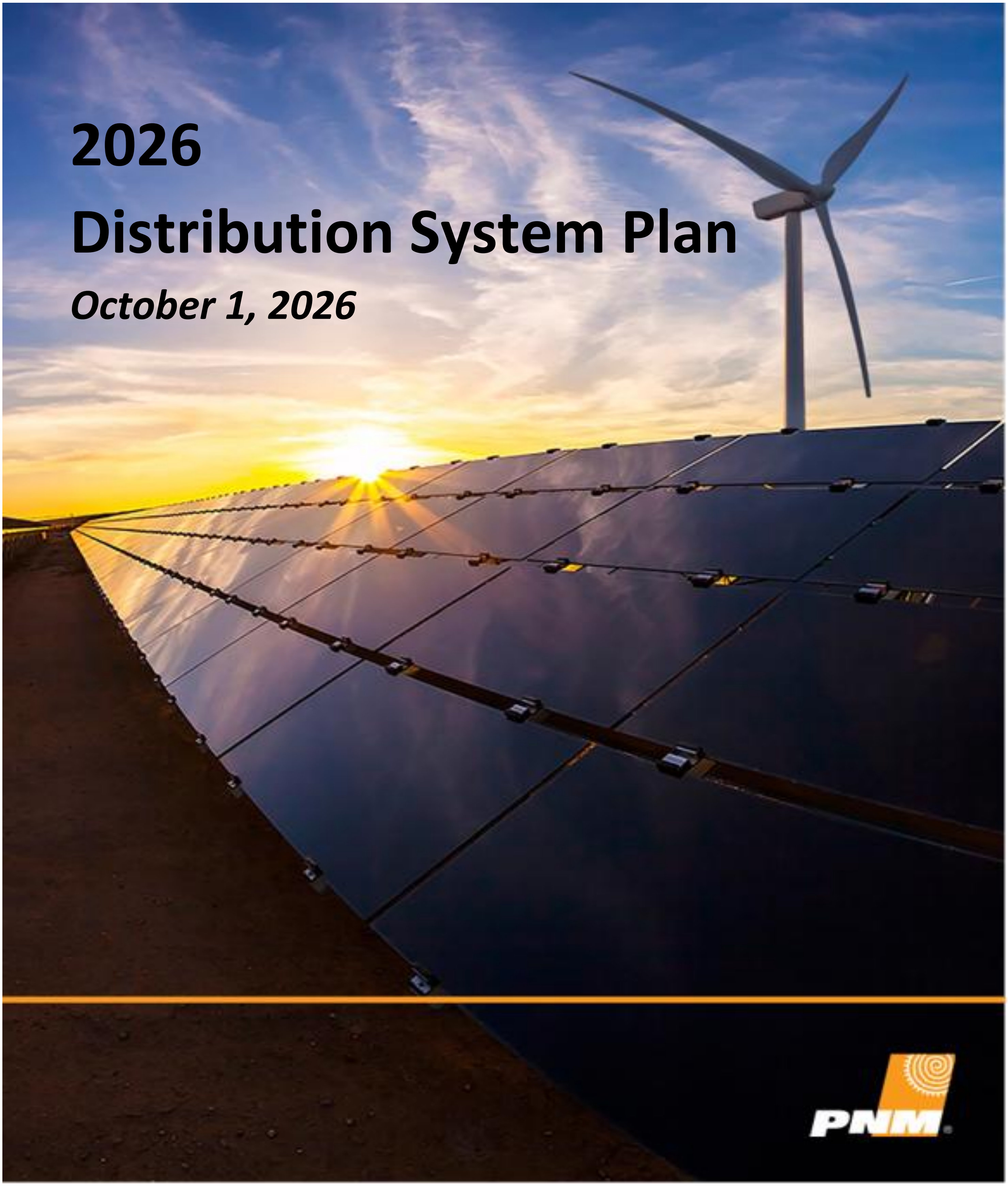
2026

Distribution System Plan

October 1, 2026



Safe Harbor Statement

Statements made in this document that relate to future events or Public Service Company of New Mexico's (PNM), expectations, projections, estimates, intentions, goals, targets, and strategies are made pursuant to the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based upon current expectations and estimates. Because actual results may differ materially from those expressed or implied by these forward-looking statements, PNM cautions readers not to place undue reliance on these statements. PNM's business is influenced by many factors, often beyond PNM's control, which can cause actual results to differ from those expressed or implied by the forward-looking statements. For a discussion of risk factors and other important factors affecting forward-looking statements, please see PNM's Form 10-K and Form 10-Q filings with the Securities and Exchange Commission, the factors of which are specifically incorporated by reference herein. PNM assumes no obligation to update this information, except to the extent the events or circumstances constitute material changes in the Distribution System Plan that are required to be reported to the New Mexico Public Regulation Commission.

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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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Table of Contents

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.
BCA	Benefit-Cost Analysis; a structured comparison of the benefits, costs, risks, and timing of an investment or alternative.
BESS	Battery Energy Storage System: equipment that stores electrical energy and later discharges it to serve load or provide grid services.
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.
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.

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.
Distribution Automation (DA)	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.
DR	Demand Response; changes in customer electricity use in response to utility instructions, price signals, incentives, or system conditions.
DSM	Demand-Side Management; programs or measures that modify the level or timing of customer electricity consumption.
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.

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
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.

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.
OATT	Open Access Transmission Tariff; the FERC-jurisdictional tariff governing transmission and related interconnection services.

OMS	Outage Management System; a system used to identify, manage, analyze, and report customer interruptions and restoration activity.
Overhead (OH) 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.
Transportation Electrification	Replacement of transportation energy use with electricity, including vehicles, charging infrastructure, programs, rates, and supporting distribution investments.
Underground (UG) Distribution	Distribution cables and associated equipment installed below ground.
Utility Network (UN)	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 17,700 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 692 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.

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 whether 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, $344 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 Chapter 62, Article 17 of the New Mexico Statutes. The Act addresses energy efficiency and load management programs, cost recovery, measurement and verification, self-directed programs, and integrated resource planning.

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] *See* NMPRC Case No. 22-00058-UT.

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 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.

1.13.3.1 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 (to be updated upon completion of the 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 multiple 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
- 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. The sessions were also announced during PNM's regular bi-weekly stakeholder engagement meetings to ensure robust awareness and participation. 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 as an appendix to this document.

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 X comments and have addressed each of those formally in a comment tracking document provided as an appendix to this report.

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 responses addressed:

- Future

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

The second meeting focused on:

- Future

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 regarding planning assumptions, methodologies, modeling approaches, proposed investments, and other 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 development of the DSP. Consultant support included activities such as engineering analysis, forecasting, system studies, grid modernization assessments, hosting capacity evaluations, stakeholder facilitation, 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

Stakeholder discussions focused on a range of topics affecting distribution system planning, including:

- Future

2.11 Issues Resolved Through Stakeholder Engagement

The stakeholder engagement process contributed to resolution or clarification of several issues, including:

- Future

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

Consistent with a planning process involving a diverse range of stakeholders, certain issues remained unresolved at the time of filing. These issues generally involved differing viewpoints regarding:

- Future

PNM acknowledges these differing viewpoints and intends to continue engagement on these issues 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 10 MVA. 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 based in Albuquerque, N.M. 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 New Mexico tribal communities of the Tesuque, Cochiti, Santo Domingo, San Felipe, Santa Ana, Sandia, Isleta, and Laguna Pueblos. As shown in Figure 4-1, PNM's electric service territory covers geographically diverse areas. Electric demand and energy usage varies based upon geography, customer mix, and climate.

Figure 4-1: 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. 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 9,087 miles of overhead lines, including about 5,866 miles of primary overhead distribution and 3,221 miles of secondary overhead distribution.

3.5 Total Miles of Underground Distribution

The underground distribution system consists of approximately 8,609 miles of underground lines, including about 6,335 miles of primary underground distribution and 2,274 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 692.6 MW of installed capacity. Solar generation is the predominant DER technology, with 47,540 installations representing approximately 597.1 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 3-3 summarizes current DER deployment by technology.

