[Cover Page]

SAFE HARBOR STATEMENT

Statements made in this document that relate to future events or Public Service Company of New Mexico's (PNM's), 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, that 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 Integrated Resource Plan that are required to be reported to the New Mexico Public Regulation Commission pursuant to Rule 17.7.3.8E of the New Mexico Administrative Code.

ACKNOWLEDGEMENTS

[Insert acknowledgements of stakeholders, consultants, and contributors to the 2026 IRP process.]

[Drafting space]

TABLE OF CONTENTS

EXECUTIVE SUMMARY

[This section will be added upon completion of the IRP Report]

1. INTRODUCTION

Public Service Company of New Mexico's 2026 Integrated Resource Plan continues PNM's long-term planning effort to provide customers with reliable and affordable electric service while advancing New Mexico's transition to a carbon-free energy future. This IRP builds on the foundation established in PNM's 2023 IRP and reflects the significant changes that have occurred since that filing, including higher near- and long-term load expectations, continued progress in adding renewable and battery storage resources, evolving federal tax and trade policy, regional market developments, and the growing importance of transmission, resource adequacy, and emerging clean firm technologies.

PNM's 2023 IRP identified a path toward meeting the requirements of the Energy Transition Act and achieving a carbon-free resource portfolio by 2045. Since that time, PNM has taken substantial steps to implement that plan. PNM has pursued and received approval for new solar and battery storage resources, advanced resource procurement to meet 2026 and 2028 system needs, filed for approval of a 2029–2032 resource portfolio, continued planning for its exit from the Four Corners Power Plant, and expanded programs for demand-side resources, grid modernization, regional markets, and transmission alternatives. These actions demonstrate meaningful progress toward decarbonization while preserving the reliability and flexibility needed to serve customers under changing system conditions. PNM's commitment to decarbonize its generation portfolio aligns with the state of New Mexico's policy to achieve deep reductions to its carbon footprint.

At the same time, the planning environment has changed materially since the 2023 IRP. PNM's load forecast has increased, driven in part by broader electrification trends, economic development opportunities, and large-load interest in New Mexico. Resource development timelines have lengthened because of supply-chain constraints, permitting challenges, inflationary pressures, and increased demand for generation, storage, and transmission equipment. Federal policy has also shifted, affecting the availability and timing of clean energy tax benefits that had been expected to help reduce customer costs. These developments reinforce the need for proactive planning, earlier procurement, and a flexible framework that can adapt as market conditions, customer needs, and technology options continue to evolve.

The 2026 IRP is therefore not limited to identifying a single static least-cost portfolio. Instead, it evaluates a broad range of plausible futures, scenarios, and sensitivities to understand the resource needs that may emerge under different combinations of load growth, technology cost, policy, reliability, and market conditions. This planning approach recognizes that the next several years will be critical for positioning PNM's system for the 2030s and beyond. Many resources that may be needed in the mid-2030s require years of advanced development, including generation, storage, transmission, demand-side capabilities, and emerging clean firm technologies. As a result, decisions made during the 2026 IRP Action Plan period will influence PNM's ability to reliably and affordably serve customers well into the future. PNM has made substantial progress on a carbon free energy portfolio. Since the previous IRP, PNM has added substantial solar and storage resources.

Each IRP provides an opportunity to refine PNM's plans to meet the challenges ahead as the future comes into sharper focus. PNM has reduced or proposed to reduce the need in the near term for firm generating resources through extending the operation of the Valencia Energy Facility through a new PPA and requesting a life extension for the Reeves Generating Station. However, a 2031 exit from the Four Corners Power Plant (FCPP) will lead to the loss of 200 MW of firm generating capability. New resources to compensate for an exit from FCPP have been requested in the 2029 to 2032 resource filing which will help reshape the resource portfolio and move the system toward a higher percentage of carbon-free energy.

While there is great opportunity ahead, there is also significant challenges. Many of the options require years of lead time and preparation to integrate into the portfolio. Permitting and development timelines require years to complete – and more recently, have extended beyond historical norms – which means planning must be done today for 2030 system needs. Achieving a reliable, sustainable, and affordable portfolio requires proactive planning and deliberate, sustained action.

A central purpose of this IRP is to identify the types and timing of resources PNM may need to maintain reliability, manage costs, reduce carbon emissions, and comply with applicable regulatory and environmental requirements. PNM's analysis considers commercially available resources such as solar, wind, battery storage, energy efficiency, demand response, and natural gas capacity, while also evaluating longer-lead and emerging technologies that may become important to achieving a reliable carbon-free portfolio by 2045. These technologies may include long-duration energy storage, advanced or enhanced geothermal, hydrogen-capable resources, advanced nuclear, fusion, and other clean firm options as they become commercially viable.

Stakeholder engagement remains a fundamental part of PNM's IRP process. Consistent with the updated New Mexico Public Regulation Commission IRP Rule, PNM conducted a facilitated stakeholder process with the support of the Commission-appointed independent facilitator. Through workshops, office hours, written feedback, and stakeholder-requested modeling, participants provided meaningful input on assumptions, modeling approaches, scenarios, resource technologies, transmission considerations, the Statement of Need, and the Action Plan. PNM appreciates the time and expertise contributed by stakeholders and has incorporated stakeholder perspectives throughout this IRP where appropriate.

This IRP also reflects lessons learned from implementation of the 2023 Action Plan. PNM has advanced procurement activities, evaluated emerging and long-lead technologies, assessed continued use of existing generation sites, expanded analysis of demand-side resources, progressed grid modernization efforts, and continued participation in regional market development. Several of these efforts remain ongoing and are carried forward or refined in the 2026 Action Plan. The 2026 IRP therefore serves both as a progress report on prior planning commitments and as a forward-looking roadmap for the next phase of PNM's resource transition.

Ultimately, the 2026 IRP is intended to provide a transparent and disciplined planning framework for navigating uncertainty. The specific resources that PNM ultimately procures will depend on competitive solicitation results, regulatory approvals, project viability, customer needs, cost trends, technology development, transmission availability, and reliability requirements. The IRP does not predetermine the outcome of future procurement processes; rather, it identifies the resource needs, risks, and decision pathways that should guide those processes. By maintaining flexibility and beginning critical planning activities early, PNM can better manage affordability, support economic development, maintain reliability, and continue progress toward a carbon-free system.

The sections that follow describe PNM's planning framework, stakeholder process, planning objectives, review of the 2023 IRP, key developments since the prior IRP, modeling enhancements, portfolio analysis, Statement of Need, and Action Plan. Together, these elements provide the basis for PNM's long-term resource strategy and the near-term actions needed to continue serving customers reliably and responsibly through a period of significant industry transformation.

1.1 IRP Policy Considerations

PNM has prepared this IRP in accordance with 17.7.3 New Mexico Administrative Code (NMAC), Integrated Resource Plans for Electric Utilities (IRP Rule). The IRP Rule was originally issued by the NMPRC on March 1, 2007, and has been amended on four occasions, most recently on October 27, 2022. As established by the IRP Rule, the purpose of the IRP is to identify the most cost-effective portfolio of resources to meet the future needs of customers:

> The objective of this rule is to set forth the commission's requirements for the preparation, filing, review, and acceptance of integrated resource plans by public utilities supplying electric service in New Mexico in order to identify the most cost-effective portfolio of resources to supply the energy needs of customers.
>
> – 17.7.3.6A NMAC

The IRP Rule further requires that New Mexico electric public utilities file an IRP every three years that includes the following information (17.7.3.89B NMAC):

- A description of existing electric supply-side and demand-side resources;
- A current load forecast;
- A load and resources table;
- Identification of resource options;
- A determination of resource portfolios;
- A Statement of Need;
- An Action Plan

The Statement of Need requires this IRP to clearly articulate what types and quantities of resources will be needed to meet future resource needs:

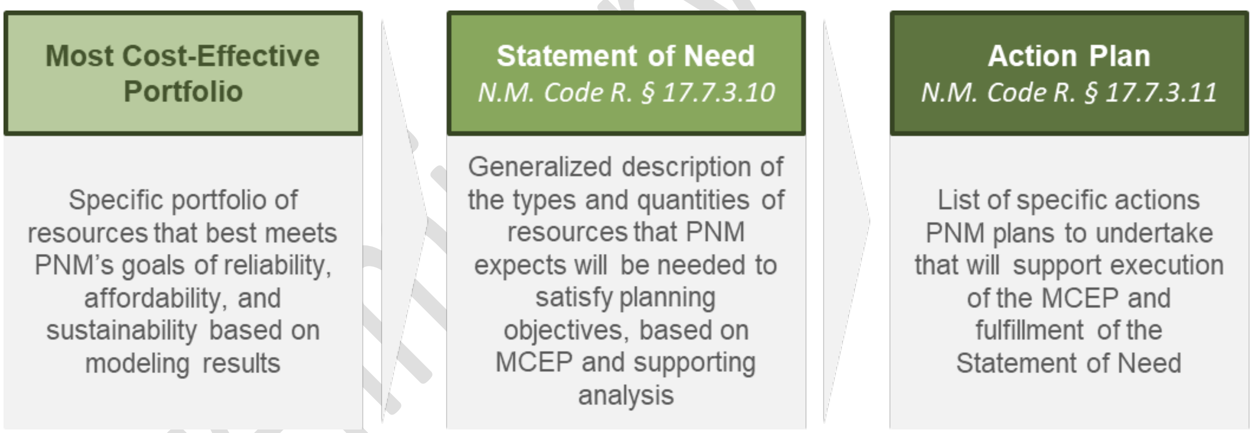
A. The statement of need is a description and explanation of the amount and the types of new resources, including the technical characteristics of any proposed new resources, to be procured, expressed in terms of energy or capacity, necessary to reliably meet an identified level of electricity demand in the planning horizon and to effect state policies.

B. The statement of need shall not solely be based on projections of peak load. The need may be attributed to, but not limited by, incremental load growth, renewable energy customer programs, or replacement of existing resources, and may be defined in terms of meeting net capacity, providing reliability reserves, securing flexible resources, securing demand-side resources, securing renewable energy, expanding or modifying transmission or distribution grids, or securing energy storage as required to comply with resource requirements established by statute or commission decisions.

– 17.7.3.10 NMAC

The IRP Rule requires this IRP to designate a "Most Cost-Effective Portfolio" (MCEP) as part of its stated objective. The determination of the MCEP serves as an important step in creating the Statement of Need and Action Plan. Figure [ ] illustrates the relationship between the Most Cost-Effective Portfolio, the Statement of Need, and the Action Plan.

FIGURE [ ]. RELATIONSHIP BETWEEN THE MOST COST-EFFECTIVE PORTFOLIO, STATEMENT OF NEED, AND ACTION PLAN



The IRP Rule establishes a facilitated stakeholder process led by an NMPRC appointee. The facilitated stakeholder process established by the rule enhances the transparency of this planning process and allows third-party stakeholders to have direct input into this IRP. Through this process, PNM's Statement of Need and Action Plan are created with consultation and input from stakeholders and NMPRC staff. PNM provided IRP stakeholders are further empowered by the ability to access, under confidentiality, the IRP modeling software used in this IRP, enabling the ability to perform their own independent analysis.

The facilitated stakeholder process continues after PNM files its IRP. The existing process by which stakeholders comment on the filing will become more interactive, as PNM replies to all stakeholders having either adopted their proposed changes or providing a rationale for not doing so.

1.1.1 IRP Planning Process

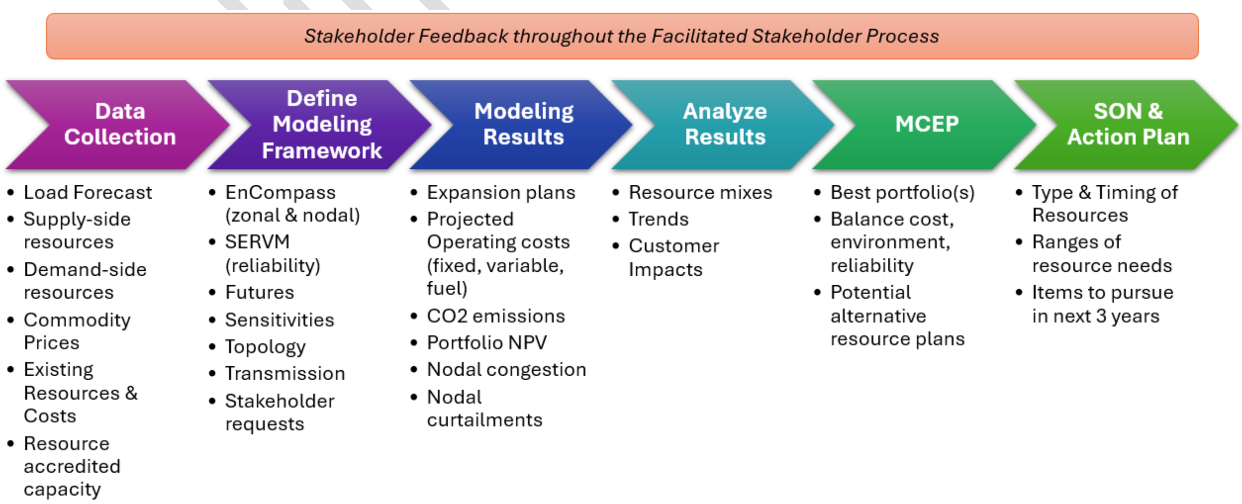
The IRP planning process identifies the mix of resources that, together, reliably meets system operational requirements, adheres to regulatory requirements, and mitigates environmental impacts, all while minimizing costs to customers. This planning process ensures PNM can respond to projected future events and ensure adequate resources are available to meet a variety of expected system conditions demand and maintain service reliability. The IRP is renewed every three years, with earlier notifications to the NMPRC and stakeholders if material changes in assumptions would lead to a revised course of action.

The 2026 IRP planning process horizon spans a 20-year time period; for this IRP, the horizon considered spans between 2026 through 2045. By evaluating PNM's IRP portfolios that incorporate milestone requirements set forth in the ETA through the complete transition to its goal, PNM strives to demonstrate that the actions undertaken herein are not only in the best interests of customers today but will enable its complete transition to a carbon-free portfolio by 2045.

The IRP process is forward-looking, and therefore subject to uncertainty; wherever possible, PNM mitigates this uncertainty by relying on known and reasonably expected variables to develop assumptions. These include assumptions about technology availability and price, current regulations, anticipated future regulations, and consumer usage patterns.

PNM engaged in a robust and collaborative process for its IRP analyses to identify the MCEP, develop the Statement of Need, and establish the Action Plan. The process included reviewing existing resources, forecasting future energy needs, examining future resource options, and designing scenarios, sensitivity analyses, and probabilities of risks and uncertainties to evaluate various resource portfolios—all summarized in Figure [ ]. Throughout the process, the PNM Integrated Resource Planning team worked to solicit and incorporate input from participants in the facilitated stakeholder processes. Details regarding the facilitator stakeholder process are described in the Section [...].

FIGURE 2-1. SUMMARY OF IRP PLANNING PROCESS



Relationship to Transmission Planning Processes

PNM's Integrated Resource Plan (IRP) and its Transmission Planning process are distinct but interdependent functions, each with a different regulatory scope, modeling approach, and planning horizon. Transmission planning accounts for both retail and wholesale network customers under PNM's Open Access Transmission Tariff (OATT) and is governed by NERC's mandatory TPL-001 Reliability Standards, using a ten-year planning horizon updated annually and relying on granular power flow and electromagnetic transient models. The IRP, by contrast, is limited by rule to serving New Mexico jurisdictional retail customers, spans a twenty-year horizon on a three-year cycle, and relies on capacity expansion modeling to identify the least-cost, reliable resource portfolio. While the IRP does not independently determine specific transmission lines or elements needed to serve the system, it incorporates the expected costs of transmission upgrades associated with new generation additions, using information provided by PNM's Transmission Planning team.

Despite these differences, the two processes function as a continuous, mutually reinforcing feedback loop rather than as sequential or independent activities. Transmission Planning provides the IRP with critical deliverability constraints, generator interconnection costs and timing, and reliability need dates that shape which resources can be feasibly selected and when they can be placed in service; in turn, the IRP's preferred resource portfolios and public policy assumptions become key inputs to subsequent TPL-001 Planning Assessments and regional transmission plans. PNM has reinforced this coordination organizationally by combining its formerly separate IRP and Transmission Planning teams into a single Integrated System Planning process, reflecting an industry-wide shift toward more tightly coordinated resource and transmission planning as the pace and scale of the energy transition accelerates.

This shift toward "Integrated System Planning" reflects a broader industry recognition that a utility's generation, transmission, distribution, and customer-program investments are most effectively planned together rather than in isolation. For PNM, adopting this approach means that transmission analysis can be incorporated more directly into future IRP cycles, better aligning near-term operational realities with long-term resource decisions. PNM continues to seek out additional opportunities to strengthen this integration across its planning processes.

Key Term

Integrated System Planning (ISP) refers to a coordinated process in which a utility develops a single long-term plan that links together the different elements of its system – which may include generation, transmission, distribution, and customer programs.

1.2 Public Stakeholder Process

Active and broad stakeholder participation is a crucial element of a successful planning process that serves the public interest of New Mexico, and the diversity of perspectives offered by PNM's stakeholders directly enhances the quality of the IRP. The updated New Mexico Public Regulation (NMPRC) IRP Rule also places heightened emphasis on transparency and the importance of robust stakeholder participation, specifying that the utility must engage in a facilitated stakeholder process led by a Commission-appointed independent facilitator.

In late 2025, following Commission approval PNM initiated the 2026 Facilitated Stakeholder Process early to allow for an extended period of time – well beyond the minimum timeframe required by the Rule – to share information and solicit public feedback across a broad range of planning topics. The Commission appointed Gridworks to lead and facilitate this process. Between December 2025 and August 2026, PNM hosted nine open workshops covering IRP modeling, methodologies, and analytical results, alongside multiple office hours and Q&A sessions open to all stakeholders.

In accordance with the transparency mandates of the IRP Rule, all stakeholder modeling requests and discussions have been incorporated into this report and can be found in Section [ ]. A complete schedule of stakeholder workshops and office hours is provided in Table [ ] and a comprehensive summary of all workshop proceedings and discussions across all stakeholder meetings can be found in Appendix [ ].

TABLE [ ]. PNM'S 2026 IRP FACILITATED STAKEHOLDER PROCESS MEETINGS

Meeting	Date	Topic
Workshop 1	Dec 9, 2025	Utility Vision and Stakeholder Interests
Workshop 2	Jan 14, 2026	PNM System, Challenges and Opportunities
Office Hour	Jan 27, 2026	2023 IRP: Three Studies
Workshop 3	Feb 11, 2026	Modeling Foundation
Office Hour	Feb 18, 2026	Geothermal Costs
Office Hour	Mar 4, 2026	Transmission Modeling
Office Hour	Mar 5, 2026	Follow Up to Workshop 2 and 3
Workshop 4	Mar 11, 2026	Modeling Update and Stakeholder Run Ideas
Office Hour	Mar 25, 2026	Follow up to Workshop 4
Workshop 5	Apr 15, 2026	Base Case Results and Refining Stakeholder Requested Model Runs
Office Hour	Apr 20, 2026	PNM Transmission Modeling
Workshop 6	May 13, 2026	Model Results and Implications
Office Hour	Jun 10, 2026	Remaining Stakeholder Modeling Results
Workshop 7	Jun 17, 2026	Utility Decisions, Statement of Need, Action Plan
Workshop 8	Jul 15, 2026	Complete Statement of Need and Action Plan
Workshop 9	Aug 12, 2026	Review Key IRP Elements

Over the course of this nine-month process, stakeholders contributed to the development of the IRP in many meaningful ways. Notably, stakeholders:

- Contributed a broad range of recommendations for scenarios and sensitivities to study;
- Brainstormed topics and presented language for inclusion in PNM's Statement of Need for joint discussion;
- Offered actionable suggestions for shaping PNM's Action Plan; and
- Provided perspectives that challenged conventional thinking and ultimately led to a more robust final product.

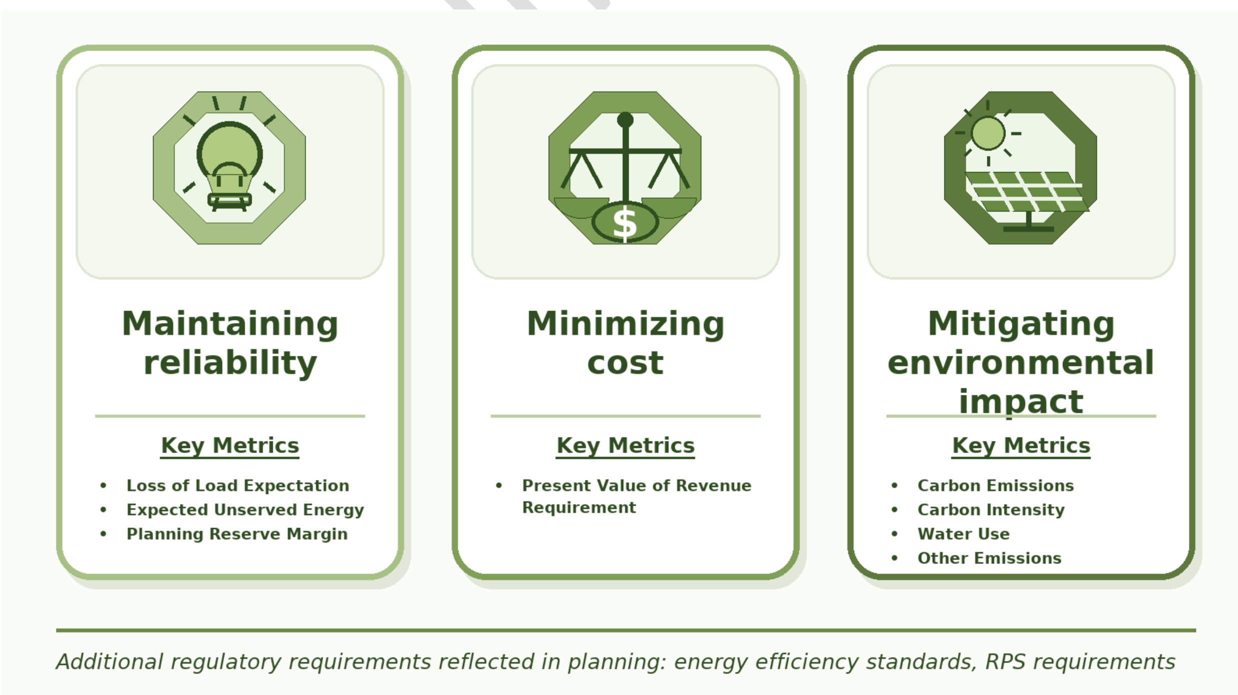
Throughout this document, PNM highlights the most prominent and direct stakeholder contributions that helped shape the ultimate plan. Additionally, stakeholders provided valuable feedback on areas to improve the process for future IRP cycles.

PNM deeply values the many hours that stakeholders dedicated to this effort. Going forward, continued stakeholder engagement will remain essential to shaping the future of PNM's resource portfolio, and PNM invite any interested parties wishing to contribute to future planning steps to notify PNM of their interest.

1.3 Planning Objectives

Consistent with the objectives used in the past to develop the IRPs, this IRP aims to identify the types and timing of resources that meet customer electricity supply needs reliably, with limited environmental impact, and at the lowest reasonable cost. A secondary objective of this IRP is to study and outline the challenges and uncertainties PNM expects to confront as its portfolio changes and progresses to the mandated 2045 carbon-free goal.

Figure [ ]: Core objectives considered in PNM's long-term planning process



Reliability

Reliable electric service for PNM's customers is of paramount importance. They expect and rely on stable, reliable electric service for their homes and businesses, and fulfilling this obligation is a matter of public welfare and safety.

PNM prioritizes reliability as a required condition for all portfolios in the IRP planning process; this objective is consistent with the standards for electric service set forth in 17.9.560.13C NMAC:

> The generating capacity of the utility's plant supplemented by the electric power regularly available from other sources must be sufficiently large so as to meet all normal demands for service and provide a reasonable reserve for emergencies.
>
> – 17.9.560.13C NMAC[1]

Reliability planning informs both the amount of resources needed in PNM's portfolio and how those resources are operated. PNM evaluates resource adequacy using an industry-standard LOLE target of 0.1 days per year, supplemented by EUE to capture the frequency, duration, and magnitude of potential reliability risks. PNM also models portfolio operations on an hourly basis to ensure operating reserves are maintained, consistent with NERC reliability standards.

This IRP further incorporates extreme-weather stress tests to evaluate portfolio resilience as renewable and storage penetration increases.

Affordability

The IRP compares potential plans using the net present value of revenue requirements across a 20-year period (2026-2045) to identify the best plans to meets reliability, environmental, and regulatory requirements at the lowest reasonable cost.

Each portfolio considered is constructed in a long-term capacity expansion model that minimizes the net present value of costs over the planning horizon subject to reliability, environmental and other regulatory requirements. The planning horizon costs, referred to as revenue requirements in the expansion planning modeling, includes capital costs, fixed costs, emission costs, fuel costs, variable costs, contract costs, net market purchase costs, and others.

A cost-effective portfolio that accounts for reliability, environmental impact, and a rapidly changing technology landscape must remain flexible. Because today's least-cost pathway may not remain least cost as costs and risks evolve, PNM's planning process focuses on common themes across portfolios, including resource needs, attributes, and timing. This approach supports prudent decision-making, avoids premature technology commitments, and allows future re-optimization as emerging technologies mature. By preserving flexibility, PNM can better protect customer affordability and take advantage of changing market conditions.

Environmental Impact

[1] http://164.64.110.134/parts/title17/17.009.0560.pdf

The third planning objective is to mitigate environmental impacts. PNM recognizes climate change as a critical issue and is committed to protecting the local environment, conserving natural resources, and reducing greenhouse gas emissions associated with fossil-based generation. In response to stakeholder priorities, PNM has taken meaningful action over the past two decades to support a cleaner, more secure, and sustainable energy future.

1.4 Review of 2023 IRP

The 2023 IRP continued PNM's progress along its pathway toward meeting the New Mexico Energy Transition Act's (ETA) carbon-free goal by 2045. This section provides an overview of the 2023 IRP outcomes and details the progress made on each element of its associated Action Plan.

Key Findings

PNM's last IRP was filed with the New Mexico Public Regulation Commission (NMPRC) in December 2023, mapping the utility's resource planning from 2023 to 2043, which was accepted by the NMPRC in April 2024. Subsequently, PNM filed a Notice of Material Event arising from updated demand and energy load forecasts that demonstrated a material increase to PNM's expected load needs about a month later. That resulted in PNM's October 2024 filing of its updated 2023-24 IRP Supplemental Analysis, which was based on both revised modeling and associated Statement of Need.

Three years later, PNM remains firmly committed to its long-term goal to transition to a fully carbon-free system and has achieved a significant reduction in its carbon intensity and is currently operating below 400 lbs/MWh on a portfolio basis. In the intervening years, PNM has continued to transition its portfolio with the energization of its approved 2026 Resource Portfolio, which includes 560 MW of new installed resources and storage, including 310 MW of new 4-hour Battery Energy Storage System (BESS), and 250 MW of new solar resources.

Additionally, PNM and its partners are progressing on the development of 597 MW of resources and storage approved in the 2028 Resource Filing, including 330 MW of new 4-hour BESS, and 100 MW of new solar, along with continuation of the 167 MW Valencia Energy Facility and the 290 MW of solar resources and 268 MW of four-hour BESS for PNM's Special Service Contract customer as 36B resources. In total, since the 2023 IRP, PNM has added or obtained approval for 1,715 MW of installed resources and storage.

PNM additionally filed for approval of its 2029-2032 Resource Portfolio to replace PNM's 200 MW interest in FCPP, serve new load demand, diversify the portfolio, and lower the portfolio's carbon intensity by another 50% by 2032, to 200 lbs/MWh. That portfolio includes 800 MW of new wind resource, 240 MW of new solar, 610 MW of new 4- and 8-hour BESS, and 40 MW of new natural gas resource (depreciated by 2044). That portfolio allows PNM to continue to meet its 0.1 Loss of Load Expectation (LOLE) standard and is currently pending NMPRC consideration.

PNM has continued to build operating experience with renewable and short-duration storage technologies and identified plans to exit its interest in the Four Corners Power Plant (FCPP), the last remaining coal plant and most carbon-intensive currently in the portfolio. While the Inflation Reduction Act helped provide federal tax benefits that supported many of PNM's resource developments in these intervening years, the tax-advantaged pricing going forward is set to phase out as a result of the OBBBA OF 2025.

Beyond the resource additions described above, PNM also completed a 20-year Transmission Outlook to evaluate a variety of potential conceptual transmission line expansions that provide potential benefit to the system. This evaluation helped identify four transmission options that PNM evaluated in this 2026 IRP. It is a valuable resource that identifies opportunities to increase market access and support dynamic resource sharing with neighboring entities that becomes continually important to reliability, resilience, and affordability on the path to carbon free.

1.4.1 Four-Year Action Plan

The 2023 IRP concluded with an Action Plan that identified strategic activities designed to help PNM continue to reliably meet customer needs and expectations at a reasonable cost while making steady progress toward a carbon-free portfolio. PNM has made significant progress toward completing the elements of the 2023 Action Plan. Those action plan elements not fully resolved between the 2023 and the 2026 IRPs remain ongoing and are explored within this plan. The status of the elements since the 2nd Action Plan update filed with the Commission is discussed briefly below and summarized in Table 0-1

Table [ ]. Status of 2023 IRP Action Plan Items

#	Action Plan Elements	Status
1	Issue an all-source RFP for resources coming online between 2029 and 2032	Completed/In Progress
2	Issue an RFI/RFP for long lead time resources or newer technologies that could deliver between 2029 and 2035	Revised/Completed
3	Evaluated opportunities to abandon FCPP earlier than 2031 as available and in the interest of customers. Notice to the Commission of PNM decision against an early exit was filed on April 23, 2024.	Completed/ Concluded
4	Evaluate the ability to create new (or improve existing) demand response and other customer programs (e.g. customer sited storage, interruptible rates)	Completed
5	Assess the ability to add capacity at PNM's existing plant sit es	Completed
6	Continue to explore the expanded participation in regional m arkets	Ongoing
7	Assess the need to utilize other reliability metrics in planning	Ongoing

8	Initiate stakeholder workshops and meeting for the 2026 IRP in advance of the required six months stakeholder process as required under the IRP Rule	Completed
9	Complete the 2026 IRP	Completed

Detailed Progress by Action Plan Element

Since the filing of the *Second Action Plan Update* in Case No. 23-00409-UT, PNM has progressed each action item through concrete operational, procurement, and regulatory actions. Detailed status updates for each of the elements listed in Table [ ] are provided below:

1. 2029-2032 All-Source RFP

   PNM issued an all-source request for proposal ("RFP") for resource additions in the 2029 to 2032 timeframe on December 30, 2024. RFP bids were received by May 14, 2025. PNM completed Phase 1, Phase 2, and Phase 3 bid evaluations and determined a preferred portfolio of resources to be added during that window. PNM filed the 2029–2032 Resource Plan with the NMPRC on May 29, 2026. Additionally, PNM issued the 2029–2032 All-Source Generation Resources RFP Supplement on May 1, 2026.
2. Issue RFI/RFP for long lead time resources

   PNM completed its evaluation of data on emerging and long lead time resource technologies through collaboration with the Electric Power Research Institute ("EPRI"). Updated technology assumptions and resource characteristics derived from this research were fully incorporated into the 2026 IRP analysis to evaluate a comprehensive range of future resource options.
3. FCPP Exit

   PNM completed its evaluation of an exit from FCPP and documented the results in the 2024 Action Plan Update. The replacement resources for the 2031 exit from FCPP were evaluated and included as part of the 2029-2032 resource plan filing along with an abandonment filing to exit FCPP.
4. Evaluate ability to create new DSM/Customer programs

   In the fall of 2025, PNM contracted with ICF to conduct a Residential Appliance Saturation Survey ("RASS"), an Energy Efficiency and Demand Response Potential Study. Through these studies, PNM and ICF evaluated a broad range of demand-side resources to identify viable opportunities for meeting future customer needs. The resulting potential estimates and program assumptions were fully incorporated into the 2026 IRP analysis.
5. Expand Capacity at PNM's existing plant sites

   PNM assessed opportunities to utilize and expand capacity at existing generation sites, resulting in three notable outcomes (each addressed in more detail in Section [ ])::

- Valencia Energy Facility: NMPRC approved a PPA extension adding approximately 15 MW of additional capacity while allowing the existing capacity to remain available at this site for an additional 11 years (through 2039).
- Reeves Generating Station: PNM evaluated extending the potential operating life and intends to continue operation of Reeves Generating Station through the end of 2044 (previously planned to retire at the end of its depreciable life in 2030).
- Solar Paired Battery Storage: The NMPRC approved five 6 MW / 24 MWh (4-hour) distribution-connected battery storage projects located at existing PNM-owned solar facilities.

6. Evaluate expanded participation in regional markets

   PNM continued evaluating regional market opportunities to optimize system operations and enhance grid efficiency. On July 1, 2025, PNM signed an implementation agreement to join California ISO's (CAISO) Extended Day-Ahead Market (EDAM) with a target go-live date of October 2027. Additionally, PNM also announced its intention to withdraw from the Western Resource Adequacy Program (WRAP) effective November 2027 while continuing participation through the transition period.
7. Assess reliability metrics

   PNM continued evaluating the use of enhanced reliability and resource adequacy metrics in its long-term planning. As part of this effort, PNM participated in the Southwest Resource Adequacy (SWRA) Study, which examined reliability, grid resilience, and resource adequacy challenges under a wide range of future conditions and extreme weather scenarios.
8. Implement stakeholder process early

   PNM initiated the 2026 IRP stakeholder process well ahead of the required six-month timeline mandated under the IRP Rule. On July 9, 2025, PNM requested a variance from the Commission to initiate the stakeholder process early to allow for a nine-month facilitated process. Following Commission approval, the facilitated stakeholder process began in December 2025, providing approximately nine months of robust stakeholder engagement prior to the September 2026 IRP filing.

1.5 Updates since the 2023 IRP

The years since filing the 2023 IRP have seen significant operational, market, and regulatory developments. This section provides contextual updates on key developments occurring outside the specific scope of the 2023 Action Plan.

1.5.1 Reeves Generating Station Retirement

PNM evaluated whether the Reeves Generating Station should continue operating beyond the end of its depreciable life in 2030. To support this evaluation, PNM engaged an external consultant, Black & Veatch, to estimate the capital investments and ongoing maintenance expenditures required to support continued operation of the facility through 2044.

Portfolio comparisons demonstrated that extending the operating life of Reeves reduced the 20-year net present value (NPV) of system costs by approximately $50 million relative to PNM's preferred portfolio of replacement resources in PNM's 2029-2032 resource application.

Additionally, RGS continues to play a critical role in supporting transmission reliability on PNM's system, particularly in the Albuquerque load pocket. During periods of high system demand and under specific transmission outage conditions, the facility provides local voltage support and helps mitigate transmission constraints.

The Reeves extension was consistently selected as the lower-cost option across all portfolios evaluated, with the greatest value observed in scenarios that included the large load additions considered in the 2029–2032 Resource Application. As a result, the Reeves extension was considered as part of the 2029–2032 resource planning process and incorporated into the 2026 IRP.

1.5.2 Distribution Battery Filing/30 MW BESS

Since filing the 2023 IRP, PNM advanced deployment of distribution-connected battery energy storage resources to address hosting-capacity constraints and support increasing levels of distributed energy resources on its system. On April 9, 2026, the New Mexico Public Regulation Commission approved PNM's application to construct, own, and operate 30 MW of battery energy storage systems consisting of five 6-MW, four-hour battery installations located at existing PNM-owned solar facilities.

The fleet of distribution sited storage is designed to increase distribution-system hosting capacity, support additional distributed generation and community solar interconnections, improve voltage support and power quality, defer traditional distribution upgrades, and enhance overall system reliability. The battery systems are expected to be operational by mid-2027 and will provide additional operational flexibility by storing excess solar generation and discharging energy during periods of higher demand.

1.5.3 Grid Modernization Update

In 2020, the Legislature adopted Section 62-8-13 ("Grid Modernization Statute" or "Statute") of the New Mexico Public Utility Act ("PUA") to encourage grid modernization projects that benefit utility customers and the State of New Mexico. On October 3, 2022, PNM filed an application pursuant to the Grid Modernization Statute for approval of a six-year plan to implement grid modernization components, including advanced metering infrastructure ("AMI"), to modernize its electric distribution grid in Docket No. 22-00058-UT. On October 17, 2024, the Commission issued its Final Order approving PNM's application as modified by Recommended Decision and Final Order.

PNM's Grid Modernization Plan has progressed from foundational planning and procurement activities in 2025 to full-scale deployment of grid modernization technologies in 2026, with increasing operational integration expected in 2027.

The most significant milestone is the commencement of large-scale Advanced Metering Infrastructure (AMI) meter installation, including execution of contracts for AMI vendors and system integrators, deployment of AMI network access points, implementation of AMI head-end and Meter Data Management System (MDMS) environments, and initiation of integration efforts with the Customer Information System (CIS), which is expected to continue through 2028.

PNM is also deploying telecommunications infrastructure, cybersecurity enhancements, and distribution automation equipment across its service territory. During the initial phases of the Grid Modernization Plan, PNM advanced upgrades to its telecommunications network, including modernization of legacy communication systems and improvements to its wide area network infrastructure. PNM also procured and began deploying cybersecurity technologies and network monitoring tools to enhance visibility, strengthen system security, and support the increasing digitalization of grid operations. In addition, distribution automation deployments are moving forward in the field, providing the communications and operational capabilities needed to support more automated and responsive operation of the distribution system.

Customer-facing initiatives, including the Customer Energy Management Platform (CEMP) and mobile application, are advancing toward broader implementation, enabling customers to access and manage energy-use information. PNM executed vendor contracts and continued development of these customer-facing systems, while also deploying Customer Identity and Access Management (CIAM) capabilities and initiating data integration and data warehouse activities. PNM intends to make these tools available ahead of full AMI deployment so customers can become familiar with the platform and begin engaging with their energy information. As AMI data becomes available, these systems are expected to provide enhanced usage insights, support future energy efficiency and demand response offerings, and improve the overall customer experience by giving customers greater visibility into their electricity consumption.

Additionally, PNM has initiated vendor selection and system design activities for the Advanced Distribution Management System (ADMS), a key platform that will support future distribution system operations and integration of advanced grid capabilities. ADMS represents one of the most significant technology investments within the Grid Modernization Plan and is intended to provide enhanced operational awareness and control of the distribution network. During 2026, PNM is focused on selecting a vendor, completing system design activities, and establishing the framework for implementation. The first release of the ADMS is expected to be completed in 2027 and will be deployed alongside investments in AMI, telecommunications, cybersecurity, and distribution automation. Once implemented, ADMS will enable greater coordination of grid operations and provide the foundation for future advanced applications that support a more intelligent, reliable, and resilient electric system.

1.5.4 2026 Resource Application

On October 25, 2023, PNM filed an application (Case No. 23-00353-UT) with the New Mexico Public Regulation Commission (NMPRC) seeking approval of a portfolio of solar and battery storage resources needed to meet expected system reliability and resource adequacy requirements beginning in 2026. PNM demonstrated that without these resources, its reserve margin would fall below acceptable levels and its Loss of Load Expectation (LOLE) would increase significantly, requiring greater reliance on market purchases and potentially affecting reliability.

The NMPRC issued a Final Order on May 30, 2024, approving all requested resources which are listed in Table [ ].

Table [ ]. Resources procured in the 2026 Resource Application

Project	Commercial Structure	Resource Type	Capacity (MW)	Storage Volume (MWh)	Expected Commercial Operation Date
Quail Ranch	PPA	Solar	100	-	12/19/2025
	ESA	Storage	100	400	1/30/2026
Route 66	ESA	Storage	50	200	11/26/2025
Sky Ranch	ESA	Storage	100	400	4/12/2024
Sandia	PNM Owned	Storage	60	240	6/24/2026

1.5.5 2028 Resource Application

In 2024, PNM initiated the 2028 Resource RFP to acquire new resources needed to maintain system reliability, meet forecasted load growth, and support the transition to a cleaner generation portfolio. The procurement was designed to identify cost-effective resources that could be brought online by 2028 while supporting regulatory requirements and long-term planning objectives. PNM filed the 2028 Resource Application with the NMPRC on November 22, 2024 (Case No. 24-00271-UT), and received approval on June 26, 2025.

The 2028 Resource Application resulted in the selection of five projects: one purchased power agreement ("PPA"), and two energy storage agreements ("ESA"), and two certificates of public convenience and necessity ("CCN").

Table 0-1. Resources procured in the 2028 Resource Application

Project	Commercial Structure	Resource Type	Capacity (MW)	Storage Volume (MWh)	Expected Commercial Operation Date
Sunbelt	PNM Owned	Solar	100	-	5/1/2027
	PNM Owned	Storage	50	200	5/1/2027
Corazon	ESA	Storage	150	600	12/31/2027
Sun Lasso	ESA	Storage	150	600	1/15/2028
Valencia Extension	PPA	Natural Gas	167	-	6/1/2028

1.5.6 2028 Rate 36B Resource Application

In 2025, PNM identified the need for additional renewable generation and energy storage resources to support anticipated load growth associated with Rate 36B customer in New Mexico. Under the amended Special Service Contract, PNM is required to provide sufficient renewable energy to serve this load while ensuring that existing customers are not adversely impacted. PNM filed an application with the NMPRC on June 13, 2025 (Case No. 25-00048-UT), and received approval on December 18, 2025, resulting in the following six projects pursuant to 17.9.551 NMAC, an Amended Rate No. 36B, Amended Rider No. 47 and Amended Rider No. 49.

Table 0-2. Dedicated Rate 36B Customer Resources

Project	Resource Type	Capacity (MW)	Storage Volume (MWh)	Expected Commercial Operation Date
Four Mile	Solar	100	-	12/31/2027
	Storage	100	200	12/31/2027
Windy Lane	Solar	90	-	12/1/2026
	Storage	68	272	12/1/2026
Star Light	Solar	100	-	12/1/2026
	Storage	100	400	12/1/2026

1.5.7 2029-2032 RFP And Resource Application

PNM's 2023 IRP included an Action Plan item to issue an all-source RFP to identify resource needs during the 2029–2032 timeframe. The RFP was issued with the intent to evaluate bid projects and to identify potential resource additions while balancing utility-owned and third-party-owned resources to ensure timely development, system reliability, and resource adequacy.

The 2029-2032 RFP evaluation also included an evaluation of the Reeves Generating Station disposition at the end of its depreciable life in 2030, as well as replacement for PNM's share of the Four Corners Power Plant (FCPP) upon expiration of the associated coal supply contract. Furthermore, the 2023 IRP Action Plan involved assessing resources approaching the end of their contract or depreciable life to determine whether operational extensions were necessary to maintain reliable system operations.

In addition to addressing these Action Plan items, the 2029-2032 RFP was designed to evaluate resource needs driven by PNM's updated load forecast, which included several large load additions:

- Rate 36B customer load increases;
- New large load growth of 350 MW for customers with a signed contract (reimbursement agreement); and

- Additional load of 200 MW to accommodate provisions of Senate Bill 170.

PNM issued the original RFP in December 2024, soliciting offers for resources delivered by the summers of 2029, 2030, 2031, or 2032. After establishing a short-list of bids, PNM requested a bid “refresh” to update cost information following federal tax incentive changes implemented in July 2025. The refreshed bids were received by August 8, 2025. To accommodate the schedule adjusted associated with the bid refresh, PNM requested an extension to January 9, 2026, to submit a preferred portfolio to the Independent Monitor. The refreshed bid data was then incorporated into the candidate resource database for formal evaluation.

PNM performed detailed portfolio modeling of a shortlist of RFP bids, prioritizing portfolio economics, environmental impacts, and reliability analyses. Bid costs, commercial terms and operating characteristics, and the estimated costs and schedule for required transmission upgrades were fully integrated into the planning models prior to initiating the portfolio analysis.

The resulting preferred portfolio include PPAs for solar and wind resources, ESAs for battery energy storage systems (BESS), and a certificate of public convenience and necessity (CCN) for a small peaking gas facility, as described below:

Table 0-3. 2029-2032 All Source RFP Preferred Portfolio

Project	**Type**	**Capacity (MW)**	**Storage Volume (MWh)**	**Expected Commercial Operation Date**
Wildcat	Solar	90	-	2029
	Storage	50	200	2029
Palomas	Wind	800	-	2029
Encino	Storage	110	880	2029
Britton	Storage	60	480	2029
TAG II	Storage	90	720	2029
La Luz II	Natural gas	40	-	2031
Cat Hills	Solar	150	-	2031
	Storage	150	600	2031
Gila Monster	Storage	150	600	2031

1.5.8 Supplemental RFP

On May 1, 2026, Public Service Company of New Mexico (PNM) issued a 2029-2032 All-Source Generation Resources Request for Proposals Supplement ("RFP Supplement"), filed with the New Mexico Public Regulation Commission (NMPRC) pursuant to its 2023 Integrated Resource

Plan Action Plan and a January 2026 Notice of Material Event. The RFP Supplement is structured as a technology-neutral, all-source solicitation seeking 50 to 250 MW of additional accredited capacity to complement resources already identified through the 2025 RFP process and 2029-2032 resource application, which had identified nearly 2,000 MW of new resources, storage, and network upgrades. The supplemental solicitation is driven by the need to address PNM's projected 2029-2032 resource requirements — including existing load growth, approximately 600 MW of newly contracted economic-development loads, and a 200 MW proactive load-readiness margin — while expanding the field of firm, dispatchable resources beyond the limited natural gas options received in the original RFP.

The final RFP Supplement incorporates several changes from a March 6, 2026 Formal Review Draft, including: renaming the RFP to an "All-Source" solicitation; restoring appendices and DSR bid forms consistent with the original 2029-2032 RFP; expanding minimum requirements to allow a wider range of resource types; updating bid submission fee structures and schedules to reflect the May 1, 2026 release date; and adding environmental and carbon-compliance language requiring that carbon-emitting resources be proposed as limited-term PPAs through December 31, 2044, with options for carbon-free conversion. The RFP Supplement evaluation will apply New Mexico's clean-energy requirements, including a system-level carbon intensity target of 200 lbs/MWh by 2032 and zero carbon by 2045, with proposals evaluated on both cost and their ability to contribute to firm capacity required for reliability.

1.5.9 FCPP

PNM evaluated multiple options regarding its ownership share of the Four Corners Power Plant (FCPP) and ultimately determined that continuing participation through 2031 and exiting thereafter was the most cost-effective approach for customers. Key evaluations and analytical findings are summarized below.

Evaluation of Continued Participation in Four Corners through 2038

PNM evaluated whether continued participation in the FCPP beyond 2031 would benefit customers. Conducted as part of PNM's 2029-2032 RFP, this evaluation is documented in Case No. 26-0000114.

PNM developed baseline assumptions regarding capital improvements, operations and maintenance expenses, and fuel costs required to maintain current MW participation until 2038. The analysis further assumed compliance with ETA carbon emissions caps (200 lbs/MWh) beginning in 2032.

The evaluation revealed that complying with ETA emission limits would require operation of Four Corners below the physical minimum load threshold necessary for coal-fired units. Such operation is technically impractical and would substantially reduce the energy output available to serve customer needs. Even if low-load operation were feasible, PNM would remain responsible for its share of fixed costs, including minimum staffing requirements, operations and maintenance expenses, and other plant-related costs.

Furthermore, continued participation through 2038 would require substantial investments in replacement solar and storage capacity to offset reduced FCPP generation and meet emission mandates. Ultimately, maintaining participation in Four Corners through 2038 increased the 20-year NPV of revenue requirements by nearly $500 million relative to the preferred portfolio. Based on these results, PNM concluded that fulfilling its contractual obligations and retiring its ownership share of Four Corners in 2031 represents the most economical outcome for customers.

Evaluation of Early Exit from Four Corners Prior to 2031

PNM conducted multiple analysis to evaluate retiring its ownership share of the FCPP prior to 2031.

- **Initial 2021 Evaluation:** Supported PNM's Four Corners Abandonment filing in Case No. 21-00017-UT.
- **2024 Updated Assessment:** Performed per the 2023 IRP Action Plan to evaluate a potential exit in 2026.

The 2024 updated assessment determined an early exit prior to 2031 would not yield reasonable savings for customers. Compared to the 2021 findings, early-exit economics deteriorated due to substantial increases in replacement resource costs, supply chain constraints, and higher costs associated with procuring replacement capacity and energy. Sensitivity modeling demonstrated that if replacement resources were delayed or if future energy and capacity needs differed from forecasts, an early exit could increase customer costs by as much as $385 million NPV.

PNM determined that significant economic risks were associated with retiring FCPP before 2031 and therefore favored continuing to use the resource through the end of its current participation period. The results of this evaluation were documented in the PNM 2023 Integrated Resource Plan First Annual Action Plan Report Update - Case No. 23-00409-UT.

PNM also evaluated the feasibility of an abandonment in 2028. The analysis indicated that replacement resources could not be procured, approved, and operational by 2028, forcing reliance on wholesale market purchases estimated at approximately $300 million based on forward market price forecasts. Additionally, unestablished ownership transfer protocols created significant uncertainty regarding whether abandonment costs could be avoided. Consequently, an early exit prior to 2031 was deemed unviable and cost prohibitive.

1.6 Enhancements for this IRP

With each IRP cycle, PNM continually refines its analytical methodologies, tools, and modeling capabilities to advance integrated system planning and increase public transparency. For the 2026 IRP, PNM focused on three primary enhancement objectives: expanding transmission modeling within the expansion process, further deepening customer affordability analysis, and broadening candidate options for demand-side management. These enhancements are detailed below:

1.6.1 Expand DSM modeling

Advanced Metering Infrastructure (AMI) serves as a foundational platform for expanding Demand-Side Management (DSM) and broader grid modernization initiatives. Beyond core metering capabilities, AMI enables enhanced customer energy management tools, time-differentiated rate structures, improved outage management, and greater distribution system visibility. When integrated with distribution automation and Advanced Distribution Management Systems (ADMS), AMI provides the operational foundation required to deploy more dynamic, flexible DSM programs across PNM's service territory.

1.6.2 Demand response (DR) potential study

PNM engaged ICF to conduct the Energy Efficiency and Demand Response Potential Study to support this resource planning cycle. This study marks the first time for demand response potential and identified a total of nine DR options for portfolio modeling, including seven new feasible programs and extensions of two existing programs (Peak Saver and Power Saver). Modeling assumes a first year of program availability in 2030. This timing reflects both the full deployment of AMI - required for Time-of-Day (TOD), EV-TOD, and behavioral programs - and the timeframe needed to establish technically feasible and affordable structures for direct load control (DLC) programs.

1.6.3 Transmission Analysis integration

For this IRP cycle, PNM enhanced its planning process by incorporating nodal transmission modeling alongside its traditional zonal modeling framework. This dual-model approach allows PNM to evaluate how third-party use of the transmission system impacts candidate resource portfolios within PNM's balancing area and explore the viability interconnections with neighboring systems.

Previously, PNM relied solely on a standalone zonal model that used estimated transmission cost adders to account for moving power between areas when new resources were added. In this cycle, the new nodal model incorporates neighboring transmission systems and regional resource plans, evaluating each portfolio and network improvement against four specific operational metrics:

- System losses
- Resource curtailment,
- Congestion hours, and
- Congestion costs

Because the nodal model doesn't capture PNM's financial and regulatory structures, it’s results were used to determine the need for transmission cost adders for specific remote resources. Cost adder determinations were then used in a zonal model reevaluation to assess the potential impact on the portfolio resource selection.

1.6.4 Affordability Considerations

Customer affordability is one of the three major objectives, including reliability and environmental impact, PNM considers when optimizing its short- and long-term plans. PNM’s long-term plans should also consider how best to manage the pace and magnitude of investments in light of customer rate impacts. Affordability is not evaluated separately from reliability or environmental performance; rather, it is considered as part of critical balance that must be struck to ensure customers can receive services while the state progresses toward its carbon-free future.

PNM's planning environment is changing rapidly. Load growth associated with economic development, electrification, and large energy-intensive customers requires new investments in generation, storage, transmission, and distribution infrastructure. At the same time, the transition away from higher carbon-emitting resources, the need for firm and flexible dispatchable capacity, supply-chain constraints, and changes to federal tax incentives all contribute to upward pressure on costs. Additionally, the desire to remodel a system that originally took 100 years to build, into a compressed 20-year timeframe further challenges costs. The IRP therefore considers not only the least-cost mix of resources, but also considers timing, risk profile, and customer impact of resource and transmission decisions over the planning horizon.

PNM's affordability approach is guided by several principles. First, customers should receive safe and reliable service at just and reasonable rates. Second, new costs should be assigned consistent with cost causation, particularly where new large loads drive incremental system requirements. Third, portfolios should be evaluated for long-term value, not only near-term capital cost, because least-regrets transmission, a diversified resource mix, regional market participation, and grid-enhancing technologies may help reduce customer costs and mitigate reliability risk. Fourth, planning should preserve flexibility so that PNM can adjust procurement timing and resource selections as load, technology costs, market conditions, and customer commitments become clearer.

These principles are especially important where significant new load could otherwise create cost-shift risk for existing residential and small business customers. Large-load customers can provide economic development benefits and help spread fixed costs across a larger customer base, with appropriate tariff structures, service agreements, and cost-allocation mechanisms to ensure that those customers pay their share of the incremental costs and an appropriate share of existing system costs. The IRP recognizes that customer growth can support affordability when it is paired with disciplined planning and appropriate customer protections.

PNM is considering a range of ideas that can help maintain affordability while supporting reliability and clean energy policy objectives. These include:

- Large-load tariffs and service agreements that include take-or-pay provisions, collateral requirements, exit protections, and cost allocation aligned with cost causation.
- Flexible load programs, interruptible or curtailable service options, demand response, and time-varying rates that reduce demand during constrained or high-cost hours and encourage usage when renewable energy is abundant.
- Energy efficiency, demand-side management, and customer programs that reduce or shift load and can lower the amount of infrastructure needed to serve peak conditions.
- Diversified resource portfolios that include various sources and geographies for renewable energy, storage, firm dispatchable capacity, demand-side resources, and regional market opportunities to reduce exposure to fuel volatility, technology risk, and extreme weather conditions.

- Strategic transmission investments and grid-enhancing technologies that expand access to lower-cost resources, reduce congestion and renewable curtailment, increase market participation, and improve system resilience.
- State or federal funding, tax credits, securitization, low-cost financing, rate riders, and other targeted cost-recovery mechanisms that may reduce financing costs, smooth rate impacts, or accelerate investments that provide customer value. These are topics that could be addressed through the working group Action Plan item.

These tools are complementary. For example, time-varying rates and demand response can reduce peak needs; regional market participation can lower energy costs and improve access to diverse resources; and transmission expansion can reduce congestion and support both load growth and renewable integration. When considered together, these options may reduce the amount of new infrastructure needed, improve utilization of existing assets, and help manage total system cost.

