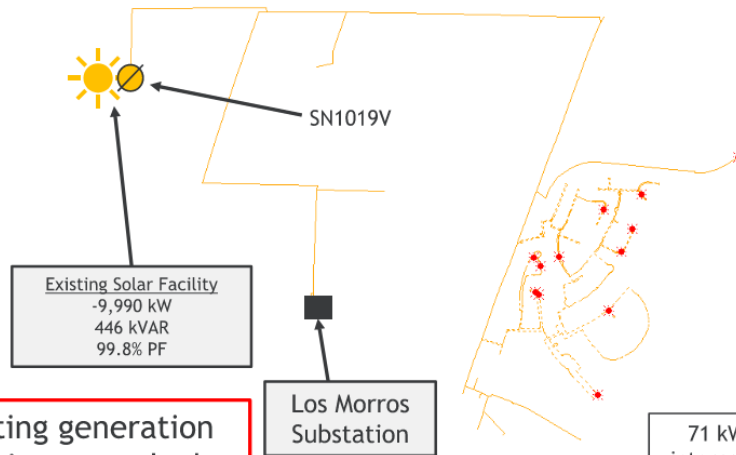
Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	LSMO12 Breaker	480
Recloser	SN1019V	600



The feeder **CANNOT** serve queued PV interconnection requests without violations.

Existing generation capacity exceeds the feeder rating.



71 kW of queued PV interconnections are on hold for LSMO12

* Queued PV Interconnection

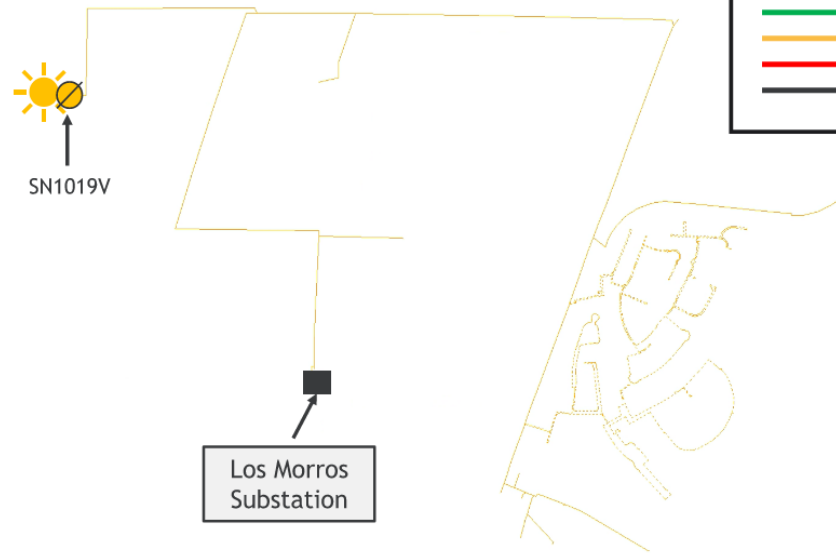
Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-9,751	1,184	9,823	-99	443	454	444	123.0	125.4	106.0

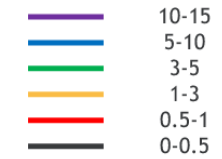
LSMO12 - Maximum Hosting Capacity Base Case w/ Queued PV

Feeder Observations

- There is **ZERO** hosting capacity available in this feeder in the base case scenario.
- The existing generation exceeds the feeder rating. The feeder is rated at 430A or 9,288 kVA due to the overhead conductor 397 AAC and the feeder relay pick up setting of 480A.
- A **106%** thermal overload is observed at the feeder getaway if generation is at full output and is coincident with minimum daylight load.



Hosting Capacity (MW)



Base Case Load Flow Analysis (Minimum daylight Load)

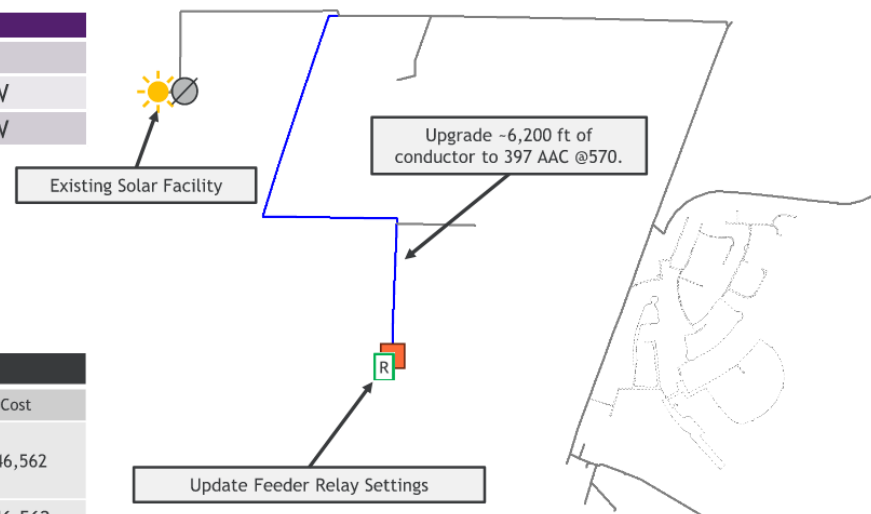
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-9,755	1,183	9,827	-99	443	454	434	123.0	125.4	106.0

LSMO12 - Feeder Upgrades

Hosting Capacity	
Base HC	0 MW
Max HC	1.47 MW
HC Increase	1.47 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~6,200 ft of 1/0 ACSR to 397 AAC @570 from Pole C28D034 to Pole C28B081.	\$46,562
Update Feeder Relay Settings.	
TOTAL	\$46,562



Financial Analysis	
HC Increase	1.47
Cost (\$)	46,562
Hosting Capacity Benefit Cost	31.56
Holistic System Benefit Cost	33.64

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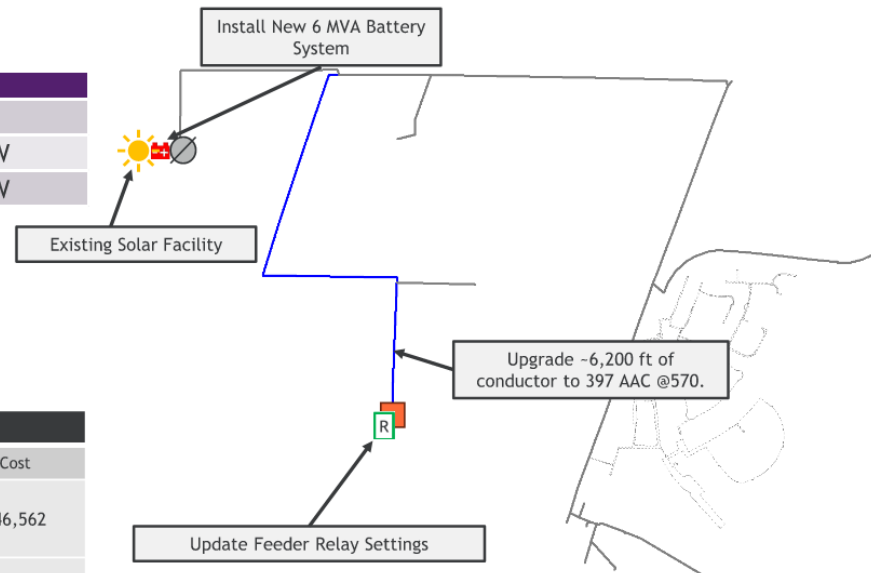
105

LSMO12 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	0 MW
Max HC	3.37 MW
HC Increase	3.37 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~6,200 ft of 1/0 ACSR to 397 AAC @570 from Pole C28D034 to Pole C28B081.	\$46,562
Update Feeder Relay Settings.	
Install New 6 MVA Battery. (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,346,562



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

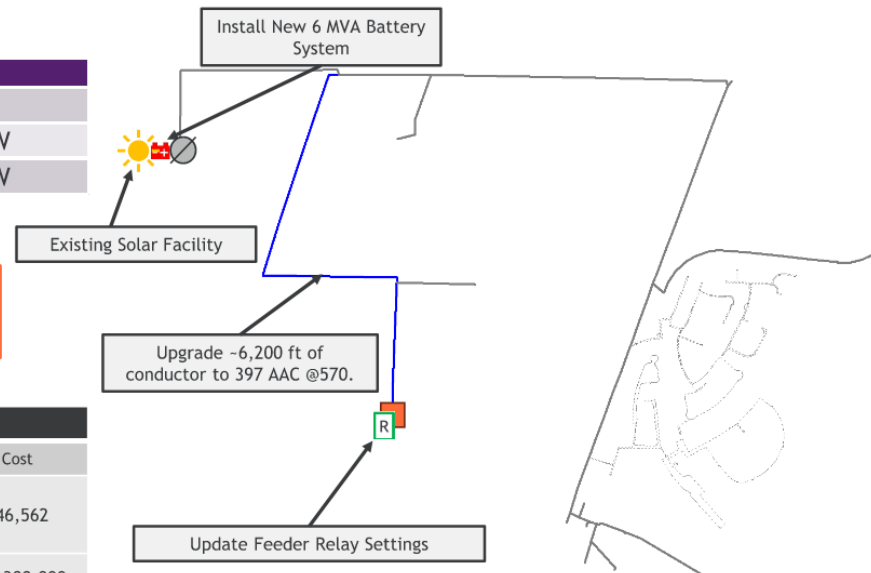
Financial Analysis	
HC Increase	3.37
Cost (\$)	14,346,562
Hosting Capacity Benefit Cost	0.24
Holistic System Benefit Cost	1.02

LSMO12 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	0 MW
Max HC	6.98 MW
HC Increase	6.98 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Upgrade ~6,200 ft of 1/0 ACSR to 397 AAC @570 from Pole C28D034 to Pole C28B081	\$46,562
Update Feeder Relay Settings	
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,396,562



Financial Analysis	
HC Increase	6.98
Cost (\$)	14,396,562
Hosting Capacity Benefit Cost	0.48
Holistic System Benefit Cost	1.96



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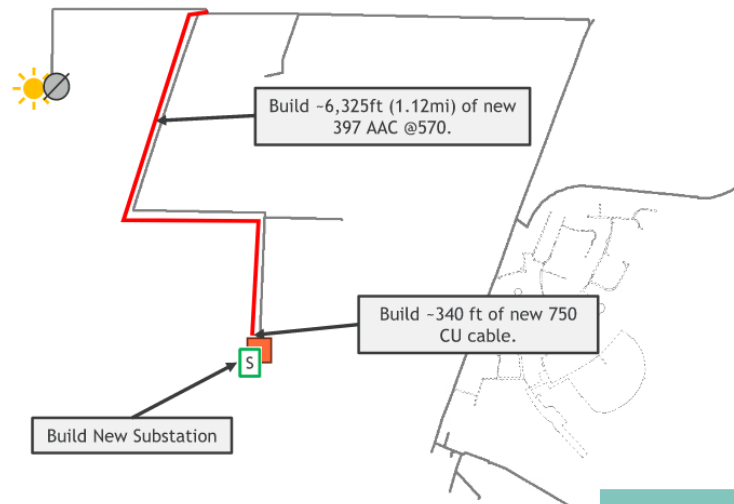
107

LSMO12 - Dedicated Feeder

Hosting Capacity	
Base HC	0 MW
Max HC	9.3 MW
HC Increase	9.3 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build -340 ft of new 750 CU cable from the New Lost Morros Substation to a new riser pole.	\$777,065
Build -6,325ft (1.2 mi) of new 397 AAC @570. Utilize double circuit construction along the existing path of Los Morros 12 main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$4,000,000
TOTAL	4,777,065



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	9.3
Cost (\$)	4,777,065
Hosting Capacity Benefit Cost	1.95
Holistic System Benefit Cost	2.07



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LSMO12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	Thermal Violation	1,469	1,469	\$46,562	31.56	33.64
Feeder Upgrades with 2 MVA BESS	Thermal Violation	3,373	3,373	\$14,346,562	0.24	1.02
2 MVA BESS Only*	-	-	-	-	-	-
Feeder Upgrades with 6 MVA BESS	Thermal Violation	6,980	6,980	\$14,396,562	0.48	1.96
6 MVA BESS Only*	-	-	-	-	-	-
Dedicated Feeder	Thermal Violation	9,296	9,296	\$4,777,065	1.95	2.07

*This scenario was not applicable to this analysis.

LSMO12 - Feeder Overview with Queued Solar with Feeder Upgrades and 6 MVA BESS Solution Constructed

Feeder Data

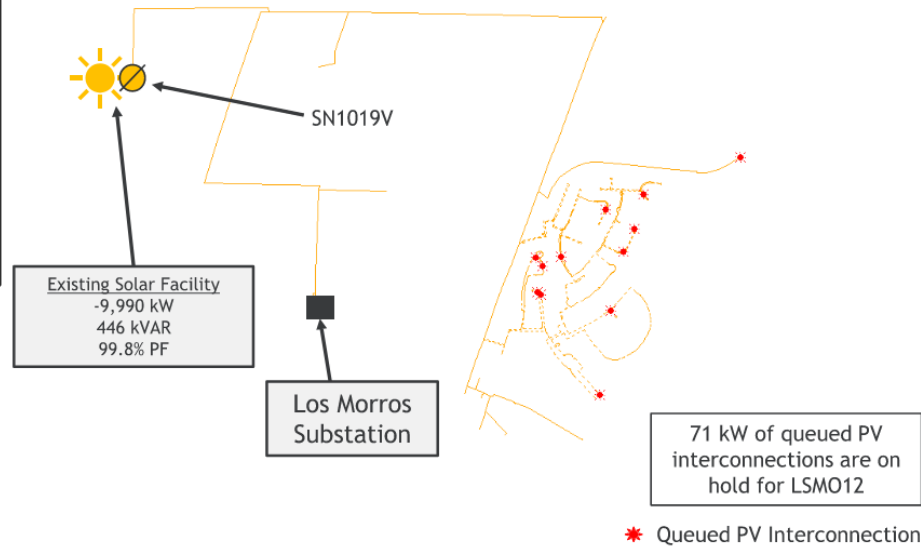
- Feeder Rating: 11,231 kVA
- Existing Generation: 10,288 kVA
- Minimum Daylight Load: -4,019 kW
- Minimum Daylight Gross Load: 307 kW / 302 kVAR
- Substation LTC Setpoint: 123 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: 17
- Total Queued AC Inverter Nameplate: 71 kW

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	LSMO12 Breaker	480
Recloser	SN1019V	600



The feeder can serve queued PV interconnection requests without violations.



Feeder Upgrades & 6 MVA BESS Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-4,019	449	4,044	-99	184	184	180	123.0	123.9	86.2

LSMO21 Analysis



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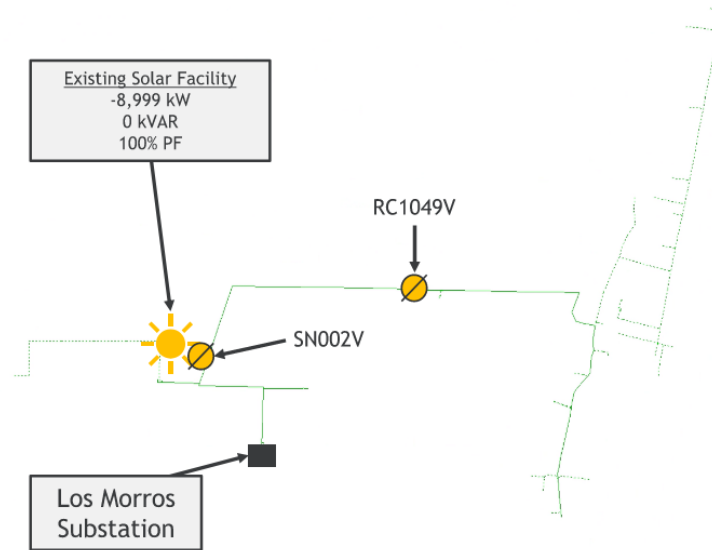
LSMO21 - Feeder Overview

Feeder Data

- Feeder Rating: 9,288 kVA
- Existing Generation: 9,032 kVA
- Minimum Daylight Load: -7,944 kW
- Minimum Daylight Gross Load: 848 kW / -3 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	LOMO21 Breaker	600
Recloser	RC1049V	460
Recloser	SN002V	450



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-7,994	333	8,001	-100	364	368	361	122.0	123.4	97.0

LSMO21 - Feeder Overview with Queued Solar

Feeder Data

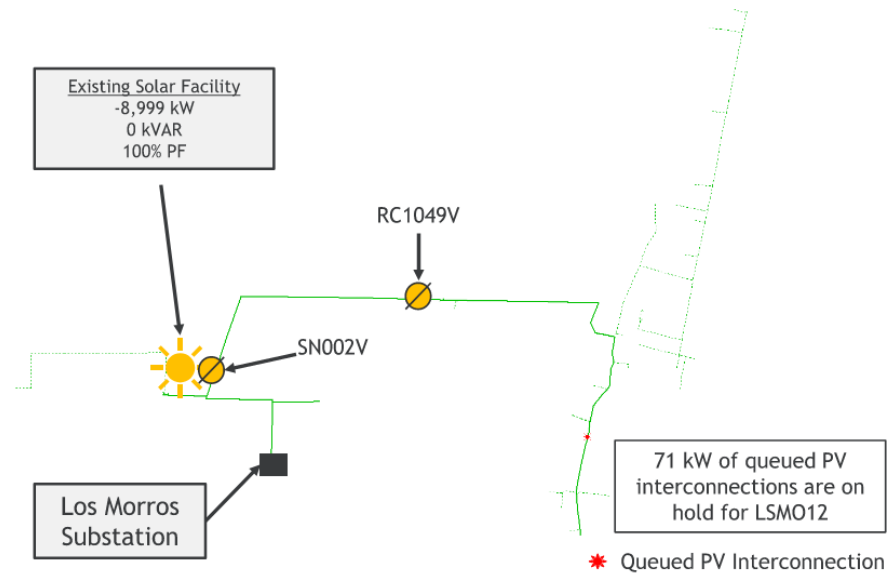
- Feeder Rating: 9,288 kVA
- Existing Generation: 9,040 kVA
- Minimum Daylight Load: -8,001 kW
- Minimum Daylight Gross Load: 848 kW / -3 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **1**
- Total Queued AC Inverter Nameplate: **8 kW**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	LOMO21 Breaker	600
Recloser	RC1049V	460
Recloser	SN002V	450



The feeder can serve queued PV interconnection requests without violations.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,001	333	8,008	-100	365	368	361	122.0	123.4	96.6

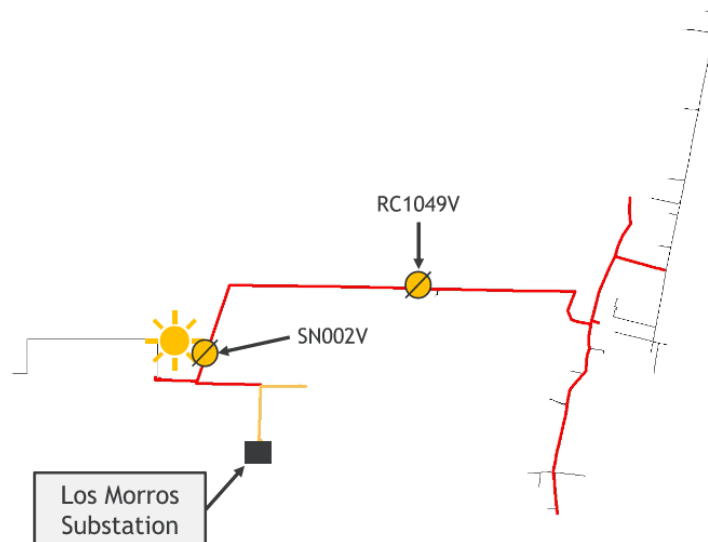
LSMO21 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity

1.27 MW

Limiting Factors

Thermal Loading Violation	92%
Voltage Violation	8%



Feeder Observations

- The existing generation has exhausted most of the hosting capacity of LOMO21 in its current state.
- The feeder getaway is built to the maximum PNM standard rating - 750 CU cable. The limiting factor for hosting capacity becomes the 397 AAC backbone conductor rated to 430 Amps.

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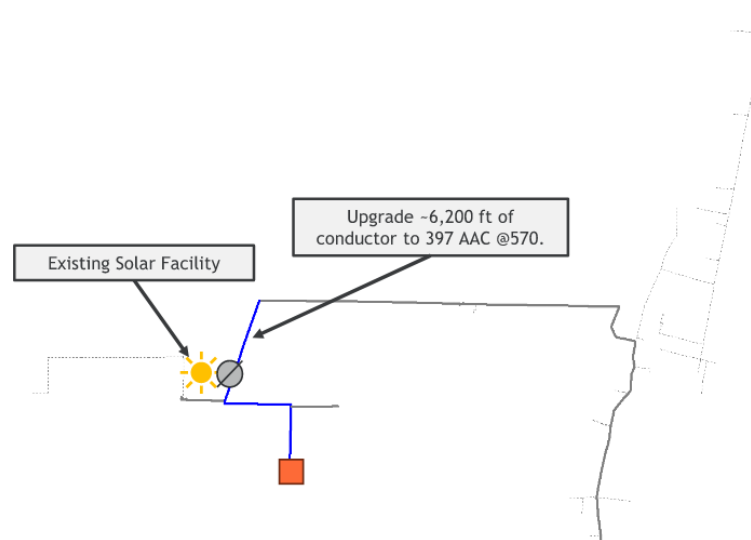
114

LSMO21 - Feeder Upgrades

Hosting Capacity	
Base HC	1.27 MW
Max HC	3.22 MW
HC Increase	1.95 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~6,200 ft of 1/0 ACSR to 397 AAC @570 from Pole C28D035 to Pole C28B081.	\$174,590
TOTAL	\$174,590



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	1.95
Cost (\$)	174,590
Hosting Capacity Benefit Cost	11.13
Holistic System Benefit Cost	11.87

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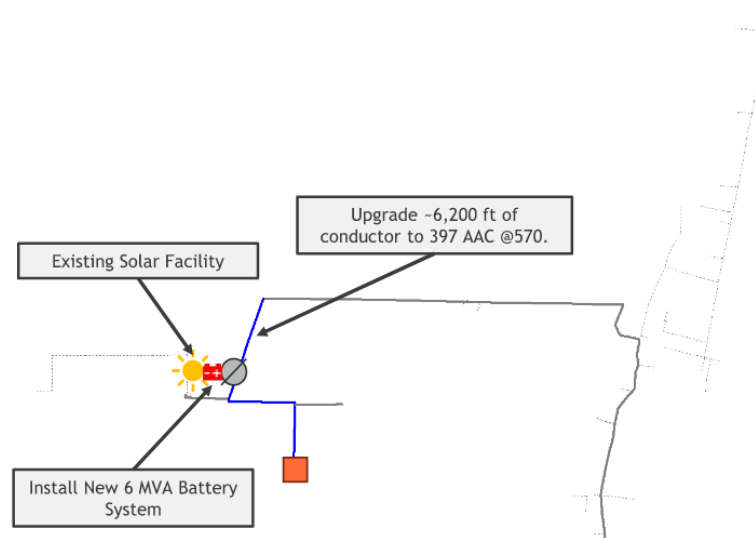
115

LSMO21 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	1.27 MW
Max HC	5.16 MW
HC Increase	3.89 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade -6,200 ft of 1/0 ACSR to 397 AAC @570 from Pole C28D035 to Pole C28B081	\$174,590
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	14,474,590



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	3.89
Cost (\$)	14,474,590
Hosting Capacity Benefit Cost	0.27
Holistic System Benefit Cost	1.04

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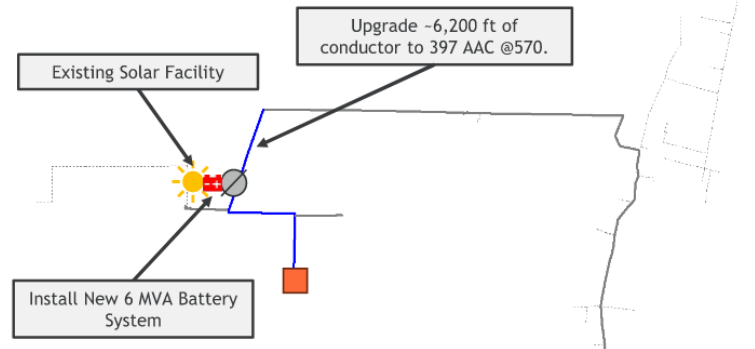
116

LSMO21 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	1.27 MW
Max HC	8.07 MW
HC Increase	6.8 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Upgrade -6,200 ft of 1/0 ACSR to 397 AAC @570 from Pole C28D035 to Pole C28B081	\$174,590
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,524,590



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	6.8
Cost (\$)	14,524,590
Hosting Capacity Benefit Cost	0.47
Holistic System Benefit Cost	1.93

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LSMO21 - Dedicated Feeder

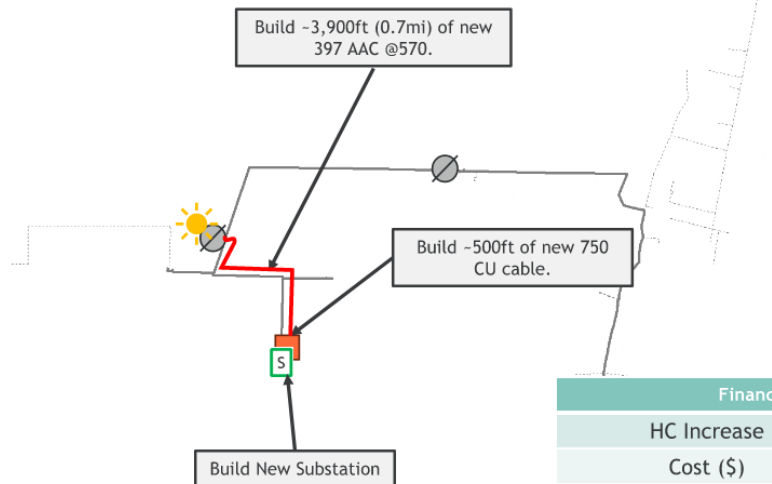
Hosting Capacity	
Base HC	1.27 MW
Max HC	10.2 MW
HC Increase	8.93 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~500ft of new 750 CU cable from the New Los Morros Substation to a new riser pole.	
Build ~3,900ft (0.7mi) of new 397 AAC @570. Utilize double circuit construction along the existing path of Los Morros 21 main line conductor.	\$593,086
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$4,000,000
TOTAL	\$4,593,086



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Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	8.93
Cost (\$)	4,593,086
Hosting Capacity Benefit Cost	1.94
Holistic System Benefit Cost	2.07

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LSMO21 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	1,272	3,216	1,944	\$174,590	11.13	11.87
Feeder Upgrades with 2 MVA BESS	1,272	5,161	3,889	\$14,474,590	0.27	1.04
2 MVA BESS Only*	-	-	-	-	-	-
Feeder Upgrades with 6 MVA BESS	1,272	8,074	6,802	\$14,524,590	0.47	1.93
6 MVA BESS Only*	-	-	-	-	-	-
Dedicated Feeder	1,272	10,196	8,924	\$4,593,086	1.94	2.07

*This scenario was not applicable to this analysis.



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PROG13 Analysis



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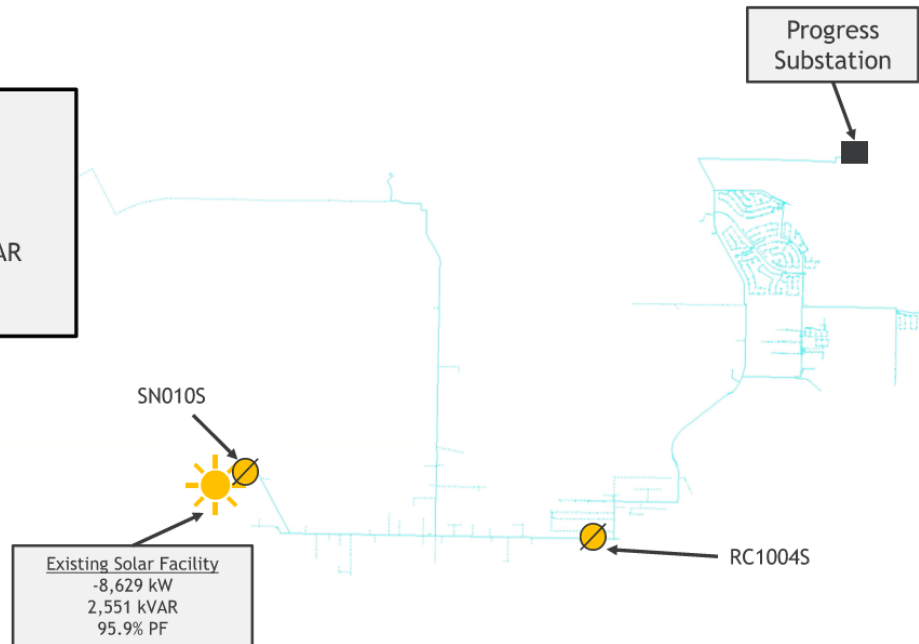
PROG13 - Feeder Overview

Feeder Data

- Feeder Rating: 9,936 kVA
- Existing Generation: 9,610 kVA
- daylight Minimum Load: -6,367 kW
- daylight Minimum Gross Load: 1,867 kW / 399 kVAR
- Substation LTC Setpoint - 123 V
- Primary Voltage - 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	PROG13 Breaker	600
Recloser	RC1004S	325
Recloser	SN010S	450



Existing Solar Facility
-8,629 kW
2,551 kVAR
95.9% PF

Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-6,367	276	6,373	-100	291	279	294	122.3	125.3	97.0

PROG13 - Feeder Overview with Queued Solar

Feeder Data

- Feeder Rating: 9,936 kVA
- Existing Generation: 9,931 kVA
- daylight Minimum Load: -6,667 kW
- daylight Minimum Gross Load: 1,867 kW / 399 kVAR
- Substation LTC Setpoint - 123 V
- Primary Voltage - 12.47 kV
- Queued Solar Projects: **58**
- Total Queued AC Inverter Nameplate: **326 kW**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	PROG13 Breaker	600
Recloser	RC1004S	325
Recloser	SN010S	450



The feeder can serve queued PV interconnection requests without violations.

326 kW of queued PV interconnections are on hold for PROG13 as of 1-1-2024

* Queued PV Interconnection

SN010S

Existing Solar Facility
-8,611 kW
2,552 kVAR
95.9% PF

Progress Substation

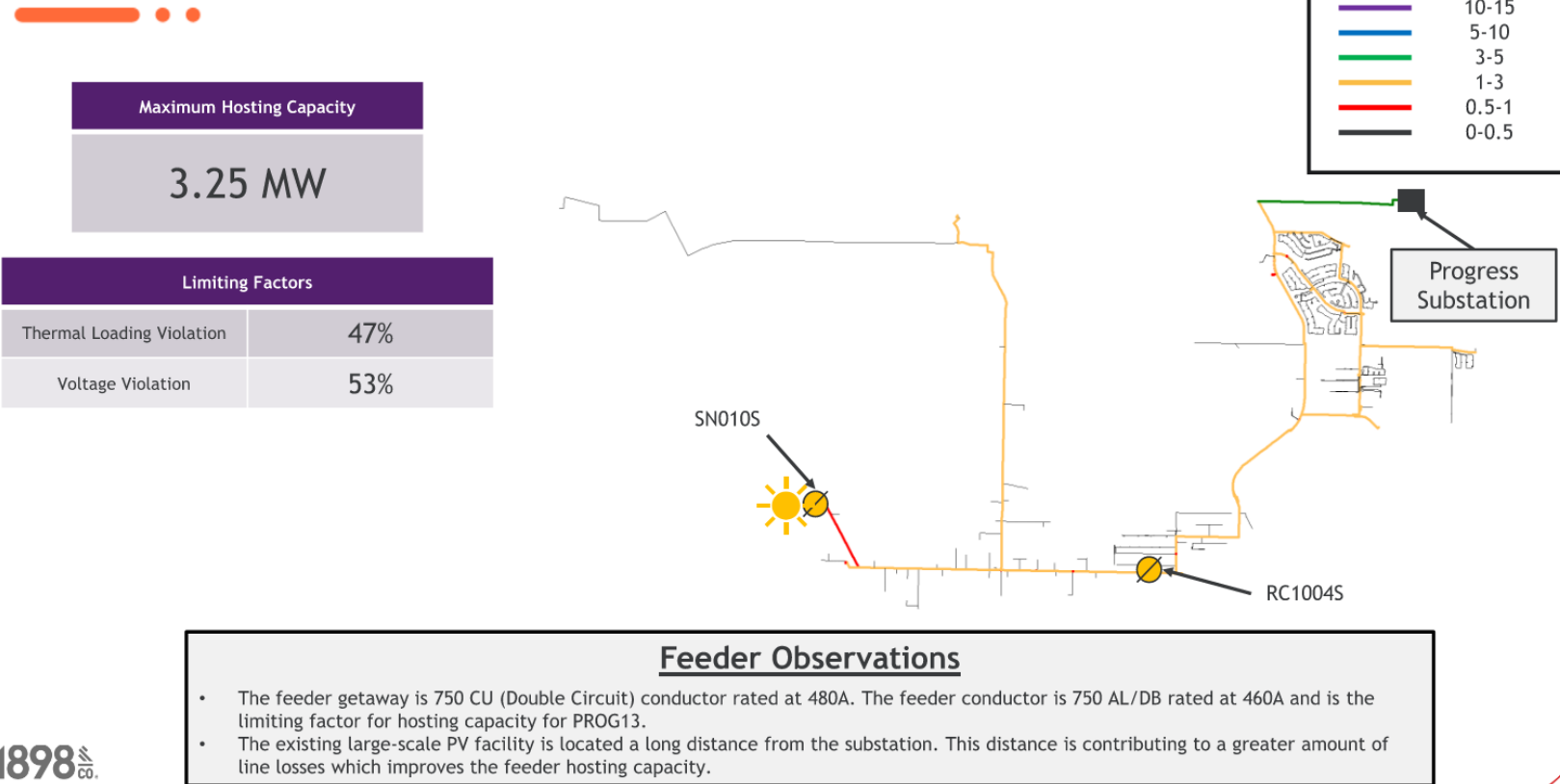


RC1004S

Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-6,667	291	6,673	-100	312	290	302	122.3	125.4	96.3

PROG13 - Maximum Hosting Capacity Base Case w/ Queued PV



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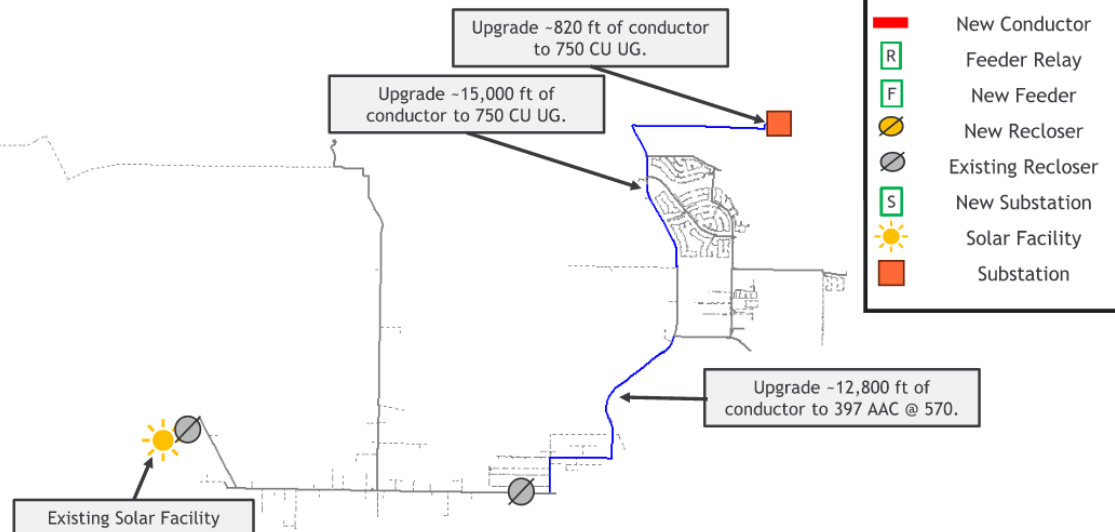
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PROG13 - Feeder Upgrades

Hosting Capacity	
Base HC	3.25 MW
Max HC	4.51 MW
HC Increase	1.26 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~820 ft of 750 CU Dbl Ckt to 750 CU UG from Progress Substation to Underground Structure PB53175	\$7,164,255
Upgrade ~15,000 ft of 750 AL UG to 750 CU UG from Underground Structure PB53175 to Pole D06D051	
Upgrade ~12,800 ft of 397 AAC to 397 AAC @ 570 from Pole D07B005 to Pole D08A099	
TOTAL	\$7,164,255



Financial Analysis	
HC Increase	1.26
Cost (\$)	7,164,255
Hosting Capacity Benefit Cost	0.17
Holistic System Benefit Cost	0.19

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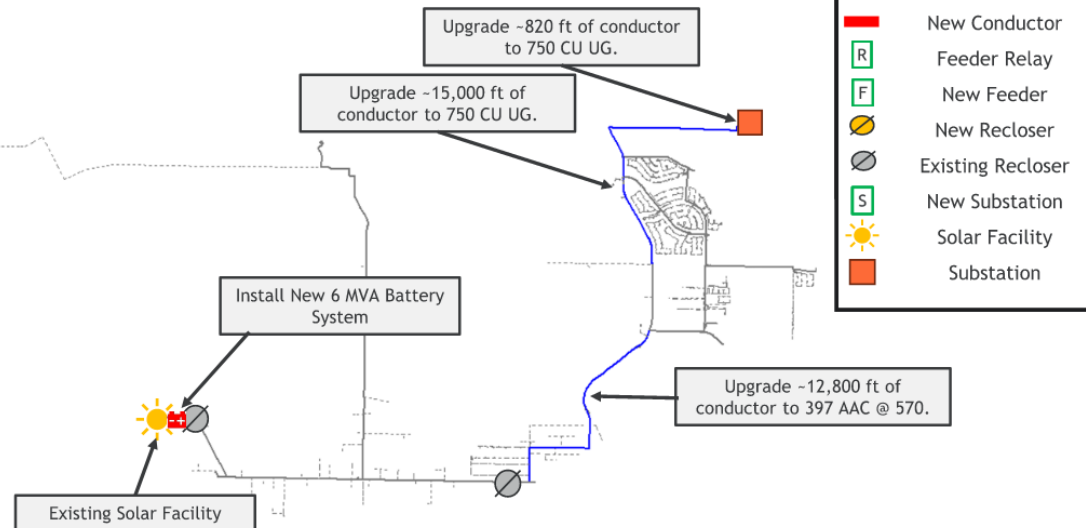
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PROG13 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	3.25 MW
Max HC	6.12 MW
HC Increase	2.87 MW

Reverse Flow Limits
Max HC

System Improvement	Cost
Upgrade ~820 ft of 750 CU Dbl Ckt to 750 CU UG from Progress Substation to Underground Structure PB5317S	\$7,164,255
Upgrade ~15,000 ft of 750 AL UG to 750 CU UG from Underground Structure PB5317S to Pole D06D051	
Upgrade ~12,800 ft of 397 AAC to 397 AAC @ 570 from Pole D07B005 to Pole D08A099	
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$21,464,255



Financial Analysis	
HC Increase	2.87
Cost (\$)	21,464,255
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.70

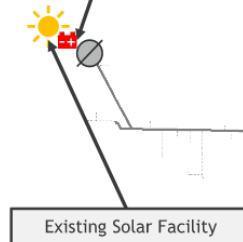
PROG13 - 2 MVA BESS Only

Hosting Capacity	
Base HC	3.25 MW
Max HC	4.85 MW
HC Increase	1.60 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,300,000

Install New 6 MVA Battery System



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Benefit Cost Ratio	
HC Increase	1.60
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.11
Holistic System Benefit Cost	1.17

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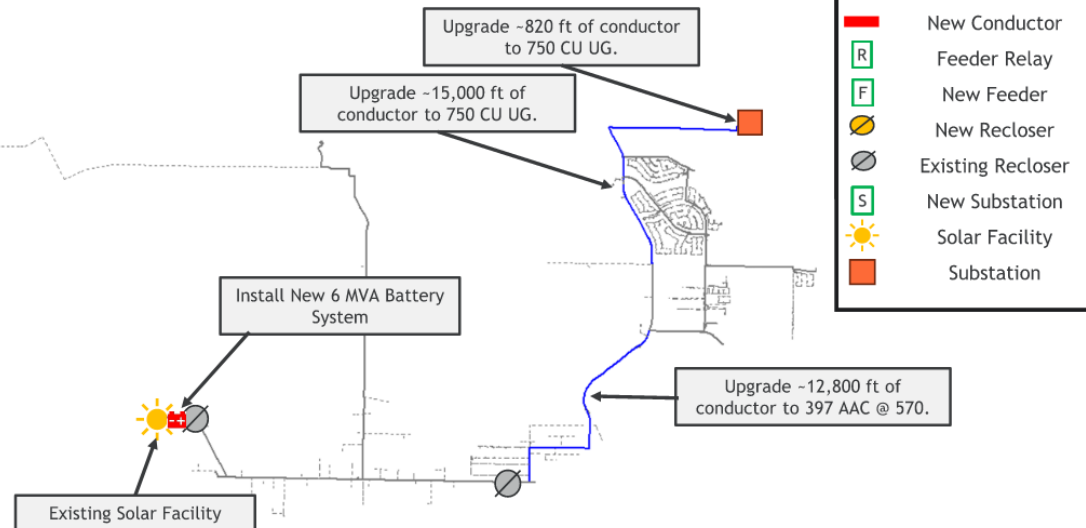
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PROG13 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	3.25 MW
Max HC	7.39 MW
HC Increase	4.14 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Upgrade - 820 ft of 750 CU Dbl Ckt to 750 CU UG from Progress Substation to Underground Structure PB53175	\$7,164,255
Upgrade - 15,000 ft of 750 AL UG to 750 CU UG from Underground Structure PB53175 to Pole D06D051	
Upgrade - 12,800 ft of 397 AAC to 397 AAC @ 570 from Pole D07B005 to Pole D08A099	
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$21,514,255



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	4.14
Cost (\$)	21,514,255
Hosting Capacity Benefit Cost	0.19
Holistic System Benefit Cost	1.23



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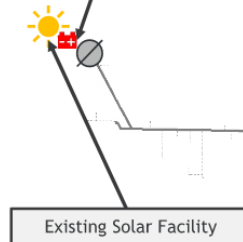
PROG13 - 6 MVA BESS Only

Hosting Capacity	
Base HC	3.25 MW
Max HC	5.68 MW
HC Increase	2.43 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,350,000

Install New 6 MVA Battery
System



Existing Solar Facility

Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	2.43
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	1.62
Holistic System Benefit Cost	2.16

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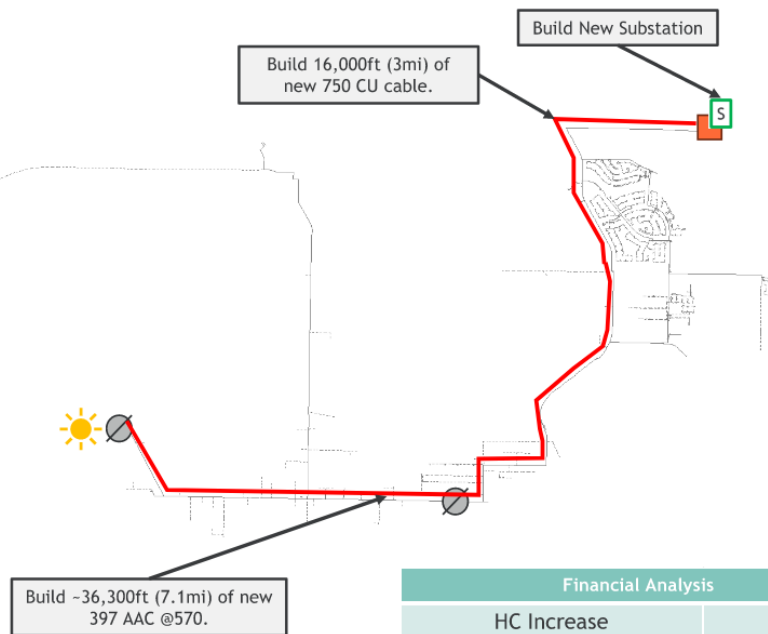
128

PROG13 - Dedicated Feeder

Hosting Capacity	
Base HC	3.25 MW
Max HC	10.9 MW
HC Increase	7.65 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~16,000ft (3mi) of new 750 CU cable from the Progress 13 Substation to a new riser pole.	\$10,415,494
Build ~36,300ft (7.1mi) of new 397 AAC @570. Utilize double circuit construction along the existing path of Progress 13 main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$18,415,494



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	7.65
Cost (\$)	18,415,494
Hosting Capacity Benefit Cost	0.42
Holistic System Benefit Cost	0.44



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PROG13 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	3,255	4,506	1,251	\$7,164,255	0.17	0.19
Feeder Upgrades with 2 MVA BESS	3,255	6,120	2,865	\$21,464,255	0.13	0.70
2 MVA BESS Only	3,255	4,850	1,595	\$14,300,000	0.11	1.17
Feeder Upgrades with 6 MVA BESS	3,255	7,391	4,136	\$21,514,255	0.19	1.23
6 MVA BESS Only	3,255	5,680	2,425	\$14,350,000	0.17	2.16
Dedicated Feeder	3,255	10,901	7,646	\$18,415,494	0.42	0.44



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SCEN12 Analysis



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SCEN12 - Feeder Overview

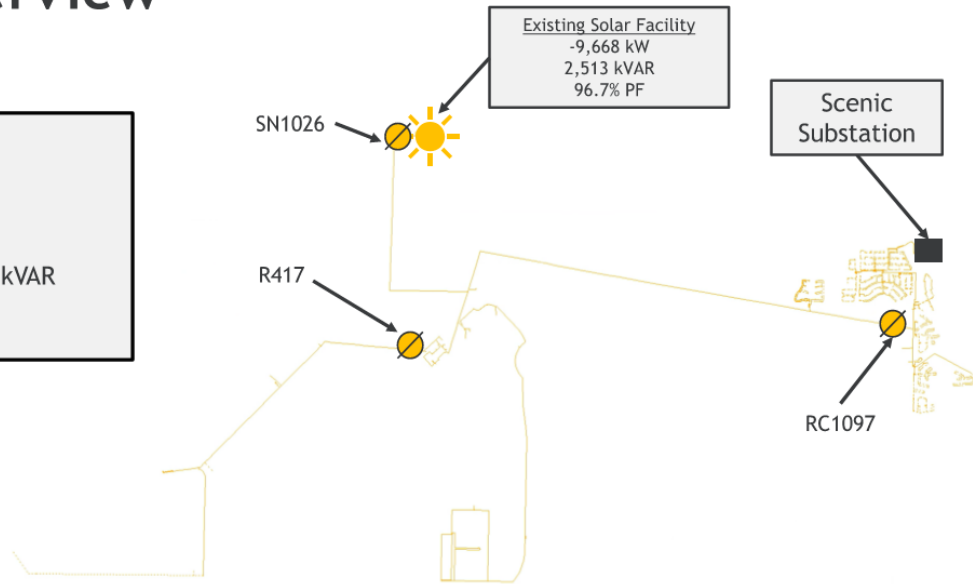
Feeder Data

- Feeder Rating: **9,936 kVA**
- Existing Generation: **10,728 kVA**
- daylight Minimum Load: -8,421 kW
- daylight Minimum Gross Load: 936 kW / 528 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	SCEN12 Breaker	600
Recloser	R417	140
Recloser	RC1091	325
Recloser	SN1026	525

Existing generation capacity exceeds the feeder rating.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,421	4,696	9,641	-87	445	438	434	121.1	122.7	97.0

SCEN12 - Feeder Overview with Queued Solar as of 1-1-24

Feeder Data

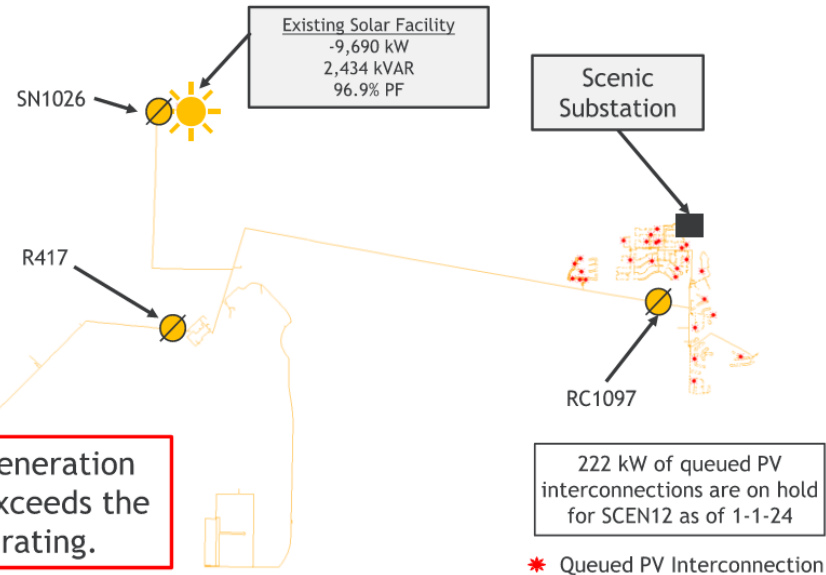
- Feeder Rating: **9,936 kVA**
- Existing Generation: **10,674 kVA**
- daylight Minimum Load: -8,632 kW
- daylight Minimum Gross Load: 936 kW / 528 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV
- Queued Solar Projects: **35**
- Total Queued AC Inverter Nameplate: **222 kW**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	SCEN12 Breaker	600
Recloser	R417	140
Recloser	RC1091	325
Recloser	SN1026	525