Table 3-3: Distribution-Connected DER by Technology

Technology	Installations	Installed capacity (MW)
Solar (excluding Community Solar)	47,540	597.100
Community Solar	9	42.750
Customer Battery Energy Storage	1041	38.705
PNM Distributed Sited Battery Energy Storage	2	12.000
Other DER	43	2.074
PNM total	**48,635**	**692.629**

**Other DER's include Wind, and Natural gas*

3.7 Total number of Distribution Premises

PNM's 15 distribution divisions serve approximately 550,000 premises. For purposes of this DSP, this total represents the current number of distribution premises.

3.7.1 Total Number of Customer Meters with AMI; Without AMI

PNM does utilize 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 later in 2026.

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) controlled, representing approximately 39.1 percent of the substations in the system.

PNM's distribution system includes 616 distribution feeders. Of these, 602 are System Control and Data Acquisition (SCADA) 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 3-4: Feeder SCADA Control Status

Control status	Feeder positions	Percentage of feeders
SCADA control	602	97.7%
Manual control	14	2.3%
PNM Total	**616**	**100.0%**

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. Most devices on the distribution feeders are locally controlled or manually operated. SCADA is used for some distribution system equipment, such as SCADAmate switches, SCADA-monitored voltage regulators and SCADA-monitored reclosers.

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.

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 3-5 summarizes PNM's systemwide results, excluding MEDs for 2021 through 2025. The totals include distribution, substation, and transmission interruptions that affect distribution customers.

Table 3-5: 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 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.

3.10 Major Areas of Distribution Planning Focus

Major areas of focus on PNM's distribution system are generally characterized by into a couple of 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.

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 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 five 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 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.

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.
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.

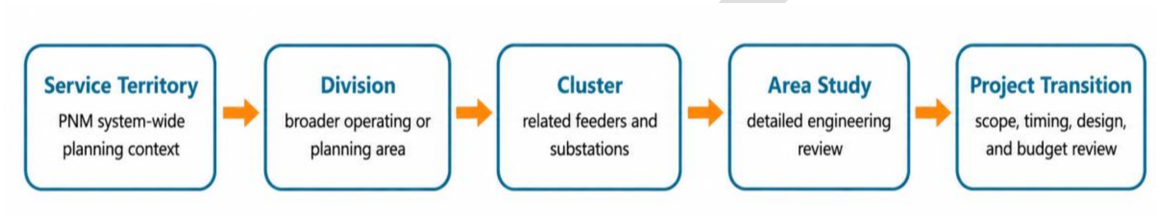
Table 4-2: Relationship Between PNM Planning Review Levels

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.

Planning level	Primary purpose	Typical outputs	How results are used
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 4-2 summarizes PNM's planning process. Each of these phases of PNM's distribution planning process are outlined in more detail below.

Figure 4-2: Distribution Planning Systematic Review from Service Territory to Project Transition



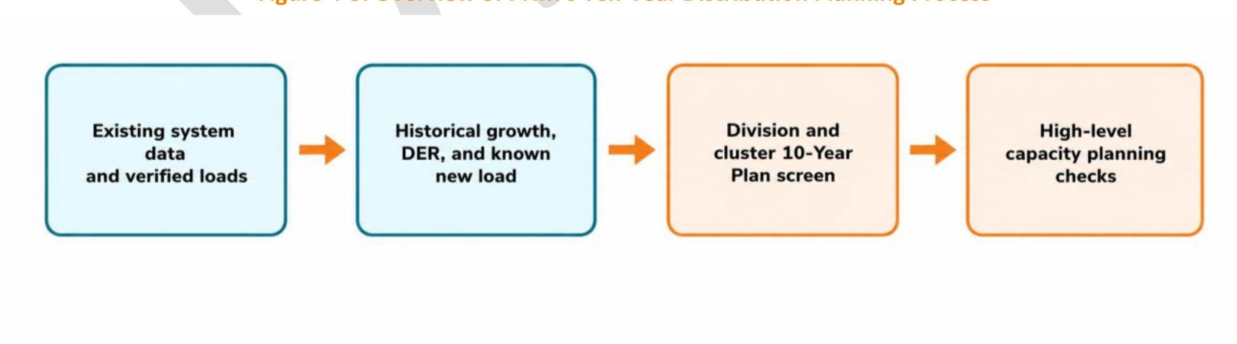
4.3 PNM's Ten-Year Planning Process

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 4-3 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 4-3: 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

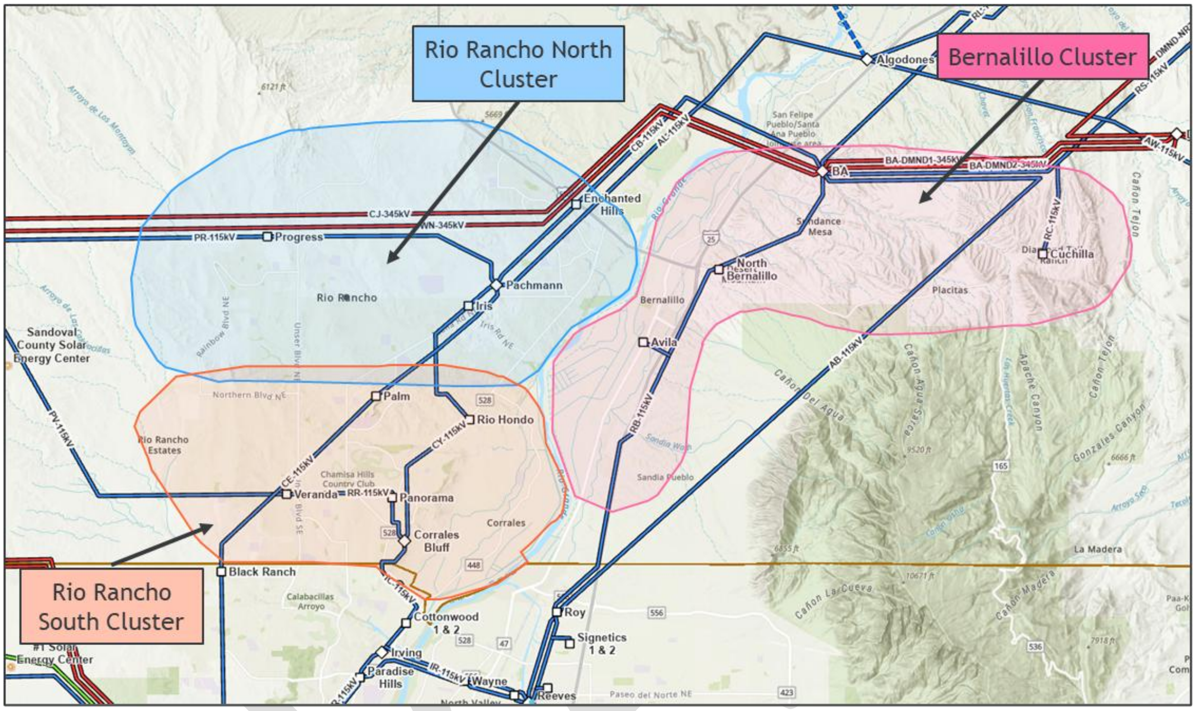
Section 4.1 defines the planning criteria used throughout this document. Within the Ten-Year Plan process, the division and cluster structure allows PNM to apply common planning criteria while still reflecting local geography, customer density, feeder topology, load growth, DER penetration, and operating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