Large-load growth is one of the most significant affordability issues facing the electric utility industry at a national and global level. New industrial, manufacturing, data center, and other high-load-factor customers may require substantial generation, storage, transmission, and distribution additions. Without appropriate protections, these additions could increase costs for existing customers. PNM's, as outlined in its action plan, will be seeking approval of a large load tariff governing allocation of dedicated facilities and resources needed to serve them, require large customers to provide sufficient credit support, make long-term service commitments, and bear the financial consequences of material reductions or cancellations in load that leave system costs behind.

At the same time, large loads can provide system benefits when they are flexible, located where infrastructure can support them efficiently, and are willing to align operations with grid conditions. Flexible large-load programs can operate similarly to a resource by reducing demand during risk hours, shifting consumption to periods of high renewable output, or responding during emergency conditions. Going forward, PNM plans to further evaluate ways to treat flexible load as an affordability and reliability tool, not merely as a customer-service option.

The IRP also recognizes that certain affordability issues can only be meaningfully addressed in future regulatory and rate review proceedings. Resource approvals, transmission expansion, rate design, securitization, cost allocation, prudence review, and tariff changes remain subject to Commission review. The IRP does not pre-approve those costs; instead, it provides a planning framework that informs future filings and demonstrates how PNM is evaluating customer impacts as part of its long-term resource strategy.

PNM's customer affordability strategy is to pursue an integrated, disciplined, and flexible resource plan that reliably serves customers, meets New Mexico's clean energy requirements, supports economic development, and protects existing customers from undue cost shifts. The most important affordability strategy is not a single program or filing; it is the coordinated use of integrated resource planning, cost-causation principles, large-load customer protections, demand-side resources, regional market participation, strategic transmission investment, and potential legislative or regulatory tools that can collectively reduce long-term customer risk.

Through this IRP, PNM seeks to advance a portfolio that balances affordability, reliability, and environmental performance while preserving the flexibility needed to respond to changing customer and system conditions and providing insights into how costs are affected by various types of futures and sensitivities. An illustrative determination of customer rate impacts is provided in Section [ ] for the CTP (which was used to define the MCEP) and HEG futures reviewed as two of the main bases cases in the IRP analysis.

2. PLANNING LANDSCAPE

Chapter Highlights

- [To be added upon completion of Chapter]

The pace of change within the utility industry has accelerated significantly since the previous IRP. While previous cycles focused on the long-term viability of a transition to carbon-free energy, the 2026 IRP is developed during a period of significant growth in energy demand across the nation. PNM is navigating a landscape where the increasing requirement for new generation must be balanced against the technical and logistical timelines for transmission expansion and supply chain delivery. This section explores the key policy, market, and technological forces that shape the 2026 planning landscape.

2.1 Shifting National Demand Dynamics

For much of the last half-century, the growth of electricity demand has been relatively modest. Resource planning during this extended period of limited growth focused primarily on maintaining a stable system footprint, replacing aging infrastructure, and modernizing the generation fleet within a predictable demand envelope.

In recent years, the national outlook for electricity demand growth has fundamentally shifted, primarily due to the **rapid development of large-scale digital infrastructure**. Across the United States, the expansion of data centers – fueled by the increasing demand for cloud computing and artificial intelligence – is creating concentrated pockets of high-intensity, round-the-clock electricity demand. These facilities often require significant capacity and high levels of reliability, necessitating a faster pace of resource procurement and interconnection than seen in previous decades. The magnitude of current expected growth has led to significant upward revisions to load forecasts across the country; this phenomenon is described in the North American Electricity Corporation's (NERC) *2025 Long Term Resource Assessment*:

> *"**Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades.** Over the 10-year period, aggregated assessment area, summer peak demand is forecasted to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter peak demand is expected to grow by 245 GW, continuing to outpace summer and exceed prior-year projections. **New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.**"[2] (emphasis added)*

Secondary to the surge in large customer growth, **electrification of vehicles and buildings** is also contributing to increased loads on the electric system. National and regional efforts to decarbonize the transportation and building sectors are shifting energy demand from fossil fuels to the electric grid. As electric vehicle (EV) adoption increases and building heating systems

---

[2] https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf

transition to electric heat pumps, utilities must plan for increasingly dynamic load shapes and higher winter and summer peak demand requirements.

For a utility like PNM, these trends introduce a critical layer of complexity to the 2026 IRP. PNM must not only execute the technically demanding task of replacing aging thermal generation with carbon-free alternatives but must also scale the grid to accommodate a potentially substantial surge in demand. This dual requirement – decarbonizing the existing fleet while expanding total system capacity – necessitates an aggressive and flexible procurement strategy to navigate a market where competition for limited manufacturing capacity and specialized labor has never been higher. Because the exact pace and magnitude of this demand shift remain uncertain, PNM tests its resource strategy across distinct modeled "futures", ranging from current trends and policies to rapid high-growth scenarios driven by accelerated electrification and data center growth. Evaluating these diverse pathways allows PNM to identify resilient, flexible capacity solutions that safeguard reliability and affordability regardless of which energy future unfolds.

2.2 State Energy Policies and Priorities

The regulatory environment remains a primary driver of resource selection for the Company. Since 2023, the federal landscape has shifted from the broad-based stimulus of the Inflation Reduction Act (IRA) to the more specific, domestic-focused mandates of the One Big Beautiful Bill Act (OBBBA). Simultaneously, New Mexico's Energy Transition Act (ETA) continues to provide the statutory guardrails for decarbonization milestones.

In parallel, state and local policies, along with clean energy commitments, continue to serve as primary drivers for the transition to carbon-free resources. Numerous states across the Western Interconnection have established rigorous decarbonization goals and clean energy mandates for the electric sector, necessitating timely investments in new renewable generation and energy storage.

These regional policies and the resulting shifts in the resource mix over the coming decades have direct and significant implications for PNM. The increasing regional development of variable renewables and energy storage is fundamentally altering the landscape. These changes impact both the timing and nature of regional reliability risks and the day-to-day dynamics observed in wholesale energy markets.

2.2.1 The Energy Transition Act (ETA) and PNM's Decarbonization Goals

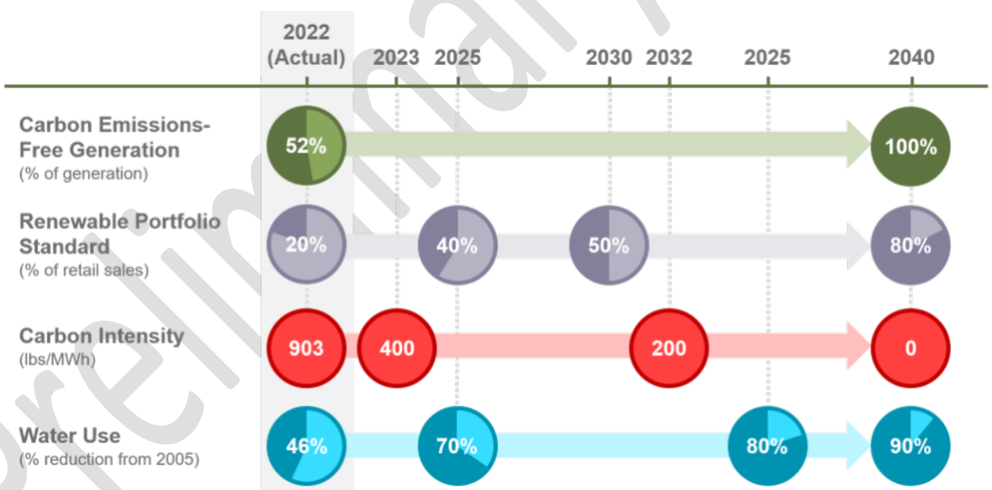
The passage of New Mexico's Energy Transition Act (ETA) in 2019 represented a landmark shift in the state's energy policy, establishing a series of milestones to guide the transition of New Mexico's electricity supply towards carbon-free sources. Looking forward, the ETA remains the definitive regulatory foundation, establishing the roadmap that shapes the Company's resource selection and portfolio modeling. The core elements of the ETA include:

- **Coal Abandonment and Securitization:** The ETA created a structured pathway for utilities to transition away from coal-fired generation. By taking advantage of this mechanism, PNM successfully utilized securitization financing to recover undepreciated investments, decommissioning costs and workforce transition funds associated with abandoning the San Juan Generating Station (SJGS) coal plant. In exchange for utilizing these financing tools, PNM is bound by the ETA's strict carbon intensity caps. Under state regulations, PNM's generating fleet was limited to an average of 400 lbs CO2/MWh beginning in 2023, with a further reduction to 200 lbs CO2/MWh required by 2032.

- **Expansion of the Renewable Portfolio Standard (RPS):** The ETA significantly increased the state's renewable energy requirements through amendments to the Renewable Energy Act,[3] establishing RPS procurement targets of 40% by 2025, 50% by 2030, and 80% by 2040. PNM has successfully met and exceeded the 40% requirement for 2025 and is currently on track to exceed the 50% milestone prior to its originally mandated timing of 2030. The establishment of these aggressive targets provides a clear signal to the industry regarding the scale of renewable development required in New Mexico over the coming decades.
- **The 2045 Statutory Carbon-Free Goal:** The ETA also established an ultimate target for New Mexico utilities: supplying 100% of retail electricity load with carbon-free resources by 2045. The legislation mandates that "reasonable and consistent progress" be demonstrated throughout the planning horizon to ensure this goal is met.

FIGURE 2-1. TIMING OF KEY PORTFOLIO MILESTONES IN THE PLANNING HORIZON AS STATED ACROSS THE ETA AND PNM'S ENVIRONMENTAL GOALS

[Note: This chart will be updated in Final IRP]



2.2.2 NEW MEXICO STATE GREENHOUSE GAS REDUCTION GOALS

In 2019, New Mexico's Governor enacted Executive Order 2019-003, which announced New Mexico's pledge to join the U.S. Climate Alliance and established the state's first formal goal to reduce economy-wide emissions by 45% by 2030, relative to 2005 levels. This commitment underscores a broader state priority to mitigate greenhouse gas emissions.

[3] New Mexico's RPS program was established with the passage of the Renewable Energy Act (SB 43) in 2004 and subsequently updated (SB 418) in 2007 to require IOUs in New Mexico to meet the following renewable procurement targets (note that RPS compliance carve-outs resulted in small deviations from these values): 5% of retail sales by 2006, 10% by 2011, 15% by 2015, and 20% by 2020.

While this executive order does not establish enforceable planning criteria or direct compliance mandates for individual utility IRPs, it reflects the broader state policy environment in which PNM operates. This overarching focus on decarbonization informs PNM’s strategic vision and reinforces the long-term priorities guiding its resource decisions.

- **Significance of Utility Decarbonization**: As the largest electric utility in New Mexico, PNM serves approximately 36% of the state’s retail load. The Company’s historical 2005 emissions baseline of 7.7 million short tons represents a substantial portion of the state's total emissions. Consequently, achieving New Mexico's economy-wide targets will depend heavily on the direct emissions reductions realized within the PNM resource portfolio. The Company's current trajectory anticipates an emissions reduction of over 80% relative to 2005 levels by 2030, which would represent a significant contribution toward the state's 45% economy-wide goal.
- **The Expanding Role of Electrification:** New Mexico’s commitment to a carbon-free economy positions PNM to play an increasingly central to the state's broader energy landscape. Achieving economy-wide decarbonization relies heavily on electrifying sectors that traditionally burn fossil fuels, such as transportation and building heating. While these efforts reduce state emissions, they shift energy demand directly onto the electric grid. To accelerate this transition, the state provides several key incentives, [*Redacted - Awaiting SME confirmation*]

At the time of this 2026 IRP, New Mexico’s policy support for electrification continues to evolve. While the Company currently models a moderate level of electrification based on existing trends in its base case plan, PNM recognizes that future legislative or regulatory actions could accelerate the growth of these new types of electric loads. To capture this potential increase, PNM evaluates an Accelerated Electrification pathway alongside a High Economic Growth (HEG) future. Such a shift would present both significant opportunities to support state goals and new challenges in maintaining grid reliability and resource adequacy in an environment of already rapidly increasing demands.

2.2.3 Senate Bill 170 (Utility Pre-Deployment Act)

Senate Bill 170 (SB 170), enacted during the 2025 New Mexico legislative session, amended Sections 62-6-26 and related provisions of the New Mexico statutes to expand the framework for economic development rates and infrastructure planning. Among other provisions, the legislation authorizes a public utility, subject to certification by the New Mexico Economic Development Department (NMEDD) and approval by the New Mexico Public Regulation Commission (NMPRC), to develop transmission, distribution, generation, energy storage, and other electric infrastructure in advance of a binding customer commitment when the infrastructure is associated with a certified economic development project. The legislation also establishes an expedited regulatory review process and authorizes prudent development costs associated with qualifying projects to be deferred for future ratemaking consideration.

For PNM's resource planning, SB 170 provides a statutory pathway to develop and recover costs for resources tied to specific, large incremental loads, most notably data center and other commercial/industrial demand, on a timeline and cost-recovery basis independent of the triennial IRP cycle. PNM has already begun utilizing this mechanism, including an application filed with the NMPRC in December 2025 seeking approval of two economic development projects, the Westpointe 115-kV Substation Project and the Mesa del Sol project. While the IRP continues to serve as PNM's primary framework for identifying the most cost-effective long-term resource portfolio, SB 170 supplements that framework by allowing PNM to respond to discrete, time-sensitive load growth that may arise between IRP filings or diverge from the load forecast underlying the current Action Plan.

2.2.4 House Bill 93

HB 93 modernized New Mexico's electrical grid by mandating advanced grid technology plans, cost recovery mechanisms for utilities, and authorized self-sourced microgrids in New Mexico, the legislation requires public utilities to file advanced grid technology plans alongside their integrated resource plans, or in advance if preferred. These plans must address transmission-line congestion, propose projects to alleviate congestion, provide cost estimates, and include any additional information requested by the Public Regulation Commission.

The Key Provisions of the Legislation include:

- Advanced Grid Technology Projects: requires utilities to consider technologies that improve efficiency, capacity, and reliability of transmission and distribution systems, including advanced conductors, dynamic line ratings, and other grid-enhancing technologies.
- Cost Recovery: allows utilities to recover reasonable costs for approved projects through tariff riders, base rates, or a combination, with costs presumed reasonable up to the commission-approved maximum.
- Commission Review Criteria: provides the PRC criteria to evaluate projects for cost-effectiveness, alignment with grid modernization priorities, energy diversification, and grid security.
- Self-Sourced Power and Microgrids: allows entities to develop qualified microgrids that generate and sell electricity. Energy from these microgrids will not be classified as retail sales until 2035, and by 2045, all energy must come from net-zero carbon resources.

Overall, HB 93 aims to enhance grid reliability, reduce greenhouse gas emissions, and increase access to renewable energy. By providing a clear regulatory framework for advanced grid technologies and microgrids, the bill encourages utilities to invest in modernization while ensuring cost-effectiveness for ratepayers.

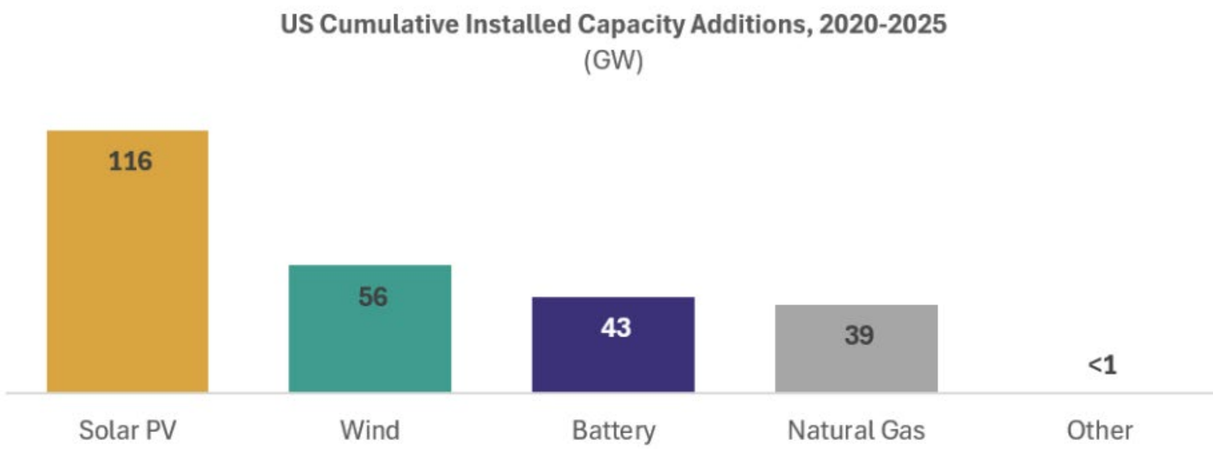
To meet the requirements of HB 93, PNM filed a Grid Modernization Plan and files annual updates on the progress of its efforts. Additionally, PNM analyzes grid enhancing technologies, including but not limited to those outlined in HB 93 in its transmission planning efforts.

2.3 Technology Trends

The generation mix being built across the United States today looks markedly different from the one utilities planned around even a few years ago. Cost declines, policy shifts, and new grid challenges have reshaped which technologies utilities procure first. Understanding these shifts provides essential context for the resource decisions discussed later in this plan. Across the

United States, almost all recent utility-scale generation capacity added to the system to meet growing demands, replace infrastructure, and meet policy and voluntary clean energy goals is accounted for by four technologies: solar PV, wind, battery storage, and natural gas. Figure 2-2 shows the capacity of new resources added for each of these technologies over the six-year period from 2020 to 2025.

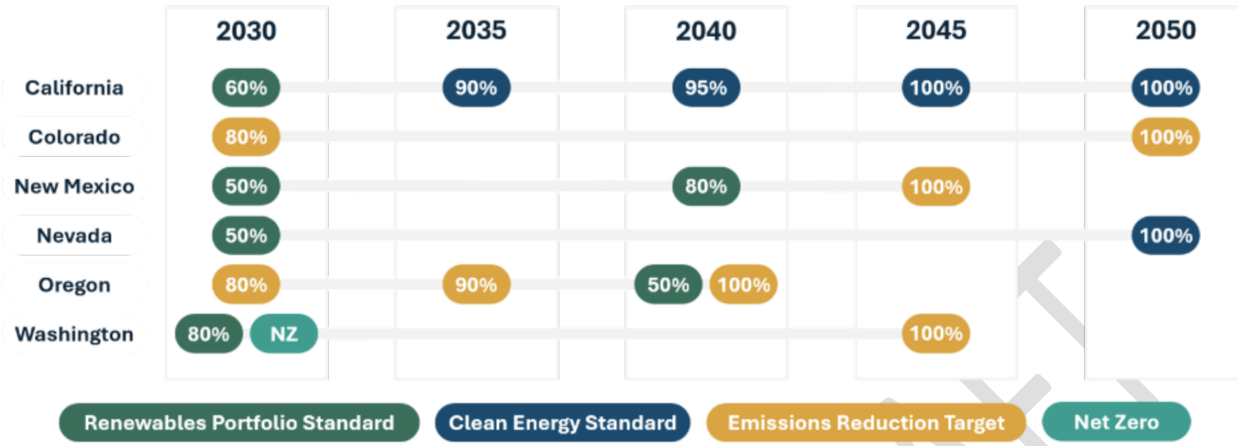
FIGURE 2-2. INSTALLED CAPACITY OF NEW RESOURCES IN THE UNITED STATES, 2020-2025



The types and quantities of resource additions are influenced by a variety of factors, but are generally driven by two major considerations:

- The need to maintain bulk system reliability as load grows and aging resources reach the ends of their lives; and
- The state policy and voluntary utility goals that require additions of renewables and/or low-carbon resources to the electricity system (see Figure 2-3 for a summary of relevant policies in the Western United States).

FIGURE 2-3. CLEAN ENERGY POLICIES BY STATE IN THE WESTERN INTERCONNECTION.



Additional voluntary goals include APS (Net zero by 2050), SRP (82% GHG intensity reduction by 2035, net zero by 2050) TEP (80% GHG reduction by 2035, net zero by 2050); Idaho Power (100% clean energy by 2045); Los Angeles Dept of Water & Power (100% clean energy by 2035); Sacramento Muni Utilities District (100% clean energy by 2030)

While installed capacity provides a useful measure of how much new infrastructure has been developed, these four technologies are not direct substitutes for one another, and a megawatt of each one provides different value to the electricity grid. The drivers at play behind the additions of these types of resources are intrinsically linked to the capabilities that they provide the electricity system:

1. **Solar and wind,** by installed capacity, account for the majority of new resource capacity added to the US electricity system since 2020, representing approximately two thirds of all new capacity. These two technologies have emerged as the lowest-cost scalable sources of renewable (and carbon-free) energy, and a significant driver behind their adoption at scale has been the increasingly ambitious state policies and voluntary goals set by utilities to transition towards clean electricity resources. At the same time, solar and wind are inherently "variable" resources – their ability to generate electricity varies from hour to hour based on changing meteorological conditions – and therefore they are limited in their ability to provide dependable capacity to the electricity system when it needs it most.
2. Another dramatic shift since 2020 has been the commercial liftoff of **grid-scale battery storage**. At the time of PNM's 2020 IRP, the national storage footprint was a modest 1,500 MW. By the end of 2025, that figure exploded to approximately 50,000 MW. This rapid growth was in part driven by the necessity of managing "net load" challenges – the steep ramp in demand that occurs when solar production drops off in the evening. This evolution has transformed battery storage from an experimental grid asset into an essential tool for ensuring reliability in a high-renewables portfolio.
3. **Natural gas** is the fourth largest segment of new resource additions across the country. As a firm resource able to dispatch when and for as long as needed, natural gas complements variable and energy-limited resources through its ability to serve loads when other resources are not available. For this reason, natural gas capacity additions

are often primarily motivated by the reliability value that they provide to the electricity system.

The remainder of this section discusses key trends and developments impacting these technologies, including recent upward pressures on cost, changes to federal tax credits, and extended project development timelines; as well as recent developments among emerging technologies that have not yet been widely deployed at scale.

2.3.1 Rising Technology Costs

While costs for most new generation technologies were either stable (natural gas) or declining (solar, wind, and storage) in the decade from 2010 to 2020, costs for many technologies have risen substantially.

The rising costs observed across the industry are the result of several intersecting factors:

1. **Global Supply Chain Concentration and Geopolitical Risk:** The supply chain for clean energy remains highly centralized. China currently accounts for 40% to 97% of global solar and battery component manufacturing, depending on the specific part. Furthermore, China processes approximately 60% of the critical metals essential for wind, solar, and storage technologies. The ongoing implementation of the OBBBA's "Prohibited Foreign Entity" (PFE) rules and the imposition of steep import tariffs has further tightened supply, as developers must now bypass these established global leaders to secure tax-credit-eligible components, often at a premium.
2. **Expansion of Trade Policy Risks:** In addition to inflationary pressures, the 2026 IRP modeling must account for the widening gap between global commodity prices and the "landed cost" of equipment in the U.S. Due to aggressive trade enforcement and anti-circumvention duties, PNM and its developers are facing higher contingency margins and "tariff pass-through" clauses in new energy storage and power purchase agreements.
3. **Inflationary Pressures on Raw Materials:** Sustained inflation has driven up the costs of essential raw materials – such as lithium, cobalt, and copper – as well as the specialized labor required for large-scale infrastructure. These inputs are the primary drivers of the "hard costs" associated with battery enclosures and power conversion systems.
4. **Impact of High Interest Rates on Capital-Intensive Assets:** To combat inflation, the Federal Reserve has maintained elevated interest rates compared to the previous decade. Because renewable and storage projects are front-loaded with significant capital expenditures (CapEx) rather than ongoing fuel costs, the cost of financing has an outsize impact on their levelized cost. High interest rates essentially increase the "hurdle rate" for new projects, which developers pass through to utilities via higher PPA and ESA pricing.
5. **Compounding Demand and Market Competition:** Federal, state, and local decarbonization mandates, coupled with the rapid growth of load from data centers and electrification, have created a "seller's market" for clean energy resources. This surge in demand is currently outstripping the pace of domestic manufacturing expansion, further exacerbating supply chain constraints and permitting delays.

These factors have significant impacts on the relative economics of different resource options for PNM's portfolio and the associated costs of different portfolio options.

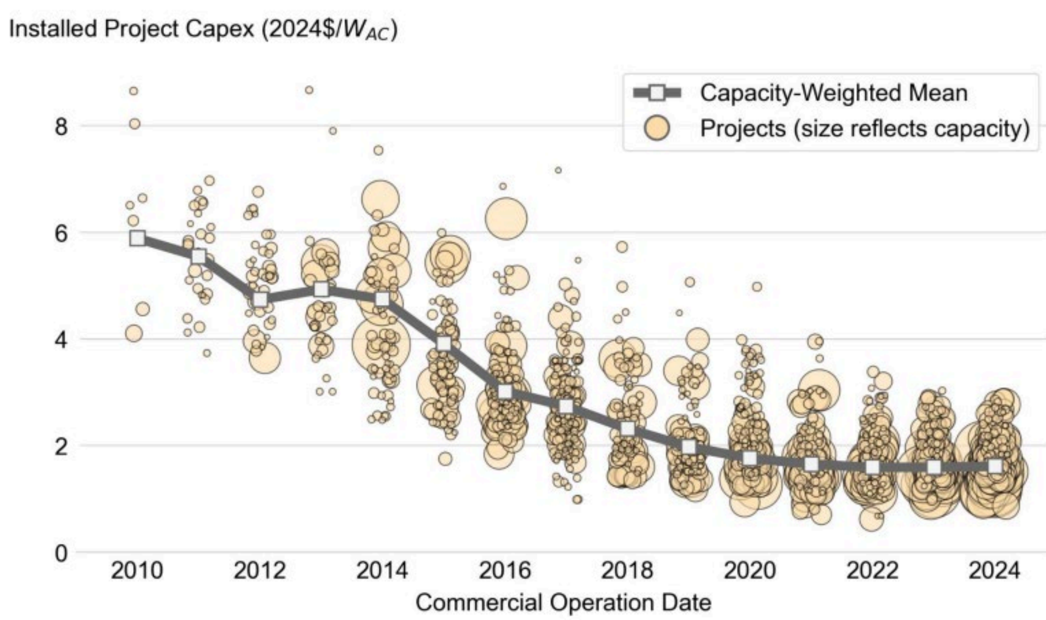
Wind and Solar

Preliminary trends of increasing wind and solar prices observed in the 2023 IRP have persisted and become more pronounced over the past three years. The factors described above, particularly global supply chain constraints, inflationary pressures, and increased competition for equipment, have been some of the largest drivers of these continuing price increases. Recent market data demonstrate that these trends have extended beyond a temporary market disruption and are now reflected across multiple industry cost metrics.

Key indicators include:

9. **Stalled Capital Cost Declines:** While capital costs represent only one component of total project costs, the long-term decline in utility-scale solar capital costs has effectively plateaued. The 2025 Lawrence Berkeley National Laboratory (LBNL) Utility-Scale Solar Update[4] reported that capacity-weighted installed costs for projects entering service in 2024 increased by approximately 1% over 2023, reaching $1.61/WAC ($1.22/WDC). Although the year-over-year increase is modest, it marks a continuation of the reversal from the sustained cost declines observed over the previous decade. Trends since 2010 in capital costs are shown in Figure 2 below.

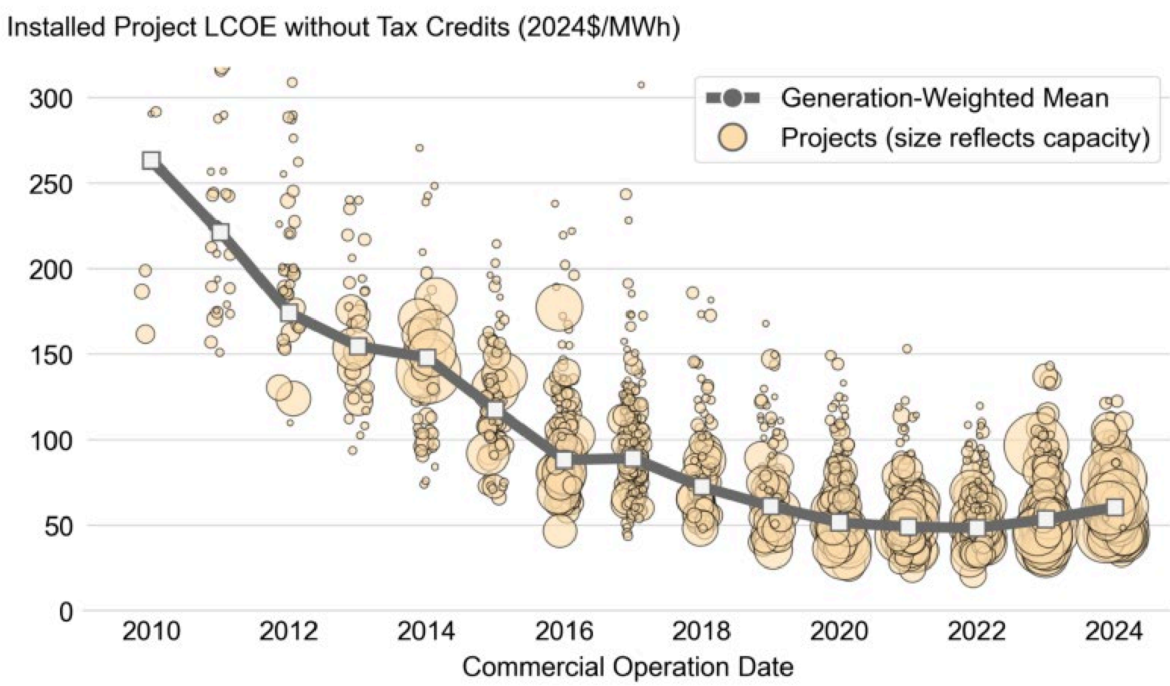
FIGURE 2. INSTALLED COSTS OF UTILITY-SCALE PV, 2010-2024[5]



[4] Seel, et al. "U.S. Utility-Scale Solar 2025 Data Update." Lawrence Berkeley National Laboratory. October 2025. https://emp.lbl.gov/sites/default/files/2025-10/Utility%20Scale%20Solar%202025%20Edition%20Slides.pdf.
[5] Seel, et al. "U.S. Utility-Scale Solar 2025 Data Update." Lawrence Berkeley National Laboratory. October 2025. https://emp.lbl.gov/sites/default/files/2025-10/Utility%20Scale%20Solar%202025%20Edition%20Slides.pdf.

10. **Levelized Cost of Energy (LCOE) Increases:** The same LBNL report found that generation-weighted LCOE from utility-scale PV has increased by 25% since 2022, up to \$60/MWh without tax credits or \$41/MWh with tax credits in 2024. The LBNL report cites higher financing costs and falling national average capacity factors as key drivers for solar LCOE increases. LCOE without tax credits since 2010 is shown in Figure 3 below.

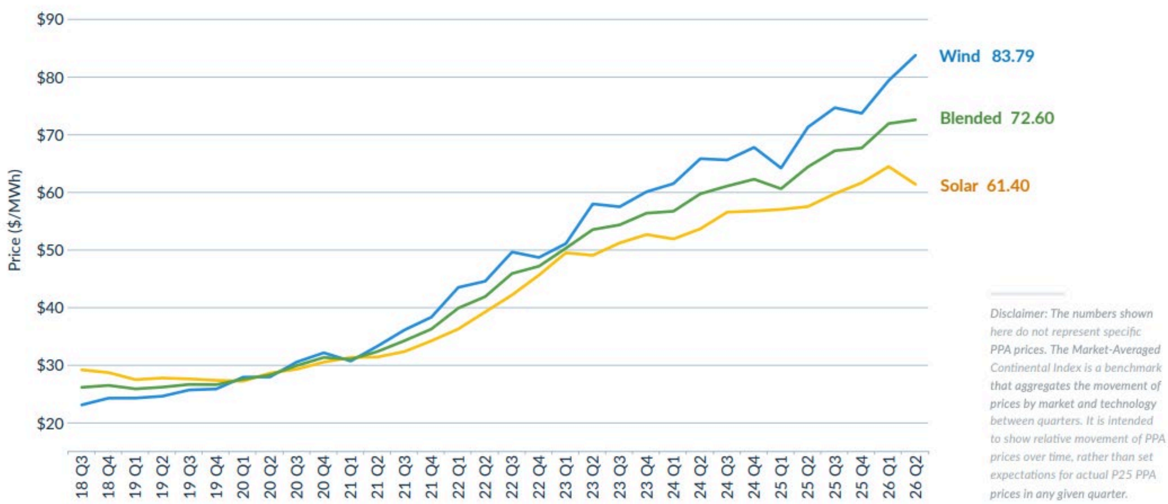
FIGURE 3. LEVELIZED COST OF ENERGY (LCOE) OF UTILITY-SCALE PV, 2010-2024[6]



11. **PPA Price Escalation:** As of the Q2 2026 LevelTen Energy PPA Price Index[7], shown in Figure 2 below, average North American solar PPA prices reached \$61.40/MWh, while wind prices rose to \$83.79/MWh. Q1 and Q2 2026 PPA prices represent the highest rates reported since LevelTen began indexing data in 2018. These PPA prices reflect an average year-over-year solar PPA cost increase of 13% and wind PPA cost increase of 9%.

[6] Seel, et al. "U.S. Utility-Scale Solar 2025 Data Update." Lawrence Berkeley National Laboratory. October 2025. https://emp.lbl.gov/sites/default/files/2025-10/Utility%20Scale%20Solar%202025%20Edition%20Slides.pdf.
[7] "Q2 2026 PPA Price Index Executive Summary." LevelTen Energy. https://go.leveltenenergy.com/2026Q2_NA_PPAPriceIndex_ES.

FIGURE 4. MARKET-AVERAGED CONTINENTAL INDEX SOLAR AND WIND PPA PRICES[8]



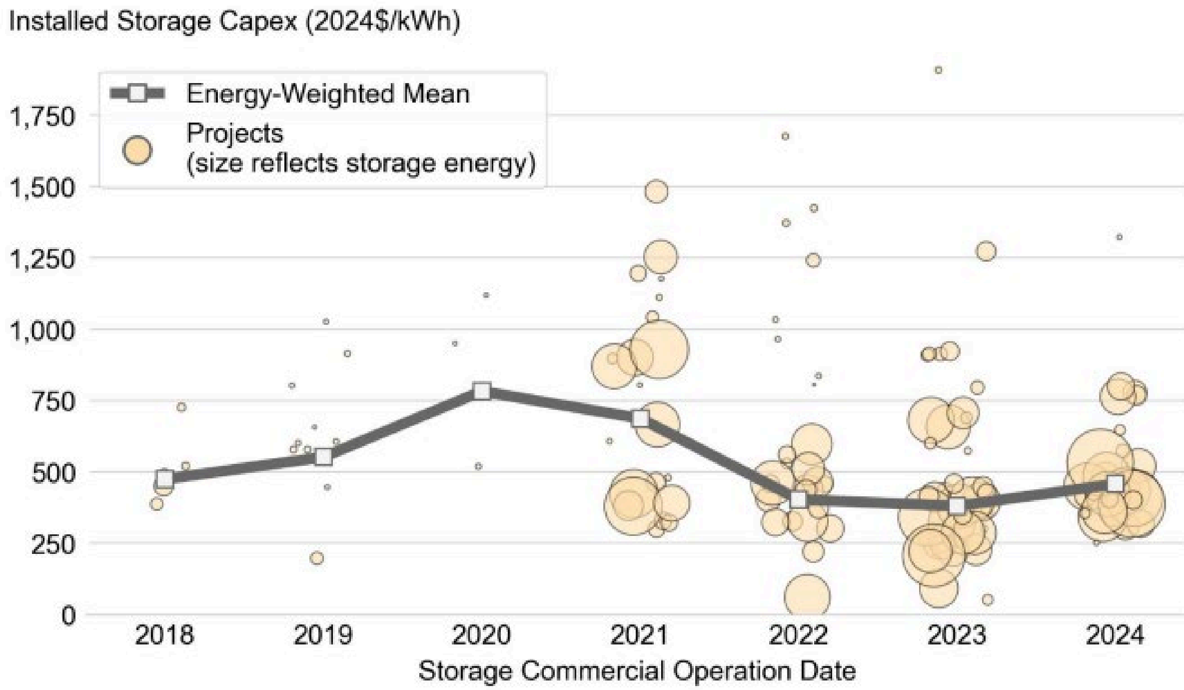
The accelerated phase-out of federal clean energy tax credits under the One Big Beautiful Bill Act (OBBBA) is expected to further increase costs of wind and solar projects that begin construction after mid-2026. In addition, import tariffs implemented during 22025 and 2026 have begun increasing the cost of renewable energy equipment and components. The magnitude and duration of these impacts remain uncertain due to evolving tariff implementation and ongoing legal challenges. Together, these factors create additional upward pressure on solar and wind project costs beyond the increases reported to date.

Battery Storage

Unlike solar and wind, where broad equipment cost increases have been more widespread, utility-scale battery storage prices have generally been more stable as battery cell manufacturing has expanded. This trend can be seen in Figure 5 below.

[8] "Q2 2026 PPA Price Index Executive Summary." LevelTen Energy. https://go.leveltenenergy.com/2026Q2_NA_PPAPriceIndex_ES.

FIGURE 5. INSTALLED COSTS OF CO-LOCATED BATTERY STORAGE, 2018-2024[9]



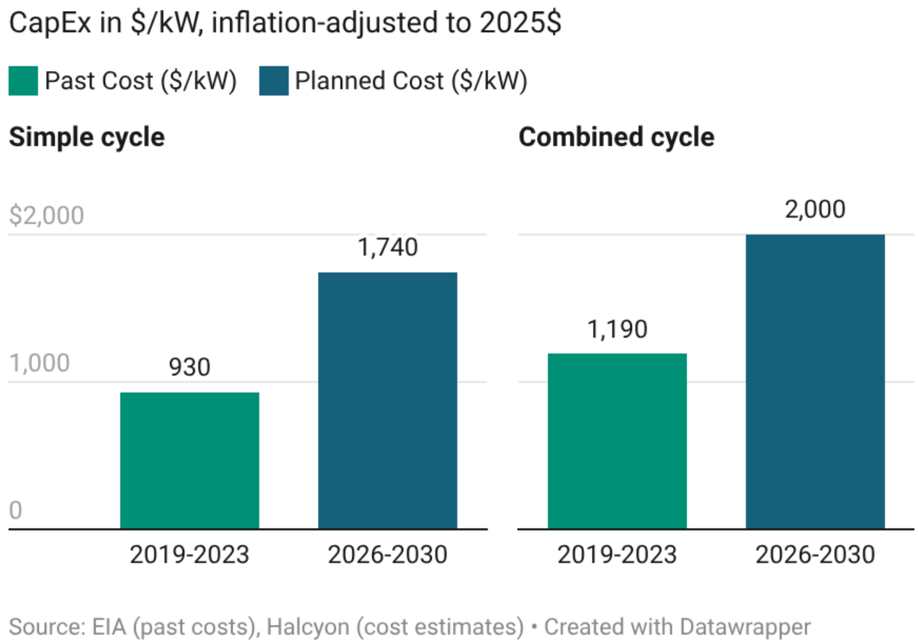
However, utility-scale projects still face cost pressures driven by balance-of-plant equipment, labor, and tariffs. PNM experienced these shifting market realities directly during the recent renegotiation of the San Juan Energy Storage Agreement (ESA). The resulting 24% price increase over the original contract was primarily driven by the exhaustion of legacy pricing tiers and the need to align with current market procurement structures, rather than a fundamental spike in battery technology costs.

Natural Gas

Cost increases for natural gas generation have been driven largely by growing demand for firm, dispatchable capacity. The rapid expansion of data centers, advanced manufacturing, and other high-load-factor customers has increased the need for reliable, around-the-clock power. Unlike traditional weather-sensitive or peaking loads, these customers require continuous 24/7 service that cannot be met by intermittent renewable resources or short-duration battery storage alone. Consequently, the need for dispatchable resources has increased substantially. Natural gas generation, specifically simple-cycle combustion turbine generators (CTGs) and combined-cycle gas turbines (CCGTs), remains a primary mechanism to provide this firm, on-demand operational flexibility.

[9] Seel, et al. "U.S. Utility-Scale Solar 2025 Data Update." Lawrence Berkeley National Laboratory. October 2025. https://emp.lbl.gov/sites/default/files/2025-10/Utility%20Scale%20Solar%202025%20Edition%20Slides.pdf.

FIGURE 2-5. INSTALLED COST OF NATURAL GAS POWER PLANTS[10]



However, securing this dispatchable capacity has become significantly more capital-intensive. A joint industry analysis by GridLab, Energy Futures Group, and Halcyon highlights this shift, noting:

> *"…a significant and persistent increase in the capital costs of new gas combustion turbine and combined cycle gas turbine power plants in the United States. This trend marks a stark departure from historical cost assumptions and public cost projections."*[11]

The report further observes that "[t]hese elevated costs are likely to persist rather than decline, at least in the short-to-midterm."

Impact of Import Tariffs and Trade Enforcement

The transition toward domestic supply chains under the OBBBA is occurring simultaneously with a period of heightened trade enforcement. For PNM, federal import tariffs represent a direct upward pressure on the capital costs of new resources, often offsetting the pricing benefits of technological maturation. Key trade-related cost drivers include:

- **Escalating Section 301 Duties:** Section 301 tariffs on non-EV lithium-ion batteries stand at 25%, while duties on solar cells and modules remain at 50%. These tariffs ensure that the cost of global supply cannot undercut the higher price points of emerging domestic manufacturers.
- **Upstream Critical Mineral Duties:** New 25% duties on natural graphite and permanent magnets – essential for battery anodes and wind turbine generators – have further

---

[10] Wiser et al. "Retail Electricity Price Trends and Drivers: Data Update — 2026 Edition." LBNL/Brattle Group. July 2026. Reproduced with permission.

[11] https://gridlab.org/portfolio-item/gas-tubine-cost-report/

increased the cost of even "Western-assembled" components that rely on refined global materials.

- **Anti-Circumvention and Reciprocal Duties:** The expansion of Antidumping and Countervailing Duties (AD/CVD) on Southeast Asian manufacturing hubs, combined with broader baseline reciprocal tariffs, has curtailed developers' ability to route around traditional supply chains. This leaves entities like PNM facing a higher-cost, domestic-focused procurement path for major project components.

2.3.2 Federal Tax Credits

The federal policy environment remains a fundamental factor influencing the economic evaluation of resources in the 2026 IRP. PNM's 2023 IRP was published shortly after the passage of the landmark Inflation Reduction Act of 2022, which established a broad slate of tax incentives and government funding collectively intended to accelerate a transition towards lower carbon sources of electricity. Since the previous planning cycle, the landscape has shifted from the long-term incentives of the IRA of 2022 to the more restrictive requirements of the OBBBA of 2025. This new legislation significantly reduces the opportunities to benefit from federal tax credits by accelerating phase-outs for certain technologies and adding new eligibility restrictions.

Accelerated Phase-out Timelines for Variable Resources

The OBBBA altered the eligibility window for wind and solar projects, introducing compressed timelines for federal support that differ from previous planning assumptions.

- **The July 4, 2026 Construction Deadline:** Under the OBBBA, wind and solar resources must begin construction by July 4, 2026, to remain eligible for federal tax credits under standard multi-year deployment schedules. If a project misses this July 2026 construction milestone, it faces an immediate tax credit expiration unless it can be fully placed in service on or before December 31, 2027. This creates a severe near-term development crunch, compressing the long-term runway originally projected under the IRA into a tight, immediate compliance window.
- **Differential Eligibility Horizons:** The OBBBA departs from the uniform technology-neutral framework of the IRA by establishing divergent phase-out schedules for different technologies. While wind and solar face an accelerated expiration of federal tax credits, the OBBBA maintains longer eligibility windows for "clean firm" technologies, such as geothermal, nuclear, and battery energy storage, which remain eligible for full incentives into the 2030s.
- **Impact on Resource Parity:** These varying federal support timelines require PNM to re-evaluate the comparative long-term economics of its resource options. The 2026 IRP modeling accounts for the reality that certain variable resources will lose federal subsidies sooner than clean firm alternatives, impacting the total cost of ownership and the optimal portfolio mix for PNM's customers.

Tax Credit Tiers and the Impact of the OBBBA

While the OBBBA of 2025 preserved the foundational tax credit structure established by the IRA, it introduced stringent Foreign Entity of Concern (FEOC) restrictions designed to secure domestic supply chains. The tax credit framework continues to operate on a tiered model, but with critical new procurement safeguards:

- **Base and Prevailing Wage Credits:** All eligible technologies can claim a "base" credit (6% for ITC or approximately $5/MWh for PTC). This value is multiplied by five for projects that meet prevailing wage and apprenticeship requirements, bringing the credits to 30% for ITC and approximately $26/MWh for PTC. The OBBBA preserved this baseline tier framework from the original IRA.
- **Domestic Content Adders:** Originally created under the IRA, the 10 percentage point bonus adder for domestic content remains intact under the OBBBA. To qualify, projects must meet specific thresholds for U.S.-sourced steel, iron, and manufactured products. Failing to meet these thresholds does not disqualify a project from receiving the standard baseline credit, but developers cannot claim the extra bonus.
- **Energy Community Adders:** The OBBBA preserved the IRA's 10 percentage point bonus adder for projects located in designated "Energy Communities", such as brownfield sites, historical fossil-fuel economic areas, or coal mine/plant closure communities, and expanded eligibility to encompass nuclear energy communities. Stacked with the domestic content bonus, a fully compliant project can reach up to a 50% total ITC (or equivalent PTC boost).
- **FEOC Exclusions:** A critical provision of the OBBBA is the exclusion of tax credits for projects that utilize components, particularly battery cells or critical minerals, sourced from designated "entities of concern." While developers bear the direct burden of proving supply chain compliance, this shift potentially increases project costs and bid prices for PNM as developers pass along the higher expense of securing compliant, non-FEOC equipment.

2.3.3 Resource Performance Trends

Aligning real-world battery storage performance, including capacity degradation rates and forced outage rates, with long-term planning assumptions is critical for developing plans that will meet PNM's customer needs. Although grid-scale battery storage lacks the extensive operational history of conventional thermal resources, a decade of industry experience now provides crucial insight, helping reduce uncertainty in key resource planning assumptions.

The 2023 IRP highlighted that the rate of forced outages in data reported by the California Independent System Operator (CAISO) exceeded 10% across all storage resources, which was higher than most manufacturers' specifications for expected outage rates. In revisiting this finding, more recent data from CAISO indicates that forced outage rates have been declining over time and have started to align with manufacturers' specifications. The figure below shows the distribution of the utility-scale storage forced outages rate for all installed capacity in the CAISO for every 10-minute interval in a month from October 2021 to October 2024. Over this three-year period, there has been a noticeable decline in the median monthly forced outage rate, suggesting technology performance has matured as more storage has been deployed.

[Chart Redacted – Awaiting confirmation this is not confidential]

Other more recent studies support this claim. An IEEE study "Forced Outage Rate of Utility-scale Energy Storage Units"[12] reported that the equivalent forced outage rate for utility-scale battery storage in ERCOT is 4.82%. As more data emerges both within PNM's system and from the industry more broadly, PNM will continue to align and adjust as needed its planning inputs and assumptions to improve robustness of its modeling.

2.3.4 Project Development Timelines

The fundamental economic driver behind rising supply-side costs is an unprecedented expansion in electricity demand that has rapidly outpaced equipment manufacturing capacity, specialized labor, and raw materials. Global supply chain constraints have severely extended delivery schedules for long-lead-time equipment, most notably main power transformers, combustion turbines, and high-voltage circuit breakers, stretching procurement timelines from months to several years. In this market environment, securing critical utility infrastructure requires far greater forward lead time than in past planning cycles.

To adapt to these extended lead times, PNM has fundamentally evolved its procurement framework by expanding its forward planning horizon. As demonstrated by the focus period in this IRP, PNM now provides the extended runway necessary to order long-lead equipment earlier, navigate manufacturing backlogs, and execute competitive solicitations far enough in advance to insulate project schedules and ensure timely system additions.

2.3.5 Emerging Technologies

While research, development, and deployment activities are accelerating industry-wide, technical modeling for the 2026 IRP underscores a fundamental reality: reaching a fully decarbonized, reliable grid will require the integration of technologies that are not currently commercially mature at utility scale. As traditional thermal capacity retires, a structural gap remains between variable renewable generation and continuous, high-reliability customer demand. Short-duration battery energy storage can manage intra-day shifts, but closing the multi-day and seasonal reliability gap requires resources that can deliver sustained, dispatchable capacity without greenhouse gas emissions.

A central focus of PNM's 2026 IRP stakeholder process was determining how to responsibly model emerging technologies without over-relying on speculative assumptions. To establish a defensible, data-driven foundation, PNM partnered with EPRI to develop detailed cost trajectories, heat rates, round-trip efficiencies, and commercialization timelines across three core emerging technology categories:

- **Long-Duration Energy Storage (LDES):** Technologies capable of discharging energy over days or weeks, rather than hours, to maintain reliability during extended periods of low renewable production.

[12] Shuai, H. & Tomsovic, K. "Forced Outage Rate of Utility-Scale Energy Storage Units." IEEE Xplore. March 23, 2026. https://ieeexplore.ieee.org/document/11438461.

- **Next-Generation Carbon-Free Generation:** Emerging baseload or load-following resources that provide dependable, dispatchable power without greenhouse gas emissions.
- **Advanced Thermal and Alternative Fuels:** Advancements in existing thermal infrastructure that would allow for the use of carbon-free fuels.

In the 2026 IRP, these technologies are represented using generic cost and performance proxies to chart a long-term directional path for portfolio optimization. However, PNM recognizes that generic modeling assumptions are no substitute for market-tested pricing and firm commercial guarantees.

Inclusion in the IRP Action Plan does not constitute an immediate procurement commitment. Instead, it serves as a call to market: emerging technology vendors must participate in future competitive All-Source Requests for Proposals (RFPs) to replace these generic proxies with binding, market-validated data. Final procurement decisions will strictly depend on whether these next-generation technologies can bid into competitive solicitations and demonstrate that they can satisfy PNM's core statutory obligations, ensuring 24/7 system adequacy, operational safety, and customer affordability.

Stakeholder Input: Focus on Emerging Technologies

Stakeholders expressed significant interest in the role of emerging technologies – particularly enhanced geothermal – in supporting PNM's long-term decarbonization goals. These participants emphasized that "clean firm" resources are vital for maintaining system reliability as the portfolio transitions away from traditional thermal generation. While these technologies are currently in various stages of developmental maturity, stakeholders encouraged PNM to evaluate alternative scenarios under varying assumptions.

FIGURE 2-7. LONG DURATION STORAGE TECHNOLOGIES CHARACTERIZED IN US DEPARTMENT OF ENERGY'S PATHWAYS TO COMMERCIAL LIFTOFF: LONG DURATION ENERGY STORAGE[13]

NON-EXHAUSTIVE – HYDROGEN AND HYBRID LONG DURATION STORAGE EXCLUDE

Faces geologic constraints[4] | Not enough public datapoints to obtain a reliable value | Less Desirable — More Desirable

Inter-day | Can function as both | Multi-day/week

Duration	Energy storage form	Technology	Nominal duration, hrs	LCOS[5], $/MWh	Min. deployment size, MW	Average RTE, %	TRL
Inter-day	Mechanical	Traditional pumped hydro (PSH) (faces geologic constraints)	0–15	70–170	200 – 400	70–80	9
		Novel pumped hydro (PSH)	0–15	70–170	10–100	50–80	5-8
		Gravity-based (faces geologic constraints)	0–15	90–120	20–1,000	70–90	6-8
		Compressed air (CAES) (faces geologic constraints)	6–24	80–150	200–500	40–70	7-9
		Liquid air (LAES)[1]	10–25	175–300	50–100	40–70	6-9
		Liquid CO2[1]	4–24	50–60	10–500	70–80	4-6
Multi-day / week	Thermal	Sensible heat (e.g., molten salts, rock material, concrete)[2]	10-200[2]	300	10–500	55–90	6-9
		Latent heat (e.g., aluminum alloy)	25–100	300	10–100	20–50	3-5
		Thermochemical heat (e.g., zeolites, silica gel)	XX	XX	XX	XX	XX
	Electrochemical	Aqueous electrolyte flow batteries	25–100	100-140	10–100	50–80	4-9
		Metal anode batteries	50–200	100	10–100	40–70	4-9
		Hybrid flow battery, with liquid electrolyte and metal anode (some are Inter-day)[2,3]	8–50[2]	XX	>100	55–75	4-9

2.4 Markets and Regional Coordination

Most of the Western Interconnection operates as a patchwork of individual Balancing Authorities and utilities, unlike regions organized under Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs). Historically, these entities — including PNM — planned resources and operated their systems independently, coordinating primarily through long-term contracts and bilateral wholesale trading. Each utility remains responsible for reliably planning and procuring its own resources. Regional energy markets and resource adequacy programs do not replace that obligation; rather, they add a new layer of economic optimization, system efficiency, and reliability coordination.

Regional markets improve efficiency when prices, transmission availability, and system conditions allow energy to move between participants. However, arriving with sufficient capacity remains each utility's responsibility. This concept was introduced in 2014 through the Western Energy Imbalance Market (WEIM), which optimizes resources already online in real time. Organized day-ahead markets are now extending that optimization into the next-day timeframe, helping ensure the right resources are committed and ready before each operating day.

A parallel evolution is underway in the longer-term planning timeframe, where emerging regional resource adequacy programs aim to add a regional perspective to utility planning. These

[13] "Pathways to Commercial Liftoff: Long Duration Energy Storage Opportunities." U.S. Department of Energy. https://www.energy.gov/sites/default/files/2023-09/Pathways%20to%20Commercial%20Liftoff%20Long%20Duration%20Energy%20Storage%20Opportunities_508.pdf.

programs are intended to increase visibility into resources being procured across the region, support common planning metrics, and demonstrate adequacy and deliverability, helping reduce unnecessary or duplicative resource costs for customers over time.

2.4.1 ORGANIZED WHOLESALE ENERGY MARKETS

Western regional energy markets are undergoing rapid structural change, with several market constructs and governance models advancing at the same time. One major thread is governance reform for programs currently operated by the California Independent System Operator (CAISO), including the Western Energy Imbalance Market (WEIM), the Extended Day-Ahead Market (EDAM), and a potential future regional resource adequacy program. A new Regional Organization is being formed to eventually govern these CAISO-operated market functions, addressing long-standing concerns about independent regional decision-making while preserving the operational benefits of broader market coordination.

SPP Market Options

Southwest Power Pool (SPP) offers a parallel set of western market options, including the Western Energy Imbalance Service (WEIS), Markets+, and an expanding SPP Regional Transmission Organization (RTO) footprint. In resource adequacy, the Western Resource Adequacy Program (WRAP) laid important groundwork by advancing common planning concepts, forward-showing expectations, and regional visibility into resource sufficiency. As discussed below, PNM and other EDAM participants elected to leave WRAP in Q4 2025 in favor of a resource adequacy approach aligned with EDAM; see Section 6, Regional Resource Adequacy, for further detail.