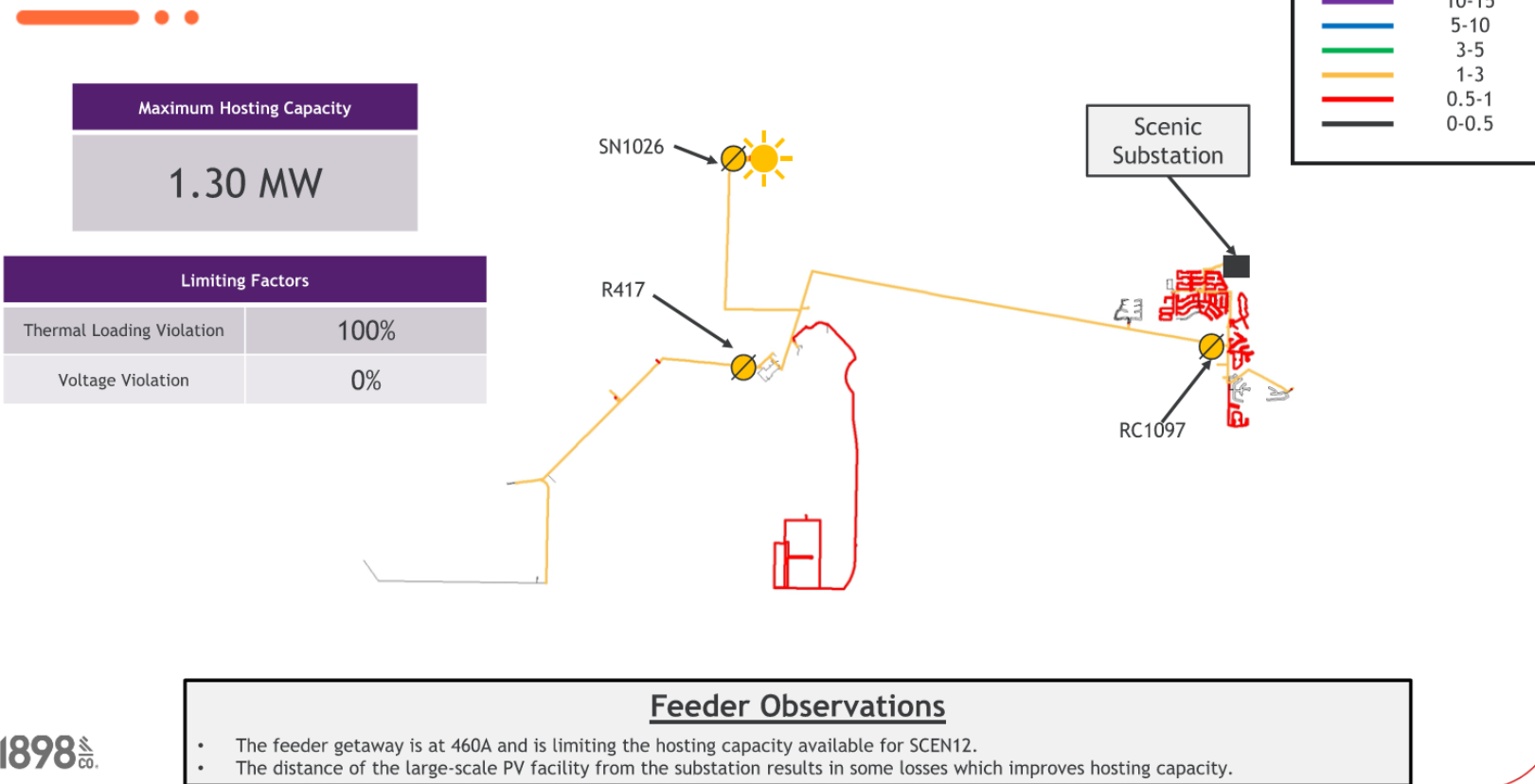
The feeder can serve queued PV interconnection requests without violations.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,632	4,704	9,830	-88	454	449	440	121.1	122.8	98.9

SCEN12 - Maximum Hosting Capacity Base Case w/ Queued PV



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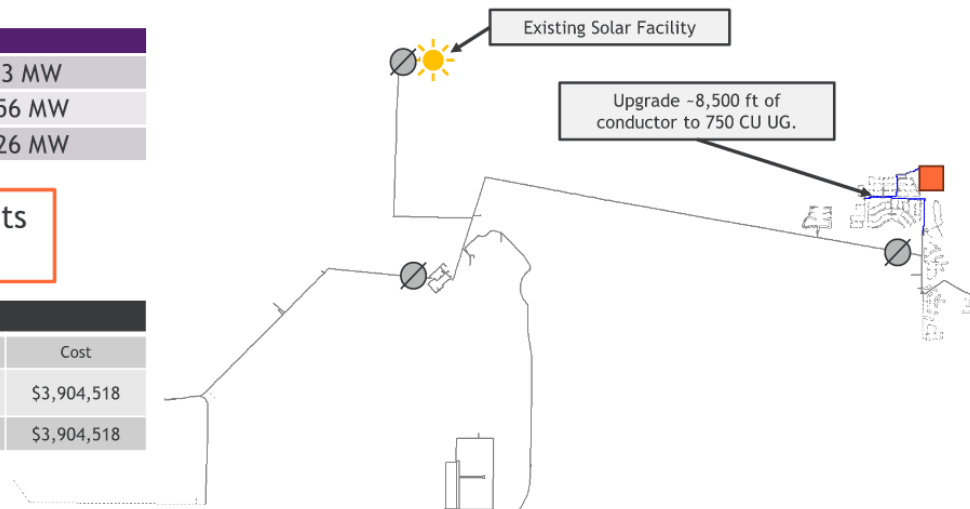
134

SCEN12 - Feeder Upgrades

Hosting Capacity	
Base HC	1.3 MW
Max HC	2.56 MW
HC Increase	1.26 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~8,500 ft of 750 AL Db to 750 CU UG from Underground Structure PB53175 to Pole D13B008	\$3,904,518
TOTAL	\$3,904,518



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	1.26
Cost (\$)	3,904,518
Hosting Capacity Benefit Cost	0.32
Holistic System Benefit Cost	0.34



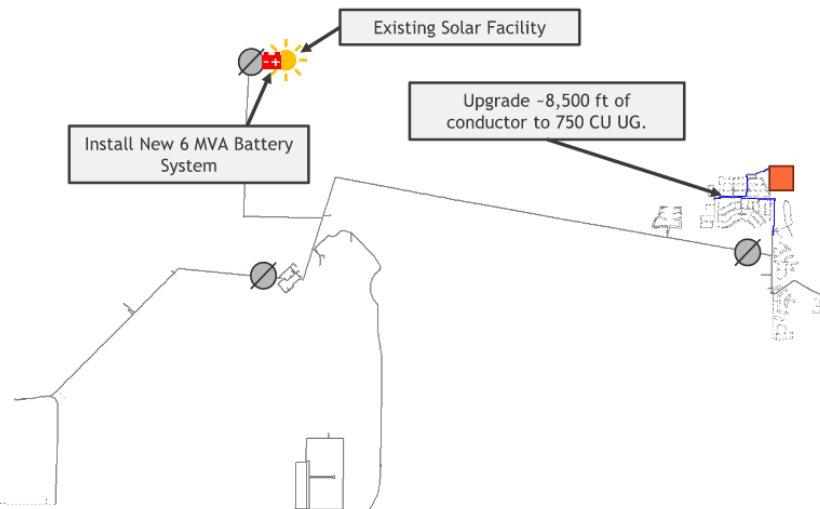
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SCEN12 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	1.3 MW
Max HC	4.18 MW
HC Increase	2.88 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~8,500 ft of 750 AL Db to 750 CU UG from Underground Structure PB53175 to Pole D13B008	\$3,904,518
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$18,204,518



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	2.88
Cost (\$)	18,204,518
Hosting Capacity Benefit Cost	0.16
Holistic System Benefit Cost	0.81



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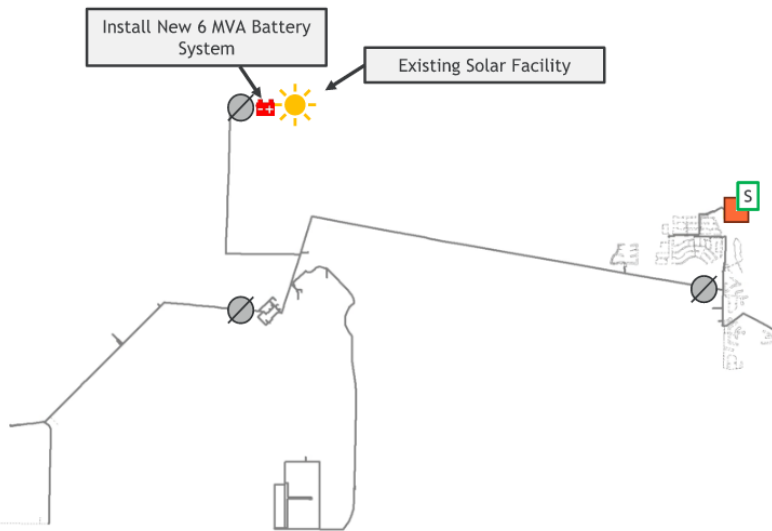
136

SCEN12 - 2 MVA BESS Only

Hosting Capacity	
Base HC	1.3 MW
Max HC	2.91 MW
HC Increase	1.61 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,300,000



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

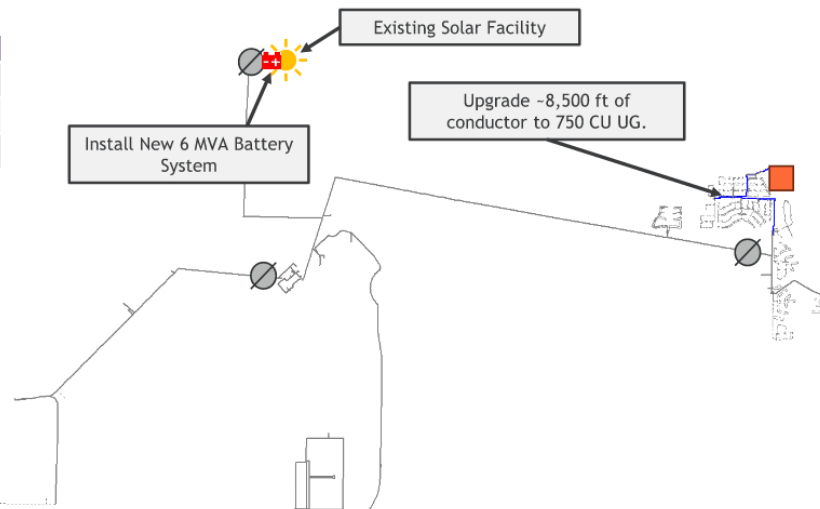
Financial Analysis	
HC Increase	1.61
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.11
Holistic System Benefit Cost	1.62

SCEN12 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	1.3 MW
Max HC	6.45 MW
HC Increase	5.15 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Upgrade ~8,500 ft of 750 AL Db to 750 CU UG from Underground Structure PB53175 to Pole D13B008	\$3,904,518
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$18,254,518



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	5.15
Cost (\$)	18,254,518
Hosting Capacity Benefit Cost	0.28
Holistic System Benefit Cost	1.51



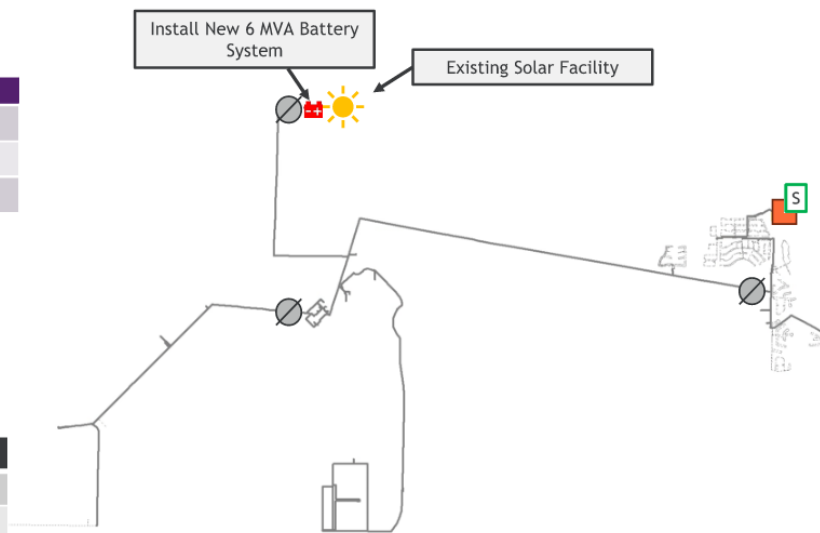
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SCEN12 - 6 MVA BESS Only

Hosting Capacity	
Base HC	1.3 MW
Max HC	4.48 MW
HC Increase	3.18 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,350,000



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

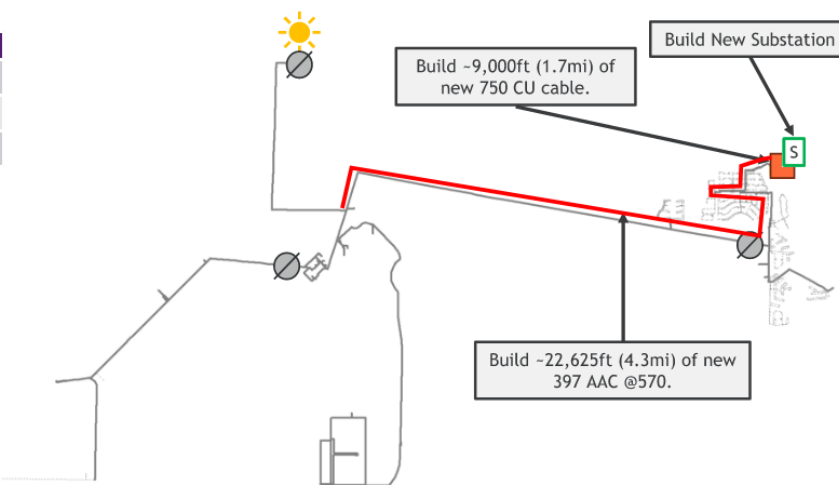
Financial Analysis	
HC Increase	3.18
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.22
Holistic System Benefit Cost	3.08

SCEN12 - Dedicated Feeder

Hosting Capacity	
Base HC	1.3 MW
Max HC	9.91 MW
HC Increase	8.61 MW

Reverse Flow Limits
Max HC

System Improvement	Cost
Build ~9,000ft (1.7mi) of new 750 CU cable from the Scenic 12 Substation to a new riser pole.	\$6,097,893
Build ~22,625ft (4.3mi) of new 397 AAC @570. Utilize double circuit construction along the existing path of Scenic 12 main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$14,097,893



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	8.61
Cost (\$)	14,097,893
Hosting Capacity Benefit Cost	0.61
Holistic System Benefit Cost	0.65

SCEN12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	1,297	2,559	1,262	\$3,904,518	0.32	0.34
Feeder Upgrades with 2 MVA BESS	1,297	4,179	2,882	\$18,204,518	0.16	0.81
2 MVA BESS Only	1,297	2,910	1,613	\$14,300,000	0.11	1.62
Feeder Upgrades with 6 MVA BESS	1,297	6,453	5,156	\$18,254,518	0.28	1.51
6 MVA BESS Only	1,297	4,480	3,183	\$14,350,000	0.22	3.08
Dedicated Feeder	1,297	9,906	8,609	\$14,097,893	0.61	0.65



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SCEN12 - Feeder Overview with Queued Solar as of 8-19-24

Feeder Data

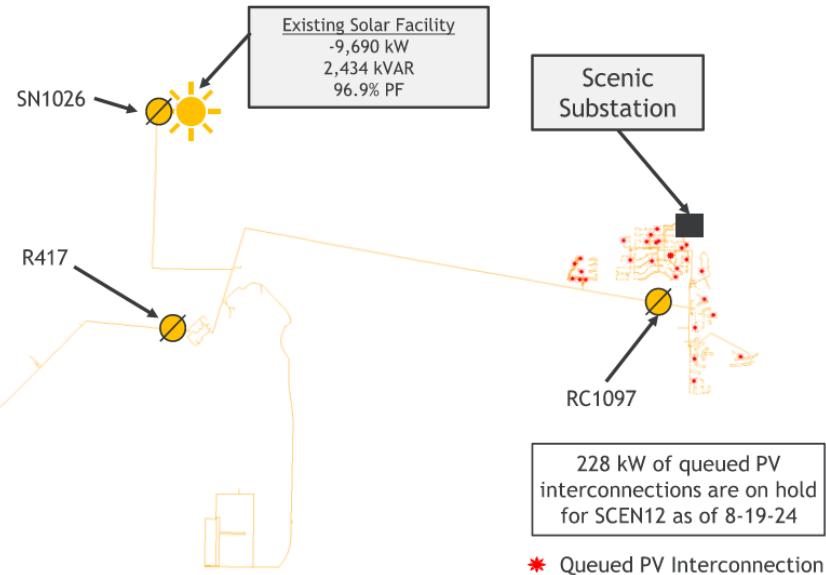
- Feeder Rating: **9,936 kVA**
- Existing Generation: **10,680 kVA**
- daylight Minimum Load: -8,644 kW
- daylight Minimum Gross Load: 936 kW / 528 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV
- Queued Solar Projects: 36
- Total Queued AC Inverter Nameplate: 228 kW

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	SCEN12 Breaker	600
Recloser	R417	140
Recloser	RC1091	325
Recloser	SN1026	525



The feeder can serve queued PV interconnection requests without violations.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,644	4,705	9,841	-88	454	450	440	121.1	122.8	98.9

SOCO12 Analysis



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SOC012 - Feeder Overview

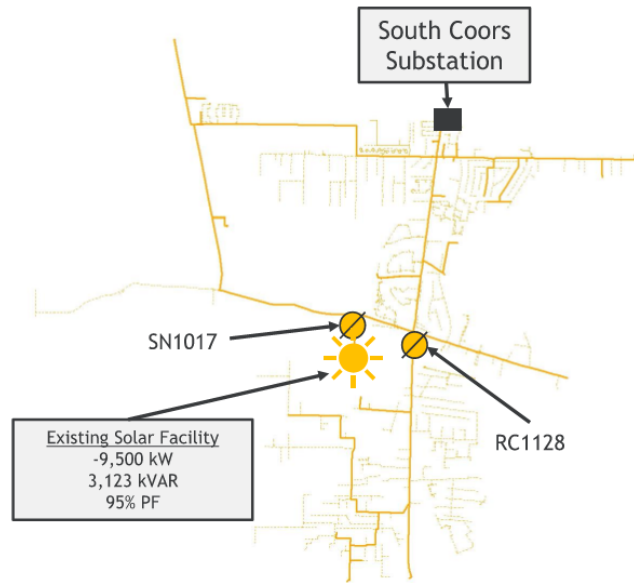
Feeder Data

- Feeder Rating - **9,288 kVA**
- Existing Generation - **10,708 kVA**
- Minimum Daylight Load: -7,707 kW
- Minimum Daylight Gross Load- 2,143 kW / 957 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	SOC012 Breaker	600
Recloser	RC1128	290
Recloser	SN1017	625

Existing generation capacity exceeds the feeder rating.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-7,707	3,546	8,484	-91	381	392	387	121.6	123.0	97.0

SOCO12 - Feeder Overview with Queued Solar as of 1-1-14

Feeder Data

- Feeder Rating - **9,288 kVA**
- Existing Generation - **11,063 kVA**
- Minimum Daylight Load: -8,067 kW
- Minimum Daylight Gross Load- 2,143 kW / 957 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV
- Queued Solar Projects: **55**
- Total Queued AC Inverter Nameplate: **364 kW**

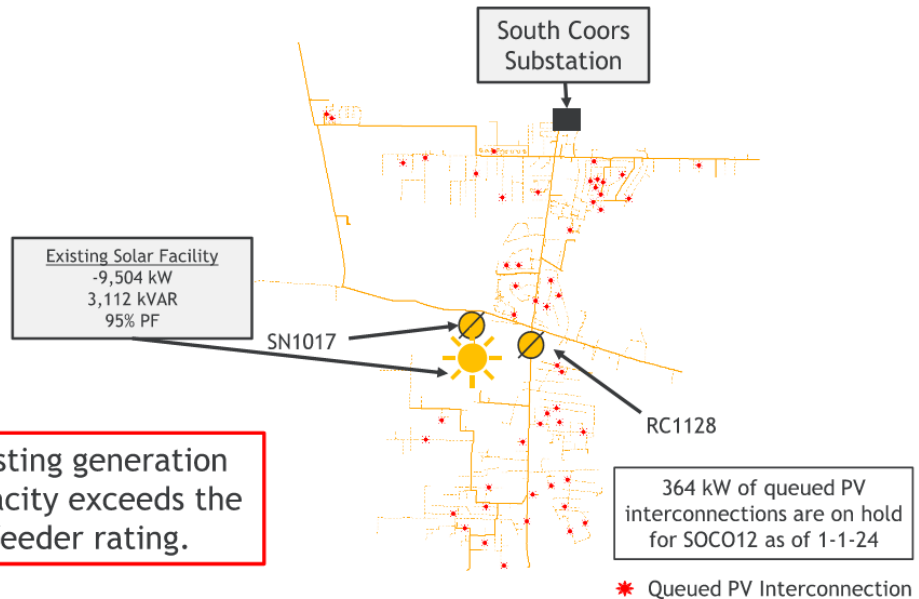
Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	SOCO12 Breaker	600
Recloser	RC1128	290
Recloser	SN1017	625



The feeder can serve queued PV interconnection requests without violations.

Existing generation capacity exceeds the feeder rating.



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,067	3,561	8,818	-91	401	404	400	121.8	123.5	98.2

SOCO12 - Maximum Hosting Capacity Base Case w/ Queued PV

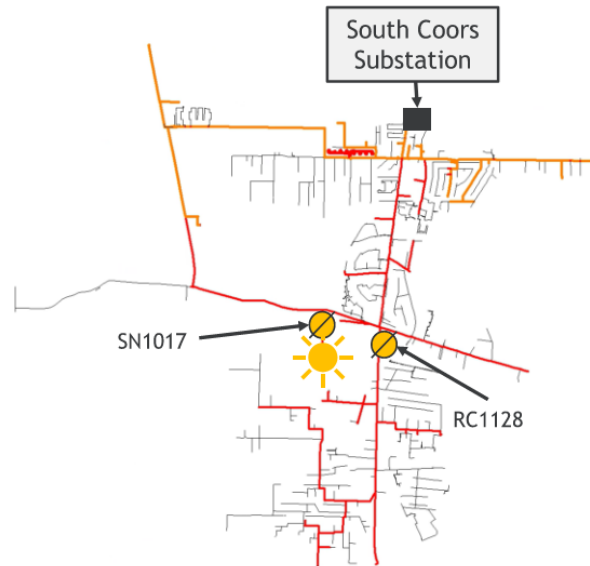
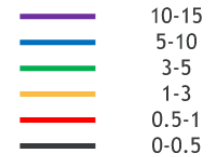
Maximum Hosting Capacity

1.22 MW

Limiting Factors

Thermal Loading Violation	100%
Voltage Violation	0%

Hosting Capacity (MW)



Feeder Observations

- The feeder getaway is 750 AL (Riser) and should be upgraded to the maximum PNM standard 750 CU getaway cable.
- The existing generation exceeds feeder rating. Minimum daylight gross load is necessary to keep feeder within planning criteria.
- Some hosting capacity is remaining on this feeder as enough generation is consumed by local customer load. Queued PV customers may be able to interconnect to this feeder.

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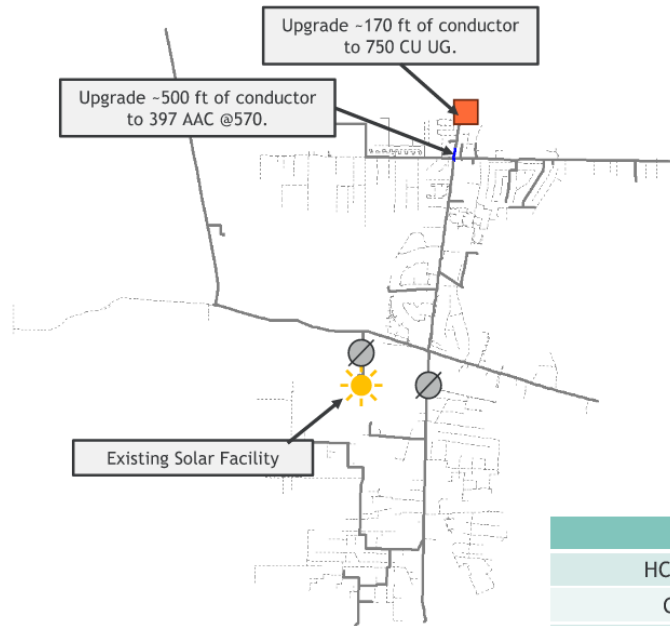
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SOC012 - Feeder Upgrades

Hosting Capacity	
Base HC	1.22 MW
Max HC	3.17 MW
HC Increase	1.95 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade -170 ft 750 AL Riser to 750 CU UG South Coors Substation to Pole D19D104	\$12,053,358
Upgrade -500 ft 397 AAC to 397 AAC @570 from Pole D20B342 to Pole D20B339	
TOTAL	\$12,053,358



Financial Analysis	
HC Increase	1.95
Cost (\$)	12,053,358
Hosting Capacity Benefit Cost	0.16
Holistic System Benefit Cost	0.17



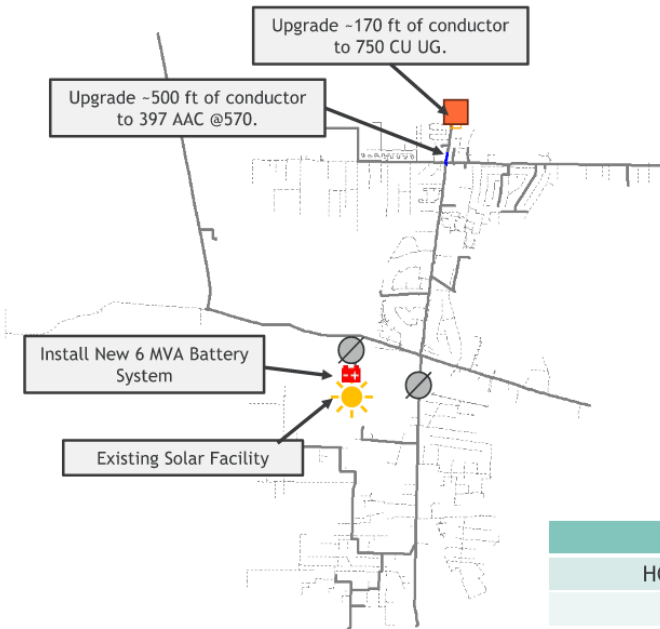
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SOCO12 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	1.22 MW
Max HC	5.01 MW
HC Increase	3.79 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~170 ft 750 AL Riser to 750 CU UG South Coors Substation to Pole D19D104	\$12,053,358
Upgrade ~500 ft 397 AAC to 397 AAC @570 from Pole D20B342 to Pole D20B339	
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$26,353,358



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

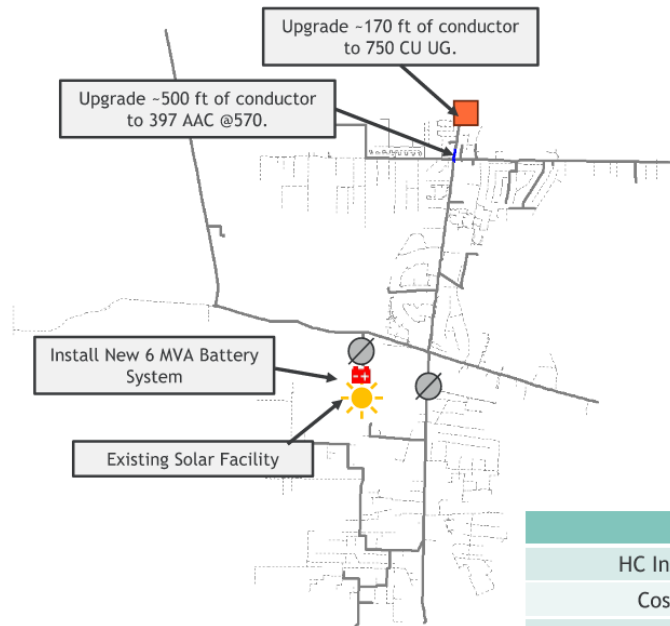
Financial Analysis	
HC Increase	3.79
Cost (\$)	26,353,358
Hosting Capacity Benefit Cost	0.14
Holistic System Benefit Cost	0.62

SOCO12 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	1.22 MW
Max HC	6.52 MW
HC Increase	5.3 MW

Thermal Loading Limits
Max HC

System Improvement	Cost
Upgrade -170 ft 750 AL Riser to 750 CU UG South Coors Substation to Pole D19D104	\$12,053,358
Upgrade -500 ft 397 AAC to 397 AAC @570 from Pole D20B342 to Pole D20B339	
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$26,403,358



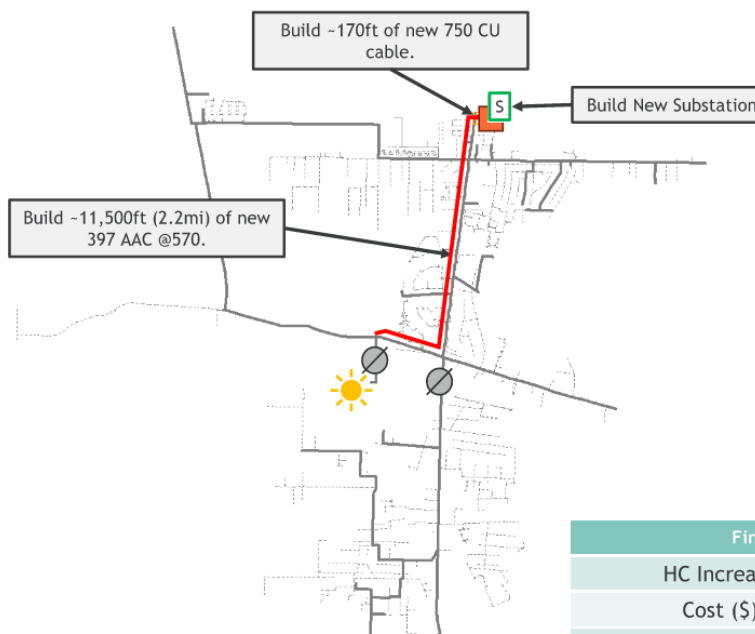
Financial Analysis	
HC Increase	5.3
Cost (\$)	26,403,358
Hosting Capacity Benefit Cost	0.20
Holistic System Benefit Cost	1.10

SOCO12 - Dedicated Feeder

Hosting Capacity	
Base HC	1.22 MW
Max HC	10.35 MW
HC Increase	9.13 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~170ft of new 750 CU cable from the South Coors 12 Substation to a new riser pole.	\$1,224,026
Build ~11,500ft (2.2mi) of new 397 AAC @570. Utilize double circuit construction along the existing path of South Coors 12 main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$9,224,026



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	9.13
Cost (\$)	9,224,026
Hosting Capacity Benefit Cost	0.99
Holistic System Benefit Cost	1.05



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SOC012 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	1,224	3,167	1,943	\$12,053,358	0.16	0.17
Feeder Upgrades with 2 MVA BESS	1,224	5,011	3,787	\$26,353,358	0.14	0.62
2 MVA BESS Only*	-	-	-	-	-	-
Feeder Upgrades with 6 MVA BESS	1,224	6,515	5,291	\$26,403,358	0.20	1.10
6 MVA BESS Only*	-	-	-	-	-	-
Dedicated Feeder	1,224	10,350	9,126	\$9,224,026	0.99	1.05

*This scenario was not applicable to this analysis.



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SOC012 - Feeder Overview with Queued Solar as of 8-19-24

Feeder Data

- Feeder Rating - **9,288 kVA**
- Existing Generation - **11,063 kVA**
- Minimum Daylight Load: -8,022 kW
- Minimum Daylight Gross Load- 2,143 kW / 957 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV
- Queued Solar Projects: **56**
- Total Queued AC Inverter Nameplate: **373 kW**

Protection & Equipment Pickup/Ratings

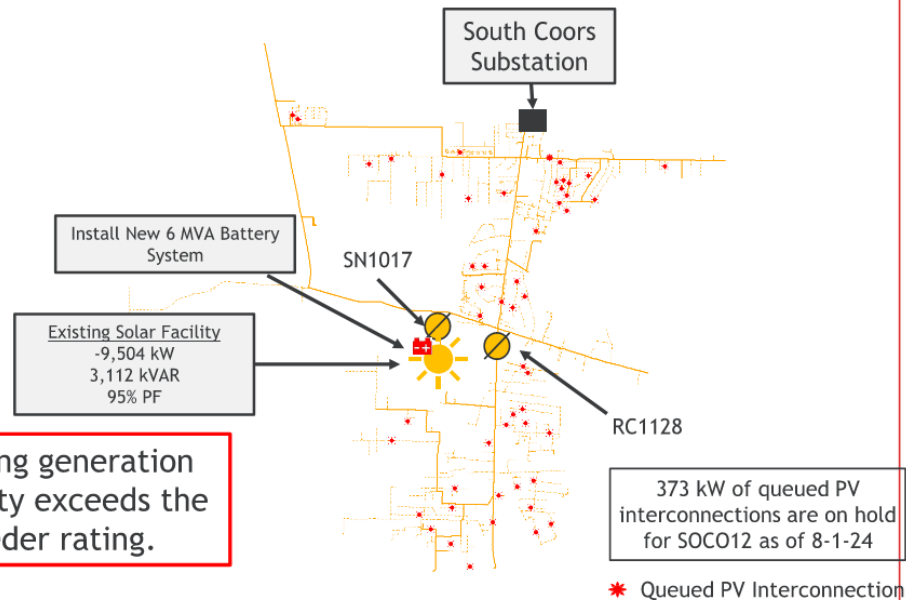
Device	Name	Pick Up Rating (A)
Breaker	SOC012 Breaker	600
Recloser	RC1128	290
Recloser	SN1017	625



The feeder can serve queued PV interconnection requests without violations.

Existing generation capacity exceeds the feeder rating.

Base Case Load Flow Analysis (Minimum daylight Load)									
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,022	3,571	8,827	-91	402	404	400	121.8	123.5	98.1



STPE12 Analysis



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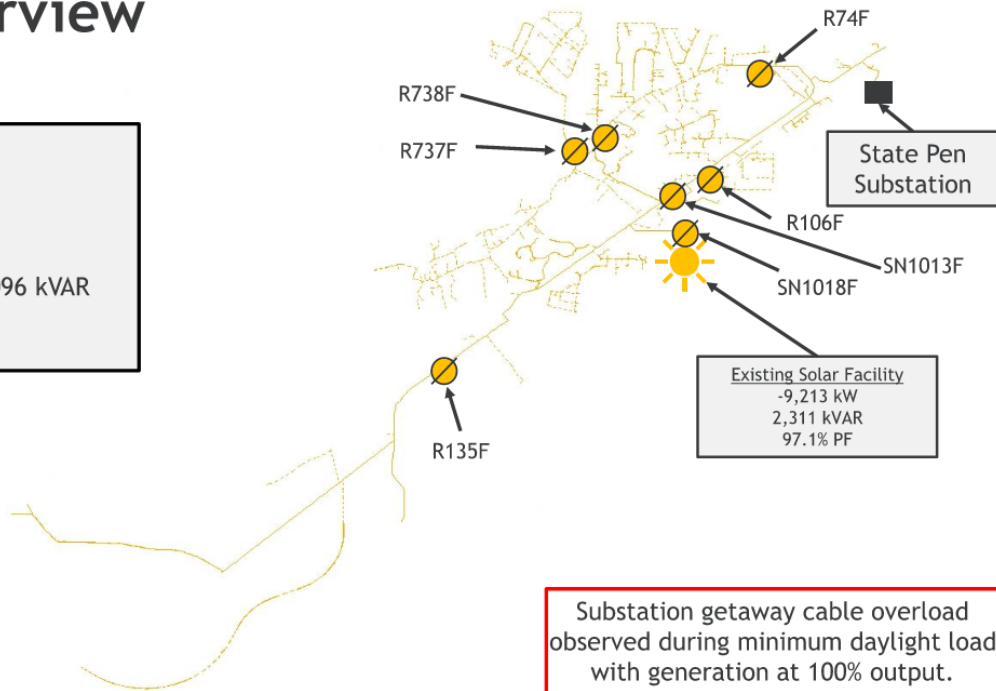
STPE12 - Feeder Overview

Feeder Data

- Feeder Rating - **8,208 kVA**
- Existing Generation - **10,066 kVA**
- Daylight Minimum Load: -7,839 kW
- Daylight Minimum Gross Load: 1,390 kW / 1,096 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	STPE Breaker	600
Recloser	R135F	190
Recloser	R74F	300
Recloser	R106F	200
Recloser	R737F	200
Recloser	R738F	300
Recloser	SN1018F	500
Recloser	SN1013F	600



Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-7,839	3,780	8,703	-90	387	376	426	119.9	124.3	112.0

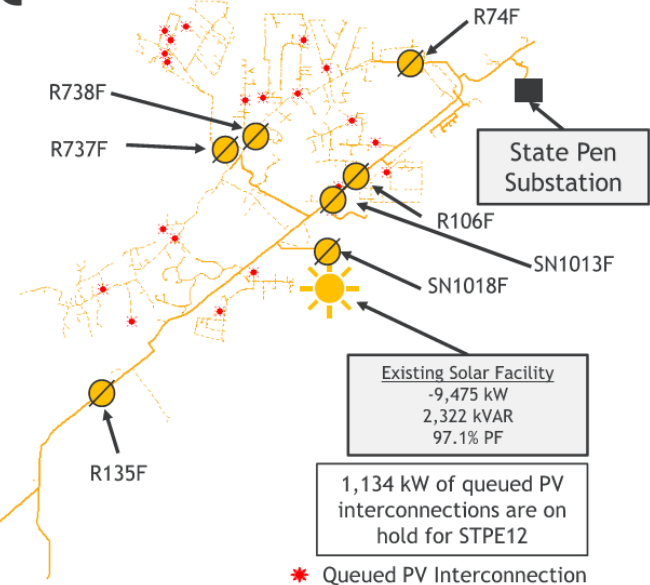
STPE12 - Feeder Overview with Queued Solar

Feeder Data

- Feeder Rating - **8,208 kVA**
- Existing Generation - **11,175 kW**
- Daylight Minimum Load: -8,903 kW
- Daylight Minimum Gross Load: 1,390 kW / 1,096 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV
- Queued Solar Projects: **23**
- Total Queued AC Inverter Nameplate: **1,134 kW**



The feeder **CANNOT** serve queued PV interconnection requests without violations.



Substation getaway cable overload observed during minimum daylight load with generation at 100% output.

Base Case Load Flow Analysis (Minimum daylight Load)

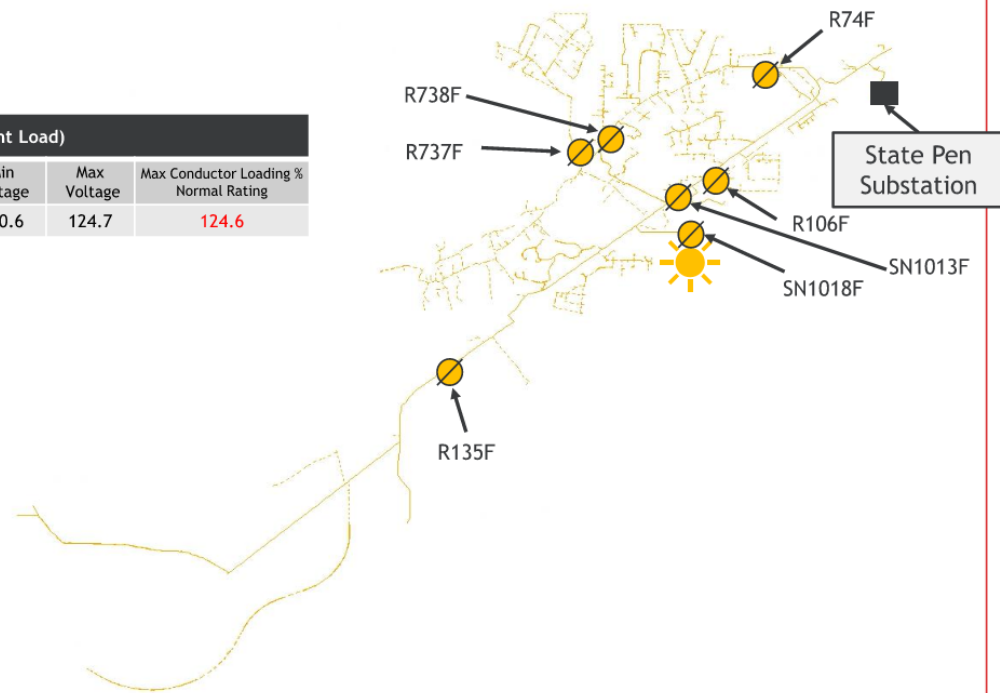
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,903	3,941	9,736	-91	433	424	473	120.6	124.7	124.6

STPE12 - Maximum Hosting Capacity Base Case w/ Queued PV

Base Case Load Flow Analysis (Minimum daylight Load)									
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,903	3,941	9,736	-91	433	424	473	120.6	124.7	124.6

Feeder Observations

- There is **ZERO** hosting capacity available in this feeder in the base case scenario.
- A **124.6%** thermal overload is observed at the feeder getaway if generation is at full output and is coincident with minimum daylight load. The getaway is 750AL DbICkt which has a rating of 380A or 8,208 kVA.

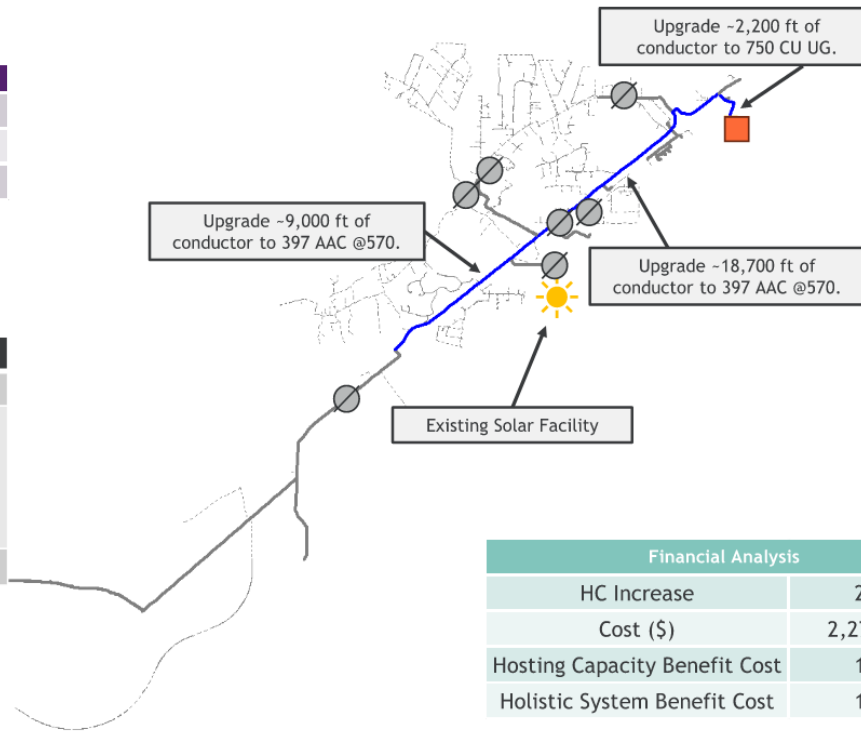


STPE12 - Feeder Upgrades

Hosting Capacity	
Base HC	0 MW
Max HC	2.52 MW
HC Increase	2.52 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade -2,200 ft of 750 AL Dbl Ckt to 750 CU UG from State Pen Substation to Pole V63C007	\$2,275,192
Upgrade -18,700 ft of 397 AAC to 397 AAC @570 from Pole V63C007 to Pole U64C015	
Upgrade -9,000 ft of 2/0 ACSR to 397 AAC @570 from Pole U64C015 to Pole T65D008	
TOTAL	\$2,275,192



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	2.52
Cost (\$)	2,275,192
Hosting Capacity Benefit Cost	1.11
Holistic System Benefit Cost	1.18

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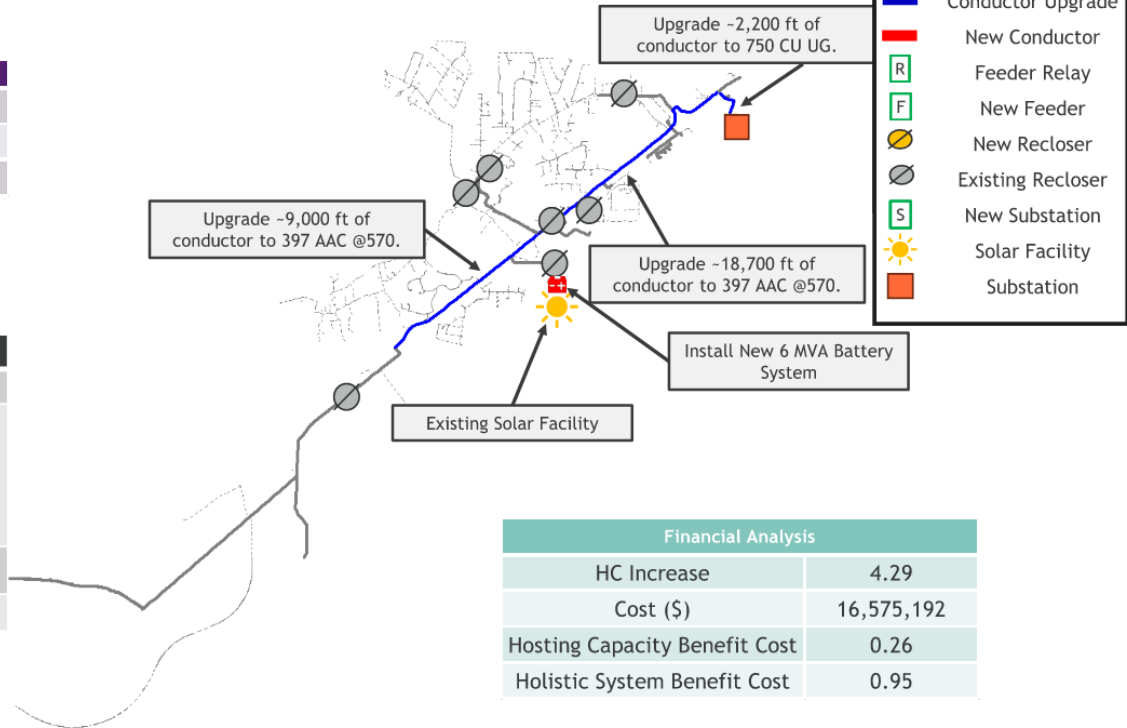
157

STPE12 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	0 MW
Max HC	4.29 MW
HC Increase	4.29 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade -2,200 ft of 750 AL Dbl Ckt to 750 CU UG from State Pen Substation to Pole V63C007	\$2,275,192
Upgrade -18,700 ft of 397 AAC to 397 AAC @570 from Pole V63C007 to Pole U64C015	
Upgrade -9,000 ft of 2/0 ACSR to 397 AAC @570 from Pole U64C015 to Pole T65D008	
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$16,575,192



Financial Analysis	
HC Increase	4.29
Cost (\$)	16,575,192
Hosting Capacity Benefit Cost	0.26
Holistic System Benefit Cost	0.95

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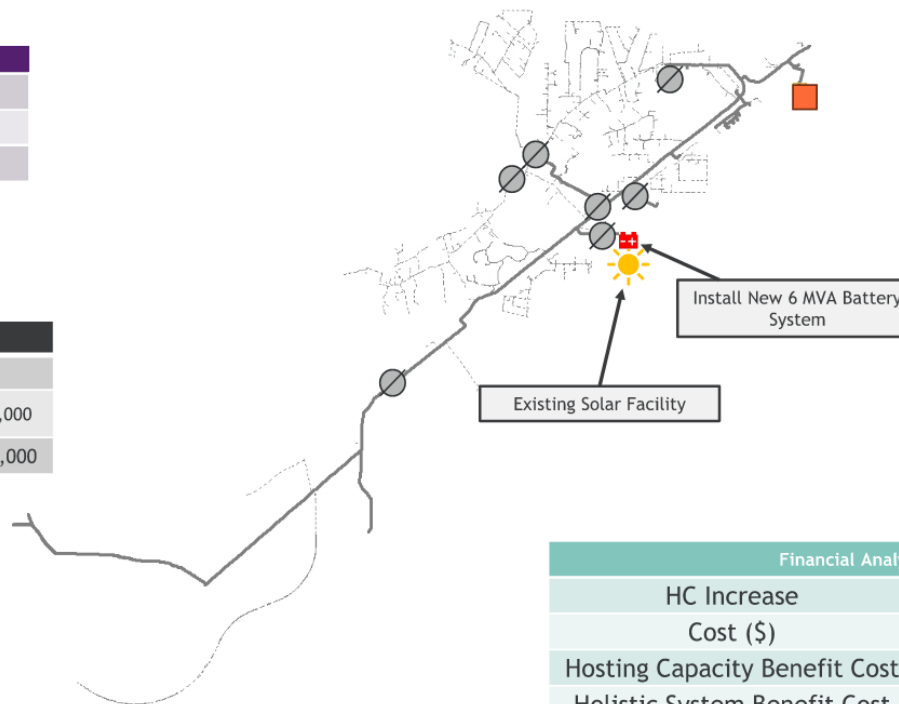
158

STPE12 - 2MVA BESS Only

Hosting Capacity	
Base HC	0 MW
Max HC	1.28 MW
HC Increase	1.28 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,300,000



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

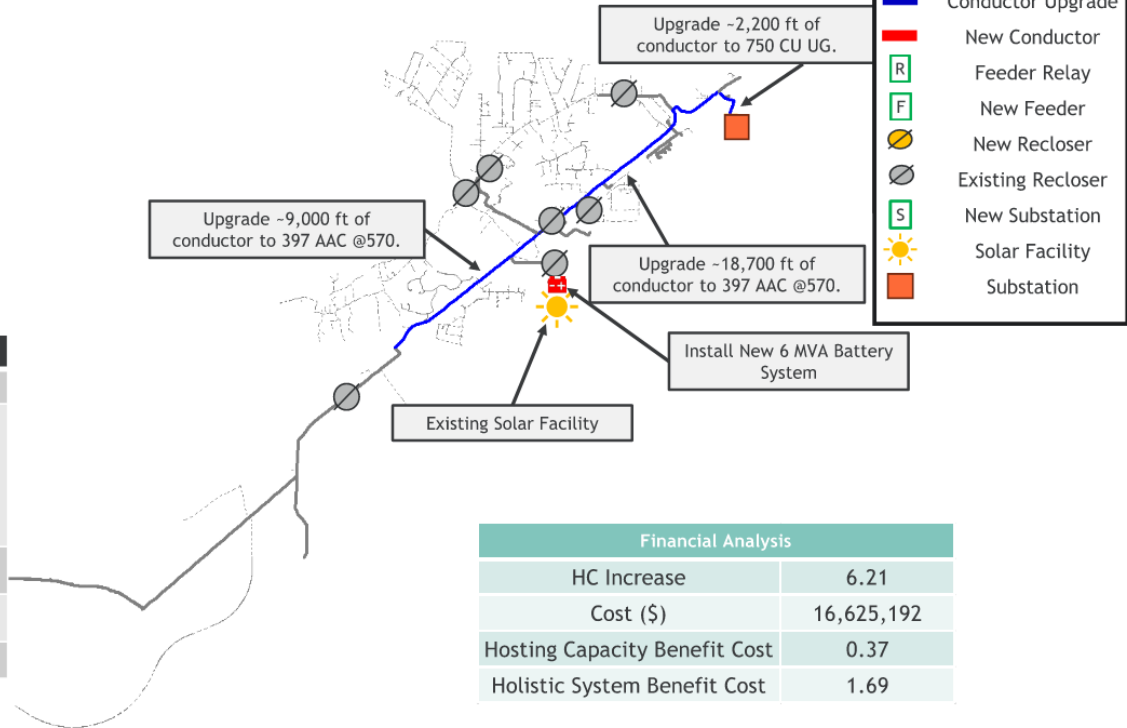
Financial Analysis	
HC Increase	1.28
Cost (\$)	\$14,300,000
Hosting Capacity Benefit Cost	0.09
Holistic System Benefit Cost	1.54

STPE12 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	0 MW
Max HC	6.21 MW
HC Increase	6.21 MW

Thermal Loading Limits
Max HC

System Improvement	Cost
Upgrade -2,200 ft of 750 AL Dbl Ckt to 750 CU UG from State Pen Substation to Pole V63C007	\$2,275,192
Upgrade -18,700 ft of 397 AAC to 397 AAC @570 from Pole V63C007 to Pole U64C015	
Upgrade -9,000 ft of 2/0 ACSR to 397 AAC @570 from Pole U64C015 to Pole T65D008	
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$16,625,192



Financial Analysis	
HC Increase	6.21
Cost (\$)	16,625,192
Hosting Capacity Benefit Cost	0.37
Holistic System Benefit Cost	1.69



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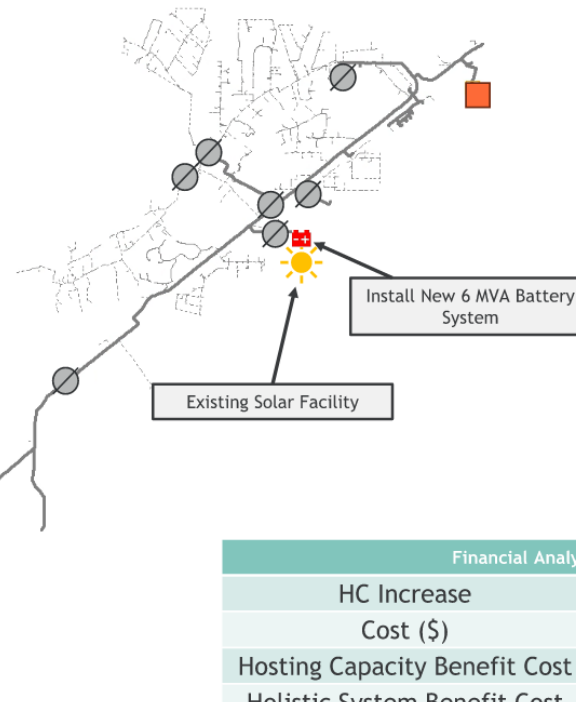
160

STPE12 - 6MVA BESS Only

Hosting Capacity	
Base HC	0 MW
Max HC	1.60 MW
HC Increase	1.60 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,350,000



Financial Analysis	
HC Increase	1.60
Cost (\$)	\$14,350,000
Hosting Capacity Benefit Cost	0.11
Holistic System Benefit Cost	2.17

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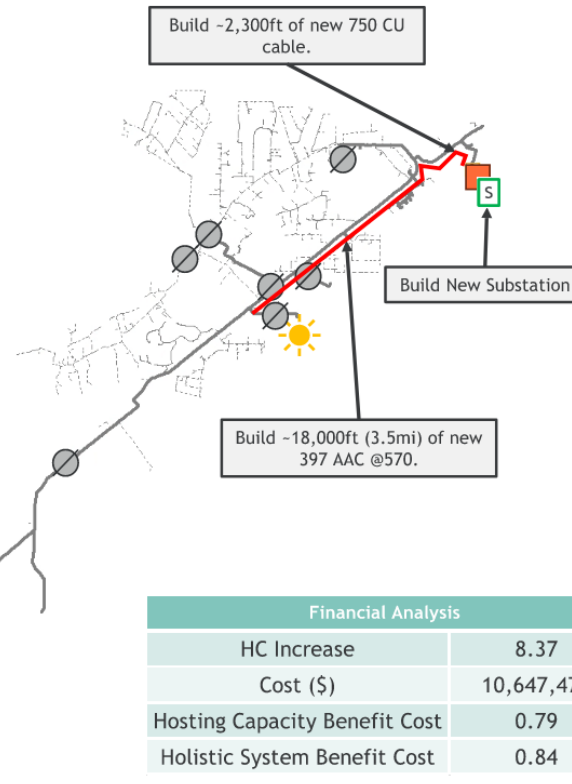
161

STPE12 - Dedicated Feeder

Hosting Capacity	
Base HC	0 MW
Max HC	8.37 MW
HC Increase	8.37 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~2,300ft of new 750 CU cable from the State Pen 12 Substation to a new riser pole.	\$2,647,470
Build ~18,000ft (3.5mi) of new 397 AAC @570. Utilize double circuit construction along the existing path of State Pen 12 main line conductor.	
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$10,647,470



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

Financial Analysis	
HC Increase	8.37
Cost (\$)	10,647,470
Hosting Capacity Benefit Cost	0.79
Holistic System Benefit Cost	0.84

STPE12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	Thermal Violation	2,520	2,520	\$2,275,192	1.11	1.18
Feeder Upgrades with 2 MVA BESS	Thermal Violation	4,289	4,289	\$16,575,192	0.26	0.95
2 MVA BESS Only	Thermal Violation	1,280	1,280	\$14,300,000	0.09	1.54
Feeder Upgrades with 6 MVA BESS	Thermal Violation	6,207	6,207	\$16,625,192	0.37	1.69
6 MVA BESS Only	Thermal Violation	1,600	1,600	\$14,350,000	0.11	2.17
Dedicated Feeder	Thermal Violation	8,370	8,370	\$10,647,470	0.79	0.84



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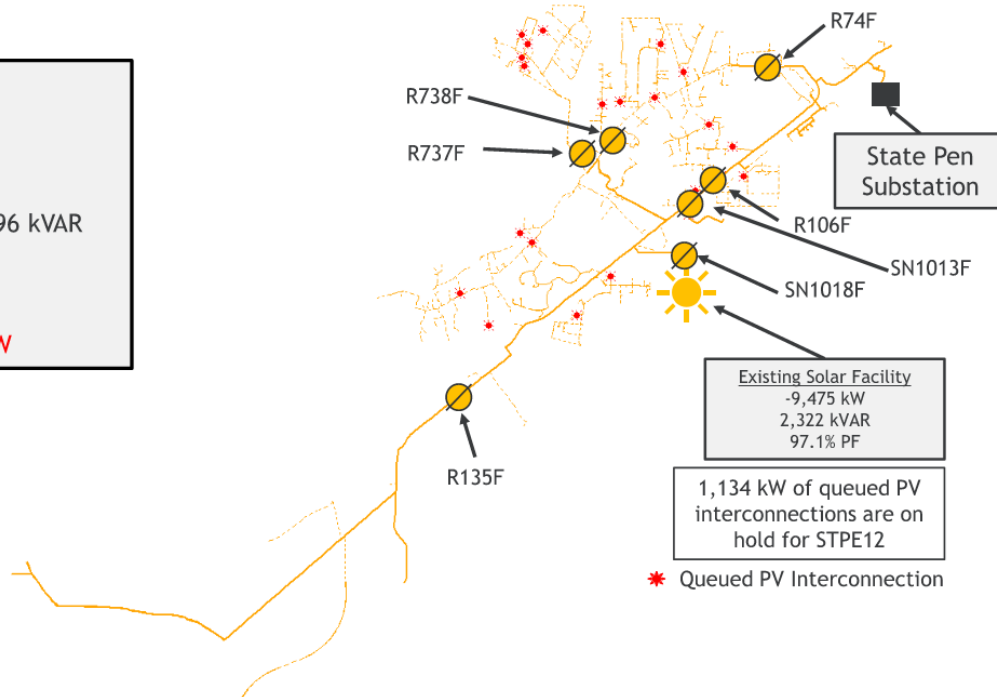
STPE12 - Feeder Overview with Queued Solar with Conductor Upgrades and 6 MVA BESS Solution Constructed

Feeder Data

- Feeder Rating - 11,231 kVA
- Existing Generation - 11,175 kVA
- Daylight Minimum Load: -3,401 kW
- Daylight Minimum Gross Load: 1,390 kW / 1,096 kVAR
- Substation LTC Setpoint - 122 V
- Primary Voltage - 12.47 kV
- Queued Solar Projects: **23**
- Total Queued AC Inverter Nameplate: **1,134 kW**



The feeder can serve queued PV interconnection requests without violations.