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

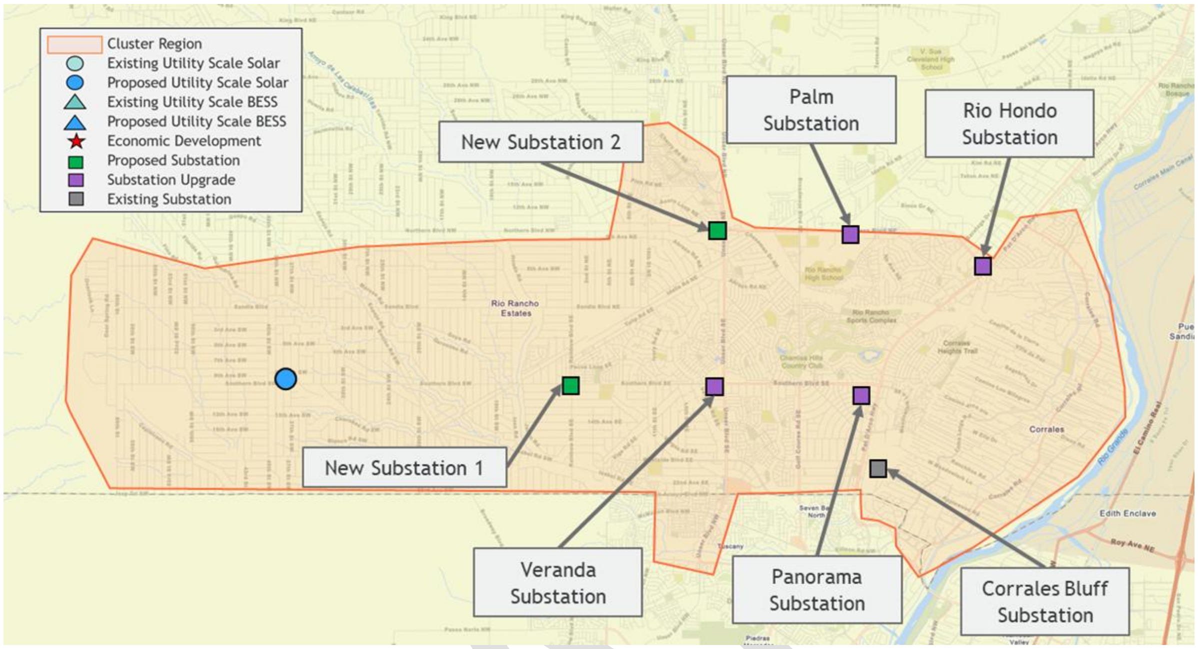
Figure 4-4: Example of a Division Divided into Planning Clusters - Sandoval Division



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 4-5 then shows one cluster in greater detail, including the substations and proposed capacity additions that are evaluated as part of the planning process.

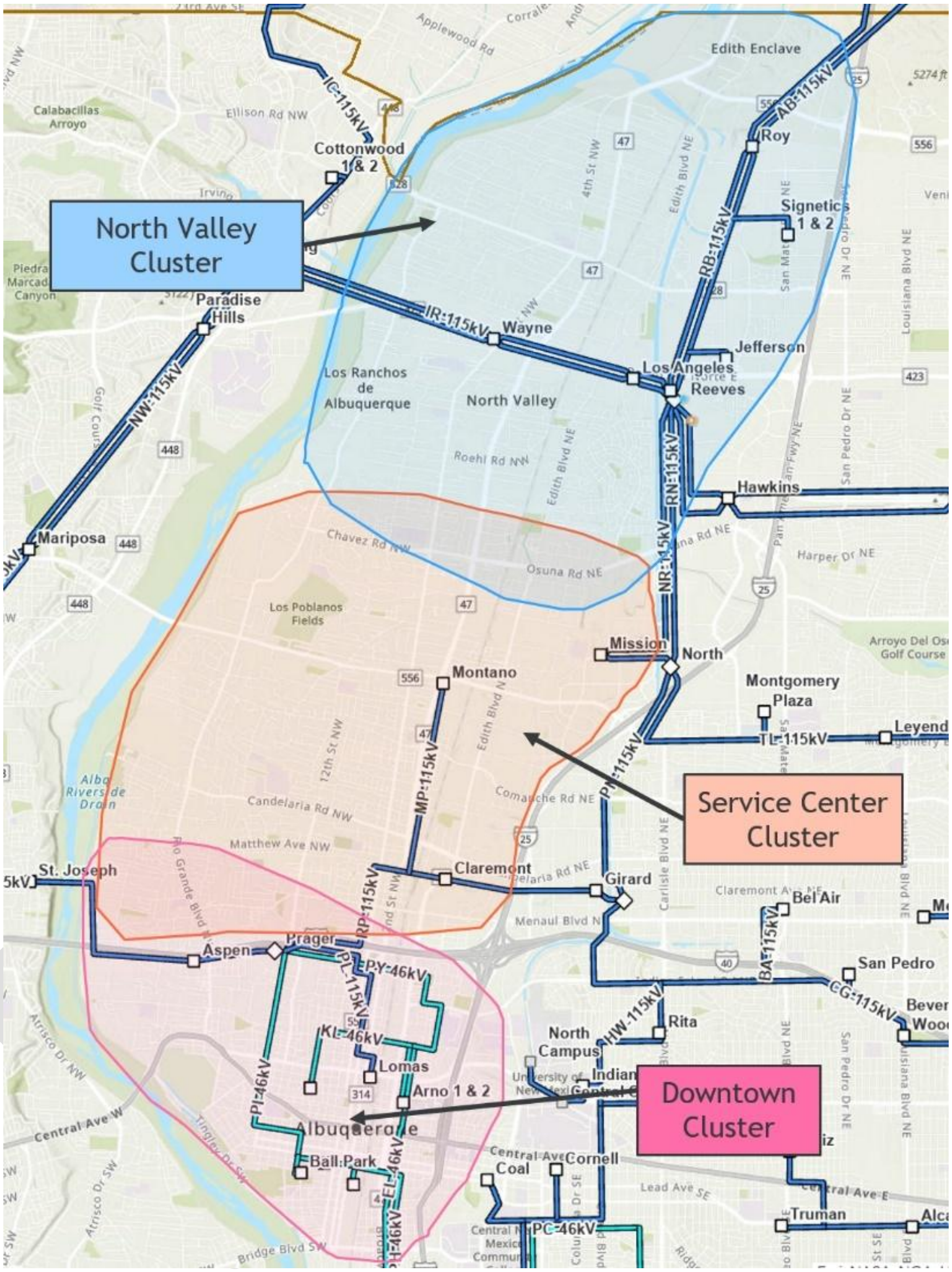
Figure 4-5: Example of a Cluster Used for Detailed Planning Review - Rio Rancho South Cluster



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 change the forecast.

Figure 4-6 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 4-6: 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%**

Source example: Las Vegas Cluster 2025 Load Existing System Substation Transformer Hosting Capacity, Las Vegas Division 2026 Ten-Year Distribution System Plan. This table is included to show the Ten-Year Plan indicator structure, not to provide feeder-level interconnection approval. Remaining hosting capacity 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.

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

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.

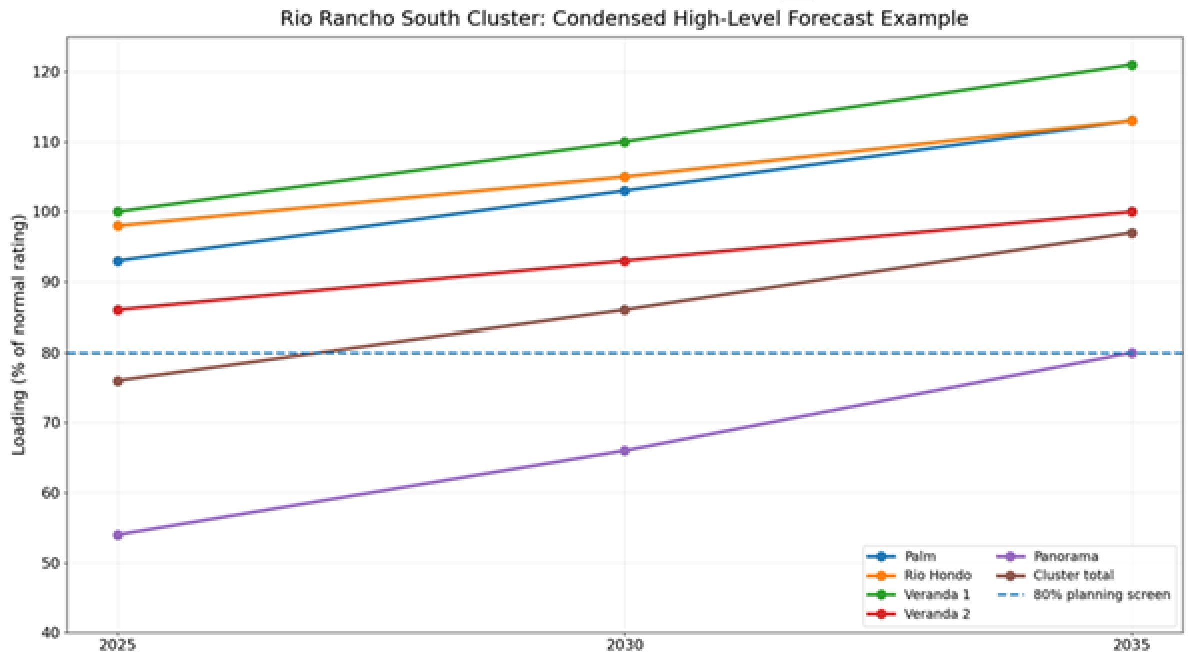
Source example: Sandoval Division 2026 Ten-Year Distribution System Plan, Rio Rancho South Cluster. The table is condensed to show the planning method and is not intended to replace the full annual Ten-Year Plan forecast.