PNM's Participation in Wholesale Markets

The remainder of this section describes how PNM is navigating this evolving landscape, including the analysis supporting its market-participation decisions and the implications for future Integrated Resource Planning. Together, these considerations connect regional market evolution, resource adequacy alignment, and PNM's long-term portfolio choices under the IRP process. Customer benefit quantification and PNM's resource adequacy strategy are addressed in Section 6, Wholesale Market Opportunities & Risks.

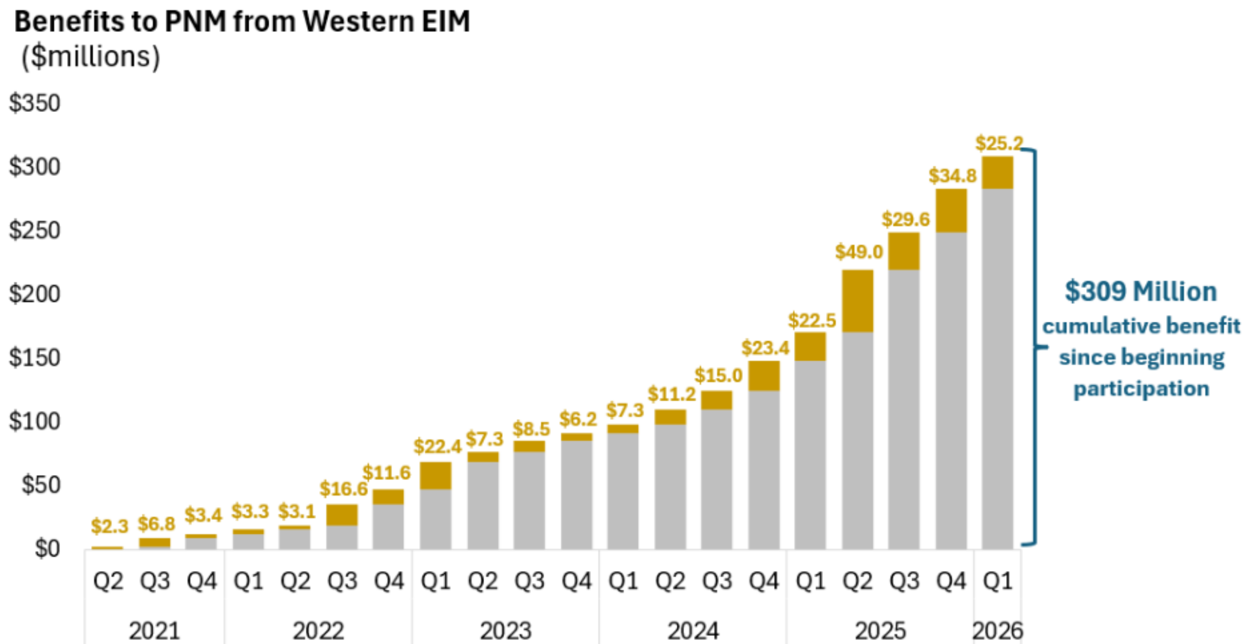
FIGURE 2-11. GENERATION PLANNING AND MARKET OPERATIONS TIMESCALES ALIGNED WITH EMERGING REGIONAL COORDINATION EFFORTS

Western Energy Imbalance Market

The Western Energy Imbalance Market (WEIM), introduced in 2014, was the West's first major step toward organized regional market coordination. It is a voluntary, real-time energy market that allows participating balancing areas to access energy across a broader regional footprint close to the time it is needed. WEIM does not replace each utility's responsibility to plan for and procure sufficient resources. Instead, it optimizes the dispatch of resources already online by identifying lower-cost energy that can move between participants when transmission and system conditions allow, helping balance supply and demand, reduce reliance on more expensive local dispatch, and improve the use of available generation and transmission in real time.

Ahead of PNM's participation, the NMPRC issued an order in Case No. 18-00261-UT allowing PNM to seek potential recovery of WEIM-related costs in future rate cases and requiring compliance reports on WEIM costs and savings. PNM joined WEIM in April 2021. Since then, participation has consistently benefited customers, with estimated quarterly benefits ranging from $2 million to $49 million. Through the first quarter of 2026, PNM's cumulative customer benefit from WEIM participation is estimated at $309 million.

Figure 2-12. Cumulative economic benefits to PNM from participation in the Western Energy Imbalance Market



- WEIM delivers cost savings through more efficient real-time dispatch across its footprint. These savings come from the following:
- Lower-cost wholesale energy trades between Balancing Areas that would not otherwise occur through manual bilateral trading
- Redispatch of resources to relieve transmission constraints across the system
- Improved reliability through automated market dispatch during local generation scarcity
- Greater opportunity to sell excess generation when PNM's resources produce more than customers consume in real time

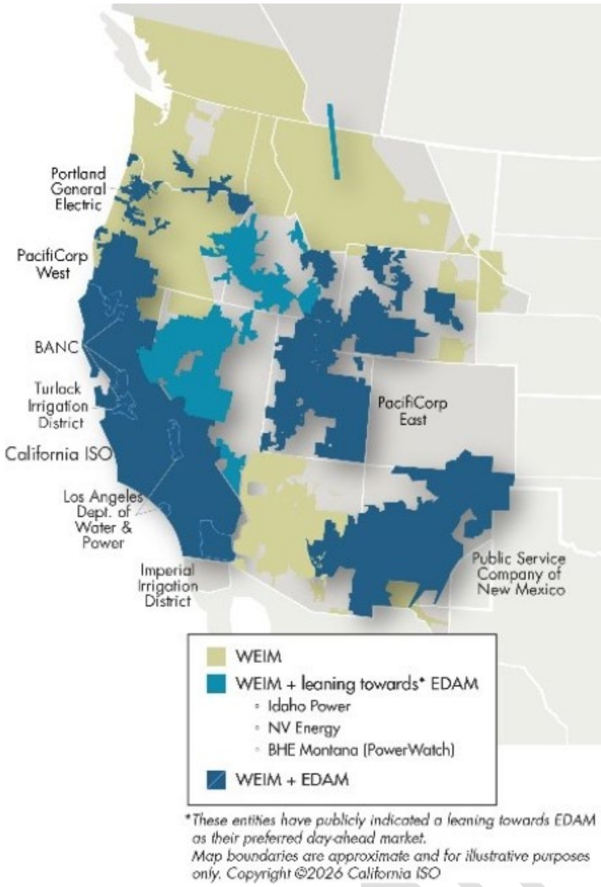
While WEIM produces savings through more efficient operations, it has no direct effect on PNM's resource adequacy needs. WEIM participants must pass sufficiency tests before each operating hour, confirming they are not relying on other participants' capacity or flexibility. Entities that fail these tests are excluded from full market optimization until they qualify. In short, WEIM helps ensure the most cost-effective generation is dispatched intra-hour across a wide footprint, but it does not directly affect planning reserve margins or required capacity.

Extended Day-Ahead Market

The Extended Day-Ahead Market (EDAM) builds on WEIM by expanding regional optimization into the day-ahead timeframe, when most electricity schedules and resource commitments are set for the following operating day. Where WEIM optimizes dispatch in real time, EDAM allows participating balancing areas to coordinate day-ahead unit commitment, scheduling, congestion management, and transmission use across a broader footprint before the operating day begins. EDAM went live on May 1, 2026, with PacifiCorp as the first participating entity, marking the West's first organized day-ahead market expansion under the CAISO framework.

Figure 2-12 shows the Western EIM footprint and how expected Extended Day Ahead Market participants will create more regional efficiencies by regional diversity.

Figure [ ] Western EIM and expected EDAM participation



PNM is preparing to join EDAM in October 2027, extending the operational and customer benefits it has seen through WEIM into the day-ahead timeframe. PNM evaluated day-ahead market options to determine which option would deliver the greatest customer benefit and best fit PNM's system, transmission position, and long-term planning needs. This evaluation included comparing EDAM with Markets+, the day-ahead option being developed through Southwest Power Pool. The analysis showed that EDAM would provide the greatest customer benefit for PNM. Because most resources exported over the PNM transmission system are delivered to California, participating in a different day-ahead market footprint than those resources would have created added operational challenges and seams risk, reinforcing the case for EDAM.

Separate production cost analyses by E3 and The Brattle Group supported this conclusion and were presented during a public regional market workshop series the NMPRC convened in 2023 and 2024 as part of Case No. 23-00268-UT. Workshop materials are available in the case docket and on YouTube. Brattle's conservative estimate put PNM's annual customer benefit from EDAM participation at $20 million.

As with WEIM, EDAM participants must meet resource sufficiency requirements by demonstrating enough supply, bid range, and imbalance reserves to meet expected load and operational needs before receiving the full benefits of market optimization. EDAM does not change a utility's underlying obligation to arrive at the market with adequate capacity, nor does it alter planning reserve requirements. Over time, however, the pricing, congestion, and dispatch data EDAM produces may help PNM better value portfolio options by revealing the market value of resource attributes, location, flexibility, and transmission deliverability.

Evolution of Pricing Dynamics

As the structures that govern western wholesale markets evolve, so too are the pricing dynamics observed within them. These shifts in pricing patterns — when and where wholesale energy is low-cost versus high-cost — reflect changing fundamentals of electricity system operations as the resource mix transitions away from baseload generation and toward higher penetrations of solar, wind, and battery storage. PNM monitors these trends for multiple reasons:

- As a wholesale market participant, PNM is directly impacted by pricing observed in wholesale markets, and changes to those pricing patterns will directly influence both new resource decisions and how resources are operated to maximize benefits for PNM's customers; and
- The pricing patterns observed in neighboring markets – and the underlying fundamentals of driving them – offer useful, real-world insight into how electricity systems with high penetrations of renewables and energy storage are likely to operate.

These two motivations are increasingly intertwined: as wholesale market structures evolve and organized markets take shape across the West, liquidity across markets is likely to increase, making dynamics in neighboring markets even more directly relevant to PNM's own market position.

Renewable Curtailment & Negative Pricing

As PNM and other utilities throughout the West add more solar and wind, there will be more hours of overgeneration when available renewable generation is greater than customer demand. To plan for periods of overgeneration, PNM has three primary options: sell the excess energy to neighboring regions, use it to charge storage resources, or curtail the renewable output.

PNM's participation in the WEIM and its planned participation in the EDAM are important tools for PNM to reduce its clean energy curtailment. These regional markets allow electricity to be more easily traded across balancing areas, allowing surplus renewable energy in one area to serve customers in another. Utilizing more renewable energy reduces the need to rely on fossil generation which can be more costly and generate CO_2 emissions. CAISO estimates that over 258,000 MWh of renewable energy curtailment was avoided in 2025 due to the energy transfers facilitated by the WEIM, resulting in a reduction of approximately 110,500 tons of CO_2 across the WEIM footprint in 2025[14].

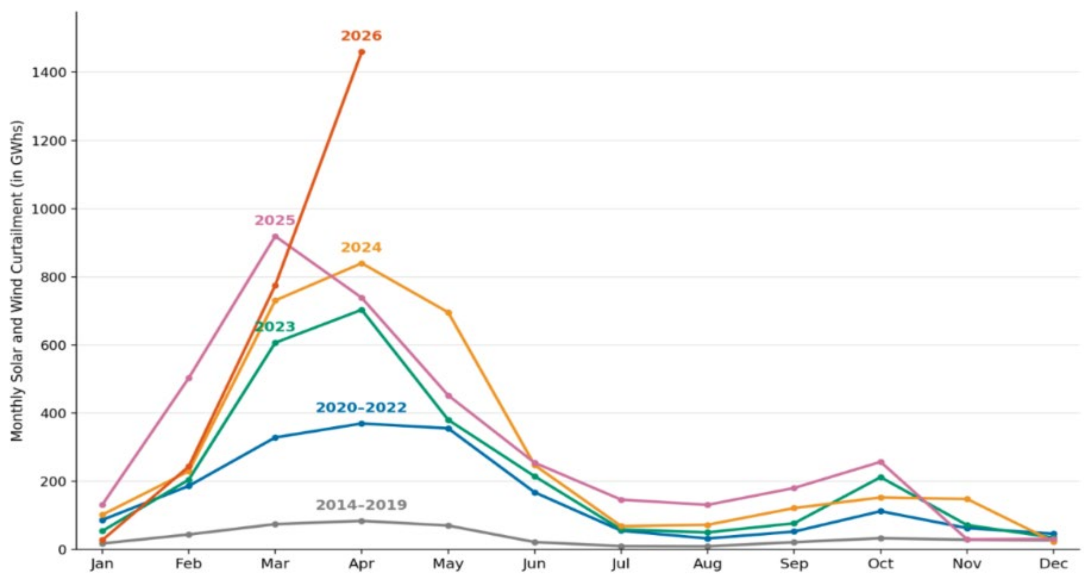
---

[14] Western Energy Imbalance Market Benefits Report: Fourth Quarter 2025. California ISO. https://www.westernenergymarkets.com/documents/iso-western-energy-imbalance-market-benefits-report-q4-2025.pdf

Battery storage provides a secondary means for reducing renewable curtailment. Outside of reliability needs, PNM operates its batteries to charge during periods of high renewable energy when energy prices are lowest. The energy can then be discharged to the grid during the highest priced hours when there would not otherwise be sufficient generation to meet demand.

Even with regional market participation and more storage, renewable curtailment on PNM's system is expected to rise as renewable penetration increases. As more solar and wind resources are added, generation output from these resources will continue to stack during the same hours, while demand will not grow significantly in those same hours. The CAISO system reveals how renewable curtailment can increase over time as renewable penetration grows. As shown in Figure 1[15], curtailment on California's system has increased year over year, particularly during spring months when solar generation is abundant but electricity demand for air conditioning remains relatively low. While curtailment is high during shoulder months, high levels of renewables remain valuable during the summer season when more generation is needed to meet high electricity demands during the day and to charge battery storage to meet the evening peak. Similar curtailment patterns have been observed in other high renewable markets, and PNM expects similar trends to emerge on its system.

FIGURE 2-14. RENEWABLE CURTAILMENT IN CAISO[16]



2.4.2 REGIONAL RESOURCE ADEQUACY PROGRAMS

An effort is now underway to design a Regional Resource Adequacy program for EDAM participants. As of July 2026, public stakeholder processes have commenced and are intended

[15] Davis, Lucas. "Visualizing California Renewable Curtailments". Energy Institute Blog. June 15, 2026. https://energyathaas.wordpress.com/2026/06/15/visualizing-california-renewables-curtailments/

[16] Davis, Lucas. "Visualizing California Renewable Curtailments". Energy Institute Blog. June 15, 2026. https://energyathaas.wordpress.com/2026/06/15/visualizing-california-renewables-curtailments/

to evaluate how resource adequacy obligations, forward showings, deliverability requirements, and market participation rules could be better aligned with the EDAM footprint. PNM is actively participating in the design and stakeholder processes.

The proposed EDAM-aligned resource adequacy program follows important groundwork established by the Western Resource Adequacy Program (WRAP). PNM participated in WRAP during its non-binding phase, which helped develop regional experience with forward showings, common resource counting concepts, and visibility into regional capacity positions. However, PNM elected to leave WRAP ahead of binding obligations (Q4 2025), along with other EDAM participants, because a long-term resource adequacy program is most effective when it aligns with the organized market footprint in which resources are scheduled, optimized, and delivered. Aligning resource adequacy with EDAM better supports consistency between planning requirements and the market platform that will manage day-ahead operations and transmission optimization.

The value proposition of a regional resource adequacy program is that it provides transparent visibility into whether the region is collectively procuring the types and amounts of resources needed to reliably serve load under stressed conditions. It also begins to align planning metrics and assumptions among neighboring utilities and load-serving entities, including how capacity is counted, how deliverability is demonstrated, and how uncertainty, outages, load risk, and resource performance are reflected. Common metrics can help instill trust among market participants by demonstrating that each entity is bringing sufficient resources to the regional market and is not relying on others to meet its own obligations. When regional adequacy is visible and transparent, entities should have greater confidence offering their full resource capability into energy markets, which can improve liquidity, reduce withholding concerns, support more efficient dispatch, and lower costs for customers.

Over time, a regional resource adequacy program could also create a stronger analytical foundation for evaluating planning reserve margins and resource investment needs. As regional data becomes more transparent, comparable, and statistically meaningful across a larger set of loads, resources, and weather conditions, utilities and regulators may be able to better assess the contribution of regional diversity, deliverability, and correlated risk to resource adequacy outcomes. That information could eventually support more refined estimates of required reserves and reduce unnecessary investment in duplicative capacity, while still preserving each utility's obligation to plan for and procure adequate resources for its customers.

PNM will continue to participate in these efforts and will continue to assess the value of its participation as well as monitor how those efforts may eventually affect the IRP planning process.

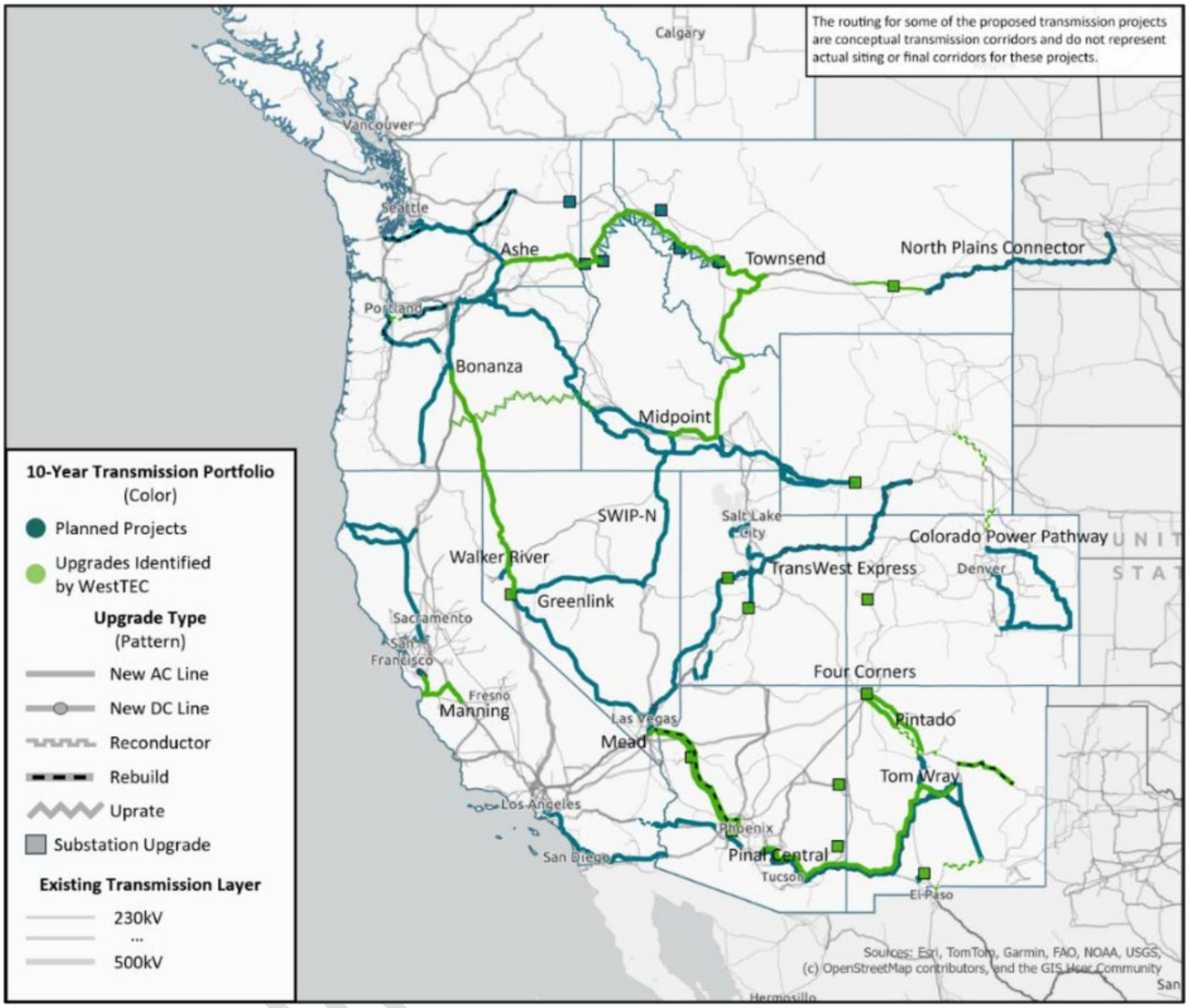
2.4.3 Interregional Transmission Planning Efforts

The Western Transmission Expansion Coalition's (WestTEC), a partnership of utilities, transmission providers, state agencies, system operators, public power entities, developers, tribal representatives, and other stakeholders, published a 10-year Horizon Study[17] in 2026 that examined the need for new regional transmission projects to meet load growth and integrate renewable resources at scale across the West. The study identified a need for more than 12,600 miles of new or upgraded high-voltage transmission by 2035, including major interregional corridors designed to improve transfer capability between western subregions and reduce congestion on critical WECC paths. Figure 2-14 summarizes the results of that planning effort, including both projects already under development and new conceptual projects identified by WestTEC.

PNM's IRP incorporated certain projects from the WestTEC study in its IRP evaluation to further its understanding of the value of each of those projects to PNM customers. As noted in the Action Plan, PNM will continue to evaluated these projects to define benefits and pursue those if they provide demonstrated value to PNM customers.

[17] Davis, Lucas. "Visualizing California Renewable Curtailments". Energy Institute Blog. June 15, 2026. https://energyathaas.wordpress.com/2026/06/15/visualizing-california-renewables-curtailments/

FIGURE 2-15. SUMMARY OF WESTTEC 10-YEAR TRANSMISSION PLAN[18]



[18] Western Transmission Expansion Coalition. "West-Wide Transmission Study 10-Year Horizon Report." February 2026. https://www.westernpowerpool.org/private-media/documents/WestTEC_10-year_Full_Report.pdf.

3. Load Forecast

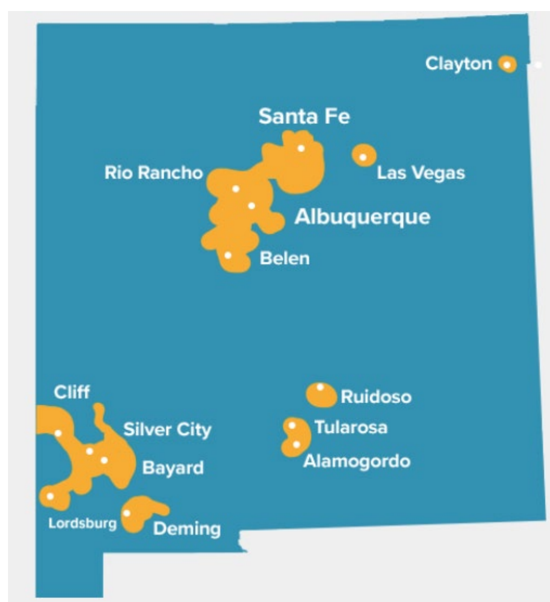
Chapter Highlights

- PNM provides retail electric service to customers throughout the state of New Mexico; customers include residential, commercial, industrial, and other end users of electricity.
- PNM tailors programs and services to meet customers' needs and preferences, which includes energy-saving measures, a TOU pilot, a new transportation electrification program, and a revamp of the renewable energy programs.
- PNM's peak demand, exceeds 2,200 MW in 2026, is expected to grow at an average rate of 2.5% per year over the 20-year IRP horizon. This forecast reflects current expectations for economic and demographic changes, economic development projects, behind-the-meter solar adoption, and electric vehicle adoption.
- PNM's IRP includes multiple load forecast scenarios. These futures and extreme load growth sensitivity consider the different levels of the variables described above as well as building electrification, time-of-use rate design, and extreme weather events and significant economic development growth case. In the highest load growth forecast included in the IRP, peak demand grows at a rate of 3.2%% per year through 2045.

PNM's mission is to provide safe, reliable power to customers at affordable prices. Customer usage patterns and preferences inform resource planning and procurement decisions. As such, the portfolio analysis process in this IRP informs that the SoN is designed to evolve in concert with customer needs and preferences over the coming years. This chapter describes PNM's customers and their energy usage, customer offerings through rates and programs, as well as the forecast for peak demand and energy use through 2045.

3.1 PNM Customers

PNM's retail service territory, shown in Figure 28, covers a large area of north central New Mexico, including the cities of Albuquerque, Rio Rancho, and Santa Fe as well as most of the area around the Rio Grande Valley from Belen to Santa Fe. Other communities in PNM's territory include Lordsburg, Silver City, Deming, Alamogordo, Ruidoso, Tularosa, Clayton, Las Vegas, several New Mexico Pueblo nations, and numerous unincorporated areas.



PNM's retail electricity customers number about 562,000 and include many different types of users. For the purpose of providing retail electric service, PNM organizes these customers into nine classes that reflect different sizes, applications, and patterns of consumption. PNM's classes of service are listed in Table 12, along with breakdowns of total customers, annual load, contribution to peak, and revenue from these classes.

TABLE 12. PNM'S 2025 CUSTOMER COUNTS, USAGE, AND REVENUE

Customer Class	Customers (#)	Annual Load (GWh)	Coincident Peak (MW)
Residential	496,948	3,758	953
Small Power	54,474	1,026	246
General Power	4,303	2,085	400
Large Power	156	926	130
Large Service	13	2537	303
Private Lights	0	13	0
Irrigation	314	25	5
Water and Sewer	149	200	16
Street Lights	1	40	0
Total	**556,358**	**10,610**	**2,053**

PNM customers' demand and energy usage vary based on geography, climate, customer type, and technology adoption. Accounting for these differences is important in the planning process to ensure that all customers receive the service they require.

3.2 Existing Demand-Side Programs

As enumerated in the updated IRP Rule, demand-side resources consist of two types: energy efficiency (EE) and load management (LM). Energy efficiency refers to reductions in energy use by customers over the whole year, the timing of which is dependent on the measure. Load management programs, such as demand response (DR), reduce customer demand specifically at times of peak load or during shortages of supply. This section describes the current EE and DR programs, along with historical program performance and program descriptions in compliance with the requirements of the updated IRP Rule Section 17.7.3.10(B).

PNM's existing resource portfolio includes EE and DR programs approved by the NMPRC pursuant to the Efficient Use of Energy Act (EUEA). This portfolio is required to pass the Utility Cost Test, which compares portfolio costs to benefits. Benefits include avoided generation costs (e.g. fuel and emissions) along with avoided or deferred costs of capacity additions as well as avoided transmission & distribution costs. The EUEA requires utilities to invest between 3% and 5% of retail sales revenues in energy efficiency and load management programs. Annual PRC-approved budgets for efficiency and demand response have grown over time, reaching $36.5 million in 2026.

3.2.1 Energy Efficiency

PNM's energy efficiency programs offer a diverse set of opportunities to customers to save energy, reduce their electricity bills, and benefit the environment. The programs are designed to complement supply-side planning, to meet the requires of the EUEA, and to facilitate transformation of the New Mexico economy to the public benefit. As described in the 2024-2026 Energy Efficiency and Load Management Program Plan:

> In addition to meeting the requirements of the Act, PNM's EE programs encourage lasting structural and behavioral changes in the New Mexico economy through the process of market transformation. This is accomplished by promoting the purchase of energy efficient products and services, increasing customer awareness of energy efficiency measures, providing incentives to change behaviors, and removing market barriers. Over time, distributors will stock more efficient equipment, contractors will promote more efficient equipment to their customers, and customers will become more inclined to purchase efficient equipment.

– 2024-2026 Energy Efficiency and Load Management Program Plan

PNM carefully tracks savings produced by its energy efficiency programs using the results from an annual measurement and verification process. The process is conducted by an independent third-party evaluator selected by the NMPRC and reports metrics including customer adoption rates as well as energy savings, carbon emissions reductions, and reductions in water use by generators that is attributable to PNM's EE programs. Table XX summarizes the results of the programs from 2008 through 2025. Since 2012, efficiency programs have consistently yielded energy savings of 70 GWh per year or greater. Because these savings persist over time, the total impact of the efficiency programs on load is larger still: the cumulative load reduction in 2025 was 779 GWh, which resulted in nearly 3.98 million metric tons of avoided greenhouse gas emissions and over 2.3 billion gallons of water conserved1.

The effects of these historical programs are captured directly in the load forecast. In forecasting load, programs are assumed to be replaced as they expire, so that demand and energy savings continue throughout the plan period. The load impacts of future energy efficiency programs are modeled explicitly in the IRP as a resource option; the characterization of this option is discussed in detail in Section 6.1.1.

TABLE XX. HISTORICAL STATISTICS FOR ENERGY EFFICIENCY PROGRAM IMPACTS

Year	Incremental Energy Savings (GWh)	Cumulative Energy Savings (GWh)	Cumulative GHG Savings (000 tons)	Cumulative Water Savings (million gal)	Peak Demand Savings (MW)	Annual Program Cost ($ millions)
2008	35	35	24	14	7.5	$8
2009	40	75	68	44	6.3	$12
2010	59	134	151	95	9.9	$17
2011	58	192	270	166	9.7	$17
2012	79	271	439	262	13.6	$17
2013	76	346	654	384	11.8	$18
2014	75	421	917	522	12.0	$22
2015	79	501	1,228	685	12.1	$24
2016	82	583	1,543	876	13.0	$26
2017	75	622	1,881	1,080	11.9	$26
2018	71	653	2,235	1,270	12.5	$23
2019	78	672	2,557	1,466	13.7	$24
2020	87	702	2,911	1,648	15.0	$26
2021	107	730	3,255	1,838	18.8	$30
2022	96	750	3,570	1,987	13.9	$31
2023	92	767.4	3,767	2,103	14.5	30.9
2024	86.4	774.5	3,889	2,226	18.0	35.8
2025	86.8	779.3	3,982	2,332	18.0	$39

Compliance with EUEA Targets

The EUEA and subsequent amendments have established minimum energy savings goals for energy efficiency programs. Historically, the comprehensive energy efficiency programs have surpassed the minimum standards required by the EUEA:

- The original EUEA established a 2014 goal of 5% of PNM's 2005 retail sales, or 411 GWh; PNM exceeded this goal with 421 GWh of cumulative savings;
- Amendments in 2013 established a 2020 goal of 8% of 2005 retail sales, or 658 GWh, which PNM surpassed with 702 GWh of cumulative savings; and

- The amendment in 2019 established goals for 2021-2025 of 5% of 2020 retail sales, or approximately 395 GWh. PNM exceeded this cumulative goal by 74 GWh;
- The Commission established a 2030 goal of 5% of 2025 sales, to which PNM received a variance allowing PNM to use 2024 sales. This goal is 405 GWh.

PNM's plan to continue existing energy efficiency programs is documented in the 2027 Energy Efficiency and Load Management Program Plan, which establishes plans for 2027-2029 that are expected to produce approximately 99 GWh of incremental net savings each year. PNM expects an increase in annual program costs, as many of the supply chain disruptions that have affected other parts of the industry also have implications for program costs as well.

Program Cost Effectiveness

As specified by the EUEA, the energy efficiency programs must pass the Utility Cost Test at the portfolio level. This means that the benefits realized through avoided energy and capacity costs must exceed the costs to administer the program and provide incentives for customer adoption. Typically, the programs exceed a benefit-cost ratio of 1.0 by a significant margin: in 2025, for example, the benefit-cost ratio of the portfolio was 1.38.

Transmission & Distribution Avoided Cost Study

In Case No. 23-00138-UT, Final Order, Paragraph 6 E, the Commission ordered that "PNM shall conduct a transmission and distribution avoided cost study to be included in its next energy efficiency and load management triennial plan for years 2027-2029, and if PNM chooses to propose proxy avoided costs, it shall update the values for those proxy costs to be current as of the year of filing". Rather than use another proxy value, as has been the case historically, PNM elected to use an independent, third-party company, DSA, with broad expertise in this area to perform the study.

This comprehensive study involved the analysis of inputs from areas throughout PNM primarily including, but not limited to, Integrated Resource Planning, Distribution and Transmission Planning, System Mapping, Load Forecasting, Energy Efficiency, Community Solar, Transportation Electrification, and Economic Development. The historical and forecast data from these multiple sources included data from traditional household meters, commercial metering (MV90 and Advanced Metering), and substation and feeder SCADA data. DSA performed the T&D avoided cost study with input from all relevant PNM subject matter experts. The results from the T&D avoided cost study, on balance, will increase cost-effectiveness relative to the proxy avoided costs. The T&D avoided cost study results will apply to 2026 and later. The detailed study can be found in Appendix [ ].

Overview of Programs

PNM's energy efficiency programs include the following incentives:

- Retailer rebates for the purchase of energy efficient products such as insulating spray foam, air purifiers, and evaporative coolers;
- Rebates for recycling older refrigerators;
- Residential incentives for efficient appliances and cooling equipment;

- Rebates to small and large commercial customers for efficient lighting and heating, ventilating, air conditioning and other energy efficiency improvements tailored to customers' businesses;
- Incentives for homebuilders to construct homes that go beyond existing energy codes;
- Energy behavioral program where residential and commercial customers receive personalized energy-saving tips and rebate recommendations;
- Energy saving kits provided to fifth-grade students, high school students, and seniors along with an interactive instructional presentation on energy efficiency; and
- Incentives that specifically target energy efficiency improvements for income-qualified and multifamily customers.

PNM promotes EE programs and efficient energy-use incentives through bill inserts, direct mail and email advertising, radio, television, print advertising, social media and other digital advertising, and community education programs. The PNM website also provides information on these programs.

Once approved by the NMPRC, EE programs remain in effect until modified or canceled by the NMPRC. Descriptions of the specific programs offered appear in Appendix L.

3.2.2 Demand Response

Demand response programs reduce customer demand at times of peak load or during shortages of supply. PNM customers can opt to have portions of their load curtailed through the Power Saver and Peak Saver programs:

- The Peak Saver load management program is designed to help medium and large commercial customers with individual or aggregated demand greater than 150 kW reduce the amount of energy they require during peak demand periods.
- The Power Saver load management program sends control signals to refrigerated air conditioning units in participating homes and small businesses during periods of peak demand. To facilitate load control, participants must have a Digital Control Unit (DCU) attached to the exterior of their air conditioning unit. This "paging" device is capable of receiving a radio signal that will activate a control sequence that cycles the unit's compressor for an interval of time (usually half the time as normal) to reduce peak demand in the summer. Alternatively, load curtailment can be achieved via communication with a participating Wi-Fi-enabled thermostat that requests a three-degree increase from the cooling unit. Participants can opt out of up to three control events per season without forfeiting their annual incentive and can request complete withdrawal from the program and incentive award at any time.

These programs were approved by the NMPRC in Case No. 07-00053-UT and reauthorized in Case No. 23-00138-UT. PNM selected the demand response program contractor through a competitive bid process. Power Saver operates from June to September to help PNM manage peak summer loads. Participants' load may be curtailed up to 100 hours over the course of the control season, with a maximum duration of four hours at any given time. Peak Saver operates year-round with a maximum curtailable load of 100 hours during control season (June through September) and 300 hours during off-peak season (October through May), also with a maximum event duration of four hours. Customers receive a minimum of 10 minutes notice for each curtailment event, though notice is typically provided farther in advance. Power Saver curtailment events cannot be called on weekend days or on NERC holidays. Peak Saver curtailment events can be called year-round, 24 hours per day at reduced capacity levels outside of peak load periods (peak load periods are June through September, non-holiday weekdays, 10 am to 10 pm MT). Historically, the actual number of calls in a year has typically been between five and fifteen, though since 2019 the average has been three calls per year.

Historical Load Impacts

PNM relies upon the same measurement and verification process used for EE to evaluate the impacts of DR programs. In the most recent independent evaluation, EcoMetric Consulting notes the impact these programs had on PNM's peak demand:

> The Evaluation team concludes that PNM's load management programs served as a capacity resource that avoided the need for additional supply-side peaking capacity in 2025. While the summer of 2025 had fewer extremely hot days compared to prior years, gross demand was still high overall.

– EcoMetric Consulting, *Evaluation of the 2025 Public Service Company of New Mexico Energy Efficiency and Demand Response Programs*

The same independent review found that together the Power Saver and Peak Saver programs together are able to reduce peak demand by an average of 48 MW (see Figure 29). Data from 2024 is used to illustrate this point because only test events were called in 2025. Test events are meant to confirm that program implementation works as intended. Not calling events in a particular year does not diminish the capacity of the resource but simply indicates that the resource was not needed that year due to variations in weather and other system factors.

FIGURE 29. PNM SYSTEM LOAD ON JULY 31, 2024

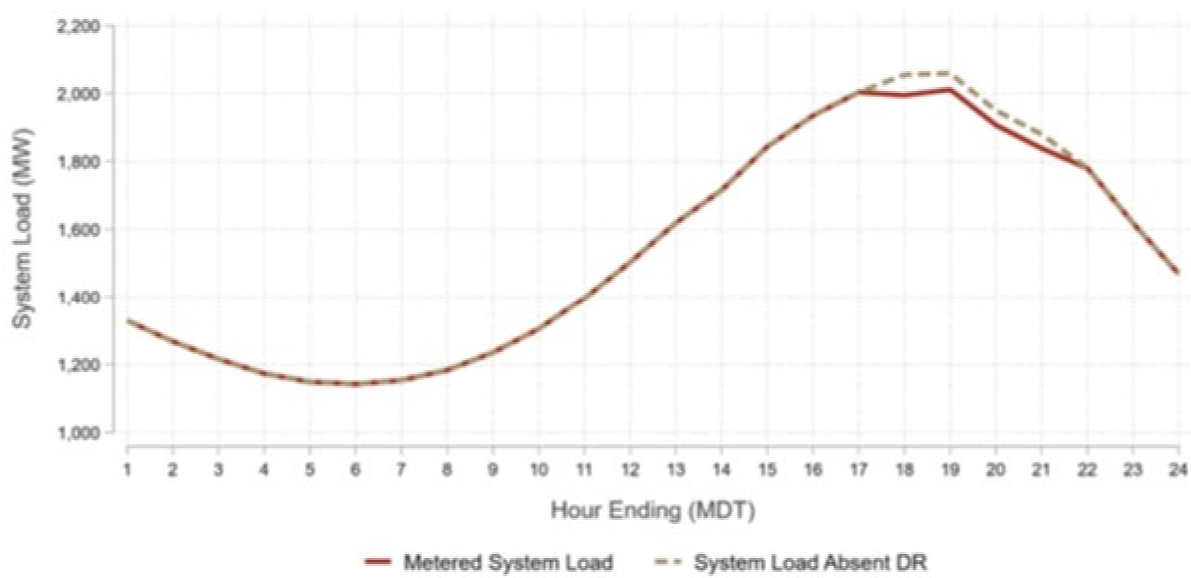


Figure reproduced from: EcoMetric Consulting, Evaluation of the 2025 Public Service Company of New Mexico Energy Efficiency and Demand Response Programs, available at:

https://www.pnm.com/documents/d/pnm.com/2_evaluation-of-2025-pnm-ee_load-mgmt-prgrams

The Peak Saver and Power Saver programs are governed by a contract covering up to 9 years, with optional three-year extensions at two points within that timeframe, contingent upon regulatory approval. This contract went into effect in 2024.

3.2.3 RFP FOR DSM RESOURCES

The following directive was ordered in Case 23-00138-UT. Below is a description of PNM's compliance with the directive.

> *PNM shall fulfill the requirements of the final order in Docket No. 20-00218-UT by including in, or issuing contemporaneously with, its request for proposals to be issued in accordance with 17.7.3.12 NMAC following acceptance of its 2023 integrated resource plan, a solicitation for new, incremental demand response resources based on all available utility demand response resources.*

PNM issued its RFP for DSM resources on September 4, 2024. DSM resources were defined to include traditional Demand Response ("DR") resources, Energy Efficiency ("EE") programs, or other resources as may be proposed. Offers for capacity from DSM resources would be considered if they provided system capacity reductions that: (i) mitigated reliability risks throughout the year, as discussed in PNM's latest Integrated Resource Plan ("IRP") or (ii) offered availability to provide other benefits to PNM's system such as load shifting, load smoothing, or avoidance of generating unit starts.

Responses to the RFP ("Proposals") by qualified Suppliers ("Suppliers") were due on December 3, 2024.

Prior to issuance of the RFP for bid, on July 10, 2024, PNM served a draft of the RFP documents to the IRP Independent Monitor ("IM"), the NMPRC Commissioners and their assistants, and all parties to the utility's pending IRP case for review and comment. The IM subsequently issued its RFP design report on August 7, 2024, outlining comments and suggestions to the RFP. Comments were also received from Western Resource Advocates, Southwest Energy Efficiency Project, the Coalition for Clean Affordable Energy, Commissioner O'Connell, and Commissioner Ellison.

In total, PNM received 29 comments from the IM and RFP stakeholders. PNM made several modifications to the RFP to address these comments and issued responses to each comment in conjunction with the issuance of the RFP for bid on September 4, 2024.

During the RFP bid period, PNM received notifications of intent to respond from 21 different DSM program developers. However, only one Proposal was received on the Proposal due date of December 3, 2024. This Proposal failed to pass the RFP minimum requirements outlined in the RFP documents. Based on non-compliance and other factors including high cost, limited RFP responses, and a lack of competitive bids to evaluate and compare, a compliance filing was made to the PRC on January 29, 2025, detailing the decision for "No Award".

PNM received feedback from three suppliers as to why Suppliers decided not to respond. One supplier stated the difficulty of pricing a solution for the start date of 2027 and beyond was too difficult to offer a compliant Proposal. Other Suppliers noted they did not have the ability to provide the solution requested or could only propose wholly different and proprietary technologies in lieu of a proposal submission. PNM filed its "2024 Demand Side Management Program RFP Results Summary" with the PRC on January 29, 2025. The Independent Monitor, Merrimack, submitted its "2024 Demand Side Management Program RFP IM Final Report" with the NMPRC on February 11, 2025.

3.3 Trends in Usage and Customer Preferences

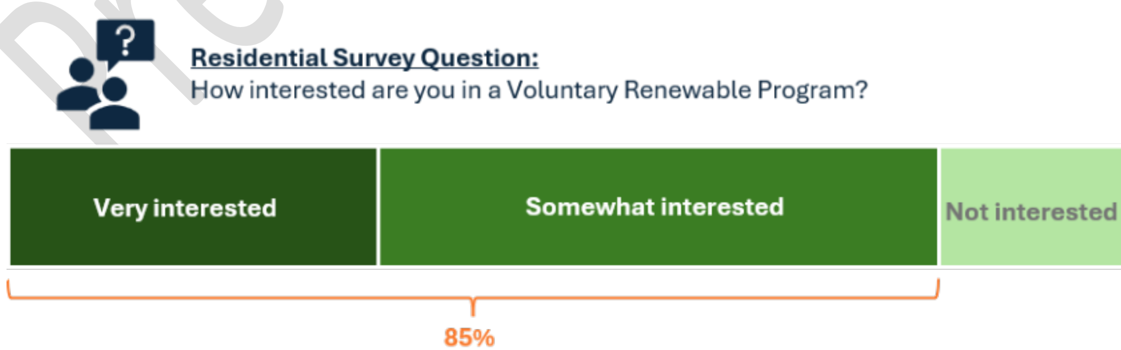
3.3.1 Voluntary Green Energy Programs

PNM conducts regular customer surveys on a variety of topics to better understand customer priorities and identify opportunities to enhance service offerings. In a recent survey, approximately 30% of respondents indicated they were "very interested" in participating in a voluntary renewable energy program, and 85% reported being at least "somewhat interested". These results demonstrate strong customer interest in renewable energy options and suggest that many customers are willing to consider programs that help reduce their environmental impact.

For customers seeking a higher level of renewable energy than that is reflected in PNM's generation portfolio, PNM offers net metering and several voluntary programs, including PNM Solar Direct, Community Solar, and PNM Sky Blue. These programs allow customers of all sizes to invest in their own on-site generation, or to procure renewable energy from utility scale resources. Because participation in these programs is voluntary and separate from PNM's standard service, the renewable energy resources dedicated to serving these customers are not included in PNM's RPS accounting. This means that the actual fraction of renewable energy produced to serve PNM customers will always be larger than the fraction reported for RPS compliance. Participation in these programs is expected to continue growing, leading to a percentage of renewable generation higher than what is required by the RPS.

Utility-led renewable energy programs provide an opportunity to meet customers' desire to tailor their energy use. Coordination between the IRP process and program design will remain important, particularly as PNM's portfolio shifts to renewable resources supplying the majority of customers' energy use. Understanding the system impacts from increased adoption of resources not counted in the RPS – privately owned resources and utility scale resources supplying voluntary programs – informs program and generation portfolio design.

Figure 30. Residential customer interest in voluntary green energy programs.



PNM Solar Direct

PNM has also been working collaboratively with larger customers to provide increased choice in energy supply. Under a program approved by the NMPRC in 2020, customers with loads larger than 2.5 MW are eligible to subscribe to a portion of the output of the 50 MW Jicarilla 2 solar plant in Rio Arriba County. This program allows large customers the option to meet their sustainability goals through a fifteen-year commitment to purchase output from this facility. Jicarilla 2 is fully subscribed by nine large and governmental customers. The site was fully commissioned in April 2022, and customers receive a bill credit for their subscription each month.

Community Solar

Community Solar is a statutory law resulting from the Community Solar Act, SB84, that was signed by Governor Michelle Lujan Grisham in April 2021 and became effective on June 18, 2021. The Commission Rule 573 implements the Community Solar Act. It is a way for customers who may not be able to install their own behind-the-meter solar to participate in a community-solar project by subscribing to a percentage of the output of a specific CS facility. In return, the customer receives a monthly bill credit ($/kWh) specific to their rate schedule for their subscription amount.[2]

Phase 1 of Community Solar authorized a statewide capacity of 300 MW_{ac} of which PNM's share is 185 MW. PNM's Community Solar sites must be within PNM's service territory and connected to PNM's distribution system. The first Community Solar site came online in September 2025. As of May 2026, there are six Community Solar sites accounting for 30 MW of solar capacity. There are approximately 7,100 customers subscribing to Community Solar Projects for almost 5 GWh in subscribed energy.

PNM Sky Blue

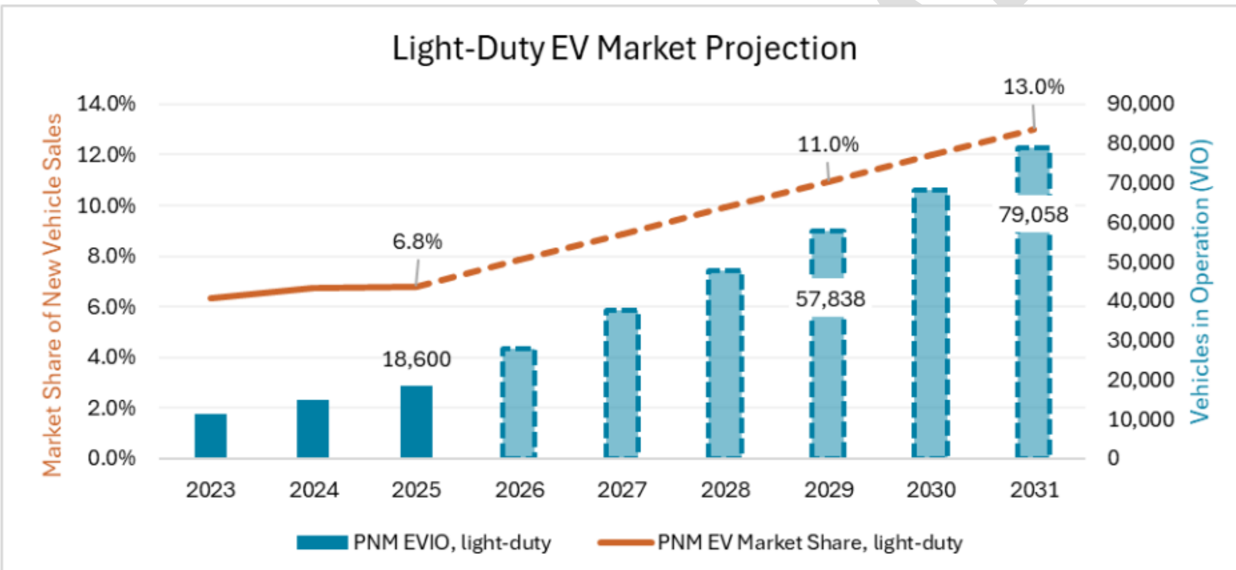
Sky Blue in its current state was a voluntary green tariff program that was offered starting in 2013 to PNM customers who were willing to pay a premium through Rider 30 to upgrade more of their energy consumption to renewables. These customers could subscribe to Sky Blue by purchasing blocks in 100 kWh increments or a percentage of their overall consumption; a mix of both wind and solar resources were dedicated to Sky Blue subscriptions. Solar energy was sourced from 1.5 MW of the Manzano Solar Energy Center (8 MW total) and wind was sourced from the New Mexico Wind Energy Center (NMWEC).[3] Sky Blue was used by some commercial customers to meet their green goals and by residential customers who were interested in solar but didn't have their own DG systems. However, by early 2025 subscriptions were declining overall. For various reasons commercial customers do not have the same green energy goals compared to several years ago and they often install their own behind-the-meter solar. Residential net metering has increased, which has impacted Sky Blue participation. Given the decline in customer numbers overall, PNM explored the idea of redesigning Sky Blue into a voluntary green tariff program that would be more responsive to today's customer needs. There was limited interest when PNM held exploratory workshops and for residential customers now, Community Solar is an effective alternative for those who want to purchase a share of a community-based solar project. As a result, in Q4-2025, PNM filed an application with the Commission seeking approval to terminate Sky Blue. There was one protest from a commercial customer. PNM worked with that customer and both parties agreed on a continuation of Sky Blue through December 31, 2026. Sky Blue will terminate shortly after.

3.3.2 Electrification

In the past several years, PNM has observed a rapid acceleration in interest in electric vehicles. Figure 31 shows this recent rapid increase: for most of the past decade, the share of new vehicles that were fully or partially electric was less than 1%, but in the past few years that share has grown significantly. At the end of 2025, nearly 7% of new vehicles sold in PNM's service territory were either battery electric vehicles (BEVs) or plug-in hybrid electric vehicles (PHEVs).

As the number of electric vehicles on the road grows, their impacts on the grid will continue to increase. The IRP incorporates a forward-looking projection of electric vehicle adoption into the demand forecast (discussed in Section **3.4**), but PNM also recognizes the importance of being a proactive partner to customers as their preferences change. To that effect, PNM filed its 2027-2029 Transportation Electrification Plan, which is currently under consideration by the NMPRC, in May 2026 (Case No. 26-XXXXX-UT). The plan provides incentives for battery electric vehicles and EV charging infrastructure, along with new rate plans to incent customers to charge during off-peak times. Additionally, 40% of the funding is dedicated to supporting transportation electrification for low-income customers and those living in underserved areas.

FIGURE 31. HISTORICAL AND PROJECTED SALES SHARE OF ELECTRIC VEHICLES IN PNM'S SERVICE TERRITORY



PNM expects its plan will provide both financial and environmental benefits for customers. EV adoption can enable customers to manage electric loads by choosing when they charge EVs. By charging during off-peak times, customers can lower electric rates by shifting load away from the hours of highest demand in a manner that provides benefits to all PNM customers. Customers will also benefit from reduced spending and air pollution by displacing gasoline with EVs powered by an increasingly cleaner grid.

In the future, New Mexico's continued pursuit of economy-wide decarbonization will likely drive additional electrification – not only of transportation, but of buildings as well. While only 25% of residential customers report heating their homes with electricity today, proliferation of heat pumps is expected to make electricity the primary heating fuel in the state. The same is true for water heating, where 23% of customers report electricity as their energy choice today.

The load growth from electrification presents an opportunity. With proper planning, significant segments of these new loads can be shaped to some extent to serve as a peak-reducing resource using a combination of rate signals and automatic controls. On the customer side, this management and the grid modernization technologies that enable it will improve the ability to communicate with customers and will lead customers to better engage with and understand their energy usage. On the system side, this management will lead to a more reliable and less costly system.

While PNM is beginning to incorporate electrification-driven increases in load in long-term planning, its forecasts under the Current Trends and Policy future do not include significant impacts from electrification within the timeframe of the planning period of this IRP. However, considering the continued push at a state level on economy-wide decarbonization, the fossil fuel market volatility, as well as requests from stakeholders, PNM analyzed a sensitivity with high EV penetration to help better identify the implications and potential actions needed for accelerated electrification.

3.3.3 Time Varying Rates

Almost all of PNM's customer classes currently have two time-varying rate options on their Time-of-Use rate schedule as of May 15, 2026.[4] These two time-varying rate options are a Time-of-Use Rate ("TOU Legacy") and a Time-of-Day Rate Pilot ("TOD pilot"). They have different peak period structures and different energy rates, although the other rate components (customer charge and demand charge, if applicable) are the same for the duration of the TOD pilot. For the large customer classes (with demand greater than 50 kW), the TOU/TOD rate options are required. The Residential, Small Power, and Irrigation customer classes have a non-TOU/TOD rate schedule on which the majority of each customer class takes service.[5]

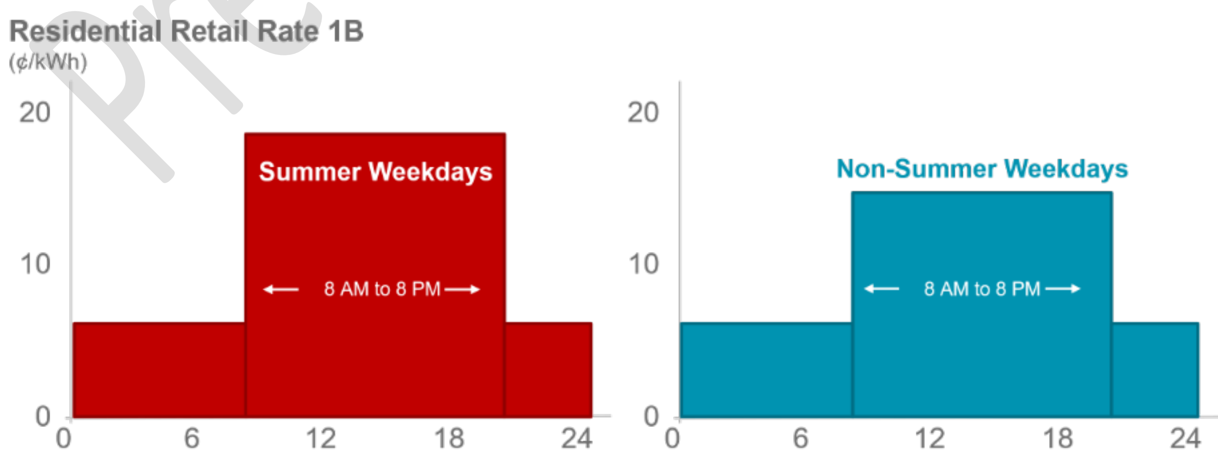
The exceptions to the time-varying rates are: (i) PNM's two lighting rate schedules (Rate 6 Private Lighting and Rate 20 Streetlighting) and, (ii) Rate 36B Special Services - Renewable Energy Resources. The former do not have any time varying rate schedules because lights are programmed to turn on at dusk and turn off at dawn, thus lack the capability to shift away from peak hours. The latter has only the Time-of-Use Rate with the associated on-peak hours.