Feeder Upgrades & 6 MVA BESS Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-3,401	2,745	4,370	-78	189	184	226	119.2	122.0	86.9

TOME12 Analysis



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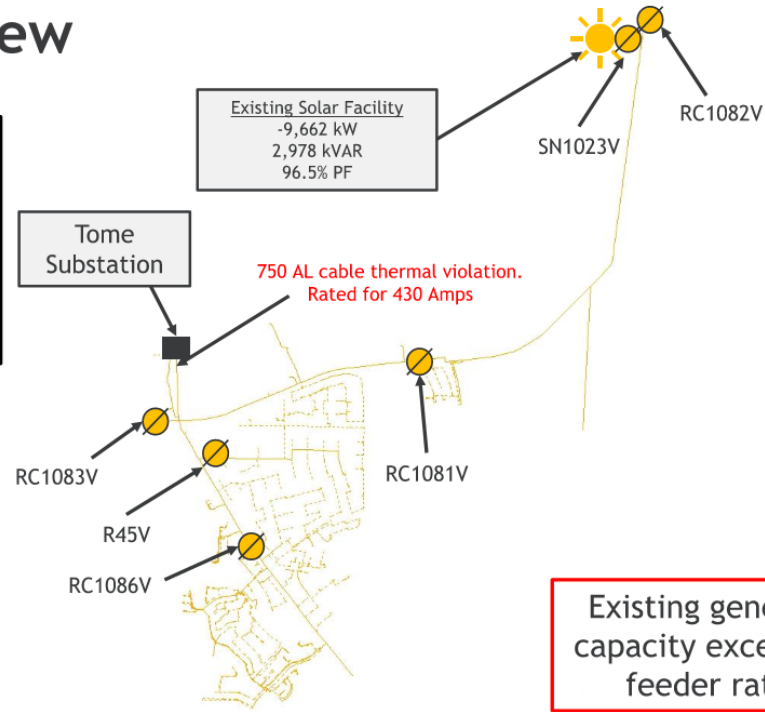
TOME12 - Feeder Overview

Feeder Data

- Feeder Rating: **9,288 kVA**
- Existing Generation: **10,698 kVA**
- Minimum Daylight Load: -8,442 kW
- Minimum Daylight Gross Load: 946 kW / 1,532 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	TOME12 Breaker	600
Recloser	R45V	200
Recloser	RC1081V	325
Recloser	RC1082V	300
Recloser	RC1083V	450
Recloser	RC1086V	200
Recloser	SN1023V	515



Existing generation capacity exceeds the feeder rating.

Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,442	1,765	8,624	-98	407	386	385	120.5	123.2	110.0

TOME12 - Feeder Overview with Queued Solar

Feeder Data

- Feeder Rating: **9,288 kVA**
- Existing Generation: **10,852 kVA**
- Minimum Daylight Load: -8,593 kW
- Minimum Daylight Gross Load: 946 kW / 1,532 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **29**
- Total Queued AC Inverter Nameplate: **174 kW**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	TOME12 Breaker	600
Recloser	R45V	200
Recloser	RC1081V	325
Recloser	RC1082V	300
Recloser	RC1083V	450
Recloser	RC1086V	200
Recloser	SN1023V	515

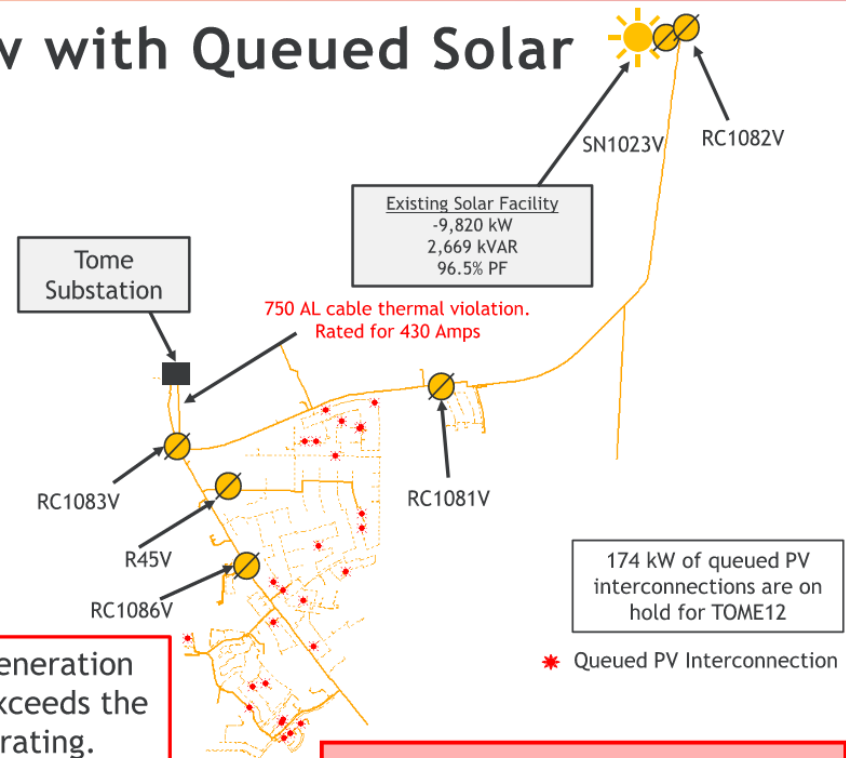
Existing generation capacity exceeds the feeder rating.

Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,593	1,720	8,768	-98	418	390	390	120.6	123.2	111.6

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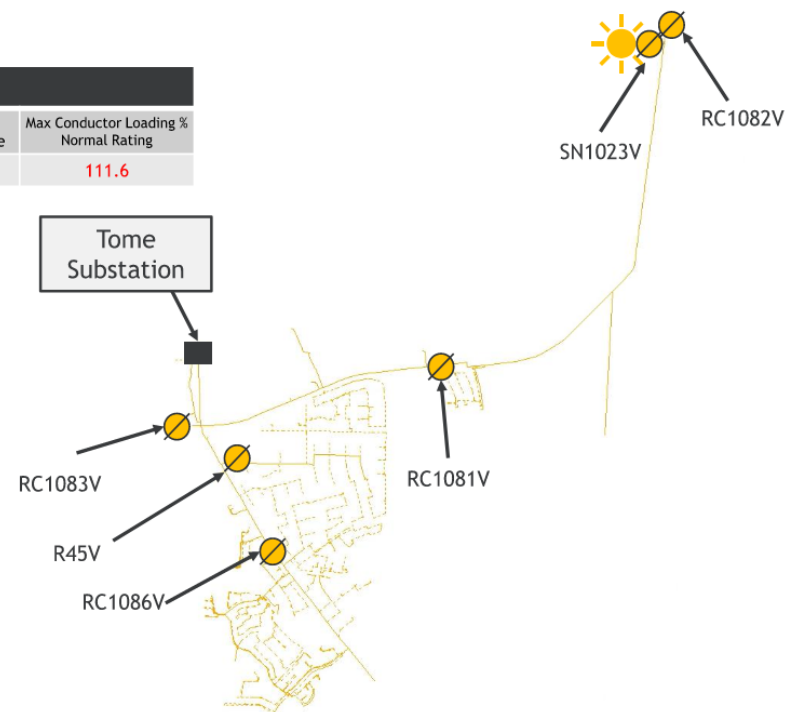
The feeder **CANNOT** serve queued PV interconnection requests without violations.

TOME12 - Maximum Hosting Capacity Base Case w/ Queued PV

Base Case Load Flow Analysis (Minimum daylight Load)									
kW	KVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-8,593	1,720	8,768	-98	418	390	390	120.6	123.2	111.6

Feeder Observations

- There is **ZERO** hosting capacity available in this feeder in the base case scenario.
- The existing generation exceeds the feeder rating.
- A **111.6%** thermal overload is observed at the feeder getaway if generation is at full output and is coincident with minimum daylight load. The getaway is 750AL (Riser) which has a rating of 430A or 9,827 kVA.

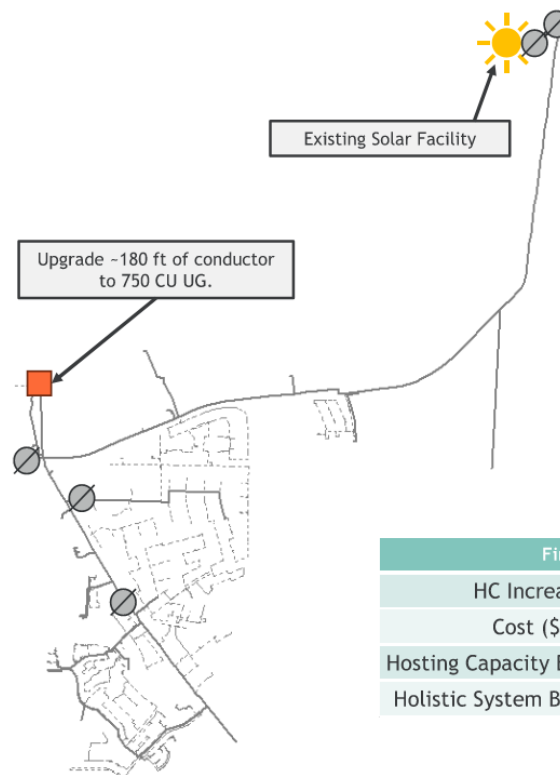


TOME12 - Feeder Upgrades

Hosting Capacity	
Base HC	0 MW
Max HC	2.62 MW
HC Increase	2.62 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~180 ft of 750 AL (RISER) to 750 CU UG from SW4837V (PME-9) to Pole D36A159	\$60,570
TOTAL	\$60,570



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	Solar Facility
	Substation

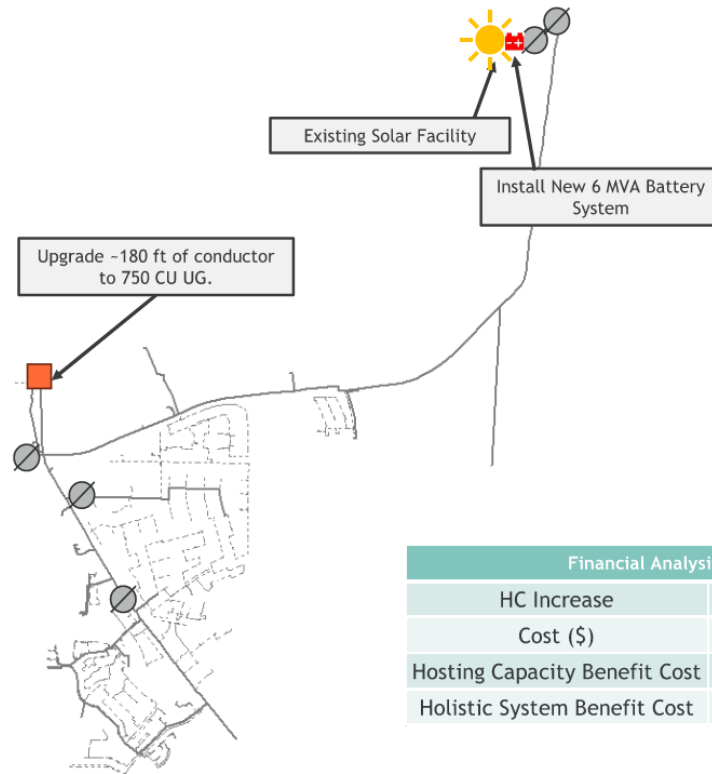
Financial Analysis	
HC Increase	2.62
Cost (\$)	60,570
Hosting Capacity Benefit Cost	43.26
Holistic System Benefit Cost	46.11

TOME12 - Feeder Upgrades & 2 MVA BESS

Hosting Capacity	
Base HC	0 MW
Max HC	4.3 MW
HC Increase	4.3 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Upgrade ~180 ft of 750 AL (RISER) to 750 CU UG from SW4837V (PME-9) to Pole D36A159	\$60,570
Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL	\$14,360,570



Financial Analysis	
HC Increase	4.3
Cost (\$)	14,360,570
Hosting Capacity Benefit Cost	0.30
Holistic System Benefit Cost	1.07



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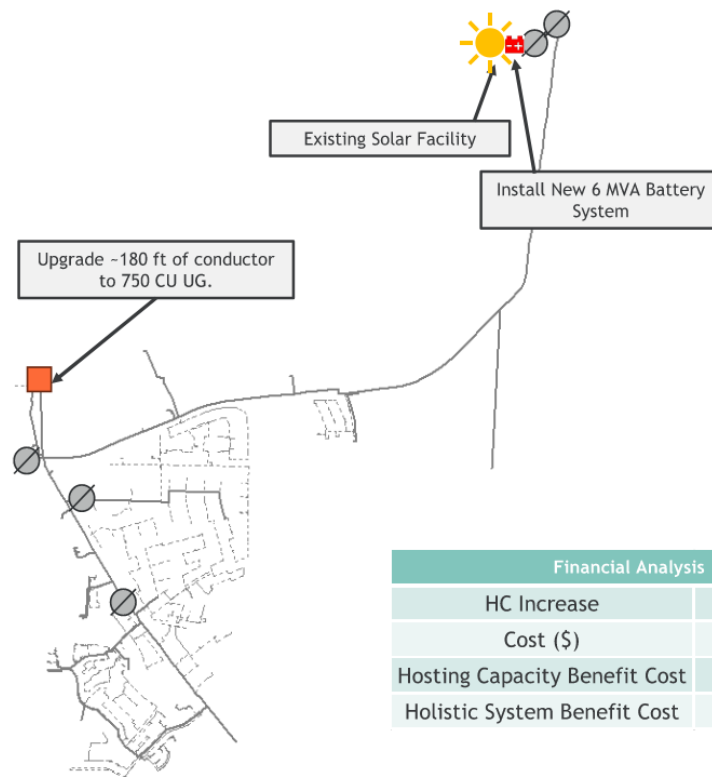
170

TOME12 - Feeder Upgrades & 6 MVA BESS

Hosting Capacity	
Base HC	0 MW
Max HC	6.46 MW
HC Increase	6.46 MW

Thermal Loading Limits
Max HC

System Improvement	
	Cost
Upgrade ~180 ft of 750 AL (RISER) to 750 CU UG from SW4837V (PME-9) to Pole D36A159	\$60,570
Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,300,000
Communication Upgrade for sophisticated BESS control schemes	\$50,000
TOTAL	\$14,410,570



Financial Analysis	
HC Increase	6.46
Cost (\$)	14,410,570
Hosting Capacity Benefit Cost	0.45
Holistic System Benefit Cost	1.92



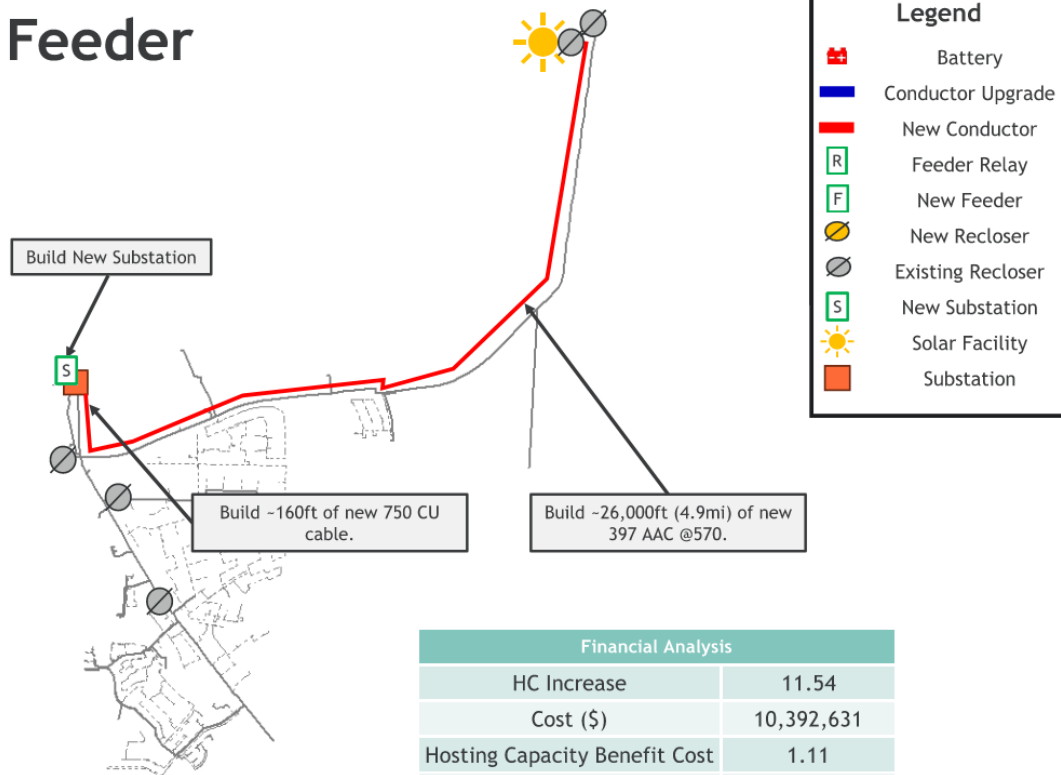
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TOME12 - Dedicated Feeder

Hosting Capacity	
Base HC	0 MW
Max HC	11.54 MW
HC Increase	11.54 MW

Reverse Flow Limits
Max HC

System Improvement	
	Cost
Build ~160ft of new 750 CU cable from the New Tome Substation to a new riser pole.	
Build ~26,000ft (4.8mi) of new 397 AAC @570. Utilize double circuit construction along the existing path of TOME12 main line conductor.	\$2,392,637
Build a New Substation Transformer - Including transformer, switchgear, and feeder relaying equipment.	\$8,000,000
TOTAL	\$10,392,637



Financial Analysis	
HC Increase	11.54
Cost (\$)	10,392,631
Hosting Capacity Benefit Cost	1.11
Holistic System Benefit Cost	1.18



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TOME12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Feeder Upgrades	Thermal Violation	2,620	2,620	\$60,570	43.26	46.11
Feeder Upgrades with 2 MVA BESS	Thermal Violation	4,299	4,299	\$14,360,570	0.30	1.07
2 MVA BESS Only*	-	-	-	-	-	-
Feeder Upgrades with 6 MVA BESS	Thermal Violation	6,460	6,460	\$14,410,570	0.45	1.92
6 MVA BESS Only*	-	-	-	-	-	-
Dedicated Feeder	Thermal Violation	11,540	11,540	\$10,392,631	1.11	1.18

*This scenario was not applicable to this analysis.



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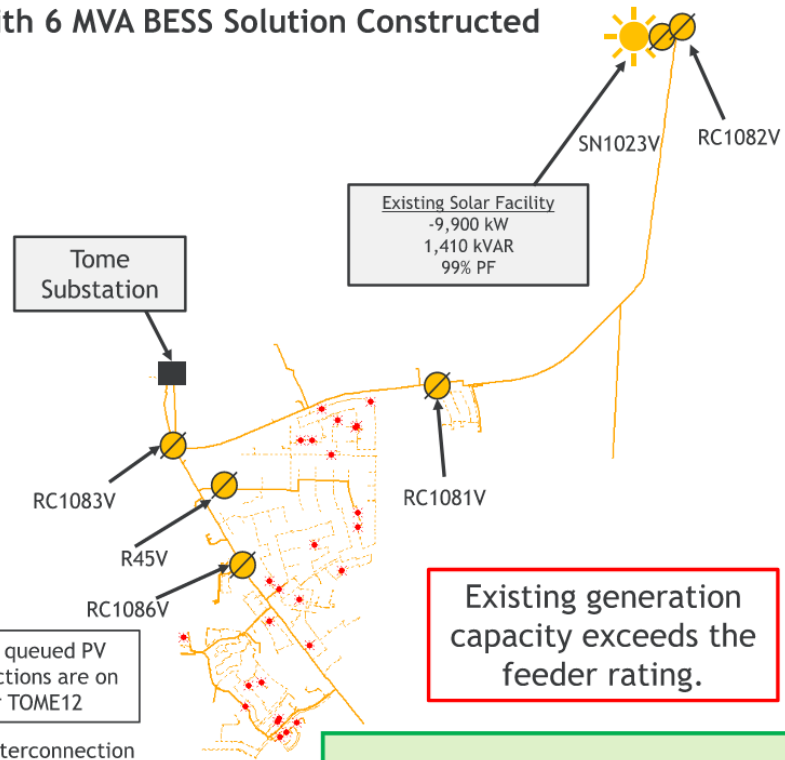
TOME12 - Feeder Overview with Queued Solar with 6 MVA BESS Solution Constructed

Feeder Data

- Feeder Rating: **9,288 kVA**
- Existing Generation: **10,852 kVA**
- Minimum Daylight Load: -3,531 kW
- Minimum Daylight Gross Load: 946 kW / 1,532 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV
- Queued Solar Projects: **29**
- Total Queued AC Inverter Nameplate: **174 kW**

Protection & Equipment Pickup/Ratings

Device	Name	Pick Up Rating (A)
Breaker	TOME12 Breaker	600
Recloser	R45V	200
Recloser	RC1081V	325
Recloser	RC1082V	300
Recloser	RC1083V	450
Recloser	RC1086V	200
Recloser	SN1023V	515



* Queued PV Interconnection

6MVA BESS Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-3,531	-1,233	3,740	94	188	161	162	120.9	122.4	88.4

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✓ The feeder can serve queued PV interconnection requests without violations.

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6.2 Community Solar Feeders Analysis

Alamogordo12 Analysis



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A10012 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)									
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
-7,928	3,496	8,664	-91	387	385	383	123.0	125.0	77.4

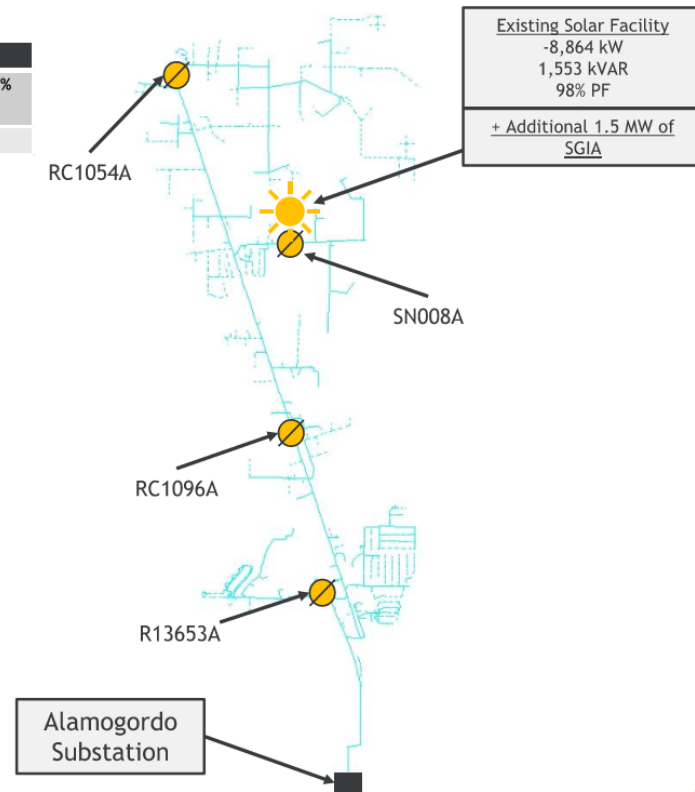
Protection Devices		
Device	Name	Pick Up Rating (A)
Breaker	A10012 Breaker	600
Recloser	R13653A	400
Recloser	RC1054A	375
Recloser	RC1096A	500
Recloser	SN008A	450

Feeder Data

- Feeder Rating: 11,663 kVA
- Existing Generation: 11,574 kVA
- Minimum Daylight Load: -9,263 kW
- Minimum Daylight Gross Load: 1,629 kW / 1,876 kVAR
- Substation LTC Setpoint: 125 V
- Primary Voltage: 12.47 kV

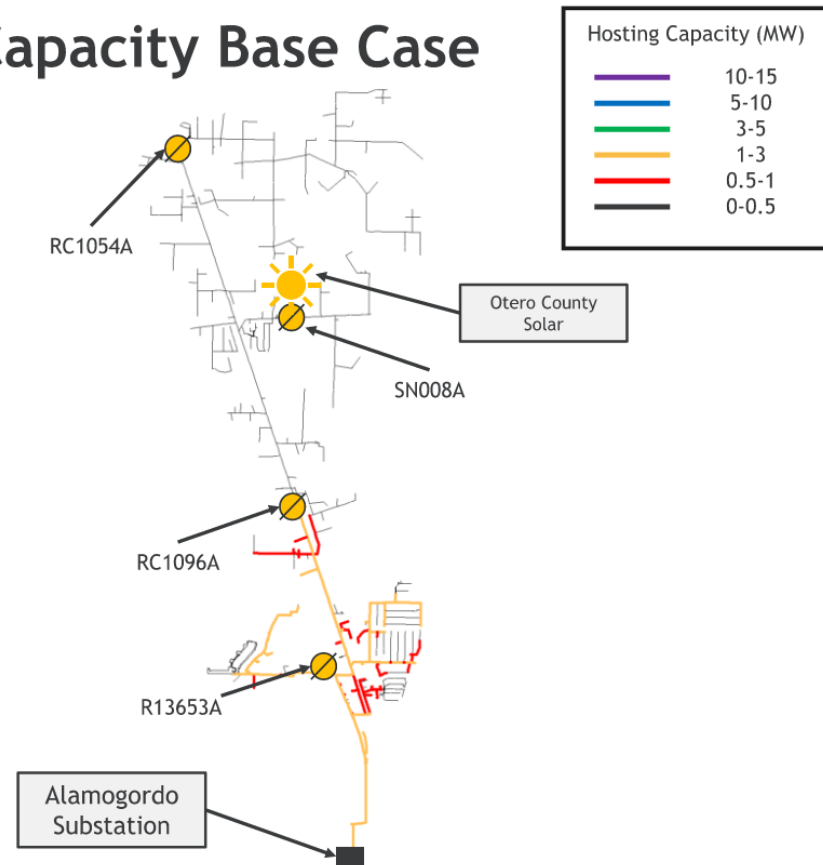


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A10012 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity	
3.75 MW	
Limiting Factors	
Thermal Loading Violation	87%
Voltage Violation	13%



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A10012 - Feeder Upgrades

System Improvement	
Improvement Details	Cost
No Applicable Traditional System Upgrades	-
TOTAL	-

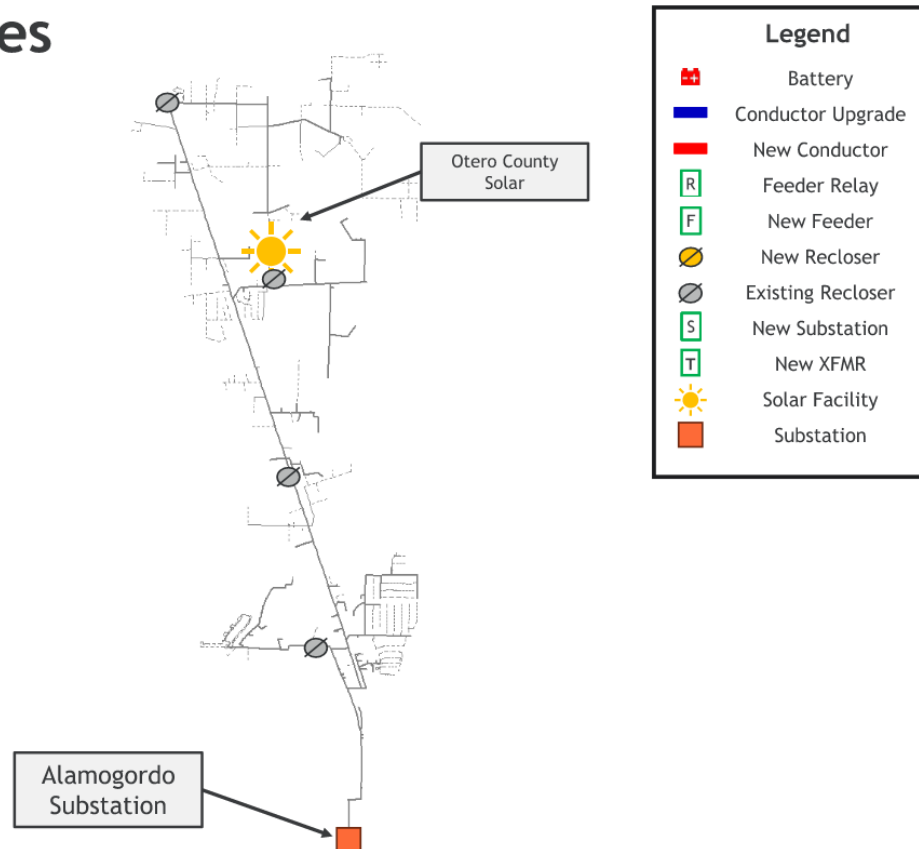
Hosting Capacity	
Base HC	3.75 MW
Max HC	3.75 MW
HC Increase	0 MW

Benefit Cost Ratio	
HC Increase	0 MW
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-

Reverse Flow Limits
Max HC



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A10012 - Feeder Upgrades & 2 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL		\$14,300,000

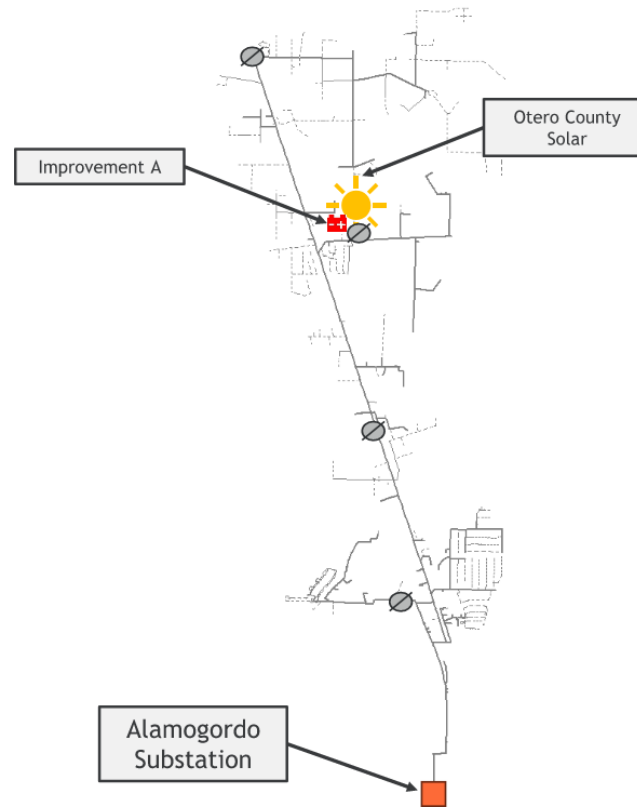
Hosting Capacity	
CS Base HC	3.75 MW
Max HC	5.55 MW
HC Increase	1.8 MW

Benefit Cost Ratio	
HC Increase	1.8 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.88

Reverse Flow Limits
Max HC



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Legend

- Battery
- Conductor Upgrade
- New Conductor
- Feeder Relay
- New Feeder
- New Recloser
- Existing Recloser
- New Substation
- New XFMR
- Solar Facility
- Substation

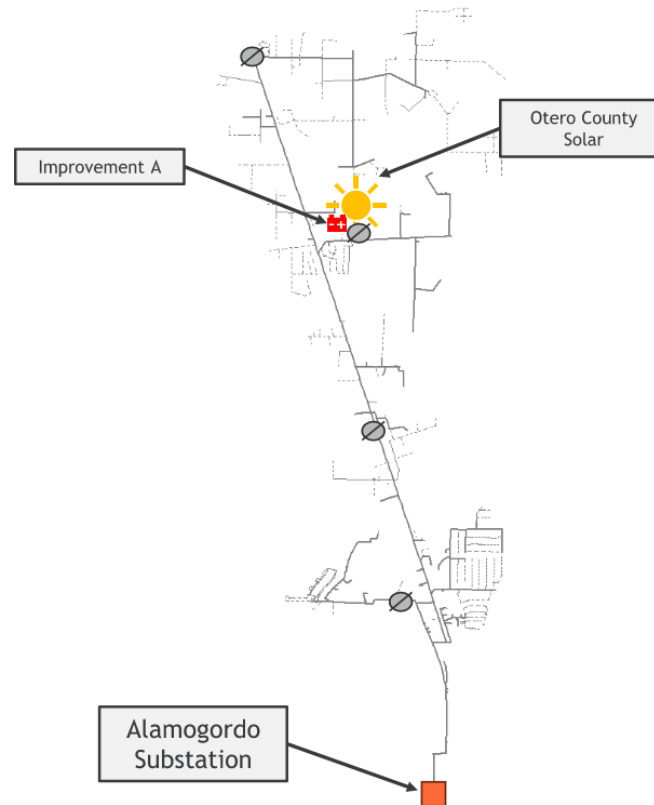
A10012 - Feeder Upgrades + 6 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery + Control Scheme (Operating at 6 MVA Charging/Discharging)	\$14,350,000
TOTAL		\$14,350,000

Hosting Capacity	
CS Base HC	3.75 MW
Max HC	9.33 MW
HC Increase	5.58 MW

Benefit Cost Ratio	
HC Increase	1.8 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.39
Holistic System Benefit Cost	1.79

Reverse Flow Limits
Max HC



A10012 - Dedicated Feeder

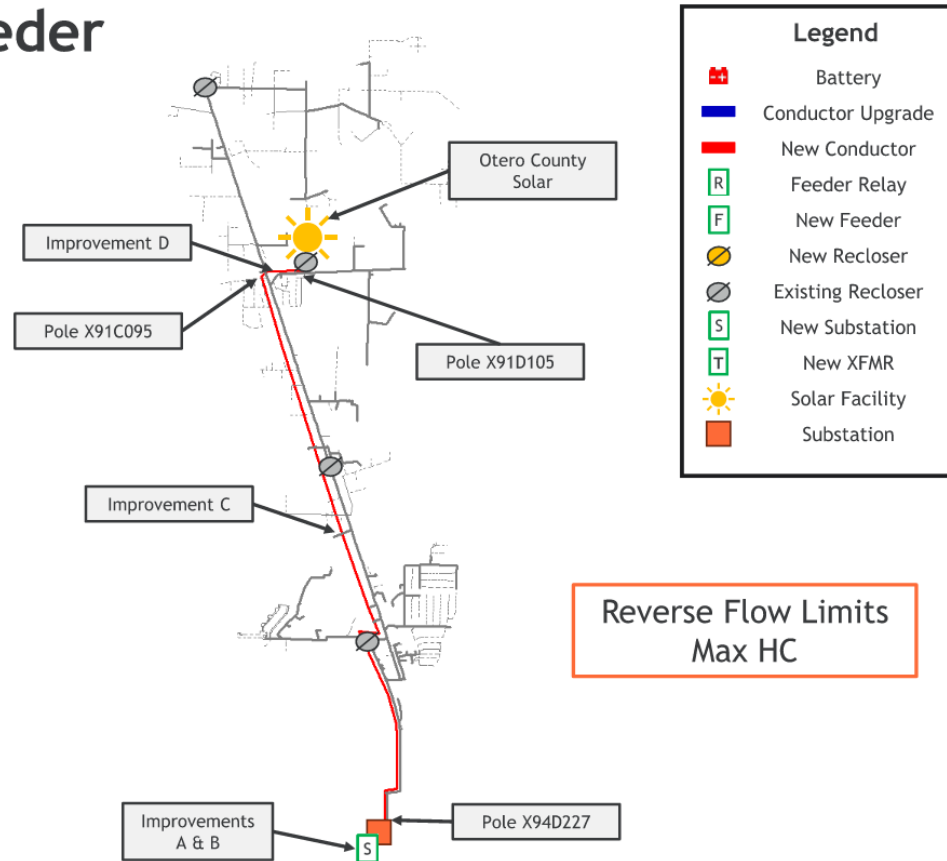
System Improvement		
Improvement Details		Cost
A	Upgrade the Substation Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
B	Build ~200 ft of 477 AAC from New Substation to Pole X94D227.	\$4,613,746
C	Build ~26,000 ft of 477 AAC from Pole X94D227 to Pole X91C095.	
D	Build ~2,000 ft of 397 AAC @ 570 from Pole X91C095 to X91D105.	
TOTAL		\$12,613,746

Hosting Capacity	
CS Base HC	3.75 MW
Max HC	12.14 MW
HC Increase	8.39 MW

Benefit Cost Ratio	
HC Increase	8.39 MW
Cost (\$)	12,613,746
Hosting Capacity Benefit Cost	0.66
Holistic System Benefit Cost	0.68

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A10012 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
Baseline	3,753	3,753	0	-	-	-
Feeder Upgrades	3,753	3,753	0	-	-	-
Feeder Upgrades + 2MVA BESS	3,753	5,548	1,795	\$14,300,000	0.13	0.88
Feeder Upgrades + 6MVA BESS	3,753	9,331	5,577	\$14,350,000	0.39	1.79
Dedicated Feeder	3,753	12,137	8,384	\$12,613,746	0.66	0.68



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El Cerro 12 Analysis



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ELCE12 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)

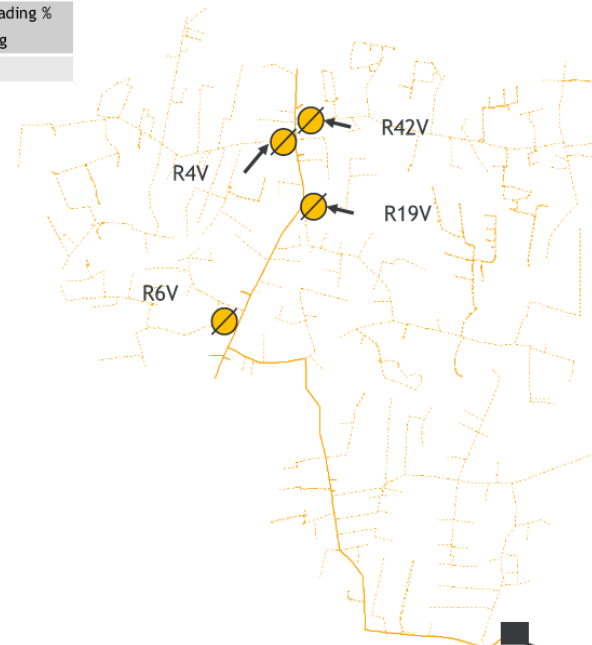
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
1,005	223	1,030	98	48	46	47	120.3	122.4	41.2

Protection Devices

Device	Name	Pick Up Rating (A)
Breaker	ELCE12 Breaker	540
Recloser	R19V	200
Recloser	R42V	250
Recloser	R4V	200
Recloser	R6V	100

Feeder Data

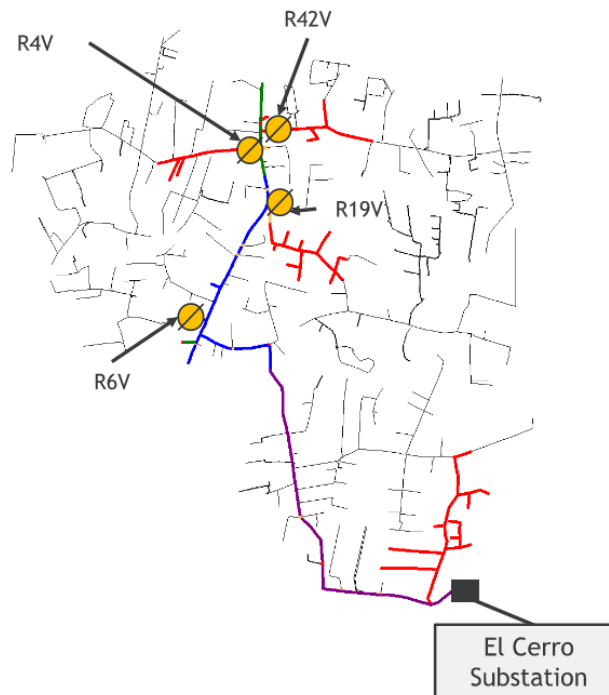
- Feeder Rating: 9,071 kVA
- Existing Generation: 872 kVA
- Minimum Daylight Load: 1,005 kW
- Minimum Daylight Gross Load: 1,817 kW / 1,556 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV



El Cerro
Substation

ELCE12 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity	
11.50 MW	
Limiting Factors	
Thermal Loading Violation	70%
Voltage Violation	30%



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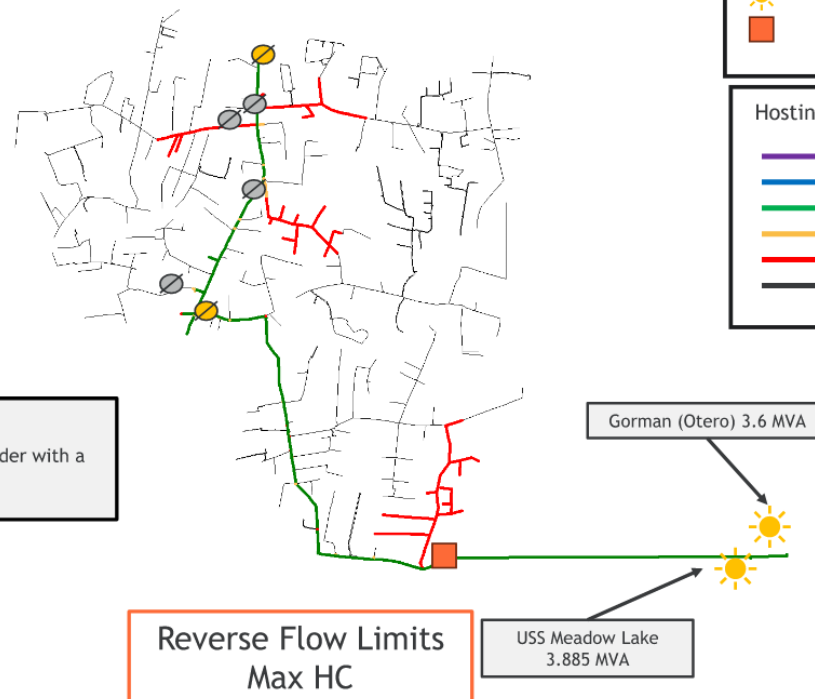
ELCE12 - Community Solar Feeder Upgrades

Hosting Capacity	
Base HC	11.5 MW
Max HC	4.92 MW
HC Increase	-6.58 MW

Limiting Factors	
Thermal Loading Violation	74%
Voltage Violation	26%

Feeder Observations

- There are two community solar projects interconnecting to the feeder with a combined output of ~7.5 MVA of generation.