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 4-7 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 4-7: 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.

4.4.1.1 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.

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.

4.4.1.2 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.

4.4.1.3 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	Total generation MW	Net community solar MW	Estimated Remaining HC MW	% XFMR utilization

		Net load MW				
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 4-8 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 4-8: Example detailed area study geography - Rio Hondo Palm Study Area

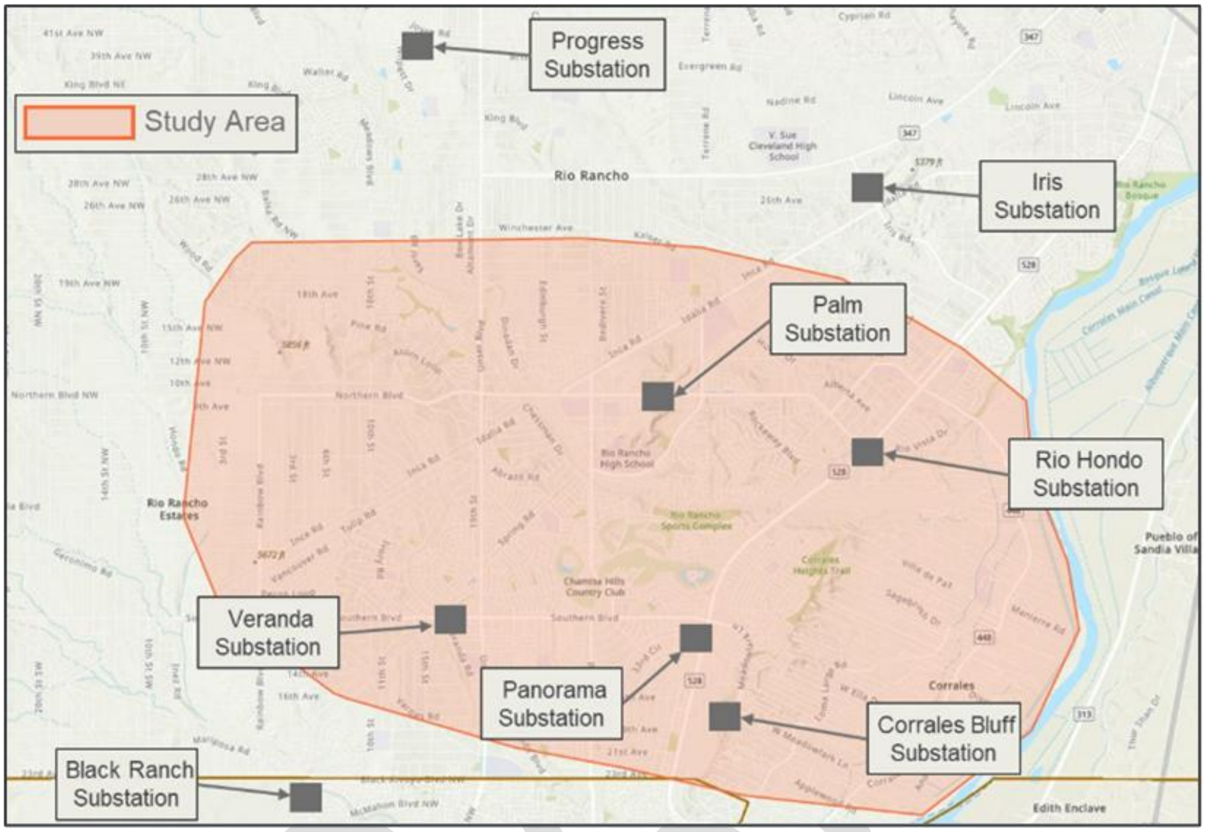


Figure 4-9 illustrates how alternative solutions are framed in an area study. In this example, the Montano and Claremont area study presents three capacity alternatives that were evaluated after both substations were identified as being at or near their capacity limits, and after reviewing nearby substations 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 4-9: 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.

Topic	10-Year Distribution System Plan	Detailed Area Study
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.

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	MENAUL	33.7											
Montgomery Park	MONTGOMERY P	33.7											
Foothills	MORRIS	33.7											

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, 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											

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	LORDSBURG T1-NORTH	7.5											
Lordsburg	LORDSBURG 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.

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. See Table 4-22 for Summary of Study results.

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	2023
Paradise Hills Area Study	Heavily loaded Black Ranch, Cottonwood II,	Paradise Hills transformer upgrade and new	Paradise Hills I Upgrade – 2023

	Mariposa, Paradise Hills, and Scenic substation transformers.	Paradise Hills, Black Ranch, and Scenic transformers installed at existing substations.	Paradise Hills II – 2023 Black Ranch II – 2024 Scenic Unit II - 2026
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 – 2026South Coors Upgrade – 2023 Anderson Upgrade - 2023
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 – 2027 Hamilton One Upgrade – 2025 Hamilton II Upgrade – 2023 Tramway Upgrade - 2023
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 – 2024 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.	New Rio Rancho South Substation I - 2027 New Rio Rancho South Substation II - 2027 Veranda I upgrade – 2024 Panorama upgrade – 2024 Palm upgrade – 2024 Rio Hondo upgrade – 2024
West Los Lunas Area Study	Inadequate capacity for an outage of Los Morros unit I.	New substation transformer at existing	New Rattlesnake transformer – 2027

		Rattlesnake switching station.	
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 NE Heights Area

The far NE Heights of Albuquerque, 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.

4.9 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.

4.9.1 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 brochure in the Appendix. However, proprietary product documentation (manuals, technical references, etc.) cannot be shared publicly or with any third party as per PNM's Synergi licensing.

4.9.2 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.

4.9.3 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.

Tool or data source	Primary use in Distribution Planning process	Outputs / planning value	Key limitations or maturation need
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.

4.10 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.

4.10.1 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.

4.10.2 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.