The specifics of each time-varying rate option will be discussed subsequently.

Time-of-Use Legacy Rates

PNM first offered its Time-of-Use Legacy ("TOU Legacy") rates in the early 1980s when the system peak was around 4:00pm and there was limited, if any, solar generation. The on-peak periods were set at 8:00am – 8:00pm, Monday-Friday, year-round. The goal was to encourage shifting or reducing consumption around the time of the system peak. PNM has seasonal rates and the summer on-peak energy rates are more expensive than the non-summer on-peak energy rates, while the off-peak rates are the same year-round. Figure 32 shows the on-peak hours for Residential customers on Rate Schedule 1B Time-of-Use Legacy Rate option, however the on-peak periods are the same for all of PNM's customer classes.

Figure 32. TOU Legacy on-peak hours for Residential (and Commercial) customers



In the past decade plus, solar generation has been installed in greater numbers, leading to the need for less traditional generation during the day as well as excess solar generation being exported to the grid. This has led to the famous “duck curve” load and has also pushed the peak load hour later in the day when residential customers come home and begin their evening activities at the same time that solar production is decreasing so load would naturally ramp up anyways. It has been revealed that the TOU Legacy rate design is somewhat antiquated with its most expensive, on-peak hours overlaying the hours of inexpensive excess solar generation being exported to the grid. As a result, PNM began working on a new TOU rate design with its stakeholders in 2018 following the Final Order in the 2016 general rate case. This new TOU rate design was named “Time-of-Day (TOD)” to distinguish it from the TOU Legacy rate. The TOD was proposed and approved as an opt-in pilot rate option for every customer class in the 2022 general rate case (Docket No. 22-00270-UT). The effective date was January 15, 2024. All of the TOU Legacy rate options remained open for customers. For Residential and Small Power customers, their TOU Legacy rate options were closed to new customers although existing customers could stay on the TOU Legacy rate option. In the next general rate case, PNM plans to close Residential and Small Power TOU Legacy Rate options and move the existing customers to the TOD Pilot rate option with the option to switch to their non-time varying rate schedule 1A or 2A.

Time-of-Day Pilot Rates

As mentioned previously, TOD pilot rate design and rates were approved in Docket No. 22-00270-UT, becoming effective on January 15, 2024. The first customers started taking service on the pilot rates on February 15, 2024 (1 residential and 2 commercial customers). The TOD pilot is opt-in so customers have to choose to take service on the pilot rates.

The on-peak period hours were selected so that the price signal would effectively communicate when energy is more expensive for the utility as well as reflecting the impact of increased solar interconnections. The on-peak hours vary by season and there is a super off-peak period for the commercial customers.

Residential customers have a 2-period TOD pilot rate design. The summer on-peak hours are 5:00pm - 8:00pm Monday-Friday in June, July, and August.[6] All other hours, weekends, and the 4th of July are off-peak. The residential TOD pilot does not currently have a super off-peak period.

Commercial customers have a 3-period TOD pilot rate design. In the summer months, on-peak hours are 5:00pm to10:00pm and super off-peak hours are 8:00am to 5:00pm Monday through Friday. All other hours, weekends, and the 4th of July are off-peak.

All customer classes have the same winter on-peak hours, which are 5:00am to 8:00am and 5:00pm to 8:00pm Monday through Friday September through May. All other hours, weekends, and other major holidays are off peak. Commercial customers have the super off-peak period in the winter months as well, 8:00am to 5:00pm Monday through Friday.

Figure 33 and Figure 34 show the summer and winter peak hours for residential and commercial customers, respectively.

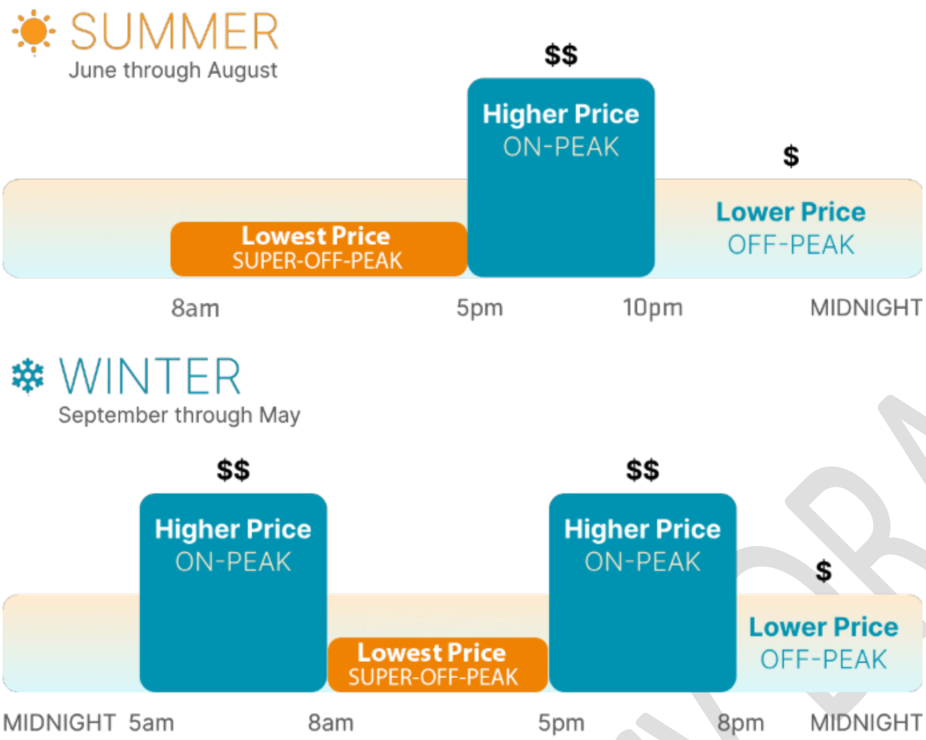
FIGURE 33. RESIDENTIAL TOD PILOT SEASONAL ON-PEAK HOURS, MONDAY-FRIDAY

When the TOD pilot was proposed in the 2022 rate case, PNM did not propose a super-off-peak period for the residential TOD pilot because it was seen as too confusing. The residential customer class had almost no experience with time-varying rates and a 3-period rate design might have deterred customers from opting in. However, in PNM's next general rate case, PNM plans on modifying the residential TOD pilot to include the super off-peak period. As of March 2026, there were approximately 2,170 residential customers taking part in the TOD pilot.

PNM's independent evaluator provides annual reports on customer satisfaction and load shifting impact that are filed with the Commission as part of the Grid Mod Annual Review filing. The 2025 load impact analysis showed that there is a statistically significant summer on-peak reduction of approximately 9% during the on-peak hours of 5:00pm to 8:00pm. The non-summer on-peak hours have morning on-peak hours, 5:00am to 8:00am, and evening on-peak hours, 5:00pm to 8:00pm. The morning on-peak saw no reduction or shifting of usage, while the non-summer evening on-peak saw a reduction of approximately 5%, although it was not significant.

AMI deployment will begin in 2027. Once AMI is fully deployed to all PNM customers, PNM will propose default TOD rates for the residential rate class in the subsequent general rate case, which is expected to be effective in 2030. Default TOD means that PNM would move all residential customers on to the TOD rate. Residential customers would retain the right to opt-out and return to Rate 1A although PNM plans to revise 1A into a seasonal flat energy rate and not the current inclining block energy rate design that is currently in effect. PNM has observed in the current residential TOD pilot, an opt-out rate of approximately 4% - 5%.[7] This may be low since the TOD pilot participants are currently characterized as early adopters, so maybe a more conservative opt-out rate would be around 10%.

FIGURE 34. COMMERCIAL TOD PILOT SEASONAL ON-PEAK HOURS, MONDAY-FRIDAY



In the first 18 months of the TOD pilot, commercial customers who switched to the TOD pilot rate option on their rate schedule largely had business operations that were compatible with TOD on-peak and super off-peak periods. School districts, small restaurants that served breakfast/lunch shifts, and single shift manufacturing are examples of early signups. In the past six months, several large box stores and water/sewage customers have either shifted all their stores or have notified PNM of their intent to move their accounts to their applicable TOD pilot rate. The lesson is that commercial customers need more time to assess how they might change business operations to take advantage of the TOD pilot rates.

In the next general rate case PNM has no plans to revise the rate design for the commercial TOD pilot rates. The on-peak, off-peak, and super off-peak periods will remain the same, as will the pricing ratios for energy charges.

It is possible that in the rate case post-AMI deployment, that PNM could revise the on-peak hours based on the results of the TOD pilot. The TOD rates will cease to be pilots in that rate case because the TOD rates will be open to all customers since they will have the appropriate meter. PNM does not plan to make the commercial TOD rates default for those customers because changing business practices to accommodate a new peak period structure is not an easy task. Furthermore, the TOD peak period structure does not benefit high load factor customers who cannot shift load.

3.3.4 ELECTRIC VEHICLE CHARGING RATES

In 2020 PNM filed its first Transportation Electrification Program (TEP) plan (Docket No. 20-00237-UT). As a part of the first TEP plan, PNM proposed two EV charging rate pilots, one residential and one commercial, to support the statutory goals of increasing EV adoption throughout PNM service territory.

Whole House Electric Vehicle (“WHEV”) pilot, residential EV charging

The residential EV charging pilot rate was called the Whole House EV pilot rate and it was a rate option offered on Rate Schedule 1A Residential Service. For qualified EV owners, the rate design offered a very low $/kWh rate to the entire house’s consumption between the hours of 10:00pm and 5:00am to encourage overnight consumption. Energy consumption between 5:00am and 10:00pm was assessed the inclining block energy charges on Rate 1A. There are around 4,625 residential EV customers taking service on the WHEV pilot rate as of May 2026. This rate is a pilot due to customer participation limits. Ultimately, the WHEV rate will be closed around 2030 after the Residential TOD pilot has been modified to include the super-off-peak period and TOD rates are the default for residential customers. The super-off-peak period will offer a low-cost energy rate to encourage EV charging during the day when solar generation is abundant.

Rate 3F Commercial Charging Stations pilot, commercial EV charging

The commercial EV charging pilot Rate 3F is for separately metered commercial charging stations. It has seasonal on-peak hours, 5:00pm to 10:00pm everyday June through August and 5:00am to 8:00am and 5:00pm to 8:00pm every day September through May. All other hours are off-peak. There are 16 commercial charging stations taking service on Rate 3F as of May 2026. Rate 3F is considered a pilot because it is currently an energy-only rate with no demand charge. This is because research has shown that in rural areas without much EV traffic, a single EV charge during on-peak hours can cause the demand to spike so that the demand charge becomes 80% to 90% of the monthly bill, which reduces the incentive for private charging companies to operate charging stations in rural locations. Once there is sufficient EV adoption throughout PNM’s service territory, then PNM plans to introduce a demand charge to Rate 3F.

3.4 Future Demand Forecast

Load forecasting is a fundamental component of resource planning. Variable loads will impact the timing and amount of generation additions and retirements, as well as the transmission and distribution infrastructure needed to deliver energy. Further, the load forecast is arguably the most critical piece in scenario planning, which helps to explore possible future conditions.

The load forecast and associated sensitivities are essential inputs to the IRP, especially in times of more volatile loads. Over the past half century, PNM’s electric loads have undergone several dramatic shifts that directly shaped the electric system as it exists today. Loads grew rapidly and steadily post-World War II as Sunbelt regions like New Mexico experienced major growth. In addition, New Mexico experienced a huge investment in defense infrastructure with national laboratories and military bases. This unprecedented increase in the need for electricity brought forth the construction of large baseload plants like Four Corners (FCPP), San Juan (SJGS) and Palo Verde (PVNGS). Later, PNM was affected by the rise and fall of uranium mining in New Mexico. The industry was the largest customer group in terms of energy, either directly buying energy from PNM, or through supply contracts with electric cooperatives serving the mines. Gearing up to serve that load and then dealing with its collapse in the 1980s following the events of Three-Mile Island had huge implications for PNM’s resource planning.

Presently, PNM faces the potential for another period of transformative changes in electricity demand. Recent load increases, particularly those driven by large industrial loads, data centers, are notable examples. Moreover, policy directions for greenhouse gas emissions reduction increasingly emphasize the electrification of the economy; therefore, PNM anticipates further impact to utility service demand as transportation, space heating, and other energy sectors potentially transition to electric solutions.

3.4.1 METHODOLOGY

To create the load forecasts, PNM develops rate-level projections for residential, small power, and general power classes, including usage per customer and the number of customers in each class. For large power customers, individual forecasts are prepared due to their significant loads. These forecasts rely on historical load data, incorporating temperature and solar profiles from multiple locations within the service territory. PNM also adjusts load data to exclude the impact of behind-the-meter generation and normalize it with historical weather metrics.

Statistically-adjusted, end-use models are used to predict future loads, accounting for factors such as economic growth, appliance saturation, energy efficiency, and the adoption of new technologies like electric vehicles, BTM solar, and heat pumps. The load forecast also reflects the cumulative effect of prior years' energy efficiency programs. As PNM addresses the effects of climate change, climate-adjusted weather years are integrated into the load forecast to consider extreme temperature impacts on heating and cooling loads, which significantly contribute to customers' total demand. Finally, customer-level load is grossed up to account for losses in the distribution and transmission systems between the point of generation and the point of delivery. This analysis allows PNM to evaluate whether a resource is located on the supply or demand side of the customer meter and to assess its value to the system.

Three adjustments are applied to the initial results of these forecasts:

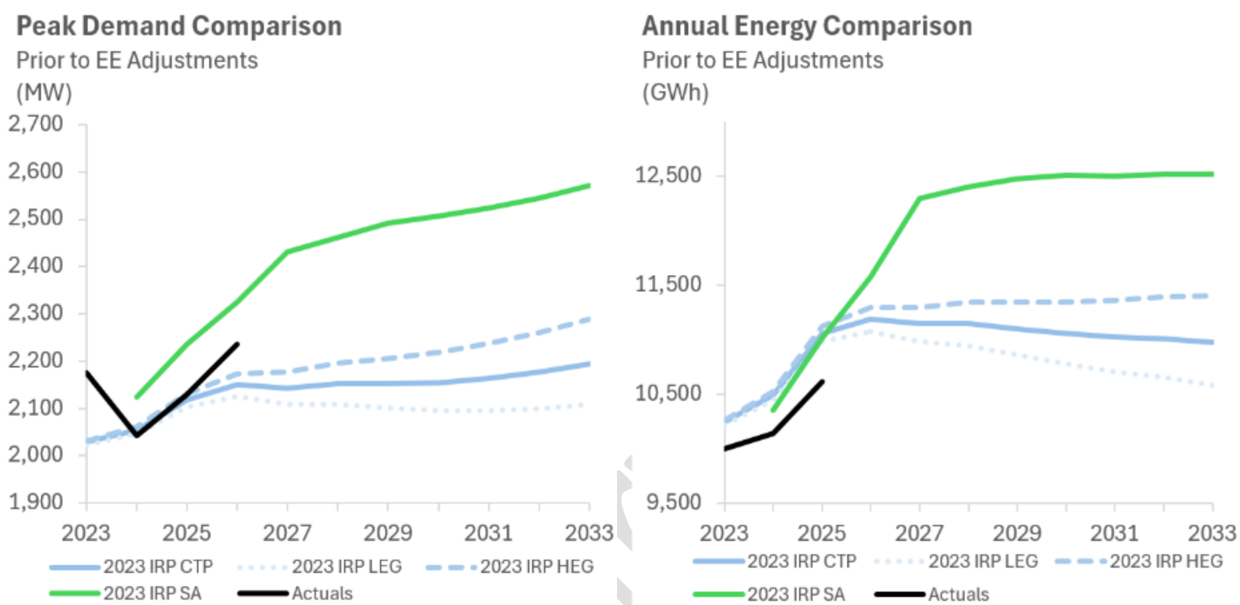
1. Loads in several cases are adjusted upward to reflect a plausible higher rate of growth of large economic development loads. This ensures that a broad range of load trajectories are studied in the IRP; and
2. In all cases, the impacts of future energy efficiency measures assumed to be embedded in the load forecast are removed to allow for energy efficiency to be treated as a resource. The methods used to characterize those opportunities, including both measures to meet the requirements of the EUEA and additional programs, are discussed in Section **6.1.**
3. The potential impacts of Senate Bill 170 are embedded within the baseline forecast and serve as part of the starting point for the resource planning analysis.

Detailed analysis of how the load forecast was derived as well as the supporting data can be found in Appendix [ ].

Historical Forecast Accuracy

The process and methodology used to forecast future demand for the purposes of long-term planning has generally produced reasonable results when compared against actual historical demand. Figure 33 compares PNM's actual historical peak demand against the range of forecasts developed in the 2023 IRP. In the overlapping periods, actuals have tracked reasonably closely to the “base case” forecasts used in 2023 IRP CTP load forecast. More recently, however, stronger-than-expected growth driven by economic development, weather conditions, and increased electric vehicle adoption has caused actual peak demand to exceed the 2023 IRP forecasts. As a result, PNM conducted the 2023 IRP Supplemental Analysis (2023 IRP SA) in response to a material increase in projected energy and peak demand identified in 2023 IRP.

FIGURE 33. COMPARISON OF LOAD FORECASTS DEVELOPED IN PRIOR IRPS AGAINST HISTORICAL PEAK DEMAND



HEG = High Economic Growth, CTP = Current Trends & Policy; LEG = Low Economic Growth; 2023 IRP forecasts include peak load impacts of energy efficiency measures

Table 14 provides additional details comparing the accuracy of peak demand forecasts developed in the 2023 IRP and 2023 IRP SA against actual results during overlapping periods. In most overlapping years, the forecasts used within the IRP are within 5% of the actual peak demand with the 2026 peak demand within 3% of the forecast. PNM’s peak demand in 2026 of 2,263 MW[9] set a record for the system, driven by weather conditions in the southwest more severe than typical summer conditions in New Mexico. The actual peak is expected to be much higher based on the utilization of both PNM’s demand response programs and therefore much closer to the 2023 IRP SA forecast. Final details of the 2026 summer peak will be reconciled after the filing of this report. Considering that year-to-year weather variability can cause variations in peak demand of this size, this recent variance is natural in the process of forecasting peak demand.

TABLE 14. COMPARISON OF PEAK DEMAND ACTUALS AGAINST 2023 IRP LOAD FORECASTS[19]

	2023	2024	2025	2026
Actual Peak Demand (MW)	2,174	2,042	2,130	2,263
2023 IRP CTP Forecast (MW)	2,029	2,054	2,119	2,150
2023 IRP CTP Forecast Variance (%)	-6.7%	0.6%	-0.6%	-5.0%
2023 IRP CTP Supplemental Analysis Forecast (MW)	n/a	2,124	2,235	2,324
2023 IRP CTP Supplemental Analysis Forecast Variance (%)	n/a	4.0%	4.9%	2.7%

3.4.2 FORECAST SUMMARY

Using the methodology described above, a wide range of load forecasts are developed for the IRP. Each forecast represents a specific set of assumptions regarding demographic growth, economic development, BTM solar adoption, EV adoption, building electrification, TOU pricing, and weather conditions.

The first three items listed in Table 15 correspond to the primary "futures" investigated through the IRP. Each of these scenarios reflects a distinct vision of the future:

- **"Current Trends & Policy"** reflects the best estimates of the future state of the world based on the knowledge at the time of the IRP's development. In this future, PNM assumes continued economic and population growth within PNM's service territory consistent with trends as forecast by Woods and Poole, as well as modest levels of incremental customer solar and electrification.
- **"High Economic Growth"** reflects a future of rapid economic expansion in New Mexico. In addition to higher growth in electricity demand, this future assumes greater electric vehicle adoption and increased levels of building electrification.
- **"Low Economic Growth"** reflects a slower pace of economic development in New Mexico. This future assumes lower growth in electricity demand, reduced electric vehicle adoption and slower industrial load growth.

TABLE 15. SUMMARY OF ASSUMPTIONS USED IN VARIOUS LOAD FORECAST SCENARIOS

Future	Economic Forecast	Economic Dev Loads	BTM Solar	EV Adoption	Building Elec	TOU Pricing Impacts	Industry
Current Trends & Policy	Reference	Reference	Reference	Reference	Reference	No	Reference
High Economic Growth	High	High	Low	High	High	No	Reference
Low Economic Growth	Low	Low	High	Low	Reference	No	Low

[19] Represents the highest peak as of August 3, 2026.Actual peak demand for summer 2026 is subject to change.

Sensitivity	Economic Forecast	Economic Dev Loads	BTM Solar	EV Adoption	Building Elec	TOU Pricing Impacts	Weather
High BTM Solar	Reference	Reference	High	Reference	Reference	No	Reference
Low BTM Solar	Reference	Reference	Low	Reference	Reference	No	Reference
High EV Adoption	Reference	Reference	Reference	High	Reference	No	Reference
Low EV Adoption	Reference	Reference	Reference	Low	Reference	No	Reference
High Building Electrification	Reference	Reference	Reference	Reference	High	No	Reference
TOU Pricing	Reference	Reference	Reference	Reference	Reference	Yes	Reference
Extreme Economic Growth	High	Extreme	Low	High	High	No	Reference

The peak demand and annual energy for each of the three futures are summarized in Figure 34 and Figure 35, respectively. Additional details for each of the demand forecasts are provided in Appendix C.

FIGURE 4-1. FORECASTS OF ANNUAL ENERGY DEMAND UNDER DIFFERENT FUTURES

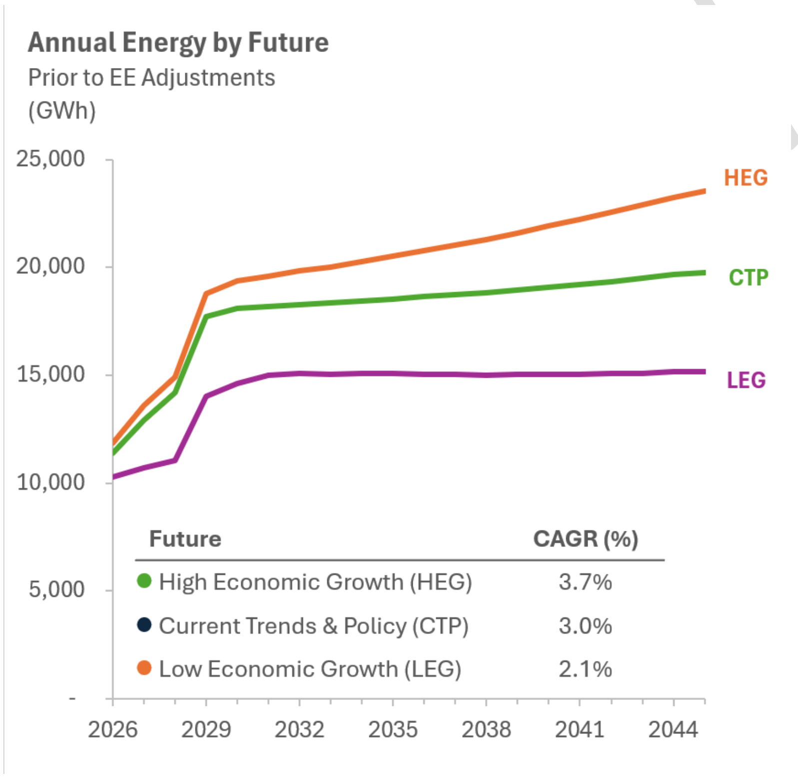
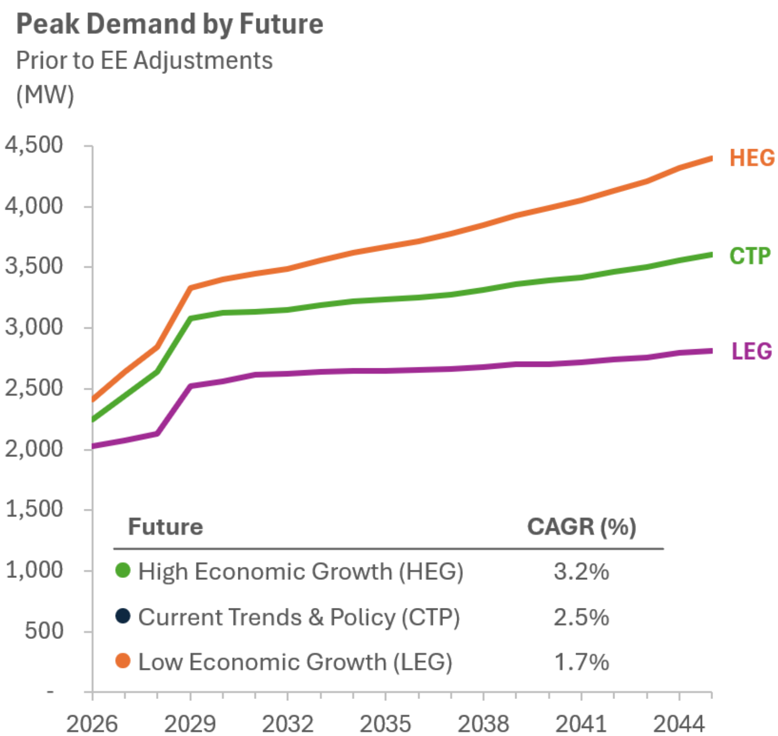


FIGURE 4-2. FORECASTS OF PEAK DEMAND UNDER DIFFERENT FUTURES



Notes: Compound annual growth rate (CAGR) represents the constant annual growth rate that would result in the projected change in load between the beginning and ending years of the study period.

The remaining items listed in [ ] represent a range of sensitivities upon the three futures, in which one or more input parameters are varied to examine their impact. Five sensitivities were created in the load forecast process that were carried forward for subsequent analysis in the IRP. Selection of specific sensitivities to study in the IRP was determined by these factors:

1) Breadth of outcomes: PNM's load is inherently uncertain, and effective planning requires consideration of a broad range of potential outcomes; certain sensitivities were included to ensure this range of conditions studied was sufficiently broad.

12. Impact of the Data Center boom: capturing the range of uncertainty with timing of high load growth.

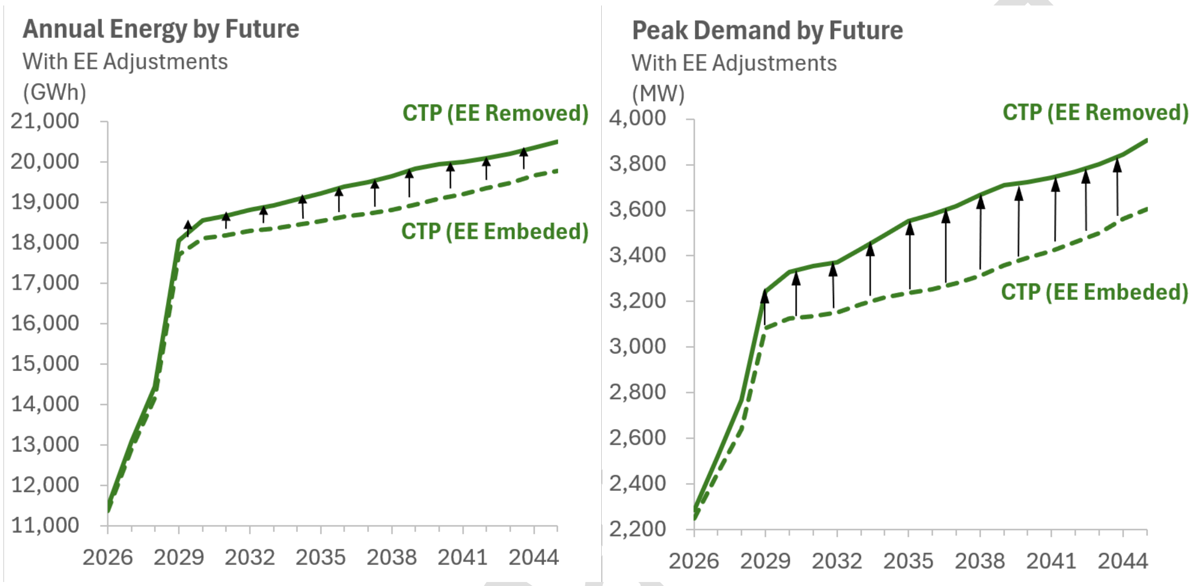
2) Understanding impacts: the analysis of certain sensitivities can provide important information to PNM, the NMPRC, and stakeholders that may help inform future decisions.

Forecast Adjustment for Embedded Energy Efficiency

One of the enhancements introduced in the 2020 IRP that is still used today was the explicit treatment of energy efficiency programs as a resource option that could compete against supply-side options in the optimization of the portfolio. Rather than planning a supply-side portfolio to meet demand reflecting a static forecast of future efficiency, this enhancement allows the IRP to consider the role of efficiency more dynamically in the construction of the portfolio.

The 2026 IRP continues to use this approach to incorporate efficiency into the planning process. Treating efficiency as a resource option requires the load forecast to be adjusted upward, reflecting the embedded impact of future energy efficiency to avoid double-counting. The result of this adjustment is a higher load forecast that is used in the analysis. This adjustment to both annual energy and peak demand is illustrated in Figure for the Current Trends & Policy future; the same adjustment is applied to all other futures and sensitivities analyzed.

FIGURE 0-3. ILLUSTRATION OF LOAD FORECAST ADJUSTMENT TO REMOVE LOAD IMPACTS OF EFFICIENCY TO ALLOW TREATMENT OF EFFICIENCY AS A RESOURCE IN IRP ANALYSIS



Commensurately, “bundles” of energy efficiency measures are characterized by their load impacts and costs and are included as resource options as discussed in Section [ ]. To the extent the bundles are selected in the portfolio, their inclusion would represent a load reduction relative to the “EE Removed” load forecast.

3.4.3 KEY ASSUMPTIONS IN LOAD FORECAST

The results described above reflect a buildup of sectoral load shapes and a number of key load modifiers. These drivers are discussed in further detail in this section.

Economic and Demographic Changes

Economic and demographic factors are a key driver of PNM’s future load growth. The demand forecasts are based on projections of (1) population growth in the service territory, (2) increases in the number of non-manufacturing jobs, and (3) real per capita income growth. Projections for each of these parameters, provided by Woods & Poole at the state and county level, are used as inputs to model future load based on historically observed relationships. The assumptions for each of these parameters are shown in Table . When compared against the 2023 IRP, the 2026 IRP reflects slightly lower levels of population growth and non-manufacturing job growth and real per capita income in the region.

TABLE 0-1. ECONOMIC & DEMOGRAPHIC ASSUMPTIONS IN THE 2026 IRP (2026-2045 AVERAGES)

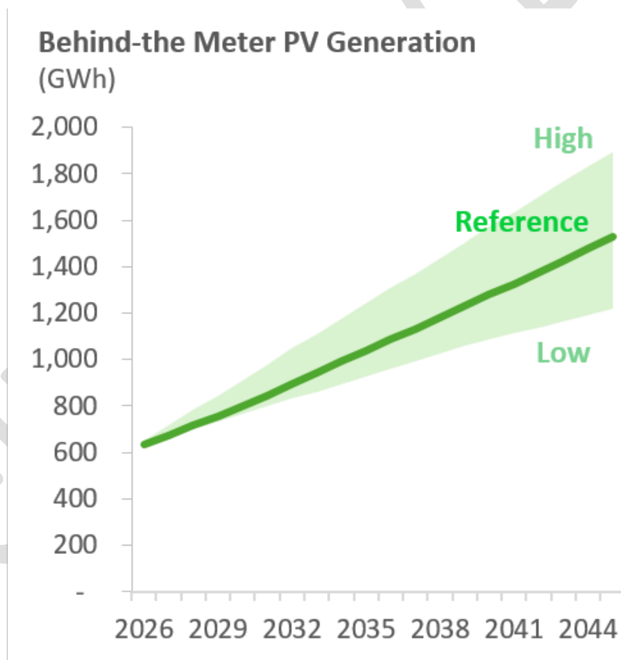
Population Growth *(# per year)*	**4,200** *(4,400)*	**8,900** *(9,400)*	**13,700** *(14,400)*
Non-Manufacturing Employment Gains *(# per year)*	**2,500** *(2,800)*	**5,300** *(5,800)*	**8,700** *(9,300)*
Real Per Capita Income Growth *(% per year)*	**0.8%** *(1.1%)*	**1.1%** *(1.5%)*	**1.5%** *(1.8%)*

Values in parentheses reflect assumptions used in the 2023 IRP load forecast

Behind-the-Meter PV

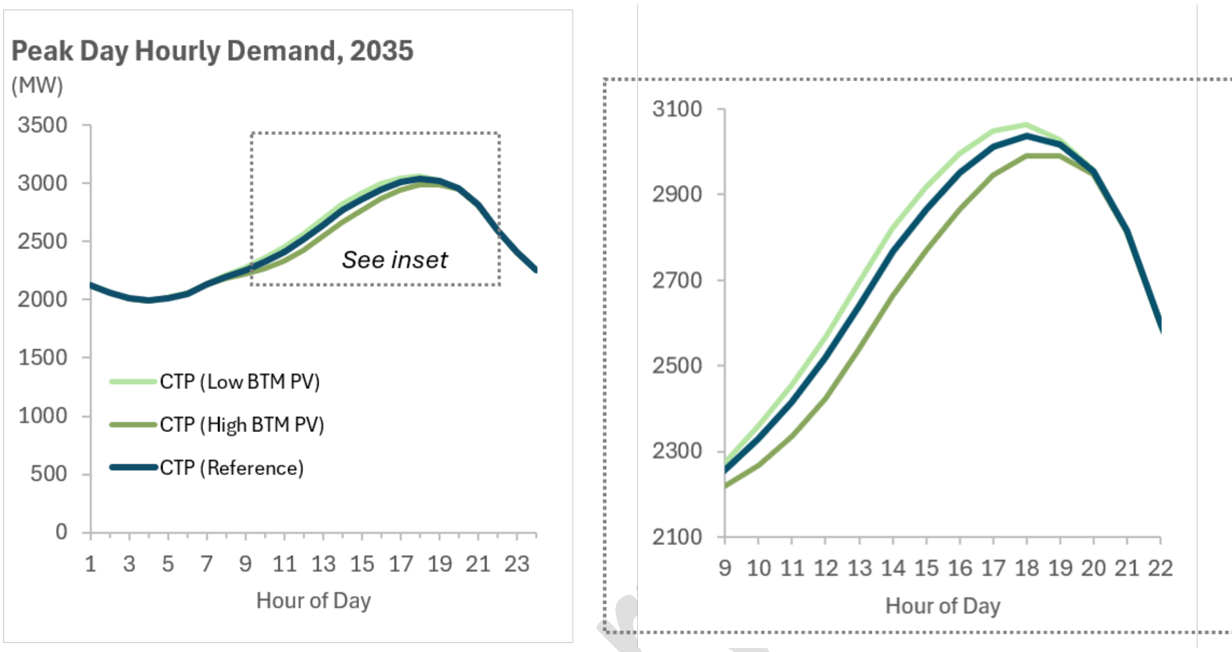
PNM's IRP analysis considers a range of future BTM solar adoption, reflecting customers' increasing interest in renewable energy. Projections reflect an acceleration of BTM solar adoption in the past few years. The current forecast is shown in [ ]

FIGURE 0-4. RANGE OF BTM SOLAR GENERATION STUDIED IN IRP



Sensitivities on BTM solar adoption reflect a plausible range of outcomes given increasing consumer preferences for customer-owned solar PV. These customer-sited solar systems are usually installed on rooftops but may have ground-mounted applications for some larger customer installations. BTM solar sensitivities range from "Low" forecast to a "High" forecast in which BTM solar production peaks at 945 MW in 2045. It is important to note that while BTM solar additions initially decrease peak load, this impact is less significant at any levels of adoption above that of the "Low" BTM solar forecast. This declining impact is expected because BTM solar shifts the peak to later hours, from 5-6 pm today to 6-7 pm by 2035, when there is little-to-no insolation, aligning with the declining impact of supply-side solar described in Section Error! Reference source not found..

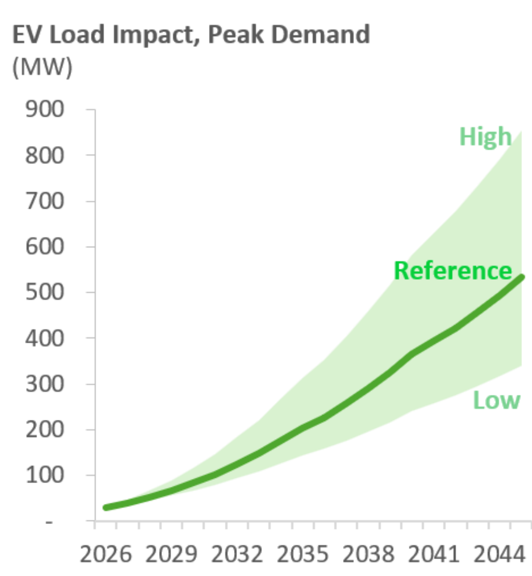
FIGURE 0-5. IMPACTS OF BTM SOLAR SENSITIVITIES ON LOAD SHAPE AND PEAK DEMAND



Transportation Electrification

Currently, demand from electric vehicles represents a small share of annual retail loads. As of 2025, the number of light-duty electric vehicles in PNM's service territory is estimated at approximately 18,600. Looking forward, PNM expects this segment of loads to grow significantly with increasing adoption of new electric vehicles. The "Reference" electric vehicle adoption scenario assumes that by 2045, this figure will increase to 245,000 EVs, reflecting the rapidly growing sales of EVs in New Mexico and the U.S. "Low" and "High" sensitivities capture a range of adoption of 164,000 to 387,000 vehicles by 2045. The implied increases in load in these scenarios are shown in Figure . With the projected acceleration in EV adoption over the forecast period, transportation electrification loads are expected to become an increasingly significant component of PNM's future loads.

FIGURE 0-6. RANGE OF ELECTRIC VEHICLE LOADS CONSIDERED IN LOAD FORECAST DEVELOPMENT



While the projections developed for the IRP are based on plausible ranges of market growth, state and national policy may also play a role in the rate of electric vehicle adoption. In studies of economy-wide decarbonization, transportation electrification has commonly been recognized as a significant potential source of carbon reductions. The transportation electrification program and the IRA both provide financial incentives for EV deployment that may impact the forecast. PNM will continue to monitor this landscape as it evolves and ensure the planning efforts remain aligned with market trends and the state's policy priorities.

FIGURE 0-7. TYPICAL WEEKDAY AND WEEKEND PROFILES FOR ELECTRIC VEHICLE CHARGING

[Graph to be added once complete]

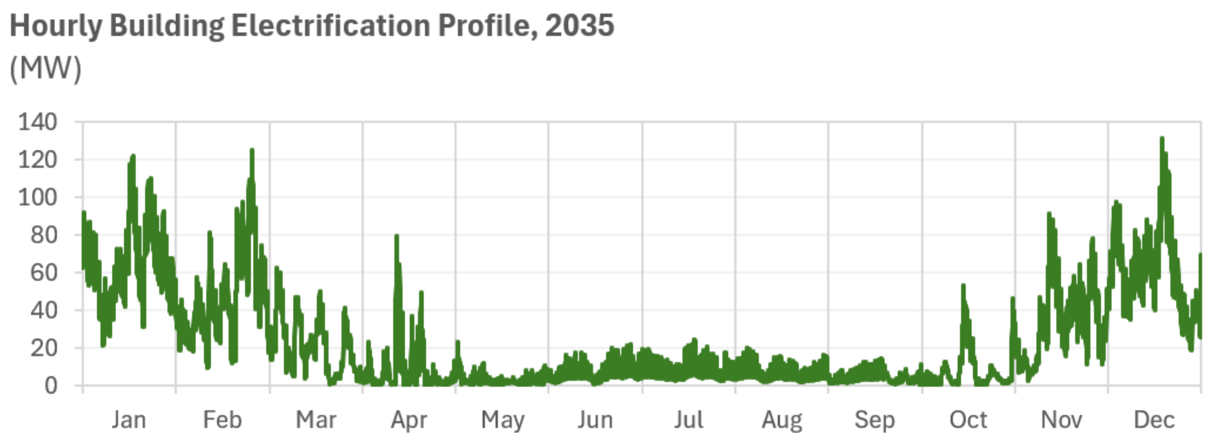
Building Electrification

Another potential source of future load growth is the electrification of building end uses. Like transportation electrification, building electrification has been identified in many studies as an effective strategy to support economy-wide carbon reductions. The impacts of the Inflation Reduction Act's tax credits for building electrification may lead to higher levels of adoption than the mid-level forecast.

While most of the load forecast scenarios studied in this IRP do not incorporate future building electrification, electrification impacts are incorporated in the High Economic Growth (HEG) future and its associated sensitivities. In these cases, a "High" building electrification forecast assumes that beginning in 2030, there is a transition from natural gas and propane to electric alternatives and that 7,000 existing homes conduct the conversion each year. In combination, these measures increase the share of buildings with electric heat to 75% by 2045, increasing PNM's annual electric load by approximately 480 GWh (roughly 4% of today's energy demand).

Electrification of space heating and water heating end uses in buildings would also alter the shape of PNM's demand throughout the year. Figure shows hourly load shape for incremental loads introduced in the High Building Electrification sensitivity, illustrating how the load impact associated with these measures is expected to be larger in the winter (predominantly due to space heating). At this level of building electrification, PNM would remain a summer peaking system – the winter peak in 2045 is approximately 600 MW lower than the summer peak – but the incremental loads in the winter do have implications for PNM's resource adequacy needs in a carbon-free portfolio when reliability risks may surface in the winter.

FIGURE 0-8. HOURLY SHAPE OF INCREMENTAL BUILDING ELECTRIFICATION LOADS MODELED IN HIGH BUILDING ELECTRIFICATION SENSITIVITY

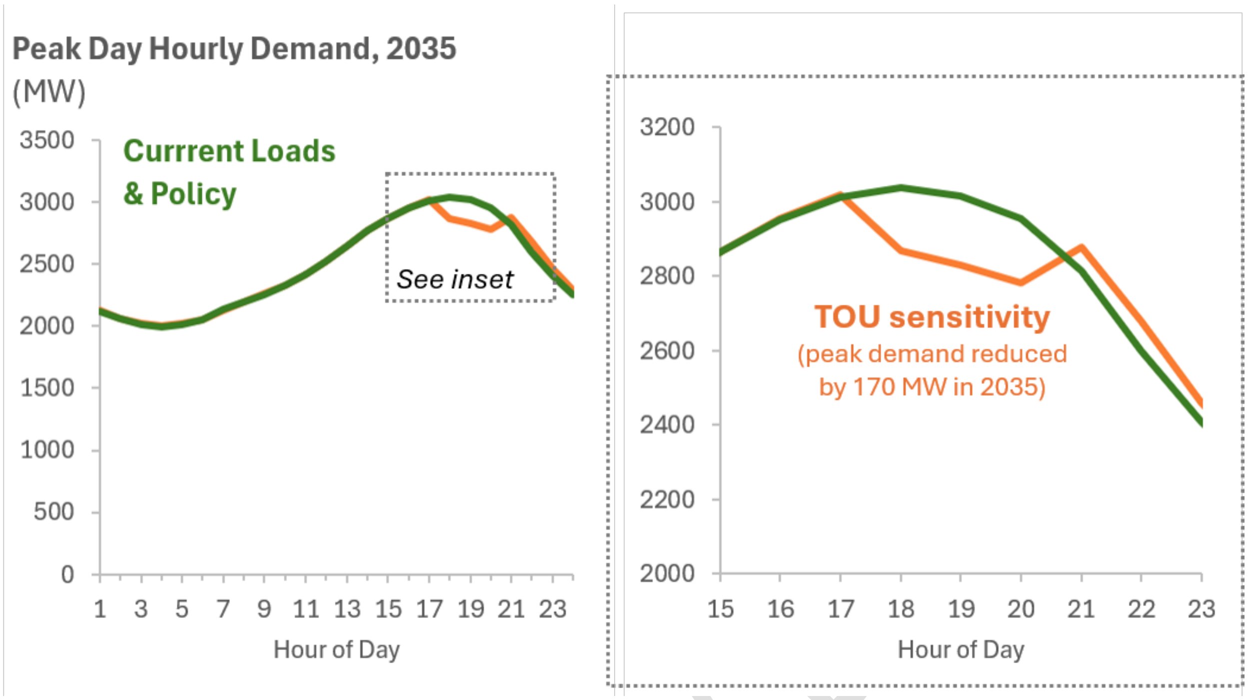


Time of Use/Time of Day Rates

As discussed in Section [ ], PNM is currently considering expansion of TOU/TOD (TOD) rates to new customer classes in the future. By better aligning customers' retail rates with PNM's own underlying cost of producing electricity, TOU/TOD rates can incentivize reductions in consumption during the peak period, reducing the need for investments to maintain resource adequacy. To characterize the potential benefits of the implementation of TOU/TOD rates, the IRP includes a sensitivity that captures the expected effect of TOU/TOD rates on load shape.

Sensitivity analysis is based on a TOU/TOD rates scheme in which the highest cost hours occur from 5-8 pm in summer and 5-8 am and 5-8 pm in winter, which PNM expects to align with periods of most constrained supply in the near term. Additionally, PNM considers an EV rate where electricity would be cheapest from 10 pm to 5 am. These rates would begin as pilots in 2025 before becoming full programs by 2030. The impact that this has on the peak day load shape is illustrated in Figure , but will vary by year due to growth and changes in the shape of retail load. By 2035, PNM estimates that TOU/TOD pricing could reduce peak demand by 170 MW.

FIGURE 0-9. IMPACTS OF TOU/TOD PRICING SENSITIVITIES ON LOAD SHAPE AND PEAK DEMAND



In the long term, it may be prudent to further adjust TOU/TOD periods to maintain alignment with the underlying cost of supply as PNM integrates additional renewable and storage resources. For simplicity, the peak period is not adjusted during this analysis, but PNM recognizes that maximizing the value a rate program will require continuous reevaluation of how to structure the periods.

4. PNM's Existing & Planned Resources

Chapter Highlights

13. PNM's existing resource portfolio includes a diverse mix of firm and dispatchable generation, including nuclear, natural gas, renewable energy, battery storage, and demand-side resources
14. Since the 2023 IRP, PNM has expanded its renewable energy and battery storage portfolio and reduced the amount of nuclear and consistent with NMPRC Rulings, plans to reduce all coal from its portfolio by 2031
15. PNM has a number of approved projects that will be coming online in the next 2 years from its Distribution Battery Filing and 2028 Resource Applications including 390 MW of solar and 648 MW of battery storage
16. PNM will also be seeking approval for pending resources as part of its 2029-2032 Resource Application, including 240 MW solar, 610 MW battery storage, and 186 MW for new and existing gas extensions

Developing a long-term resource plan begins with a comprehensive assessment of current operating capabilities. This chapter provides an overview of PNM's existing, approved, and pending generation and storage assets. PNM's generation and storage portfolio continues to transition towards the clean energy mandates established under New Mexico's ETA, while prioritizing grid reliability and affordability for customers. Over the past several years, the portfolio has systematically shifted away from coal-fired generation, marked by the retirement of the SJGS, and expanded its procurement of utility-scale renewable energy resources and battery energy storage. These additions have driven a sustained decline in portfolio carbon dioxide emissions, demonstrating steady, measurable progress toward long-term state and utility decarbonization objectives.

The IRP analysis includes both resources that are in service today and resources currently under development that PNM currently anticipates adding to its portfolio over the next several years. For clarity throughout the IRP, this collection of resources is categorized into three groups:

- **Existing Resources:** all resources currently in service at the time of the IRP's publication;
- **Approved Resources Not Yet In Service:** a collection of resource additions already approved by the Commission that will enter PNM's portfolio by 2028; and
- **Pending Resources Not Yet Approved:** an additional group of resources that includes both projects currently being considered by the Commission for approval and placeholder resources for PNM's RFP Supplement filing.

4.1 Existing Resources

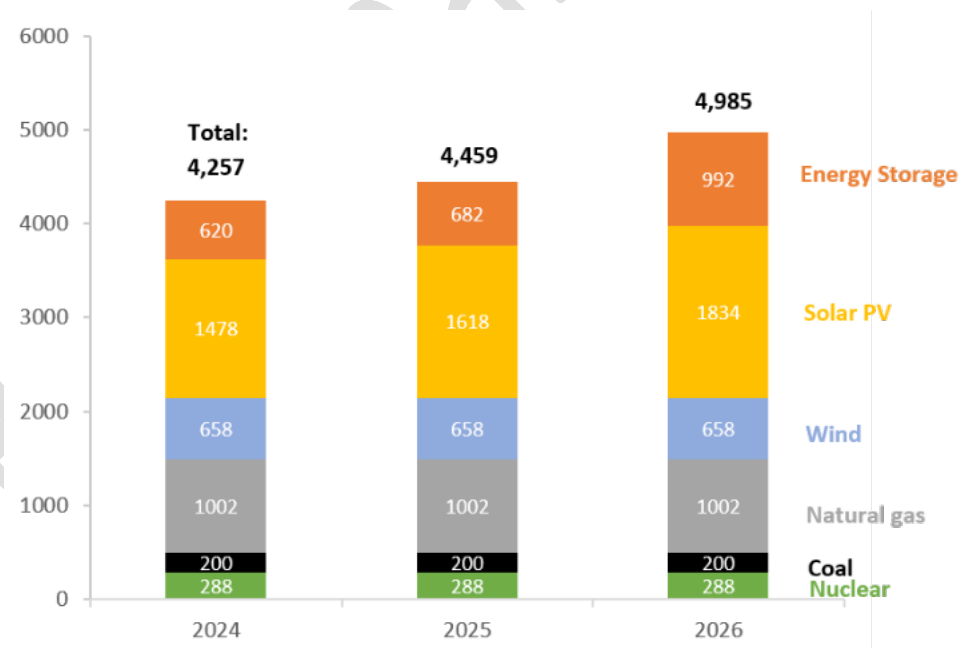
The existing resource portfolio serves as the foundation for this 2026 IRP. It comprises utility-own assets and long-term contracted resources across firm and dispatchable generation, renewable resources, energy storage, and demand-side programs.

As of this filing, PNM's supply-side generation portfolio includes:

- **Nuclear:** A 288 MW ownership interest in the Palo Verde Nuclear Generating Station (PVNGS);
- **Coal:** A 200 MW ownership share of the Four Corners Power Plant (FCPP), the sole remaining coal-fired resource in PNM's portfolio, scheduled for exit no later than 2031;
- **Natural Gas:** 1,002 MW of natural gas-fired generating capacity across PNM-owned facilities and contracted resources;
- **Wind:** 658 MW of capacity (nameplate) of wind generation resources under long-term purchase power agreements;
- **Solar:** 1,834 MW of capacity (nameplate) of utility-scale solar PV;
- **Battery Storage:** 992 MW of battery energy storage systems (BESS); and
- **Geothermal:** The 11 MW Lightning Dock geothermal generating facility in southern New Mexico.

In addition to supply-side resources, PNM relies on a portfolio of energy efficiency and demand response programs to reduce peak system requirements and help meet customer demand. These demand-side resources are detailed in Section 3.2.

FIGURE 1. PNM'S EXISTING RESOURCE PORTFOLIO BY RESOURCE TYPE



Note: PNM's existing portfolio also includes 11 MW of geothermal (included in totals)

FIGURE 3. MAP OF PNM'S EXISTING GENERATION & STORAGE RESOURCES

[Map to be uploaded upon completion]

While installed nameplate capacity provides a baseline view of system size, annual energy production better reflects how each technology contributes to serving customer load and advancing decarbonization goals. Because variable renewable resources, dispatchable thermal generation, and energy storage each serve distinct operational roles throughout the year, the resulting energy production mix differs noticeably from installed capacity.

Table 1 summarizes the key operating characteristics of PNM's current portfolio, including annual net generation, greenhouse gas emissions, carbon intensity, and water consumption based on the most recent historical operating year. These metrics highlight the portfolios ongoing transition toward lower-emitting and less water-intensive generation.

TABLE 1. KEY STATISTICS FOR PNM'S EXISTING RESOURCE PORTFOLIO (BASED ON 2025 HISTORICAL OPERATIONS)

Facility	Annual Net Generation (MWh)	Share of Annual Generation (%)	Total CO2 Emissions (short tons)	Carbon Intensity (lbs/MWh)	Total Water Use (000 gallons)	Water Use (gal/MWh)
Nuclear	2,284,469	23%	-	-	38,084	17
Coal	408,292	4%	401,252	1,966	805,064	1972
Natural Gas	1,641,097	16%	923,608	1,126	371,623	226
Geothermal	58,072	1%	-	-	-	-
Wind	1,746,125	17%	-	-	-	-
Solar	3,901,333	39%	-	-	-	-
Total	10,039,388	100%	1,324,860	266	1,214,771	122

As PNM continues integrating renewable generation, energy storage, and other carbon-free resources, the portfolio's greenhouse gas emissions and water consumption will decline further. Following the retirement of the SJGS, the FCPP represents the primary source of carbon emissions in PNM's generation portfolio. Executing PNM's planned exit from Four Corners by 2031, coupled with continued ongoing investments in renewable generation, storage, and demand-side resources, will further reduce the environmental footprint of the portfolio while maintaining reliability.

Consistent with Rule 17.7.3.8(B)(1) NMAC, this chapter describes the resources currently used to serve PNM's jurisdictional retail load. Additional technology-specific information is provided in the subsections below, while comprehensive resource and technical data is compiled in Appendix E.

4.1.1 Nuclear

PNM holds a 288 MW ownership interest in the Palo Verde Nuclear Generating Station (PVNGS), a jointly owned nuclear facility operated by Arizona Public Service Company (APS) on behalf of a consortium of Southwestern utilities. Since the 2023 IRP, PNM's ownership share has decreased from 402 MW to 288 MW following the expiration and non-renewal of 114 MW of leased capacity across 2023 and 2024. Additional information on PVNGS is provided in Appendix E.

4.1.2 Coal

Following the retirement of the SJGS in September 2022, PNM's coal-fired generation portfolio consists solely of its ownership interest in the FCPP. PNM owns a 13% share of Units 4 and 5, providing 200 MW of net dependable summer capacity.

Located on the Navajo Nation near Fruitland, New Mexico, FCPP is operated by Arizona Public Service Company (APS) and. Coal is supplied by the adjacent Navajo Mine under agreements that run through 2031. While FCPP currently delivers firm, dispatchable capacity and energy to support system reliability, it represents the single largest remaining source of carbon emissions in PNM's portfolio.

In alignment with the ETA and PNM's long-term resource strategy, the Company plans to exit its ownership interest in FCPP in July 2031. In 2021, PNM applied to the NMPRC to abandon its interest early for earlier replacement at the end of 2024. Following the NMPRC's denial of the application, but this filing was denied by the NMPRC. PNM appealed their decision to the New Mexico Supreme Court, which ultimately where the Supreme Court upheld the NMPRC's order. Consequently, PNM is modeling FCPP's continued operation through July 2031, while identifying optimal replacement resources to come online starting in 2031 to preserve maintain system reliability and satisfy state clean energy mandates. Additional detailed information regarding FCPP is provided in Appendix E.