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ELCE12 - CS & Traditional System Upgrades

System Improvement		
Improvement Details		Cost
A	No Applicable Traditional System Upgrades	-
TOTAL		-

Hosting Capacity	
CS Base HC	4.92 MW
Max HC	4.92 MW
HC Increase	0 MW

Benefit Cost Ratio	
HC Increase	0 MW
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-

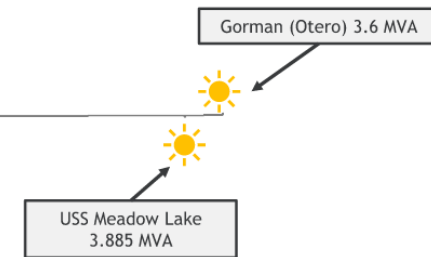
Reverse Flow Limits
Max HC

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Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

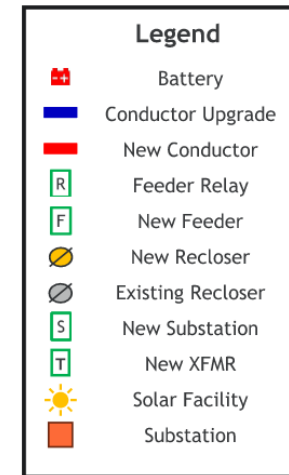
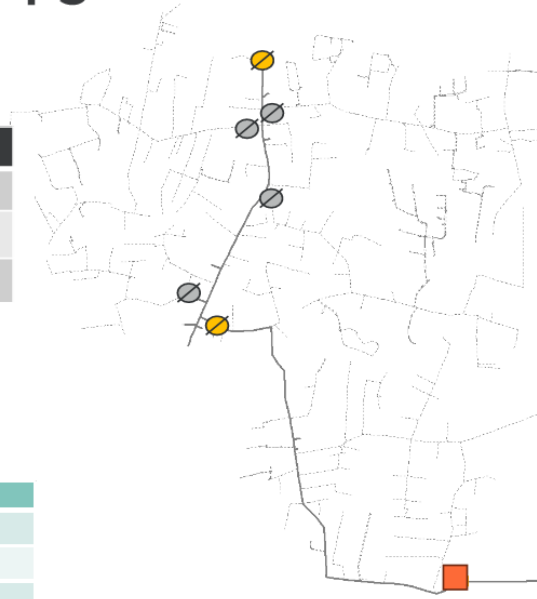


ELCE12 - CS Feeder Upgrades + 2 MVA BESS

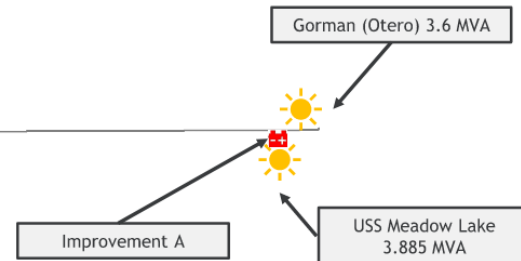
System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL		\$14,300,000

Hosting Capacity	
CS Base HC	4.92 MW
Max HC	6.83 MW
HC Increase	1.91 MW

Benefit Cost Ratio	
HC Increase	1.91 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.89



Reverse Flow Limits
Max HC



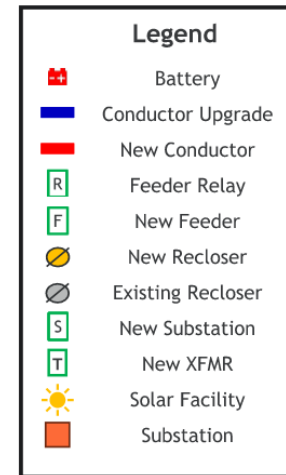
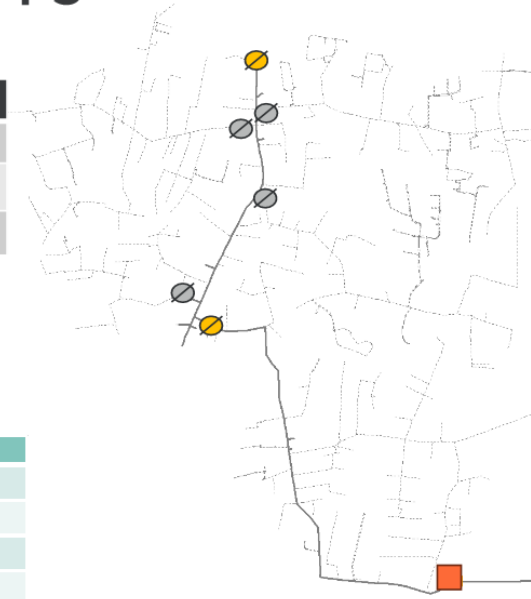
ELCE12 - CS Feeder Upgrades + 6 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery + Control Scheme (Operating at 6 MVA Charging/Discharging)	\$14,350,000
TOTAL		\$XXX

Hosting Capacity	
CS Base HC	4.92 MW
Max HC	8.77 MW
HC Increase	3.85 MW

Benefit Cost Ratio	
HC Increase	1.91 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.27
Holistic System Benefit Cost	1.69

Thermal Loading
Limits Max HC



ELCE12 - Dedicated Feeder

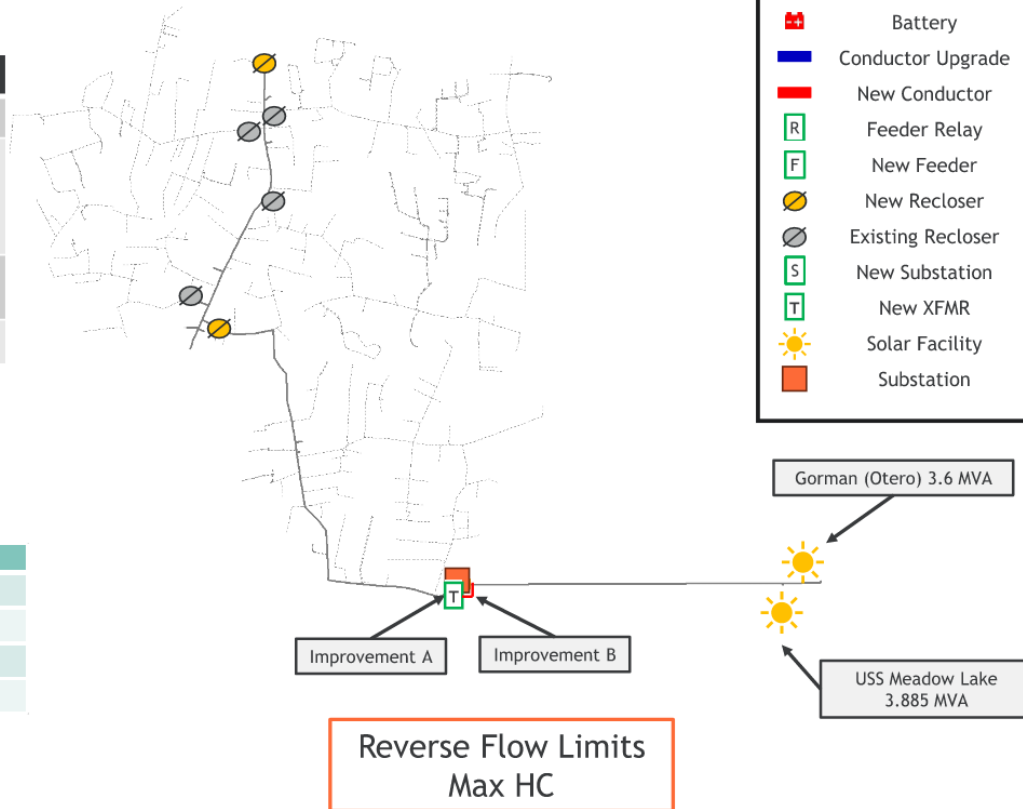
System Improvement		
Improvement Details		Cost
A	Install El Cerro Unit 2 Substation Transformer - Including transformer, switchgear, and feeder relaying equipment. This assumes that the existing El Cerro Unit 1 has been upgraded to 33.7 MVA and the 9MVA Meadow Lake facility has been moved to a new ELCE14 feeder.	\$8,000,000
B	Build ~100 ft of 750 CU from Substation to new riser pole to connect to the mainline conductor leading to solar facilities.	\$297,200
TOTAL		\$8,297,200

Hosting Capacity	
CS Base HC	4.92 MW
Max HC	12.24 MW
HC Increase	7.32 MW

Benefit Cost Ratio	
HC Increase	7.32 MW
Cost (\$)	8,297,200
Hosting Capacity Benefit Cost	0.88
Holistic System Benefit Cost	0.90



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ELCE12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
CS Feeder Upgrades Baseline	11,503	4,923	-6,580	-	-	-
CS & Traditional Upgrades	4,923	4,923	0	-	-	-
CS Upgrades + 2MVA BESS	4,923	6,827	1,904	\$14,300,000	0.13	0.89
CS Upgrades + 6MVA BESS	4,923	8,771	3,848	\$14,350,000	0.27	1.69
Dedicated Feeder	4,923	12,238	7,315	\$8,297,200	0.88	0.90



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Hondale 11 Analysis



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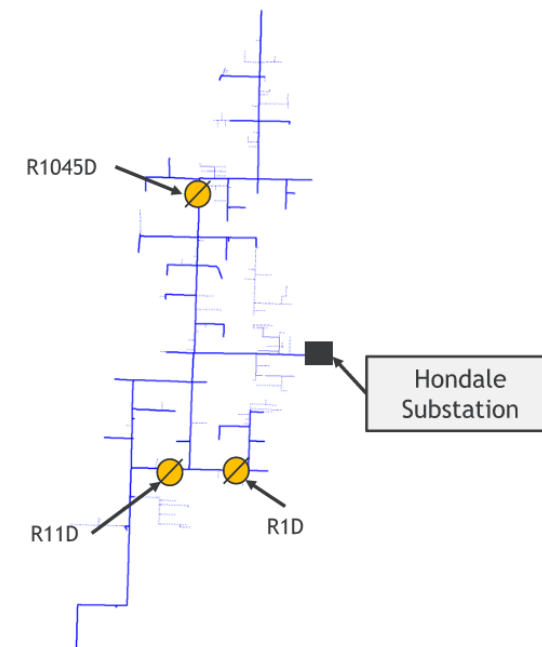
HOND11 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)									
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
116	-19	117	-99	5	4	6	121.7	122.1	2.4

Protection Devices		
Device	Name	Pick Up Rating (A)
Breaker	HOND11 Breaker	300
Recloser	R11D	140
Recloser	R1D	140
Recloser	R1045D	255

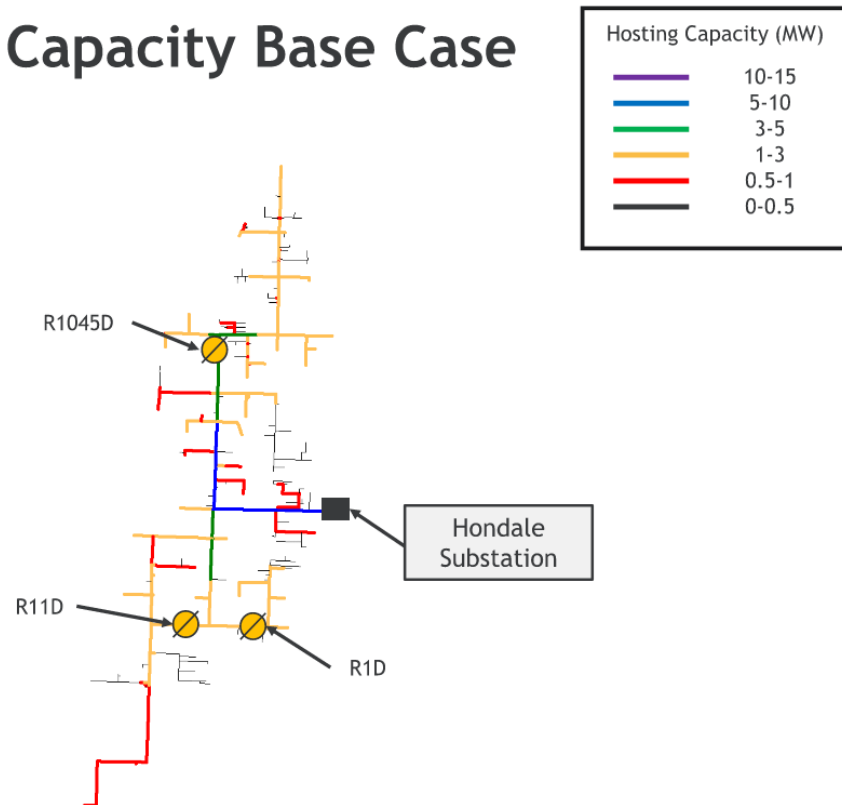
Feeder Data

- Feeder Rating: 6,454 kVA
- Existing Generation: 170 kVA
- Minimum Daylight Load: 116 kW
- Minimum Daylight Gross Load: 279 kW / -18 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 13.8 kV



HOND11 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity	
6.57 MW	
Limiting Factors	
Thermal Loading Violation	47%
Voltage Violation	53%



HOND11 - Community Solar Feeder Upgrades

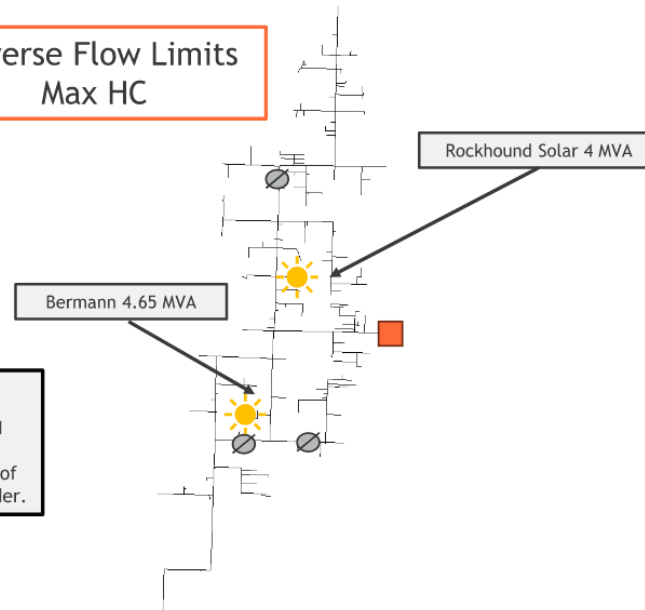
Hosting Capacity	
Base HC	6.57 MW
Max HC	4.22 MW
HC Increase	-2.35 MW

Limiting Factors	
Thermal Loading Violation	28%
Voltage Violation	72%

Feeder Observations

- Two community solar projects will be served by feeder HOND11 with a combined output of 8.65 MVA of generation.
- A small section of old 397 AAC overhead conductor just outside of the substation limits the spread of hosting capacity for this feeder.

Reverse Flow Limits
Max HC



Legend

- New Recloser
- Existing Recloser
- Solar Facility
- Substation

Hosting Capacity (MW)

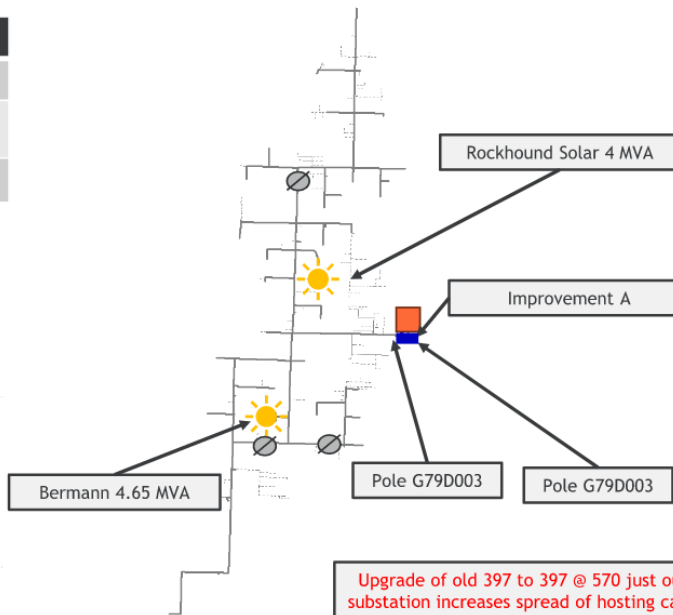
- 10-15
- 5-10
- 3-5
- 1-3
- 0.5-1
- 0-0.5

HOND11 - CS & Traditional System Upgrades

System Improvement		
Improvement Details		Cost
A	Upgrade ~270ft of 397 AAC to 397 AAC @ 570 from Pole G79D003 to Pole G79D002.	\$23,880
TOTAL		\$23,880

Hosting Capacity	
CS Base HC	4.22 MW
Max HC	4.22 MW
HC Increase	0 MW

Benefit Cost Ratio	
HC Increase	0 MW
Cost (\$)	23,880
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

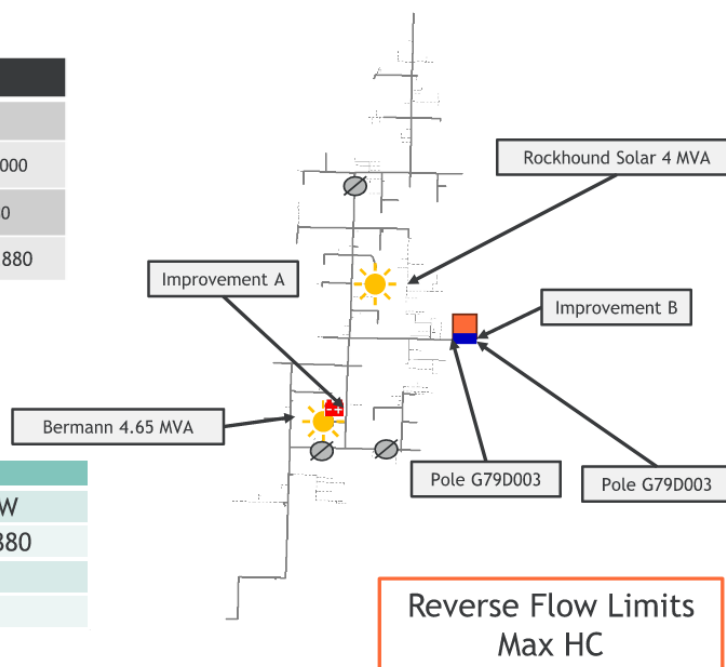
Upgrade of old 397 to 397 @ 570 just outside the substation increases spread of hosting capacity and raises HOND11 feeder rating to PNM standard. This does not increase the maximum hosting capacity of the feeder which is tied to the maximum feeder rating.

HOND11 - CS Feeder Upgrades + 2 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
B	Upgrade ~270ft of 397 AAC to 397 AAC @ 570 from Pole G79D003 to Pole G79D002.	\$23,880
TOTAL		\$14,323,880

Hosting Capacity	
CS Base HC	4.22 MW
Max HC	6.09 MW
HC Increase	1.87 MW

Benefit Cost Ratio	
HC Increase	1.87 MW
Cost (\$)	14,323,880
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.88



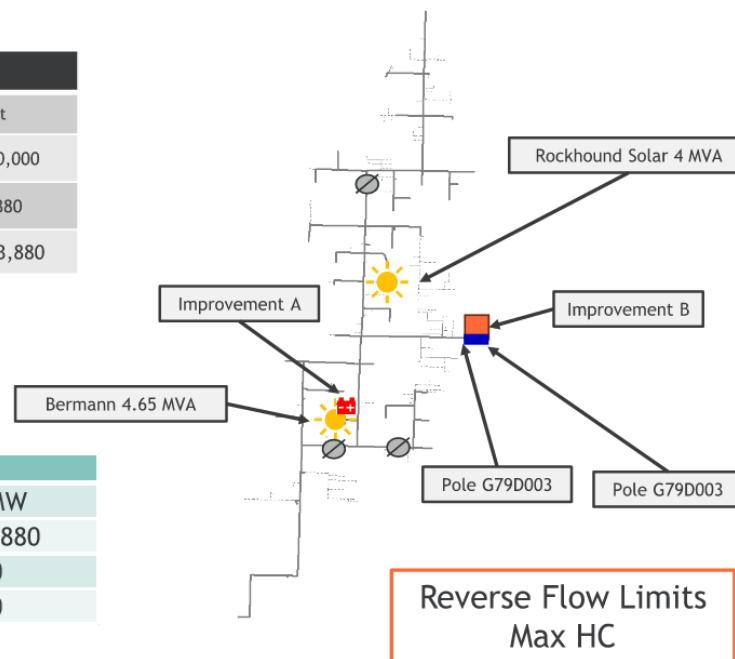
Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

HOND11 - CS Feeder Upgrades + 6 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 6 MVA Charging/Discharging)	\$14,350,000
B	Upgrade ~270ft of 397 AAC to 397 AAC @ 570 from Pole G79D003 to Pole G79D002.	\$23,880
TOTAL		\$14,323,880

Hosting Capacity	
CS Base HC	4.22 MW
Max HC	9.97 MW
HC Increase	5.75 MW

Benefit Cost Ratio	
HC Increase	1.87 MW
Cost (\$)	14,373,880
Hosting Capacity Benefit Cost	0.40
Holistic System Benefit Cost	1.80



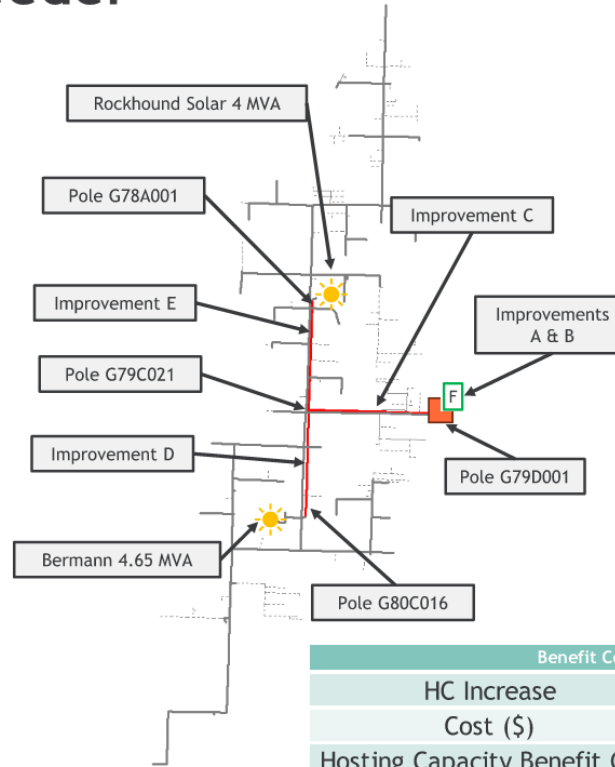
Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

HOND11 - Dedicated Feeder

System Improvement		
Improvement Details		Cost
A	New Feeder	\$4,574,152
B	Build ~250 ft of 750 CU from Substation to Pole G79D001.	
C	Build ~10,200 of 397 AAC @ 570 from Pole G79D001 to G79C021. Utilize double circuit construction along the existing path of HOND11 feeder main line conductor.	
D	Build ~8,070 of 397 AAC @ 570 from Pole G79C021 to Pole G80C016. Utilize double circuit construction along the existing path of HOND11 feeder main line conductor.	
E	Build ~8,600 of 397 AAC @ 570 from Pole G79C021 to Pole G78A001. Utilize double circuit construction along the existing path of HOND11 feeder main line conductor.	
TOTAL		\$4,574,152

Hosting Capacity	
CS Base HC	4.22 MW
Max HC	12.54 MW
HC Increase	8.32 MW

Reverse Flow Limits
Max HC



Benefit Cost Ratio	
HC Increase	8.32 MW
Cost (\$)	4,574,152
Hosting Capacity Benefit Cost	1.82
Holistic System Benefit Cost	1.85

HOND11 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
CS Feeder Upgrades Baseline	6,569	4,218	-2,352	-	-	-
CS & Traditional Upgrades	4,218	4,218	0	\$23,880	0.00	-
CS Upgrades + 2MVA BESS	4,218	6,085	1,868	\$14,323,880	0.13	0.88
CS Upgrades + 6MVA BESS	4,218	9,969	5,752	\$14,373,880	0.40	1.80
Dedicated Feeder	4,218	12,544	8,326	\$4,574,152	1.82	1.85



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Lordsburg 1000 Analysis



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LD1000 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)

kW	KVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
522	-251	579	-90	9	73	10	123.5	125.6	18.3

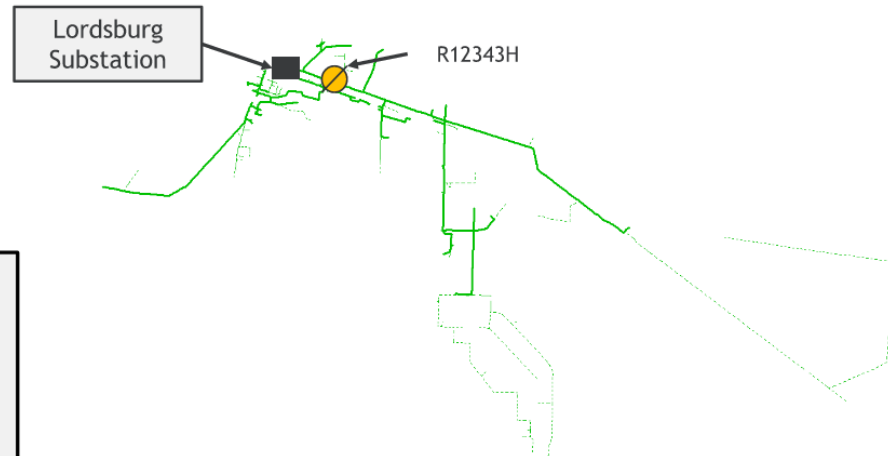
Protection Devices

Device	Name	Pick Up Rating (A)
Breaker	LD1000 Breaker	370
Recloser	R12343H	200

Base Case TM Applied

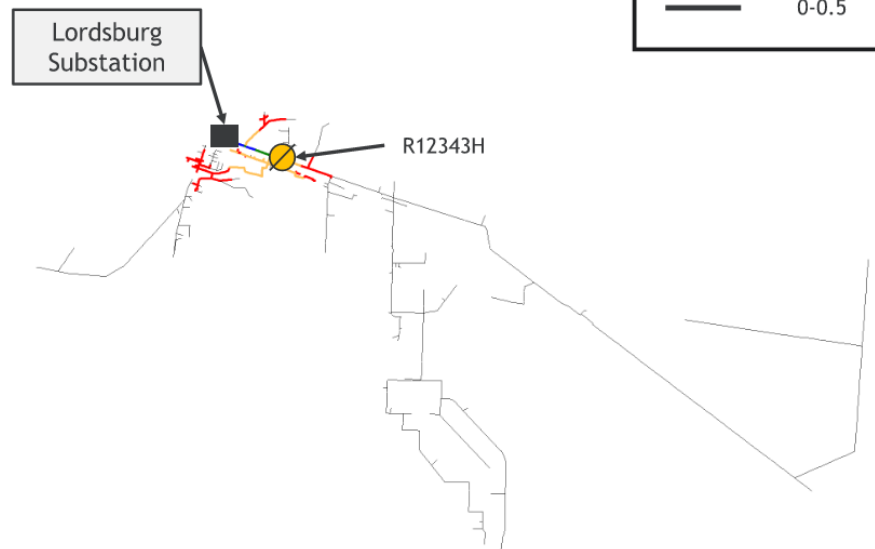
Feeder Data

- Feeder Rating: 7,192 kVA
- Existing Generation: 585 kVA
- Minimum Daylight Load: 522 kW
- Minimum Daylight Gross Load: 1,157 kW / 86 kVAR
- Substation LTC Setpoint: 125 V
- Primary Voltage: 12.47 kV



LD1000 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity	
7.71 MW	
Limiting Factors	
Thermal Loading Violation	6%
Voltage Violation	94%



LD1000 - Community Solar Feeder Upgrades

Hosting Capacity	
Base HC	7.71 MW
Max HC	2.89 MW
HC Increase	-4.82 MW

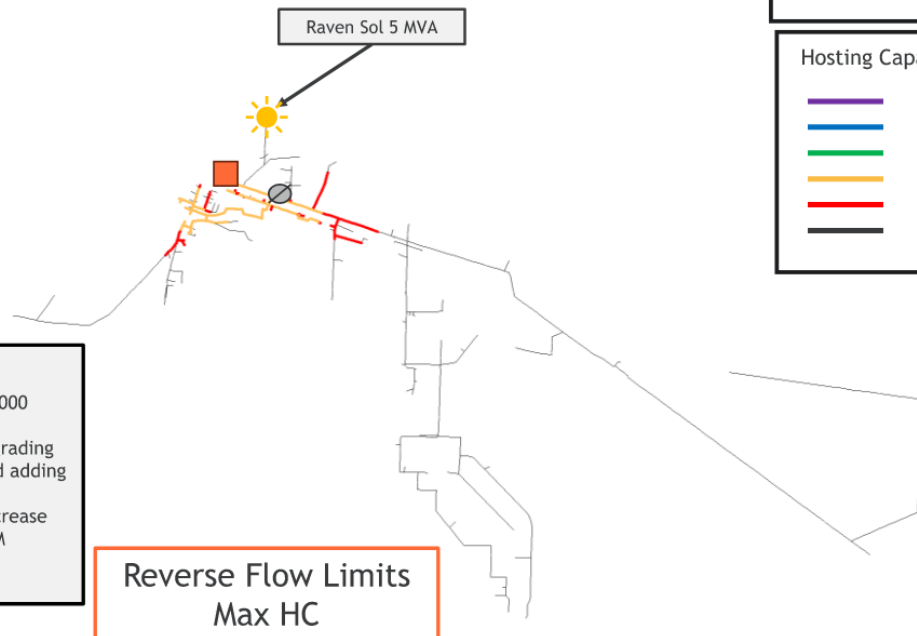
Limiting Factors	
Thermal Loading Violation	17%
Voltage Violation	83%

Feeder Observations

- One community solar project is to be served by feeder LD1000 with a rated output of 5 MVA.
- Community solar project system improvements include upgrading the feeder relay to a SEL751 with directional capability and adding a 600 kVAR capacitor bank.
- Lordsburg Transformer 2 carries a rating of 7.5 MVA. To increase hosting capacity, it must be upgraded to the maximum PNM standard of a 33.7 MVA transformer.



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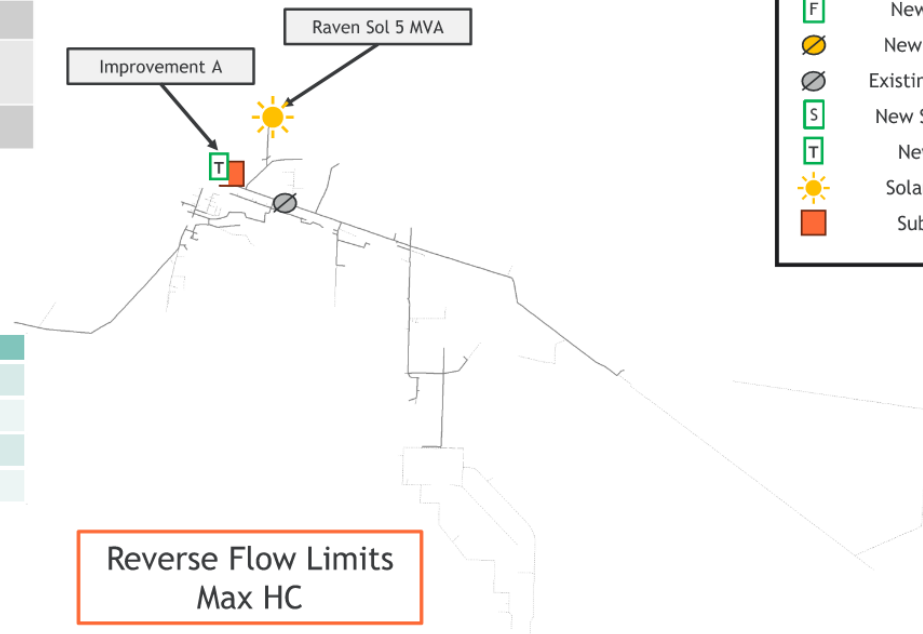


LD1000 - CS & Traditional System Upgrades

System Improvement		
Improvement Details		Cost
A	Upgrade the Lordsburg Substation T2-South Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
TOTAL		\$8,000,000

Hosting Capacity	
CS Base HC	2.89 MW
Max HC	7.06 MW
HC Increase	4.17 MW

Benefit Cost Ratio	
HC Increase	4.17 MW
Cost (\$)	8,000,000
Hosting Capacity Benefit Cost	0.52
Holistic System Benefit Cost	0.53



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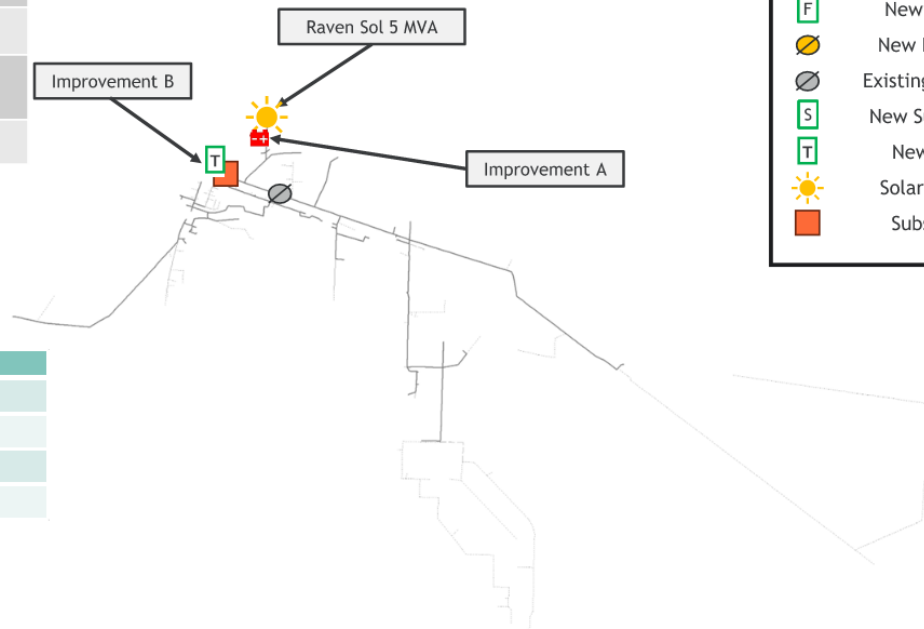
LD1000 - CS Feeder Upgrades + 2 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
B	Upgrade the Lordsburg Substation T2-South Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
TOTAL		\$22,300,000

Hosting Capacity	
CS Base HC	2.89 MW
Max HC	8.99 MW
HC Increase	6.1 MW

Benefit Cost Ratio	
HC Increase	6.1 MW
Cost (\$)	22,300,000
Hosting Capacity Benefit Cost	0.27
Holistic System Benefit Cost	0.78

Reverse Flow Limits
Max HC

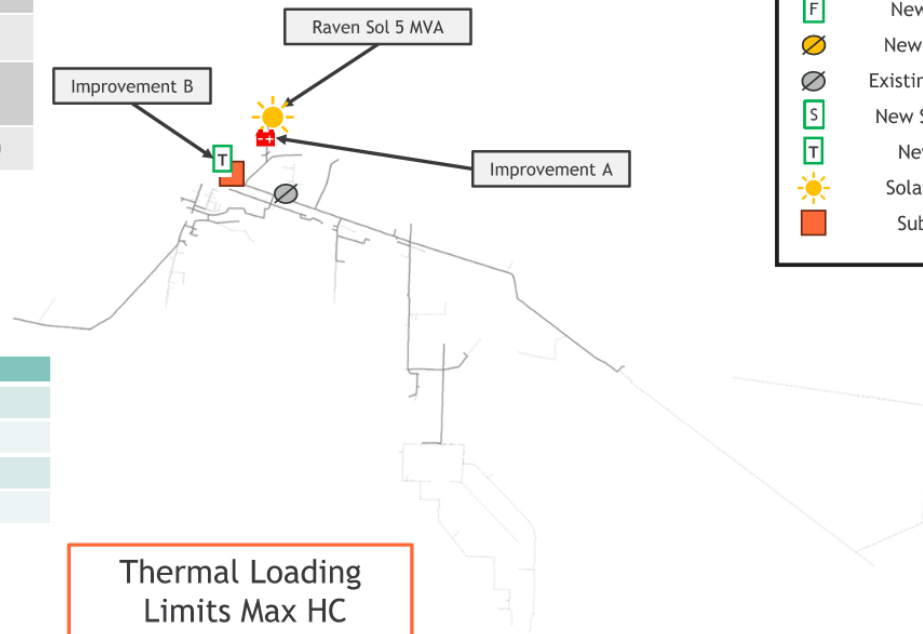


LD1000 - CS Feeder Upgrades + 6 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery + Control Scheme (Operating at 6 MVA Charging/Discharging)	\$14,350,000
B	Upgrade the Lordsburg Substation T2-South Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
TOTAL		\$22,350,000

Hosting Capacity	
CS Base HC	2.89 MW
Max HC	12.97 MW
HC Increase	10.08 MW

Benefit Cost Ratio	
HC Increase	6.1 MW
Cost (\$)	22,350,000
Hosting Capacity Benefit Cost	0.45
Holistic System Benefit Cost	1.41



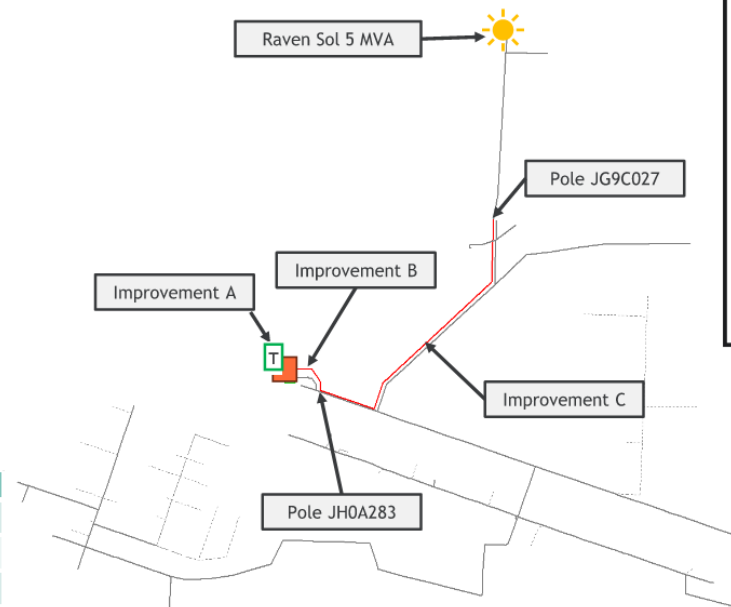
Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

LD1000 - Dedicated Feeder

System Improvement		
Improvement Details		Cost
A	Upgrade the Lordsburg Substation T2-South Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
B	Build ~600 ft of 750 CU from New Substation to Pole JH0A283.	\$902,054
C	Build ~3,800 ft of 397 AAC @ 570 from Pole JH0A283 to Pole JG9C027. Utilize double circuit construction along the existing path of LD1000 and LD038 feeder main line conductor.	
TOTAL		\$8,902,054

Hosting Capacity	
CS Base HC	2.89 MW
Max HC	7.49 MW
HC Increase	4.6 MW

Benefit Cost Ratio	
HC Increase	4.6 MW
Cost (\$)	8,902,054
Hosting Capacity Benefit Cost	0.52
Holistic System Benefit Cost	0.46



Reverse Flow Limits
Max HC

LD1000 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
CS Feeder Upgrades Baseline	7,714	2,888	-4,826	-	-	-
CS & Traditional Upgrades	2,888	7,057	4,169	\$8,000,000	0.52	0.53
CS Upgrades + 2MVA BESS	2,888	8,994	6,106	\$22,300,000	0.27	0.78
CS Upgrades + 6MVA BESS	2,888	12,973	10,085	\$22,350,000	0.45	1.41
Dedicated Feeder	2,888	7,485	4,597	\$8,902,054	0.52	0.46



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Silver City 17 Analysis



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SL0017 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)

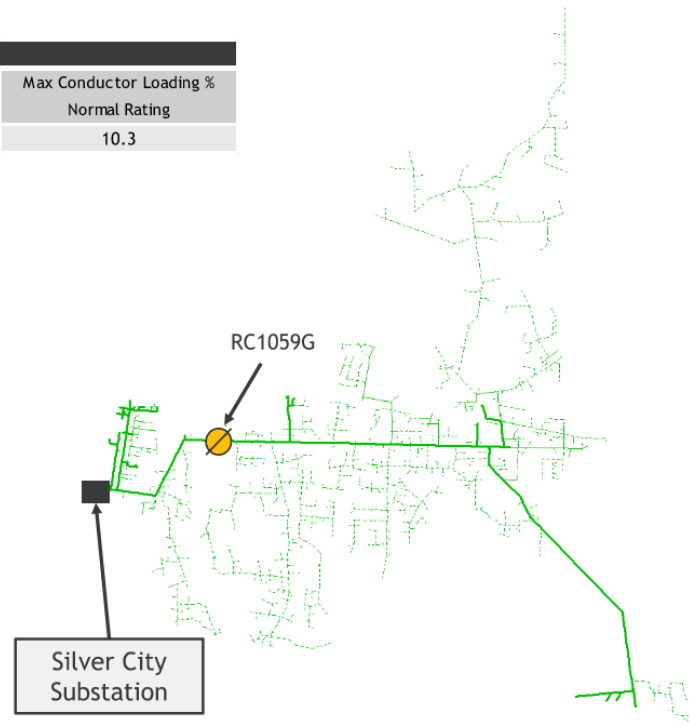
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
711	357	795	89	23	27	56	122.7	125.3	10.3

Protection Devices

Device	Name	Pick Up Rating (A)
Breaker	SL0017 Breaker	530
Recloser	RC1059G	400

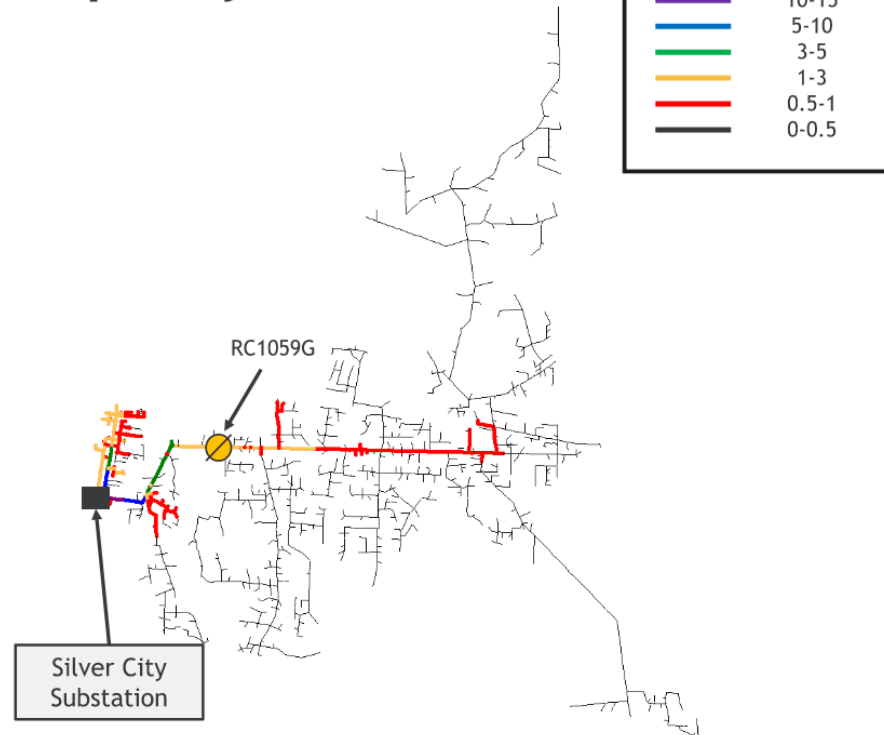
Feeder Data

- Feeder Rating: 9,331 kVA
- Existing Generation: 834 kVA
- Minimum Daylight Load: 711 kW
- Minimum Daylight Gross Load: 1,509 kW / 359 kVAR
- Substation LTC Setpoint: 125 V
- Primary Voltage: 12.47 kV



SL0017 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity	
11.01 MW	
Limiting Factors	
Thermal Loading Violation	28%
Voltage Violation	72%



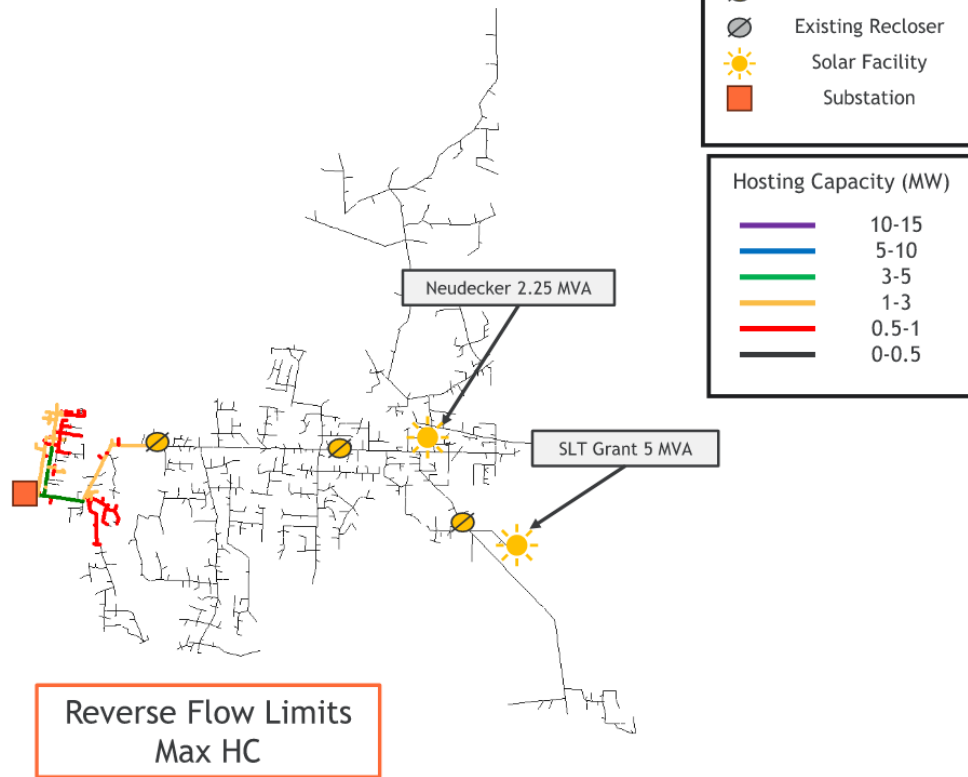
SL0017 - Community Solar Feeder Upgrades

Hosting Capacity	
Base HC	11.01 MW
Max HC	5.74 MW
HC Increase	-5.27 MW

Limiting Factors	
Thermal Loading Violation	88%
Voltage Violation	12%

Feeder Observations

- Feeder SL0017 will serve two community solar facilities with a combined output of 7.25 MVA of generation.
- Community solar project system improvements include a transformer upgrade, 600 kVAR capacitor bank, and an upgrade of the feeder relay to SEL751 with directional capabilities.