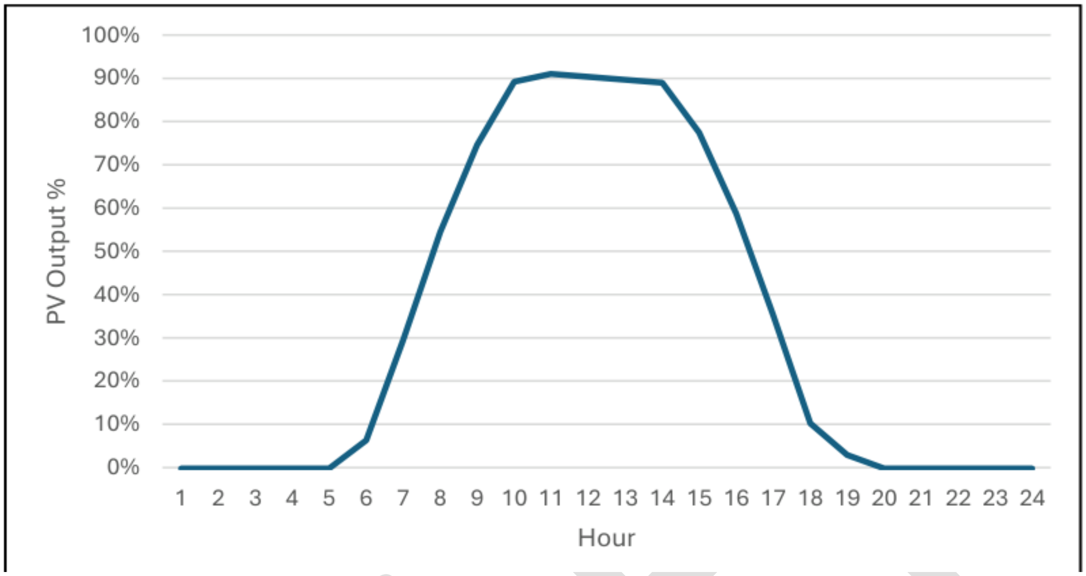
4.10.3 DER, Storage, Microgrids, and EVs

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 4-11 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 4-11: 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.

4.10.4 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.

4.10.5 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.

4.11 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.

4.11.1 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.

4.11.2 First Phase Hosting Capacity Analysis Study

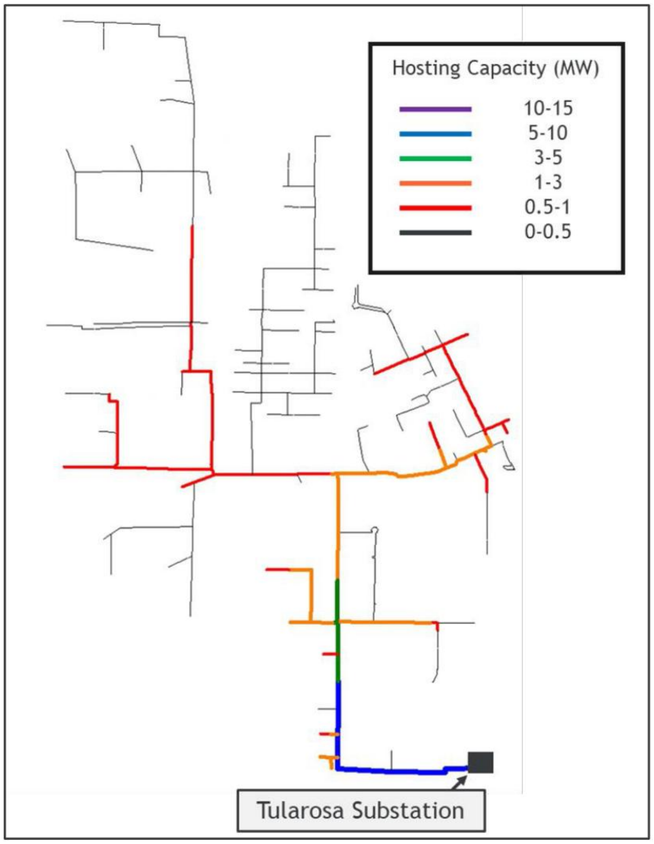
PNM's first Rule 568 Hosting Capacity study, completed on May 22, 2024,[2] evaluated 30 PNM feeders to understand the actual distribution-system limits for hosting additional PV generation. The study consisted of 18 feeders that PNM considered at PV saturation (aggregate DER exceeds 90% of feeder rating), 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 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 4-14 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 4-14 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).

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

Figure 4-14: 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 4-25: 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.

PV penetration level	Recommended hosting capacity refresh concept	Planning implication
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.

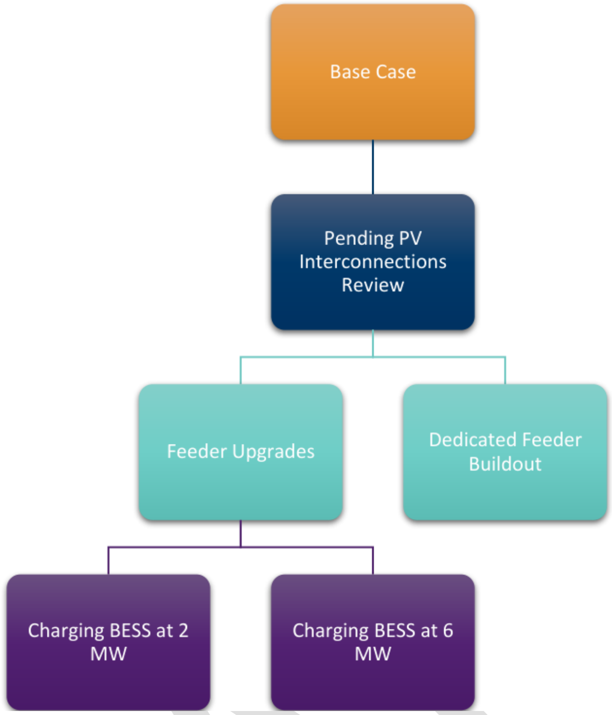
4.11.3 Second Phase Hosting Capacity Analysis Study

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 4-15 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.

[3] NMPRC 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 4-15: Hosting Capacity Analysis and Capital Project Evaluation Approach



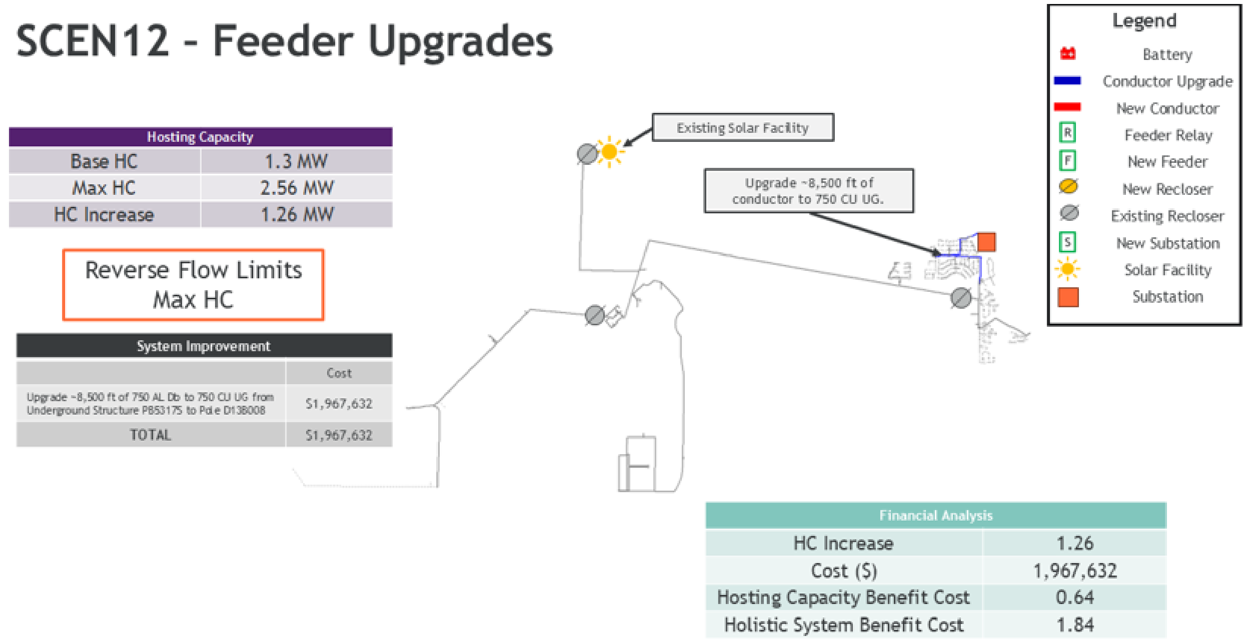
Source example: Rule 568 Hosting Capacity Improvement Solutions Report. The figure is included to summarize the analysis sequence at a high level.