4.1.3 Natural Gas

Natural gas-fired generation remains essential for maintaining system and operational flexibility as PNM integrates higher penetrations of renewable energy. PNM's existing natural gas fleet comprises of six utility-owned assets generating facilities and one long-term power purchase agreement, representing approximately 1,000 MW of dispatchable generating capacity.

The fleet is strategically distributed across PNM's service territory to fulfill distinct operational needs:

- **Southern New Mexico Assets:** Located near the El Paso Natural Gas pipeline system, these facilities provide efficient access to regional natural gas supplies.
- **Albuquerque Metro Assets:** Located near the Albuquerque load center, these units provide generation in a transmission-constrained area while providing essential voltage support and grid reliability.

With baseload needs met primarily from nuclear and coal, and energy needs increasingly supplied by renewables, the natural gas fleet functions predominately in a peaking and load-following role. These assets primarily serve a peaking role by providing dispatchable capacity that can respond quickly during periods of high demand or reduced renewable generation. This operating profile is reflected in the fleet's relatively low utilization, with capacity factors ranging from 5% to 26%. Table 2 details the operating characteristics, including capacity factor, for each natural gas resource based on the most recent historical operating year.

TABLE 2. SUMMARY STATISTICS FOR EXISTING NATURAL GAS RESOURCES (BASED ON 2025 HISTORICAL OPERATIONS)

Facility	Type	Installed Capacity (MW)	Annual Net Generation (MWh)	Capacity Factor (%)	Total CO2 Emissions (short tons)	Carbon Intensity (lbs/MWh)	Water Use (000 gallons)	Water Use Intensity (gallons/MWh)
Afton	Combined cycle	235	486,991	24%	255,268	1048	23,620	52
La Luz	Combustion turbine	41	16,369	5%	9,304	1137	588	39
Lordsburg	Combustion turbine	86	71,495	9%	41,111	1150	13,672	199
Luna	Combined cycle	190	434,140	26%	174,520	804	183,141	437
Reeves	Gas steam turbine	146	182,626	14%	141,582	1551	149,134	895
Rio Bravo	Combustion turbine	149	296,977	23%	203,654	1372	392	1
Valencia	Combustion turbine	155	152,499	11%	98,171	1287	1,076	7
Total		1,002	1,641,097	19%	923,608	1,126	371,623	226

Natural gas resources are dispatched to complement variable renewable generation, meet peak customer demand, maintain required operating reserves, and respond to real-time grid conditions. Although natural gas accounts for a smaller share of PNM's total annual energy production than in prior years, these units continue to deliver crucial reliability and firming services that cannot currently be met by renewable resources and short-duration energy storage alone.

To support reliable operations while managing ratepayer costs, PNM actively manages fuel procurement for the natural gas fleet through a balanced mix of forward purchases and spot market transactions. System fuel requirements are continually evaluated against projected customer demand, weather forecasts, scheduled planned maintenance, and expected market system operating conditions to ensure adequate fuel availability.

Consistent with New Mexico's clean energy mandates, PNM projects the total annual energy output and capacity factors of its natural gas fleet to decline as carbon-free resources expand. Nevertheless, dispatchable natural gas remains a critical resource for system reliability - delivering firm, fast-ramping capacity when wind and solar generation output is unavailable. Future decisions regarding individual thermal units will continuously weigh these operational reliability needs against emerging zero-carbon firm technologies, evolving environmental policies, and commercial availability.

Key Study Callout: Reeves Life Extension Analysis
Reeves Generating Station ("Reeves") is a 146-MW firm, dispatchable natural gas resource located directly in the Albuquerque load area. Beyond supplying peak capacity, Reeves provides critical local voltage support and alleviates transmission constraints under normal and contingency operating conditions. With Reeves approaching the end of its depreciable life in 2030, PNM engaged Black & Veatch to determine the capital and operational expenditures required to extend the facility's life through 2044. PNM then evaluated portfolio economics with and without the extension across the 2029–2032 resource planning framework: • Base case Load: Extending Reeves through 2044 consistently reduced total 20-year Present Value Revenue Requirements (PVRR) by $50 million to $75 million NPV compared to retirement in 2030. • High Large-Load Growth Scenarios: Under elevated load growth assumptions, the extension's economic benefit increased significantly, reducing 20-year NPV costs by more than $140 million. • Grid Reliability: The extension preserves vital in-region transmission support within the Albuquerque load pocket that would otherwise require costly network upgrades. Conclusion: Based on these findings, the Reeves life extension was integrated into the 2026 IRP baseline portfolio as a proven, cost-effective solution for resource adequacy and local grid reliability. *(Further details are provided in Appendix E.)*

4.1.4 Geothermal

Geothermal generation delivers firm, carbon-free baseload energy that uniquely complements PNM's renewable energy portfolio. Unlike wind and solar generation, geothermal facilities can operate continuously regardless of weather conditions, providing high capacity-factor energy with minimal greenhouse gas emissions. PNM purchases 11 MW of geothermal capacity from the Lightning Dock Geothermal Facility under a long-term PPA. While geothermal currently accounts for a small share of PNM's total generating portfolio, its non-variable operating profile enhances resource diversity and supports grid stability during the transition to a zero-carbon system. Further operational and contractual specifications are provided in Appendix E.

4.1.5 Wind

Wind generation is a key component of PNM's carbon-free resource portfolio, delivering a substantial share of the energy required to serve retail load. PNM procures approximately 658 MW of nameplate wind capacity across five utility-scale facilities under long-term PPAs. As shown in Table [ ], these five wind PPAs generated approximately 1,750 GWh of carbon-free electricity, representing nearly 20% of PNM's total annual energy production. Additional details on each wind facility can be found in Appendix E.

TABLE 3. SUMMARY STATISTICS FOR EXISTING WIND RESOURCES (BASED ON 2025 OPERATIONS)

Resource	Nameplate Capacity (MW)	Annual Net Generation (MWh)	Capacity Factor (%)
Casa Mesa	50	180,605	41%
La Joya I	165	494,483	34%
La Joya II	141	402,901	33%
NMWEC	200	504,921	29%
Red Mesa	102	163,215	18%
Total	658	1,746,125	30%

Wind generation exhibits distinct diurnal and seasonal patterns that dictate its hourly and monthly contribution to PNM's energy portfolio. As shown in Figure 4, New Mexico wind resources produce peak energy output during the spring and winter months, with lower production in the summer. On a daily basis, wind generation typically ramps up during the late afternoon, evening, and overnight hours, delivering carbon-free energy when solar output is declining or unavailable.

FIGURE 4. HISTORICAL AVERAGE CAPACITY FACTOR BY MONTH AND TIME OF DAY FOR PNM'S WIND RESOURCES (2025)

	Hour of Day																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	36%	37%	36%	33%	31%	30%	29%	31%	28%	26%	27%	30%	34%	39%	40%	40%	45%	46%	46%	45%	43%	42%	40%	37%
Feb	47%	46%	44%	42%	42%	41%	41%	37%	27%	25%	27%	27%	29%	31%	32%	32%	37%	44%	47%	48%	48%	48%	46%	46%
Mar	47%	49%	48%	46%	44%	43%	39%	29%	25%	25%	26%	27%	28%	30%	30%	31%	35%	44%	47%	47%	47%	45%	46%	49%
Apr	43%	45%	43%	41%	37%	33%	29%	21%	20%	21%	23%	24%	28%	29%	29%	32%	32%	35%	39%	39%	42%	44%	44%	42%
May	27%	27%	28%	25%	23%	24%	21%	18%	18%	18%	20%	19%	21%	23%	25%	27%	28%	31%	28%	31%	35%	36%	34%	30%
Jun	33%	31%	29%	25%	24%	22%	16%	13%	12%	12%	14%	15%	16%	17%	21%	26%	28%	28%	29%	29%	32%	34%	37%	35%
Jul	24%	22%	23%	23%	23%	22%	16%	13%	13%	13%	12%	12%	14%	15%	19%	25%	27%	29%	27%	27%	26%	27%	28%	26%
Aug	32%	33%	31%	30%	29%	26%	19%	12%	11%	11%	9%	10%	11%	13%	17%	19%	23%	27%	30%	30%	33%	32%	29%	30%
Sep	22%	21%	19%	18%	16%	16%	14%	12%	11%	12%	12%	14%	16%	19%	20%	21%	24%	23%	25%	28%	27%	28%	26%	23%
Oct	35%	34%	32%	30%	28%	24%	25%	22%	19%	20%	21%	24%	26%	28%	28%	28%	30%	31%	34%	39%	40%	38%	39%	38%
Nov	38%	37%	36%	34%	32%	31%	30%	26%	20%	18%	20%	21%	23%	25%	25%	26%	30%	34%	38%	40%	38%	38%	38%	39%
Dec	50%	47%	46%	47%	47%	45%	43%	43%	37%	32%	33%	33%	35%	36%	38%	38%	40%	44%	47%	48%	47%	48%	47%	48%

PNM's wind fleet has achieved a long-term average annual capacity of [%] since 2003, ranging between [ ]% and [ ]%. As illustrated in Figure [ ], capacity factors during typical peak demand periods is lower ranging [ ]% to [ ]%. Additional historical operating metrics for the wind fleet is compiled in Appendix E.

4.1.6 Solar

Utility-scale solar photovoltaic (PV) generation is a critical component of PNM's carbon-free resource portfolio and will play an expanding role in meeting long-term customer energy needs. The solar portfolio combines utility-owned facilities and contracted resources across 19 sites throughout New Mexico. Together, these resources represent over 1,834 MW of installed solar capacity.

Table 4. Summary statistics for typical existing solar resources (based on 2025 operations)

Resource	Nameplate Capacity (MW)	Annual Net Generation (MWh)	Capacity Factor (%)
In service before 1/1/2025			
Arroyo Solar	300	698,239	27%
Atrisco Solar	300	722,743	28%
Britton	50	141,555	32%
Encino	50	142,767	33%
Encino North	50	136,776	31%
Jicarilla Solar 1	50	112,498	26%
Jicarilla Solar 2	50	127,606	29%
Route 66 Cibola	50	123,467	28%
San Juan North Solar 1	200	502,243	29%
Sky Ranch Solar	190	504,115	30%
Aggregated Small Solar 1	186	470,486	29%
Total	1,476	3,682,495	28%
In service after 1/1/2025			
Quail Ranch Solar	100	NA	NA
Tag Solar	140	NA	NA
Aggregated Small Solar 2	118	NA	NA
Total	358	NA	NA

Solar generation follows distinct daily and seasonal production profiles, peaking during midday hours and reaching maximum seasonal output in the spring and early summer months. Conversely, generation declines during the winter months and ceases entirely overnight. Figure

5 illustrates the typical historical average hourly production profile of PNM's solar portfolio by month.

FIGURE 5. HISTORICAL AVERAGE CAPACITY FACTOR BY MONTH AND TIME OF DAY FOR PNM'S SOLAR RESOURCES (2025)

		Hour of Day																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Month	Jan	-	-	-	-	-	-	-	4%	42%	65%	66%	62%	61%	62%	65%	60%	24%	1%	-	-	-	-	-	-
	Feb	-	-	-	-	-	-	-	17%	58%	73%	75%	75%	74%	75%	73%	68%	46%	8%	-	-	-	-	-	-
	Mar	-	-	-	-	-	-	5%	41%	62%	66%	67%	66%	68%	65%	63%	60%	49%	18%	1%	-	-	-	-	-
	Apr	-	-	-	-	-	1%	32%	63%	70%	75%	75%	74%	73%	73%	71%	68%	64%	35%	4%	-	-	-	-	-
	May	-	-	-	-	-	8%	53%	71%	76%	75%	78%	78%	77%	74%	70%	65%	62%	45%	11%	-	-	-	-	-
	Jun	-	-	-	-	-	11%	54%	73%	78%	83%	87%	89%	84%	76%	71%	68%	64%	54%	19%	1%	-	-	-	-
	Jul	-	-	-	-	-	6%	41%	69%	78%	82%	86%	86%	84%	78%	72%	65%	56%	43%	15%	-	-	-	-	-
	Aug	-	-	-	-	-	1%	30%	70%	82%	87%	88%	86%	84%	80%	72%	64%	53%	31%	6%	-	-	-	-	-
	Sep	-	-	-	-	-	-	15%	56%	71%	78%	78%	75%	74%	72%	65%	62%	48%	14%	-	-	-	-	-	-
	Oct	-	-	-	-	-	-	5%	44%	65%	66%	64%	62%	60%	59%	55%	52%	27%	2%	-	-	-	-	-	-
	Nov	-	-	-	-	-	-	-	23%	60%	65%	64%	62%	61%	60%	60%	49%	11%	-	-	-	-	-	-	-
	Dec	-	-	-	-	-	-	-	6%	44%	62%	62%	59%	58%	62%	62%	48%	9%	-	-	-	-	-	-	-

Historical average annual average capacity factors for PNM's solar portfolio resources have ranged between [ ]% and [ ]% (or average [ ]% since 20[ ]). As illustrated in Figure [ ], the capacity factor during typical system peak hours ranges from [ ]% to [ ]%. Additional facility-specific historical performance data is compiled in Appendix E.

PNM's solar portfolio has expanded rapidly in recent years, driven primarily by replacement capacity needs following the retirement of the SJGS. This expansion was executed through successive competitive procurements and Commission-approved resource plans. Additional details on annual solar capacity additions are compiled in Appendix E.

Many of PNM's utility-scale solar facilities are paired with battery energy storage systems (BESS), allowing solar energy generated during peak daylight hours to be captured and dispatched later in the day to align with customer demand. This solar-plus-storage configuration significantly enhances the operational value and capacity contribution of solar resources—supporting system reliability and reducing reliance on fossil-fueled generation during evening peak load hours.

4.1.7 ENERGY STORAGE

Battery energy storage has become a vital component of PNM's supply-side portfolio, providing the operational flexibility needed to maintain grid reliability on a high-renewables system. PNM's storage fleet includes both standalone facility deployments and hybrid resources co-located with utility-scale solar. These systems absorb excess generation during periods of high renewable output and discharge energy during high-demand windows or periods of reduced renewable production.

Beyond energy time-shifting, BESS resources supply essential grid stability services, including spinning and operating reserves, fast frequency response, ramping capability, and local voltage support. These ancillary capabilities maximize the effective capacity value of renewable generation, displace fossil-fueled peaking dispatch, and enhance real-time system resilience.

At the time of this filing, PNM's storage portfolio comprises 992 MW / 3,968 MWh of operational capacity across its service territory. Facility-specific configurations and development milestones are detailed in Appendix E.

4.2 Approved Resources Not Yet In-Service

To meet projected load growth, maintain resource adequacy, and satisfy New Mexico ETA targets, the New Mexico Public Regulation Commission (NMPRC) has approved several near-term resource additions that are not yet commercial or fully operational. These approved projects, comprising new solar and battery energy storage, represent committed capacity that will integrate into PNM's operating fleet over the coming planning horizon.

While these resources have secured necessary regulatory approvals from the Commission, they remain in various stages of final procurement, interconnection, permitting, or construction. Table 0-1 details these approved, non-operational assets along with their expected, nameplate capacities, and commercial operation dates (COD).

Table 0-1. List of Approved Resources Not Yet In Service

Category	Plant Name	Capacity (MW)	Expected In-Service Year
Distribution Battery Filing	Distribution Storage Extension	30	2028
2028 Resource Application	Corazon Storage	150	2027
	Valencia Extension	167	2028
	Sunbelt Solar	100	2027
	Sunbelt Storage	50	2027
	Sun Lasso Storage	150	2027
2028 Resource Application (Rate 36B customer expansion)	Four Mile Solar	100	2027
	Four-Mile Storage	100	2027
	Windy Lane Solar	90	2026
	Windy Lane Storage	68	2026
	Starlight Solar	100	2026
	Starlight Storage	100	2026

4.3 Pending Resources Not Yet Approved

To address future load growth and ongoing system transformation, PNM continuously evaluates additional supply-side options beyond its existing and NMPRC-approved portfolio. This section outlines proposed and modeled resource additions that are currently pending regulatory review.

Unlike the approved resources detailed in previous sections, the projects summarized below have not yet received formal authorization from the NMPRC. Their ultimate inclusion in PNM's operating fleet remains contingent upon regulatory approval, final contractual execution, and the satisfaction of project development milestones. Table 0-2 outlines these pending resource proposals along with their capacity, and targeted commercial operation dates.

TABLE 0-2. LIST OF PENDING RESOURCES NOT YET APPROVED

Category	Plant Name	Capacity (MW)	Expected In-Service Year
2029-2032 Resource Application	Palomas Wind	800	2029
	La Luz II	40	2031
	TAG II BESS	90	2029
	Britton BESS	60	2029
	Encino BESS	110	2029
	Wildcat BESS 50	50	2029
	Cat Hills BESS	150	2031
	Gila Monster BESS	150	2031
	Wildcat Solar	90	2029
	Cat Hills Solar	150	2031
	Reeves Extension	146	2031

5. TRANSMISSION AND DISTRIBUTION SYSTEM

5.1 Existing System

PNM is one of more than 60 transmission service providers in the Western Interconnection. As both a Transmission Operator and Transmission Owner, PNM provides open access transmission services under a pro forma Federal Energy Regulatory Commission (FERC) tariff to serve retail and wholesale customers. PNM operates its transmission system within a NERC-certified Balancing Authority Area (BAA), monitoring key transmission paths and interconnections to neighboring BAAs to ensure safe, reliable operation.

PNM's transmission system is designed and operated to mandatory and enforceable NERC planning requirements, including N-1 contingency standards, meaning the loss of any single major element (such as a line, transformer, or tie point) should not disrupt reliability. PNM additionally adheres to system operating limits and WECC Path Ratings limits, which define the maximum power flow allowed on each element to maintain this standard. In most cases, customers should remain unaffected when a single or transmission element is temporarily out of service.

In its role as a Transmission Service Provider, PNM also must serve both retail loads and network customers under its Open Access Transmission Tariff (OATT), pursuant to FERC regulations. Wholesale customers currently account for approximately 50% of transmission system utilization and fall into two categories: Network Integration Transmission customers and Point-to-Point customers.

5.1.1 HISTORICAL DEVELOPMENT

PNM's transmission system has evolved significantly over the years as system conditions dictated expansion and changes. The original system consisted of 46 kV and 115 kV lines that delivered locally generated power to nearby loads. During the 1950s and 1960s, inter-city lines were built to allow generators to provide mutual backup support, improving overall service reliability. PNM's first external interconnection was a 230 kV line to Four Corners, built in 1962 concurrent with construction of the original Four Corners Power Plant (FCPP).

Most elements of the current 345 kV transmission system were developed in the late 1960s and early 1970s, coinciding with construction of FCPP and the San Juan Generating Station (SJGS) in northwestern New Mexico. To deliver power from these large baseload coal and nuclear facilities to growing urban load centers, PNM built multiple 345 kV transmission corridors. Because coal and nuclear generation was remote and low-cost, power plants near load centers were generally held in reserve, operating only during summer peak hours or when transmission import limits would otherwise be exceeded.

In 1984, a 216-mile 345 kV line was completed from the BA 345 kV Switching Station (North of Albuquerque) to Clovis, New Mexico—the Eastern Interconnection Project (EIP). This line connected PNM with Southwestern Public Service (SPS) in the Eastern Interconnection via the Blackwater AC-DC-AC converter station.

During the 1990s, PNM pursued the Ojo Line Extension (OLE) project to construct a third 345 kV path from the Four Corners area to major northern New Mexico load centers. After the required Certificate of Convenience and Necessity (CCN) was denied, PNM refocused on reinforcing the existing northern New Mexico system and siting new resources closer to load centers.

The Eastern Interconnection was further expanded in 2019 and 2021, adding double-circuit capacity from Clines Corners Switching Station to the BA 345 kV Switching Station and extending a 345 kV line from Clines Corners to Pajarito Switching Station via the Western Spirit project. These expansions facilitate delivery of wind resources to PNM and neighboring systems.

5.1.2 Use of Grid Enhancing Technologies (GETs)

Over the last several decades, PNM has focused on maximizing the capability of its existing transmission system before pursuing major new transmission investments. Through the deployment of grid-enhancing technologies or "GETs" the use of remedial action schemes, and other targeted reliability improvements, PNM has been able to increase the utilization and efficiency of its transmission network while maintaining safe and reliable service to customers. This approach has allowed the Company to defer or avoid certain large-scale infrastructure projects, reducing costs to customers, and making more effective use of existing assets. While PNM has been deploying GETs for many years, several new FERC Orders 2023 and 1920 now require the utility industry to consider GETs to ensure low-cost, and timely solutions can be deployed to defer more costly longer-term solutions.

PNM's efforts have been particularly important as the electric grid has evolved to accommodate changing generation resources, increased renewable energy development, electrification trends, and growing customer demand. By leveraging technology and operational innovation, PNM has been able to extract additional capacity and flexibility from its transmission system while continuing to meet reliability, operational, and planning standards.

However, the cumulative effect of these optimization efforts is that much of the latent capacity that once existed on the system has now been utilized. Many transmission facilities are operating closer to their practical physical and planning limits during peak conditions, leaving less flexibility to accommodate new load growth, large new customer interconnections, generation additions, or unexpected system contingencies without additional infrastructure investments. While grid-enhancing technologies and operational efficiencies remain important tools, they no longer provide the magnitude of capacity increases needed to address projected future growth on a standalone basis.

As a result, future transmission planning must increasingly balance continued optimization of existing assets with strategic investments in new transmission infrastructure. New transmission facilities will be necessary to maintain reliability, support economic development, facilitate resource and load interconnections, improve system resilience, and ensure that the transmission network can continue to serve customers efficiently under a wide range of future operating conditions. The Company has largely exhausted the low-cost opportunities to unlock additional capacity from its existing system, making new transmission development an increasingly important component of its long-term planning strategy using GETs.

PNM's GETs deployed to date include:

Line Ratings: PNM is deploying Ambient Adjusted Ratings (AARs) pursuant to FERC Order 881, to extract additional capability from system by adjusting the operational rating of any (conductor-limited) lines according to ambient temperature at the time

- PNM is also working towards dynamic line ratings which additionally incorporate real-time wind speed and solar insolation in the transmission line operational rating.
- PNM has installed monitoring equipment to allow for temporary emergency ratings based on actual ambient temperature and wind conditions.
- PNM has increased ratings of transmission lines by using higher wind speed assumptions, where technically justified and cleared several lines for short-duration high-temperature operation during critical conditions.

Power Flow Control: Includes series compensation on transmission lines, phase shifting transformers (PST), and other technology to optimally manage flows on the system.

PNM has deployed the following Power Flow Control GETS solutions:

- Rio Puerco and Abo series compensation – aiding Four Corners to and Western Spirit Transmission Lines
- Belen PST
- Series Reactors at Norton and Belen
- Albuquerque power factor control (RCCS) system
- PNM also utilizes redispatch and battery charge/discharge to control power flows

Topology Optimization: Includes redirection of power to avoid congestion or overloads

Remedial Action Schemes (RAS), which are automated protection schemes designed to increase transmission capacity all over the system – PNM has deployed nearly a dozen of these across the system to maximize transmission capability beyond traditional operational limits.

Energy Imbalance Market participation (EIM) and future extended day-ahead market (EDAM) systems optimize dispatch and transmission schedules across the region, beyond PNM's system.

Advanced planning methods such as hosting capacity, grid strength assessments – both of which are in progress and flow gate analysis which is planned for future operations.

Pursuant to FERC Order 2023, PNM published public-facing, interactive heatmap software in Q3 2025 to inform generation and economic developers on optimal locations to build new generation or loads.

Advanced Conductor: PNM is actively using advanced conductors and evaluating its continued use as part of its 10- and 20-year planning and generation interconnection processes as well as economic development studies – benefits will continue to be unlocked over time as more advanced conductor is deployed across the system.

In 2026, PNM is rebuilding an existing 115 kV line using advanced conductor (ACCC) to optimize line flow capability within existing easements and pole heights and will continue to deploy to maximize capability.

Other: PNM uses Flexible AC Transmission Systems (FACTS) devices which allow for greater utilization of the transmission system

PNM's FACTS include:

- Rio Puerco and Guadalupe Static Var Compensators (SVC) – Voltage support to maximize the capacity of the transmission system
- Blackwater synchronous condenser –Provides short circuit capability to maximize utilization of existing transmission assets which has allowed for increased wind integration and transfers from eastern NM

PNM will continue evaluating grid-enhancing technologies based on its historical approach and which also align with the requirements of FERC Orders 2023 and 1920, as part of its transmission planning process, identifying opportunities where GETs are feasible to support system needs and facilitate the integration of new resource additions. While much of the readily available latent capacity has already been captured through PNM's extensive GETs deployment to date, PNM will continue to consider GETs — where feasible — as a lower-cost, faster-to-deploy alternative to traditional infrastructure upgrades. This includes when evaluating how best to interconnect and integrate future resource alternatives identified in IRPs.

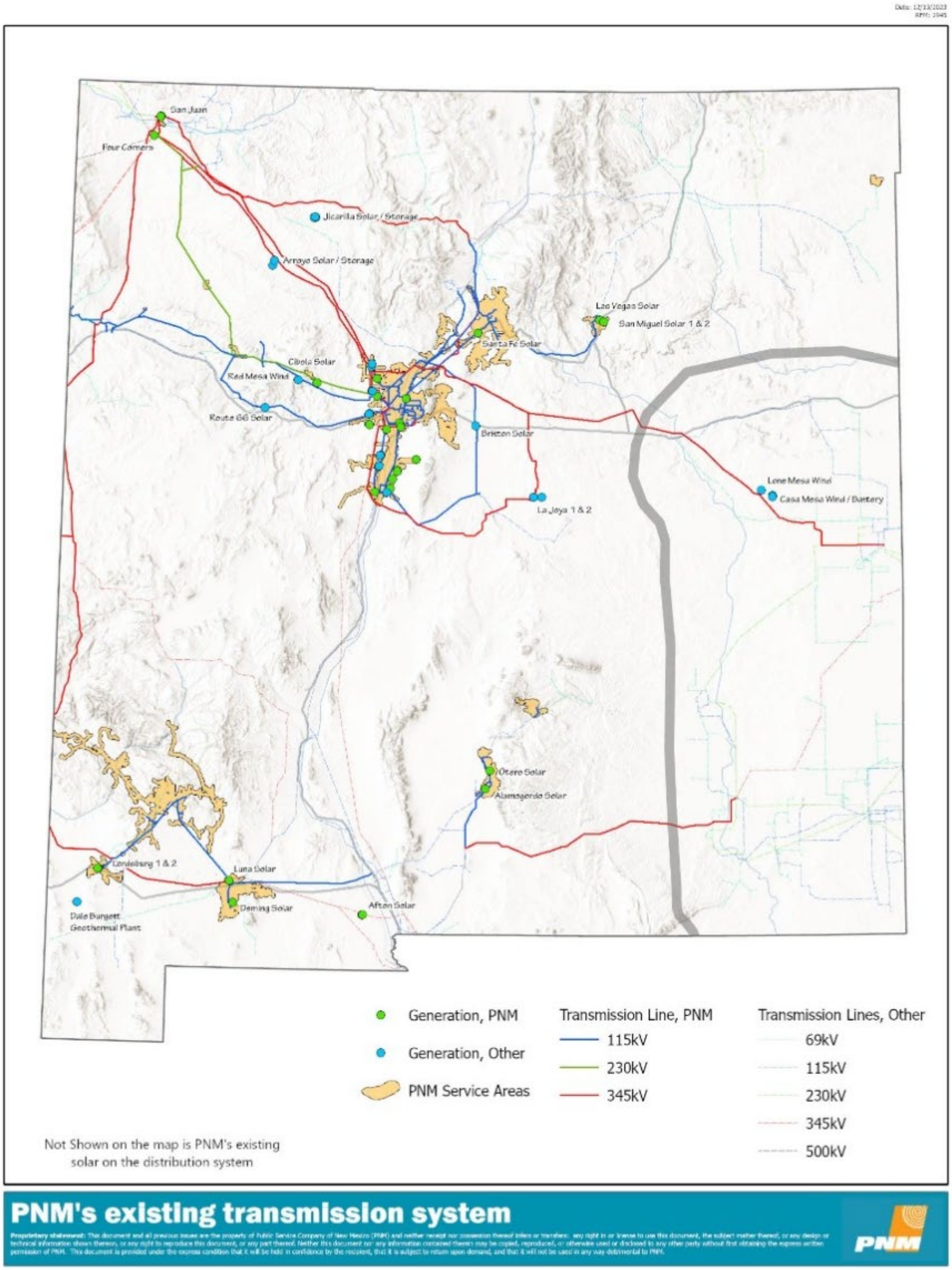
5.1.3 CURRENT SYSTEM CONFIGURATION

Most of PNM's transmission system consists of 345 kV and 230 kV lines built in the 1960s and 1970s, linking the Four Corners area in northwestern New Mexico to load centers in the south and southeast. Power historically flowed from north to south, driven by baseload generation at Four Corners and in Arizona. The growing integration of inverter-based resources (IBR)—solar and wind facilities that convert DC generation to AC power—in northern and eastern New Mexico has reduced northbound-to-southbound flows and, during periods of low load and high renewable output, has reversed flows from south to north.

In southern New Mexico, PNM jointly owns two 345 kV lines running from eastern Arizona eastward toward El Paso, Texas, on which power has historically flowed eastward and southward. Large autotransformers at load centers step voltage down from 345 kV to 115 kV, and substations on 115 kV, 69 kV, and 46 kV lines further reduce voltages to distribution levels for end-user delivery.

PNM's existing transmission system is shown in Figure 47. Its three key elements are: (1) the high-voltage backbone between Four Corners and the northern load center; (2) the high-voltage lines linking Four Corners with PNM's southern service territory; and (3) the Eastern Interconnection Project, recently expanded to support wind resource delivery to and beyond PNM's system.

FIGURE 47. MAP OF PNM'S EXISTING TRANSMISSION SYSTEM



In addition to its own facilities, PNM purchases transmission service from several regional providers to deliver generation to load. These agreements are summarized in Table 1.

TABLE 1 TRANSMISSION SERVICE AGREEMENTS WITH NEIGHBORING PROVIDERS

Service Provider	Transmission Service Description
Arizona Public Service (APS)	PNM contracts with APS for point-to-point service to deliver output from Palo Verde Nuclear Generating Station (PVNGS) to PNM's system: a non-OATT bilateral contract for 130 MW and OATT service for 145 MW (both Phoenix to Four Corners).
Tri-State Generation & Transmission	PNM contracts for network service under Tri-State's OATT to serve retail load in the Town of Clayton (approximately 3.5 MW).
El Paso Electric (EPE)	PNM contracts with EPE for point-to-point services to facilitate north-south transfers within New Mexico: 295 MW southbound-to-northbound and 25 MW northbound-to-southbound.
Western Area Power Administration (WAPA)	Under a bilateral transmission exchange: WAPA provides 134 MW (Phoenix to Four Corners) to deliver PVNGS output to PNM; PNM provides 247 MW (Four Corners to various New Mexico delivery points) to WAPA.

PNM's transmission system was originally designed to deliver power from large baseload generators in northwestern New Mexico to load centers across the state. As PNM's portfolio and neighboring utilities transition to more dispersed and diverse renewable resources, system utilization is shifting accordingly. Maintaining, operating, and expanding the transmission system will be essential for integrating new renewable resources and enabling more dynamic participation in Western Interconnection wholesale markets. PNM programmatically provides significant capital investment to address legacy issues in both transmission and distribution.

The subsections below describe current transmission system dynamics, how those dynamics are expected to evolve, and considerations for system expansion as part of PNM's long-term planning.

A key feature of New Mexico's grid geography is that nearly all power serving customers in North Central New Mexico—regardless of where it is generated—must flow across the northern New Mexico transmission system. This includes generation from the Four Corners area, the western grid, and southern New Mexico resources routed northward through portions of El Paso Electric's facilities. This geographic concentration makes the northern system a critical reliability element for the entire PNM service territory.

Northern Load Center

Reliably meeting peak demand in the northern load area requires both the bulk transmission system and locally sited generation resources. The existing transmission infrastructure, at certain times, cannot import enough power from outside the region to meet peak demand—particularly following an unplanned outage of a major transmission element. In that scenario, locally dispatchable generation continues to provide the additional capacity needed to avoid customer outages.

Reeves Generating Station, Rio Bravo, and the Valencia PPA are the primary resources fulfilling this role. Although these facilities typically operate at low capacity factors, their ability to produce reliable power on demand—and sustain output over extended periods when called upon—makes them indispensable for local reliability during peak periods and following transmission contingencies.

Southern Transmission System

PNM's southern New Mexico system delivers power to multiple jurisdictional service territories, including Deming, Silver City, Lordsburg, Alamogordo, and Ruidoso, as well as to northern New Mexico. The southern system includes three solar facilities and three natural gas generation facilities located at Afton, Luna, and Lordsburg. In addition to PNM's ownership share in WECC-Rated Path 47—a designated transmission path that enables power transfers between the southern and northern parts of the state—PNM purchases transmission service from El Paso Electric (EPE) to serve portions of the Alamogordo area and from Tucson Electric Power (TEP) to serve portions of the Deming and Silver City areas. PNM also uses EPE and TEP service to move a portion of southern New Mexico generation northward.

The Afton, Luna, and Lordsburg natural gas facilities provide a combined 510 MW of capacity. Because they are located within the WECC-Rated Path 47 transmission boundary, these resources can reliably serve all southern New Mexico loads. When surplus capacity is available, combined transmission rights over PNM, Tri-State, and EPE assets total 345 MW from south to north, allowing this generation to serve northern loads as well.

Currently, southern New Mexico generation is sufficient to serve all PNM loads in the southern system. PNM also holds approximately 75 MW of transmission rights for northbound-to-southbound delivery across the Path 47 boundary, providing flexibility to serve southern loads from northern resources when needed.

Four Corners Area

The transmission lines connecting the Four Corners area to the Albuquerque load center have historically formed the backbone of PNM's transmission system, originally designed to carry baseload output from FCPP and Palo Verde Nuclear Generating Station (PVNGS) to PNM's largest load center in northern New Mexico.

While this corridor's capacity remains essential for meeting peak demand, its utilization has changed significantly as intermittent renewable resources have been added in northern and eastern New Mexico. Greater renewable energy delivery into the northern load pocket has reduced power flows on the Four Corners-Albuquerque segment and, during periods of high renewable output, reversed the historic direction of flow from south to north. This trend is expected to continue. The available transfer capacity on a transmission path above what is currently being used is referred to as transmission headroom; creating headroom is essential for connecting new generation resources.

By 2031, PNM plans to exit FCPP (200 MW) and as such, there will be times when this existing transmission capacity can support import of alternative resources in the northwestern part of the state.

The transmission no longer dedicated to import SJGS since its retirement has been largely absorbed by the portfolio of solar and storage replacement resources approved by the NMPRC in Case No. 19-00195-UT. The upcoming retirements of FCPP will provide certain hours where there may be additional headroom to support the next generation of resource additions.

Eastern New Mexico

Development of wind resources in eastern New Mexico has driven significant expansion of the transmission system in that region. Eastern New Mexico benefits from exceptionally high-quality wind resources that have attracted interest from developers and off-takers outside the state. A substantial share of the contemplated new capacity is intended to support the clean energy goals of neighboring western states—demonstrating PNM's role as a regional transmission provider, not just a local utility.

Wind resources currently operating in eastern New Mexico include: 250 MW at Taiban Mesa serving PNM loads; 235 MW at Guadalupe serving Arizona loads; and approximately 790 MW at Blackwater and Clines Corners serving California loads. These facilities interconnect to PNM's 216-mile Eastern Interconnect Project (EIP)—the 345 kV line from the BA 345 kV Switching Station to PNM's Blackwater 345 kV Station near Clovis. An additional 306 MW wind farm at Clines Corners was made possible by the BB2 line, a second 345 kV circuit between Clines Corners and BA Station. Combined, these additions bring total firm transmission service on this corridor to 1,507 MW.

In December 2021, the Western Spirit Transmission Project—developed by Pattern Energy and subsequently acquired by PNM—was energized, enabling interconnection of an additional 800 MW of wind resources. The project was fully subscribed at energization, expanding total wind capacity in eastern New Mexico to nearly 2,400 MW.

West of Albuquerque

West of Albuquerque, approximately 150 MW of existing generation relies on PNM's transmission system to serve PNM and Network Transmission Customer loads in northern New Mexico. With the addition of the PEGS Solar (TSGT) project, this portion of the transmission system is now fully subscribed. PNM is also currently pending approval of its first new transmission in the metro area in some time, seeking a Certificate of Convenience and Necessity (CCN) for approval of a 345 kV transmission line from Rio Puerco 345 kV to Pajarito 345 kV and terminating in Prosperity 345 kV.

South of Albuquerque

In Valencia County, south of Albuquerque, approximately 250 MW of existing resources are delivered into the northern load center over the existing transmission system, which is now fully subscribed. The 190 MW Sky Ranch photovoltaic (PV) and battery energy storage system (BESS) project was interconnected in 2024, along with associated transmission upgrades. An additional

100 MW Star Light PV and BESS project was energized in 2026 to serve growing large customer loads in the area.

5.2 Distribution System

PNM maintains an extensive distribution system to deliver safe, reliable power from generation and transmission sources to customers' homes and businesses. The distribution system uses overhead and underground conductors connected to substations, which feed electricity through feeder circuits to neighborhoods and commercial areas. Distribution transformers at each service connection further reduce voltage to usable levels, and meters measure consumption and other delivery attributes at each customer location.

Distribution infrastructure—including transformers, conductors, and meters—requires ongoing investment to accommodate electrification and distributed generation as customer energy profiles evolve. Many of these assets were designed before behind-the-meter customer solar, direct distribution level connected generation (such as Community Solar), electric vehicles, or electrification were anticipated.

PNM addresses the distribution system with overarching goals: enhancing customer satisfaction and system reliability; proactively managing aging assets; and increasing grid resiliency. This long-term asset management plan drives capital investment decisions through project prioritization, alignment with distribution area capacity plans, and field performance reports. Comprehensive investment in aging infrastructure will better position core assets to support New Mexico's decarbonization goals while sustaining customer reliability expectations.

PNM is concurrently preparing its 2026 Distribution System Plan (DSP) to be filed with the NMPRC for the first time on October 1, 2026. The DSP will provide a forward-looking framework for maintaining a safe, reliable, resilient, flexible, and affordable distribution system as customer needs and New Mexico's energy landscape continue to evolve. While the DSP focuses on the planning, operation, and modernization of the electric distribution system, it is closely coordinated with PNM's Grid Modernization Plan. Additionally, PNM is continuing to find opportunities to link its planning processes to the degree possible, and this IRP is linked through its evaluation of distribution sited alternatives in concert with transmission sited alternatives to ensure the most efficient solutions are being identified.

Together, these planning processes ensure that generation resources, transmission infrastructure, distribution facilities, and customer-sited technologies are developed in a coordinated manner to reliably and affordably serve customers while supporting state energy policies and economic growth.

PNM currently serves its customers through a distribution system consisting of approximately 197 energized substation transformers providing 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 (DER) installations totaling approximately 692 MW, primarily customer-sited solar generation. While these resources provide customer benefits and contribute to New Mexico's clean energy objectives, they also introduce new planning and operational considerations, including reverse power flow, voltage management, protection coordination, minimum-load conditions, hosting capacity limitations, communications requirements, and increased system visibility needs.

The DSP and IRP are increasingly linked through the growing role of distributed energy resources, electrification, and customer load flexibility. Historically, distribution planning focused primarily on ensuring sufficient capacity and reliability at the local level. As DER adoption expands and customer behavior becomes more dynamic, distribution planning plays a greater role in determining how customer-sited resources may contribute to broader system needs addressed through the IRP. Going forward, distribution planning can provide future information regarding the location, magnitude, and operational capabilities of distributed resources that may influence future resource requirements, peak demand forecasts, and system flexibility needs evaluated through the IRP process.

PNM utilizes a layered distribution planning process beginning with its annual Ten-Year Distribution System Plan. This foundational planning effort evaluates transformer and feeder loading, projected load growth, contingency capability, known economic development projects, and high-level DER hosting capacity. Potential system constraints are subsequently examined through outage-contingency analyses, feeder reconfiguration studies, detailed area studies, and feeder-specific hosting capacity assessments. This progression allows PNM to evaluate operational solutions, load transfers, targeted upgrades, and potential non-wires alternatives before advancing major capital projects. Detailed engineering studies ultimately determine the scope, timing, cost, and location of required investments.

Distribution planning identifies where growth is expected to occur, where system constraints on the lower voltage system may emerge, and where customer resources may help defer or reduce infrastructure needs. As these processes continue to mature, these insights can help inform and improve the assumptions used in the IRP and help ensure resource planning reflects actual system conditions and customer adoption trends.

Over the next five years, PNM plans to further integrate distribution planning with broader enterprise planning functions through development of a consistent, location-specific forecasting framework. Future forecasts will incorporate increasingly detailed information regarding organic customer growth, economic development projects, electric vehicles, building electrification, customer-owned generation and storage, and flexible loads. By utilizing common assumptions and datasets across distribution, transmission, operational, financial, and resource planning functions, PNM will improve planning consistency and support more coordinated investment decisions.

The DSP further establishes a more systematic framework for evaluating potential investments. PNM is implementing and refining the Copperleaf decision-support platform to compare traditional infrastructure projects, grid modernization technologies, distributed resources, and other alternatives using consistent measures of cost, risk, reliability, resilience, safety, customer benefit, and strategic value. This approach is intended to improve investment prioritization, transparency, and alignment with long-term customer and regulatory objectives.

This evaluation framework complements the IRP's objective of identifying least-cost, least-risk portfolios capable of meeting future customer needs. By applying consistent risk and value methodologies across distribution and resource planning processes, PNM can better assess tradeoffs among generation resources, transmission investments, distribution upgrades, demand-side programs, and non-wires alternatives, resulting in more integrated and cost-effective planning outcomes.

The DSP also recognizes that distribution planning operates within a broader state and federal regulatory framework addressing utility service obligations, grid modernization, transportation electrification, energy efficiency, community solar, distributed generation, interconnection requirements, wholesale market participation, and data sharing. Distribution planning translates these requirements into practical infrastructure and operational decisions while supporting New Mexico's renewable energy, carbon reduction, economic development, and electrification goals.

In support of the IRP, the DSP identifies how distribution infrastructure enables the deployment and integration of resources that contribute to meeting Energy Transition Act objectives and customer demands. Distribution investments create the capability necessary to interconnect renewable resources, community solar projects, energy storage systems, electric vehicle charging infrastructure, and other emerging technologies that are increasingly reflected in future resource portfolios considered through the IRP.

Stakeholder engagement is a foundational element of both distribution and resource planning. PNM's stakeholder process includes public meetings, advance review of draft plans, formal written comment opportunities, responses to stakeholder recommendations, and discussion of revisions and unresolved issues prior to filing. This process improves transparency, incorporates diverse perspectives, and creates a clear record demonstrating how stakeholder input influenced final planning decisions.

The DSP action plan focuses on implementing grid modernization initiatives, improving forecasting and data integration, refining hosting capacity and non-wires alternative evaluations, advancing targeted reliability and capacity projects, developing strategic partnerships, and establishing performance metrics to measure outcomes. Key performance areas include reliability, resilience, safety, DER integration, hosting capacity, operational visibility, project execution, customer affordability, and progress toward integrated planning.

Together, the DSP and IRP provide a coordinated framework for planning New Mexico's future electric system. The DSP ensures that local infrastructure can reliably deliver electricity and accommodate evolving customer technologies, while the IRP ensures that sufficient generation, storage, and system resources are available to meet future demand. By integrating these planning processes, PNM can make more informed investment decisions, improve affordability, support state policy objectives, and maintain reliable service as the electric system continues to transform.

5.3 Grid Modernization Plan

PNM's Commission-approved Grid Modernization Plan is a foundational element of both its DSP and IRP, providing the operational capabilities needed to support New Mexico's transition to a carbon-free electric system while maintaining reliability, resilience, and affordability. PNM initially filed the Grid Modernization Plan in October 2022 (Case No. 22-00058-UT), followed by a cost-benefit analysis in November 2023. The plan includes approximately $344 million in capital investments over its first six years, which was subsequently increased to $383 million in PNM's 2025 annual reconciliation and compliance filing (Case No. 26-00069-UT).

The Grid Modernization Plan is designed to address the evolving demands placed on a distribution system originally built to serve largely one-directional power flows. Today, increasing levels of customer-sited solar, battery storage, electric vehicles, electrification technologies, and new large loads require greater visibility, automation, and operational flexibility. Through advanced technologies and enhanced grid intelligence, PNM will be better positioned to act as a distribution system orchestrator, using real-time system information to safely and efficiently integrate distributed resources while optimizing utilization of existing infrastructure.

Consistent with extensive stakeholder engagement undertaken throughout development of the Grid Modernization Plan and DSP, PNM's grid modernization investments are guided by four primary objectives:

- Equitable Grid Access by ensuring all customers, including low-income and underserved communities, benefit from a modern electric grid;
- Enhanced Reliability and Resiliency through improved system monitoring, automation, and outage response capabilities;
- Accelerated Clean Energy Integration by enabling the efficient interconnection and management of renewable generation, battery storage, and other distributed energy resources (DERs); and
- Greater Customer Empowerment through expanded access to energy usage information, advanced rate options, and tools that support energy efficiency, electrification, and DER participation.

Implementation of the Grid Modernization Plan is occurring in phases. During 2025, PNM completed foundational activities, including execution of contracts for Advanced Metering Infrastructure (AMI) and system integration services, deployment of AMI communications infrastructure, development of the Customer Energy Management Platform, telecommunications upgrades, cybersecurity planning, and establishment of program governance processes. Beginning in 2026, PNM transitions to broad deployment of AMI meters, distribution automation technologies, customer-facing digital tools, telecommunications infrastructure, and cybersecurity systems, while advancing development of the Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management System (DERMS). Through the remainder of the program, PNM expects to complete AMI deployment, implement ADMS and DERMS capabilities, expand distribution automation across the service territory, and continue investments in telecommunications, cybersecurity, and supporting system architecture.

The Grid Modernization Plan complements the ongoing distribution planning activities documented in the DSP. PNM conducts annual planning assessments that evaluate load growth, substation and feeder capacity constraints, outage exposure, and DER hosting capacity to identify required distribution system investments. These analyses, together with feeder-level engineering studies, help identify opportunities to increase system flexibility and accommodate higher levels of customer-sited resources.

One example is PNM's deployment of distribution-connected battery energy storage systems. Engineering studies evaluating the feasibility and benefits of strategically located battery installations demonstrated their ability to increase solar hosting capacity, defer traditional infrastructure upgrades, and improve distribution system performance. The first phase of the program, consisting of two battery projects totaling 12 MW, was approved by the NMPRC in December 2023 and placed into service in October 2024. A second phase consisting of five battery projects totaling 30 MW was approved in April 2026 and is expected to be placed into service by summer 2027. These projects provide a practical example of how distribution planning, grid modernization, and DER integration initiatives work together to support the energy transition.

The planning analyses performed under the DSP also provide important inputs to the IRP. Forecasts of customer adoption of behind-the-meter solar, battery storage, electric vehicles, and other distributed technologies inform both distribution and resource planning decisions. Similarly, PNM's long-term DER Integration Plan and hosting capacity analyses help identify how customer resources can be accommodated and leveraged as part of the broader resource portfolio.

From an IRP perspective, grid modernization investments create the operational foundation needed to reliably integrate increasing amounts of renewable generation, energy storage, distributed resources, and flexible demand technologies. Investments in AMI, telecommunications networks, distribution automation, ADMS, DERMS, fault location, isolation and service restoration technologies, Volt/VAR optimization, cybersecurity enhancements, and advanced system models improve system visibility, forecasting capabilities, and operational control. These capabilities enhance reliability and resiliency while supporting evaluation and deployment of demand response, virtual power plants, non-wires alternatives, and other distributed solutions that may complement or defer traditional supply-side resource investments.

Together, the DSP, Grid Modernization Plan, systematic distribution infrastructure investments, and distribution battery program establish a coordinated strategy for preparing PNM's distribution system for the Energy Transition Act requirements and a carbon-free future. The DSP identifies system needs and investment priorities, the Grid Modernization Plan provides the technologies and capabilities required to manage an increasingly complex distribution network, and the IRP evaluates how these capabilities can support the integration of cost-effective distributed and utility-scale resources. Collectively, these initiatives position PNM to maintain reliability and resiliency, enable greater customer participation, and optimize the use of existing infrastructure throughout the energy transition.

5.4 System Reliability Performance

In addition to the resource-oriented metrics that the IRP tracks, including planning reserve margin, Loss of Load Expectation or “LOLE” and Expected Unserved Energy or “EUE”, system reliability is measured using a number of additional metrics.

Maintaining a reliable and resilient electric system is a fundamental objective of PNM's transmission and distribution planning processes. PNM monitors a comprehensive set of reliability metrics to evaluate system performance, identify emerging risks, prioritize infrastructure investments, and assess the effectiveness of operational and planning initiatives. These metrics provide insight into both the frequency and duration of customer outages, the performance of transmission and distribution assets, and the ability of the electric system to withstand and recover from disruptive events.

Distribution Reliability Metrics

PNM utilizes industry-standard reliability indices established by the Institute of Electrical and Electronics Engineers (IEEE) to measure distribution system performance. These metrics are monitored across the system and evaluated over time to identify trends and opportunities for improvement.

System Average Interruption Duration Index (SAIDI) measures the average total duration of sustained outages experienced by customers during a reporting period. SAIDI is a key indicator of overall system reliability from a customer perspective and reflects the effectiveness of system design, maintenance practices, vegetation management, and outage restoration efforts.

System Average Interruption Frequency Index (SAIFI) measures the average number of sustained interruptions experienced by a customer during a reporting period. SAIFI is used to evaluate the frequency of outages and helps identify areas where system reinforcement, automation, equipment replacement, or operational changes may reduce outage occurrences.

Customer Average Interruption Duration Index (CAIDI) measures the average time required to restore service once an outage occurs. This metric evaluates restoration performance and reflects the effectiveness of outage management systems, field response procedures, distribution automation, and system visibility.

In addition to these standardized reliability measures, PNM considers :

- Feeder performance and reliability rankings.
- Substation outage exposure and contingency risks.
- Equipment failures and condition assessments.
- Distribution circuit loading and capacity utilization.
- Customer outages and outage causes.

These metrics support annual distribution planning assessments and help identify infrastructure investments, operational improvements, and grid modernization initiatives that can improve reliability and resiliency.

Transmission Reliability Metrics

PNM maintains and plans its transmission system in accordance with North American Electric Reliability Corporation (NERC) reliability standards and applicable Western Electricity Coordinating Council (WECC) criteria. Transmission reliability assessments focus on maintaining system security under both normal operating conditions and credible contingency events.

Key transmission reliability metrics and planning criteria include:

- N-1 Contingency Performance. PNM evaluates the ability of the transmission system to withstand the loss of a single transmission element, such as a transmission line, transformer, generator, or reactive power device, without causing widespread customer outages or unacceptable system conditions.

- Thermal Loading. Transmission equipment loading is monitored to ensure transmission lines, transformers, and associated facilities remain within established thermal ratings under both normal and contingency conditions.
- Voltage Performance. PNM monitors bus voltages across the transmission system to ensure voltages remain within established operating limits under a range of system conditions and contingencies.
- System Stability. Transmission planners evaluate transient, dynamic, and voltage stability performance to ensure the system remains stable following major disturbances and continues to support reliable delivery of electricity.
- Transfer Capability and Congestion. PNM assesses available transmission capacity and identifies constraints that may limit the delivery of generation resources or increase operational risk.
- Transformer and Substation Capacity Utilization. Loading levels and forecast growth are evaluated to identify locations where upgrades or additional facilities may be required to maintain reliability.

Reliability performance metrics serve as important inputs to PNM’s planning efforts at large. Distribution reliability metrics help identify areas where infrastructure investments, distribution automation, advanced metering infrastructure, or operational improvements can enhance customer service and reduce outage impacts. Transmission reliability assessments identify facility upgrades and system reinforcements necessary to maintain bulk power system reliability while accommodating changing load patterns and new generation resources.

As PNM transitions toward a carbon-free resource portfolio, reliability metrics also help evaluate the operational impacts of increasing levels of renewable generation, energy storage, electrification, and distributed energy resources. Investments identified through distribution planning, transmission planning, and grid modernization initiatives are prioritized, in part, based on their ability to maintain or improve reliability performance while supporting long-term clean energy objectives.

By continuously monitoring these reliability indicators and incorporating the results into both near-term operational decision-making and long-term planning processes, PNM seeks to provide safe, reliable, resilient, and affordable electric service throughout the energy transition.

5.5 Critical Facilities and Infrastructure

PNM maintains contingency resources to ensure reliable service in the event of an unanticipated failure of critical facilities or infrastructure. As PNM's portfolio and physical infrastructure evolve, the nature and profile of system risks change accordingly. To address this, PNM has established a dedicated Crisis Management and Resilience function responsible for identifying and managing rapidly evolving crises that could threaten system reliability, infrastructure integrity, personnel safety, or customer service.

This function operates an enterprise-wide "All Hazards" response plan—an industry-standard framework that prepares the organization to respond to any emergency, regardless of cause. The plan is supported by a business continuity program that establishes protocols for sustaining operations during disruptions. PNM also maintains hazard-specific and business-area-specific response plans, with particular focus on risks that present unique operational challenges:

- Severe storms and extreme weather
- Wildfires
- Cyberattacks
- Pandemics

PNM conducts hazard and impact assessments of its infrastructure using a tiered approach grounded in industry standards and best practices, prioritizing risks that pose the greatest threats to safety, security, and service reliability. PNM also engages with the broader utility industry in support of state and federal preparedness efforts, including disaster planning, grid recovery and resilience coordination, generation resource adequacy, and fuel supply security.

5.6 Today's Transmission Planning Process

Transmission planning is the ongoing, iterative process by which utilities, including Planning Coordinators and Transmission Planners identify the transmission facilities needed to reliably and economically serve future electricity demand, integrate new generation resources, and maintain compliance with mandatory federal reliability standards. In the United States, planning occurs at three overlapping levels: local/utility (Transmission Planner), regional (Planning Coordinator or RTO/ISO), and interregional (coordination among neighboring planning regions pursuant to FERC Orders 1000 and 2023, including the FERC-required interregional cost allocation processes).

5.6.1 Planning Horizons and Study Cycles

Transmission planning is conducted over multiple time horizons, each with different levels of granularity:

- Near-term / operating horizon (0–2 years): confirms readiness of facilities already under construction and validates near-term reliability under actual forecasted conditions.
- Near-term planning horizon (Year 1–5): detailed power-flow, short-circuit, and stability studies against near-firm load and generation forecasts; typically the basis for capital project approval.
- Long-term planning horizon (Year 6–10, and increasingly 10–20 for some regions): scenario-based studies that stress-test the system against a range of future conditions (load growth trajectories, generation retirements/additions, policy scenarios) rather than a single forecast.