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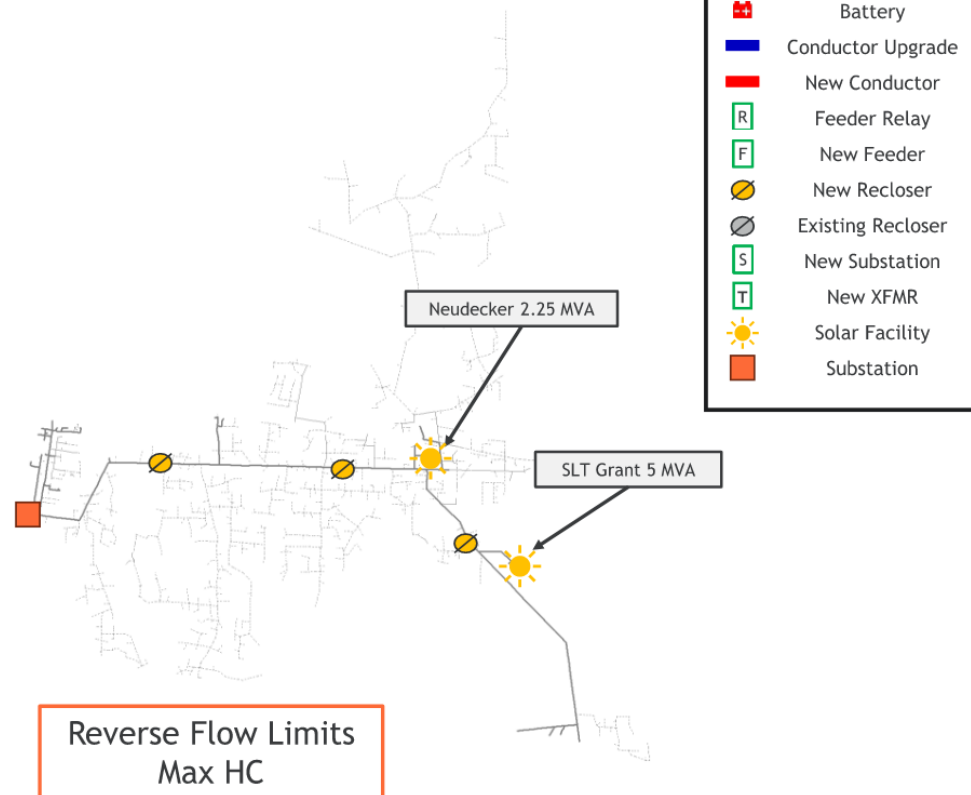
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SL0017 - CS & Traditional System Upgrades

System Improvement		
Improvement Details		Cost
A	No Applicable Traditional System Upgrades	
TOTAL		\$XXX

Hosting Capacity	
CS Base HC	5.74 MW
Max HC	5.74 MW
HC Increase	0 MW

Benefit Cost Ratio	
HC Increase	0 MW
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-



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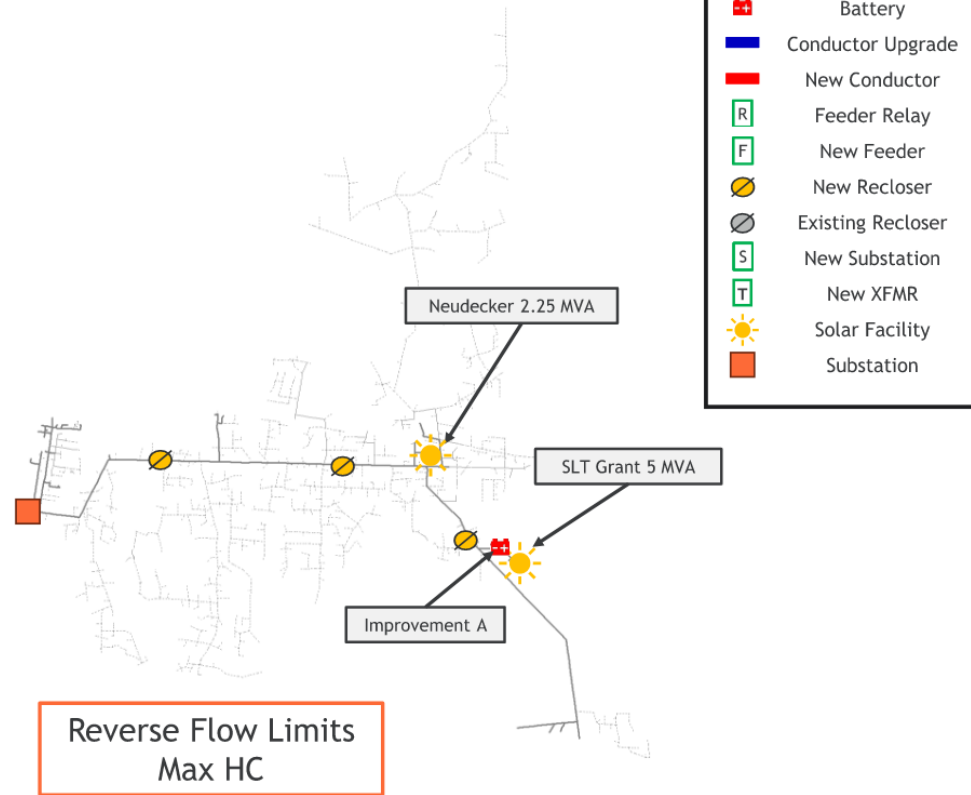
40

SL0017 - CS Feeder Upgrades + 2 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL		\$XXX

Hosting Capacity	
CS Base HC	5.74 MW
Max HC	7.47 MW
HC Increase	1.73 MW

Benefit Cost Ratio	
HC Increase	1.73 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.12
Holistic System Benefit Cost	0.88



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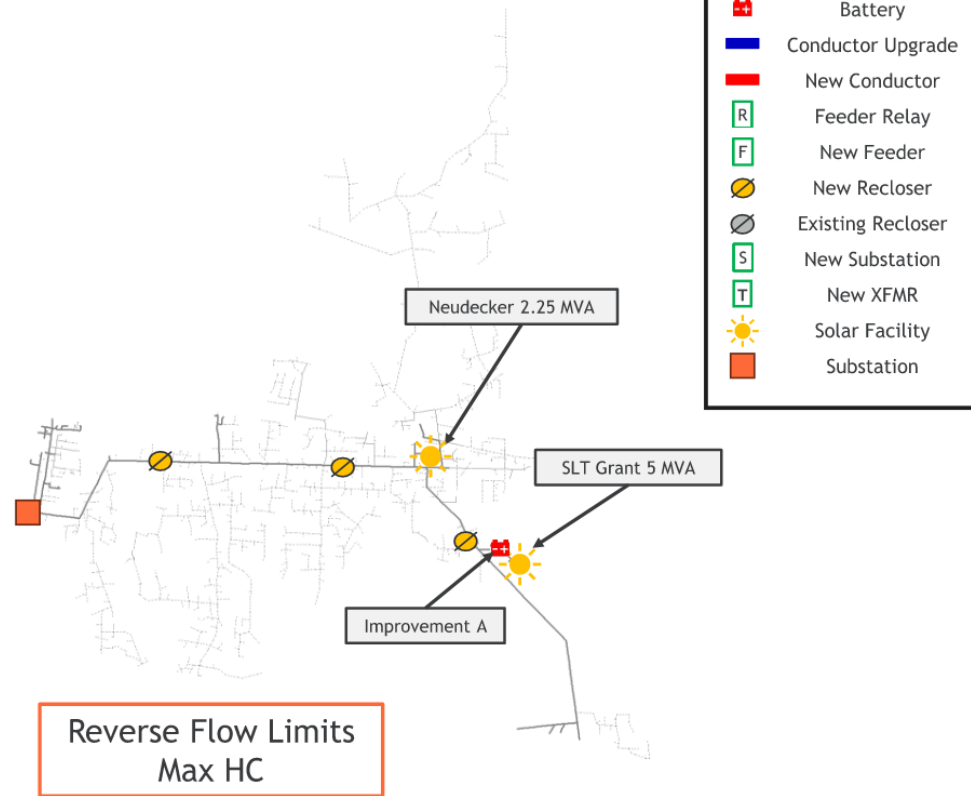
41

SL0017 - CS Feeder Upgrades + 6 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery + Control Scheme (Operating at 6 MVA Charging/Discharging)	\$14,350,000
TOTAL		\$XXX

Hosting Capacity	
CS Base HC	5.74 MW
Max HC	11.23 MW
HC Increase	5.49 MW

Benefit Cost Ratio	
HC Increase	1.73 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.38
Holistic System Benefit Cost	1.79



SL0017 - Dedicated Feeder

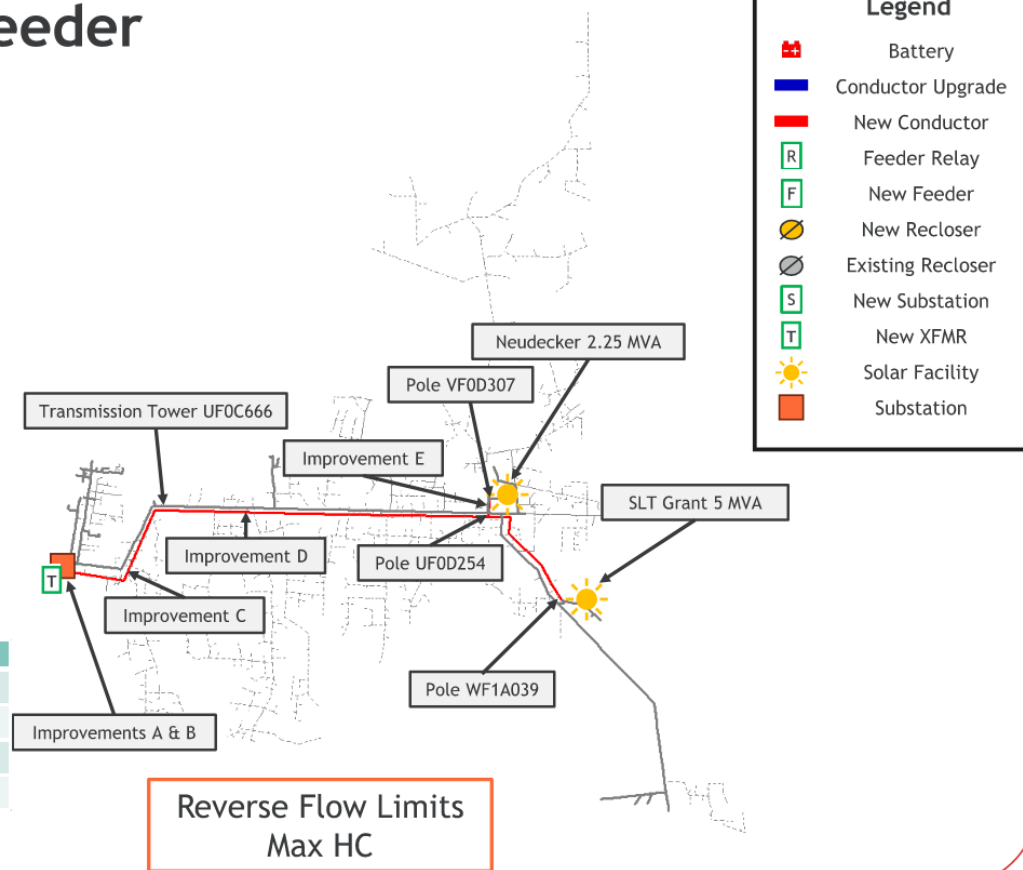
System Improvement		
Improvement Details		Cost
A	Upgrade the Silver City T2 South Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
B	Install New Feeder	\$4,339,062
C	Build ~8,100 ft of 477 ACSR from New Feeder to Transmission tower UF0C666.	
D	Build ~25,000 ft of 397 AAC @ 570 from Transmission tower UF0C666 to Pole WF1A039.	
E	Build ~975 ft of 397 AAC @ 570 from Pole UF0D254 to Pole VF0D307.	
TOTAL		\$12,339,062

Hosting Capacity	
CS Base HC	5.74 MW
Max HC	12.37 MW
HC Increase	6.63 MW

Benefit Cost Ratio	
HC Increase	6.63 MW
Cost (\$)	12,339,062
Hosting Capacity Benefit Cost	0.54
Holistic System Benefit Cost	0.55



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SL0017 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
CS Feeder Upgrades Baseline	11,014	5,741	-5,273	-	-	-
CS & Traditional Upgrades	5,741	5,741	0	-	-	-
CS Upgrades + 2MVA BESS	5,741	7,470	1,729	\$14,300,000	0.12	0.88
CS Upgrades + 6MVA BESS	5,741	11,229	5,488	\$14,350,000	0.38	1.79
Dedicated Feeder	5,741	12,375	6,634	\$12,339,062	0.54	0.55



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Tularosa 13 Analysis



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TULA13 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)

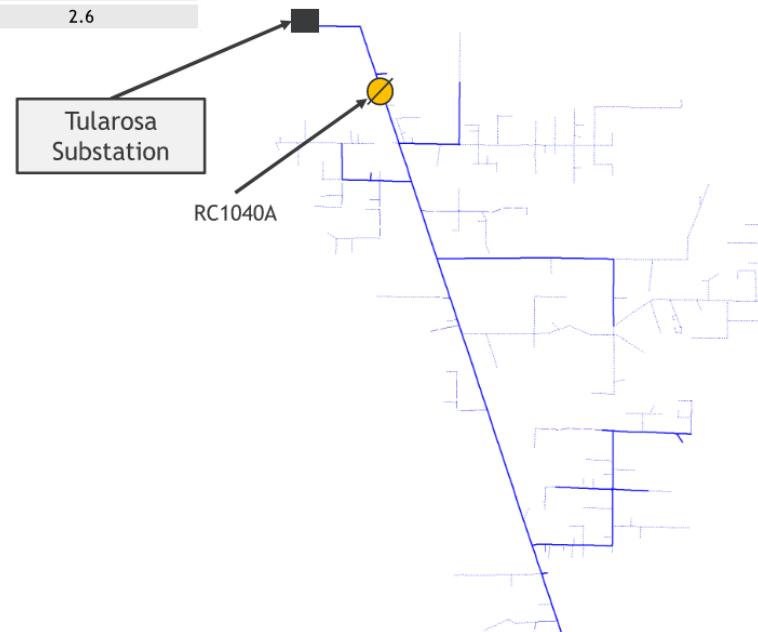
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
35	125	130	27	6	8	3	124.5	125.1	2.6

Protection Devices

Device	Name	Pick Up Rating (A)
Breaker	TULA13 Breaker	300
Recloser	RC1040A	250

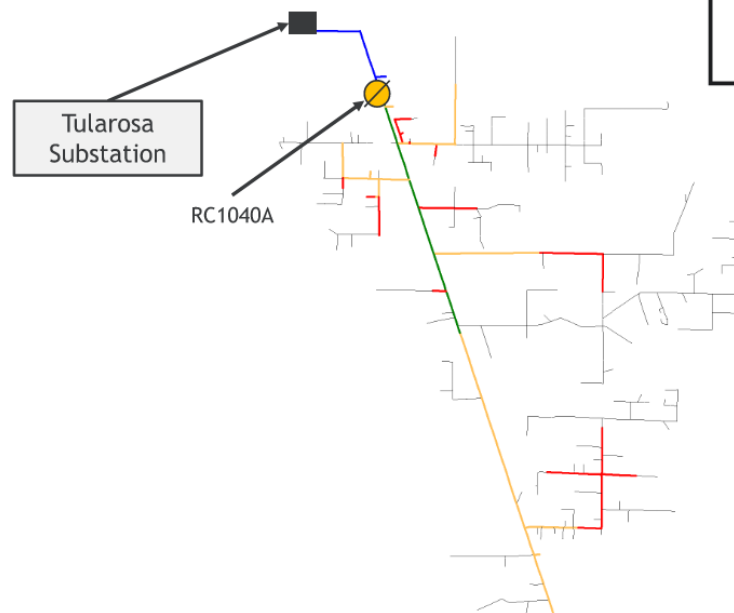
Feeder Data

- Feeder Rating: 5,832 kVA
- Existing Generation: 329 kVA
- Minimum Daylight Load: 35 kW
- Minimum Daylight Gross Load: 342 kW / 126 kVAR
- Substation LTC Setpoint: 125 V
- Primary Voltage: 12.47 kV



TULA13 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity	
5.87 MW	
Limiting Factors	
Thermal Loading Violation	24%
Voltage Violation	76%



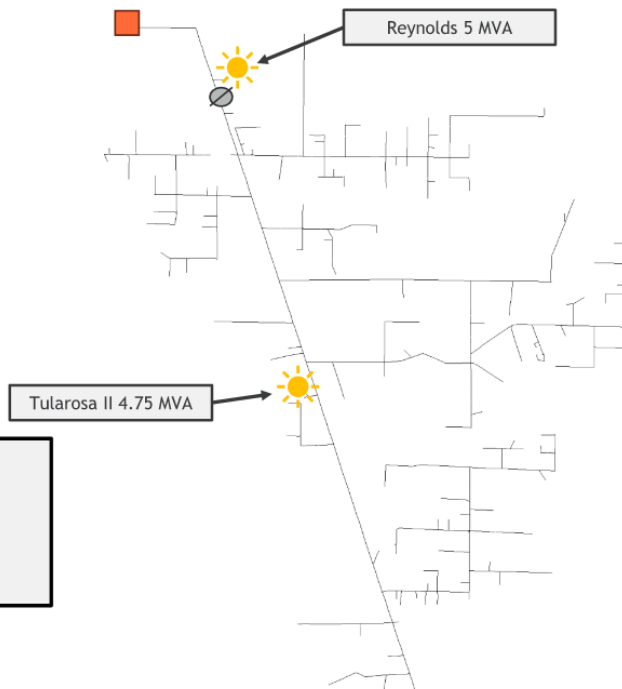
TULA13 - Community Solar Feeder Upgrades

Hosting Capacity	
Base HC	5.87 MW
Max HC	1.68 MW
HC Increase	-4.19 MW

Limiting Factors	
Thermal Loading Violation	100%
Voltage Violation	0%

Feeder Observations

- Feeder TULA13 will serve two community solar projects with a combined rated output of 9.75 MVA.
- Community solar project improvements include upgrading the feeder relay to SEL751 with directional capabilities.



Legend	
	New Recloser
	Existing Recloser
	Solar Facility
	Substation

Hosting Capacity (MW)	
	10-15
	5-10
	3-5
	1-3
	0.5-1
	0-0.5

Reverse Flow Limits
Max HC

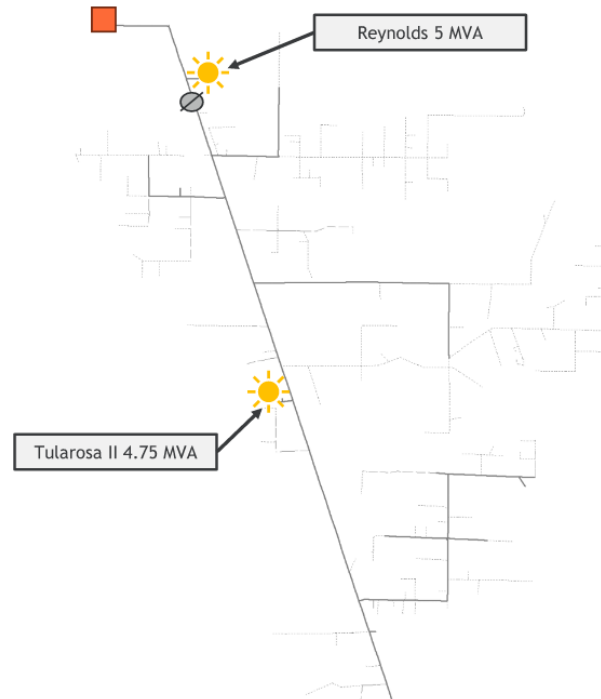
TULA13 - CS & Traditional System Upgrades

System Improvement		
Improvement Details		Cost
A	No Applicable Traditional System Improvements	-
TOTAL		\$XXX

Hosting Capacity	
CS Base HC	1.68 MW
Max HC	1.68 MW
HC Increase	0 MW

Benefit Cost Ratio	
HC Increase	0 MW
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-

Reverse Flow Limits
Max HC



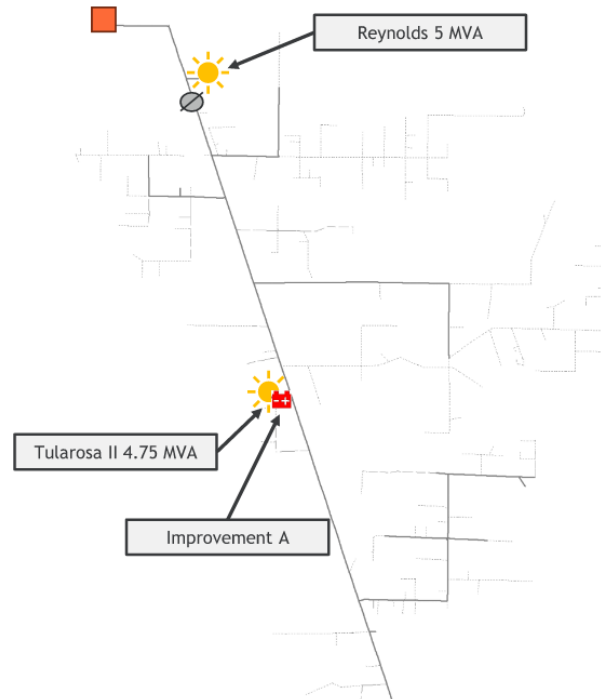
Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

TULA13 - CS Feeder Upgrades + 2 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL		\$14,300,000

Hosting Capacity	
CS Base HC	1.68 MW
Max HC	3.59 MW
HC Increase	1.91 MW

Benefit Cost Ratio	
HC Increase	1.91 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.89



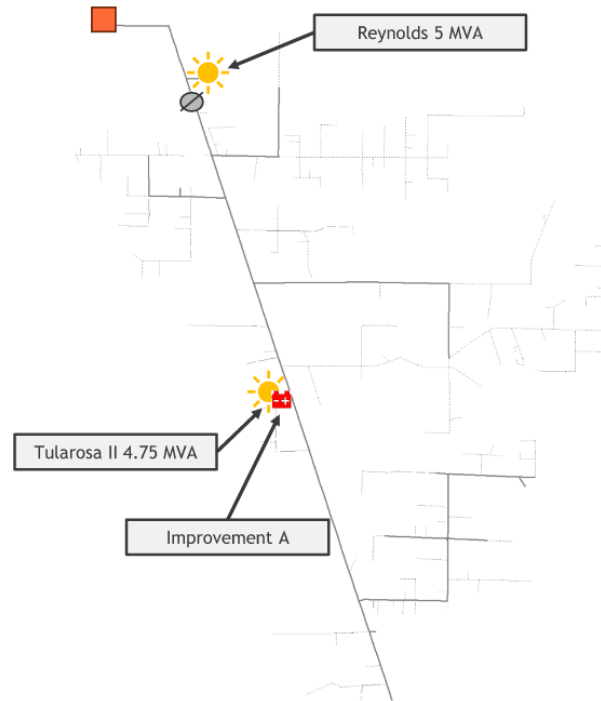
TULA13 - CS Feeder Upgrades + 6 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery + Control Scheme (Operating at 6 MVA Charging/Discharging)	\$14,350,000
TOTAL		\$14,350,000

Hosting Capacity	
CS Base HC	1.68 MW
Max HC	7.49 MW
HC Increase	5.81 MW

Benefit Cost Ratio	
HC Increase	1.94 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.40
Holistic System Benefit Cost	1.80

Reverse Flow Limits
Max HC



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

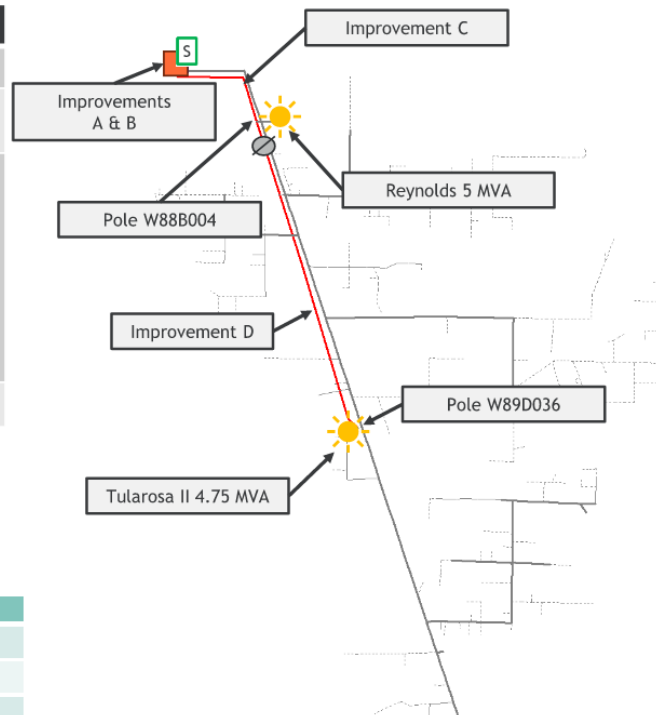
TULA13 - Dedicated Feeder

System Improvement		
Improvement Details		Cost
A	Build New Unit 2 transformer - Including switchgear, and feeder relaying equipment if necessary. Cost shared with Tularosa Feeder 14.	\$4,000,000
B	Build 300 ft of 750 CU UG from New Substation to Pole W88A075.	\$2,684,780
C	Build ~4,000 ft of 477 ACSR from Pole W88A075 to Pole W88B004. Utilize double circuit construction along the existing path of TULA13 feeder main line conductor.	
D	Build ~10,650 ft of 477 ACSR from Pole W88B004 to Pole W89D036. Utilize double circuit construction along the existing path of TULA13 feeder main line conductor.	
TOTAL		\$6,684,780

Hosting Capacity	
CS Base HC	1.68 MW
Max HC	11.27 MW
HC Increase	9.59 MW

Benefit Cost Ratio	
HC Increase	9.59 MW
Cost (\$)	6,684,780
Hosting Capacity Benefit Cost	1.43
Holistic System Benefit Cost	1.46

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Reverse Flow Limits
Max HC

TULA13 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
CS Feeder Upgrades Baseline	5,867	1,678	-4,189	-	-	-
CS & Traditional Upgrades	1,678	1,678	0	-	-	-
CS Upgrades + 2MVA BESS	1,678	3,588	1,910	\$14,300,000	0.13	0.89
CS Upgrades + 6MVA BESS	1,678	7,487	5,809	\$14,350,000	0.40	1.81
Dedicated Feeder	1,678	11,267	9,589	\$6,684,780	1.43	1.46



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Tularosa 14 Analysis



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TULA14 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
354	-243	429	-82	15	16	26	124.6	125.1	15.1

Protection Devices

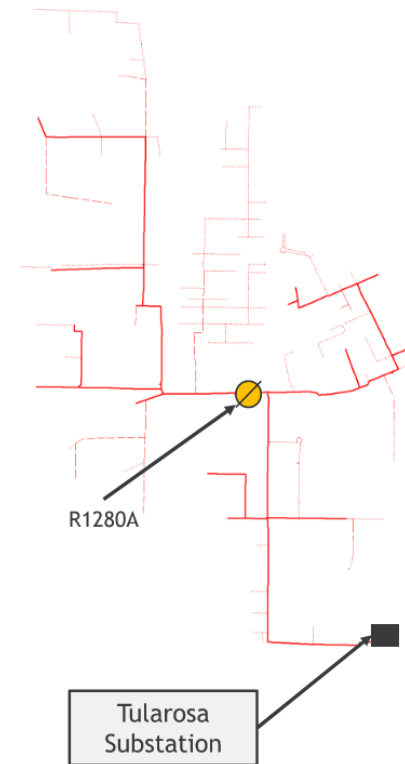
Device	Name	Pick Up Rating (A)
Breaker	TULA14 Breaker	300
Recloser	R1280A	160

Feeder Data

- Feeder Rating: 5,832 kVA
- Existing Generation: 151 kVA
- Minimum Daylight Load: 354 kW
- Minimum Daylight Gross Load: 499 kW / 84 kVAR
- Substation LTC Setpoint: 125 V
- Primary Voltage: 12.47 kV



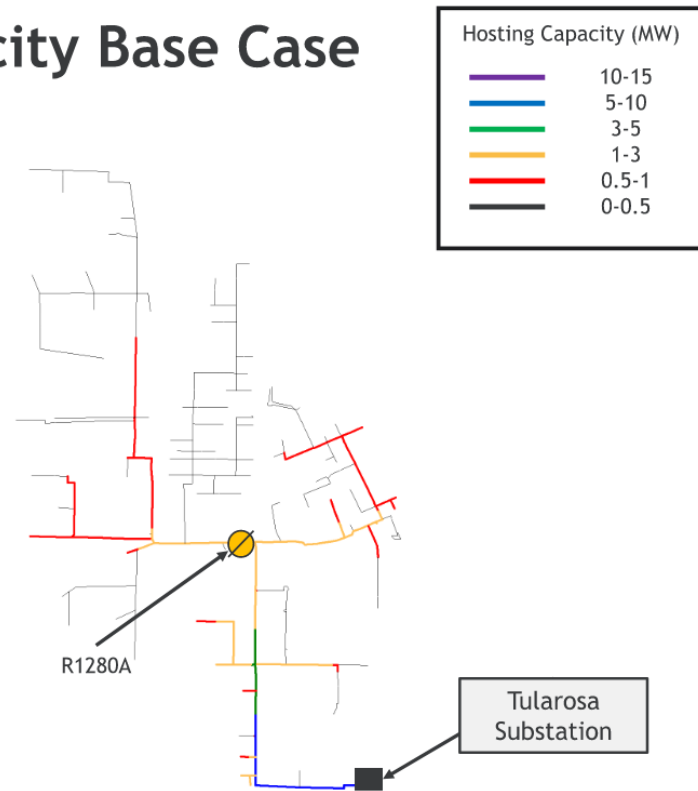
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TULA14 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity	
6.19 MW	
Limiting Factors	
Thermal Loading Violation	20%
Voltage Violation	80%



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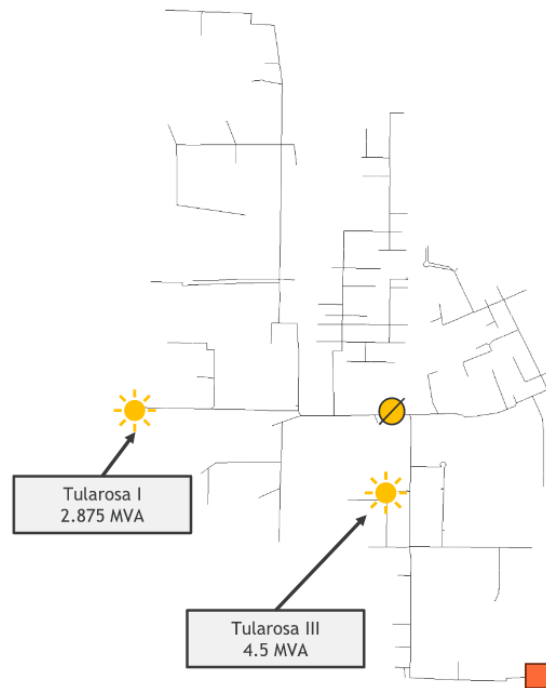
TULA14 - Community Solar Feeder Upgrades

Hosting Capacity	
Base HC	6.19 MW
Max HC	4.31 MW
HC Increase	-1.88 MW

Limiting Factors	
Thermal Loading Violation	20%
Voltage Violation	80%

Feeder Observations

- Feeder TULA14 will serve two community solar facilities with a combined rated output of 7.4 MVA of generation.
- Community solar project improvements include a 1,200 kVAR capacitor bank and upgrading the feeder relay to SEL751 with directional capabilities.



Legend

- New Recloser
- Existing Recloser
- Solar Facility
- Substation

Hosting Capacity (MW)

- 10-15
- 5-10
- 3-5
- 1-3
- 0.5-1
- 0-0.5

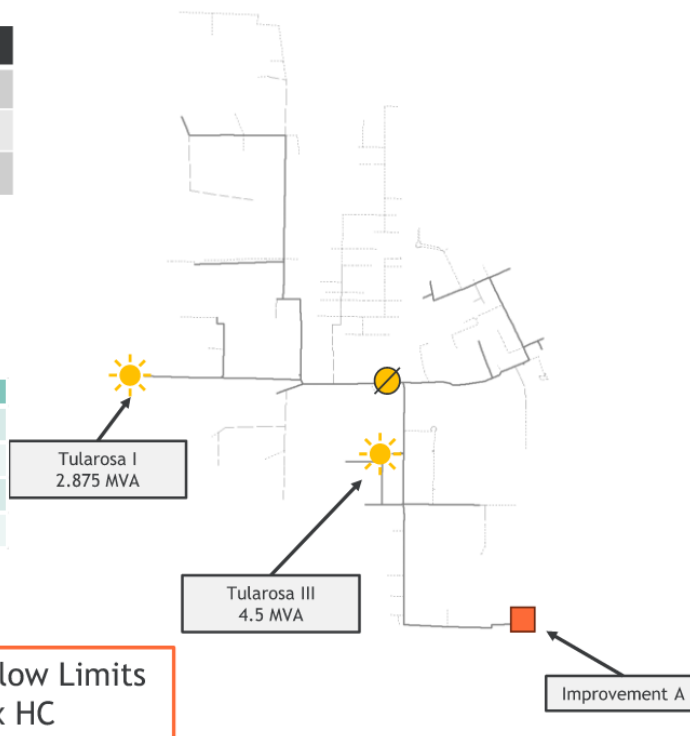
Reverse Flow Limits
Max HC

TULA14 - CS & Traditional System Upgrades

System Improvement		
Improvement Details		Cost
A	No Applicable Traditional System Improvements	-
TOTAL		\$XXX

Hosting Capacity	
CS Base HC	4.31 MW
Max HC	4.31 MW
HC Increase	0 MW

Benefit Cost Ratio	
HC Increase	0 MW
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-



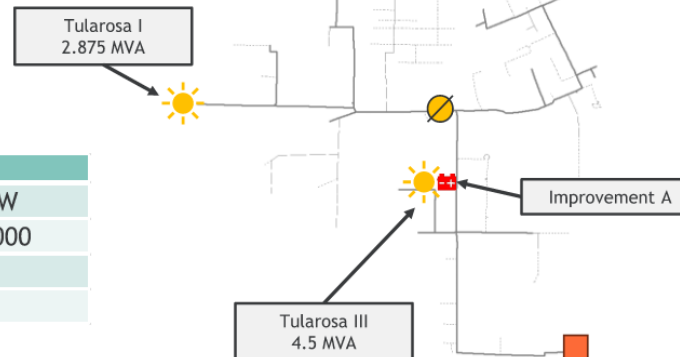
Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

TULA14 - CS Feeder Upgrades + 2 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL		\$14,300,000

Hosting Capacity	
CS Base HC	4.31 MW
Max HC	6.25 MW
HC Increase	1.94 MW

Benefit Cost Ratio	
HC Increase	1.94 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.14
Holistic System Benefit Cost	0.89



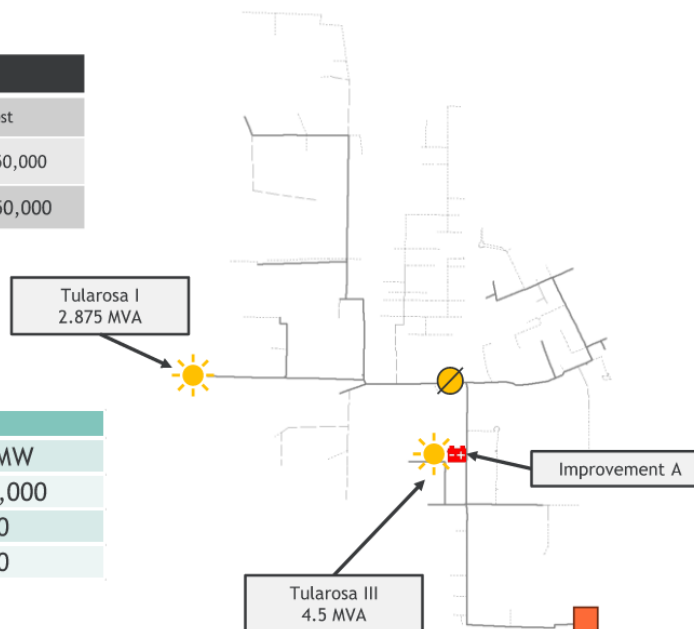
Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

TULA14 - CS Feeder Upgrades + 6 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery + Control Scheme (Operating at 6 MVA Charging/Discharging)	\$14,350,000
TOTAL		\$14,350,000

Hosting Capacity	
CS Base HC	4.31 MW
Max HC	10.02 MW
HC Increase	5.71 MW

Benefit Cost Ratio	
HC Increase	1.94 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.40
Holistic System Benefit Cost	1.80



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

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Thermal Loading
Limits Max HC

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TULA14 - Dedicated Feeder

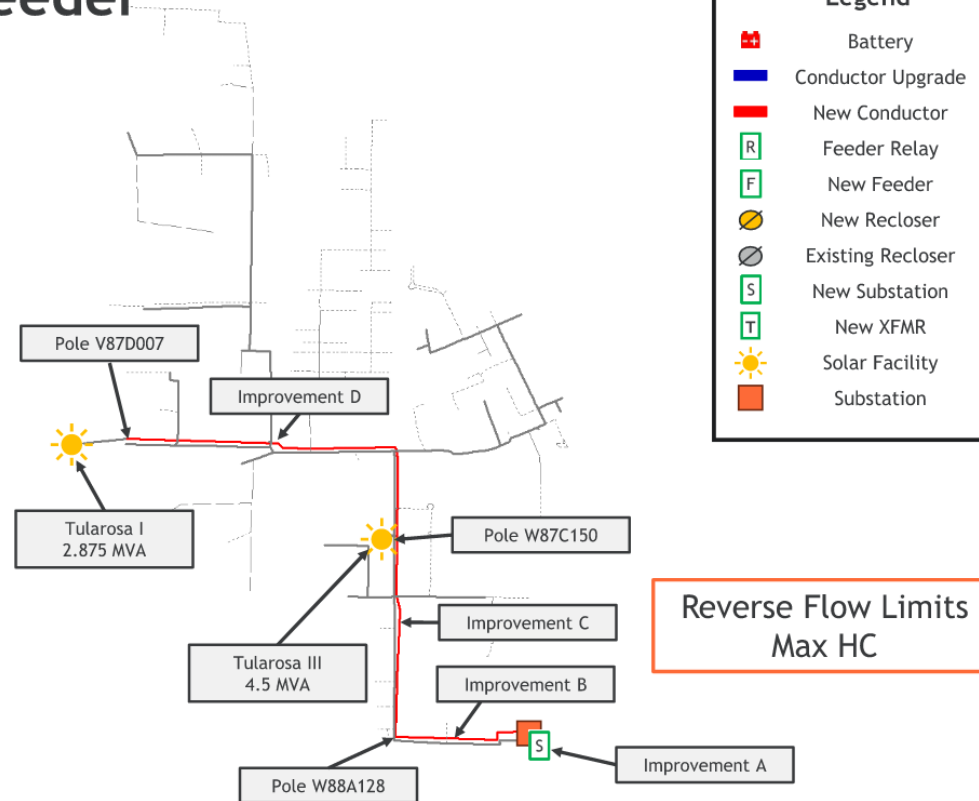
System Improvement		
Improvement Details		Cost
A	Build New Unit 2 Substation - Including switchgear, and feeder relaying equipment if necessary. Cost shared with Tularosa Feeder 13.	\$4,000,000
B	Build -2,600 ft of 477 ACSR from New Substation to Pole W88A128. Utilize double circuit construction along the existing path of TULA14.	\$2,391,436
C	Build -3,730 ft of 397 AAC @ 570 from Pole W88A128 to Pole W87C150. Utilize double circuit construction along the existing path of TULA14.	
D	Build -6,600 ft of 397 AAC @ 570 from Pole W87C150 to Pole V87D007. Utilize double circuit construction along the existing path of TULA14.	
TOTAL		\$6,391,436

Hosting Capacity	
CS Base HC	4.31 MW
Max HC	11.59 MW
HC Increase	7.28 MW

Benefit Cost Ratio	
HC Increase	7.28 MW
Cost (\$)	6,391,436
Hosting Capacity Benefit Cost	1.14
Holistic System Benefit Cost	1.16



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TULA14 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
CS Feeder Upgrades Baseline	6,185	4,314	-1,871	-	-	-
CS & Traditional Upgrades	4,314	4,314	0	-	-	-
CS Upgrades + 2MVA BESS	4,314	6,253	1,939	\$14,300,000	0.14	0.89
CS Upgrades + 6MVA BESS	4,314	10,024	5,710	\$14,350,000	0.40	1.80
Dedicated Feeder	4,314	11,585	7,271	\$6,391,436	1.14	1.16



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Veranda 22 Analysis



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VERA22 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)

kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
391	-469	610	-64	29	20	35	121.8	124.1	11.9

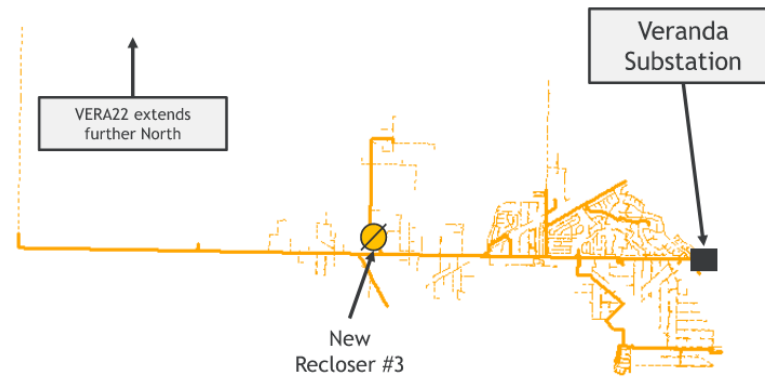
Protection Devices

Device	Name	Pick Up Rating (A)
Breaker	VERA22 Breaker	600
Recloser	New Recloser #3	150

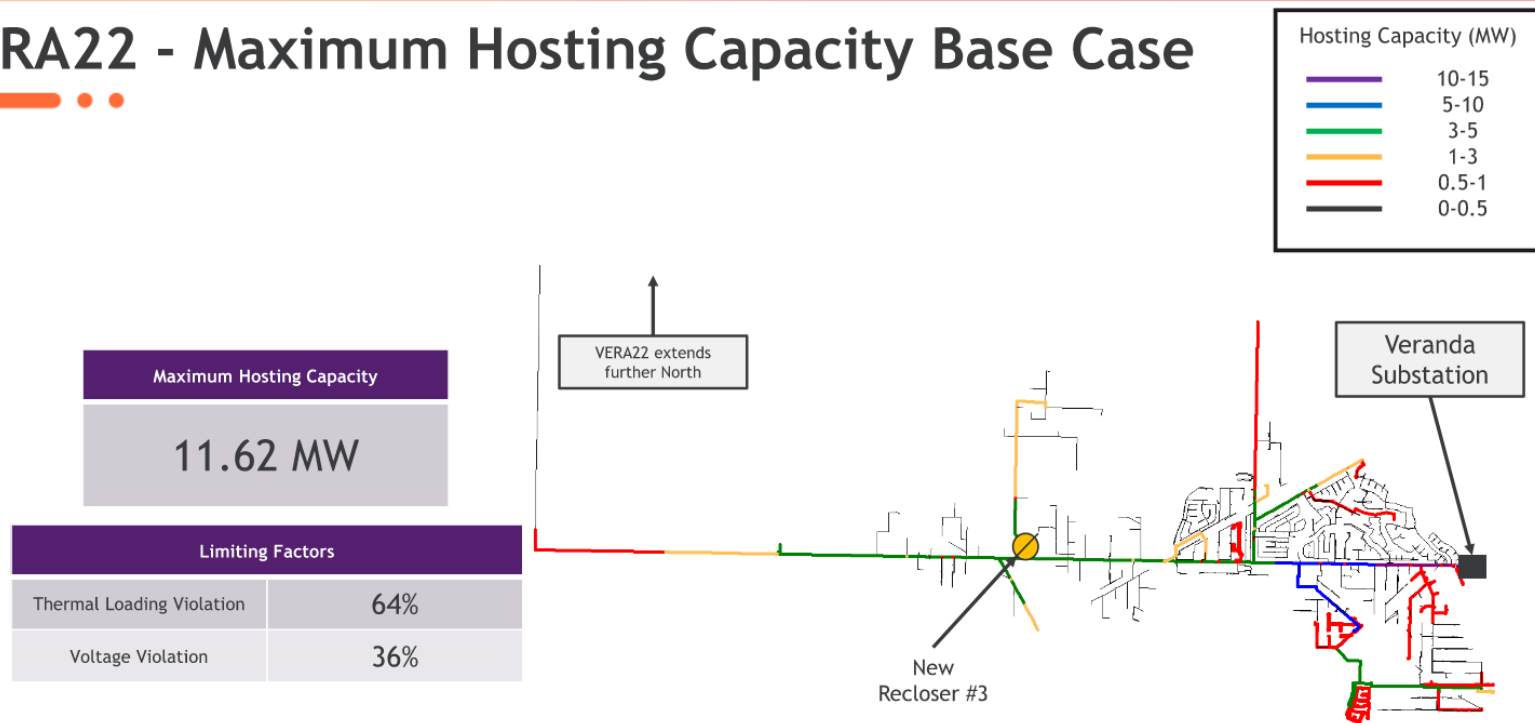
Base Case TM Applied

Feeder Data

- Feeder Rating: 11,231 kVA
- Existing Generation: 2,811 kVA
- Minimum Daylight Load: 391 kW
- Minimum Daylight Gross Load: 3,149 kW / 1,939 kVAR
- Substation LTC Setpoint: 123 V
- Primary Voltage: 12.47 kV



VERA22 - Maximum Hosting Capacity Base Case



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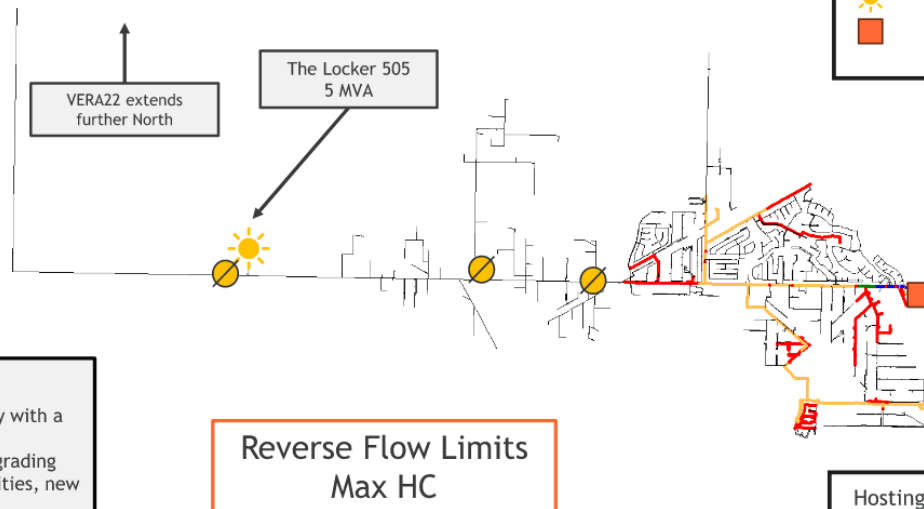
VERA22 - Community Solar Feeder Upgrades

Hosting Capacity	
Base HC	11.62 MW
Max HC	6.9 MW
HC Increase	-4.72 MW

Limiting Factors	
Thermal Loading Violation	64%
Voltage Violation	36%

Feeder Observations

- Feeder VERA22 will serve a community solar facility with a rated output of 5 MVA.
- Community solar project improvements include upgrading the feeder relay to SEL751 with directional capabilities, new voltage regulator, and new reclosers.



Legend	
	New Recloser
	Existing Recloser
	Solar Facility
	Substation

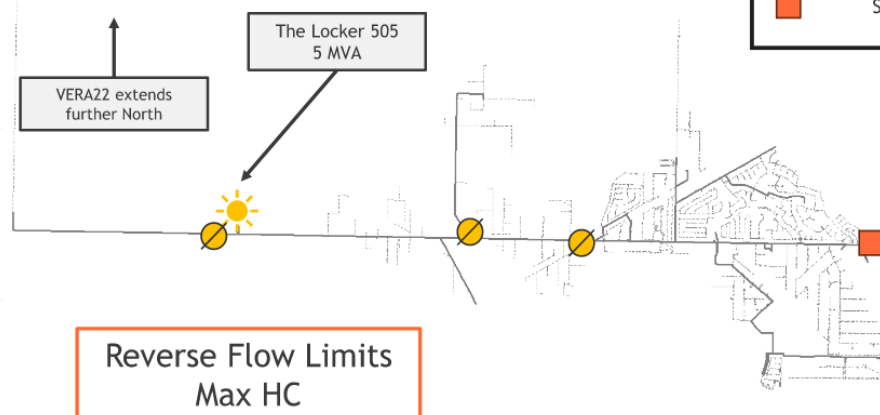
Hosting Capacity (MW)	
	10-15
	5-10
	3-5
	1-3
	0.5-1
	0-0.5

VERA22 - CS & Traditional System Upgrades

System Improvement		
Improvement Details		Cost
A	No Applicable Traditional System Improvements	-
TOTAL		-

Hosting Capacity	
CS Base HC	6.9 MW
Max HC	6.9 MW
HC Increase	0 MW

Benefit Cost Ratio	
HC Increase	0 MW
Cost (\$)	0
Hosting Capacity Benefit Cost	-
Holistic System Benefit Cost	-



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

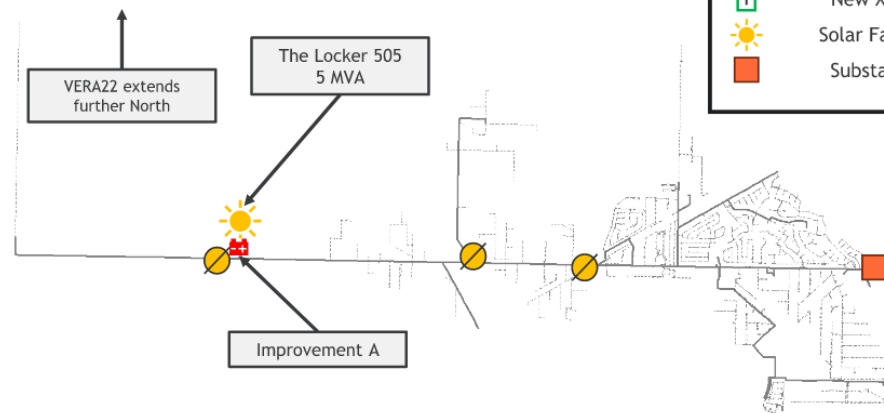
VERA22 - CS Feeder Upgrades + 2 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
TOTAL		\$14,300,000

Hosting Capacity	
CS Base HC	6.9 MW
Max HC	8.71 MW
HC Increase	1.81 MW

Benefit Cost Ratio	
HC Increase	1.81 MW
Cost (\$)	14,300,000
Hosting Capacity Benefit Cost	0.13
Holistic System Benefit Cost	0.88

Reverse Flow Limits
Max HC



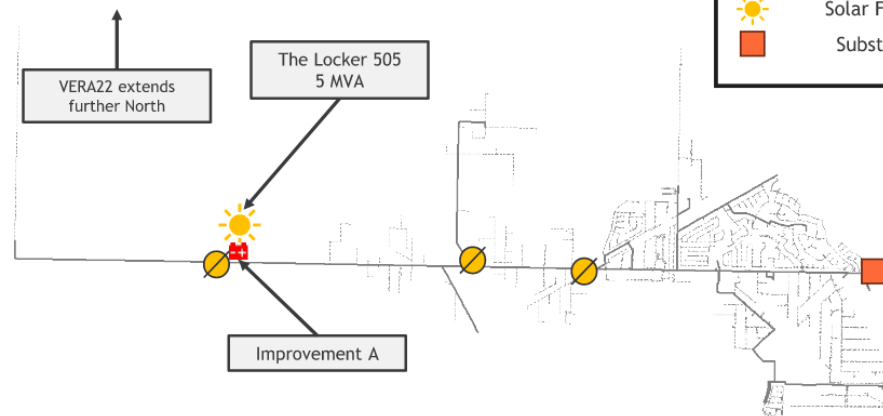
VERA22 - CS Feeder Upgrades + 6 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery + Control Scheme (Operating at 6 MVA Charging/Discharging)	\$14,350,000
TOTAL		\$14,350,000

Hosting Capacity	
CS Base HC	6.9 MW
Max HC	9.46 MW
HC Increase	2.56 MW

Benefit Cost Ratio	
HC Increase	1.81 MW
Cost (\$)	14,350,000
Hosting Capacity Benefit Cost	0.18
Holistic System Benefit Cost	1.62

Thermal Loading
Limits Max HC



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

VERA22 - Dedicated Feeder

System Improvement		
Improvement Details		Cost
A	Install a new Veranda Unit 3 Substation Transformer - Including switchgear, and feeder relaying equipment.	\$8,000,000
B	Build ~200 ft of 750 CU from New Substation to Pole E09C107.	\$5,750,883
C	Build ~34,200 ft of 397 AAC @ 570 from Pole E09C107 to Pole B09D017. Utilize double circuit construction along the existing path of VERA22.	
TOTAL		\$13,740,883

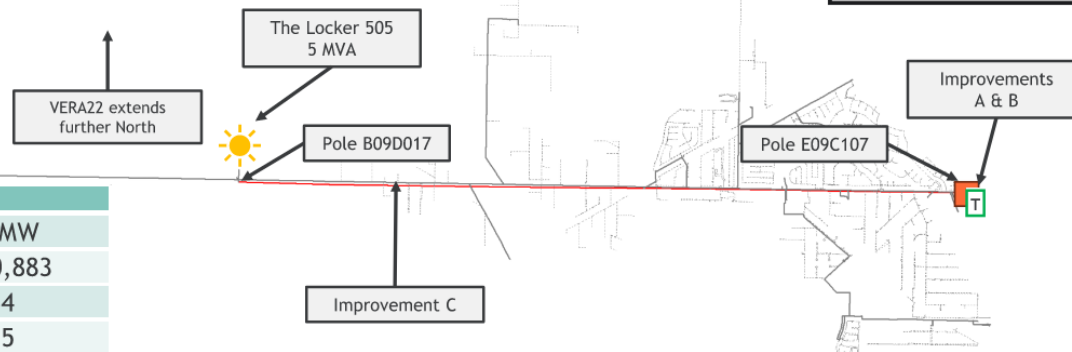
Hosting Capacity	
CS Base HC	6.9 MW
Max HC	11.62 MW
HC Increase	4.72 MW

Benefit Cost Ratio	
HC Increase	4.72 MW
Cost (\$)	13,740,883
Hosting Capacity Benefit Cost	0.34
Holistic System Benefit Cost	0.35

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Reverse Flow Limits
Max HC

Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation



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VERA22 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
CS Feeder Upgrades Baseline	11,621	6,897	-4,724	-	-	-
CS & Traditional Upgrades	6,897	6,897	0	-	-	-
CS Upgrades + 2MVA BESS	6,897	8,707	1,810	\$14,300,000	0.13	0.88
CS Upgrades + 6MVA BESS	6,897	9,457	2,560	\$14,350,000	0.18	1.62
Dedicated Feeder	6,897	11,621	4,724	\$13,740,883	0.34	0.35



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Van Buren 12 Analysis



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VNBU12 - Feeder Overview

Base Case Load Flow Analysis (Minimum daylight Load)

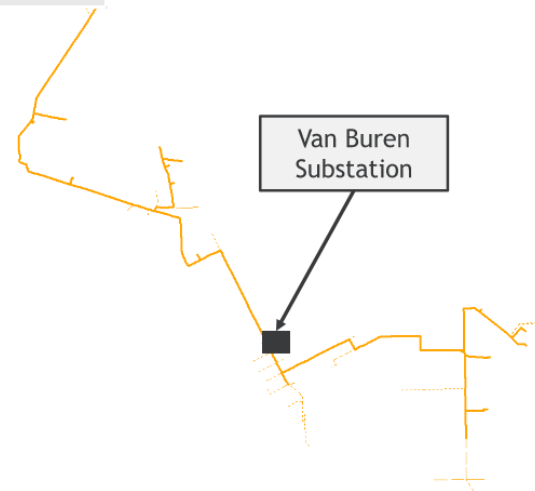
kW	kVAR	kVA	PF %	Phase A Amps	Phase B Amps	Phase C Amps	Min Voltage	Max Voltage	Max Conductor Loading % Normal Rating
147	103	179	82	8	8	8	121.8	122.0	4.0

Protection Devices

Device	Name	Pick Up Rating (A)
Breaker	VNBU12 Breaker	300

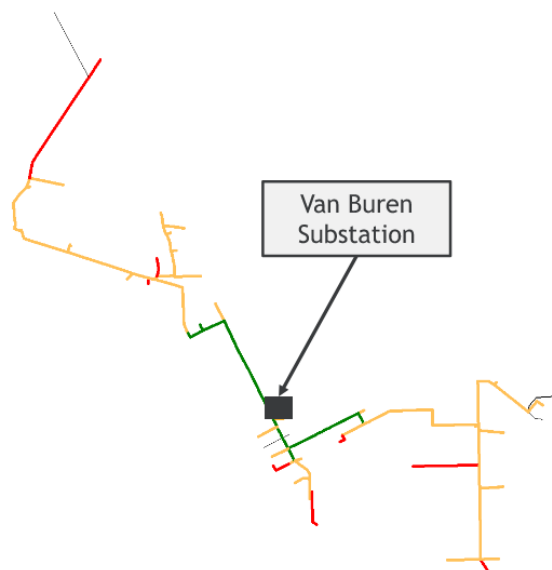
Feeder Data

- Feeder Rating: 4,428 kVA
- Existing Generation: 6 kVA
- Minimum Daylight Load: 147 kW
- Minimum Daylight Gross Load: 153 kW / 109 kVAR
- Substation LTC Setpoint: 122 V
- Primary Voltage: 12.47 kV



VNBU12 - Maximum Hosting Capacity Base Case

Maximum Hosting Capacity	
4.57 MW	
Limiting Factors	
Thermal Loading Violation	52%
Voltage Violation	48%



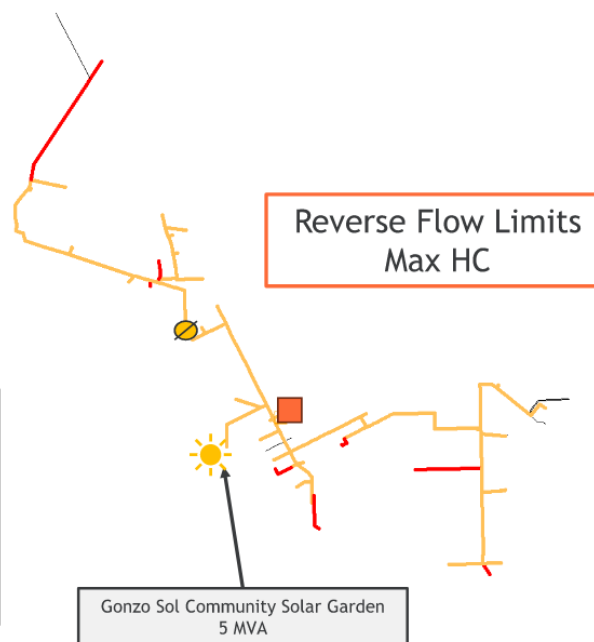
VNBU12 - Community Solar Feeder Upgrades

Hosting Capacity	
Base HC	4.57 MW
Max HC	4.27 MW
HC Increase	-0.3 MW

Limiting Factors	
Thermal Loading Violation	54%
Voltage Violation	46%

Feeder Observations

- Feeder VNBU12 will serve one community solar facility with a rated output of 5 MVA.
- Community solar project improvements include an upgrade of the feeder relay to SEL751 with directional capability, a new recloser, and a feeder getaway upgrade to 750 AL UG cable.
- The Van Buren substation transformer is rated at 10.5 MVA and will need to be upgraded to increase hosting capacity.