Figure 4-16 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 4-16: Hosting Capacity Improvement Solutions Evaluated in Rule 568 Planning Work

Figure 4-17 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 4-17: 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 4-18 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 4-18: Hosting Capacity Improvement Alternative Option Considered

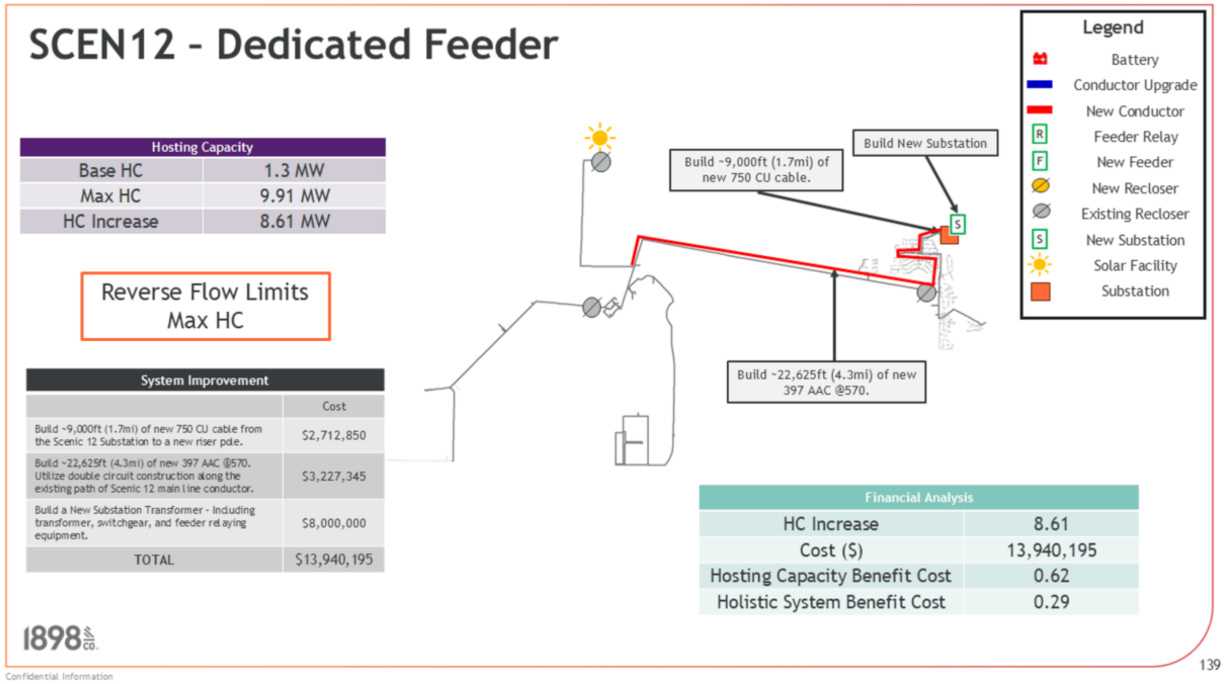


Table 4-26: Example of Combined Community-Solar and Traditional System Upgrades Used to Increase Hosting Capacity

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.

Hosting capacity improvement option	Planning function	Important considerations
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.

4.11.4 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 and updated feeder hosting capacity results for these 27 feeders are included in the Appendix.

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.

4.11.5 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.

4.11.6 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 4-27: 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.

Roadmap item	Planning purpose	DSP treatment
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

PNM'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.

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 risks 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

PNM believes that the basis for consistent and integrated planning begins with 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 bottom-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 this corporate forecast.

For the Distribution System Plan, the methodology used in the recent Avoided Cost Study, UT 26-0000072, 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 UN 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 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 HFRAs 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 HFRAs, 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 HFRAs:

- Establish prioritized telecommunications rollout
- Subsegment HFRAs into smaller operational areas and create a program to install necessary hardware and upgrades to:
  - Provide asset health, current state/status
  - 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-er 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 State College'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)
  - 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 assents 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 HFRAs 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.

To that end, PNM is systematically replacing relays at the distribution level, with special concentration on high-risk wildfire areas. Upgraded distribution protection devices going forward should also allow for more sophisticated functionality such as traveling wave technology suited for lower voltages and distribution protection falling conductor functionality.

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:

Capital Category	2023 Historical Capital Spend	2024 Historical Capital Spend	2025 Historical Capital Spend	2023-25 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	$ 12,771	$ 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
	$ 287,248,298	**$ 240,454,942**	**$ 319,433,575**	**$ 847,136,815**

Historical distribution O&M is outlined directly below:

	2023 Historical O&M Spend	2024 Historical O&M Spend	2025 Historical O&M Spend	2023-25 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)

PNM will update this section prior to the second stakeholder engagement session on September 21, 2026.

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.

PNM will update this section prior to the second stakeholder engagement session on September 21,2026.

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 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.

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, AMI visibility	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.*

****Future****

Background: Pursuant to PNM's Ten-Year Plan and other supporting studies, the identified projects address PNM system and customer needs on a benefit-cost 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.
- **C**AIDI (Customer Average Interruption Duration Index): Average restoration time per outage.
- Circuit reliability performance: Number of circuits performing below established reliability targets.

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

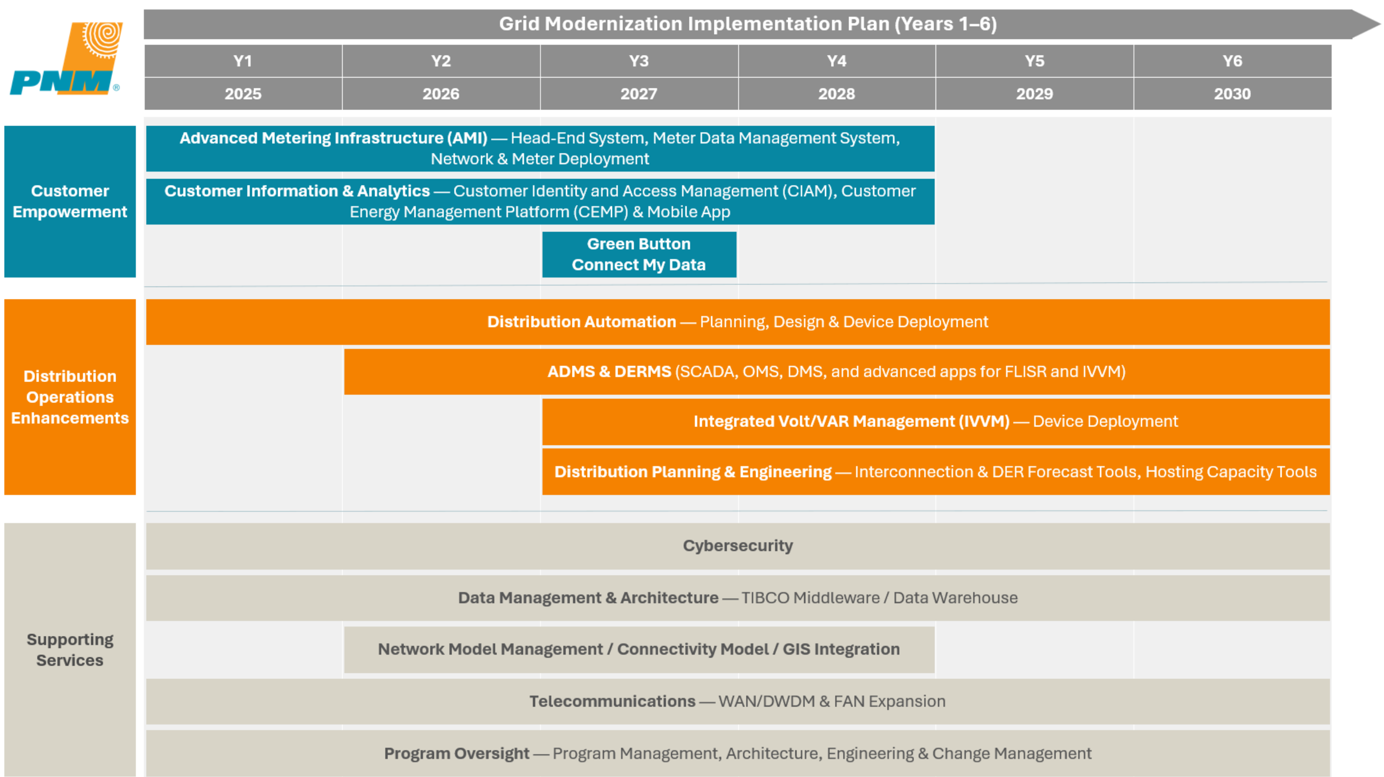
These metrics measure outcomes from the customer's perspective.