Most Transmission Planners and Planning Coordinators run this cycle annually, producing a formal “Planning Assessment” (the term used in NERC's TPL standard) that is refreshed each year and shared with stakeholders, neighboring systems, and state regulators.

5.6.2 THE CORE PLANNING WORKFLOW

- Load forecasting: development of peak demand, energy, and geographic/nodal load forecasts, increasingly incorporating large single-customer loads (e.g., data centers) as discrete, trackable line items rather than embedded in general load growth.
- Resource and topology assumptions: incorporation of the generation interconnection queue, planned retirements, announced large loads, and existing/planned transmission topology.

    Base case model development: construction of powerflow cases (commonly in the industry-standard formats used by tools (such as PSLF) representing normal (P0) and contingency conditions.

- Steady-state (thermal/voltage), short-circuit, and stability (dynamic) analysis: testing the system against a defined set of single and multiple contingencies.
- Needs identification: identification of thermal overloads, voltage violations, stability limitations, short-circuit duty exceedances, or protection system deficiencies.
- Alternatives analysis: evaluation of transmission upgrades, non-wires alternatives (storage, demand response, distributed energy resources), and operating procedures to resolve identified needs, with cost-effectiveness and constructability comparisons.
- Stakeholder review and cost allocation: WestConnect or other planning organizations consider, and assignment of costs under FERC-approved tariff formulas.
- Approval and reporting: Planning Coordinator review and reporting to NERC to demonstrate compliance.

5.6.3 KEY PARTICIPANTS

Role	Function
Transmission Planner (TP)	Performs studies of its own footprint (often a single utility) and develops local Corrective Action Plans.
Planning Coordinator (PC)	Aggregates and coordinates planning across one or more Transmission Planners' footprints; ensures a wide-area view.
RTO/ISO	In organized markets, often serves as the Planning Coordinator and runs a regional, stakeholder-driven expansion plan (e.g., RTEP, MTEP, ITP).
Regional Entity	One of NERC's regional bodies that monitors and enforces compliance with reliability standards.
State/Local Regulators	Review and, in many states, must approve individual transmission projects, siting, and cost recovery.
FERC	Approves NERC reliability standards, RTO/ISO tariffs and planning processes, and cost allocation methods for transmission projects.

This is a factual, sourced overview of an evolving regulatory area; large-load and generator interconnection rules referenced below were in active rulemaking as of mid-2026 and should be verified against current FERC/NERC filings before use in a specific filing or decision.

5.6.4 Federal NERC Reliability Standards and Required Studies

Since the Energy Policy Act of 2005, the FERC has had authority to approve mandatory, enforceable Reliability Standards for the Bulk Electric System (BES), developed by the North American Electric Reliability Corporation (NERC) as the FERC-certified Electric Reliability Organization. Transmission planning is governed primarily by the TPL family of standards, supported by related Facilities (FAC), Modeling (MOD), and interconnection-related standards.

TPL-001 — Transmission System Planning Performance Requirements

The cornerstone planning standard is currently TPL-001-5.1 (Transmission System Planning Performance Requirements), most recently revised to strengthen study of protection-system single points of failure and approved by FERC. TPL-001 requires each Transmission Planner and Planning Coordinator to:

- Maintain accurate system models consistent with data submitted under MOD-032 (Data for Power System Modeling and Analysis).
- Perform an annual Planning Assessment covering a near-term (years 1–5) and a longer-term (out to at least year 10) horizon.
- Study a defined table of contingency categories (P0 through P7 in the standard's Table 1), ranging from normal system conditions (P0) through single-contingency events (P1–P2), multiple-contingency events (P3–P6), and extreme events, verifying that the system remains within thermal, voltage, and stability limits and, for most categories, avoids uncontrolled cascading or islanding.
- Evaluate stability, short-circuit, and voltage performance, including protection system single points of failure and their potential to cause cascading outages.
- Develop Corrective Action Plans (CAPs) for any identified violations, and report those plans and study assumptions to stakeholders, neighboring Planning Coordinators, and the Regional Entity.
- Respond to comments/technical review of the Planning Assessment within defined timeframes.

Other Standards That Support the Planning Function

Standard	Purpose
MOD-032	Requires TPs/PCs to submit steady-state, dynamics, and short-circuit modeling data on a defined cycle, forming the base cases used in TPL studies.
FAC-001 / FAC-002	Establish facility connection requirements and require assessment of the reliability impact of new facilities (including generation and load interconnections) before they are energized.
FAC-008 / FAC-009	Require establishment and documentation of Facility Ratings used consistently across planning and operating studies.
FAC-013	Requires the establishment of transfer capability methodology used in planning studies.
FAC-014	Requires establishment of System Operating Limits (SOLs) consistent with planning assessments.

TPL-007	Addresses planning for geomagnetic disturbance (GMD) events.
PRC-series (e.g., PRC-023, PRC-025)	Govern protection system coordination and load-shedding relay settings that interact with planning assumptions.
IRO/TOP-series	Operating-horizon standards that rely on planning-horizon System Operating Limits and models as inputs.

FERC Orders Shaping the Planning Process Itself

In addition to NERC reliability standards, several FERC orders under the Federal Power Act define how regional and interregional planning must be conducted and how costs are allocated:

- Order No. 890 (2007): required open, transparent, and coordinated regional transmission planning processes and comparable treatment of transmission alternatives, including demand-side and non-wires options.
- Order No. 1000 (2011): required each public utility transmission provider to participate in a regional transmission planning process that considers public policy requirements, established interregional coordination requirements, and required removal of a federal right of first refusal in certain circumstances, paired with defined regional cost allocation methods.
- Order No. 2023 (2023, as revised by Order No. 2023-A, 2024): reformed generator interconnection procedures (discussed in Section 4).
- Order No. 1920 (2024): the most recent major long-term regional transmission planning and cost allocation rule, requiring transmission providers to conduct long-term (at least 20-year) scenario-based planning, consider a broader set of benefits in cost allocation, and coordinate with state entities on cost allocation; compliance filings and rehearing proceedings were still working through FERC and the courts as of mid-2026.

Together, the NERC reliability standards (mandatory, enforceable, reliability-focused) and the FERC planning/cost-allocation orders (process- and market-focused) form the two-part federal framework within which every U.S. transmission provider's planning process must operate.

5.6.5 Planning for Large Loads

Electric utilities across North America are experiencing unprecedented growth in demand from large-load customers, including data centers and advanced manufacturing facilities, among others. These customers can require significant capacity and may seek service on timelines shorter than those historically associated with utility planning cycles. As a result, planning for large loads has become an increasingly important component of PNM's planning efforts.

For PNM, evaluating large-load interconnection requests requires consideration of not only the physical infrastructure needed to serve the customer, but also the broader impacts on system reliability, resource adequacy, affordability, and achievement of New Mexico's clean energy objectives. Accordingly, large-load assessments are often assessed in multiple related planning processes. As these trends continue, planning processes will increasingly require evaluation of multiple load growth scenarios rather than relying solely on deterministic forecasts.

The transmission and distribution plans and the IRP will increasingly be required to provide complementary frameworks for evaluating large-load growth. The T&D planning focuses on the infrastructure, operational, and reliability requirements needed to physically serve new customer demand, while the IRP evaluates the generation, storage, transmission, and demand-side resources necessary to meet long-term energy and capacity needs.

Inputs from large-load inform both planning processes by providing forecasts of future demand, infrastructure requirements, system constraints, and flexibility opportunities. Likewise, grid modernization investments, advanced metering infrastructure, distribution automation, advanced distribution management systems, and distributed energy resource management systems provide the visibility and operational capabilities necessary to manage increasingly complex load profiles.

PNM anticipates that large-load planning will continue to evolve over the next decade as data centers, advanced manufacturing, electrification initiatives, and other emerging customer classes become a larger portion of system demand. In addition to evaluating energy and capacity requirements, future planning efforts will increasingly assess load flexibility, operational characteristics, infrastructure timing requirements, customer-sited resources, and potential reliability impacts.

Accordingly, PNM will continue to refine its planning methodologies to ensure large loads are integrated in a manner that maintains reliability and resiliency, supports economic development, protects existing customers from undue cost and risk, and advances New Mexico's clean energy goals. In the future, PNM will seek to incorporate both load growth and load flexibility into long-term planning, PNM can more effectively identify cost-effective infrastructure investments and resource solutions that benefit all customers.

Additionally, large retail loads have not been required to register as NERC entities solely based on their size and have generally not been directly subject to NERC Reliability Standards. However, in 2026 FERC directed NERC to develop registration criteria and reliability standards for certain large computational loads, such as data centers and other high-density computing facilities, in response to emerging bulk power system reliability concerns. If adopted, these requirements could establish direct reliability obligations for qualifying large-load customers for the first time and likely include additional related planning standards for utilities.

5.6.6 Transmission Planning for Integrating New Generation

New generation — including wind, solar, battery storage, natural gas, and increasingly hybrid/co-located resources — connects to the transmission system through a distinct but related interconnection process, governed by FERC's pro forma Large Generator Interconnection Procedures (LGIP) and Agreement (LGIA), as most recently and substantially reformed by Order No. 2023.

5.6.7 FERC Order No. 2003/2006/845 Foundations

FERC's original standardized interconnection rules — Order No. 2003 (large generators) and Order No. 2006 (small generators), later updated by Order No. 845 (2018) — established the baseline pro forma LGIP/LGIA, including the interconnection customer's right to request different levels of interconnection service (network resource vs. energy-only) and options such as surplus interconnection service and provisions allowing operating flexibility (e.g., alternative transmission technologies at the customer's request).

5.6.8 Order No. 2023 — The Current Framework

Order No. 2023 (July 2023), refined by Order No. 2023-A (March 2024), represents the most significant overhaul of generator interconnection procedures in roughly two decades, aimed at addressing a national interconnection queue that had grown to well over 2,000 gigawatts of pending generation and storage capacity. Key features include:

- First-ready, first-served cluster studies: transmission providers must study interconnection requests in clusters (rather than one at a time, first-come-first-served), replacing queue position with demonstrated project readiness as the basis for prioritization.
- Stronger readiness requirements: nonrefundable application fees, site-control documentation, and increasing commercial-readiness/study deposits at each stage (cluster study, cluster restudy, facilities study) are designed to filter out speculative projects clogging the queue.
- Firm study deadlines with penalties: transmission providers face financial penalties for missing statutory study deadlines, replacing the prior "reasonable efforts" standard.
- Co-location and technology neutrality: the rule facilitates co-locating storage with generation under a single interconnection request (supporting hybrid solar-plus-storage and similar projects) and requires more consistent treatment of new and evolving technologies.
- Affected-system study coordination: clearer rules for studying and allocating costs for upgrades needed on neighboring ("affected") transmission systems.

PNM has fully implemented Order 2023 into its planning process with completion of its transitional cluster in 2026.

Typical Generator Interconnection Study Sequence

- Interconnection request and cluster window: developer submits site-control evidence, technical data, and required deposits during a defined annual (or periodic) intake window.
- Cluster study (feasibility/system impact combined or phased, depending on region): thermal, voltage, short-circuit, and stability analysis of the entire cluster of requests together, identifying needed network upgrades and estimated costs/timing.
- Cluster restudy: a follow-on study after projects withdraw or materially change, to reflect the updated cluster composition.
- Facilities study: detailed engineering and cost estimates for the specific interconnection facilities and any assigned network upgrades.
- Generator Interconnection Agreement (GIA): the FERC pro forma agreement (as modified by each transmission provider's FERC-approved tariff) establishing the commercial and technical terms, cost responsibility, and milestones for interconnection.
- Affected systems studies: parallel studies of any neighboring transmission systems whose facilities may be impacted by the new generation.

These generator studies interact directly with the TPL-001 Planning Assessment described in Section 2: network upgrades identified through the interconnection process become inputs to (and, once approved, part of) the base transmission topology used in subsequent regional and long-term planning studies, and vice versa.

5.6.9 How These Functions Feed the Integrated Resource Plan

An Integrated Resource Plan (IRP) is the long-range (typically 10–20+ year) plan a utility or load-serving entity develops — generally under state regulatory requirements — to identify the least-cost, reliable combination of generation, transmission, demand-side, and storage resources needed to meet forecasted customer demand while satisfying reliability, policy, and environmental constraints. Transmission planning is not a separate, downstream activity from the IRP; the two processes are iterative and mutually dependent.

Inputs from Transmission Planning into the IRP

- Deliverability constraints: TPL-001 Planning Assessments and generator interconnection studies determine which candidate resources (existing or proposed) can actually deliver their output to load given transmission limitations — information the IRP's capacity-expansion model needs to avoid selecting resources that cannot be reliably interconnected or delivered in the assumed timeframe.
- Interconnection cost and timing: the network upgrade costs and study-driven timelines coming out of the Order No. 2023 cluster process feed directly into the levelized cost and in-service-date assumptions the IRP uses to rank competing generation and storage portfolios.
- Load forecasts: are a primary driver that anchors the entire IRP, and require their own sensitivity/scenario to capture future possible load scenarios.
- Reliability need dates: Corrective Action Plans from the TPL-001 process establish firm need-by dates for transmission reinforcements, which the IRP must treat as constraints (or, alternatively, as candidate non-wires-alternative opportunities if a resource solution can substitute for a wires solution).
- Regional and interregional plans: FERC Order No. 1000/1920-driven regional transmission plans and cost allocations shape which transmission expansion, potentially affecting IRP resource siting choices.

Outputs from the IRP Back into Transmission Planning

- Preferred resource portfolios (including proposed retirements, new generation, storage, and demand-side resources) become the generation and load assumptions used in the next annual TPL-001 Planning Assessment and in regional planning base cases.
- IRP-identified public policy requirements (e.g., state clean energy standards) are explicitly incorporated into Order No. 1000-compliant regional transmission plans as a distinct driver, alongside reliability and economic drivers.
- Long-term, scenario-based planning required by Order No. 1920 is intended to better align the multi-decade time horizon of transmission planning with the multi-decade time horizon utilities already use in IRPs, reducing the historical mismatch between shorter transmission planning horizons and longer-range resource planning.

The Integrated Feedback Loop

In practice, this creates a continuous feedback loop rather than a one-directional pipeline: the IRP's resource forecast (including large loads and new generation) sets the assumptions for the transmission Planning Assessment; the Planning Assessment's reliability needs, deliverability findings, and interconnection cost/timing results are then fed back into the next IRP cycle as constraints and cost inputs; and both processes must reconcile with NERC's mandatory reliability standards, FERC's generator interconnection framework, and the fast-evolving large-load interconnection rules, that are reshaping load forecasts and network upgrade obligations in real time as of 2026.

5.6.10 Summary

Transmission, distribution, grid modernization, generator interconnection, and resource planning are increasingly interconnected and must be coordinated to effectively plan the future electric system. Forecasted load growth, distributed energy resource adoption, electrification, and the development of new generation resources all create interactions between these planning processes. Information developed through each planning effort informs the others, helping ensure that resource portfolios are technically feasible, interconnection requirements are understood, grid infrastructure is appropriately sized and located, and customer needs are met reliably and cost-effectively. This coordinated planning approach allows PNM to identify integrated solutions that optimize existing infrastructure, support timely system expansion, and advance the transition to a cleaner and more resilient grid.

5.7 How Transmission Planning has evolved in IRP Modeling

5.7.1 The 2017 and 2020 IRPs: Early EnCompass-Era Modeling Choices

The 2017 IRP: Adoption of Loss-of-Load-Probability Modeling

While the 2017 IRP's most significant modeling change was the adoption of SERVM for loss-of-load-probability (LOLP) analysis — replacing a simple peak-hour planning reserve margin approach — this shift also began to establish the broader analytical discipline (probabilistic, hourly, multi-year simulation) that would later make PNM comfortable investing in more granular transmission representations. The 2017 IRP's conclusion that the prior 13% reserve margin was insufficient to meet a “two dys in ten years” reliability target set a precedent: as the resource mix grew more complex, PNM's models needed to grow more granular to keep pace — a lesson later applied to transmission modeling as well.

The 2020 IRP: A Direct, Documented Attempt to Build Transmission Co-Optimization Into EnCompass

The most direct antecedent to today's EnCompass structure came in the 2020 IRP, when PNM attempted to have EnCompass represent transmission upgrades as explicit, physical, co-optimized choices alongside generation resources — rather than as simplified cost adders. The 2023 IRP describes the outcome plainly:

> *EnCompass includes functionality to co-optimize generation and transmission investments. In developing the analysis for the 2020 IRP, PNM tested this functionality, exploring the potential to*

> *represent transmission upgrades physically in the model as explicit choices. PNM spent months developing and testing this functionality,but ultimately could not conclusively demonstrate that the results from the model were both sufficient to maintain reliability and provide least cost outcomes for customers. Extremely long model runtimes compounded the challenge of implementing this functionality, and PNM ultimately used transmission cost adders to reflect the associated costs of transmission upgrades in developing the 2020 IRP.*

— PNM 2023 IRP Final Draft, Section 5.2.2

This 2020 experience directly shaped EnCompass's structure for years afterward in two ways: first, it confirmed that full physical co-optimization was not yet computationally practical for PNM's system, cementing the zonal cost-adder approach as the default; and second, it created the internal technical knowledge and motivation within PNM's modeling team to keep searching for a more granular alternative — which is precisely what led to the nodal EnCompass license obtained during the following IRP cycle.

5.7.2 The 2023 IRP: Zonal Cost-Adder Structure and Planting the Nodal Seed

Stakeholder Re-Examination of the Modeling Approach

The 2023 IRP revisited the transmission modeling question directly with stakeholders, dedicating two full Public Advisory Group workshops to the topic (September 13, 2022 and October 6, 2022), including a presentation from external consultant E3 comparing transmission modeling approaches used by other Western utilities. The 2023 IRP's own account of the outcome:

> *For the 2023 IRP, PNM revisited this modeling methodology and solicited feedback from stakeholders in workshops on the pros and cons of using different approaches to representing transmission in capacity expansion using a zonal modeling tool. The minimal feedback received from stakeholders, coupled with a review of current practices used by neighboring utilities, informed PNM's choice to continue to use transmission cost adders in the 2023 IRP.*

— PNM 2023 IRP Final Draft, Section 5.2.2

The Structural Mechanics of the 2023 EnCompass Cost-Adder Model

The 2023 IRP documents the specific structural design PNM used to translate real transmission projects into EnCompass model inputs — a design that directly foreshadows the zonal side of the 2026 IRP's two-stage framework. PNM organized transmission cost adders into distinct geographic regions, each with its own unit cost per kW derived from named candidate projects:

Region	Representative Candidate Project(s)	Unit Cost Basis
North	Four Corners-West Mesa Expansion; Rio Puerco-OJ West; Ojo-Norton	Project-specific $/kW
West	McKinley-Rio Puerco Transmission Project	Project-specific $/kW
East	Western Spirit-Pajarito Expansion	Project-specific $/kW

Load (near Albuquerque metro)	Belen-Person 115 kV; Rio Puerco-KM-BW 115 kV	Averaged: $625/kW
All other regions	No specific project identified	Weighted average generic adder: $901/kW

This regional-bucket structure — rather than a single statewide adder — is the direct structural ancestor of the zonal treatment used in the 2026 IRP (zones such as 4C-PV-SJ, PNM-N, PNM-E, PNM-S referenced in Workshop 3). The methodology's core mechanics, described in the 2023 IRP, also carried forward unchanged into the 2026 IRP's cost-adder walkthrough (e.g., the Four Corners–Albuquerque example: $448M ÷ 700 MW = $640,000/MW):

- Each region's unit cost ($/kW) is multiplied by a candidate resource's capacity (MW) to calculate the capital cost adder applied to that resource in the zonal capacity expansion optimization.
- Once a region's identified project capacity limit is reached, a generic (higher, less specific) adder applies to any additional capacity sited there.
- No generic transmission project was identified for delivering power from southern to northern New Mexico load centers, reflecting the real-world absence of any economically viable proposal for that corridor at the time — illustrating how EnCompass's structure is bounded by the actual state of transmission planning, not an idealized one.

The Critical Structural Turning Point: Licensing a Nodal Version of EnCompass

Despite reaffirming the zonal cost-adder structure for the 2023 IRP itself, this same section of the document discloses the single most consequential structural change to EnCompass going forward — PNM's decision to license a nodal version of the tool:

> *Using information on transmission impacts of new resources in the IRP is a goal that PNM has been pursuing for years, and PNM is continuing to develop accurate models to take advantage of new functionality. PNM has recently licensed a nodal version of EnCompass. PNM hopes to utilize this new tool to quantify congestion and better understand interconnection and transmission service for its system. PNM expects that insights gained from a nodal model will also prove useful to enhance resource planning and modeling in future IRPs, providing important information on system limitations, capabilities and costs/benefits in its existing zonal modeling framework.*

— PNM 2023 IRP Final Draft, Section 5.2.2

This is the direct structural origin of the node-level modeling (resources mapped to specific interconnection points such as Four Corners 345 kV, Pajarito 345 kV, and Atrisco 345 kV) later demonstrated throughout the 2026 IRP workshops.

Organizational Structure: Merging IRP and Transmission Planning Teams

A structural change outside of the software itself, but essential to enabling EnCompass's evolution, was PNM's decision — announced in the 2023 IRP's acknowledgements — to combine its Integrated Resource Planning team with its Transmission Planning and Engineering teams into a single organization:

> *To move toward an even more integrated planning approach, PNM recently combined its Integrated Resource Planning team with the Transmission Planning and Engineering teams to expand consideration of solutions across the generation, transmission, and distribution segments.*

> *Integrated Systems Planning is critical to an efficient and cost-effective realization of a clean energy future.*

— PNM 2023 IRP Final Draft, Acknowledgements (Laurie Williams, Executive Director, Integrated Systems Planning)

This organizational merger removed a structural barrier that had previously separated the teams responsible for EnCompass-based resource planning from the teams responsible for the annual NERC-driven transmission planning process described in Section 3 above — making it organizationally feasible to pursue the nodal EnCompass integration that followed.

The 20-Year Transmission Planning Study: A New Structural Input

The 2023 IRP also discloses that PNM had, during that IRP cycle, scoped and completed a new 20-year transmission planning study — extending well beyond the traditional 10-year local transmission planning horizon — specifically to identify transmission solutions needed to support the IRP's Most Cost-Effective Portfolio(s) through 2043. This study was expected to take about one year (completion targeted for was completed in late 2024 and used multi-scenario analysis to identify the transmission projects that support both reliability and renewable integration. This 20-Year Transmission Outlook became, and remains, the direct source of the candidate project costs cited repeatedly throughout the 2026 IRP Workshop 3 and Workshop 5 transmission sensitivities (e.g., Rio Sol, Sun Zia, Blackwater DC Tie, and the new Four Corners line), extending the structural role that regional planning studies have always played in populating EnCompass's transmission inputs.

5.7.3 Historical EnCompass Modeling Structure

Historical Layer	Structural Contribution to EnCompass
2020 IRP (failed co-optimization attempt)	Confirmed physical/explicit co-optimization was not yet computationally viable, cementing zonal cost adders as the near-term structure while motivating a search for a granular alternative.
2023 IRP stakeholder workshops & regional cost-adder design	Formalized the regional-bucket ($/kW) cost-adder structure (North, West, East, Load, generic) that directly preceded the 2026 IRP's zonal treatment.
2023 licensing of nodal EnCompass	Directly created the technical capability for node-level resource mapping and congestion/curtailment quantification used throughout the 2026 IRP.
Integrated Systems Planning organizational merger	Removed the organizational separation between IRP and Transmission Planning teams, enabling coordinated development of the nodal tool.
2023 20-Year Transmission Planning Study	Became the ongoing source of candidate transmission project costs feeding both the zonal cost adders and the nodal expansion sensitivities used in the 2026 IRP.

Summary

The structure of PNM's EnCompass model today — a zonal capacity expansion framework using region-specific transmission cost adders, now paired with a licensed nodal module capable of resource-to-node mapping and congestion quantification. It is the layered product of: (1) a permanently separate, NERC-mandated local transmission planning process that necessitated a translation layer between granular power-flow analysis and EnCompass's optimization; (2) PNM's participation in regional and national transmission-planning coordination bodies that continuously supply candidate project data; (3) a documented, unsuccessful 2020 IRP attempt at full transmission/generation co-optimization that cemented the cost-adder approach as the practical near-term structure; and (4) the deliberate 2023 IRP decision to preserve that zonal structure for immediate use while simultaneously licensing a nodal EnCompass module — backed by an organizational merger of the IRP and Transmission Planning teams and a new 20-year transmission study — that directly enabled the two-stage zonal-plus-nodal EnCompass structure demonstrated throughout the 2026 IRP process.

Wholesale Market Opportunities & Risks Merchant Transmission: Independent Transmission Developers Active in New Mexico in 2026

Overview of Active and Under-Development Merchant Transmission Projects

New Mexico's abundant wind and solar resources have attracted a wave of independent (merchant) transmission development. Most of this activity is facilitated through public-private co-development and lease arrangements with the New Mexico Renewable Energy Transmission Authority (RETA), a state instrumentality created by the Legislature in 2007 to plan, finance, develop, and acquire high-voltage transmission and energy storage projects that promote renewable energy expansion and economic development in New Mexico.

As of mid-2026, SunZia has transitioned from development to full commercial operation. Seven additional independent transmission projects remain actively in development and represent the near- and mid-term pipeline most relevant to future interconnection and resource planning: RioSol, Hidden Mountain Extension, North Path, Mora, Vista Trail, Eastern New Mexico Connector, and Southline. . In addition, a newer multi-state initiative — the Western Transmission Consortium (TWTC), of which PNM is a founding member — has begun studying a set of interjurisdictional “Southwest Pod” transmission projects that include New Mexico, though specific routes and in-service dates have not yet been published.

Project Location Map

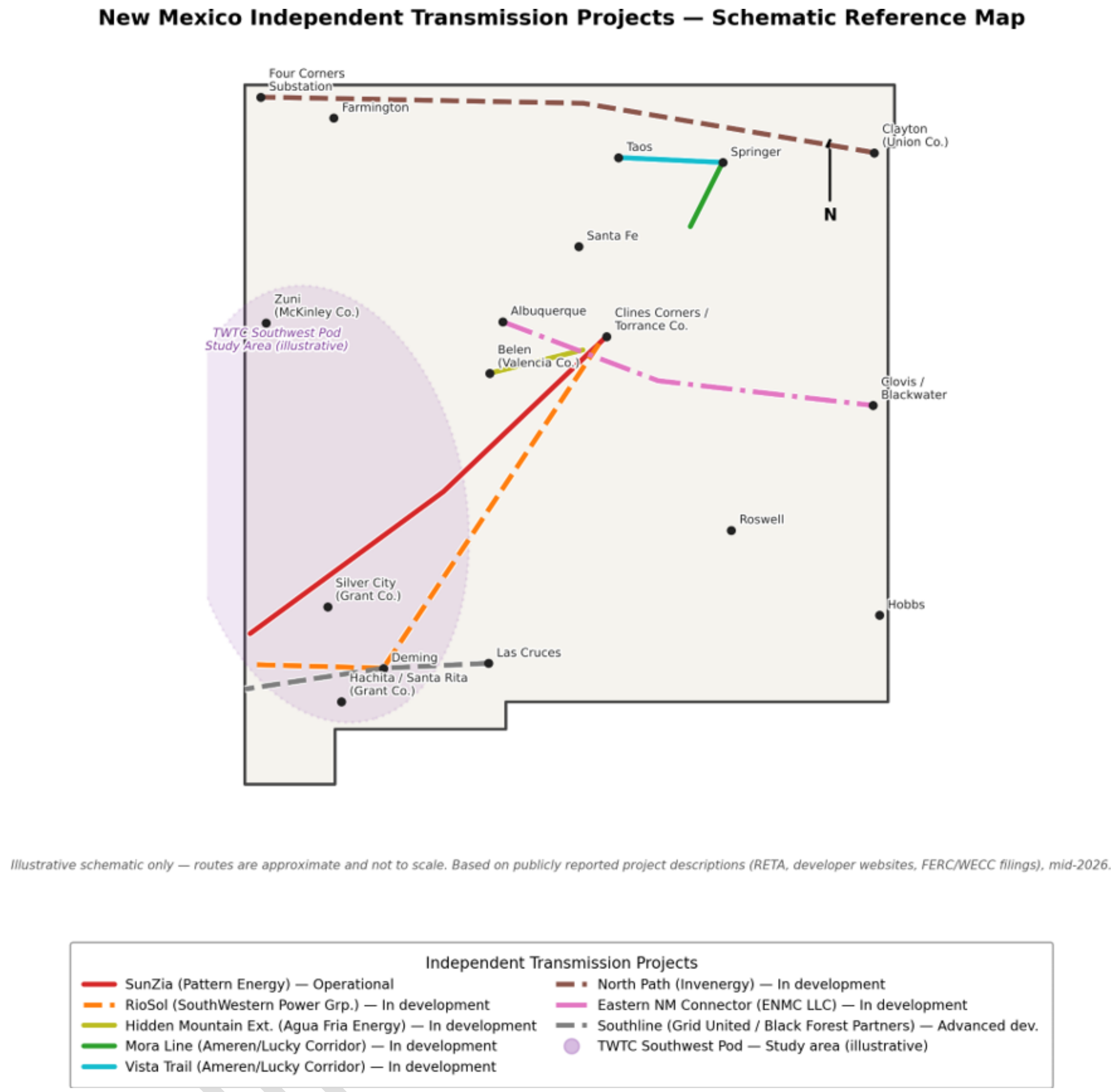


Figure 1. Schematic reference map of independent transmission projects in New Mexico. Routes are illustrative and approximate, not engineering-grade alignments; consult individual developer/RETA project pages for authoritative routing.

Summary Table

Developer	Project	Length / Type	Capacity	Status (mid-2026)
Pattern Energy Group	SunZia Transmission	550 mi, ±525 kV HVDC	3,000–3,650 MW	Operational – energized June 2026
SouthWestern Power Group (El Rio Sol	RioSol	550 mi (~350 mi in NM), 500 kV AC	1,500–1,600 MW	In development – construction targeted late 2026/2027; in-service ~2028–2029

Transmission, LLC)				
Agua Fria Energy (SWPG affiliate)	Hidden Mountain Extension	~20–21 mi, 345 kV AC	~1,000 MW	In development – lease Oct. 2024; targeted in-service Dec. 2028
Invenergy Transmission	North Path	~400 mi, 525 kV HVDC	Up to 4,000 MW	In development – routing/permitting; targeted ~2032
Ameren Transmission (Lucky Corridor, LLC)	Mora Transmission Project	~115–117 mi, 345 kV / 115 kV AC	182 MW	In development – targeted commercial operation 2027
Ameren Transmission (Lucky Corridor, LLC)	Vista Trail Transmission Project	~65 mi, 345 kV AC	~850 MW	In development – route selection phase; targeted 2027
Eastern New Mexico Connector, LLC	Eastern New Mexico Connector	278 mi, up to 500 kV AC	3,200 MW	In development – lease approved Dec. 2025; phased through ~2032
Grid United & Black Forest Partners	Southline Transmission Project	~280 mi, double-circuit HV AC	Bidirectional (N/A)	Advanced/pre-construction – construction expected late 2026; Phase 1 ~2028, full ~2029
Western Transmission Consortium (TWTC) – 84-member multi-state utility consortium incl. PNM	Southwest Pod (Blue Bird, Hachita, Santa Rita, Elkhorn, Zuni)	~1,100–2,000 mi across AZ, CO, NV, NM, UT (aggregate); NM-specific mileage not yet published	Not yet published	Initial study phase – project companies launched Aug./Sep. 2025; routes/timelines to be determined

5.7.4 Detailed Project Descriptions

1. Pattern Energy Group — SunZia Transmission (Operational)

SunZia is the largest clean-energy infrastructure project in U.S. history — a 550-mile ±525 kV HVDC line connecting central New Mexico (Torrance, Lincoln, and San Miguel counties) to south-central Arizona, paired with the 3,650 MW SunZia Wind farm. After nearly two decades of development, the project became fully operational in June 2026, delivering up to 3,000–3,650 MW and an estimated $20.5 billion in total economic benefit to New Mexico and the Southwest. It uses Hitachi Energy's HVDC Light® Voltage Source Converter technology — one of the largest VSC-based HVDC installations in the world.

2. SouthWestern Power Group / El Rio Sol Transmission, LLC — RioSol (In Development)

RioSol is effectively “Line 2” of the original SunZia project concept (SWPG retained this line after selling Line 1 to Pattern Energy in 2022). It is a 550-mile, 500 kV single-circuit HVAC line (~350 miles in New Mexico) co-located with SunZia, rated at 1,500–1,600 MW. RioSol completed an open capacity solicitation in 2025 and received FERC negotiated-rate authority. Construction is expected to begin in late 2026/2027, with commercial operation targeted for 2028–2029. A 2024 economic study projects $2.4 billion in project investment and $1.17 billion in regional economic benefit.

3. Agua Fria Energy — Hidden Mountain Extension (In Development)

A SWPG-affiliated developer building a ~20-mile, 345 kV multi-circuit line connecting RioSol's planned Tom Ray substation to PNM's existing Hidden Mountain substation in Valencia County, unlocking renewable capacity from Torrance and San Miguel county wind/solar projects. RETA entered a lease agreement in October 2024, with in-service targeted for December 31, 2028.

4. Invenergy Transmission — North Path (In Development)

A proposed ~400-mile, 525 kV HVDC line connecting northeastern New Mexico (Union County) to the Four Corners region in northwestern New Mexico, rated at up to 4,000 MW. Invenergy is co-developing with RETA under a January 2023 joint development agreement. The project remains in the routing, permitting, and community-engagement phase — including briefings to county commissions and coordination with Tribal governments — with expected completion around 2032.

5. Ameren Transmission (Lucky Corridor, LLC) — Mora Transmission Project (In Development)

A combination of a ~47-mile 345 kV segment (Don Carlos Wind Farm to a new Mora/Springer-area substation) and a ~66–70-mile 115 kV segment (Springer to PNM's Arriba substation), totaling roughly 115–117 miles and delivering 182 MW of wind power. Estimated project cost is $83 million, with commercial operation targeted for 2027; design work is reported to be substantially complete.

6. Ameren Transmission (Lucky Corridor, LLC) — Vista Trail Transmission Project (In Development)

A proposed ~65-mile, 345 kV AC line between Tri-State's Taos and Springer substations (~850 MW), intended to serve Clearway Energy's Gallegos/Don Carlos wind development and deliver power toward the Four Corners trading hub. The project remains in route-selection and stakeholder-engagement phase, with commercial operation targeted for 2027.

7. Eastern New Mexico Connector, LLC (In Development)

A newly formed developer (organized in New Mexico in October 2025) co-developing a 278-mile, up-to-500 kV double-circuit AC line with RETA, connecting PNM's Blackwater, Taiban Mesa, Hidden Mountain, and Pajarito substations at a rated capacity of 3,200 MW. The lease agreement was approved in December 2025; the project will be built in five phases, with renewable interconnections targeted for 2032.

8. Grid United & Black Forest Partners — Southline Transmission Project (Advanced Development)

An approximately 280-mile, double-circuit high-voltage line connecting the El Paso and Tucson transmission systems in two phases (Pima County, AZ → Grant County, NM → Doña Ana County, NM). Southline has completed NEPA review, obtained major state/federal permits, and secured 100% of private land rights in New Mexico. It was selected by the U.S. Department of Energy for the Transmission Facilitation Program (combined capacity contract value exceeding $700 million). Construction is expected to begin in late 2026, with Phase 1 operational by 2028 and the full project by 2029.

9. Western Transmission Consortium (TWTC) — Southwest Pod (Initial Study Phase)

The Western Transmission Consortium (TWTC) is a pioneering, member-owned entity — distinct from the single-developer IPP projects above — dedicated to building interregional and interjurisdictional transmission infrastructure across the eleven western states. TWTC officially launched its operational phase in May 2025 with founding members representing 84 utilities across 11 western states, including PNM as a founding member. Unlike the merchant developers described above, TWTC itself will not own transmission assets; instead, it forms individual project companies as specific opportunities are curated, with member utilities and independent transmission companies syndicating investment on a case-by-case basis.

TWTC's Southwest Pod consists of eight to nine transmission projects spanning approximately 1,100–2,000 miles across Arizona, Colorado, Nevada, New Mexico, and Utah. Five projects — named after historic turquoise mines in the Southwest (Blue Bird, Hachita, Santa Rita, Elkhorn, and Zuni) — launched their initial study phase in August/September 2025. The Hachita, Santa Rita, and Zuni project names reference locations in Grant and McKinley counties in southwestern New Mexico, suggesting a New Mexico nexus for at least a subset of these projects, though TWTC has not yet published specific routes, capacities, or in-service dates for individual Southwest Pod projects. ”

Because TWTC is a regional utility consortium rather than a merchant transmission developer, and because individual Southwest Pod project routes remain under study, the map in Figure 1 shows only a general, illustrative study-area indicator for the Southwest Pod rather than a specific route line. This should be treated as directional only and updated once TWTC publishes project-specific routing.

5.7.5 2026 IRP Transmission Candidate Transmission Projects

The 2026 IRP transmission project sensitivities are not a random assortment of candidate projects — they represent PNM's four distinct “seams” to the outside world, chosen specifically to test different regional market-access hypotheses against one another and against a pure internal-reinforcement alternative.

Project	Direction	Market Being Tested	Interconnection Type
Blackwater Connection to SPP	East	Southwest Power Pool (SPP)	AC/DC/AC asynchronous tie
Rio Puerco Switching Station – Four Corners	Northwest	Ties into Arizona neighbor systems.	Synchronous AC (within WECC)
Rio Sol Connection	Southwest	Arizona / Desert Southwest market	Synchronous AC (within WECC)
Sun Zia Connection	East-central	CAISO (via the Sun Zia line)	Synchronous AC (within WECC)

This geographic spread means the nodal/zonal sensitivity analysis is not testing whether PNM should build more transmission in the abstract — it is testing which specific external market connection provides the most value, since PNM can realistically prioritize only a limited number of large capital projects at once. See modeling section for analysis.

Summary: Ultimately, the pace, cost, and reliability of PNM's transmission system will influence PNM's resource portfolio planning and IRPs. As FERC's Order No. 1920 recognizes, transmission planning can no longer be treated as a downstream consequence of resource decisions — it must be conducted concurrently, on a long-term, scenario-based basis, so that PNM and its stakeholders can see, well in advance, where new generation, storage, and large-load additions are likely to require network upgrades. This forward-looking, integrated approach to transmission planning is not simply a compliance exercise — it is foundational to PNM's ability to deliver reliable, resilient, and affordable service to customers over the 20-year planning horizon. As load growth accelerates, merchant projects are advanced, and the resource mix continues to diversify, PNM will continue to pursue the full range of tools available — from GETs and right-sizing of existing facilities to targeted new transmission investment to potential strategic merchant development partnerships — to ensure that the transmission system keeps pace with the resource additions this IRP identifies, while protecting customers from unnecessary cost and preserving the reliability New Mexicans depend on.

6. Reliability & Resource Adequacy

The provision of reliable electric service is a core element of PNM's obligation to serve its customers. Electricity supports essential daily needs, including heating and cooling buildings during extreme weather, charging vehicles, operating businesses, and powering communications, data, water, public safety, and other infrastructure that increasingly depends on continuous electric service.

This chapter describes the connected planning and operating functions PNM uses to maintain reliability, explains how resource adequacy needs are changing as load and the resource mix evolve, and summarizes how this IRP uses probabilistic loss-of-load-probability modeling, effective load carrying capability analysis, and planning reserve margin requirements to test whether candidate portfolios can reliably serve customers under a broad range of system conditions.

6.1 Elements of Reliability

Reliability is delivered through multiple connected planning and operating functions. PNM must plan for sufficient generation, transmission, and distribution infrastructure; maintain those assets to ensure their performance; operate the system in real time; and coordinate those activities across the path from the point of generation to the customer meter. Each function addresses a different aspect of reliability: generation planning evaluates whether the portfolio can meet customer demand under a range of system conditions; transmission and distribution planning evaluate whether power can be delivered where and when it is needed; and operations maintain service as load, weather, equipment availability, and market conditions change.

The IRP is focused primarily on the resource-planning function, but it cannot be interpreted in isolation. A portfolio that appears adequate from a capacity perspective must still be deliverable across the transmission and distribution system, and operating reliability depends on having sufficient dispatchable, flexible, and responsive capability available in the time frame in which system conditions change.

6.1.1 Generation Planning & Resource Adequacy

Maintaining resource adequacy means planning for a portfolio of supply-side, demand-side, and market resources that can serve customer demand under stressed but plausible combinations of load, weather, resource availability, forced outages, and market conditions. Standards for measuring resource adequacy vary by jurisdiction, but a common industry benchmark is the one-day-in-ten-year reliability standard, typically measured by a loss-of-load-expectation of 0.1 days per year.

Establishing how much capacity is needed, when it is needed, and which resource attributes can meet that need is a central function of this IRP. The IRP identifies resource needs and informs the Statement of Need; subsequent procurement and approval processes determine whether specific resources are proposed, selected, contracted, approved, and placed in service. This distinction is important: the IRP may model generic resources or identify a need for attributes such as accredited capacity, energy, flexibility, or dispatchability, but separate evidence is required before describing any resource as approved or committed.

To plan for resource adequacy, PNM maintains a “planning reserve margin” (PRM) requirement. Resources are counted towards this requirement based on their effective load carrying capability (ELCC), a technology-agnostic measure of their contribution towards reliability needs that accounts for each resource’s specific capabilities and limitations. Consistent with industry best practice, both the requirement and capacity contributions are derived directly from detailed loss-of-load-probability (LOLP) modeling, described in greater detail in Section 5.3.

6.1.2 Transmission Planning

PNM plans its transmission system through ongoing 10-year and 20-year transmission planning processes that evaluate whether the existing and planned grid can reliably serve forecasted customer demand, integrate new generation, and accommodate changes in load over near-term and longer-term planning horizons. These processes use transmission models, load forecasts, generation and retirement assumptions, known interconnection activity, and planned system topology to test the system under normal and contingency conditions. The studies identify potential thermal overloads, voltage violations, stability concerns, short-circuit duty issues, protection-system limitations, or other deliverability constraints that could affect reliable service.

When a reliability need is identified through transmission planning, PNM evaluates corrective actions such as transmission upgrades, operating procedures, or potentially non-wires alternatives where applicable. The planning process is iterative: transmission study findings inform resource planning by identifying deliverability limits, interconnection costs, upgrade timing, and reliability need dates, while IRP assumptions about future load, generation, storage, and retirements feed back into future transmission planning assessments.

6.1.3 Distribution Planning

Distribution planning addresses the local infrastructure needed to deliver electricity from the transmission system and distributed resources to customers. It evaluates feeders, substations, voltage performance, protection systems, equipment loading, customer growth, distributed energy resource adoption, transportation and building electrification, resilience needs, and local reliability performance. Because many emerging reliability needs arise close to the customer meter, distribution planning is increasingly connected to resource planning, transmission planning, demand response, energy efficiency, customer programs, and distributed energy resources.

6.1.4 Operational Reliability

As a balancing authority area, PNM is responsible for maintaining balance between generation and load in real-time operations. PNM operates the electric system subject to applicable NERC and WECC reliability standards and coordinates reserves, dispatch, interchange, and market activity to respond to normal variability and unexpected events.

"Operating reserves" refer to capacity not used to serve load that can be dispatched by operators in response to variations in conditions or unforeseen events. In accordance with NERC standards, PNM's operators maintain operating reserves for two purposes:

17. **Contingency reserves** are used to respond to unexpected changes in the system, for example, unplanned outages of a generator or transmission line. In the Western Interconnection, NERC/WECC standards require that BAAs maintain contingency reserves equal to the greater of (1) 3% of PNM load plus 3% of online generation, or (2) the single largest contingency on PNM's system,[20] whichever is greater.

- **Regulation reserves** are used to respond to second-to-second variations in PNM's load and renewable generation output. For example, PNM maintains 13.8 MW of regulation reserves, on top of the contingency reserves, for fast frequency response in compliance with NERC Standard BAL-003-1.[30]

[Redacted Waiting on Confirmation from SME] Participation in WPP RSG enables its 30+ member utilities to share contingency reserves, allowing for more efficient, cost-effective dispatch.[29] In the event of an imbalance on PNM's system requiring contingency reserves, PNM may provide or receive assistance from the WPP RSG to meet contingency reserves for a maximum of one hour, during which PNM must restore balance to the system.

Operating reserves held by PNM may be "spinning" – meaning that they are provided by resources that are already synchronized to the grid – or "non-spinning" – meaning that they are not currently operating but can start within a ten-minute period. PNM uses both spinning and non-spinning reserves to meet the contingency and regulation requirements described above.

TABLE [ ]. OPERATING RESERVES HELD BY PNM IN REAL-TIME OPERATIONS

	Contingency Reserves	Regulation Reserves
Purpose	Respond to unforeseen events	Balance normal variations
Typical Requirement	Greater of (1) 3% of load and 3% online generation or (2) single largest contingency	13.8 MW
Contributing Resources	Spin, non-spin, and WPP RSG participation	Spin

PNM is also required to account for flexibility requirements associated with participation in the CAISO Western Energy Imbalance Market (EIM). CAISO's resource sufficiency evaluation includes a flexible ramp sufficiency test, a bid capacity test, balancing test and feasibility test; if a balancing area fails any test, transfers between that balancing area and the rest of the EIM may be limited. These requirements are distinct from long-term resource adequacy and contingency-

[20] Currently, PNM's largest contingency is the 235 MW Afton combined cycle power plant. As PNM's portfolio evolves over time, the single largest contingency may change to a different generator or transmission asset.

reserve planning, but they reinforce the same portfolio design principle: resources must be capable of serving energy and capacity needs in the time frames in which reliability risks emerge.

6.1.5 Resilience

Climate change, and associated extreme weather events, present an emerging risk to reliability, driving an increased need for planning resilient power systems. In the west, this has materialized as increases in the intensity and frequency of extremes. Recent examples of these extreme weather events include the 2020 and 2022 west-wide heatwaves and 2021 Winter Storm Uri. Although extreme weather events are expected to intensify in the coming decades, significant uncertainty surrounding their frequency, duration, and severity makes them challenging to incorporate into planning and modeling efforts. [Redacted waiting on confirmation from SME]

Table [ ]. Integration of key lessons from the resilience study into the current planning process.

Resilience Study Finding	Reflection in PNM's Current IRP
Different resource portfolios that meet the same LOLE planning standard exhibit varying performance during extreme events.	While PNM plans its portfolios to target a specific LOLE standard, alternative reliability metrics (expected unserved energy, loss of load hours) are evaluated and reported (see Section).
Stress testing candidate portfolios for resilience can help identify differences in their performance.	As a final step in the portfolio evaluation process, PNM reproduces several of the "stress tests" created in the resilience study and tests portfolios under those specific events (see Section).
Weatherization of all generation resources to allow for performance under extreme conditions provides additional resilience.	Cost assumptions for all new resources are intended to reflect necessary weatherization measures.
Firm generation resources reduce the severity of extreme event impacts in both summer and winter.	The IRP evaluates an expansive range of firm resource options, including emerging technologies not previously considered in the IRP (see Sections).
Broader southwest dynamics will have significant impact on PNM's ability to avoid outages under winter extreme events.	For the LOLP analysis, PNM and Pow have updated the representation of neighboring electric systems to capture more realistic expected future changes in loads and resources (see Section)
As PNM expands its energy storage portfolio, its operational limits and utilization should be understood and considered in resource adequacy modeling.	PNM incorporates a forced outage rate for battery storage into its reliability modeling that is consistent with actual performance data (see Section)

6.2 Regional Outlook & Industry Trends

6.2.1 Regional Load-Resource Balance

Both PNM's 2020 and 2023 IRPs identified growing concerns regarding regional resource adequacy as an important trend to monitor. As documented in both reports, a confluence of factors – increasing loads, aging plant retirements, and increasing frequency of extreme weather – contributed to growing reliability risks at the time. During this period (2020-2023) NERC's Summer Reliability Assessments classified the Southwest US as experiencing "elevated" reliability risks.

Since this time, more recent publications provide updated viewpoints on regional resource adequacy, including NERC's *2026 Summer Reliability Assessment* and E3's *2025 Resource Adequacy Assessment: Desert Southwest* ("2025 Southwest RA Study"). Both studies indicate that the region's utilities have successfully maintained resource portfolios sufficient to meet growing loads. NERC's assessment now classifies the Southwest as experiencing "normal" levels of summer reliability risk, and the 2025 Southwest RA Study similarly notes:

> *"Since 2021, observed resource additions in the Southwest have largely aligned with projections from five years ago. While load growth has slightly outpaced prior forecasts, the region has largely maintained a stable balance of loads and resources during this period."*

At the same time, both studies warn of potential future resource adequacy challenges and the need for significant new resource investments to maintain adequacy. NERC's assessment warns that "[t]he subregion faces grid reliability concerns posed by large loads if new generation resources are delayed as new load comes online,"[21] and E3's study quantifies the scale of new resource needs across the region required to mitigate those challenges:

> *"Meeting the needs forecasted in this study would require that utilities add over 4,000 MW of new installed capacity to the system each year over the next decade – a quantity that exceeds the necessary rate of additions previously identified in the 2021 study and eclipses the long-term historical average by a factor of four."*

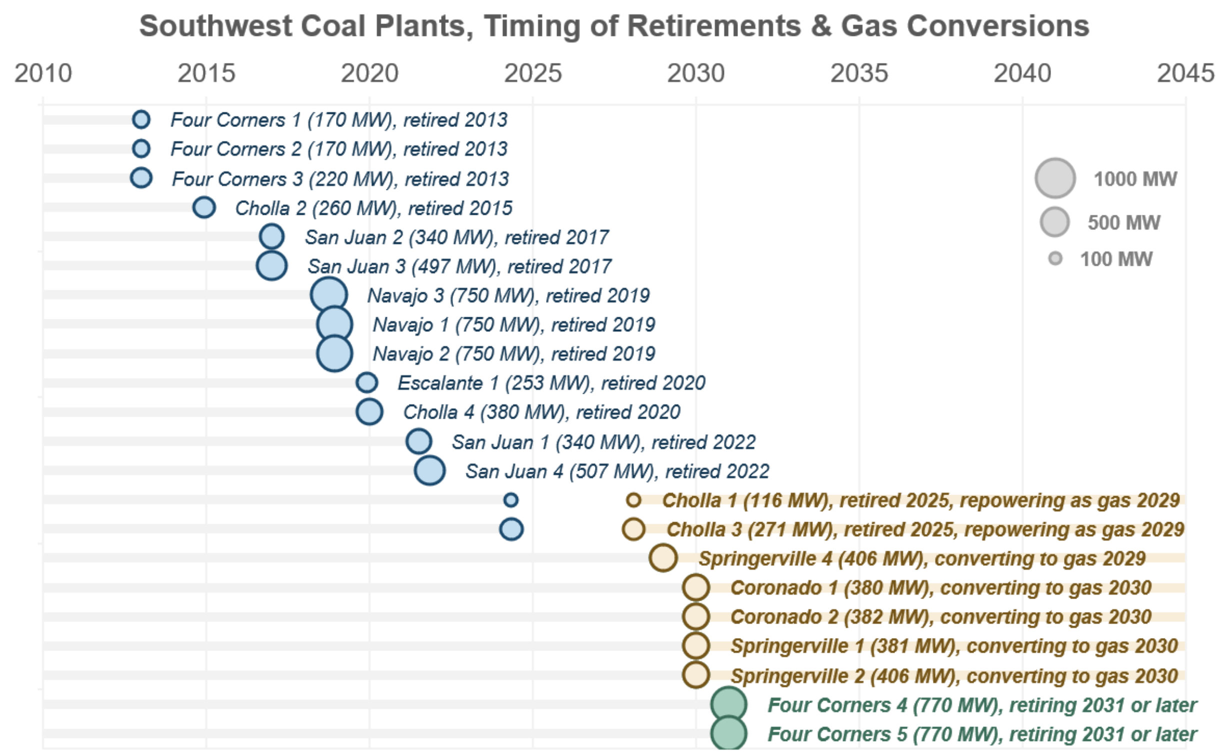
In addition to driving procurement of new resources, the region's growing capacity needs have also prompted utilities to reevaluate plans to retire aging baseload generators. In the past two years, several of the region's largest utilities have announced plans to convert coal-fired power plants to natural gas rather than retire them, preserving the firm capacity those resources provide. Announced plant conversions announced:

- Coronado Units 1 and 2 (762 MW), previously scheduled for retirement by 2032, now planned for conversion to natural gas by 2030;
- Springerville Units 1, 2, and 4 (1,193 MW), previously scheduled for retirement at various points, now planned for conversion to natural gas by 2030; and
- Cholla Units 1 and 3 (380 MW), retired in 2025 and now planned for repowering by 2029.

Together, these plants represent over 2,000 MW of capacity previously scheduled for retirement. Figure 0-1 provides a more complete picture of both historical and future plans for retirement and conversion of coal plants across the Southwestern region, highlighting the sharp recent transition towards natural gas conversion projects as a means of preserving capacity at existing plant sites.

[21] https://feature.wecc.org/2026-sra/index.html

FIGURE 0-1. HISTORICAL AND FUTURE TIMING OF COAL PLANT RETIREMENTS AND NATURAL GAS CONVERSIONS IN THE SOUTHWEST US



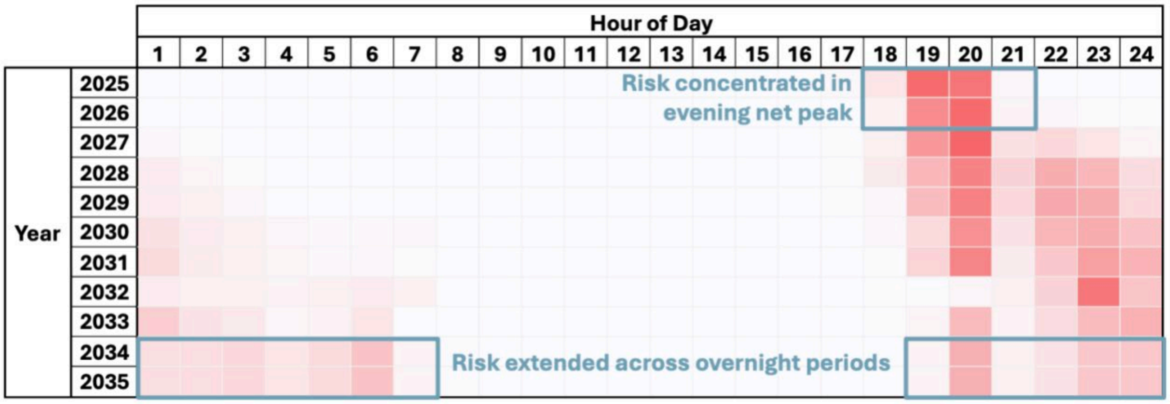
6.2.2 SHIFTING RELIABILITY RISKS

Challenges to system reliability are also evolving as the resource mix changes. Historically, reliability planning focused on ensuring sufficient capability to meet demand during peak periods. Rapid increases in the penetrations of variable resources – particularly solar – across the region cause the periods of highest reliability risk to shift into the "net peak" period, which typically occurs during the evening hours during or after sunset.