Legend	
	New Recloser
	Existing Recloser
	Solar Facility
	Substation

Hosting Capacity (MW)	
	10-15
	5-10
	3-5
	1-3
	0.5-1
	0-0.5

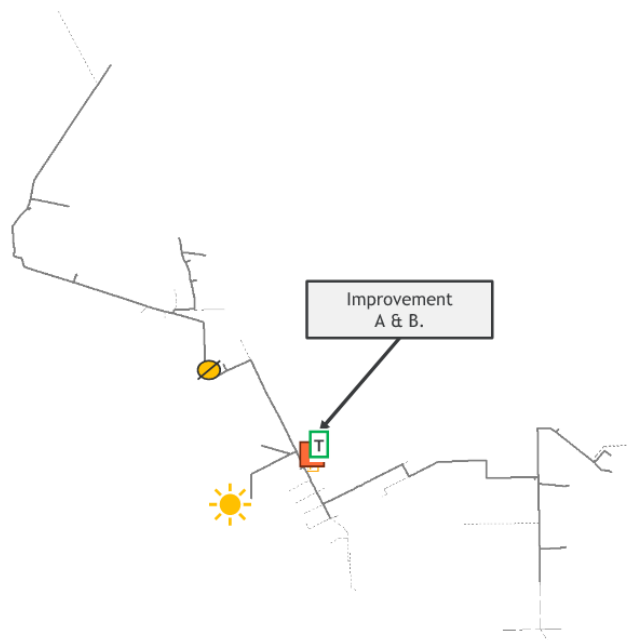
VNBU12 - CS & Traditional System Upgrades

System Improvement		
Improvement Details		Cost
A	Upgrade the Substation Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
B	Upgrade -110 ft of conductor to 750 CU UG from Substation to Pole N53B088.	\$297,000
TOTAL		\$8,297,000

Hosting Capacity	
CS Base HC	4.27 MW
Max HC	6.43 MW
HC Increase	2.16 MW

Benefit Cost Ratio	
HC Increase	2.16 MW
Cost (\$)	8,297,200
Hosting Capacity Benefit Cost	0.26
Holistic System Benefit Cost	0.61

Reverse Flow Limits
Max HC



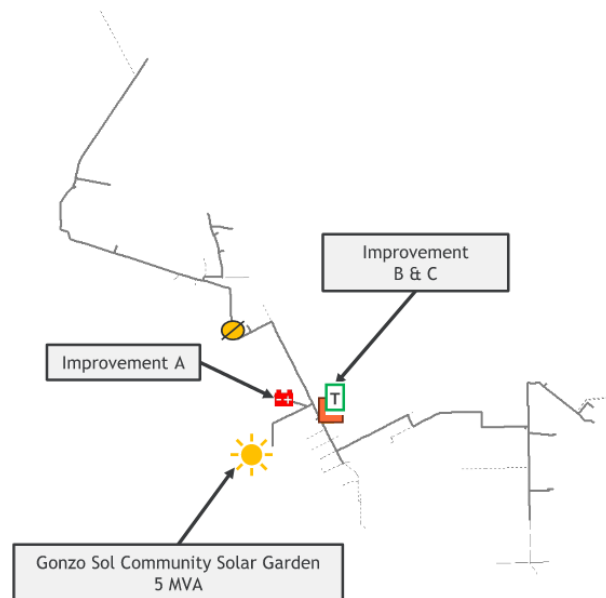
Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

VNBU12 - CS Feeder Upgrades + 2 MVA BESS

System Improvement		
Improvement Details		Cost
A	Install New 6 MVA Battery (Operating at 2 MVA Charging/Discharging)	\$14,300,000
B	Upgrade the Substation Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
C	Upgrade ~110 ft of conductor to 750 CU UG from Substation to Pole N53B088.	\$297,000
TOTAL		-

Hosting Capacity	
CS Base HC	4.27 MW
Max HC	8.84 MW
HC Increase	4.57 MW

Benefit Cost Ratio	
HC Increase	4.57 MW
Cost (\$)	22,597,200
Hosting Capacity Benefit Cost	0.20
Holistic System Benefit Cost	0.71



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

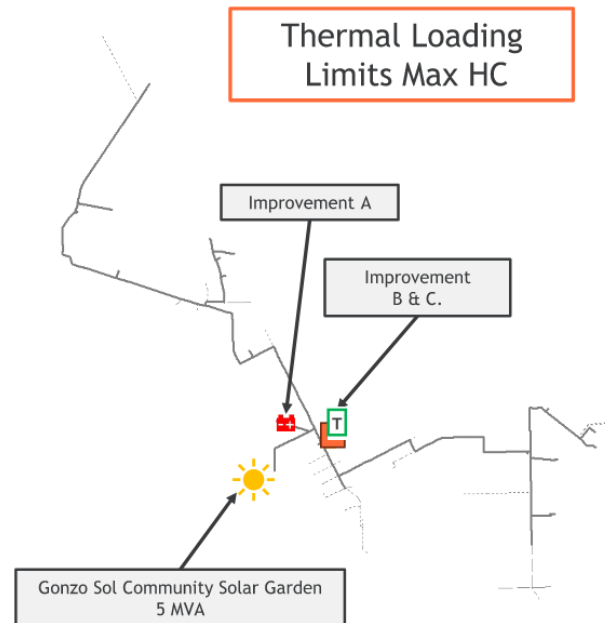
Reverse Flow Limits
Max HC

VNBU12 - CS Feeder Upgrades + 6 MVA BESS

System Improvement		
	Improvement Details	Cost
A	Install New 6 MVA Battery + Control Scheme (Operating at 6 MVA Charging/Discharging)	\$14,350,000
B	Upgrade the Substation Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
C	Upgrade -110 ft of conductor to 750 CU UG from Substation to Pole N53B088.	\$297,000
TOTAL		\$22,647,200

Hosting Capacity	
CS Base HC	4.27 MW
Max HC	12.85 MW
HC Increase	8.58 MW

Benefit Cost Ratio	
HC Increase	4.57 MW
Cost (\$)	22,647,200
Hosting Capacity Benefit Cost	0.38
Holistic System Benefit Cost	1.22



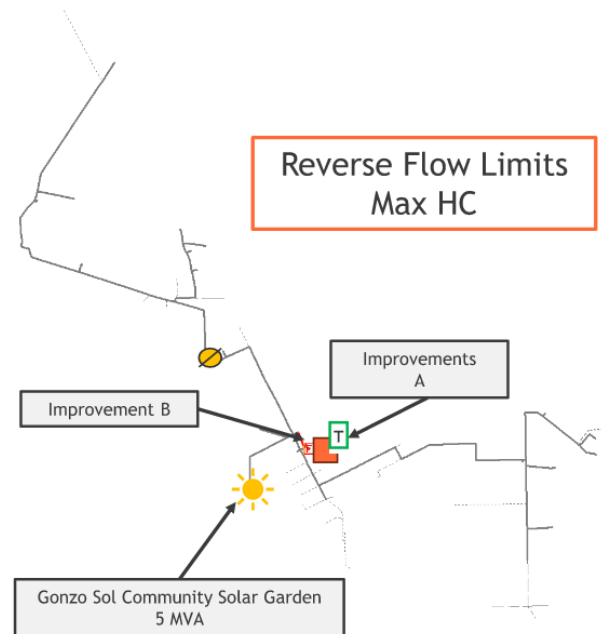
Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

VNBU12 - Dedicated Feeder

System Improvement		
	Improvement Details	Cost
A	Upgrade the Substation Transformer - Including switchgear, and feeder relaying equipment if necessary.	\$8,000,000
B	Build - 500 ft of 397 AAC @ 570 from Pole N53B088 to Pole N53B700.	\$335,134
TOTAL		\$8,335,134

Hosting Capacity	
CS Base HC	4.27 MW
Max HC	9.22 MW
HC Increase	4.95 MW

HC Increase	4.95 MW
Cost (\$)	8,335,134
Hosting Capacity Benefit Cost	0.59
Holistic System Benefit Cost	0.60



Legend	
	Battery
	Conductor Upgrade
	New Conductor
	Feeder Relay
	New Feeder
	New Recloser
	Existing Recloser
	New Substation
	New XFMR
	Solar Facility
	Substation

VNBU12 - Hosting Capacity Analysis Summary

Hosting Capacity Improvement Solution	Base Case Hosting Capacity kVA	New Maximum Hosting Capacity kVA	Net Hosting Capacity Increase kVA	Capital Project Cost	Net Hosting Capacity Increase (kVA) over Cost (\$K)	Holistic System Benefit Cost Ratio Score
CS Feeder Upgrades Baseline	4,575	4,271	-304	-	-	-
CS & Traditional Upgrades	4,271	6,430	2,160	\$8,297,200	0.26	0.61
CS Upgrades + 2MVA BESS	4,271	8,836	4,566	\$22,597,200	0.20	0.71
CS Upgrades + 6MVA BESS	4,271	12,854	8,584	\$22,647,200	0.38	1.22
Dedicated Feeder	4,271	9,219	4,948	\$8,335,134	0.59	0.60

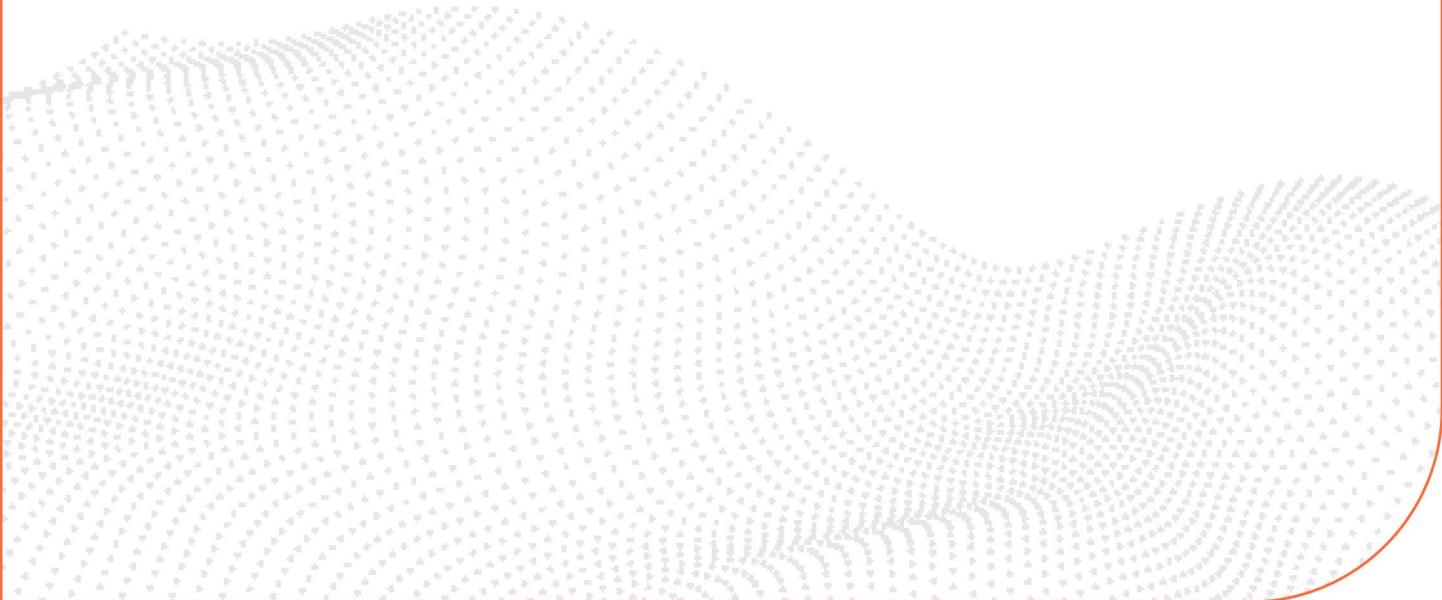


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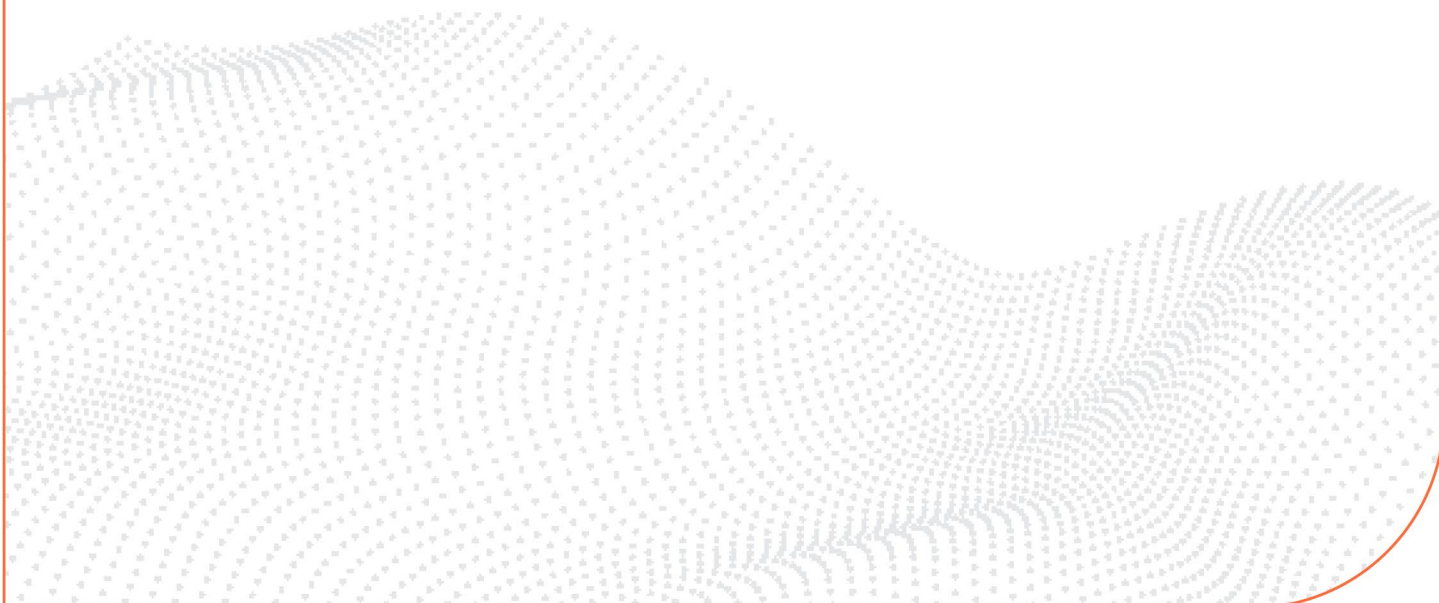
HOSTING CAPACITY ANALYSIS REFRESH - 2026

PUBLIC SERVICE COMPANY OF NEW MEXICO

PROJECT NO. 200627

REVISION 1

September 28, 2026



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1.0 Executive Summary

Photovoltaic (PV) penetration is growing within the Public Service Company of New Mexico (PNM or the Company) system. High PV penetration can present benefits but can also result in challenges for operating and maintaining the distribution system. PNM requested a hosting capacity analysis study for twenty-seven (27) distribution feeders to understand each feeder's capacity to host new generation.

Hosting capacity analysis, performed within the Synergi Electric software platform, used power flow simulations to evaluate the ability of distribution feeders to successfully interconnect new PV generation without violating thermal or voltage planning criteria. Hosting capacity analysis is an evolving tool that many electric utilities in North America are leveraging to understand the limitations of their system, identify system improvements, and communicate findings effectively.

1.1 Key Findings

Interconnecting new PV generation to the distribution system can result in voltage and/or thermal loading violations. PNM defines thermal loading and voltage planning criteria to maintain satisfactory power quality to customers and reliable operation of the distribution system. Hosting capacity analysis conducted on a feeder-by-feeder basis and using power flow simulations provided insights into the limitations of each distribution feeder analyzed. Table 1-1 shows the Synergi analysis maximum hosting capacity results for the analyzed feeders. This study did not determine the appropriate actions to facilitate additional generation growth on the feeders analyzed.

Table 1-1: Maximum Synergi Hosting Capacity Analysis Results

Feeder	Feeder Rating kVA	Assumptions	Synergi Max Hosting Capacity kVA	Comments
A10012	11,663	SGIA 2.0 MVA	4,200	
A10083	11,663	3.5 MVA Community Solar Project	4,331	
ARIB11	11,231		1,067	
COLL12	9,071	SGIA 0.47 MVA	0	Thermal Loading Violation
DEMW11	9,370	SGIA 8.25 MVA	1,355	
ELCE11	11,231		2,579	
ELCE12	11,231	3.0 MVA Community Solar Project	9,621	
GOLD13	12,429	SGIA 11 MVA	2,258	
HOND11	10,039	2 Community Solar Projects (Combined 8.65 MVA)	2,282	
HOND12	10,039		1,903	
JARA12	11,231		3,177	
LD0318	7,500	2 Community Solar Projects (Combined 5.42 MVA)	3,330	
LD1000	7,500	5.0 MVA Community Solar Project	2,695	
LOHO12	11,231		3,261	
LOHO13	11,231		0	Thermal Loading Violation
LOHO14	11,231		1,535	
LSMO12	11,231		1,703	
LSMO21	9,287	SGIA 2 MVA	1,009	
PROG13	9,935	SGIA 2.6 MVA	6,133	
SCEN12	9,935		0	Thermal Loading Violation
SL0017	9,380	5.0 MVA Community Solar Project	5,449	
SOCO12	11,231	2 MVA BESS	5,087	
STPE12	11,231		1,062	
TOME12	9,071	2 MVA BESS	1,598	
TULA13	11,231	2 Community Solar Projects (Combined 9.75 MVA)	1,826	
TULA14	11,231	2 Community Solar Projects (Combined 7.38 MVA)	4,397	
VNBU12	9,287	5.0 MVA Community Solar Project	5,862	

1.1.1 Maximum Hosting Capacity - Thermal Constraint

Maximum hosting capacity is important to determine so that each distribution feeder can be classified by its capability to successfully serve new PV interconnections. Maximum hosting capacity is related to the thermal limitations of the distribution feeder, specifically the feeder rating. The feeder rating defines the amount of power that can flow on a distribution feeder. Power flow, resulting from either customer load or generation, cannot exceed the feeder rating without causing thermal loading criteria violations and damage to PNM equipment. Minimum daylight gross load (MDGL), or customer demand during the minimum daylight load time, can consume excess PV generation and limit the power flow on a distribution feeder.

Maximum hosting capacity can be further limited by the substation transformer or transmission constraints. These factors were not studied in this report.

1.1.2 Spread of Hosting Capacity - Thermal & Voltage Constraints

Maximum remaining hosting capacity is an important quantity to understand the capability of a distribution feeder to host new PV generation, but this quantity does not provide insight into where new generation could be successfully interconnected on a feeder. Spread of hosting capacity is used to describe the capability of all line sections of a distribution feeder to host new PV generation. Conductor and equipment ratings define the amount of power that can flow through each line section of a distribution feeder. Power flow, resulting from either customer load or generation, cannot exceed the rating of any conductor or equipment without causing thermal loading criteria violations. Voltage violations can also constrain how much new generation can be successfully interconnected to line sections on a distribution feeder. Power flow simulations must be performed to understand the voltage impacts of connecting new generation to a distribution feeder. Incremental Hosting capacity analysis was performed on this subset of feeders in Synergi to create heat maps that communicate the spread of hosting capacity throughout a distribution feeder.

2.0 Inputs and Assumptions

Several distribution feeders within the PNM system already have large amounts of interconnected PV generation. High PV penetration can present challenges for operating and maintaining the distribution system. The purpose of this study is to understand the actual limits on distribution feeders for hosting PV generation. This study does not determine the appropriate actions to facilitate additional generation growth within their system.

2.1 Study Feeders

PNM selected 27 distribution feeders for a detailed study to understand each feeder's capacity to host new generation. Distribution feeders were selected from four main regions, as shown in Figure 2-1 below. The number of distribution feeders within each geographical region is represented by the number in each circle.

Figure 2-1: Study Feeder Locations

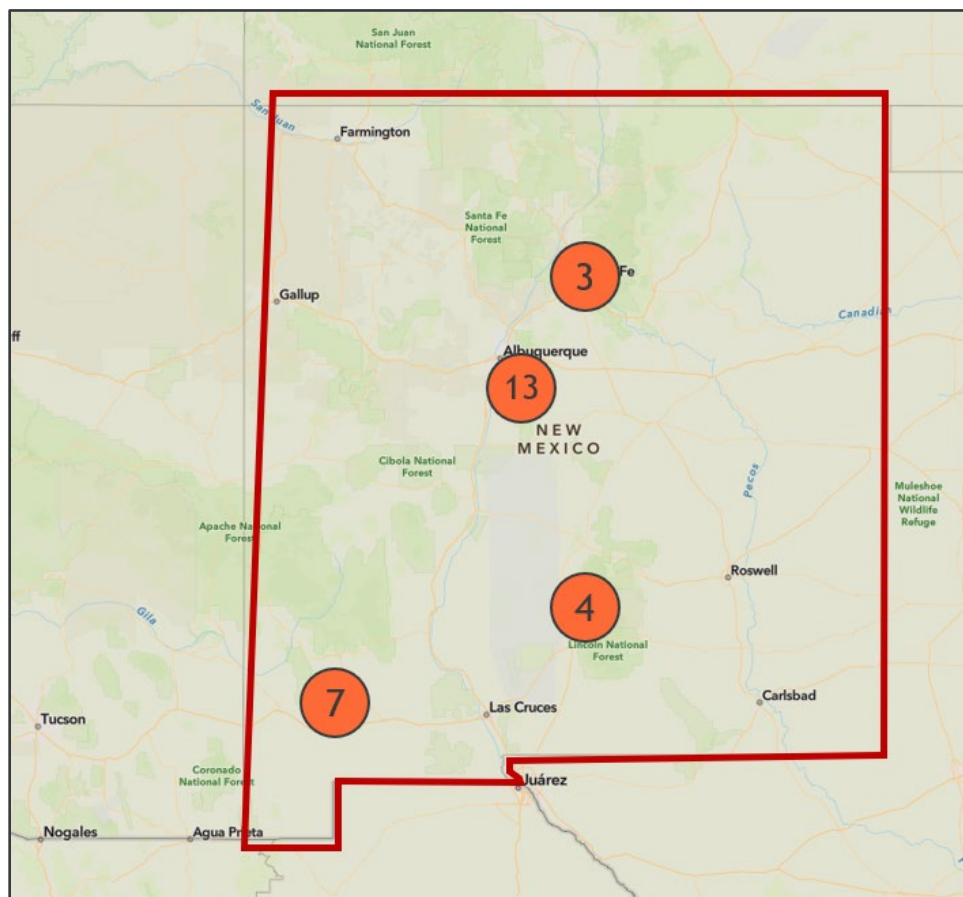


Table 2-1 shows the 27 distribution feeders selected for this study.

Table 2-1: Distribution Feeders for Hosting Capacity Analysis

Feeder	Divisions
A10012	Alamogordo
A10083	Alamogordo
ARIB11	Las Vegas
COLL12	Valencia
DEMW11	Deming
ELCE11	Valencia
ELCE12	Valencia
GOLD13	Deming
HOND11	Deming
HOND12	Deming
JARA12	Valencia
LD0318	Lordsburg
LD1000	Lordsburg
LSM012	Valencia
LSM021	Valencia
LOHO12	ABQ West
LOHO13	ABQ West
LOHO14	ABQ West
PROG13	Sandoval
SCEN12	ABQ West
SL0017	Silver City
SOCO12	ABQ West
STPE12	Santa Fe
TOME12	Valencia
TULA13	Alamogordo
TULA14	Alamogordo
VNBU12	Clayton

2.2 Distribution Feeder Ratings

Table 2-2 shows the documented ratings for all distribution feeders included in this study. PNM determines distribution feeder ratings based on the ampacity of conductors and cables, relaying and protection equipment, and a system design criterion of 600 Amps. PNM's Design Manual (DM-16) distribution standards are referenced for both overhead conductor and underground cable ampacity ratings for determining actual feeder ratings. Equipment, conductors, and cables should not exceed 100% of the normal rating. Protective devices (relays, reclosers, sectionalizers, fuses) should not exceed 90% of the device pickup, or 90% of the device normal rating if capable of directionality.

Existing nameplate PV capacity was aggregated for each feeder using PNM's CoGen report which is an internal data extraction tool. The CoGen report pulls existing generation information from the mapping system and is organized by distribution feeder. Existing nameplate PV capacity includes both rooftop and utility-scale PV systems. Several of the distribution feeders in this study have small generator interconnection agreements (SGIA) that are signed, but the facilities have not been fully constructed. Where large-scale PV facilities have not yet completed construction, capacity is reserved on the feeder based on the contractual SGIA. The feeder rating utilization shows the nameplate capacity of approved PV systems compared against the feeder rating. Many of the feeders on this list show nameplate PV capacity greater than the present distribution feeder rating and are highlighted.

Table 2-2: Distribution Feeder ratings

Feeder	Feeder Rating kVA	Feeder Rating Limiting Factor	Connected PV Capacity kVA	SGIA Reservation Capacity kVA	Community Solar Capacity kVA	Total Approved PV Capacity kVA	Feeder Rating Utilization %
A10012	11,663	Protection Setting	8,648	2000	0	10,648	91%
A10083	11,663	Protection Setting	7,273	0	3,500	10,773	92%
ARIB11	11,231	Getaway Rating	10,332	0	0	10,332	92%
COLL12	9,071	Getaway Rating	9,373	0	0	9,373	103%
DEMW11	9,370	XFMR Rating	56	8,250	0	8,306	89%
ELCE11	11,231	Getaway Rating	9,400	0	0	9,400	84%
ELCE12	11,231	Getaway Rating	1,172	0	3,000	4,172	36%
GOLD13	12,429	Getaway Rating	354	11,000	0	11,354	91%
HOND11	10,039	Getaway Rating	248	0	8,650	8,898	89%
HOND12	10,039	Getaway Rating	9,158	0	0	9,158	91%
JARA12	11,231	Getaway Rating	10,064	0	0	10,064	90%
LD0318	7,500	XFMR Rating	385	0	5,415	5,800	77%
LD1000	7,500	XFMR Rating	975	0	5,000	5,975	80%
LOHO12	11,231	Getaway Rating	10,038	0	0	10,038	89%
LOHO13	11,231	Getaway Rating	11,725	0	0	11,725	104%
LOHO14	11,231	Getaway Rating	10,000	0	0	10,000	89%
LSMO12	11,231	Getaway Rating	10,249	0	0	10,249	91%
LSMO21	9,287	Conductor Rating	9,036	2,000	0	11,036	119%
PROG13	9,935	Conductor Rating	10,185	2,600	0	12,785	129%
SCEN12	9,935	Conductor Rating	11,262	0	0	11,262	113%
SL0017	9,380	XFMR Rating	900	0	5,000	5,900	63%
SOCO12	11,231	Getaway Rating	11,214	0	0	11,214	99%
STPE12	11,231	Getaway Rating	10,337	0	0	10,337	92%
TOME12	9,071	Getaway Rating	11,052	0	0	11,052	122%
TULA13	11,231	Getaway Rating	419	0	9,750	10,169	91%
TULA14	11,231	Getaway Rating	219	0	7,375	7,594	68%
VNBU12	9,287	Conductor Rating	8	0	5,000	5,008	54%

2.3 Minimum Daylight Load

PNM routinely reviews distribution feeder load to allocate system models and perform planning studies. Minimum daylight load (MDL) is defined as the lowest kW reading by the feeder meter during daylight hours. PNM defines mountain time zone daylight hours in New Mexico as shown in Table 2-3.

Table 2-3: Daylight Time Periods for PV Studies

7 AM - 7 PM	8 AM - 5 PM	8 AM - 4 PM
April	March	January
May	September	February
June	October	November
July		December
August		

Feeder load data was reviewed from October 1, 2024, through Sept 31, 2025. Two data sources were reviewed to understand the coincident behavior of loads and generation sources on each distribution feeder.

- **Feeder Meter Readings** - 15-minute load data was reviewed for each distribution feeder meter to understand the net feeder load during the previous 12-month period.
- **PV Facility Profiler Readings** - Large-scale PV facilities are metered individually at up to 5-minute intervals and stored in PNM's Profiler system.

Analyzing these data sets was necessary to understand gross load, which represents customer demand. The feeder meter readings are considered the net load. Profiler readings document the output of large-scale solar facilities. Rooftop PV facility output is estimated using the CoGen report. Gross load is necessary to understand when allocating distribution planning models. Gross load is calculated as the summation of net load and output of generating facilities shown in Equation 2-1 below.

Equation 2-1: Gross Feeder Load

$$\text{Gross Load} = \text{Net Load} + \text{PV Output}$$

PNM has developed the analysis using the actual daylight minimum loads to identify the minimum load timeframe.

2.3.1 Minimum Daylight Gross Load

12 months of load and generation data were reviewed to understand the coincident behavior of load and PV output for each distribution feeder. Minimum daylight gross load (MDGL) is defined as the lowest customer demand during daylight hours. Table 2-4 shows the MDGL for each distribution feeder in the study at the specified Daylight Minimum Load. PNM does not have

telemetry for rooftop solar facilities. Rooftop PV is further discussed in Section 2.3.9. It is assumed for PNM studies that rooftop PV facilities are operating at Solar Irradiance output during the minimum daylight load time. Capacitor banks supply reactive power to distribution feeders. At this step in the data review/cleanup process, capacitor bank status is not determined. As a result, the kVAR values shown in Table 2-4 are estimated values based on calculations using the feeder meter readings and the PV Profiler readings. Where minimum daylight gross load kVAR demand is negative, it is likely that capacitor banks are supplying reactive power to the distribution feeder. When building Synergi models, capacitor bank status is reviewed to improve the accuracy of the power flow analysis results.

Table 2-4: Minimum Daylight Gross Load

Feeder	kW	kVAR	kVA	Power Factor %	Date
A10012	-6,323	3,327	7,145	-88.5	04/20/2025 12:00 PM
A10083	-4,355	2,224	4,890	-89.1	03/13/2025 01:00 PM
ARIB11	-7,900	-200	7,903	-100.0	05/25/2025 08:00 AM
COLL12	-7,752	1,860	7,972	-97.2	03/30/2025 02:00 PM
DEMW11	43	-10	44	-97.4	05/04/2025 10:00 AM
ELCE11	-6,624	3,522	7,502	-88.3	10/17/2024 11:15 AM
ELCE12	896	-1,055	1,384	-64.7	04/29/2025 12:15 PM
GOLD13	566	-1,272	1,392	-40.7	03/13/2025 02:30 PM
HOND11	167	-1,314	1,325	-12.6	11/21/2024 12:30 PM
HOND12	-7,899	2,466	8,275	-95.5	02/20/2025 11:45 AM
JARA12	-8,049	2,911	8,559	-94.0	03/16/2025 11:45 AM
LD0318	1,000	-620	1,177	-85.0	03/30/2025 12:15 PM
LD1000	50	-520	522	-9.6	04/19/2025 05:00 PM
LSMO12	-9,400	1,100	9,464	-99.3	03/29/2025 12:15 PM
LSMO21	-6,247	1,442	6,411	-97.4	03/13/2025 01:00 PM
LOHO12	-8,024	1,835	8,231	-97.5	03/12/2025 10:00 AM
LOHO13	-10,350	1,792	10,504	-98.5	04/06/2025 01:30 PM
LOHO14	-9,829	1,196	9,901	-99.3	09/17/2025 04:00 PM
PROG13	-4,748	492	4,773	-99.5	05/20/2025 11:30 AM
SCEN12	-8,865	4,810	10,086	-87.9	04/03/2025 01:00 PM
SL0017	760	360	841	90.4	04/29/2025 02:15 PM
SOCO12	-7,584	3,585	8,389	-90.4	04/03/2025 03:00 PM
STPE12	-7,183	3,301	7,905	-90.9	05/14/2025 11:30 AM
TOME12	-8,800	2,800	9,235	-95.3	03/18/2025 04:15 PM
TULA13	23	3	23	99.2	03/12/2025 12:45 PM
TULA14	278	-232	362	-76.8	05/02/2025 01:30 PM
VNBU12	310	200	369	84.0	06/01/2025 07:00 AM

2.3.2 Minimum Daylight Load

Once the minimum daylight gross load value was determined, the input data sources were reviewed. The feeder meter reading during the minimum daylight gross load time was recorded for use in allocating the Synergi model. Table 2-5 shows the minimum daylight load (feeder meter reading) coincident with the minimum daylight gross load for each distribution feeder in the study.

Table 2-5: Minimum Daylight Load

Feeder	Amps A	Amps B	Amps C	kW	kVA	Power Factor %	Date
A10012	325	321	316	-6,323	7,145	-88.5	04/20/2025 12:00 PM
A10083	214	231	212	-4,355	4,890	-89.1	03/13/2025 01:00 PM
ARIB11	362	367	351	-7,900	7,903	100.0	05/25/2025 08:00 AM
COLL12	371	363	365	-7,752	7,972	-97.2	03/30/2025 02:00 PM
DEMW11	2	4	1	43	44	-97.4	05/04/2025 10:00 AM
ELCE11	338	345	339	-6,624	7,502	-88.3	10/17/2024 11:15 AM
ELCE12	71	62	62	896	1,384	-64.7	04/29/2025 12:15 PM
GOLD13	55	56	61	566	1,392	-40.7	03/13/2025 02:30 PM
HOND11	54	54	55	167	1,325	-12.6	11/21/2024 12:30 PM
HOND12	341	339	339	-7,899	8,275	-95.5	02/20/2025 11:45 AM
JARA12	405	379	380	-8,049	8,559	-94.0	03/16/2025 11:45 AM
LD0318	57	50	49	1,000	1,177	-85.0	03/30/2025 12:15 PM
LD1000	34	41	6	50	522	-9.6	04/19/2025 05:00 PM
LSMO12	431	433	434	-9,400	9,464	-99.3	03/29/2025 12:15 PM
LSMO21	293	295	289	-6,247	6,411	-97.4	03/13/2025 01:00 PM
LOHO12	380	369	375	-8,024	8,231	-97.5	03/12/2025 10:00 AM
LOHO13	477	476	482	-10,350	10,504	-98.5	04/06/2025 01:30 PM
LOHO14	453	447	448	-9,829	9,901	-99.3	09/17/2025 04:00 PM
PROG13	210	223	223	-4,748	4,773	-99.5	05/20/2025 11:30 AM
SCEN12	466	458	455	-8,865	10,086	-87.9	04/03/2025 01:00 PM
SL0017	28	27	57	760	841	90.4	04/29/2025 02:15 PM
SOCO12	373	382	394	-7,584	8,389	-90.4	04/03/2025 03:00 PM
STPE12	359	350	376	-7,183	7,905	-90.9	05/14/2025 11:30 AM
TOME12	435	419	406	-8,800	9,235	-95.3	03/18/2025 04:15 PM
TULA13	0	9.3	0	23	23	99.2	03/12/2025 12:45 PM
TULA14	15	17	19	278	362	-76.8	05/02/2025 01:30 PM
VNBU12	17	17	17	310	369	84.0	06/01/2025 07:00 AM

2.3.3 Large-Scale PV Output

Several of the study feeders presently serve large-scale PV facilities. The coincident output of these facilities during the minimum daylight load time was used to define the PV facility generation output during the load allocation process. PNM records large-scale PV facility output using the Itron Profiler meter data visualization software. Table 2-6 shows the coincident output of each existing large solar facility within the study. The present rated output of each facility is also shown for reference.

Table 2-6: Large PV Facility Minimum Daylight Load Coincident Output

Feeder	Facility Name	Profiler #	Interrupter #	Present Rated Output kVA	kW	kVAR	Date
A10012	Otero	61512	SN008	7,500	-7,796	1,691	04/20/2025 12:00 PM
A10083	Alamo Airport	61506	SN004	5,000	-5,270	1,332	03/13/2025 1:00 PM
ARIB11	San Miguel	61538	SN1024L	10,000	-9,959	733	05/25/2025 8:00 AM
COLL12	Vista	61510	SN007	8,400	-8,287	697	03/30/2025 2:00 PM
ELCE11	Meadow Lake	61516	SN009	9,000	-8,731	1,605	10/17/2024 11:15 AM
HOND12	Deming	61504	SN003	9,000	-8,728	2,154	02/20/2025 11:45 AM
JARA12	Rio Comm	61526	SN1016V	10,000	-9,795	695	03/16/2025 11:45 AM
LOHO12	Facebook 3	61532	SN1021	10,000	-9,954	670	03/12/2025 10:00 AM
LOHO13	Santolina	61522	SN1014	11,000	-9,943	655	04/06/2025 1:30 PM
LOHO14	Facebook 2	61530	SN1020	10,000	-10,014	642	09/17/2025 4:00 PM
LSMO12	Facebook 1	61528	SN1019	10,000	-9,974	673	03/29/2025 12:15 PM
LSMO21	Los Lunas	61502	SN002	7,000	-6,908	1,330	03/13/2025 1:00 PM
PROG13	Sandoval	61518	SN010	6,000	-6,198	1,670	05/20/2025 11:30 AM
SCEN12	Rio Rancho	61544	SN1026V	10,000	-7,764	2,105	04/03/2025 1:00 PM
SOCO12	South Valley	61524	SN1017	10,000	-9,888	3,147	04/03/2025 3:00 PM
STPE12	Santa Fe	61520	SN1018F	10,000	-9,199	2,396	05/14/2025 11:30 AM
TOME12	Rio De Oro	61536	SN1023V	10,200	-10,130	2,446	03/18/2025 4:15 PM

Note: Negative kW indicates generation being delivered to the distribution feeder.

2.3.4 Community Solar Interconnection List

Several of the study feeders have community solar interconnection studies performed. Because these community solar projects were not online during the data review timeframe, these community solar projects were interconnected to these feeders after allocating the models for the existing scenario. Table 2-7 shows the community solar interconnection feeders list.

Table 2-7: Community Solar Interconnection feeders list

Feeder	Facility Name	Present Rated Output kVA
A10083	SLT Otero Pluma LLC	3,500
ELCE12	USS Meadow Lake Solar	3,000
HOND11	Rockhound CSol Power LLC	4,000
	Bergmann PPC New Energy LLC	4,650
LD1000	Raven Sol CSol Power LLC	5,000
LD0318	SLT Hidalgo Pluma LLC	3,750
	Los Ebanistas Fletcher Solar LLC	1,665
SL0017	SLT Grant Pluma LLC	5,000
TULA13	Reynolds Pluma LLC	5,000
	Tularosa II - SVOE LLC	4,750
TULA14	Tularosa I - SVOE LLC	2,875
	Tularosa III - SVOE LLC	4,500
VNBU12	Gonzo Sol CSol Power LLC	5,000

2.3.5 SGIA Interconnection List

Several of the study feeders have SGIA Interconnection. These SGIA projects were interconnected to these feeders after allocating the models for the existing scenario. Table 2-8 shows the SGIA interconnection feeders list.

Table 2-8: SGIA Interconnection feeders list

Feeder	Facility Name	SGIA Additional kVA
A10012	SGI-2012-06	2,000
DEMW11	SGI-2017-09	8,250
GOLD13	SGI-2017-08	11,000
LSMO21	SGI-2012-04	2,000
PROG13	SGI-2013-03	2,600

2.3.6 BESS Interconnection List

Two of the study feeders have BESS Interconnection. These BESS projects were interconnected to these feeders after allocating the models for the existing scenario. Table 2-9 shows the BESS interconnection feeders list.

Table 2-9: BESS Interconnection feeders list

Feeder	Present Rated Output kVA
SOC012	2,000
TOME12	2,000

2.3.7 Distribution Feeder Equipment Status

Once the minimum daylight load time was determined for each distribution feeder, dynamic equipment was reviewed for setting the proper status when allocating the Synergi model. Some distribution feeders within the study contain line voltage regulators. Existing documentation was reviewed for defining the appropriate setpoints within the Synergi model.

PNM utilizes distribution line capacitors for power factor correction and voltage support. Some are connected as fixed banks. Others are switched banks and are remotely controlled by the Volt Var Management System (VVMS) program or by local voltage control. The VVMS polls the System Control and Data Acquisition (SCADA) system for real-time loading information on each distribution feeder to determine if a capacitor bank needs to be switched ON or OFF based on power factor control set points and available capacitor bank size. If called for, the next available VVMS controlled capacitor bank will be switched ON if the VAR requirement is at least 60% of the bank size and switched OFF if the VAR requirement is 80% of the bank size. Power factor set points are changed seasonally but are always set for a slight lead (system will attempt to deliver VARs into transmission). Where available, VVMS records were reviewed during each of the feeder minimum daylight load times to determine the status of switchable capacitor banks to correctly set each device in the model. However, this program is not available in all regions of the PNM service territory due to communications constraints. Where this VVMS system is not available, local voltage control is often used. Assumptions for capacitor status were made on feeders where the VVMS records are not available.

2.3.8 Primary Metered Customers

Some large customers served by the distribution system have primary meters. Where available, primary meter data was reviewed to understand the coincident demand of these large customers during the minimum daylight load time. The coincident demand of these customers was defined in the Synergi model and used for load allocation to represent the distribution feeder more accurately during the minimum daylight load time. Not all distribution feeders have large customers that utilize primary metering.

2.3.9 Rooftop PV Output

Rooftop PV is distributed throughout many of the feeders analyzed in this study. PNM does not have telemetry at these smaller rooftop PV facilities. Assumptions must be made for the coincident output of these rooftop facilities during the minimum daylight load time. Rooftop PV facilities will be assumed to operate in accordance with a PNM-developed region solar irradiance profile. There are several irradiance profiles for different divisions in the PNM System, as well as a New Mexico Average (NM Average) irradiance profile. For this project, the percent output of the solar irradiance for NM Average is compared to the individual division Irradiance and allocated to the highest percent output for the Rooftop PV.

2.4 Hosting Capacity Planning Criteria

Thermal loading and voltage are the main criteria that influence hosting capacity analysis within the Synergi software platform. PNM standard planning criteria were applied to this hosting capacity analysis.

2.4.1 Thermal Loading Criteria

- Equipment, conductors, and cables should not exceed 100% of the normal rating.
- PNM operates a 600 Amp standard system. Phase amperage should not exceed 600 Amps for any configuration.
- Protective devices (relays, reclosers, sectionalizers, fuses) should not exceed 90% of the device pickup, or 90% of the device normal rating if capable of directionality.

2.4.2 Primary Voltage Criteria

Steady state planning efforts will ensure that all customers in the study area are served within the ANSI C84.1 Range A limits as shown in

Table 2-10 below.

Table 2-10: Primary Voltage Criteria

	Minimum		Maximum	
	% Drop	Voltage	% Rise	Voltage
Range A	3.5	118.7	2.4	126
Range B	6.9	114.6	3.3	127

2.5 Synergi Electric Distribution Feeder Models

Distribution planning models are used to evaluate the electric distribution system from many different perspectives. PNM assets are modeled in Schneider Electric's ArcFM global information system (GIS) platform and updated regularly. Synergi Electric, created by DNV, is the software that PNM distribution planners use on a regular basis to conduct studies. Synergi Electric will pull asset information from the GIS platform to construct a planning model that can perform power flow analysis and other various simulations.

2.5.1 Synergi Planning Model Load Allocation

Power flow simulations are most often used to understand system impacts during times of maximum load. During maximum load the system is most constrained, and historically, damage to equipment is most likely to occur. However, when studying PV interconnections, minimum daylight load is a scenario that is important to evaluate. During minimum daylight load, PV generation can coincidentally be operating at maximum output. In this instance, there is minimal customer load to consume excess PV generation locally. This scenario results in the greatest amount of excess PV generation, which can increase power flow on a distribution feeder and stress the PNM system in the same way as high load. Hosting capacity analysis is focused on interconnecting new PV capacity to distribution feeders, so minimum daylight load is the foundation that distribution planning models were based on for this study.

Several data sources were reviewed for each feeder to understand customer load and existing generation during the minimum daylight load time. 15-minute feeder load data was gathered to understand the power flow observed at the feeder head. If large-scale solar facilities exist on the feeder, Profiler meter data was reviewed to understand solar generation output. Large primary metered customer load data was also reviewed as applicable. These data sources were evaluated together to understand coincident behavior of customer loads, generating facilities, and primary metered customers to determine an appropriate minimum daylight load time. At the minimum daylight load time, equipment status was reviewed for voltage regulators, capacitors, and other dynamic devices.

The following process was followed to allocate the planning model once all input data was gathered. Once the planning model was allocated and verified, hosting capacity analysis could be performed.

- Set rooftop solar to solar irradiance % output of nameplate DC rating. The Synergi model also maintains a record of the AC inverter rating at each facility. The AC inverter rating can limit the output of the generator if the DC component is overbuilt.
- Set large-scale solar facilities to the coincident output during the minimum daylight load time.
- Set primary metered customers to the coincident demand during the minimum daylight load time.
- Set capacitors and voltage regulating equipment to proper status during the minimum daylight load time.
- Set protective devices to the appropriate pickups/ratings.
- Set feeder rating and other limiting factors.
- Set the feeder meter to the coincident feeder load using phase amps and power factor during the minimum daylight load time.
- Allocated model using connected kVA method.
- Adjust all solar facilities (large-scale PV) to 100% output of nameplate DC rating. This adjustment is performed to represent a worst-case scenario for the distribution feeder with the understanding that the time-of-day minimum daylight load is observed can change from year to year.
- Perform power flow analysis to confirm model parameters and results.

3.0 Hosting Capacity Analysis Approach

Hosting capacity analysis is a tool used by many utilities to evaluate the limitations of the existing system for hosting future PV interconnections. Hosting capacity results give insights into the distribution system for planners and utility employees. Results can also be helpful for utility customers and solar developers looking to identify potential sites for new generation projects. There are various methods used to conduct hosting capacity analysis and each method provides a different perspective of the utility system. When hosting capacity is limited, it is an indication that additional study should be considered before interconnecting more generation. The focus of this study report is to use hosting capacity analysis to better understand the individual limits of each unique distribution feeder for hosting additional PV capacity and understand system level trends.

3.1 Synergi Electric and Hosting Capacity Analysis

Synergi Electric is a distribution planning software sold by DNV Group, headquartered in Oslo, Norway. It is used by many electric utilities in North America for planning and analyzing the distribution system. PNM uses Synergi Electric to perform area planning studies, contingency planning studies, PV interconnection impact studies, and protection coordination studies. Synergi Electric also provides several different hosting capacity methods that can be used by distribution planners to understand the impacts to the distribution system from increasing PV penetration. Each method has a specific purpose that aligns with the desired objective. The objectives of this study report were to understand the maximum amount of new generation that can be interconnected to distribution feeders and to understand the spread of available hosting capacity by generating heat maps that show hosting capacity for all line sections of the distribution feeder. The incremental hosting capacity method aligned best with these objectives.