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 table below:



10 APPENDICES

10.1 DER (To be added prior to final report)

- Status of current interconnection queues, including data describing time from application to interconnection, and interconnection cost on a feeder-by-feeder basis
- Current DER deployment by technology, size, and geographic dispersion.
- DER interconnection queue information, such as total projects, nameplate capacity, and type

10.2 Battery Storage (To be added prior to final report)

- Total number of battery energy storage systems, including nameplate and operating information.

10.3 Microgrids (To be added prior to final report)

- Identification and characterization of microgrids

10.4 Electric Vehicles

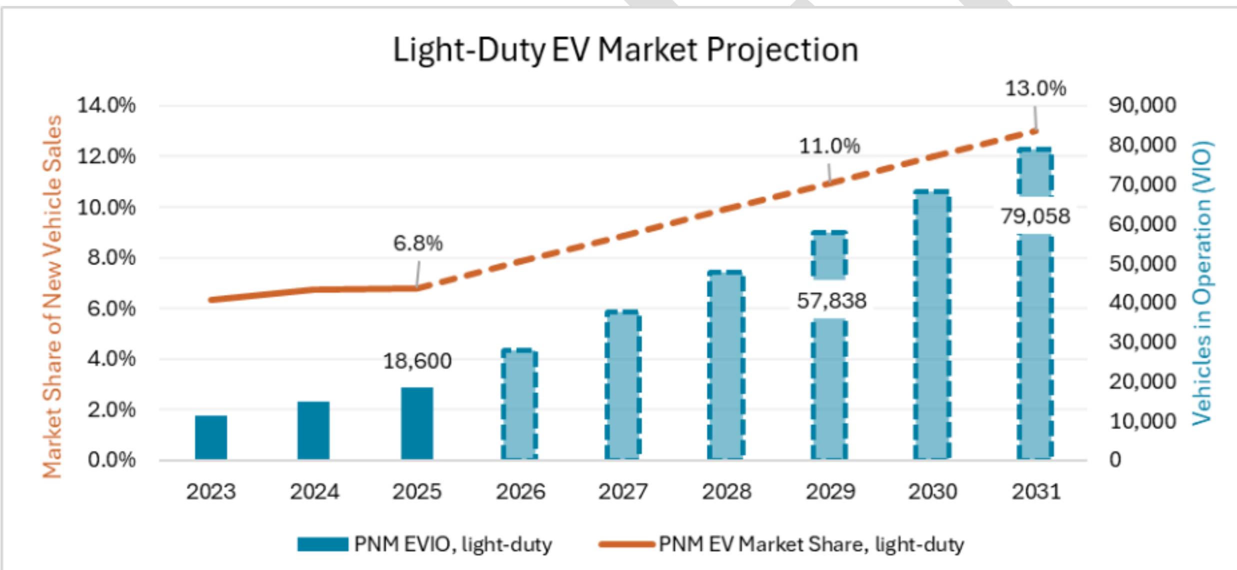
10.4.1 Current Electric Vehicle Market and Electric Vehicle Market Projections

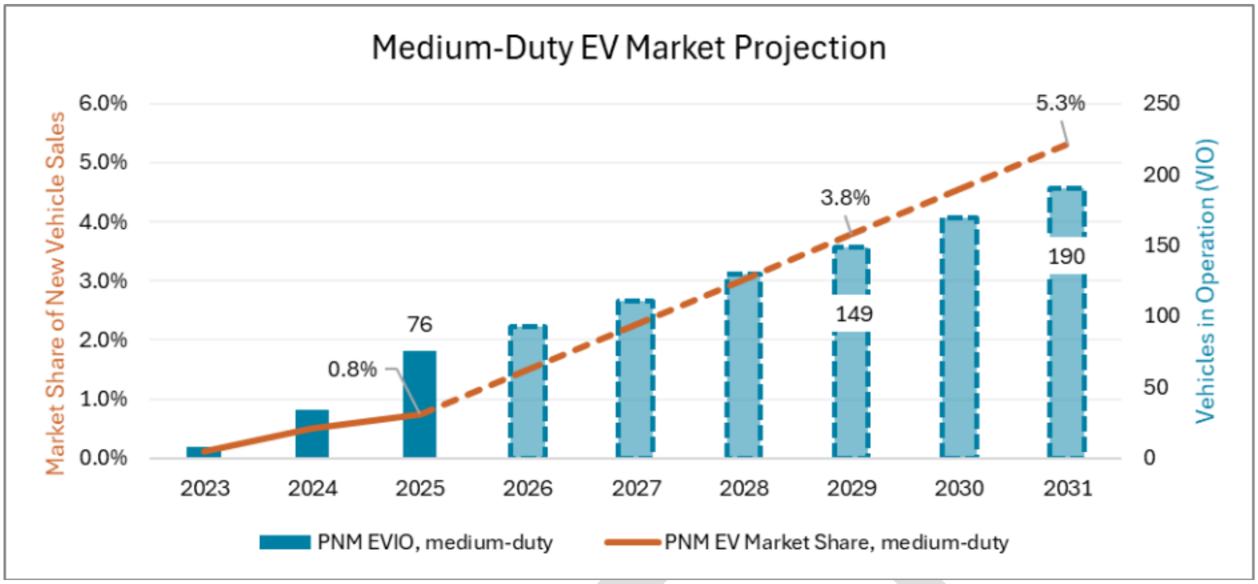
Electric vehicle technologies have progressed significantly since the 2024-2026 TEP was filed in June 2023, but the market for electric transportation is uncertain. On the national level and in PNM's service territory, the rate of growth in EV adoption has fluctuated significantly month-to-month over 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.

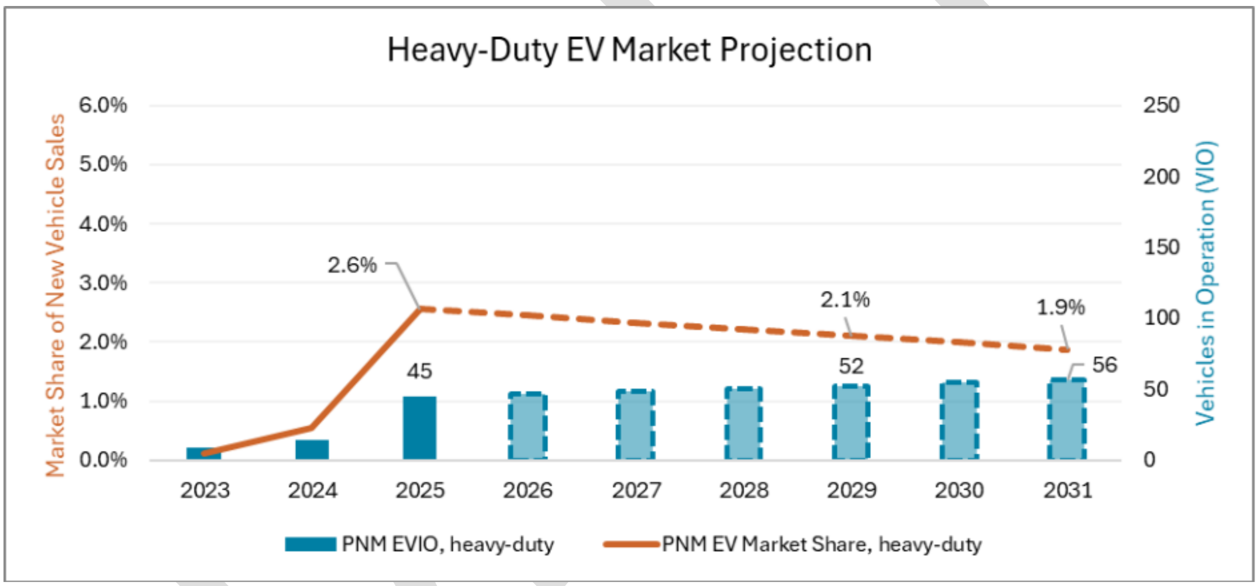
Two of the most common measures of EV adoption are the market share of new vehicle sales and the number of electric vehicles in operation (EVIO). Market share is a leading indicator that quantifies the popularity of EVs among consumers in the market for a new vehicle, while EVIO is a lagging indicator 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.