E3's 2025 Southwest RA Study provides an indication of how these patterns may change over the next decade. Figure 0-2, reproduced from that report, shows the year-by-year progression of relative reliability risks by hour of the day across the region based on utilities' recent resource plans. Several observations are notable and relevant to PNM's planning:

- **Near-Term (Current Risk):** Due to the large-scale of additions of solar resources, the greatest reliability risks in the region have already shifted to the early evening hours.
- **Medium-Term (Storage Exhaustion):** Within the next several years, as the penetration of storage resources increases, risks may begin to materialize even later in the nighttime period on days when the state of charge from those resources is exhausted.
- **Long-Term (Energy-Constrained System):** By the mid 2030s, utilities' continued additions of renewables and storage will result in risk periods that span the entirety of the overnight period, reflecting a system that is "energy-constrained" outside of daylight hours.

FIGURE 0-2. SHIFTING RELIABILITY RISK BY HOUR OF DAY IN THE SOUTHWEST REGION, 2025-2035
Source: E3, 2025 Resource Adequacy Assessment, Desert Southwest. Reproduced with permission.



This regional progression closely mirrors the risk evolution identified in PNM's planning. As described in PNM's 2023 IRP:

> *"Today, the most prevalent periods of reliability risk (or "loss of load risk") occur in the late summer evenings, as the sun sets and demand for power is still high. As the system evolves, these patterns of loss of load risk will start to shift later in the evening and eventually may migrate to the winter season."*

This parallel has several direct implications for PNM's planning:

- **Operational Alignment:** The seasons and hours of day when PNM faces heightened reliability risks closely align with the region's broader reliability risk profile. Consequently, PNM's tightest load-resource periods coincide with periods of peak wholesale market prices and reduced market liquidity. Maintaining planning assumptions that limit over-reliance on unspecified market purchases will be essential to protecting customers from reliability and cost exposure.

- **Analytical Rigor:** Employing probabilistic modeling across all 8,760 hours of the year (a practice PNM has maintained since its 2017 IRP) is widely recognized as industry best practice and remains critical for robust long-term planning. Aligning need determination and resource accreditation methodologies (such as ELCC) with this framework ensures the identification of least-cost portfolios that fully satisfy PNM's near- and long-term reliability requirements.

These dynamics highlight the importance of a resource adequacy planning paradigm that accounts for risks that may occur at all times of the year and not only during the historical peak period.

6.2.3 EXTREME WEATHER EVENT RISK

[This subsection is currently being drafted]

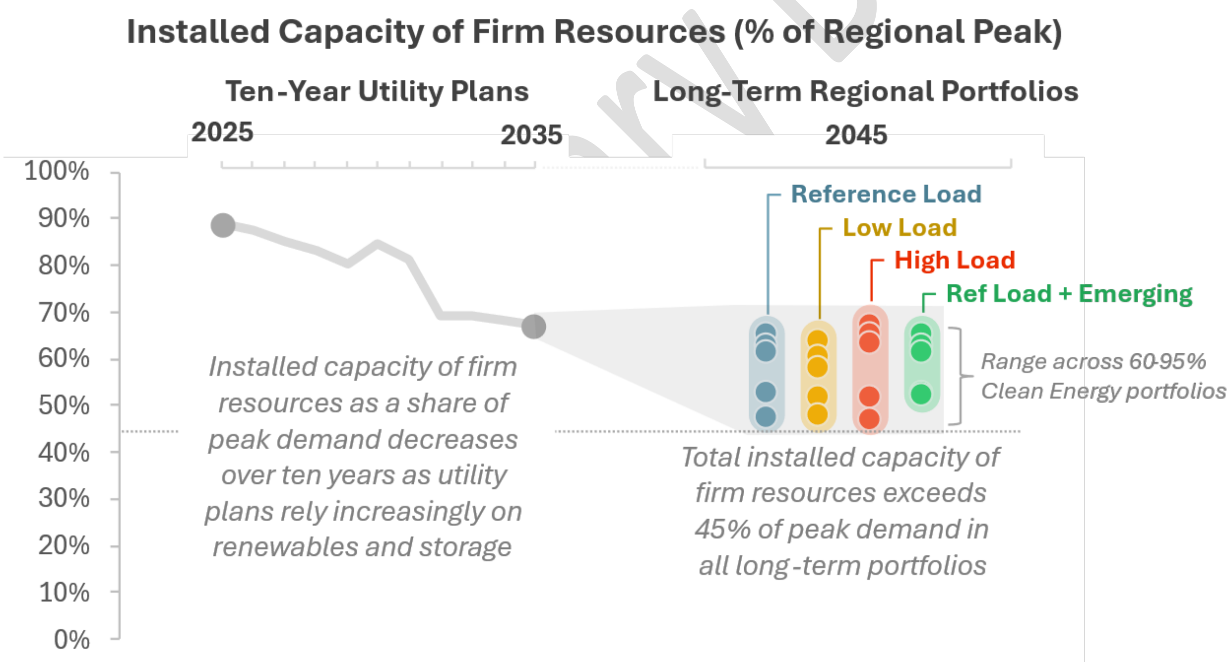
6.2.4 IMPORTANCE OF FIRM RESOURCES

The shifting risk profile and the declining marginal value of renewables and storage has an important corollary: to ensure reliability even during extended periods of low renewable production, some form of firm generating resource (a resource capable of generating at full capacity over sustained periods of time) is needed as a complement to renewable and short-duration storage resources. This tenet is one of the key findings of E3's 2025 Southwest RA study:

> *"Firm generation resources remain essential to ensuring long-term resource adequacy. Even as renewables and storage serve growing energy needs, their firm capacity contributions decline over time as more are added to the system. To mitigate the risk of energy deficiencies during periods of low renewable output, firm resource options capable of producing energy on demand across sustained periods are necessary."*

Figure 0-3, reproduced from E3's study based on detailed reliability analysis of the Southwest region, provides a useful indication of the scale of potential long-term firm resource needs: across a range of long-term load forecasts and resource mixes – including penetrations of carbon-free resources reaching 95% of annual energy demand – the installed capacity of firm resources needed to ensure reliability varies between 45-70% of peak demand.

FIGURE 0-3. PENETRATION OF FIRM RESOURCES IN SOUTHWEST UTILITY PORTFOLIOS
Source: E3, 2025 Resource Adequacy Assessment, Desert Southwest. Reproduced with permission.



These findings add to a growing body of literature studying the challenges and reliability risks of electricity systems at very high penetrations of renewables and energy storage, presented in Table 0-3. Consistent with these findings, PNM's 2023 IRP identified "firm generating resources" (or "FGR") as one of three broad categories of generation needed to meet growing electricity demands while maintaining reliability. As defined in the 2023 IRP, these are resources "…with the capability to operate at or near full capacity for extended periods of time that will allow PNM to maintain reliability even under the most constrained conditions in the system, which may include both periods of high demand as well as periods of low output from variable resources."

TABLE 0-1. SURVEY OF STUDIES EXAMINING CONTRIBUTIONS OF FIRM RESOURCES TOWARDS RESOURCE ADEQUACY

Study	Key Observations
Long-Run Resource Adequacy under Deep Decarbonization Pathways for California[22] **(E3, 2018)**	"This study demonstrates that it is possible to maintain resource adequacy for a deeply decarbonized California electricity system that is heavily dependent on renewables and electric energy storage ***as long as sufficient firm capacity is available for periods of sustained low solar production***."
Clean Firm Power is the Key to California's Carbon-Free Energy Future[23] **(Environmental Defense Fund & Clean Air Task Force, 2021)**	"…squeezing out the last increments of carbon from power generation while ***maintaining affordability and reliability will require clean firm power***."
The Moonshot 100% Clean Electricity Study: Assessing the Tradeoffs Among Clean Portfolios with a PNM Case Study[24] **(GridLab, 2023)**	Although winter demand is low relative to summer demand, there are sustained multi-day periods where solar and wind resources cannot fully meet load, even with battery storage. During this period, low levels of wind and solar in neighboring regions limits clean imports, except during mid-day hours when solar is highest. In these conditions, ***hydrogen CTs or alternative clean firm resources are required to meet demand***.
LA100: The Los Angeles 100% Renewable Energy Study[25] **(NREL, XXXX)**	"[n]ew in-basin renewable ***firm capacity*** – resources that use renewably produced and storable fuels, can come online within minutes, and can run for hours to days – ***is a key element of maintaining reliability*** at least cost…"
Getting to 100%: Six strategies for the challenging last 10%[26] **(Mai, T., et al, 2021)**	"To fill the capacity gap, ***a solution needs to be reliably available during high-stress periods***. There are many terms used to characterize such a technology, including ***'firm' capacity resource***, peakers, and technology with high capacity credit—where capacity credit is the fraction of nameplate capacity that can be reliably counted toward planning reserves or similar resource adequacy measures… For very high [renewable energy] systems, such a solution needs to be available for different response durations, including multi-day periods of low [variable renewable energy] output."
The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation[27] **(Sepulveda, N., et al, 2018)**	"…even in regions with abundant renewable resources, ***firm low-carbon resources can lower the cost of deep decarbonization significantly***, even if the firm resources have much higher levelized costs than do variable renewables, and even if very-low-cost battery energy storage technologies are available."

[22] https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf
[23] https://www.edf.org/sites/default/files/documents/LongCA.pdf
[24] https://gridlab.org/wp-content/uploads/2023/08/GridLab_Moonshot-Study_Report.pdf
[25]
[26] https://doi.org/10.1016/j.joule.2021.03.028
[27] https://doi.org/10.1016/j.joule.2018.08.006

6.2.5 Regional Resource Adequacy Programs

In response to ongoing and anticipated resource adequacy challenges across the region, a variety of entities across the Western region have been engaged in efforts to develop regional resource adequacy programs. A regional resource adequacy program's value lies in providing transparent visibility into whether the region is collectively procuring enough resources to reliably serve load under stressed conditions. It also helps align planning metrics among neighboring utilities, including how capacity is counted, how deliverability is demonstrated, and how uncertainty, outages, load risk, and resource performance are reflected. Common metrics build trust by showing that each entity brings sufficient resources to market rather than relying on others, which can improve confidence, liquidity, and dispatch efficiency while lowering costs for customers.

The first of these efforts was the Western Resource Adequacy Program (WRAP), an initiative begun by the Western Power Pool in 2019. PNM participated in WRAP's non-binding phase, gaining experience with forward showings, common resource-counting concepts, and regional visibility into capacity positions. In Q4 2025, PNM and several other EDAM participants elected to leave WRAP ahead of binding obligations to pursue options more closely aligned with emerging wholesale market footprints:

> *"This decision follows careful consideration of several factors, most notably the emergence of two day-ahead markets in the West: the CAISO Extended Day-Ahead Market (EDAM) and SPP Markets+ (M+). Given these developments, PNM believes it is prudent to pursue resource adequacy programs aligned with each market, consistent with practices in other ISO/RTOs."*[28]

A similar effort is now underway to design a regional resource adequacy program for EDAM participants. As of July 2026, public stakeholder processes are evaluating how resource adequacy obligations, forward showings, deliverability requirements, and market participation rules could align with the EDAM footprint. PNM is actively participating in this design and stakeholder process.

Over time, if successful, a regional program could strengthen the analytical basis for evaluating planning reserve margins and resource investment needs. As regional data becomes more transparent and comparable across a larger set of loads, resources, and weather conditions, utilities and regulators may be better able to assess how regional diversity, deliverability, and correlated risk affect resource adequacy. This information could help refine reserve estimates and reduce unnecessary duplicative investment while preserving each utility's obligation to plan for and procure adequate resources for its customers.

6.3 2026 Resource Adequacy Study

PNM follows the industry standard approach of meeting a planning reserve margin (PRM), above forecasted peak demand, to ensure resource adequacy, accounting for extreme weather, outages, and operating reserve requirements. In the EnCompass model, the PRM is set to determine the amount of accredited capacity needed to meet PNM's reliability standard, which is

---

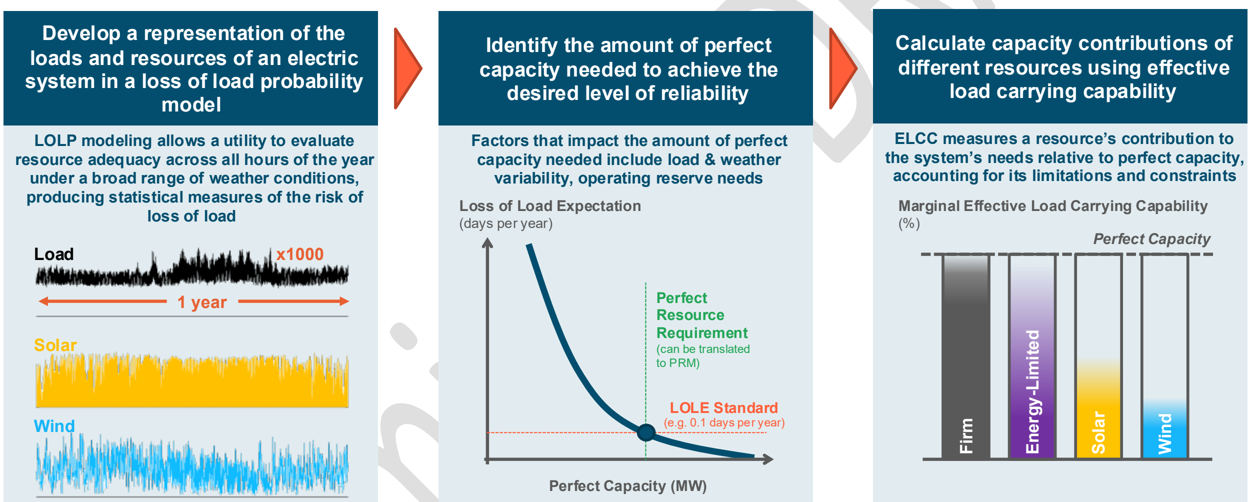
[28] https://www.westernpowerpool.org/private-media/documents/WRAP_-_PNM_Withdraw_Letter_-_10.28.25.pdf

then verified using SERVM. Over time, the PRM and resource accreditation have evolved as the industry changes in response to increasing penetrations of variable resources and storage, as well as extreme weather, shifting the periods of highest reliability risk.

6.3.1 Background & Key Concepts

Best practices in planning for resource adequacy involve three related steps: probabilistic reliability modeling, need determination, and capacity accreditation. As shown in Figure 0-4, loss-of-load probability modeling first represents hourly load, renewable production, and resource availability across many potential system conditions. That modeling is then used to identify the amount of perfectly available capacity needed to meet the applicable reliability standard, which can be translated into a PRM. Finally, individual resources are credited toward that need based on their effective load carrying capability, so each resource's accredited capacity reflects its expected contribution to reliability during periods of system risk.

Figure 0-4. Best practices for resource adequacy: need determination and capacity accreditation
Source: E3, 2025 Resource Adequacy Assessment, Desert Southwest. Reproduced with permission.



Loss of Load Probability Modeling

Best practices in resource adequacy planning continue to evolve, but broad consensus exists that a robust approach must evaluate the possibility that load shedding due to insufficient resources could occur at times outside of the traditional peak period. As described in a recent whitepaper published by the ESIG:

> *"Modeling sequential grid operations is critical to capture the whole picture: the variability of wind and solar resources along with the energy limitations of storage and load flexibility. Chronological stochastic analysis is thus increasingly important, simulating a full hour-to-hour dispatch of the system's resources for an entire year of operation across many different weather patterns, load profiles, and random outage draws."*

This line of thinking has heavily influenced PNM's continued efforts to refine its reliability planning approaches over the past several IRP cycles. Consistent with recommendations from ESIG and WECC, PNM continues to rely primarily on LOLP modeling within its portfolio planning process to (1) derive a planning reserve margin (PRM) requirement and technology-specific effective load carrying capability (ELCC) values for capacity accreditation, and (2) quantify reliability statistics for various resource portfolios based on their performance across the full range of conditions throughout the year. The methods for developing a portfolio that meets these objectives for reliability while accounting for risks that may manifest throughout the year are described further in Section.

Planning Reserve Margin

The planning reserve margin ("PRM") represents the amount of capacity needed above forecasted peak demand to satisfy a specified resource adequacy standard. PNM derives the PRM through loss-of-load probability ("LOLP") modeling, which evaluates the amount of capacity needed to maintain reliability across a range of load, weather, resource availability, and operating conditions. At a high level, the PRM accounts for uncertainty and potential variance in system conditions, including the possibility that peak demand is higher than expected, weather conditions differ from normal planning assumptions, or operating reserve requirements increase the amount of capacity that must be available to reliably serve load.

Historically, many utility planning frameworks expressed the PRM using an installed capacity ("ICAP") accounting convention. Under that convention, conventional resources were generally counted at their full nameplate or seasonal-rated capacity, and the PRM itself embedded several categories of reliability risk, including load variability, operating reserve requirements, and forced outages. This approach provided a practical reserve-margin framework for portfolios dominated by conventional generating resources, but it becomes less transparent as portfolios add larger amounts of variable renewable resources, storage, hybrid resources, and demand-side resources.

Utilities and regional planning entities are increasingly shifting toward accounting conventions in which resource unavailability is reflected through resource-specific capacity accreditation rather than embedded entirely in the reserve margin. Under this approach, forced outages, weather-dependent production profiles, storage duration limits, and other resource-specific availability characteristics are applied as derates to the capacity value of each resource. The PRM then represents the system-level margin needed above forecasted peak demand, while effective load carrying capability (ELCC) – discussed in greater depth below – determines how much each resource counts toward that requirement.

Today, best practice is to use LOLP modeling to derive the PRM based on a benchmark of perfectly available capacity through a "tuning" process, whereby the target PRM is determined by iteratively solving for how much capacity would enable a system to achieve the desired standard. In that framework, the PRM primarily reflects load variability, weather-driven uncertainty in demand, operating reserve requirements, and other system-level planning uncertainties. Actual resources are then credited against the PRM requirement based on their accredited capacity value.

Effective Load Carrying Capability

All resources do not provide equivalent contributions to meeting the planning reserve margin. Each resource's contribution depends on the various factors that impact its availability when it may be needed to meet system needs, which vary across technologies. For instance:

- Variable resources like wind and solar experience fluctuations in output as a result of uncontrollable meteorological conditions and diurnal cycles, meaning that their available capacity is often lower than their maximum capacity during critical periods;
- Energy storage resources have finite limits on how long they can discharge based on their rated duration;
- Firm resources are generally available at seasonal rated capacity except when experiencing a forced outage rate.

Measuring the relative contributions of each resource in a manner that accounts for these limitations requires the use of "effective load carrying capability" (ELCC) to count capacity towards the requirement (a practice known as "capacity accreditation"). ELCC is a statistical measure of a resource's contribution to resource adequacy measured relative to a benchmark of theoretical "perfect" capacity. This concept and its linkage to LOLP modeling is described in a recent E3 whitepaper on resource adequacy:

> *"ELCC is a natural extension of LOLP modeling, measuring the change in total capacity provided by a portfolio of resources from adding or subtracting a quantity of an individual resource type. ELCC measures the capacity contribution from adding resources individually or in combination, providing a means to send efficient signals for investment in each resource type based on the marginal contributions it makes toward the portfolio's ability to avoid loss of load."*[29]

ELCC (and similar concepts) are now widely used by utilities, resource adequacy programs, and capacity markets for capacity accreditation. It has become the *de facto* preferred method for multiple related reasons:

- ELCC reflects resource availability during critical periods, regardless of when they may occur.
- **ELCC provides an economically efficient signal for investment in new resources.** By using a marginal ELCC methodology to assign capacity credits to new resources, planners may identify the least-cost portfolio to satisfy a given resource adequacy criteria.
- **ELCC captures the complex phenomena** that have been identified across the growing body of research into emerging resource adequacy challenges. These include saturation effects, complex interactive effects among technologies, and asymmetric risks. These phenomena, and how they are captured in ELCC calculations, are described in Table 0-4.

TABLE 0-2. DESCRIPTION OF PLANNING CHALLENGES CAPTURED IN THE ELCC METHODOLOGY

Phenomenon	Reflection in ELCC Calculations
Saturation effects: Individual resources decrease in effectiveness as their penetrations grow and system risks shift (e.g. value of additional solar declines as risk shifts from peak to net peak period)	ELCC curves for individual resources show declining marginal value with successive increments of capacity

[29] https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf

Interactive Effects: Complementary resources contribute more to system needs than the sum of their individual parts (e.g. solar and storage are a complementary pair)	ELCC calculations for combinations of resources can account for "diversity benefits" of complementary resources, which may be rendered in a multidimensional ELCC function
Asymmetric Risks: Resource adequacy risks tend to cluster during periods of higher-than-normal plant outages (e.g. large or numerous thermal outages can be a driver of loss-of-load risk)	Calculated ELCC values derate capacity credits based on availability during critical periods, which may be lower than average availability

6.3.2 Methodology Highlights

PNM's 2026 resource adequacy study, conducted by PowerGEM using the SERVM loss-of-load-probability (LOLP) model, includes two distinct elements: (1) calculation of a planning reserve margin requirement consistent with PNM's planning standard, equal to an LOLE of 0.1 days per year (or "one day in ten year"); and (2) calculation of effective load carrying capability values used to count resources towards the PRM requirement. The methods used in this study are aligned with industry best practices as described above and consistent with previous resource adequacy studies supporting PNM's IRPs. Input data and assumptions have been refreshed for consistency with planning assumptions used in this IRP, and PowerGEM has also made extensive updates to the representations of neighboring electricity systems to reflect planning assumptions contemporaneous with this IRP. These data and assumptions are documented more completely in Appendix [ ].

While the methods used herein are largely consistent with previous IRPs, PNM continues to incorporate improvements in the methods used to ensure resource adequacy planning. The 2026 resource adequacy study includes three such enhancements, each of which is described in further detail below: (1) application of ELCC to thermal resources, (2) incorporation of seasonal import limits, and (3) novel methods for accounting for solar and storage interactive effects.

Application of ELCC to Thermal Resources

PNM's approach to capacity accreditation for thermal resources has evolved progressively in a manner that has increasingly improved alignment with the methods used for renewable and storage capacity accreditation.

- Prior to the 2020 IRP, PNM relied on a PRM accounting convention known as the "Installed Capacity (ICAP) convention for thermal resources. Under this convention, all firm resources were counted towards the requirement at their full rated capacity, and a portion of the PRM requirement itself accounted for the possibility that some portion of that fleet would be unavailable when needed due to forced outages. This simple approach was widely used by utilities historically, when the large majority of resources on the electric system were "firm" resources that could be dispatched at maximum capacity when needed.
- In the 2020 and 2023 IRP, PNM transitioned to the use of an "Unforced Capacity" (UCAP) methodology, where the capacity accredited to each thermal resource was derated by its expected forced outage rate. The purpose of this adjustment was to better

align the conventions used to accredit thermal resources with the ELCC approach applied to renewable and storage resources.

- In the 2026 IRP, PNM has transitioned from the UCAP approach to use of ELCC for thermal resources, harmonizing the capacity accreditation methods used across thermal, renewable, and storage resources. The application of an ELCC approach to thermal resources typically yields lower capacity values than the UCAP approach, a reflection of the fact that reliability events are more likely to occur during periods when the quantity of capacity experiencing forced outages is larger than average.

The transition to use of ELCC for thermal resource capacity accreditation provides for the most consistent accounting of capacity across technologies and ensures a level playing field when considering the relative effectiveness of all new resources in meeting PNM's future capacity needs.

Seasonal Import Limits

One of the key assumptions that impacts both the PRM requirement and the ELCC calculations for existing and new resources is the representation of "market assistance," representing PNM's ability to purchase electricity from other utilities in the region to meet a portion of its own needs.

Historically, the characterization of market assistance limits has focused on the summer season, the periods of greatest historical risk. In the 2020 and 2023 IRPs, PNM's resource adequacy planning studies incorporated an import limit of 50 MW during summer net peak hours. This limit was determined based on real-world operating conditions during the summer of 2020, when west-wide heat waves resulted in tight conditions across the Western Interconnection.

The roundtrip resource adequacy analysis conducted in the 2023 IRP revealed that with higher penetrations of renewables and storage, loss of load risk could eventually migrate to winter season:

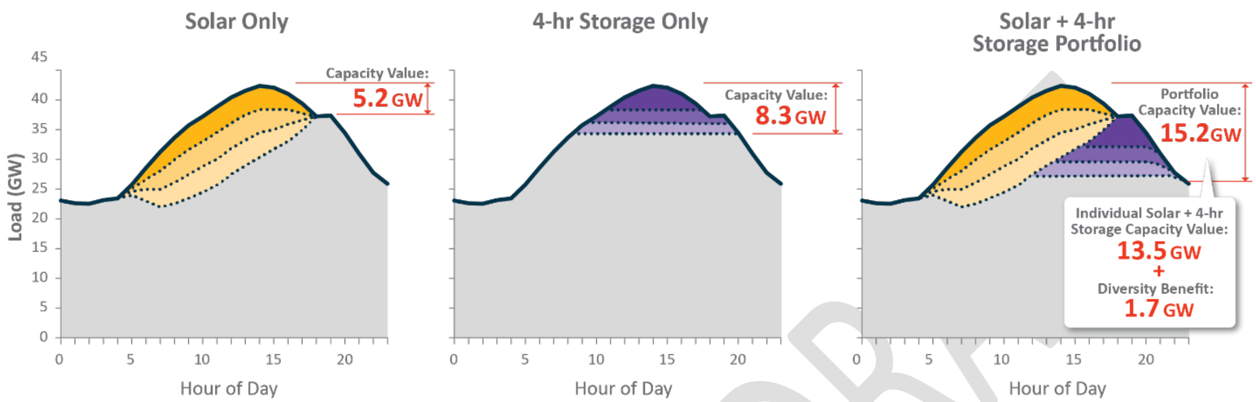
> *"Today, the most prevalent periods of reliability risk (or "loss of load risk") occur in the late summer evenings, as the sun sets and demand for power is still high. As the system evolves, these patterns of loss of load risk will start to shift later in the evening and eventually may migrate to the winter season…. In [the All Technologies] scenario, the predominant periods of loss of load risk are (1) in the summer evenings, stretching all the way to the early morning hours; and (2) in the winter mornings before sunrise."*

This finding prompted a need for a critical review of import availability during winter months. Based on historical operational data, PNM and PowerGEM developed a winter import limit profile, limiting imports to 250 MW during overnight hours and 800 MW during daylight hours. This winter limit has been incorporated into all resource adequacy studies, along with the 50 MW limit during summer net peak hours.

Updated Treatment of Solar-Storage Interactive Effects

In summer peaking systems like PNM, solar and storage resources complement one another in contribution to system resource adequacy needs: the two resources in combination provide more effective capacity than the sum of their individual contributions. This effect, illustrated in Figure 0-5, can be understood as the result of the fact that increasing penetrations of solar shorten the time period across which storage resources must operate, allowing those resources to be used more effectively during critical periods. The effect has been identified in multiple studies, including the resource adequacy study completed in support of PNM's 2023 IRP.

FIGURE 0-5. COMPLEMENTARITY OF SOLAR AND STORAGE TO MEETING RESOURCE ADEQUACY NEEDS
Illustrative figure, reproduced with permission from E3, Capacity and Reliability Planning in the Era of Decarbonization



While the effect itself has been established, capturing this relationship dynamically within IRP planning tools is a computational challenge. EnCompass, the capacity expansion model used by PNM, currently includes functionality that allows for dynamic ELCC curves for each resource, where the capacity credit of a single resource (e.g. solar) changes as a function of its penetration; however, it does not allow for that capacity credit to change endogenously as a function of the penetration of other resources (e.g. storage) on the system.

To account for these interactive effects with these limitations, PNM has incorporated improvements in the scope and outputs of the resource adequacy study over successive study cycles, enabling improvements in the approximation of the interactive effects:

- In the 2020 IRP, no complementary interactive effects between new solar and storage resources were captured in the modeling; each resource was modeled with an independent ELCC curve. This approach was criticized by stakeholders, who cited the lack of consideration of interactive effects as one of the reasons that PNM's 2040 resource portfolios showed LOLE results below 0.1 days per year.
- In the 2023 IRP, to improve accounting of interactive effects, PNM incorporated ELCC curves for each technology that change over time that captured *assumed* changes in underlying portfolio: in the near-term, the storage ELCC curve was calculated relative to a system with 1,500 MW of solar; in the medium-term, the curve was recalculated relative to a system with 2,000 MW of solar; and in the long-term the curve was recalculated assuming 2,500 MW of solar. This approach allowed PNM to capture higher capacity contributions for storage resources over time, but resulted in sharp transitions in capacity accreditation in PNM's loads and resources at the transition points between the curves.

18. The 2026 IRP incorporates a novel approach for capturing these interactive effects, whereby the ELCC curve for storage is calculated *assuming* that solar resources are

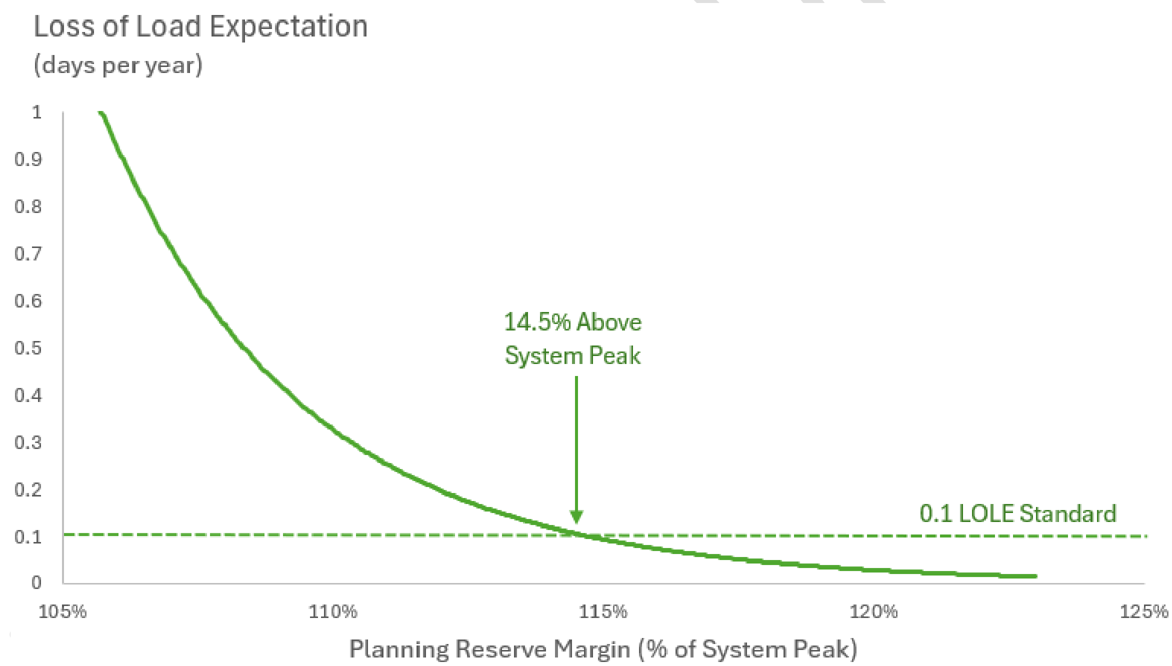
also added to the system at a two-to-one ratio.[30] This approach allows PNM to derive and apply a single ELCC curve for storage resources across the planning horizon that simultaneously captures the complementarity of solar and storage additions across the horizon.

6.3.3 Key Results

Planning Reserve Margin Requirement

The 2026 Resource Adequacy study indicates that a **14.5% target planning reserve margin** (target PRM) is sufficient to satisfy the LOLE standard of 0.1 days per year. Applying this target PRM ensures capacity expansion modeling builds sufficient resources in each year to meet this standard. Figure 0-6 shows the illustrative relationship between planning reserve margin and the resulting level of reliability (lower levels of planning reserves translate to higher frequency of loss of load).

Figure 0-6. Relationship between LOLE and Planning Reserve Margin



The Resource Adequacy study also includes a calculation of the accredited capacity of resources included in PNM's current portfolio using a 2029 base year, which can be used to determine PNM's initial position when comparing to system projected peak demand. These values capture the technology-specific characteristics and limitations of each type of resource, reflecting their performance during the periods when they are needed by the system. The results of this analysis, shown in Table [ ] capture important differences in the contributions by technology type to meet PNM's resource adequacy needs:

[30] This relative rate of additions is based on previous IRP modeling showing solar and storage added to the system at approximately this ratio across a wide range of scenarios.

- Most firm dispatchable resources, such as nuclear and natural gas, generally exhibit high ELCCs (over 90%), reflecting the fact that these units can be operated at maximum capacity to serve loads when needed except in the event of rare forced outage events. The comparatively lower ELCCs for coal and geothermal resources are a result of higher forced outage rates (over 20%).
- Energy-limited dynamic balancing resources (battery storage and DR) exhibit moderately high ELCCs, reflecting the fact that while these resources can generally be dispatched when needed, their finite limits on how long they can operate temper their accredited capacity.
- Variable resources (solar and wind) show comparatively low ELCCs (under 20%), largely due to their highly variable output and non-coincidence with system critical hours.

TABLE [ ]. ELCC VALUES FOR PNM'S EXISTING RESOURCE PORTFOLIO
Includes existing resources, approved new resources, and new resources pending approval through 2029

Unit Category	Installed MW	ELCC %	Accredited MW
Nuclear	288	94%	271
Coal	200	72%	143
Natural Gas CC	425	92%	393
Natural Gas CT	614	98%	602
Natural Gas ST	145	92%	133
Geothermal	11	76%	8
Wind	1,408	12%	169
Solar	2,412	19%	458
Battery	1,950	75%	1,471
Demand Response	70	63%	44

These values are applicable to PNM's current portfolio of resources; ELCCs for incremental additions vary by technology due to saturation effects and interactions with other resources on the system. The ELCC curves applied to new technologies, also produced within this study, are discussed in SECTION XX (NEW RESOURCE OPTIONS).

6.4 Existing System Load-Resource Balance

The outputs from the resource adequacy study presented above provide the basis for the derivation of PNM's initial loads and resources table, which compares PNM's total capacity needs (peak demand plus the PRM) against the accredited capacity provided by the resources currently in its portfolio. For clarity, resources are subdivided into three groups: (1) existing resources that are in service at the time of the IRP's publication; (2) new resources that have been approved by

NMPRC and are currently under development; and (3) proposed new resources that have not yet been approved by NMPRC**.** shows the load-resource balance over time across the three primary load forecasts developed for the IRP. For each of these load forecasts, the gap between the peak demand plus PRM and the accredited capacity provided by the current portfolio represents the additional amount of accredited capacity that would be needed to ensure resource adequacy. The timing of when new capacity resources varies according to the pace of load growth:

- Under the CTP future, this need for new capacity emerges in the early 2030s;
- In the HEG forecast, additional capacity is needed as soon as 2027; and
- In the LEG forecast, additional capacity is not needed until roughly 2040.

Table 0-5 provides additional detail on PNM's loads and resources, including existing resources, approved new resources, and new resources pending approval. Due to load growth, resource retirements, and contract expirations, the current portfolio is insufficient to meet PNM's long-term resource adequacy needs; a capacity deficit emerges in 2035 and increases to over 2,000 MW by 2045. In most years, the capacity need grows by less than 50 MW due to ongoing assumed load growth; larger increases occur upon specific unit retirements or contract expirations, including:

- Expiration of the Valencia PPA extension in 2040;
- Retirements of Afton, Luna, and Rio Bravo by 2045;
- Expiration of a number of existing wind, solar, and storage PPAs in the early 2040s; and
- Assumed retirement of Palo Verde Unit 1 at the end of its current license (2045).

TABLE 0-3. CURRENT SYSTEM LOAD-RESOURCE BALANCE UNDER CTP LOAD FORECAST

All values in megawatts; resources accredited using an ELCC methodology; PRM requirement of 14.5%

Year	Existing Resources	Approved New Resources	New Resources Pending Approval	Total Resources	Peak Demand	Peak Demand + PRM	Capacity Position
2026	2,572	0	0	2,572	2,250	2,576	(4)
2027	2,572	163	0	2,736	2,448	2,803	(67)
2028	2,736	426	0	3,162	2,641	3,024	138
2029	2,829	426	440	3,694	3,082	3,529	165
2030	2,787	426	440	3,652	3,124	3,577	75
2031	2,643	426	636	3,705	3,136	3,591	114
2032	2,640	426	636	3,703	3,152	3,609	94
2033	2,638	426	636	3,700	3,188	3,650	50
2034	2,635	426	636	3,698	3,218	3,685	13
2035	2,626	426	636	3,689	3,238	3,708	(18)
2036	2,618	426	636	3,680	3,254	3,726	(46)
2037	2,615	426	636	3,678	3,278	3,753	(75)
2038	2,613	426	636	3,676	3,312	3,792	(117)
2039	2,611	426	636	3,673	3,360	3,847	(174)
2040	2,445	426	636	3,507	3,391	3,883	(375)
2041	2,405	426	636	3,468	3,420	3,916	(448)
2042	2,403	426	636	3,466	3,461	3,963	(497)
2043	2,175	426	636	3,238	3,500	4,008	(770)
2044	1,574	426	636	2,637	3,562	4,078	(1,441)
2045	773	426	636	1,835	3,604	4,127	(2,291)

Table 0-6 shows PNM's loads and resources under the HEG forecast. This load forecast, which is approximately 200 MW higher than the CTP forecast in 2026 and increases at a faster rate, experiences an immediate capacity deficit. Through 2031, that deficit remains relatively stable with planned resource additions. Thereafter it increases at a rapid rate, reaching roughly 500 MW by 2035, 1,000 MW by 2040, and surpassing 3,000 MW by the end of the modeling horizon.

TABLE 0-4. CURRENT SYSTEM LOAD-RESOURCE BALANCE UNDER HEG LOAD FORECAST

All values in megawatts; resources accredited using an ELCC methodology; PRM requirement of 14.5%

Year	Existing Resources	Approved New Resources	New Resources Pending Approval	Total Resources	Peak Demand	Peak Demand + PRM	Capacity Position
2026	2,572	0	0	2,572	2,414	2,764	(192)
2027	2,572	163	0	2,736	2,639	3,022	(286)
2028	2,736	426	0	3,162	2,844	3,256	(94)
2029	2,829	426	440	3,694	3,331	3,814	(120)
2030	2,787	426	440	3,652	3,405	3,899	(246)
2031	2,643	426	636	3,705	3,447	3,947	(242)
2032	2,640	426	636	3,703	3,491	3,997	(294)
2033	2,638	426	636	3,700	3,558	4,074	(373)
2034	2,635	426	636	3,698	3,619	4,144	(446)
2035	2,626	426	636	3,689	3,671	4,203	(514)
2036	2,618	426	636	3,680	3,719	4,258	(578)
2037	2,615	426	636	3,678	3,778	4,326	(648)
2038	2,613	426	636	3,676	3,850	4,408	(733)
2039	2,611	426	636	3,673	3,932	4,502	(829)
2040	2,445	426	636	3,507	3,994	4,573	(1,066)
2041	2,405	426	636	3,468	4,056	4,644	(1,176)
2042	2,403	426	636	3,466	4,135	4,735	(1,269)
2043	2,175	426	636	3,238	4,212	4,823	(1,585)
2044	1,574	426	636	2,637	4,318	4,944	(2,307)
2045	773	426	636	1,835	4,398	5,036	(3,200)

Table 0-7 shows PNM's loads and resources under the LEG forecast. This forecast is roughly 200 MW lower than the CTP forecast in 2026 and grows at a very slow rate in most years. As a result, PNM's current portfolio of resources – including assumed new resource additions – is sufficient to meet reliability needs through 2043. The subsequent retirement of a substantial portion of PNM's existing gas resources results in the emergence of a large capacity need in the final two years of the horizon.

TABLE 0-5. CURRENT SYSTEM LOAD-RESOURCE BALANCE UNDER LEG LOAD FORECAST

All values in megawatts; resources accredited using an ELCC methodology; PRM requirement of 14.5%

Year	Existing Resources	Approved New Resources	New Resources Pending Approval	Total Resources	Peak Demand	Peak Demand + PRM	Capacity Position
2026	2,572	0	0	2,572	2,026	2,320	253
2027	2,572	163	0	2,736	2,078	2,379	356
2028	2,736	426	0	3,162	2,130	2,439	723
2029	2,829	426	440	3,694	2,523	2,889	806
2030	2,787	426	440	3,652	2,565	2,937	715
2031	2,643	426	636	3,705	2,616	2,995	710
2032	2,640	426	636	3,703	2,624	3,004	698
2033	2,638	426	636	3,700	2,640	3,023	678
2034	2,635	426	636	3,698	2,648	3,032	666
2035	2,626	426	636	3,689	2,652	3,037	653
2036	2,618	426	636	3,680	2,653	3,038	642
2037	2,615	426	636	3,678	2,662	3,048	630
2038	2,613	426	636	3,676	2,678	3,066	609
2039	2,611	426	636	3,673	2,700	3,092	582
2040	2,445	426	636	3,507	2,707	3,100	408
2041	2,405	426	636	3,468	2,718	3,112	356
2042	2,403	426	636	3,466	2,739	3,136	329
2043	2,175	426	636	3,238	2,758	3,158	80
2044	1,574	426	636	2,637	2,794	3,199	(562)
2045	773	426	636	1,835	2,816	3,224	(1,389)

7. ANALYTICAL APPROACH

To achieve the objectives outlined above, PNM relies upon a robust analytical framework that builds upon and enhances the methods used in previous IRPs to conduct an extensive analysis. The focus of this year's plan on the transition to a carbon-free portfolio presents a number of uniquely challenging issues, none more significant or conspicuous than the question of how PNM might achieve this goal while maintaining reliability. To ensure answers to this and other questions are robust, PNM employs sophisticated software to optimize the portfolio while accounting for resource adequacy needs. This section describes these components to help identify the MCEP from the modeling results across a range of evolving system conditions.

7.1 Planning Horizon

The 2026 IRP maps out a long-range framework to maintain a reliable and affordable resource portfolio that meets environmental requirements for PNM's customers over the next 20 years. To ground this framework, PNM had established clear definitions for the key planning horizons in the 2026 IRP:

TABLE 2-1. 2026 IRP PLANNING HORIZONS

The Action Plan Period (2027–2029):

Legally defined by rule as the three-year period following the filing of the IRP, this is the near-term window where PNM carries out specific, concrete implementation efforts tied to the 2026 IRP. Accordingly, implementation activities, such as the potential development and issuance of a future competitive procurement, align with this Action Plan window.

The Focus Period (2033–2036)

A look-ahead period bridging the immediate action plan timeframe and the medium-term horizon. Because new resources and associated system expansion require extensive lead times to design, clear interconnection queues, procure equipment, and construct, PNM must evaluate system requirements further out. The Focus Period represents the target window where resources solicited during the Action Plan Period are scheduled to enter commercial service to address incremental need from resource retirement(s) and/or increasing demand expected during the Focus Period.

The Planning Period (2026–2045)

Legally defined by rule as the 20-year future period for which PNM develops its IRP. This macro-level time horizon is utilized to evaluate long-term system trajectories, statutory clean energy mandates, and lifecycle economic trends.

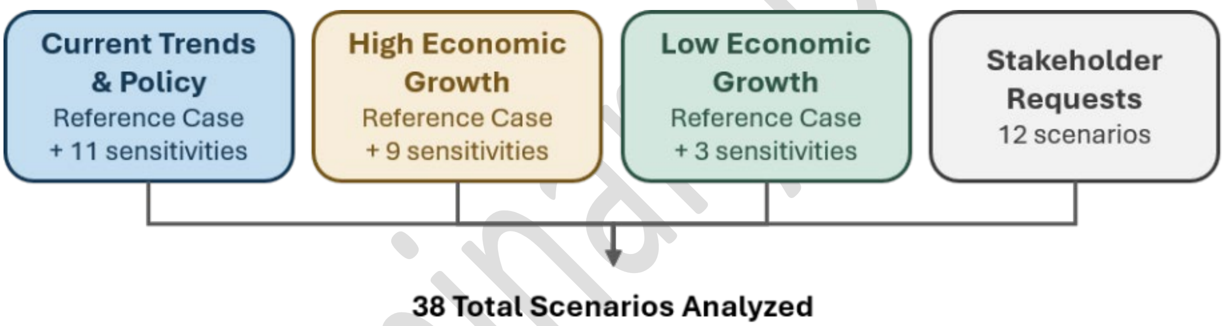
7.2 Scenario Analysis Framework

PNM 2026 IRP applies a scenario analysis framework to create and analyze optimized resource portfolios under a range of future assumptions. The scenarios and sensitivities analyzed explore both (a) how external conditions may impact the least-cost resource portfolios to meet customer needs and policy objectives, and (b) how specific decisions made by PNM could alter the composition of the resource portfolio and impact cost, reliability, and affordability metrics.

The 2026 IRP includes analysis of a total of 38 distinct scenarios and sensitivities, described below and summarized in Figure 5-1:

- **Three core scenarios,** corresponding to the range of demand forecasts presented in Section 3, analyzed under a defined set of standard assumptions;
- **Twelve sensitivities**, each of which alters a specific assumption within the standard assumptions to test its impact upon results, each analyzed under one or more of the core scenarios described above; and
- **Twelve stakeholder scenarios**, whose parameters and assumptions were defined through the collaborative stakeholder process.

FIGURE 5-1. SCENARIO FRAMEWORK USED IN THE 2026 IRP



7.2.1 CORE SCENARIOS

The 2026 IRP focuses on three core scenarios that create a future envelope for potential load growth. In light of the level of uncertainty of potential future large customer growth, this orientation ensures that the learnings and outputs produced by the IRP can continue to provide actionable intelligence to inform decisions even if future updates to the load forecast are needed. Each of the three core scenarios is defined by one of the load forecasts described in Section 3:

- The **"Current Trends & Policy"** future reflects the best estimates of the future state of the world based on the knowledge at the time of the IRP's development. Specifically, in this future, PNM assumes continued economic and population growth within PNM's service territory consistent with trends as forecast by Woods and Poole, as well as modest levels of incremental customer solar and electrification.
- The **"High Economic Growth"** future reflects an alternative assumption of more aggressive future growth of the New Mexico economy. In addition to driving an increase in the growth of electric demands, this future assumes that rapid economic growth also leads to greater levels of customer adoption of electric vehicles. While the HEG future generally incorporates high-growth forecast components, the Low BTM Solar forecast is

utilized because lower levels of customer-sited solar result in higher net system load and are therefore more consistent with the objective of representing a higher load growth future. In combination, these factors increase demand while reshaping its daily patterns.

- The **"Low Economic Growth"** future reflects an alternative assumption of slower economic growth of the New Mexico economy. In contrast to the High Economic Growth future, lower levels of economic growth are assumed to reduce customer adoption of electric vehicles. While the LEG future generally incorporates low-growth forecast assumptions, the High BTM Solar forecast is utilized because higher levels of customer-sited solar reduce net system load and are therefore more consistent with the objective of representing a lower load growth future. In combination, these factors reduce demand while altering the daily load profile.

TABLE 6-1. STANDARD ASSUMPTIONS ACROSS CORE SCENARIOS

Category	Key Assumptions
Financial Assumptions	• Weighted average cost of capital of 6.9% • General inflation of 3%
Resource Adequacy	• Planning reserve margin target of 14.5% • Technology-specific ELCC curves used for capacity accreditation
Carbon and Renewable Targets	• Emissions intensity target of 200 lbs/MWh by 2032 • RPS targets (50% by 2030 and and 80% by 2040) • Carbon-free requirement by 2045
Existing Resources	• Palo Verde online throughout 20-year planning horizon • Four Corners Power Plant exit by end of 2031 • La Luz and Lordsburg units converted to hydrogen fuel beginning in 2045 • Operating life of Reeves Generating Station (146 MW) extended through 2044 • Other existing gas units remain in service through 2044 • Existing PPAs and ESAs expire at contract end
Approved Resources Under Development	• New resources approved in 2026 and 2028 applications included in all portfolios
New Resources Pending Approval	• Preferred Portfolio from 2029-2032 Resource application included in all scenarios • New 172 MW combustion turbine included as a proxy unit in 2029 in all scenarios. Actual resource selection to be determined though 2029-2032 All-Source RFP Supplement

	bid evaluation and subsequent resource application, subject to Commission approval.
New Resource Options	• All candidate resource technologies included in all scenarios, with exception of specific sensitivity analysis • Technology pricing and future technology cost curves developed using EPRI provided data, NREL's latest 2024 Annual Technologies Baseline (ATB), and consultant provided information. • Generic new wind resources limited to 1,000 MW based on capacity of Western Spirit #3 transmission line • All other supply-side resources not limited in resource potential • Emerging technologies allowed as candidate resources between 2029 and 2035 • EE/DR modeled as a resource; potential limited based on EE/DR studies
Federal Tax Credits	• No tax credits available to new wind and solar resources beginning 2029 • Investment tax credits for energy storage resources of 30% through 2033, stepping down to 22.5% in 2034, 15% in 2034, and 0% in 2035 and thereafter
Commodity Pricing	• Reference Case natural gas prices • No explicit cost applied to carbon emissions throughout horizon

7.2.2 Sensitivities

A **"sensitivity"** is an analysis of the impact of varying a single input assumption within a defined scenario or future. The adjustment of a single assumption isolates the impact of critical uncertainties or decision points to identify the key risk factors to the portfolio, quantifying their impact on the expected cost as well as how they affect the types of resources identified in the plan. In the facilitated stakeholder process for the 2023 IRP, stakeholders provided feedback on the design of sensitivities for PNM's 26 IRP analysis; several of the sensitivities described below were informed directly by those comments.

[Figure to be updated upon completion]

Figure 5-2. Sensitivities studied under each of the three futures

	CTP	HEG	LEG
Standard Assumptions	■	■	■
No Energy Transition Act	■	■	■
400 lbs/MWh through 2044	■	■	■

Federal CO2 tax in 2030	■	■	■
High electric vehicles	■	■	■
Time-of-use rates	■	■	■
Extreme economic growth	■	■	■
Late long-duration storage maturity	■	■	■
No new natural gas resources	■	■	■
Transmission – Rio Sol	■	■	■
Transmission – Sun Zia	■	■	■
Transmission – Blackwater DC Tie	■	■	■
Transmission – Four Corners	■	■	■

These sensitivities generally fall into four categories: (1) policy and regulatory, (2) load forecast, (3) technology availability, and (4) transmission. Descriptions of each of these categories and the relevant sensitivities follow.

Policy and Regulatory sensitivities are designed to examine the impacts of both existing and potential future policies and regulations on PNM's portfolio decisions. These sensitivities provide PNM with a better understanding of how existing regulations impact future resource decisions and enable PNM to mitigate risks of future policy changes.

TABLE 6-2. DESCRIPTION OF POLICY & REGULATORY SENSITIVITIES

No Energy Transition Act	Does not impose CO_2 emission limits, Renewable Portfolio Standard (RPS) requirements, and carbon-free energy requirements across the modeling horizon.
400 lbs/MWh through 2044	The assumption here is that the energy transition act maintains a carbon intensity requirement of 400 lbs./MWh through 2044 and a carbon-free generation portfolio beginning in 2045.
Federal CO2 tax in 2030	A federal CO_2 tax is assumed to be implemented beginning in 2030.

Load Forecast sensitivities test the impact of various alternative assumptions regarding the level and shape of PNM's future electricity demand. These results provide PNM with useful directional information on how portfolio strategies should evolve in the event that future electricity demand deviates from PNM's initial load forecast.

TABLE 6-3. DESCRIPTION OF LOAD FORECAST SENSITIVITIES

High electric vehicles	This sensitivity assumes a high electric vehicle forecast applied to evaluate the impacts of accelerated electric vehicle adoption.
Time of use rates	The time of use forecast is applied to evaluate the impacts of customer load shifting and changes in load shape associated with TOU rate adoption.

Extreme economic growth

Technology availability sensitivities evaluate how PNM's portfolio would change under circumstances that limit or constrain the availability of certain types of new generation. These sensitivities provide useful insight into how alternative resources may meet PNM's needs and allows for quantification of the value provided by a diverse electricity portfolio.

TABLE 6-4. DESCRIPTION OF TECHNOLOGY AVAILABILITY SENSITIVITIES

Late Long Duration Storage Maturity	This assumes a delay in the availability of long duration energy storage resources until 2040 to evaluate the impacts of slower technology commercialization.
No New Natural Gas Resources	This sensitivity removes all new gas-fired candidate resources from consideration, allowing the analysis to evaluate portfolio development without new natural gas.

Transmission sensitivities evaluate the impact of the inclusion of discrete new transmission projects would enable access to new markets that would impact the operations of PNM's resources. These sensitivities represent a step forward in PNM's efforts to integrate generation and transmission planning by providing a means of examining the joint impacts of the two decisions together. Transmission sensitivities are evaluated only in production cost modeling and utilize the same portfolio of resources developed under the standard assumptions described in Section XXX.

TABLE 6-5. DESCRIPTION OF TRANSMISSION PROJECT SENSITIVITIES

Transmission - Rio Sol	This assumes the Rio Sol transmission project is available for consideration in the portfolio analysis.
Transmission - Sun Zia	This evaluates portfolio outcomes with the Sun Zia transmission project available in the analysis.
Transmission - Blackwater DC Tie	This sensitivity models the Blackwater DC Tie transmission project when developing future resource portfolios.
Transmission - Four Corners	This includes the Four Corners transmission project in the portfolio analysis.

7.2.3 STAKEHOLDER-REQUESTED SCENARIOS

In addition, stakeholders were invited to submit requests for additional changes to the futures and sensitivities to model using the IRP tools. This resulted in an additional twelve scenarios for analysis in the IRP; the details of those scenarios are presented in Table jhg and results are included in Appendix XXX.