3.1.1 Incremental Hosting Capacity Method

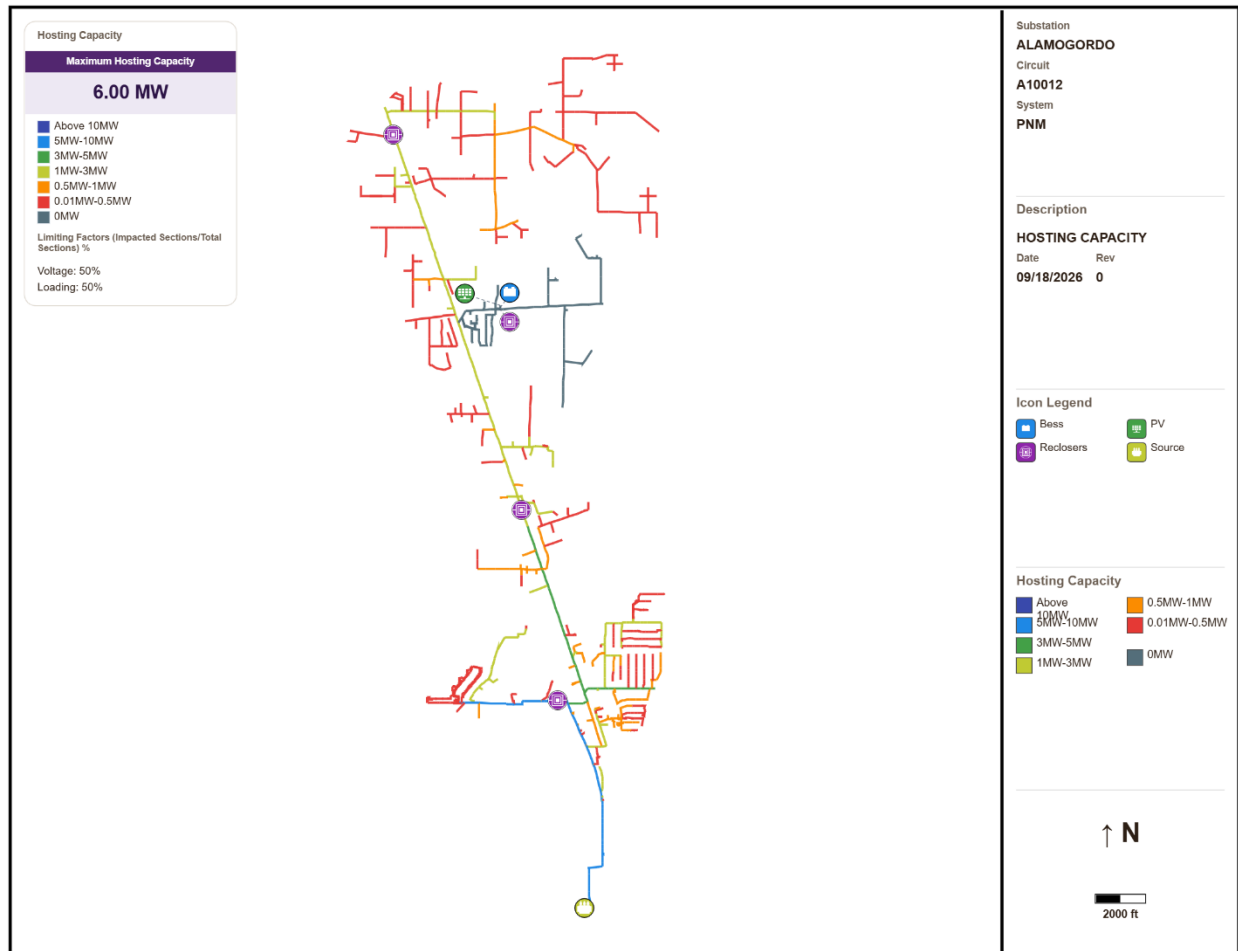
The incremental hosting capacity analysis method evaluates the limitations of hosting new generation on every line section within the distribution feeder model. Heat maps can be generated to display the study results for every line section on the feeder and gain insights into where on the distribution feeder new generation capacity should be able to successfully interconnect. This incremental hosting capacity method is used by many utilities in North America because analysis can be performed relatively quickly and can be visualized geo-spatially. Often, results are shared online through public maps that all customers can access.

3.1.2 Interpreting Hosting Capacity Heat Maps

Hosting capacity heat maps are used by many electric utilities to share the results of hosting capacity studies in a visual format. The analysis generates specific results for each line section, but for the purposes of visualizing results, several ranges for hosting capacity are listed and correspond to a specific color. Figure 3-1 shows an example of a hosting capacity heat map for a single distribution feeder. Where there is the greatest amount of hosting capacity, the line thickness also increases to draw attention to areas where larger generators would have more

success interconnecting. In general, the hosting capacity is greatest near the substation which is identified by the source symbol. Moving away from the substation, the hosting capacity for this feeder decreases. The red lines represent less than 500 kW of hosting capacity. The detailed hosting capacity visuals contained in the appendix explain what may be limiting the hosting capacity of a distribution feeder evaluated in this study. It is important to understand that the hosting capacity of a feeder changes as new generation is added to it. Therefore, it is important to conduct hosting capacity analysis on a regular basis, especially for feeders that are experiencing a high number of interconnection requests.

Figure 3-1: Hosting Capacity Heat Map Example



4.0 Hosting Capacity Analysis

Table 4-1 shows the 27 distribution feeders that are being analyzed in this effort. The feeder rating utilization is calculated by comparing the total approved PV capacity, using the CoGen report and pending SGIA interconnections, against the feeder rating. Several feeders have approved PV capacity beyond the feeder rating identified by a feeder utilization greater than 100% and are highlighted. Analysis for the 27 feeders is summarized and presented in the following sections.

Table 4-1: Distribution Feeders

Feeder	Region	Feeder Rating kVA	Total Approved PV Capacity kVA	Feeder Rating Utilization %
A10012	Alamogordo	11,663	10,648	91%
A10083	Alamogordo	11,663	10,773	92%
ARIB11	Las Vegas	11,231	10,332	92%
COLL12	Valencia	9,071	9,843	109%
DEMW11	Deming	9,370	8,306	89%
ELCE11	Valencia	11,231	9,400	84%
ELCE12	Valencia	11,231	4,172	36%
GOLD13	Deming	12,429	11,354	91%
HOND11	Deming	10,039	8,898	89%
HOND12	Deming	10,039	9,158	91%
JARA12	Valencia	11,231	10,064	90%
LD0318	Lordsburg	7,500	5,800	77%
LD1000	Lordsburg	7,500	5,975	80%
LSMO12	Valencia	11,231	10,249	91%
LSMO21	Valencia	9,287	11,036	119%
LOHO12	ABQ West	11,231	10,038	89%
LOHO13	ABQ West	11,231	11,725	104%
LOHO14	ABQ West	11,231	10,000	89%
PROG13	Sandoval	9,935	12,785	129%
SCEN12	ABQ West	9,935	11,262	113%
SL0017	Silver City	9,380	5,900	63%
SOCO12	ABQ West	11,231	11,214	99%
STPE12	Santa Fe	11,231	10,337	92%
TOME12	Valencia	9,071	11,052	122%
TULA13	Alamogordo	11,231	10,169	91%
TULA14	Alamogordo	11,231	7,594	68%
VNBU12	Clayton	9,287	5,008	54%

4.1 Existing System

Initial base case models were created for 27 distribution feeders selected for this study using the process outlined in Section 2.5.1. Table 4-2 shows the Synergi-calculated results for each feeder based on the existing PNM system. Synergi-modeled generation capacity may differ slightly from that documented in the CoGen report. Synergi's maximum hosting capacity represents the amount of additional PV generation that could be interconnected if placed at an optimal location, most often near the substation, where equipment ratings are highest.

Table 4-2: Synergi Hosting Capacity Results

Feeder	Feeder Rating kVA	Synergi Existing Gen kVA	Synergi MDL kW	Synergi MDL kVA	Synergi MDGL kVA	Synergi Maximum Hosting Capacity kVA
A10012	11,663	10,560	-7,464	8,587	2,709	4,200
A10083	11,663	10,458	-7,332	7,742	2,944	4,331
ARIB11	11,231	10,137	-8,005	8,005	2,211	1,067
COLL12	9,071	9,561	-8,393	9,226	299	Thermal Violation
DEMW11	9,370	8,296	-8,015	8,022	126	1,355
ELCE11	11,231	9,383	-6,480	7,295	1,937	2,579
ELCE12	11,231	3,910	-2,042	2,294	1,821	9,621
GOLD13	12,429	11,290	-10,172	10,190	856	2,258
HOND11	10,039	8,855	-7,998	8,072	468	2,282
HOND12	10,039	9,313	-8,139	8,418	714	1,903
JARA12	11,231	10,360	-8,090	8,727	801	3,177
LD0318	7,500	5,894	-4,166	4,261	1,451	3,330
LD1000	7,500	5,545	-4,801	4,946	660	2,695
LSMO12	11,231	10,299	-9,530	9,725	454	1,703
LSMO21	9,287	9,030	-8,278	8,294	728	1,009
LOHO12	11,231	10,287	-7,971	8,037	1,731	3,261
LOHO13	11,231	12,367	-10,749	10,839	1,412	Thermal Violation
LOHO14	11,231	10,152	-9,698	10,013	60	1,535
PROG13	9,935	9,679	-3,798	4,147	5,320	6,133
SCEN12	9,935	11,512	-8,441	8,802	1,916	Thermal Violation
SL0017	9,380	5,806	-3,923	4,202	1,785	5,449
SOCO12	11,231	9,021	-6,146	6,634	2,465	5,087
STPE12	11,231	10,526	-8,022	8,859	1,829	1,062
TOME12	9,071	8,983	-7,494	7,853	746	1,598
TULA13	11,231	10,162	-9,407	9,697	410	1,826
TULA14	11,231	7,703	-6,834	6,998	472	4,397
VNBU12	9,287	5,009	-4,636	4,662	378	5,862

Note: Negative MDL kW indicates reverse power flow on the feeder.

A general trend was observed among the various feeders analyzed considering the results shown in the table above. Maximum hosting capacity for these feeders is often limited by the thermal constraints of PNM equipment. This base case hosting capacity analysis showed the technical limitation to hosting capacity for each distribution feeder. The technical limitations were related to high voltage or thermal overloads. After conducting the analysis, heat maps were created for each distribution feeder to visualize results for each line section. Heat maps and additional study insights are shown in Appendix 6.0.

4.2 Feeders with no Additional Hosting Capacity

Some of the Synergi analyzed feeders were observed to have very little or zero remaining hosting capacity. Where thermal and voltage criteria violations were observed in the base case scenario (See Table 4-2), no hosting capacity remains. Where no additional hosting capacity is available, a large reverse power flow is occurring indicated by the observed large negative minimum daylight load KW. Also, the total existing generation on the feeder is near/exceeding the feeder rating. For these feeders, there is potential for damage to PNM equipment if the existing generation operates at full rated output coincident with minimum daylight gross load. Negative minimum daylight load should be monitored in the field. As the minimum daylight load approaches the feeder rating, thermal and voltage criteria violations, and damage to PNM equipment, may result. Increasing minimum daylight gross load, or system improvements to increase equipment ratings, are required to mitigate thermal violations associated with excess PV generation. Because the amount of load and generation on a feeder can change, new interconnection projects will continue to be reviewed per Rule 568 with Supplemental Reviews or Detailed Studies until further analysis identifies solutions. If the studies show that the system is at risk, restrictions could be placed on the feeder to interconnect additional PV generation, absent customer willingness to pay for the necessary system upgrades.

5.0 Conclusion

Several distribution feeders within the PNM system have large amounts of PV generation connected. High PV penetration can present challenges for operating and maintaining the distribution system. This study was performed to understand the actual limits on distribution feeders for hosting new PV generation in their existing configuration. Table 5-1 shows the Synergi analysis maximum hosting capacity results for the existing system.

Table 5-1: Maximum Synergi Hosting Capacity Analysis Results

Feeder	Feeder Rating kVA	Assumptions	Synergi Max Hosting Capacity kVA	Comments
A10012	11,663	SGIA 2.0 MVA	4,200	
A10083	11,663	3.5 MVA Community Solar Project	4,331	
ARIB11	11,231		1,067	
COLL12	9,071	SGIA 0.47 MVA	0	Thermal Loading Violation
DEMW11	9,370	SGIA 8.25 MVA	1,355	
ELCE11	11,231		2,579	
ELCE12	11,231	3.0 MVA Community Solar Project	9,621	
GOLD13	12,429	SGIA 11 MVA	2,258	
HOND11	10,039	2 Community Solar Projects (Combined 8.65 MVA)	2,282	
HOND12	10,039		1,903	
JARA12	11,231		3,177	
LD0318	7,500	2 Community Solar Projects (Combined 5.42 MVA)	3,330	
LD1000	7,500	5.0 MVA Community Solar Project	2,695	
LOHO12	11,231		3,261	
LOHO13	11,231		0	Thermal Loading Violation
LOHO14	11,231		1,535	
LSMO12	11,231		1,703	
LSMO21	9,287	SGIA 2 MVA	1,009	
PROG13	9,935	SGIA 2.6 MVA	6,133	
SCEN12	9,935		0	Thermal Loading Violation
SL0017	9,380	5.0 MVA Community Solar Project	5,449	
SOC012	11,231	2 MVA BESS	5,087	
STPE12	11,231		1,062	
TOME12	9,071	2 MVA BESS	1,598	
TULA13	11,231	2 Community Solar Projects (Combined 9.75 MVA)	1,826	
TULA14	11,231	2 Community Solar Projects (Combined 7.38 MVA)	4,397	
VNBU12	9,287	5.0 MVA Community Solar Project	5,862	

5.1 Hosting Capacity Analysis Observations

The incremental hosting capacity method, employed in the Synergi Electric software, was used to evaluate all distribution feeders in the study set. Thermal and voltage planning criteria were defined to understand if hosting new PV generation would cause planning criteria to be violated. Maximum hosting capacity values were gathered for each feeder analyzed and hosting capacity heat maps were generated to understand the spread of hosting capacity throughout every line section of each distribution feeder.

5.1.1 Maximum Hosting Capacity - Thermal Constraint

The feeder rating defines the amount of power that can flow on a distribution feeder. Power typically flows from the transmission system through the distribution feeder to PNM customers. However, as PV penetration increases, power can also flow from distributed generators through the distribution feeder and to the transmission system. Power flow, resulting from either customer load or generation, cannot exceed the feeder rating without causing thermal loading criteria violations. If thermal criteria are exceeded, damage to PNM equipment can result. Customer demand, or minimum daylight gross load as defined in this study, can consume excess PV generation on a distribution feeder. If excess PV generation is consumed by local customer load, greater amounts of PV generation can be successfully interconnected to a distribution feeder without experiencing thermal loading violations.

This study focused on understanding hosting capacity of distribution feeders. However, the substation transformer can also be a limiting factor to hosting capacity. Power flow through the substation transformer cannot exceed the normal rating without causing criteria violations and damage to PNM equipment. Where substation transformers are not constructed to the present NM standard size of 33.7 MVA, substation transformers may become a limiting factor to hosting capacity as multiple distribution feeders are often served by a single substation transformer. The substation transformer limitation was not a focus of this study but is a constraint that PNM must consider in future iterations of hosting capacity analysis.

5.1.2 Spread of Hosting Capacity - Thermal & Voltage Constraints

Conductor and equipment ratings define the amount of power that can flow through each line section of a distribution feeder. Power flow, resulting from either customer load or generation, cannot exceed the rating of any conductor or equipment without causing thermal loading criteria violations. Detailed feeder modeling and simulations are necessary to understand the power flow through a distribution feeder and confirm compliance with planning criteria. If power flow analysis identifies existing thermal or voltage violations, the feeder may not be capable of successfully hosting new generation until violations are resolved.

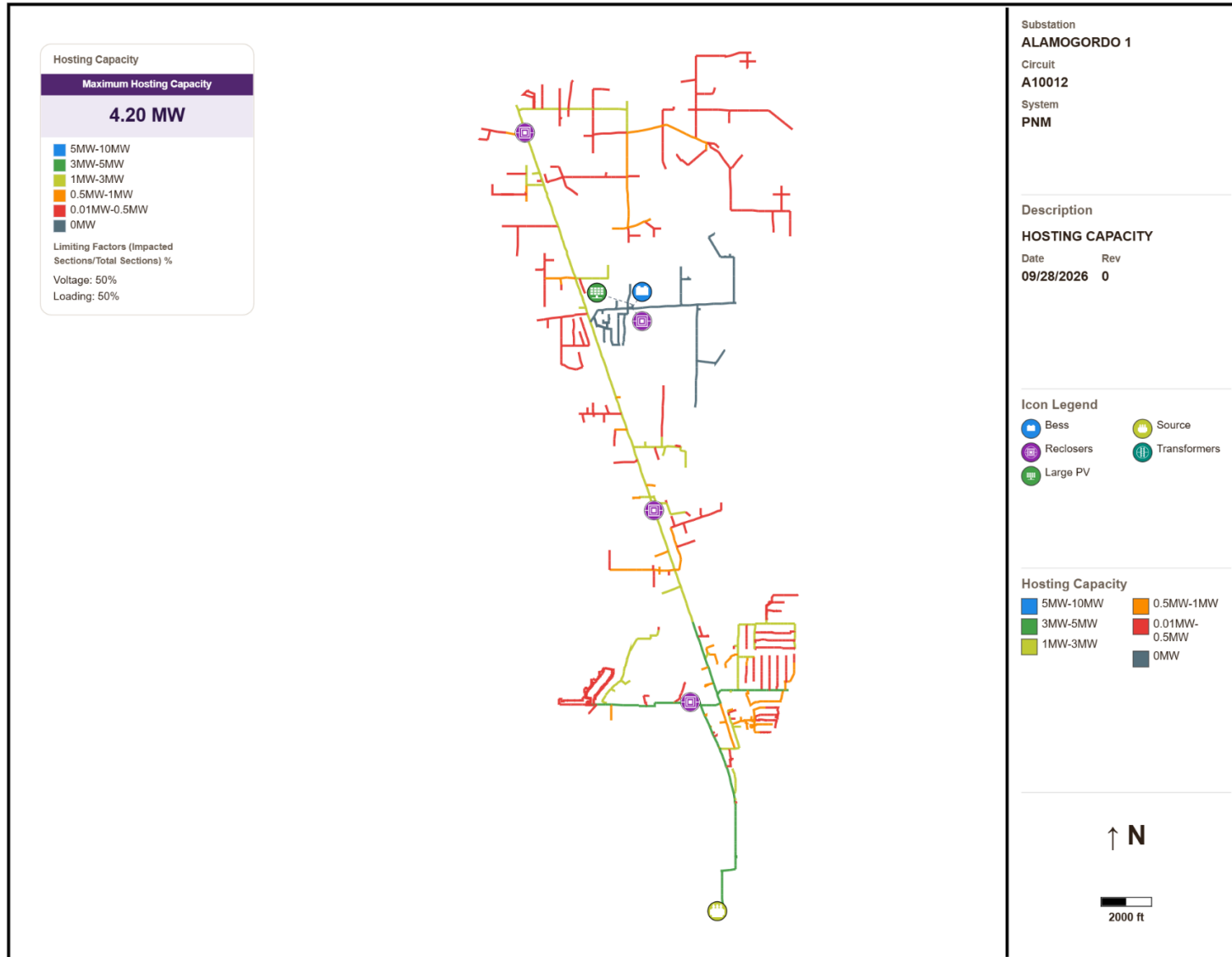
Interconnecting new generation to the distribution system can result in new thermal or voltage violations. Feeder configuration, location of generation and loads, power factor of generation and loads, substation LTC setpoint, equipment ratings, line losses, and other factors influence the impacts of interconnecting new generation. Performing power flow and hosting capacity analysis in Synergi provides additional insights to the impact of new PV generation to the PNM system like

high voltage limits/violations and thermal violations that are not related to the feeder rating. The incremental hosting capacity method is necessary to communicate the spread of available hosting capacity for all line sections through heat maps.

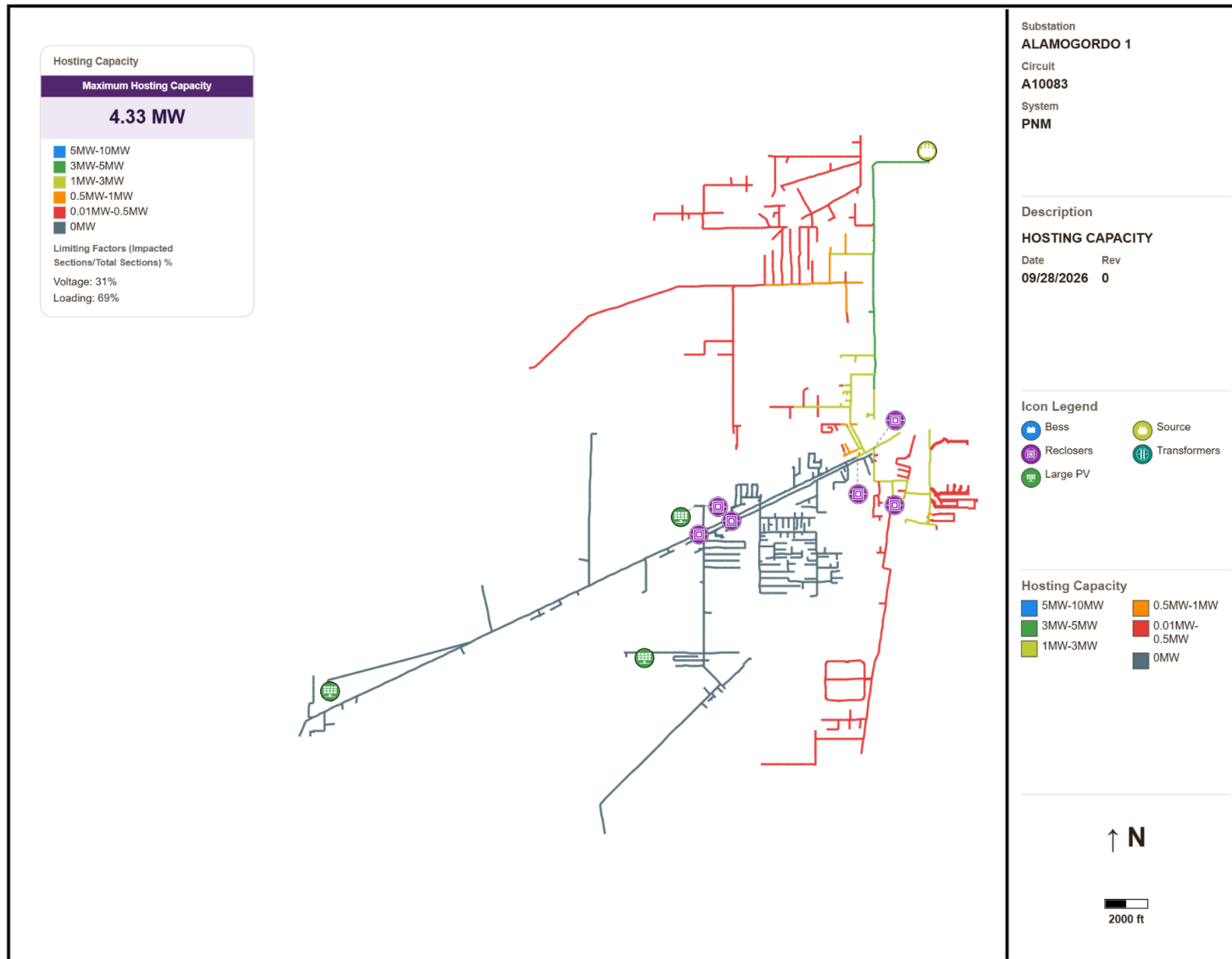
6.0 Appendices

Hosting Capacity Heat Maps

A10012 - Hosting Capacity Heat Map



A10083 - Hosting Capacity Heat Map

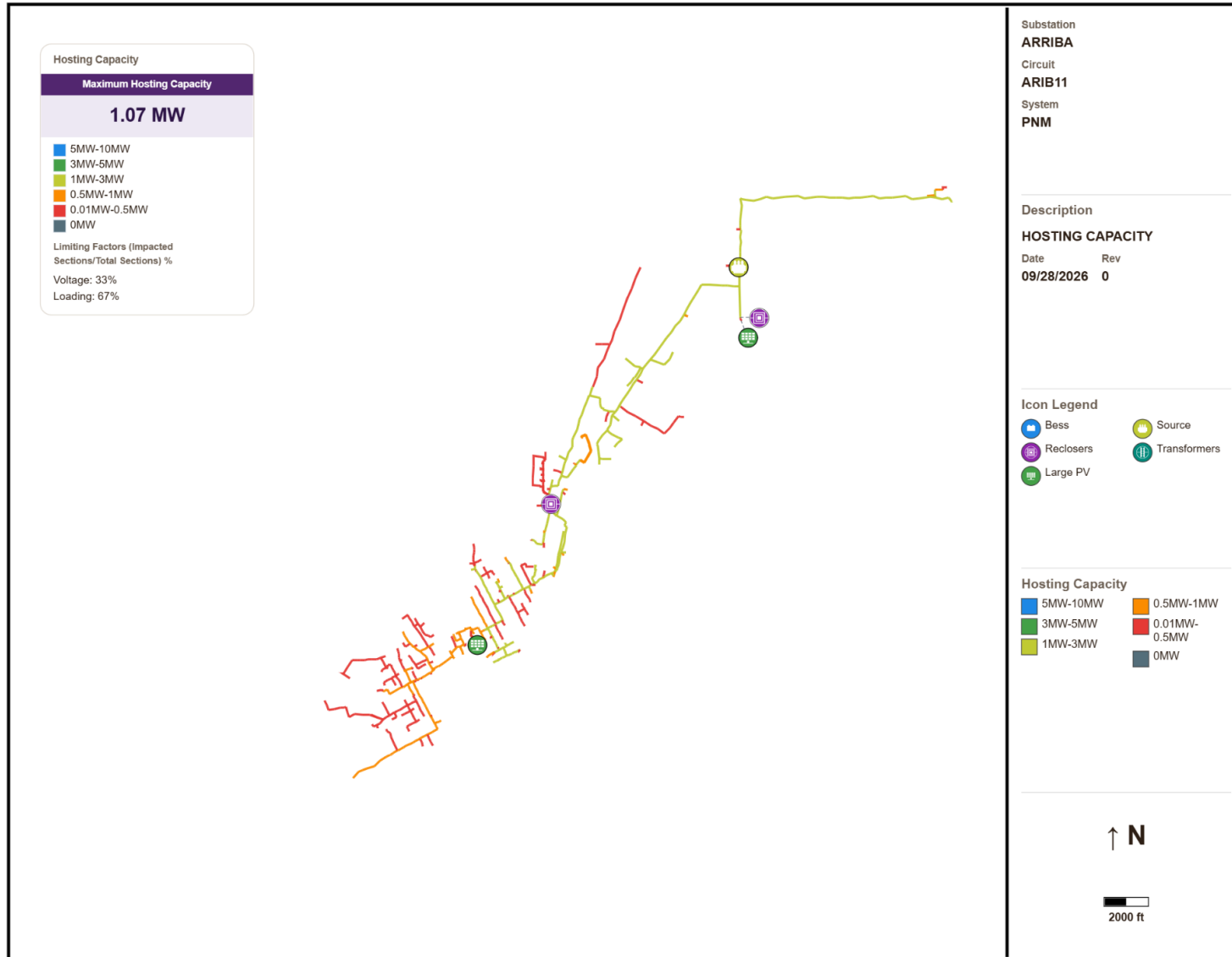


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Hosting Capacity Analysis Refresh 2026

ARIB11 - Hosting Capacity Heat Map

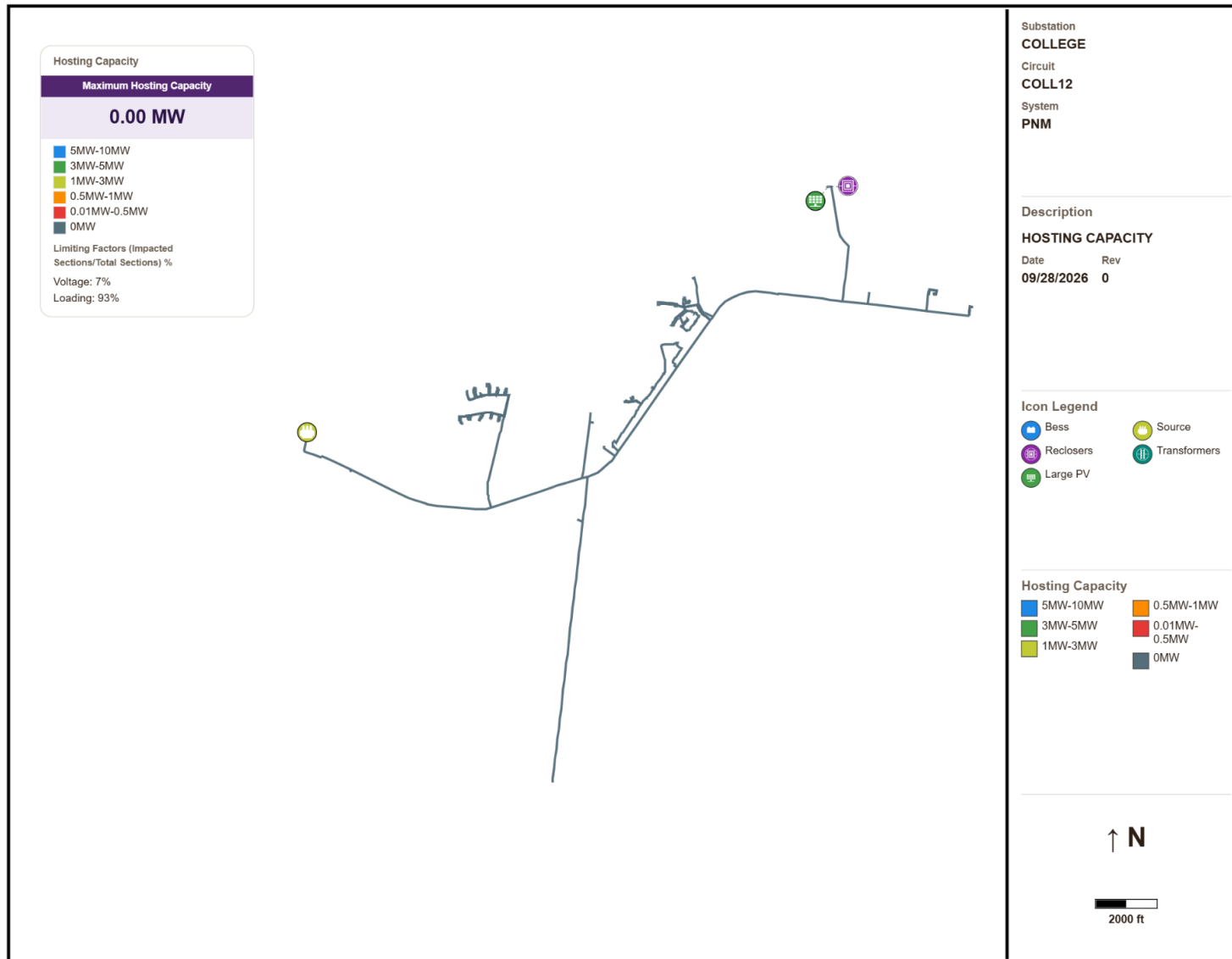


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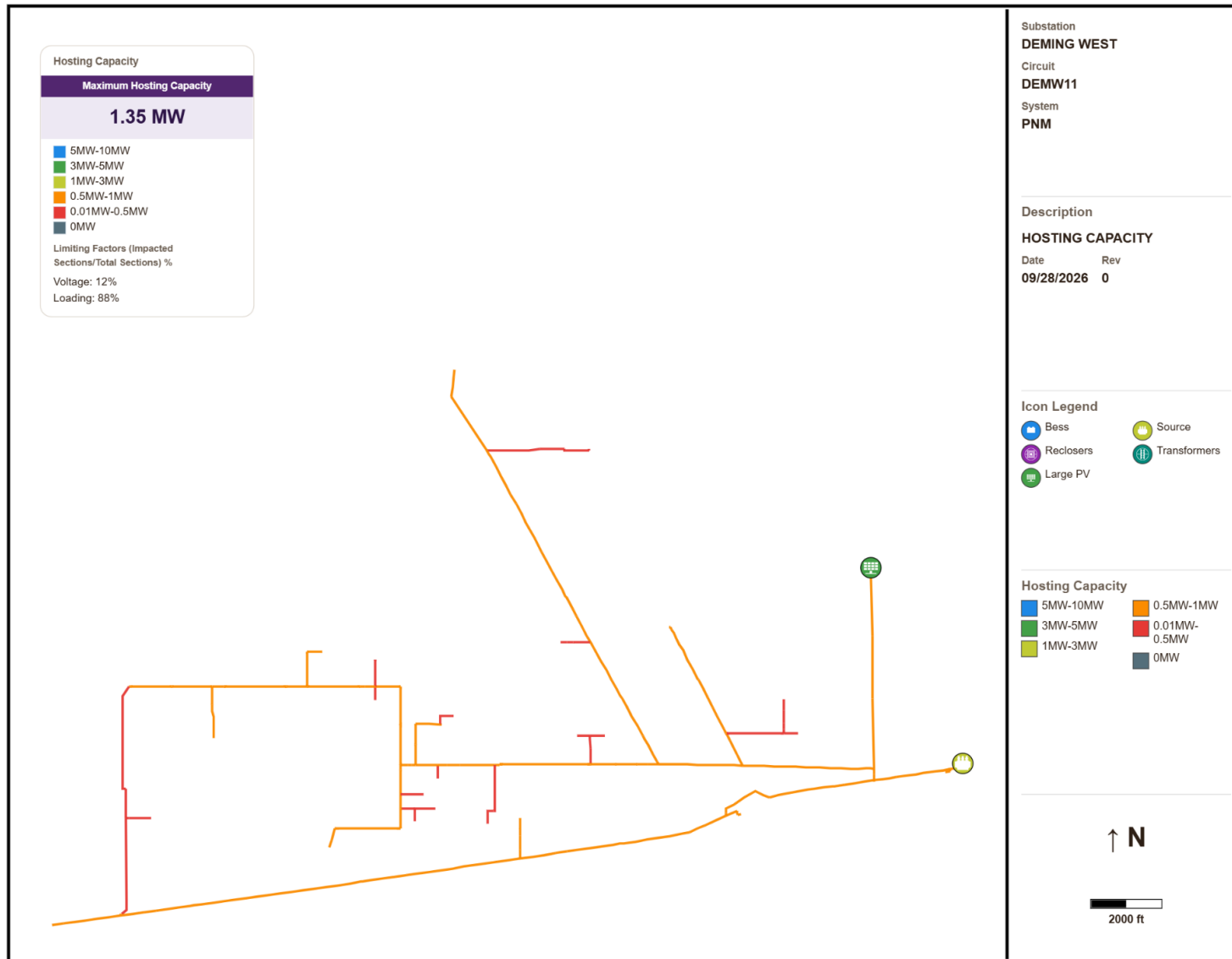
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Hosting Capacity Analysis Refresh 2026

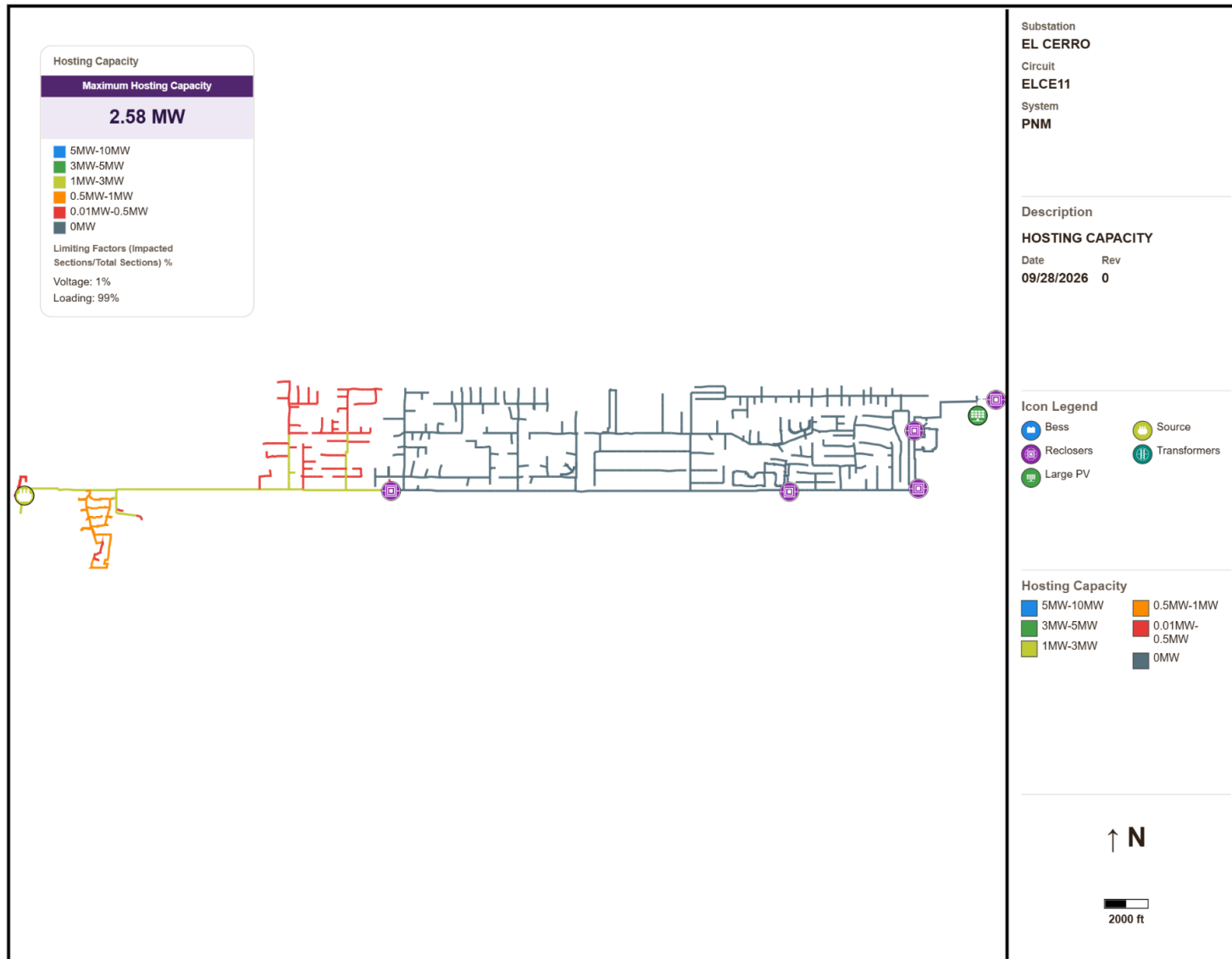
COLL12 - Hosting Capacity Heat Map



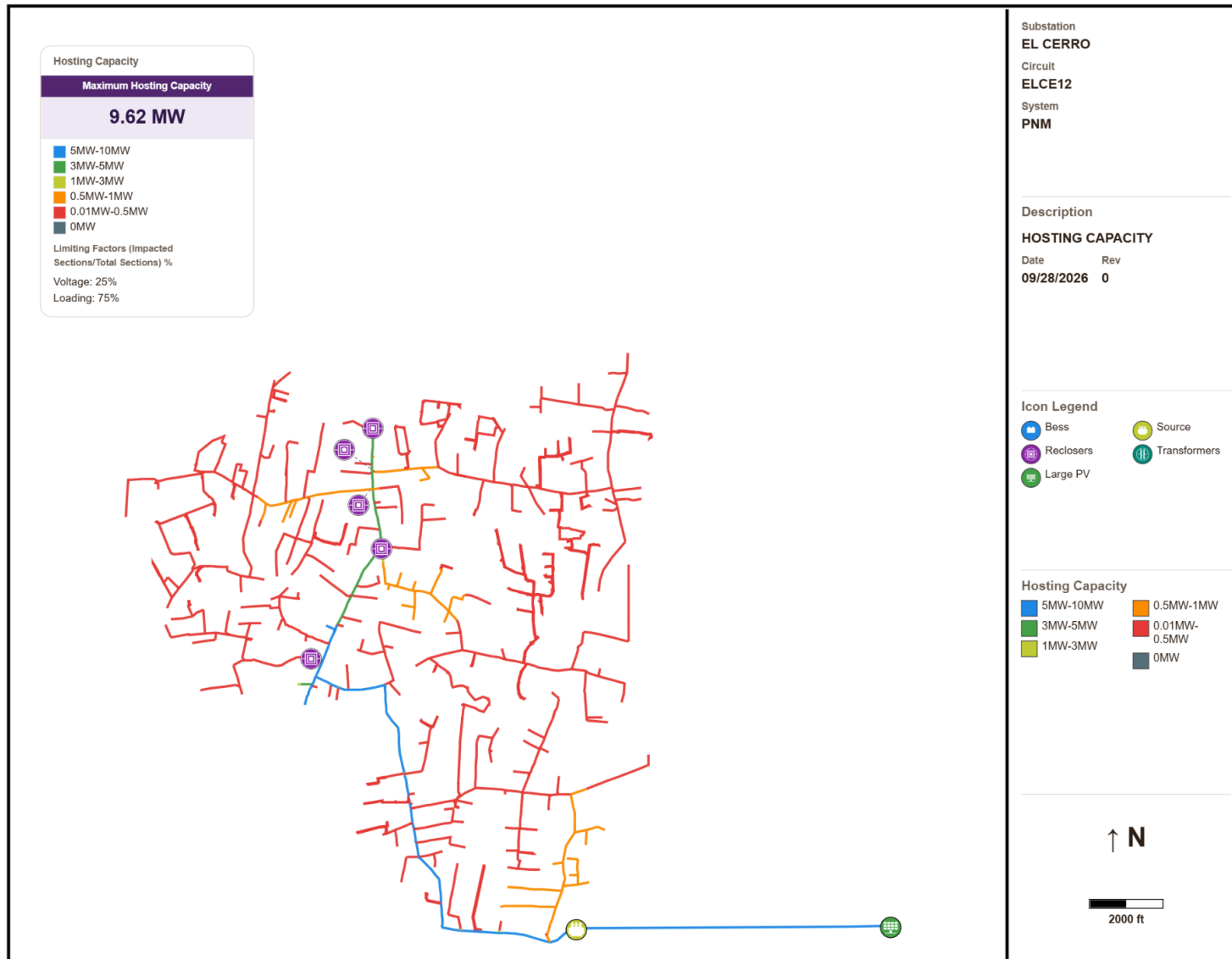
DEMW11 - Hosting Capacity Heat Map



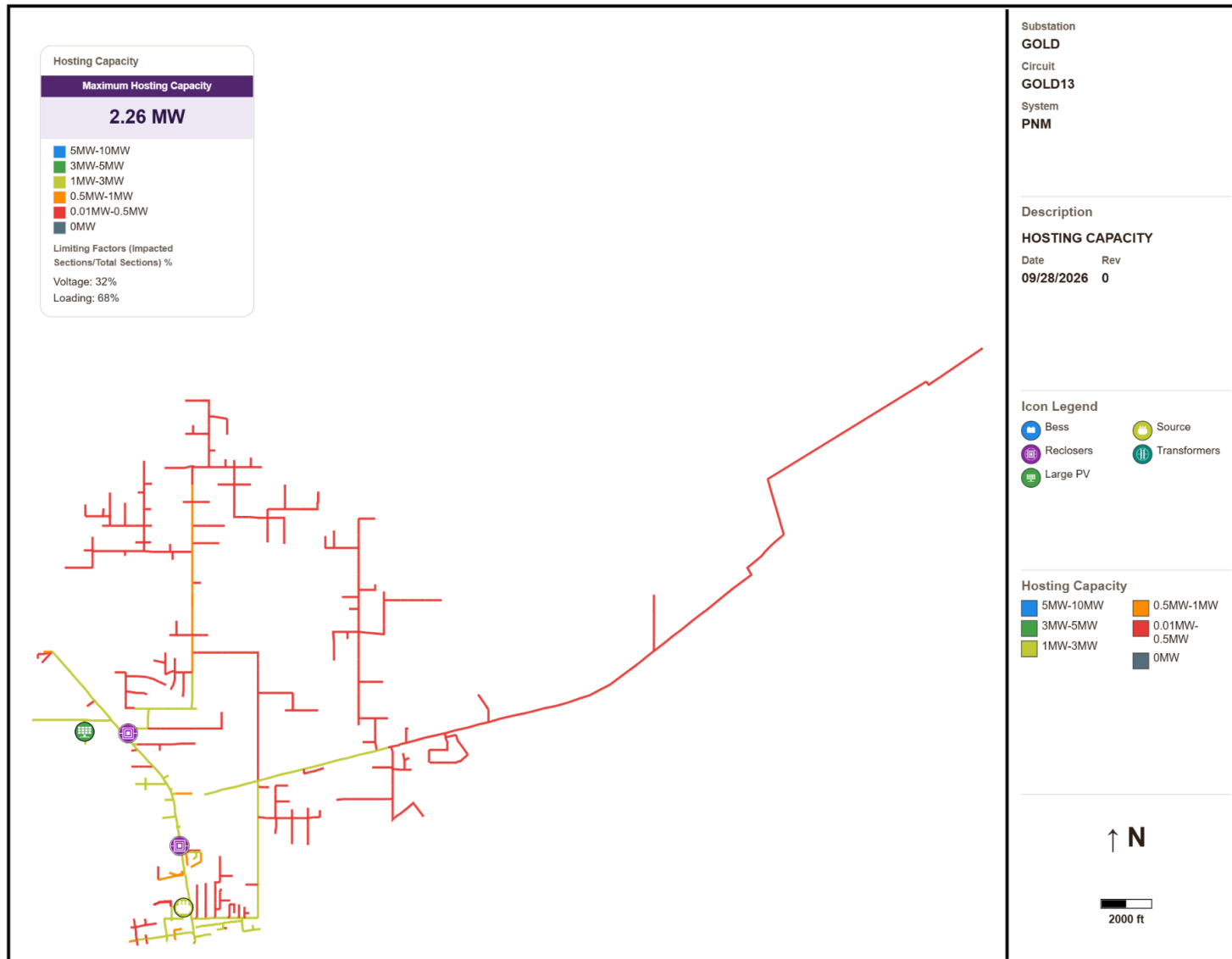
ELCE11 - Hosting Capacity Heat Map



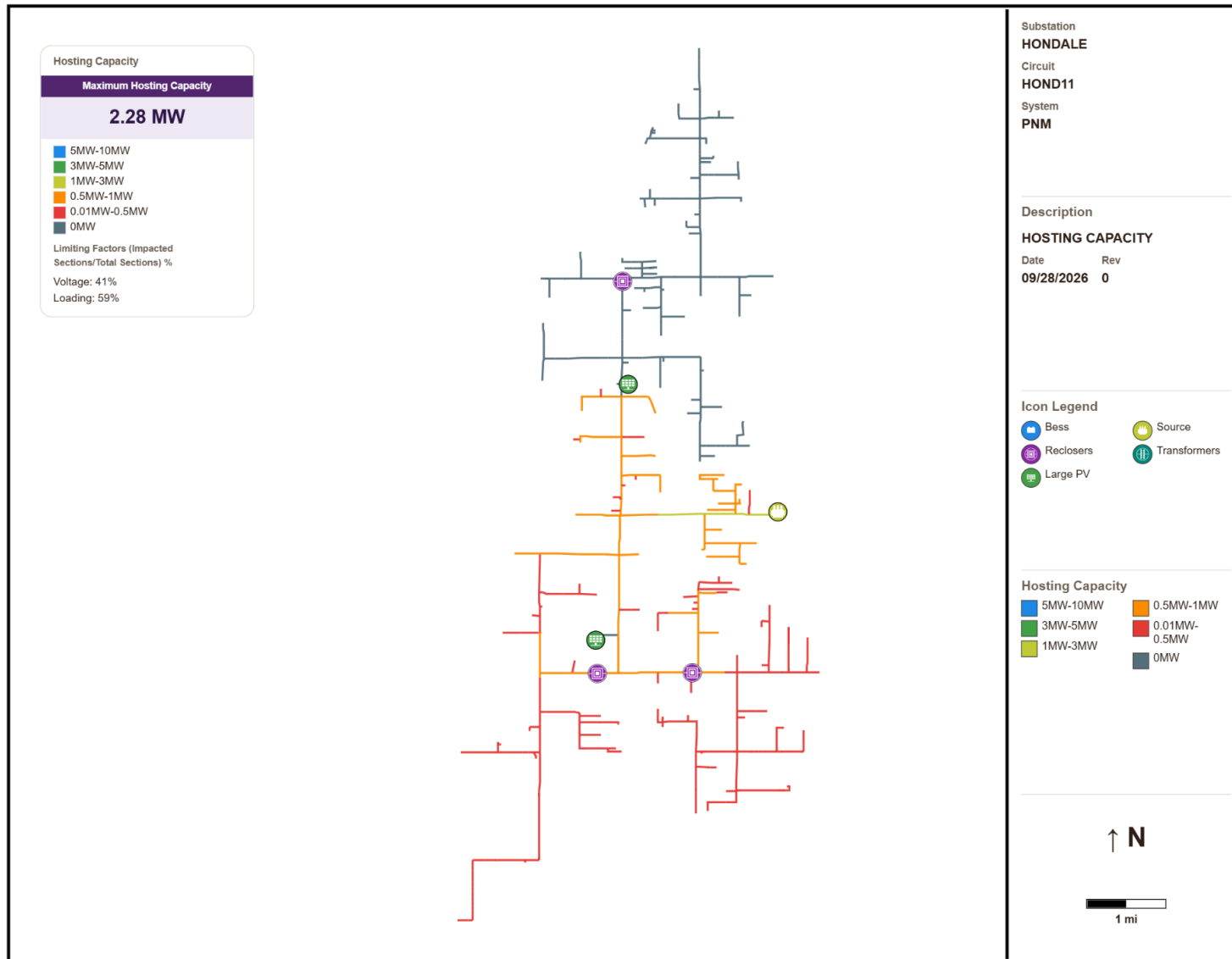
ELCE12 - Hosting Capacity Heat Map



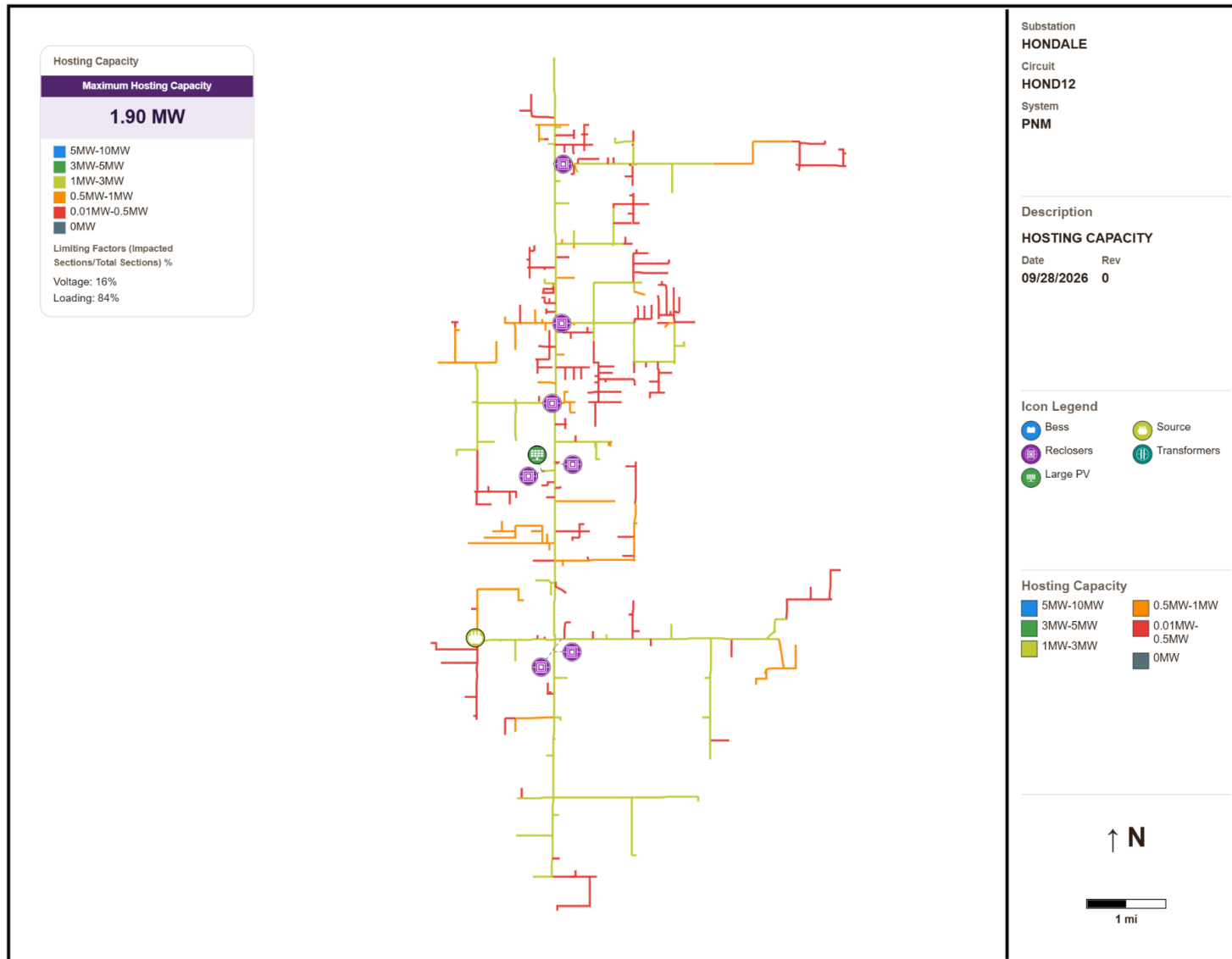
GOLD13 - Hosting Capacity Heat Map



HOND11 - Hosting Capacity Heat Map



HOND12 - Hosting Capacity Heat Map

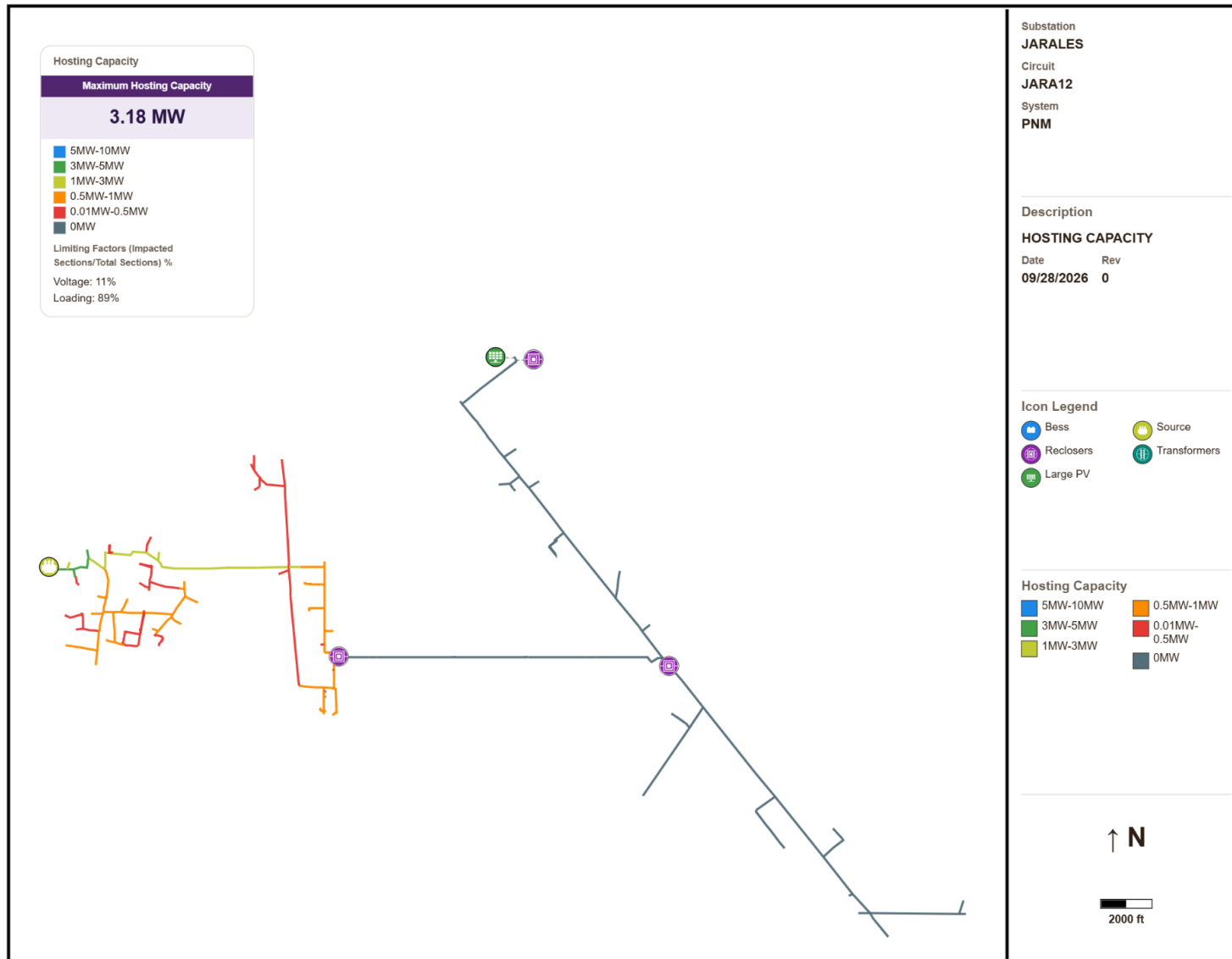


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Hosting Capacity Analysis Refresh 2026