	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





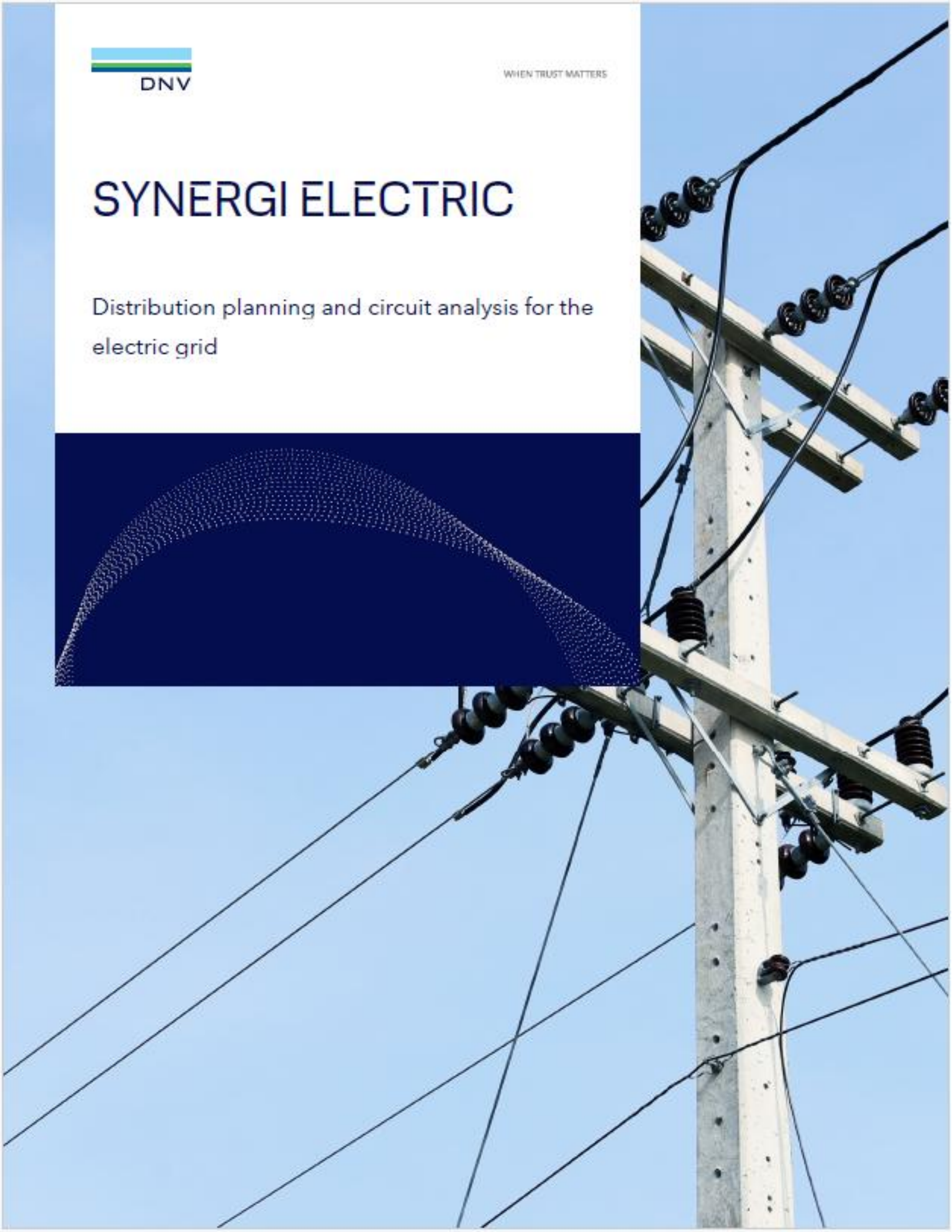


10.4.2 Current and Projected Number and Capacity of Public EV Charging Stations

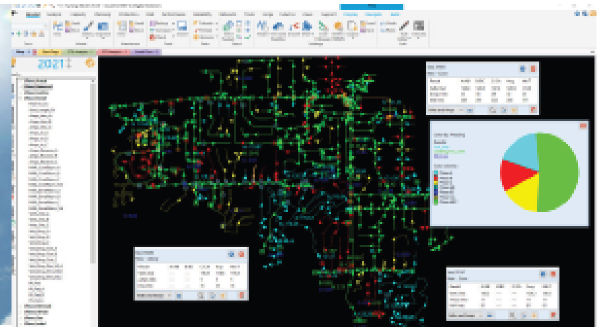
PNM does not have visibility to the total number and nameplate capacity of public charging stations across its service territory; however, PNM has developed a projection (below) of the number of public charging stations necessary to adequately support the adoption of transportation electrification consistent 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 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.[4]

10.5 Synergi Electric


DNV
WHEN TRUST MATTERS
SYNERGI ELECTRIC
Distribution planning and circuit analysis for the electric grid

DNV



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

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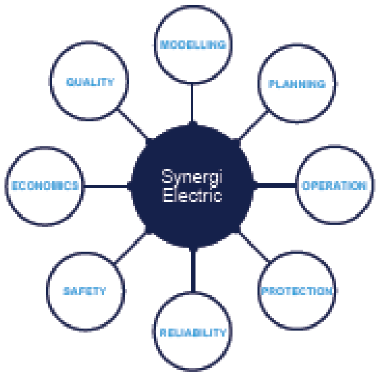

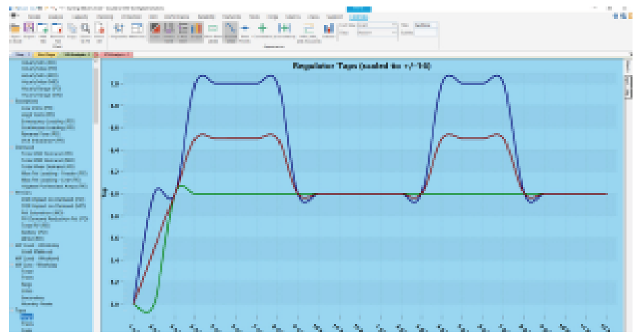

System Protection

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
5. classes, spot loads, distributed loads, EVs, growth options
6. Run load flow analysis: 8760, multi-year and quasi stead state load flow
7. Protect critical equipment and improve reliability with a full suite of tools for coordinating protective devices and evaluating system reliability
8. Analyze networks and looped systems
9. Develop and validate contingency switching plans and find the best possible switching configuration for your system
10. Automate planning studies and operations analysis functions and run batch analysis
11. 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.

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WHEN TRUST MATTERS

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.

ABOUT DNV

DNV is an independent assurance and risk management provider, operating in more than 100 countries. Through its broad experience and deep expertise DNV advances safety and sustainable performance, sets industry standards, and inspires and invents solutions.

DNV is a world-leading provider of digital solutions and software applications with focus on the energy, maritime and healthcare markets. Our solutions are used worldwide to manage risk and performance for wind turbines, electric grids, pipelines, processing plants, offshore structures, ships, and more. Supported by our domain knowledge and Veracity assurance platform, we enable companies to digitize and manage business critical activities in a sustainable, cost-efficient, safe and secure way.

DNV AS
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10.6 Hosting Capacity Improvement Solutions Study

Rule 5568 Hosting Capacity Improvement Study

Rule 568 Hosting
Capacity Improveme