JARA12 - Hosting Capacity Heat Map

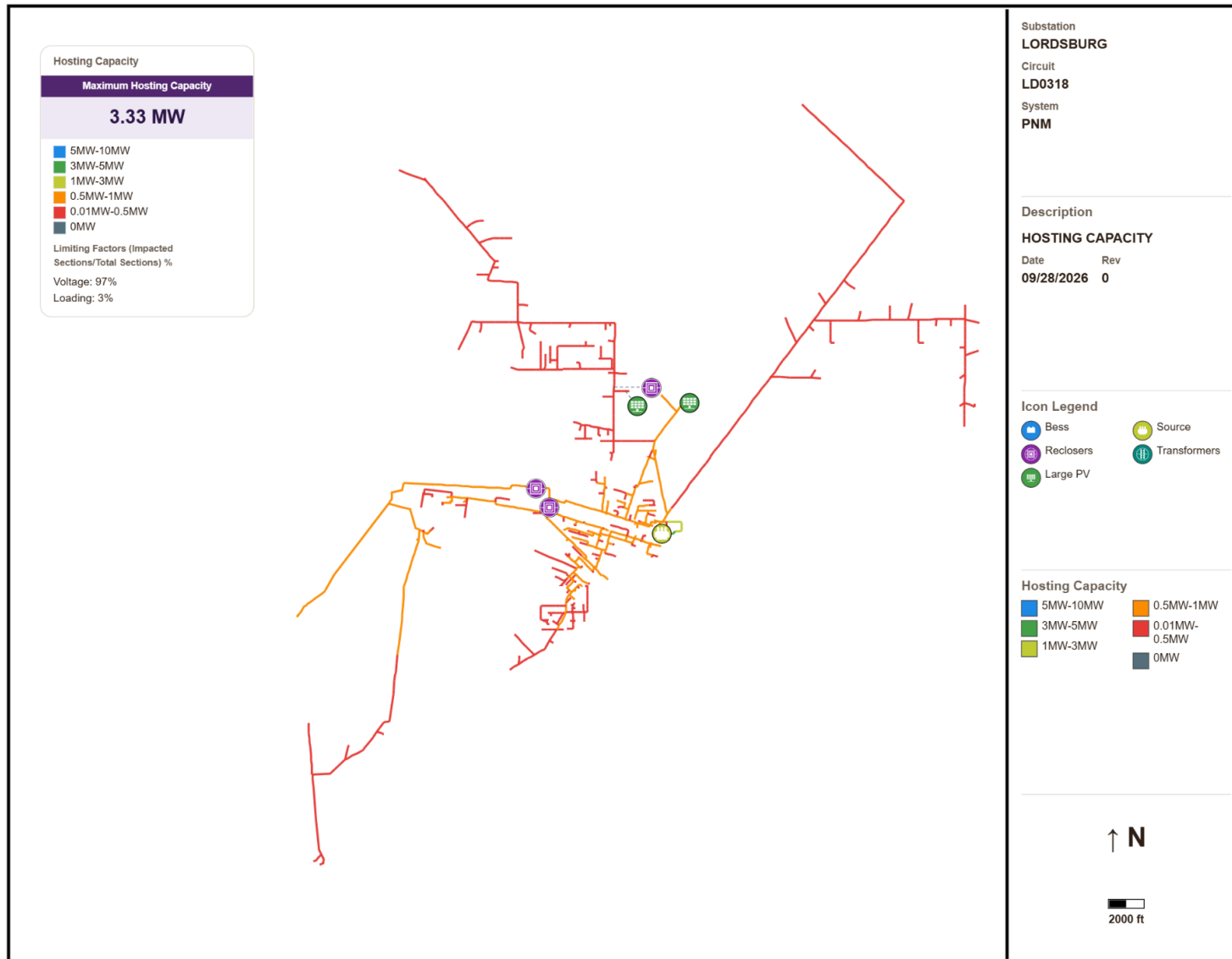


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Hosting Capacity Analysis Refresh 2026

LD0318 - Hosting Capacity Heat Map

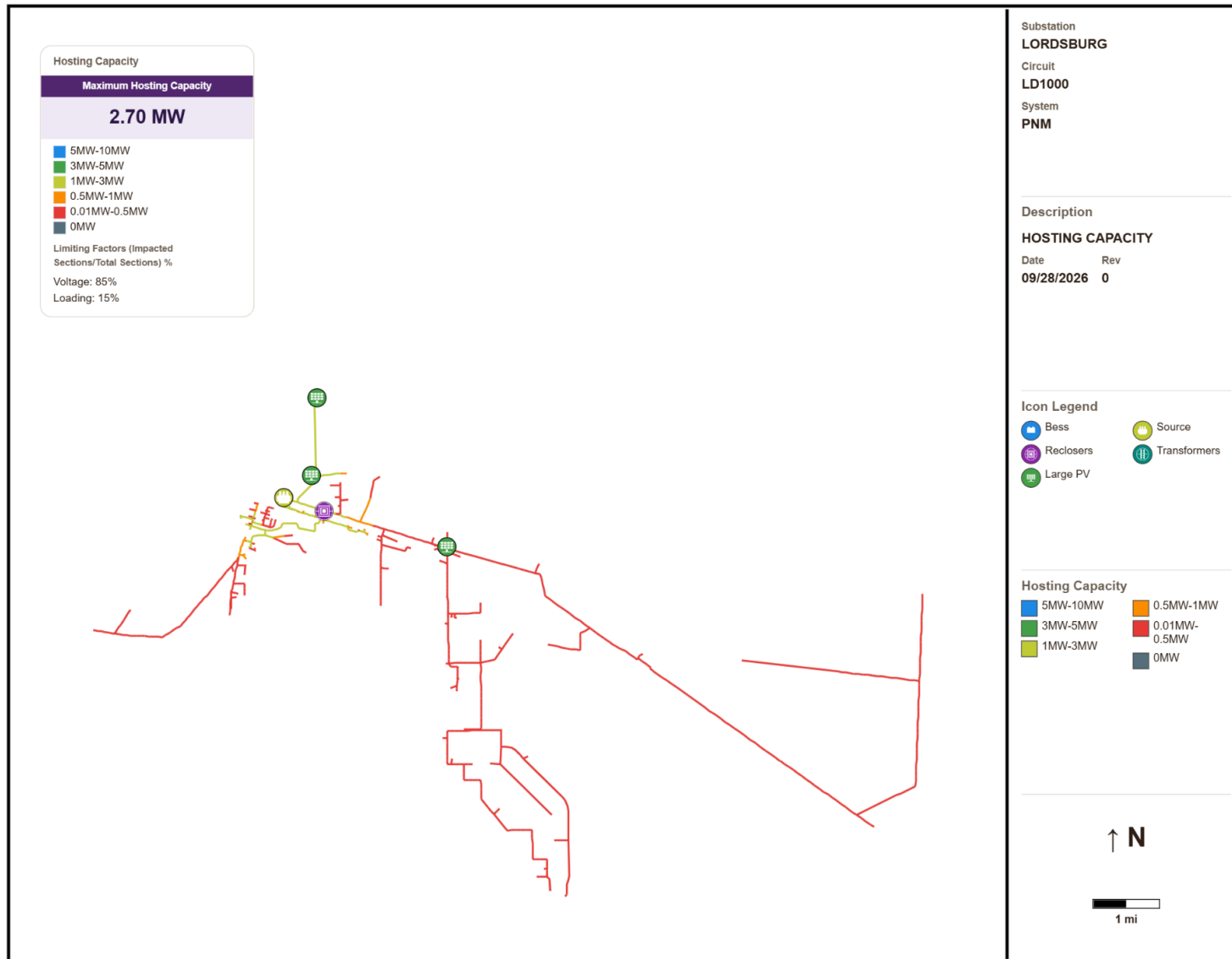


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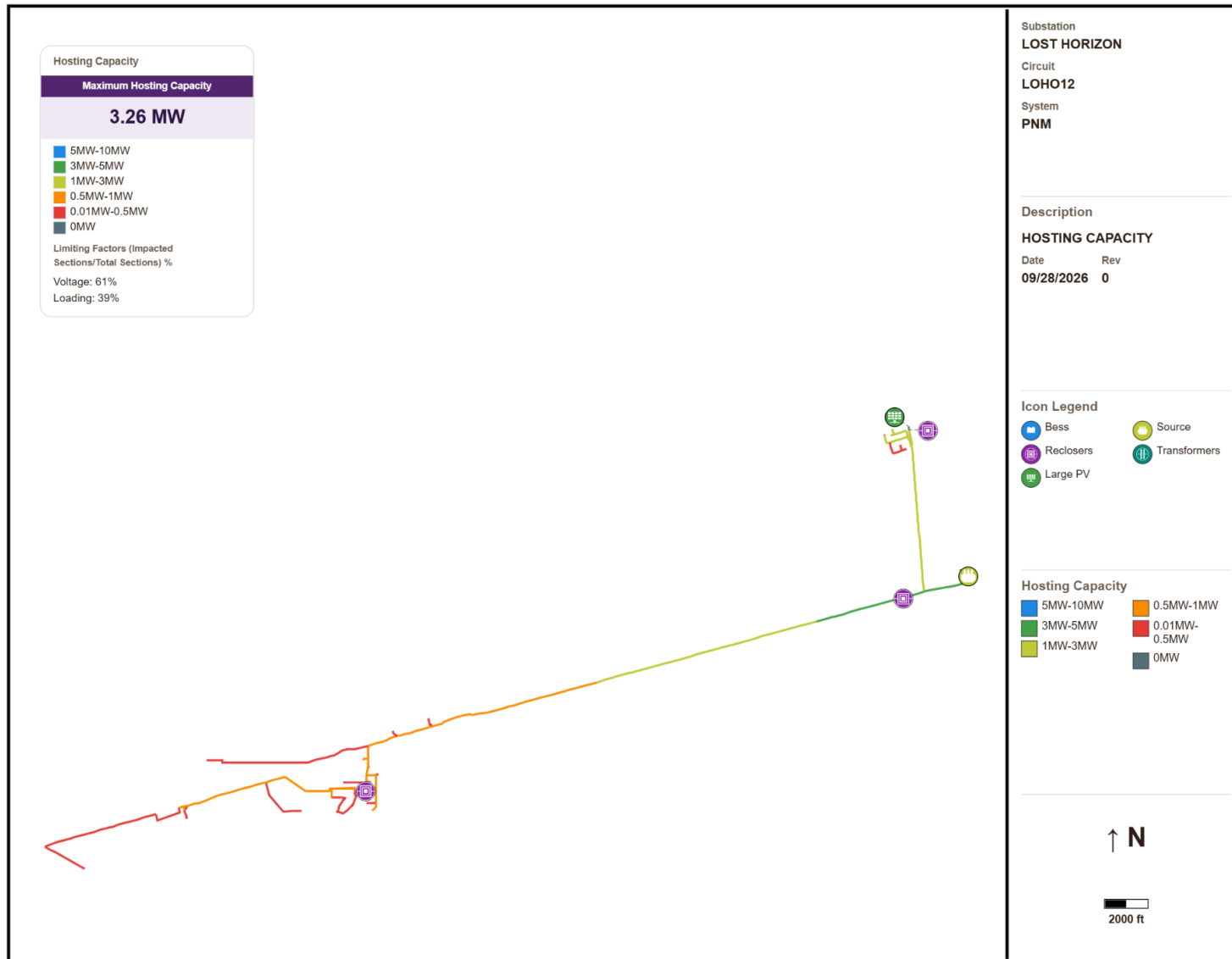
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Hosting Capacity Analysis Refresh 2026

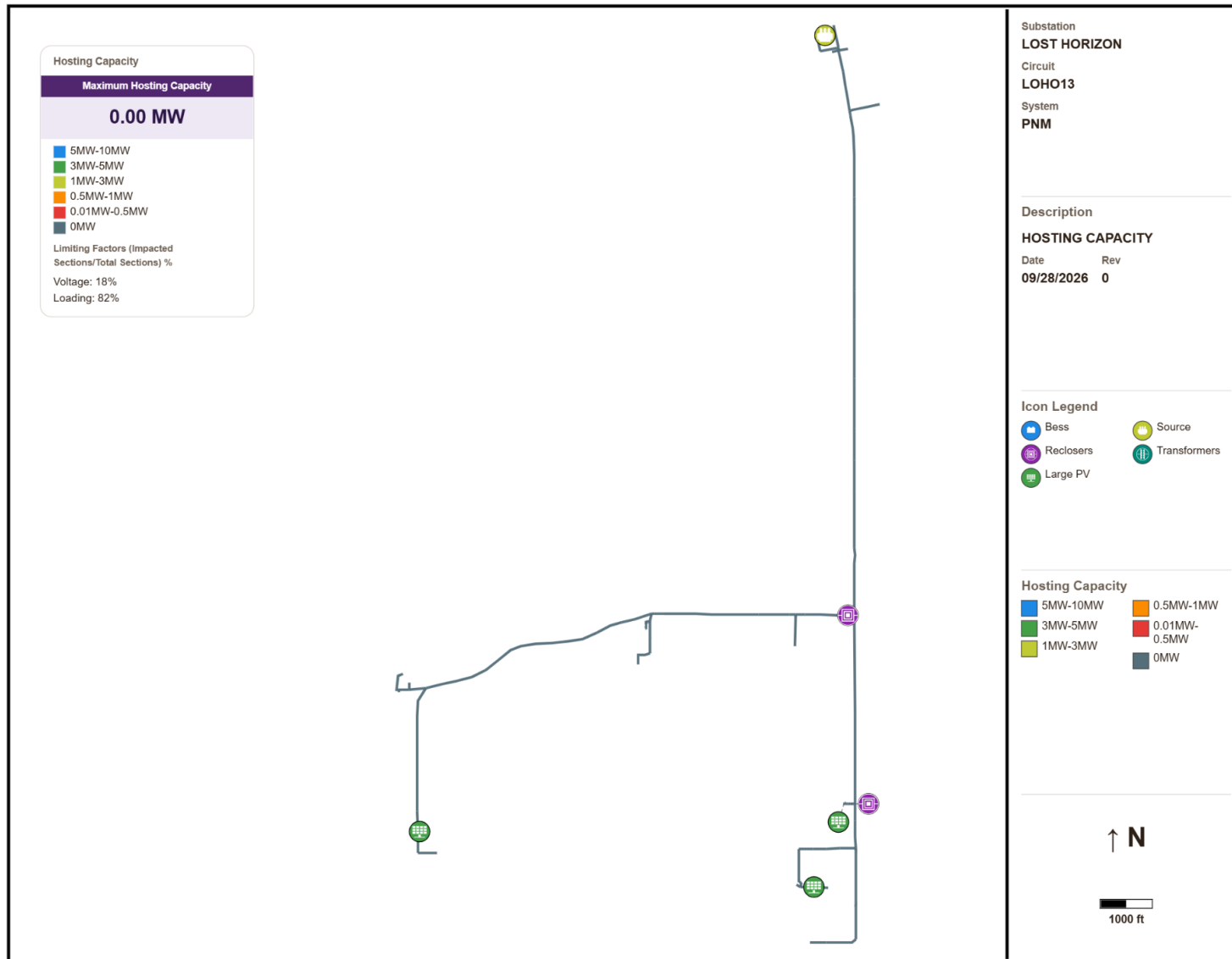
LD1000 - Hosting Capacity Heat Map



LOHO12 - Hosting Capacity Heat Map



LOHO13 - Hosting Capacity Heat Map



LOHO14 - Hosting Capacity Heat Map

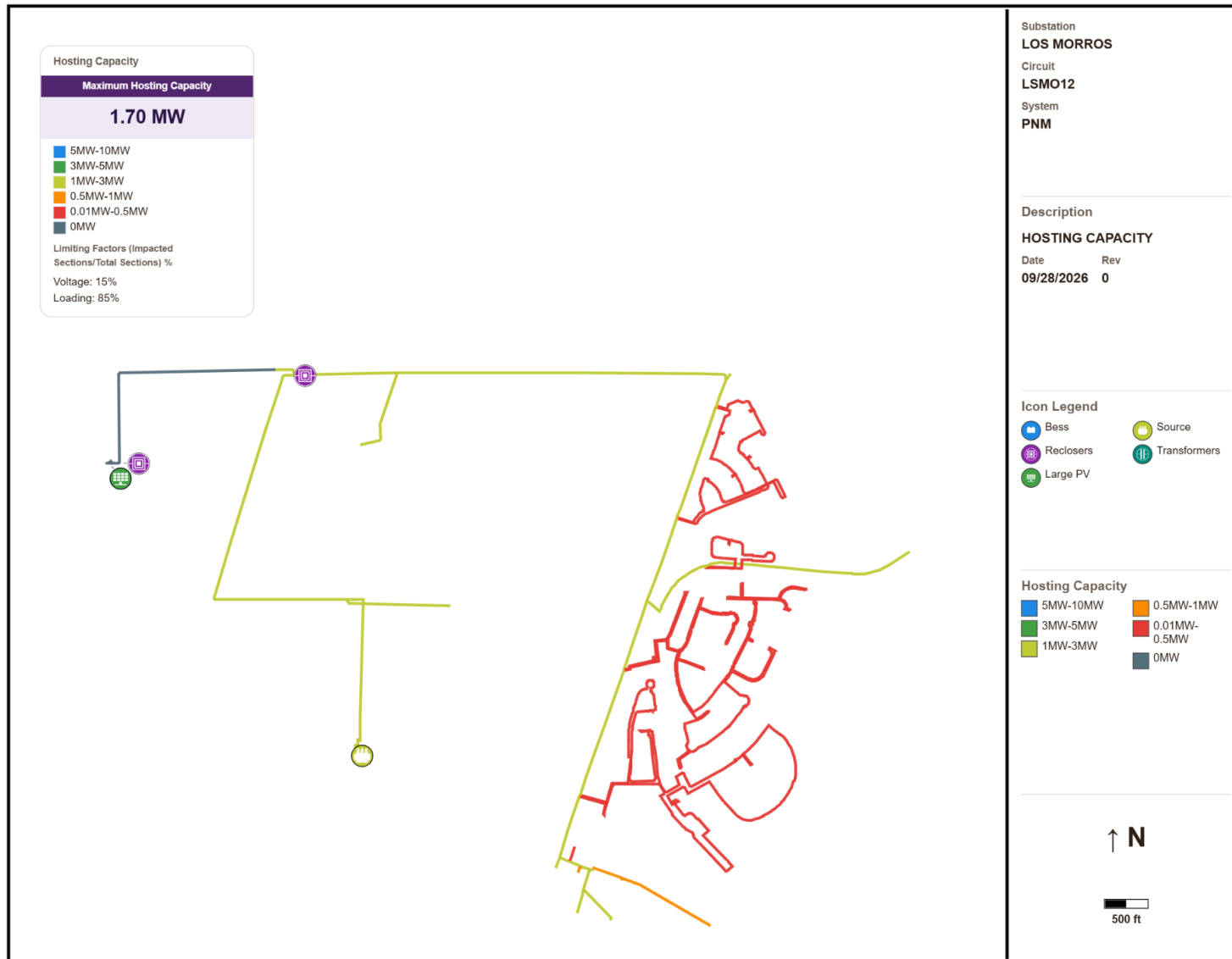


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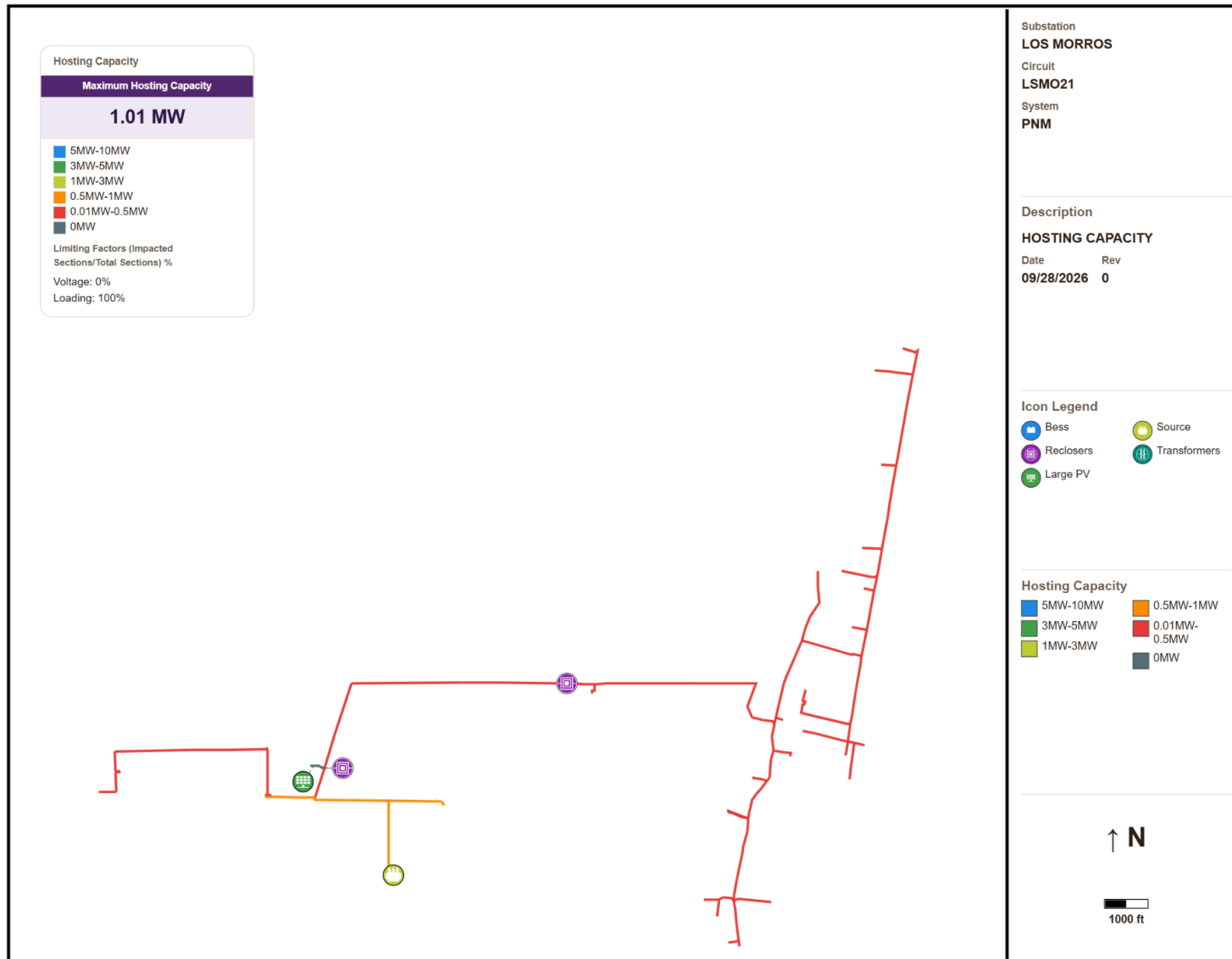
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Hosting Capacity Analysis Refresh 2026

LSMO12 - Hosting Capacity Heat Map



LSMO21 - Hosting Capacity Heat Map

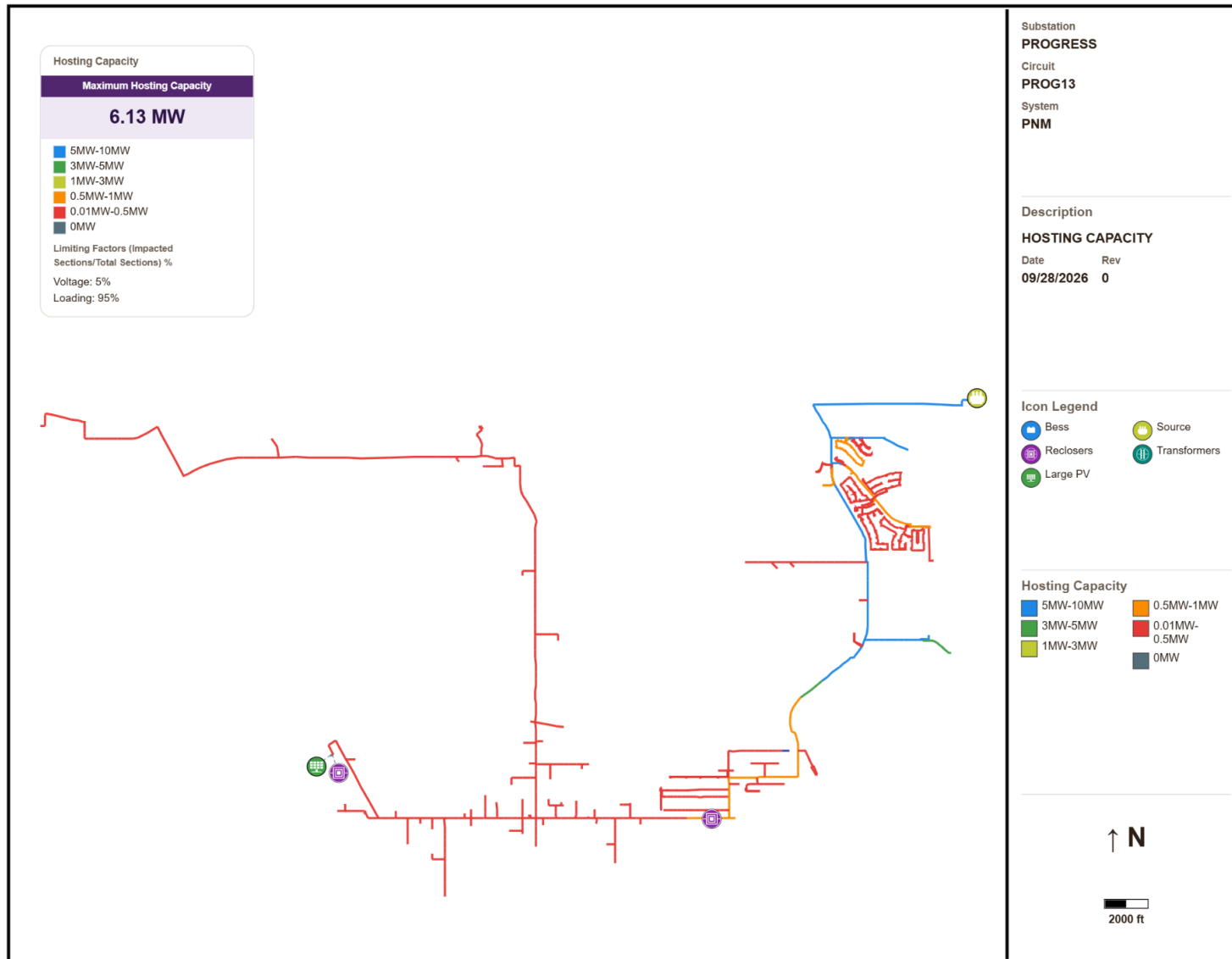


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Hosting Capacity Analysis Refresh 2026

PROG13 - Hosting Capacity Heat Map



SCEN12 - Hosting Capacity Heat Map

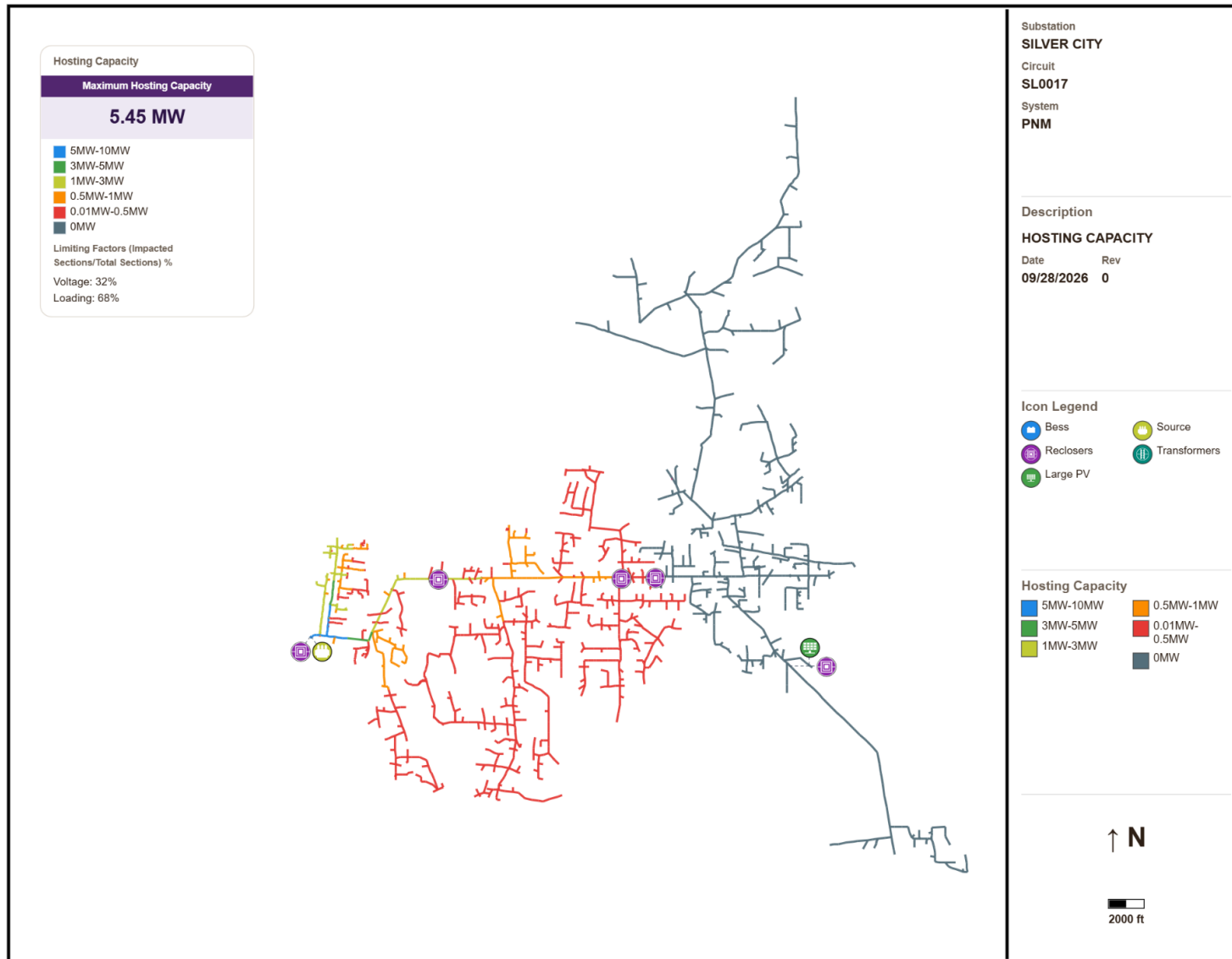


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Hosting Capacity Analysis Refresh 2026

SL0017 - Hosting Capacity Heat Map

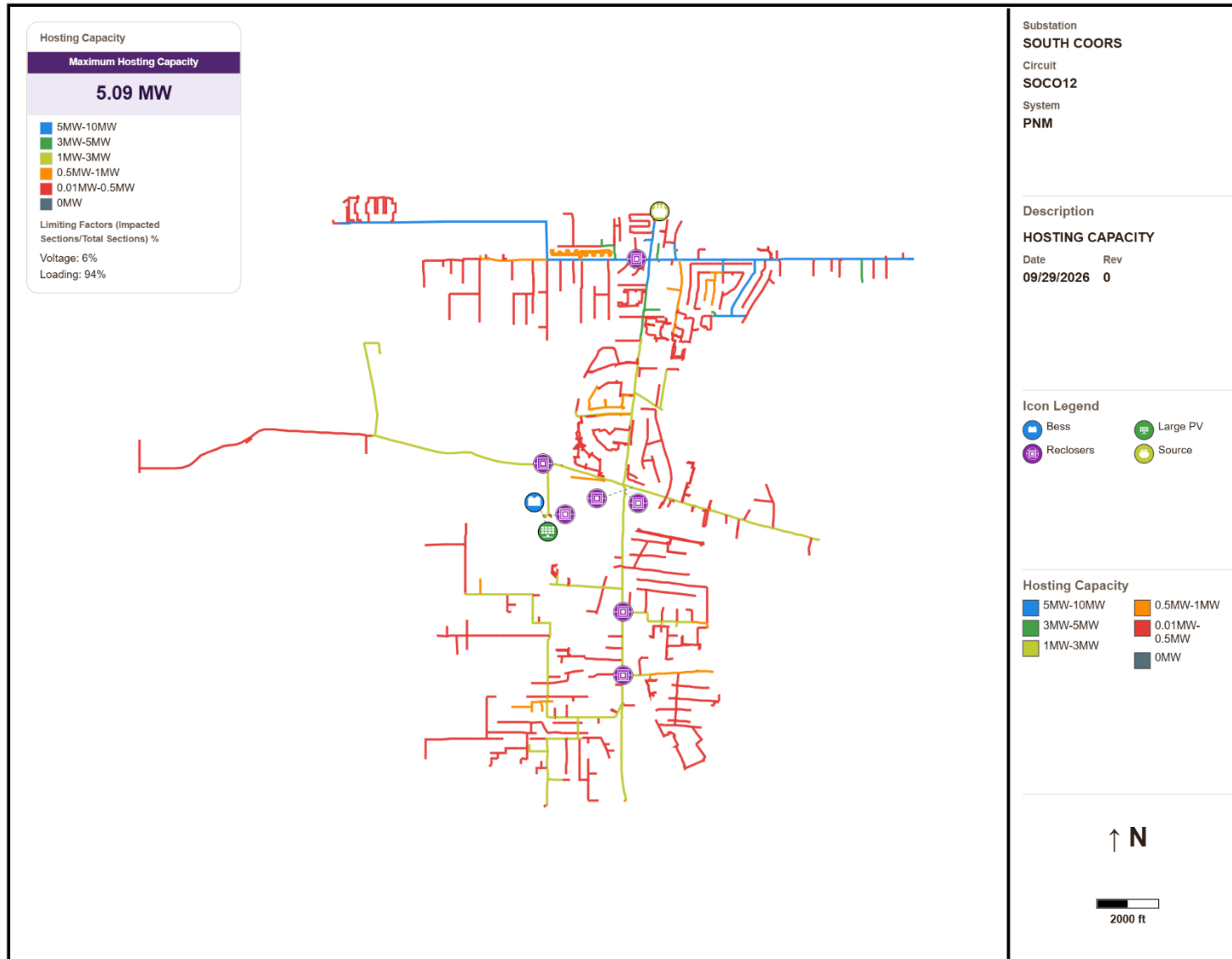


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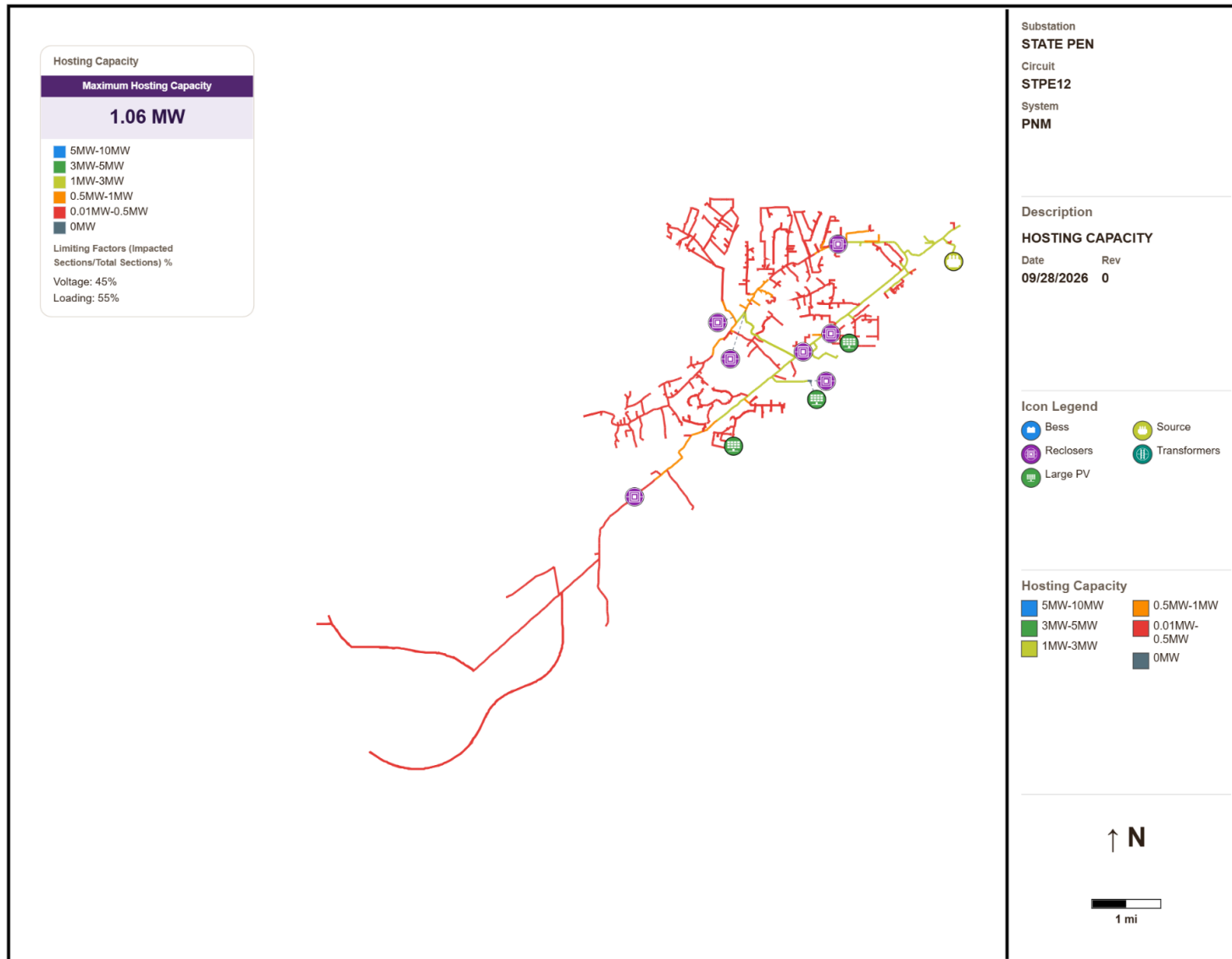
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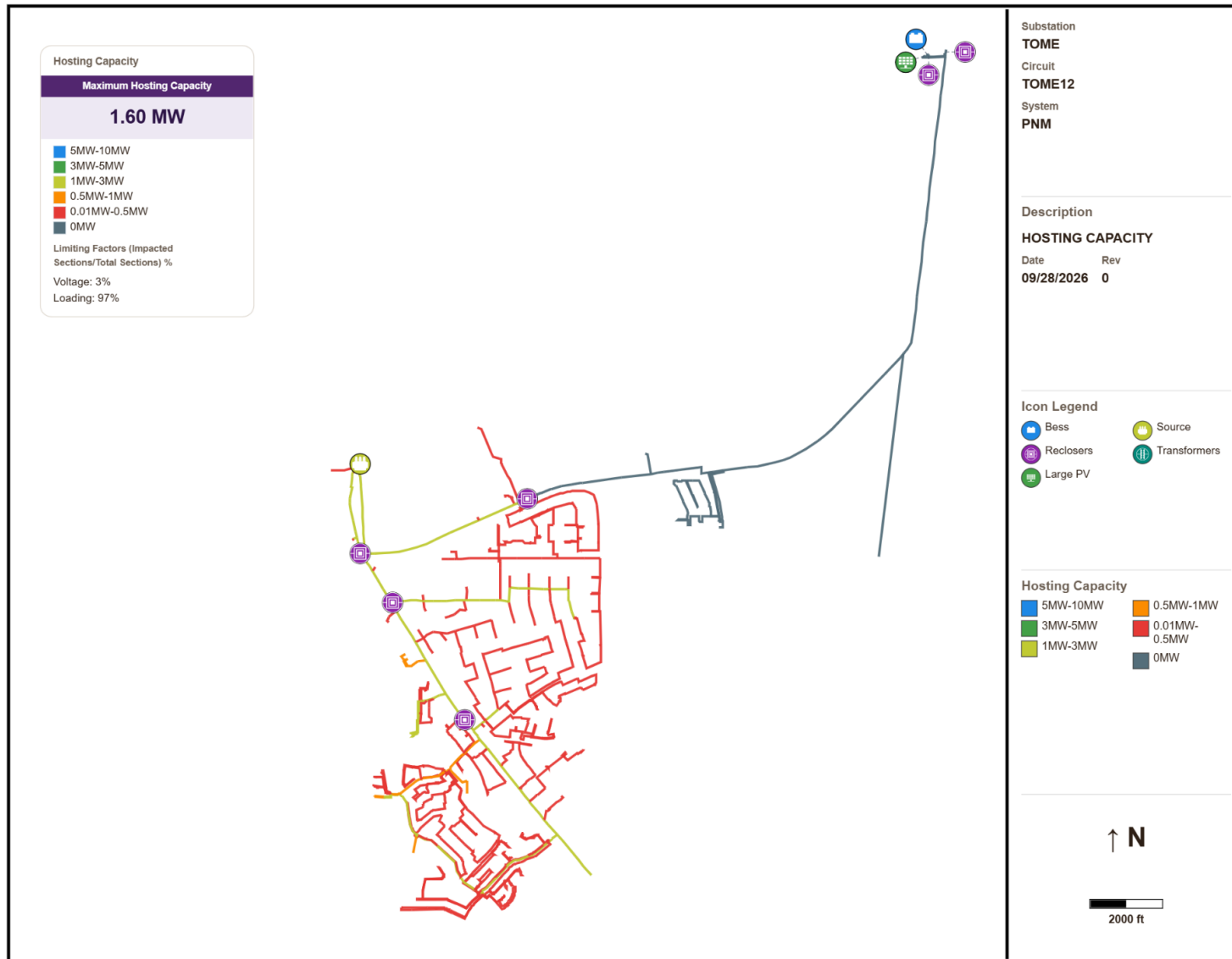
SOCO12 - Hosting Capacity Heat Map



STPE12 - Hosting Capacity Heat Map



TOME12 - Hosting Capacity Heat Map



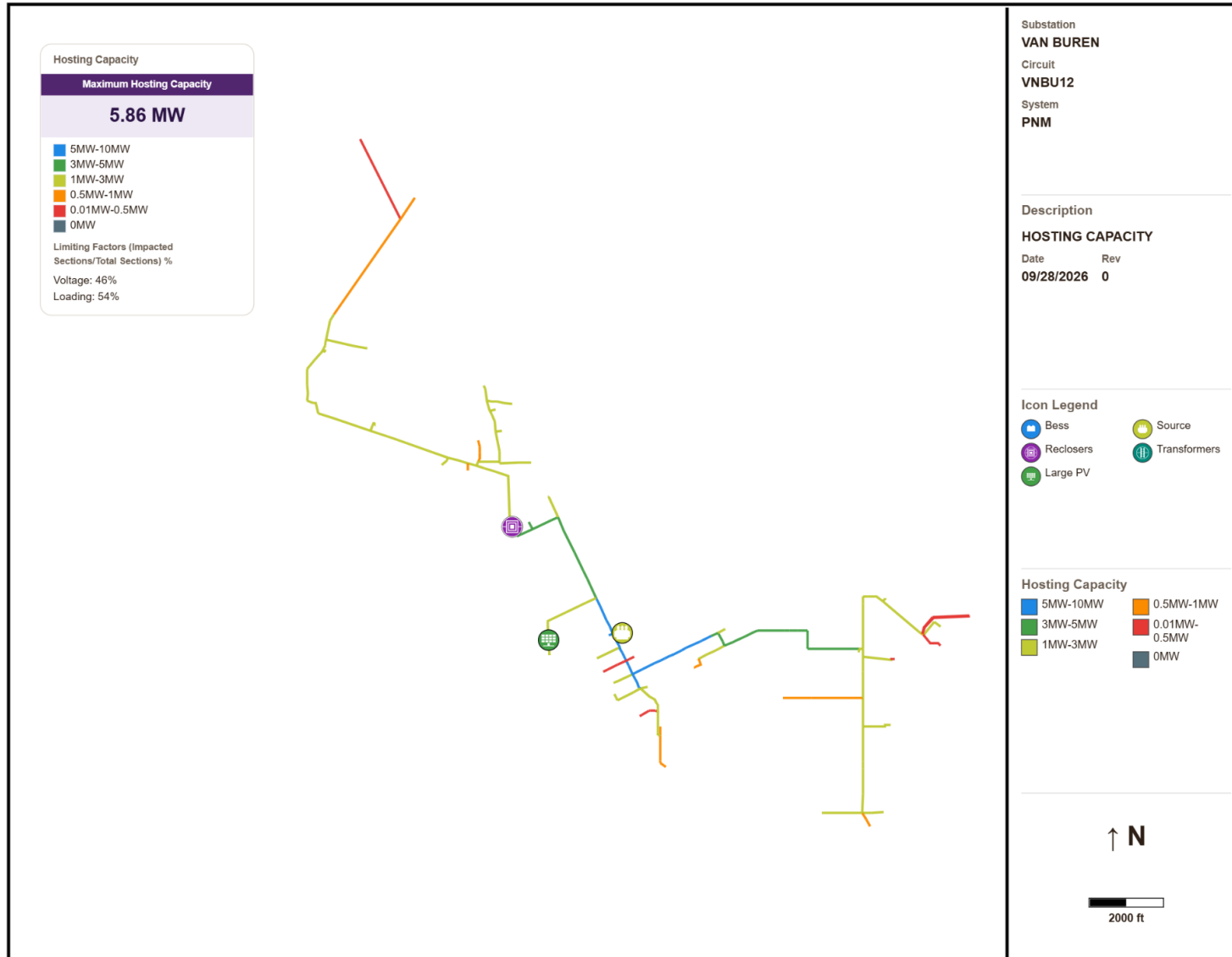
TULA13 - Hosting Capacity Heat Map



TULA14 - Hosting Capacity Heat Map



VNBU12 - Hosting Capacity Heat Map





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