TABLE 6-6. DESCRIPTION OF STAKEHOLDER REQUESTED SCENARIOS

HEG, Nuclear Fusion	Includes nuclear fusion as a candidate resource based on cost and performance characteristics specified by stakeholders
CTP, Geothermal	Includes additional geothermal candidate resources (up to 50MW of classic geothermal at $5,100/kW and unlimited enhanced geothermal at $6,100/kW)

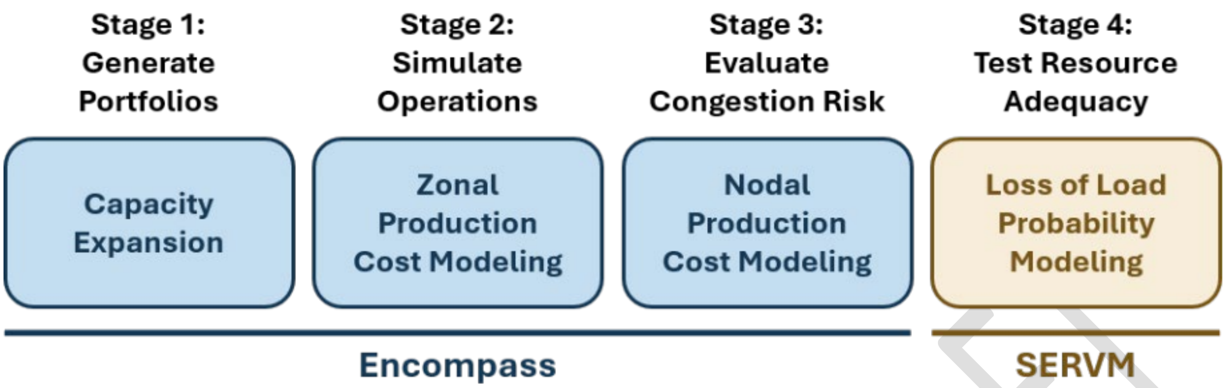
CTP, ETA Step Down	Requires a gradual reduction in the carbon intensity limit from 400 lbs/MWh in 2031 to 0 lbs/MWh by 2045
HEG, ETA Step Down	Requires a gradual reduction in the carbon intensity limit from 400 lbs/MWh in 2031 to 0 lbs/MWh by 2045
LEG, ETA Step Down	Requires a gradual reduction in the carbon intensity limit from 400 lbs/MWh in 2031 to 0 lbs/MWh by 2045
CTP, High Natural Gas Price	Assumes higher natural gas prices (based on Siemens “High” commodity price forecast)
CTP, High Behind the Meter Solar (BTMS)	Includes higher levels of behind-the-meter solar adoption
CTP, High BTMS + TOU	Includes higher levels of behind-the-meter solar adoption and incremental impacts of time-of-use rates upon demand profile
CTP, High BTMS + TOU + Force Power Saver	Includes higher levels of behind-the-meter solar adoption, incremental impacts of time-of-use rates, and an extension of the Power Saver demand response program
CTP, high BTMS + TOU + Power Saver + DR Changes	Includes higher levels of behind-the-meter solar adoption, incremental impacts of time-of-use rates, and an extension of the Power Saver and water heater demand response programs at 125% of potential, and updates to battery DLC assumptions
CTP, Geo + DR + SMR + no H2 and CCS	Implements updated geothermal costs and High BTMS + TOU + Battery DLC assumptions, adds ITC eligibility for geothermal and SMRs, delays SMR availability to 2040, and excludes hydrogen conversion and CCS technologies.
CTP, Geo + DR + SMR + no H2 and CCS + no 2029 Gas	Includes updated geothermal costs and High BTMS + TOU + Battery DLC assumptions, adds ITC eligibility for geothermal and SMRs, delays SMR availability to 2040, and excludes hydrogen conversion and CCS technologies. Along with removing the 2029 172MW gas unit.

7.3 Modeling Methodology

PNM’s 2026 IRP uses two commercial, industry-leading modeling tools: 1) EnCompass, developed by Anchor Power Solutions, to produce future portfolios through capacity expansion and production simulation, and 2) SERVM, developed by PowerGEM, for detailed reliability studies using portfolios produced by EnCompass.

Pairing these tools enables PNM to evaluate a range of cost-optimal resource portfolios that satisfy regulatory, reliability, and environmental requirements over both the near and long term. EnCompass identifies the least-cost portfolio for each year of the planning horizon (2026–2045), subject to applicable policies and system constraints. Because optimizing resource decisions across multiple future years is computationally intensive, EnCompass evaluates a subset of representative days rather than the full range of possible operating conditions. SERVM complements this analysis by testing the reliability of candidate portfolios across hundreds to thousands of simulated weather years and system conditions, verifying that they meet PNM's reliability standards[1] under a wide range of potential futures. Together, EnCompass and SERVM provide an integrated planning framework that identifies robust resource portfolios balancing affordability, reliability, and environmental objectives.

FIGURE 5-3. MODELING TOOLS, FUNCTIONS, AND KEY OUTPUTS FROM PNM'S IRP ANALYTICAL PROCESS



Additional details comparing the purposes, methodologies, and key results produced by each model are shown in Table 5-7.

TABLE 6-7. COMPARISON OF MODELING TOOLS USED IN IRP

	LTCE	Zonal PCM	Nodal PCM	LOLP
Principle Purpose	Generate portfolios	Simulate bulk system operations	Evaluate transmission congestion risk	Test system resource adequacy
Modeling Horizon	20 years	20 years	20 years	Single years
Key Model Decisions	Investments & Operations	Operations	Operations	Operations
Transmission Representation	Zonal	Zonal	Nodal	Zonal
Load & Renewable Profiles	Deterministic	Deterministic	Deterministic	Stochastic
Temporal Representation	Hourly, 36 sample days per year	Hourly, all 8760 hours per year	Hourly, all 8760 hours per year	Hourly, all 8760 hours across 1000 samples
Geographic Scope	PNM Retail	PNM Retail	WECC System	PNM BA + Neighbors
Wholesale Markets	No	Yes	Yes	Yes
Key Outputs	Installed capacity by resource, NPV fixed costs	Annual generation by resource, NPV variable costs, emissions	Congestion	Loss of Load Expectation
Scenario Application	All scenarios & sensitivities	All scenarios & sensitivities	Select scenarios & sensitivities	Select scenarios

TABLE 6-8. MODELING ACROSS SCENARIOS AND SENSITIVITIES

■ Current Trends & Policy ■ High Economic Growth ■ Low Economic Growth

	LTCE	Zonal PCM	Nodal PCM	LOLP

Standard Assumptions				
No Energy Transition Act				
400 lbs/MWh through 2044				
Federal CO2 tax in 2030				
High electric vehicles				
Time-of-use rates				
Extreme economic growth				
Late long-duration storage maturity				
No new natural gas resources				
Transmission – Rio Sol*				
Transmission – Sun Zia*				
Transmission – Blackwater DC Tie*				
Transmission – Four Corners*				

* Transmission sensitivities conducted using LTCE results from Standard Assumptions modeling

7.3.1 Capacity Expansion

EnCompass is an optimal capacity expansion and production cost simulation model developed and maintained by Anchor Power Solutions In the 2026 IRP, PNM uses EnCompass for two functions:

Long-Term capacity expansion (LTCE): EnCompass produces least-cost portfolios of resources to meet future load, reliability, and emissions reduction needs, subject to constraints on reliability, operating parameters of each resource, and environmental and regulatory requirements. Production simulation: EnCompass simulates the hourly operations for each portfolio across all 8,760 hours of the year for the full planning horizon. The model captures detailed constraints on dispatch, unit commitment, and transmission limitations to quantify the cost of operating the system to meet PNM's load.

For the 2026 IRP planning process, EnCompass' capacity expansion module identifies least-cost portfolios of resources for a planning horizon of 2026 to 2045. The model selects a portfolio which minimizes the "objective function" – the sum of all costs included in the optimization – reflecting the net present value of projected system costs over the study window, including existing and new resources and transmission related costs needed to deliver future resources to loads. Each optimization is subject to "constraints" – certain requirements that the portfolio must meet, such as but not limited to the PRM, RPS requirement and CO2 emission targets.

EnCompass' modeling functionality is foundational to PNM's ability to identify a robust plan. Several of the most important features of EnCompass used to develop the plan are described below.

TABLE 6-9. DESCRIPTION OF KEY FUNCTIONALITY OF ENCOMPASS CAPACITY EXPANSION MODEL

Cost Minimization	EnCompass is a constrained optimization model, meaning that it seeks to identify a portfolio of resources that minimizes an objective function representing PNM's costs to serve future loads while meeting defined constraints (e.g. reliability, ETA requirements, physical limits). The objective function for the capacity expansion model is the net present value of future generation and transmission costs, including fixed costs of new investments (e.g. capital, fixed O&M) and variable costs of serving load (fuel, variable O&M) throughout each year. This ensures that each portfolio generated reflects the solution with the lowest cost to PNM's customers, subject to constraints.
Planning Reserve Margin Constraint	In each year of the capacity expansion model, the PRM constraint ensures that PNM's existing resources plus new resources selected by the model supply enough accredited capacity to meet PNM's PRM requirement. This constraint ensures that each portfolio generated meets PNM's standards for resource adequacy throughout the horizon.
Dynamic ELCC Curves	An important capability of the EnCompass model is the ability to represent dynamic ELCC curves for variable (wind, solar) and energy-limited (storage) resources to quantify their contribution to PNM's reliability needs. Modeling a dynamically-changing ELCC is important for determining the optimal portfolio that ensures reliability, since marginal ELCCs for each resource change as more is added to the system. EnCompass tracks how marginal ELCCs change, capturing saturation effects (i.e. declining marginal ELCCs) as more wind, solar, and storage are added to the portfolio.
Endogenous Hourly Dispatch	EnCompass simulates the hourly system dispatch of the portfolio across a subset of "sample days" to ensure a load and resource balance. Renewable resources in EnCompass are represented with hourly profiles to capture availability that varies across time of day and seasons and different locations. Hourly system dispatch also allows for explicit modeling of storage operations, including charging and discharging patterns, and dispatchable resources which can be brought online as needed to serve load.
Environmental Constraints	Encompass has the capability to ensure portfolios are compliant with all of the environmental requirements associated with the ETA, including: • 50% and 80% RPS requirements in 2030 and 2040, respectively; • 200 lbs/MWh carbon intensity limit in 2032 and thereafter; and • 100% carbon-free generation portfolio in 2045 These constraints are included in all scenarios and sensitivities except the Policy and Regulatory sensitivities that test alternative requirements.
Explicit Modeling of Hydrogen Production and Storage	[Currently being drafted]

Emission Constraints

For each portfolio, EnCompass evaluates whether the emissions constraint is met by taking the total Carbon dioxide emissions from PNM generation in the given year, and dividing it by PNM's total generation. This is the same methodology used to determine PNM's ETA compliance between 2023 to 2025 in its reporting requirements with the Commission. PNM's total generation will often exceed retail sales because of losses in transmission and distribution, storage round-trip efficiency, along with market transactions. Additionally, the ETA defines the CO2 emission compliance rate to be met based on an average rate over a three year period, while EnCompass enforces the constraint for every year of the planning horizon.

Under this accounting regime, short-term wholesale market transactions are not directly considered in determining PNM's carbon intensity. To design portfolios that comply with the spirit and requirements of the ETA and do not rely excessively on short-term purchases, PNM does not allow for market purchases or sales in the capacity expansion step of the analysis. This approach ensures that PNM's portfolio includes enough resources to serve its loads while also complying with the requirements of the ETA. A key element in the design of portfolios is that each is capable of meeting the objectives of the ETA.

Under the ETA, PNM is not required to attribute carbon emissions to short-term wholesale market purchases. Because wholesale market purchases are included in the production cost modeling, the resulting emissions attributed to PNM's portfolio may be understated depending on real-world conditions. By focusing on emissions outputs produced by the capacity expansion model, PNM ensures that the portfolios developed in the IRP are capable of meeting future requirements regardless of the availability of short-term wholesale market purchases, which is inherently uncertain.

7.3.2 Zonal Production Cost Modeling

Capacity expansion modeling is the first step in determining the cost-optimized portfolios. By "locking-in" those portfolios, more granular projections of cost and performance of resource portfolios are simulated. Production simulations in PNM's IRP are performed down to the hourly level over the 20-year planning horizon and is necessary to understand system operations across all hours of a year, capturing a wide range of projected weather conditions impacting load and renewable resource generation, and effects on the system cost, generation, and emissions.

Production cost simulation modeling in EnCompass reflects PNM's obligation to maintain an adequate load and resource balance in real time, consistent with NERC reliability standards. The production cost simulation dispatches resources according to the following steps, consistent with real-world operations:

- Schedule "must-run" resources such as nuclear, geothermal, wind, and solar, and any other resources needed to run at their expected output.
- Additional resources are dispatched (or curtailed) economically to serve demand and energy needs, while minimizing costs to operate the portfolio.
- Generation is also committed to meet operating reserve requirements to help preserve reilibility of the system.

- Carbon emitting resources are dispatched so that annual emissions are optimized within targeted amounts to meet ETA requirements .

In addition, the production simulations allow for interactions with neighboring wholesale markets to reflect opportunities to reduce customer costs with short-term market purchases and sales. Under the ETA's rules, short-term market purchases do not count towards PNM's carbon intensity, and so in circumstances where the production simulation model chooses to buy from the market instead of dispatching PNM's own natural gas resources, the apparent emissions intensity of PNM's portfolio may appear lower than in the capacity expansion model runs.

7.3.3 Nodal Production Cost Modeling

The inclusion of nodal production cost modeling as a complement to zonal production cost modeling in the 2026 IRP is a novel development within the planning framework. PNM's nodal model differs from its zonal counterpart in several important ways:

- **Explicit physical modeling of the transmission system:** PNM's nodal model includes a detailed representation of the transmission network, including XX nodes and XX transmission elements in PNM's BAA. The nodal modeling includes a DC power flow representation of transmission flows to capture the real-world characteristics of these elements.
- **Broader geographic scope:** in contrast to the zonal model, which includes PNM's retail loads and the associated generation portfolio, the nodal model is a West-wide model that includes a representation of all loads and resources in the PNM BAA and neighboring systems. This broader geographic scope is necessary to model physical flows across the transmission network realistically.

Introduction to Nodal Production Cost Modeling

Transmission-constrained production cost models (TCPCMs) originated in the mid-twentieth century as power systems grew more interconnected. Early economic dispatch methods used simplified loss formulas, but the development of the DC power flow approximation in the 1960s and 1970s made it practical to embed transmission limits directly into linear programming dispatch models, giving rise to security-constrained economic dispatch (SCED). Electricity market restructuring in the 1990s, driven by FERC Orders 888 and 889 and the creation of ISOs and RTOs, made these models central to market design and locational marginal pricing (LMP), with major ISOs such as PJM, CAISO, MISO, and NYISO building their market operations around SCED and security-constrained unit commitment (SCUC).

Through the 2000s, tools such as PROMOD, PLEXOS, PowerWorld, and GE MAPS made production cost models standard for transmission and generation planning, including studies of renewable integration. Rising computing power in the 2010s enabled larger, higher-resolution simulations and the rise of stochastic modeling to capture uncertainty in renewable output, outages, and load. By the 2020s, transmission-constrained production cost modeling had become a core analytical tool for evaluating the economics and reliability of the energy transition.

Challenges Combining Nodal Production Cost Models with Capacity Expansion Modeling

Pairing nodal production cost models with capacity expansion modeling for a full company financial picture raises several practical problems. Nodal models solve detailed unit commitment and dispatch across thousands of buses, while expansion models must evaluate investment choices across many years and scenarios, so full nodal detail is rarely tractable across a long planning horizon; modelers typically fall back to zonal aggregation or representative days, which weakens the locational price signal the nodal model was meant to provide. Locational marginal prices also depend on the generation fleet and network topology, both of which the expansion model changes, creating circularity between the investment plan and the prices used to justify it. Keeping transmission topology consistent with each study year adds further difficulty, since interconnection, retirements, and upgrades evolve endogenously over a multi-decade horizon.

A second set of problems arises in linking physical results to company financials. Nodal models produce dispatch and price outputs, not debt schedules, tax attributes, depreciation, or equity returns, so a separate financial layer is needed and can drift out of sync with the operational results. Portfolio hedges such as FTRs or tolling agreements are often priced at zonal or hub level, creating basis risk if actual nodal congestion diverges from the hub price used in the financial model. Representative-day sampling, used to keep runtimes manageable, can also smooth over rare congestion or price-spike events that matter most for revenue volatility and risk metrics. Finally, the integer logic of unit commitment is computationally expensive, so it is often relaxed inside the expansion optimization, reducing the accuracy of the energy margin and ancillary service revenue estimates that feed the company's pro forma rate.

The two-model marriage between Nodal and Zonal Production Cost Modeling in the IRP

Because of the complexities of modeling all of the company financials and production cost constraints (namely Renewable Portfolio Standard and Energy Transition Act limits) PNM decided to create nodal and zonal encompass models in parallel for the 2026 IRP cycle. This involved creating a nodal model with separate assumptions and a dataset that extended beyond just the PNM footprint. The nodal model included the entire WECC footprint to capture New Mexico Independent Power producers that export resources out of the state to other jurisdictions. As the western grid continues to move to imbalance and day ahead markets, PNM wants to make sure its future resource plans consider how new plants fit into the changing transmission picture.

Nodal Model Development for IRP

Regional Nodal Model Development for the IRP cycle

PNM selected the Horizon data offering available through the Yes Energy EnCompass platform. Under this approach, Horizon Energy, LLC develops a comprehensive dataset by compiling publicly available information from published sources, resulting in a model that can be executed on a zonal basis. Because transmission system data is subject to Critical Energy/Electric Infrastructure Information (CEII) restrictions, Horizon does not provide the transmission network data required to convert the dataset into a nodal model. Instead, Yes Energy performs the additional work necessary to create the nodal representation by integrating power flow data and mapping generating resources from the Horizon dataset to corresponding buses in the transmission model. While this process appears straightforward conceptually, it is often labor-intensive in practice. Generator names do not always match the names of the buses to which they are electrically connected, and in some cases generating units share names with power flow buses despite being connected elsewhere on the network.

PNM further refined the baseline dataset by incorporating historical renewable generation performance, updated transmission network data, and IRP forecasts for load, natural gas prices, and market prices. These enhancements were made to align the nodal dataset with the assumptions used in the zonal IRP modeling framework. In addition, PNM reviewed publicly available resource plans from El Paso Electric, Tri-State, and other utilities across Arizona, Utah, and Colorado to validate regional load and resource assumptions in the near term. Maintaining a reasonable balance between regional load and resource development was important to avoid introducing artificial transmission congestion that could distort model results.

External Enties Loads and Resource Assumptions beyond 2035

Publicly available information regarding the quantity, type, and location of future resource additions becomes increasingly limited in the latter portion of the study horizon. Because power system flows are influenced by the amount of generation added, the locations where resources are interconnected, and their operating characteristics, developing reasonable long-term assumptions for external entities presents a significant modeling challenge. To address this uncertainty, PNM adopted a "bottom-fill" methodology to balance loads and resources outside of its service territory.

The bottom-fill methodology is based on the following assumptions:

- Generic baseload resources are added to external areas as needed to provide sufficient capacity and energy while maintaining a low dispatch cost, allowing them to occupy the lower portion of the dispatch stack.
- These resources are assumed to have a limited impact on marginal energy prices and are not intended to materially alter the dispatch of resources operating on the margin. In the absence of detailed information regarding future resource development, current and near-term regional resource patterns were used as a reasonable proxy for longer-term conditions.
- Capital costs associated with these placeholder resources are not modeled because the resources are used solely to maintain a balanced representation of load and generation in external areas and are not intended to represent specific investment decisions.
- The placement of these resources within the transmission network is inherently uncertain, as future siting decisions beyond the near term are largely unknown. Resource locations were therefore selected using engineering judgment with the objective of minimizing artificial congestion and preserving reasonable transmission flow patterns.

7.3.4 Loss-of-Load-Probability Modeling

For select scenarios, detailed reliability analyses using SERVM follows the capacity expansion and production simulation in EnCompass. The reliability analysis performed in SERVM is a traditional Loss of Load Probability (LOLP) study which verifies that the portfolios are reasonably close to a Loss of Load Expectation (LOLE) standard of 0.1 days per year, the equivalent to one day in ten years. The LOLP study examines the portfolio’s performance across a wide range of weather conditions, load variability and resource availability representing hundreds or thousands of years. If 0.1 LOLE is not met, SERVM results inform adjustments to the portfolio (e.g. adding additional capacity) to ensure the standard is met.

8. New Resource Options

Chapter Highlights
19. To be added

To fill the remaining capacity needs, as PNM plans toward a carbon-free future, the types of resources needed to ensure resource adequacy will include a diverse mix of technologies and capabilities. Table 0-1 summarizes candidate resources and the categories that PNM has determined are appropriate for each resource. The following categories describe the resource types:

- Carbon-Free: Resources that produce clean energy with little or no direct carbon emissions and are intended to meet most customer energy needs throughout the year such as energy efficiency, solar, and wind.
- Dynamic Balancing: Resources that provide operational flexibility and help balance electricity supply and demand instantaneously in response to changing system conditions. Some of these resources include demand response and short duration storage.
- Firm Dispatchable: Resources that can be operated on demand, across their range of operating capabilities, for extended periods of time to support system reliability and resource adequacy. Resources typically seen in this category are thermal generators, geothermal, and long duration storage.

20. Table 0-1. Candidate Resources by Technology Category

Candidate Resource Category	Emerging Technology
Carbon Free	**Yes/No**
Energy Efficiency	No
Solar - Photovoltaic	No
Wind	No
Dynamic Balancing	**Yes/No**
Battery Storage (4 hr.)	No
Battery Storage (8 hr.)	No
Compressed Air Energy Storage	Yes
Demand Response	No
Firm Dispatchable	**Yes/No**
Combustion Turbine (heavy frame)	No
Combustion Turbine (aero)	No
Combined Cycle	No
Combined Cycle with Carbon Capture	No
Linear Generator	Yes
Geothermal	No

Enhanced Geothermal	Yes
Iron Air Energy Storage	Yes
Pumped Hydro	No
Nuclear Small Modular Reactor	Yes

Ownership of new resources may follow three different models: a “utility self-build” project is one that the utility constructs and operates on its own. A “build-transfer” or “turnkey” project is one that is developed by a third party, often an independent power producer (IPP), and then sold to the utility to own and operate. A third approach is for PNM to purchase the output from a generator or set of generators over a contracted period through a power purchase agreement (PPA). Each of these options has specific benefits, but each also presents risks and uncertainties worth consideration when making procurement decisions.

The long-term resource planning process does not evaluate specific ownership structures, and instead, compares and evaluates all resources under a framework that is agnostic to ownership. To efficiently evaluate projects, a utility ownership finance structure is utilized across all resource options. This approach is not meant to show a preference for utility ownership, rather to ensure all technologies are considered on a level playing field using a consistent set of financing assumptions. Furthermore, capital costs and operating characteristics for supply-side candidate resources and the methodology used to develop future cost curves can be found in appendix [XXX].

8.1 New Demand-Side Resources

In addition to supply-side resources, PNM evaluated a wide range of demand-side resources to help identify the optimal mix of resources in its planning process. To support this effort, the energy efficiency and demand response potential study conducted by PNM, with support from the consultant Inner City Fund (ICF) International, was undertaken to provide a comprehensive, data-driven assessment of available demand-side resources and their role in future resource planning. The study evaluated both energy efficiency measures and a broad set of potential demand response program options — including rates and electric vehicle programs — across customer segments to estimate achievable energy savings and peak demand reductions over the planning horizon. The potential study helped inform the IRP process by identifying incremental demand-side opportunities that can compete with or complement supply-side resources, support system reliability, and meet resource adequacy needs.

Key Term

Programs refer to existing or PNM-planned EE and DR programs implemented during the statutory period to comply with the requirements established by the EUEA. EE bundles represent groups of energy efficiency measures that are beyond the statutory programs and are modeled as candidate resources. These bundles capture additional EE opportunities that may be selected by the model. DR potential programs represent a set of demand response options designed to capture future demand response opportunities across multiple customer segments and enabling technologies.

8.1.1 Energy Efficiency

In keeping with PNM's carbon-free goal, future energy efficiency (EE) measures are considered beyond the requirements established by the EUEA as a new resource option, building upon the methods used in the 2023 IRP to characterize energy efficiency as a candidate resource option in capacity expansion modeling. The EE beyond planned amounts is bundled into similarly priced groups of different measures, which can be considered by the model alongside supply-side resources. Allowing these EE bundles to be chosen by the model indicates the extent to which PNM should pursue EE above and beyond the statutory amount as a competitive solution to supply-side resources.

To enable modeling EE as a resource, PNM contracted with ICF International to develop updated hourly supply curves representing program potential. The process to develop these bundles consisted of the following steps:

1. Calculate "achievable technical" potential for EE within PNM's service territory. Based upon the updated Residential Appliance Saturation Study (RASS), calculations were performed to determine what is technically and economically feasible, then narrowing it to an achievable amount based on expected adoption rates. This method is used to calculate the total potential, rather than solely focusing on least-cost outcomes.
2. Define a set of statutory EE programs based on requirements to meet the EUEA for 2027-2029. These programs are included in PNM's triennial filing with the New Mexico Public Regulation Commission (NMPRC) and are automatically included in the portfolio to comply with the EUEA targets.
3. Define programs of EE measures ("EE bundles") beyond the EUEA's minimum requirements by grouping measures with similar levelized costs of conserved energy. These EE bundles are provided as candidate resources that the model may select, after the completion of the remaining steps.
4. Calculate annual incremental energy savings, weighted average cost, and measure lifetime for each bundle based on the included measures.
5. Develop hourly impacts for each bundle by spreading measure-level impacts over calibrated end use load shapes.

While this general approach is consistent with the methods used in the last IRP, this IRP process has made several enhancements to the modeling assumptions. Namely:

- The grouping of the measures was updated by compressing the ranges to simplify the modeling and reduce the number of options considered. These measures are then grouped by cost: "Up to $75/MWh" bundle; followed by a bundle with the cost range of $75-125/MWh; and a final bundle represents measures with a cost above $125/MWh;
- The statutory EE programs for 2027-2029 were calibrated to align with PNM's EE triennial filling;
- Based on The Potential Study an average line loss factor of 6.8% was applied to all EE bundles in the post statutory period;
- Transmission and distribution (T&D) avoided costs attributable to energy efficiency were assessed and applied to all EE programs and bundles based on the Avoided Cost of Transmission and Distribution Capacity Study performed in 2026, as shown in Table [ ]. These values were further adjusted using the effective load carrying capability (ELCC) of energy efficiency, as provided by PowerGem, to reflect the likelihood that EE resources

are available during system peak conditions. Additional information on this study is provided in Section [ ] of this report.

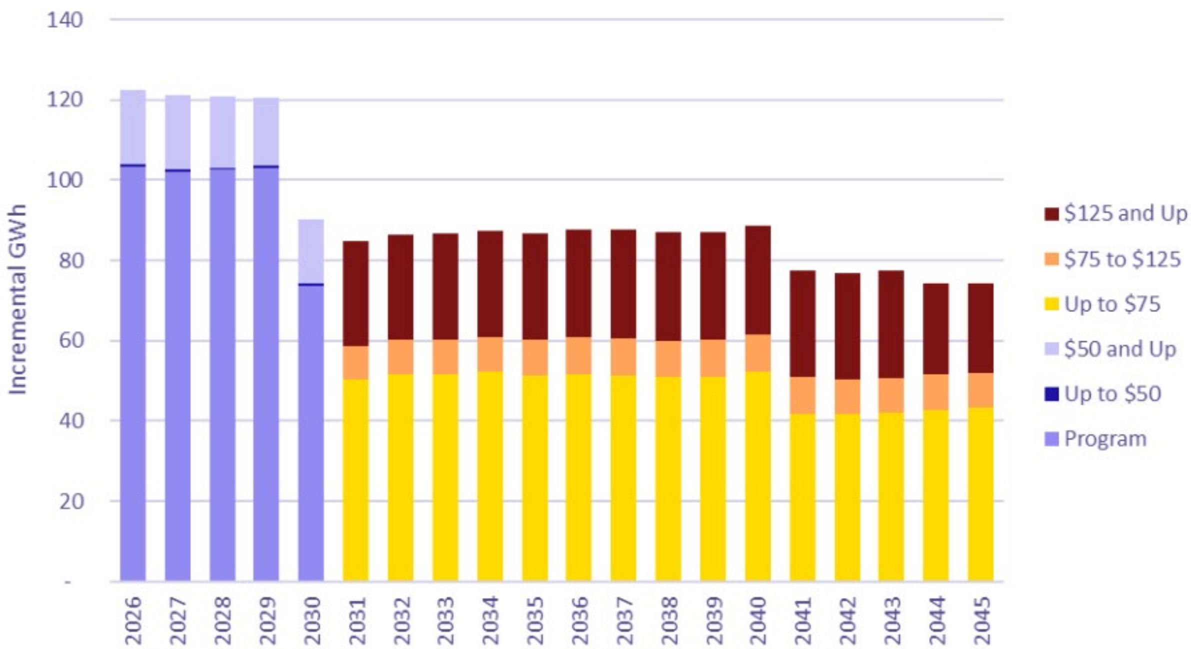
Table 0-2. Energy Efficiency Transmission and Distribution Avoided Cost Adders

Year	$/kW-yr
2026	-0.6
2027	-0.8
2028	-11.6
2029	-13.3
2030	-14.5
2031	-15.6
2032	-25.2
2033	-27.4
2034	-28.6
2035	-30.5
2036	-33.2
2037	-34.1
2038	-33.0
2039	-39.2
2040	-35.7
2041	-37.6
2042	-39.2
2043	-41.1
2044	-40.8
2045	-39.0

The results of this process are shown in Figure Figure 0-1, which summarizes the EE programs and bundles modeled in this IRP; additional details on the characteristics are provided in Appendix [ ]. The efficiency measures designated as “Program” are planned efficiency required by statute – this efficiency is included by default across all scenarios. The relatively small amount of potential in the “Up to $50” bundle in these years reflects the fact that most low-cost opportunities for energy efficiency have been exhausted by current programs.

In any given simulation year, the model may select from the additional efficiency bundles incremental to the programs under the statutory period shown in Figure 0-1. If a bundle is selected, its savings persist for the duration of the bundle’s lifetime.

FIGURE 0-1. ENERGY EFFICIENCY BUNDLES



8.1.2 DEMAND RESPONSE

Demand Response Potential Options

Stakeholder Input: Prioritizing increased demand-side resource options

During the 2023 IRP, stakeholders shared feedback that PNM could further expand its evaluation of demand-side resources in future IRP's. In particular, there was interest in exploring additional demand response options and better reflecting how program costs may change over time, rather than remaining fixed.

In response to this feedback, PNM, in collaboration with ICF, expanded the modeling approach to include nine distinct and selectable demand-side options. These potential options are designed to better reflect real-world conditions, with costs that vary from year to year based on customer participation, which may increase or decrease over time.

In support of its carbon-free mandate, PNM developed new approaches in this IRP to identify and evaluate additional demand response programs, beyond its existing load management programs, Peak Saver and Power Saver. PNM Engaged engaged ICF to conduct the Energy Efficiency and Demand Response Potential Study to support its resource planning efforts. For the purposes of the IRP, PNM included all DR potential programs identified in the potential study, regardless of cost or total energy impacts, and allowed the EnCompass model to determine the optimal selection of resources based on system needs and economics. To enable modeling of the demand response potential programs, ICF followed the following detailed robust approach:

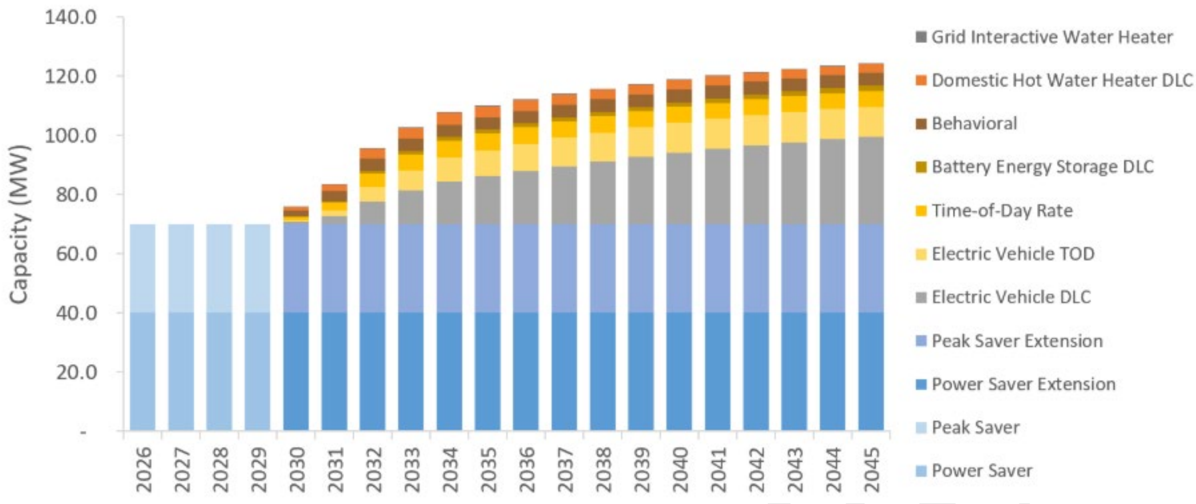
1. Data Collection: ICF compiled data from a range of sources, relying primarily on the Northwest Power and Conservation Council's 2021 Power Plan to inform demand

response program characteristics using regional data. Additional sources used to support the development of demand response potential include the PNM Energy Efficiency 2024 Annual Report and the 2024 Evaluation of Energy Efficiency and Load Management Programs report.

2. Program Characterization: Where available, ICF incorporated data specific to PNM’s service territory to inform key assumptions related to program participation, impacts, and costs. The Northwest Power and Conservation Council’s 2021 Power Plan was used to define sector eligibility for each DR potential program. For potential programs requiring enabling technologies, ICF applied equipment saturation forecasts derived from PNM’s energy efficiency portion of The Public Service Company of New Mexico Potential Study. To prevent double counting of load reductions across overlapping potential programs, ICF worked with PNM to establish a program hierarchy.
3. Baseline Peak Demand Forecast: ICF developed a peak demand forecast based on the system-level peak demand projections from PNM’s energy efficiency portion of The Public Service Company of New Mexico Potential Study. These projections were then disaggregated by sector and customer class using PNM-provided customer data and market segmentation outputs.
4. Potential Estimation: ICF estimated DR potential for each potential program by determining the eligible customer population based on enabling technology saturation and adjusting for participation in higher-priority programs within the hierarchy, applying participation rates, attrition, and event performance assumptions to estimate program adoption, and calculating total demand impacts by multiplying per-customer demand reductions by the number of participating customers across the forecast horizon. Program adoption, and therefore potential savings, is assumed to ramp up over time, reflecting factors such as customer awareness, program marketing and outreach, and technology maturity and complexity.
5. Cost Evaluation: ICF calculated levelized costs over the full forecast period (2026–2045), assuming program operation in both summer and winter peak periods. While levelized costs are presented for comparative purposes, PNM modeled DR resources in the IRP using annualized fixed costs that vary over time with participation levels. Additional detail on cost development is provided in the Public Service Company of New Mexico Potential Study.

Under this approach, a total of nine DR options were identified for inclusion in the modeling database. This amount includes two extensions of existing programs (Peak Saver and Power Saver) and seven new feasible DR potential programs developed by ICF. The capacity of these DR options during the planning period is shown in Figure 0-2.

FIGURE 0-2. TOTAL CAPACITY OF DEMAND RESPONSE POTENTIAL PROGRAMS



In PNM's 2027–2029 energy efficiency and load management triennial filing (Docket No. 26-0000074), the two existing demand response programs, Peak Saver and Power Saver, are expected to continue through 2029. Beginning 2030, however, continuation of these programs is not guaranteed due to having to obtain NMPRC reapproval every three years. The IRP does not assume that these programs will automatically persist beyond 2029. Instead, they are treated as candidate resource options beginning in 2030 that can compete with other supply-side and demand-side resources. As a result, both programs are modeled economically with the option to continue through the end of the planning horizon (2030–2045). The following sections describe each DR program in detail.

Peak Saver Extension

The Peak Saver Extension program provides peak load reduction during periods of high system demand through the curtailment of customer-sited loads. Curtailment strategies are tailored to each participating facility and may include control of lighting, HVAC, refrigeration, pumps, and other eligible equipment.

Assumed Technology Characteristics

The Peak Saver Extension is applicable to medium and large commercial and industrial customers with loads of 150 kW or greater. This demand response potential option is modeled as available year-round, with up to 100 hours of availability during the summer and up to 300 hours during the remainder of the year, for a total not to exceed 400 hours annually. Individual events are limited to a maximum duration of 4 hours. The extension of this program is first assumed to be available beginning in 2030.

Power Saver Extension

The Power Saver Extension program provides peak load reduction during periods of high system demand through the curtailment of customer-site loads. Curtailment is achieved through direct control of refrigerated air conditioning systems, typically by cycling the air conditioner to reduce overall system load.

Assumed Technology Characteristics

The Power Saver Extension is applicable to residential, small commercial, and medium commercial customers. This demand response potential program is modeled as available and affordable during the summer months, consistent with the current program design. The resource has up to 100 hours of availability during the summer season, with individual events limited to a maximum duration of 4 hours. The program extension is first assumed to be available beginning in 2030.

Battery Energy Storage Direct Load Control

Battery energy storage direct load control (DLC) leverages customer-sited battery energy storage systems to shave load through utility-directed dispatch during system peak periods or grid stress events. Participating batteries are controlled to reduce system load by discharging during events, shifting energy consumption away from peak hours.

Assumed Technology Characteristics

Battery energy storage DLC potential program is assumed to be applicable to residential, commercial, and industrial customers and operates during both summer and winter seasons. The program can be dispatched for up to 35 hours in the summer and 30 hours in the winter. The first year of expected availability is 2030, reflecting the level of market maturity and the development of a technically feasible and affordable program structure.

Domestic Hot Water Heater Direct Load Control

This potential program enables demand response through the installation of a DLC switch on participating customers' domestic hot water heaters. During peak periods or system events, PNM can temporarily interrupt or defer water heating to reduce system demand. The thermal storage capability of water heaters allows load reductions to be delivered with limited customer impact.

Assumed Technology Characteristics

Domestic hot water heater DLC potential program is designed for residential customers during both summer and winter seasons. The program can be dispatched for up to 100 hours in the summer and 100 hours in the winter. The first year of expected availability is 2030, reflecting the level of market maturity and the development of a technically feasible and affordable program structure.

Grid Interactive Water Heater

This program utilizes water heaters equipped with integrated communication ports to enable bidirectional communication between the device and the utility. Through this communication, PNM can adjust, delay or advance water heating by turning the devices on and off in response to system conditions. This is different with the direct load control which only allows devices to be turned off.

Assumed Technology Characteristics

Grid-Interactive Water Heaters are modeled as a residential demand-response potential program available in both the summer and winter seasons. This program is modeled as a resource which may be dispatched for up to 100 hours in the summer and 100 hours in the winter, for a maximum of 200 hours annually, with no single event exceeding 4 hours. The first year of expected availability is 2030, reflecting the level of market maturity and the development of a technically feasible and affordable program structure.

Time-of-Day Rate

Time-of-Day (TOD) is a rate structure that applies higher prices to one or two defined peak periods within a day and lower prices during all other periods, encouraging customers to shift electricity usage away from peak periods and reduce system peak demand. At PNM, this concept is implemented through the TOD pilot program described in Section [ ]. The TOD demand response potential program is a scaled-up application of the TOD pilot, transitioning from a pilot to broader implementation.

Assumed Technology Characteristics

TOD is a year-round program and is modeled as a load modifier for residential, commercial, and industrial customers. The first year of expected availability is 2030, reflecting the rollout of advanced metering infrastructure (AMI) deployment.

Electric Vehicle Direct Charge Management

Electric Vehicle Direct Charge Management builds on PNM's transportation electrification efforts in active managed charging. This program allows PNM to manage EV charging behaviors to postpone or curtail charging during peak demand periods, shifting load to off-peak hours while maintaining customer charging needs and supporting system peak management.

Assumed Technology Characteristics

Electric vehicle direct charge management is modeled as a residential potential program that can be called year-round. The program is limited to 80 hours annually, with 40 hours allocated to the summer and 40 hours to the winter. The first year of availability is assumed to be 2030, reflecting the time needed for customer adoption and the development of a technically feasible and affordable program structure.

Electric Vehicle Time-of-Day

This program uses TOD rate to encourage customers to shift EV charging to off-peak hours through defined charging periods, reducing peak demand impacts while preserving customer charging flexibility. The program builds on the PNM's EV charging pilot rates which is introduced in Section 3.3. This pilot supports near-term participation and is assumed to transition into a successor TOD rate design around 2030, which will continue to provide price signals to guide EV charging behavior in the long term.

Assumed Technology Characteristics

Electric vehicle TOD is a year-round program and is modeled as a load modifier for residential customers. The first year of expected availability is 2030, reflecting time needed for customer adoption and the rollout of advanced AMI deployment.

Behavioral

Behavioral potential programs are voluntary demand response programs that encourage customers to reduce electricity usage during peak periods in response to behavioral messaging, such as notifications, alerts, or conservation prompts. Load reductions are then achieved through customer action rather than direct utility control.

Assumed Technology Characteristics

Behavioral is modeled as a residential program that can be called year-round. The program is limited to approximately 11 events per year, with individual events lasting between 3 and 5 hours. Total annual event hours are capped at approximately 40 hours. The first year of expected availability is 2030, reflecting the rollout of advanced AMI deployment.

For the 2026 IRP, three adjustments are made to the modeling inputs based on the results of the potential study.

1. An 8% incentive is applied to DR program costs (excluding TOD, EV-TOD, and EV direct charge management), consistent with PNM's triennial plan filing and aligned with the requirements of the EUEA, to reflect PNM's opportunity to earn on these investments.
2. Inclusion of avoided cost adders informed by the results of The Avoided Cost of Transmission and Distribution (T&D) Capacity Study. These adders were modeled for all DR programs and potential programs and are presented in Table [ ]. For the early portion of the study period through 2035, a levelized cost value was applied and then escalated at an annual rate of approximately three percent. These values were further adjusted using the ELCC of demand response, as determined through the study work performed by PowerGem, to reflect the probability that DR resources are available during system peak conditions. Additional details regarding the development of T&D avoided costs are provided in Appendix [ ] of this report and the ELCC study results are provided in Appendix [ ] of this report.

TABLE [ ]

Demand Response Transmission and Distribution Avoided Cost Adders

Year	$/kw-yr
2026	-28.6
2027	-28.6
2028	-28.6
2029	-28.6
2030	-28.6
2031	-28.6
2032	-28.6
2033	-28.6
2034	-28.6
2035	-28.6
2036	-29.5
2037	-30.4
2038	-31.3

2039	-32.2
2040	-33.2
2041	-34.2
2042	-35.2
2043	-36.3
2044	-37.4
2045	-38.5

Beginning in 2030, all modeled DR potential programs are treated as selectable resources. Once selected, the potential DR program is assumed to operate for their full lifetime, with ramp-up periods applied to most potential programs to reflect gradual market adoption. Their cost and attributes are summarized in Table [ ] and Table [ ].

TABLE [ ]. DR POTENTIAL PROGRAM CAPACITY AND COST

DR potential programs	2030 potential (MW)	2035 potential (MW)	2030 fixed O&M ($000)	2035 fixed O&M ($000)
Battery Energy Storage DLC	0.10	1.32	$59	$162
Behavioral	2.13	4.16	$408	$864
Domestic Hot Water Heater DLC	1.12	3.88	$1,826	$2,367
EV Direct Charge Management	0.76	16.26	$692	$8,184
EV-TOD	0.56	8.62	$222	$334
Grid Interactive Water Heater	0.00	0.04	$14	$79
Peak Saver Extension	30	30	$5,807	$6,232
Power Saver Extension	40	40	$8,440	$10,208
TOD	1.19	5.68	$594	$165

TABLE [ ]. DR POTENTIAL PROGRAM ATTRIBUTES

DR potential programs	ELCC (%)	Customer Class	Availability
Battery Energy Storage DLC	63%	Residential, C&I	Year-Round
Behavioral	63%	Residential	Year-Round

Domestic Hot Water Heater DLC	63%	Residential	Year-Round
EV Direct Charge Management	63%	Residential	Year-Round
EV-TOD	63%	Residential	Year-Round
Grid Interactive Water Heater	63%	Residential	Year-Round
Peak Saver Extension	63%	C&I > 150kW	Year-Round
Power Saver Extension	63%	Residential, C&I < 150kW	Summer
TOD	63%	Residential, C&I	Year-Round

Stakeholder Input: Virtual Power Plant

During the facilitated stakeholder meetings, several stakeholders expressed interest in evaluating scenarios that maximize the deployment of Virtual Power Plants (VPPs) with the high penetration of distributed energy resources (DERs). Requested scenarios included high levels of behind-the-meter (BTM) solar adoption, high participation in time-of-use (TOU) rate, greater enrollment of light-duty electric vehicles (EVs) on either EV time-of-day (TOD) rates or managed charging programs, expanded participation in Peak Saver, Power Saver, and water heater demand response programs, and increased adoption of behind-the-meter battery storage. In response to these requests, PNM developed and analyzed a suite of scenarios with elevated DER penetration levels to assess their impact on resource needs, costs, and portfolio outcomes. The detailed results of these scenarios are discussed in Section 7.4.

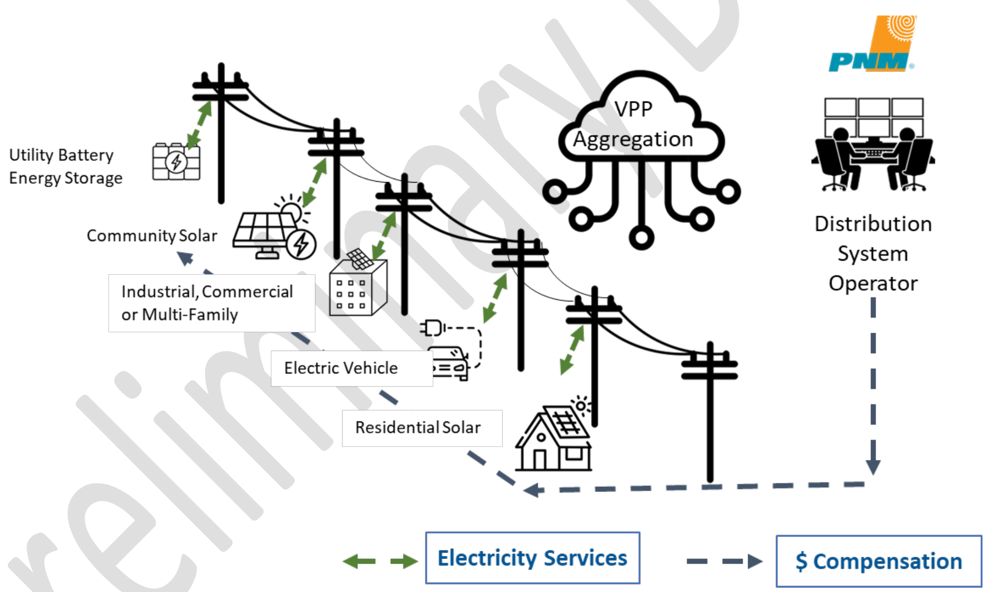
A Virtual Power Plant (VPP) is a coordinated network of distributed energy resources that can be monitored and controlled to operate as a single flexible resource. VPPs can aggregate utility-owned solar and storage assets, as well as customer-owned resources such as behind-the-meter (BTM) solar, BTM battery, electric vehicle chargers, smart thermostats, and other connected devices. Through advanced communication and control technologies, a VPP can provide capacity, energy, and grid support services, helping improve reliability, reduce peak demand, and defer or avoid investments in traditional generation and distribution infrastructure.

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 Front-of-Meter (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 of finalization of this IRP report. 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. A high level depiction of this process is shown in Figure Z.

FIGURE [ ] PNM VIRTUAL POWER PLANT



In response to stakeholder requests to evaluate scenarios that maximize the deployment of VPPs through increased adoption of distributed energy resources (DERs), PNM developed a series of stakeholder scenarios. The primary modifications included:

- Increase the BTM solar forecast from the Reference case to the High adoption case
- Apply a TOU rate sensitivity with an assumed 80% customer participation rate
- Force in the Power Saver Extension and water heater demand response programs by increasing their estimated potential by 25%
- Enhance the BTM battery forecast by assuming a 50% attachment rate of 4-hour battery storage to new BTM solar installations, with a 90% program enrollment rate and 60

dispatch events per year, and an additional 1% annual battery adoption rate for existing BTM solar customers beginning in 2030

PNM analyzed the impacts of these assumptions on the resource portfolio, and the detailed results of these scenarios are presented in Section [ ]

8.2 New Renewable Resources

Stakeholder Input: Solar Capacity Factors

Throughout the 2026 Integrated Resource Planning cycle, stakeholders were provided multiple opportunities to review PNM's work and offer feedback. During one of these review sessions, a stakeholder observed that the solar capacity factors assigned to new candidate resources were lower than those of existing solar resources in PNM's portfolio. In response, PNM conducted a further evaluation of solar facility capacity factors and determined that the candidate resource assumptions were somewhat conservative. As a direct result of that feedback, PNM increased the solar capacity factors for candidate resources to better reflect the performance of existing facilities and the expected performance of new solar resources within PNM's portfolio.

The emergence of low-cost renewable resources was one of the most notable developments in the industry during the 2009-2019[1] period. Over this timeframe, capital costs for new solar and wind generation declined by approximately 76%[2] and 50%[3], respectively. Accompanied by technological improvements in performance, these changes had significantly reduced the costs of developing these resources and enabled their rapid expansion nationwide.

More recent data indicates that the pace of cost reductions has slowed. Solar and wind cost trends have flattened, and in some cases increased, due to supply chain constraints and policy-related factors. As a result, costs are no longer declining at the same rate observed during the 2009-2019 period.

New Mexico's renewable resource potential is rich – and, unlike many states, offers both high quality solar and wind resources. The location in the southwestern United States has some of the highest quality solar resources across the state and high-quality wind resources in the eastern part of the state. The proximity to such high-quality renewable resources is likely to be a key part of the transition to a carbon-free portfolio.

8.2.1 Solar PV

Solar PV resources remain an attractive source of carbon-free electricity considered in this IRP. New Mexico's climate is conducive to an abundant high-quality solar resource, with favorable conditions for solar power year-round. New Mexico has some of the highest solar irradiance levels in the southwest region, especially in the southern part of the state.

Assumed Technology Characteristics

Key cost and performance parameters for new solar PV resources are shown in Table XXX. Yearly Cost assumptions for new solar PV resources including capital cost, fixed O&M, and variable O&M can be found in appendix [ ]

8.2.2 Wind

Stakeholder Input: Wind Operating Life

During the facilitated stakeholder meetings, a stakeholder observed that the operating life assumed for a generic wind resource used by PNM as a placeholder differed slightly from the operating life assumed for candidate wind resources representing potential future additions. This observation prompted PNM to conduct additional review and evaluation. Following that review, PNM refined the assumptions for the generic wind placeholder resource used prior to 2030 to more closely align with the assumptions applied to future candidate wind resources.

Over the past decade, wind generation in New Mexico has expanded considerably, growing by an average 300 MW per year since 2015. New Mexico's wind resource potential is significant and has attracted interest from buyers within and outside of the state. The highest quality wind in New Mexico is located in the eastern part of the state alongside the border of Texas where supplies are abundant or along the Southern High Plains depicted by the dark blue areas in Figure 0-3.

Figure 0-3. Average wind speed in the southwest U.S.

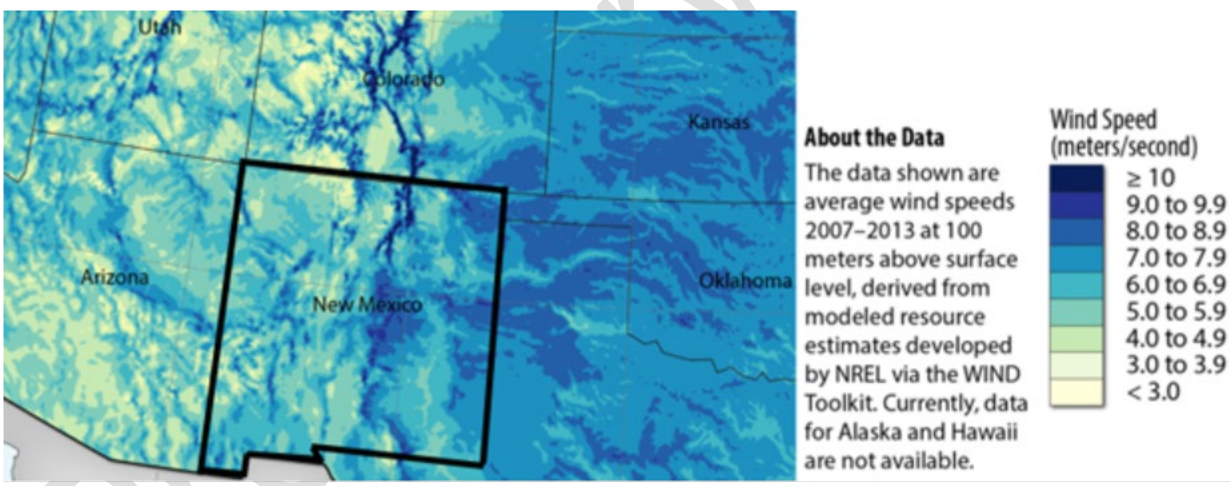


Image source: NLR, *Wind Resource Maps and Data,* available at: https://wrdb.nlr.gov/data-viewer

The high-quality wind resources in New Mexico are generally located in the eastern portion of the state. This area has experienced significant levels of commercial development to supply high-quality wind to PNM and other off takers elsewhere in the Western Interconnection; often using available transmission paths to deliver the energy. Wind resources are modeled using a 40% capacity factor based on PNM's historical wind generation performance. Annual cost assumptions, which include capital cost and variable cost, for new wind resources can be found in Appendix [ ]. Key cost assumptions for new wind resources are shown in table [ ].

8.2.3 GEOTHERMAL

Stakeholder Input: Geothermal Cost & Options

During the course of the 2026 IRP Facilitated Process, concern was raised by multiple stakeholders disagreeing with the capital cost input PNM provided for enhanced geothermal. Initial estimates ranged from 15,700$/kW to 39,400$/kW based on a three-tiered expectation of development risk. Multiple stakeholders participating in the 2026 IRP facilitated process expressed concern that the cost PNM provided was not reflective of the current costs today citing the 2025 Geothermal Drilling Cost Curves study[4]. The costs provided by PNM characterized enhanced geothermal as an emerging technology with no real-time utility scale commercial experience. Although small projects exist; transparency regarding the process and cost impacts are ambiguous with no public data supporting lower capital costs. This prompted an interim IRP meeting (i.e. office hour meeting) whereby each party presented their support for the basis of capital costs. Subject matter experts from the New Mexico Working Geothermal Group, EPRI (who provided costs estimates for the 26IRP) and PNM along with many other interested stakeholders attended. This ensuing discussion focused heavily on new drilling techniques which represented approximately 57% of the total costs. Further discussion between PNM and EPRI regarding their estimates determined that cost adjustments could be revised to take advantage of these techniques. Therefore, the original capital cost of 15,700 $/kW was reduced to 13,400$/kW reflecting these advancements.

As New Mexico transitions away from fossil fuels, it is expected that new resource technologies must emerge or advancements of existing technologies need to evolve. Next generation geothermal or enhance geothermal in which the combination of federal subsidies, technological improvements in drilling processes, coupled with emerging developments in engineering have fueled new advancements in geothermal technology. In 2025, New Mexico Governor Grisham announced a landmark partnership between XGS Energy and Meta to develop 150 MWs of advanced geothermal in New Mexico. That, combined with NM's untapped geothermal resource potential could position the state into expanding geothermal generation and furthering technology advancements. PNM studied two options for geothermal in this IRP: (1) binary geothermal similar to facilities already existing in PNM's portfolio, and (2) enhanced geothermal which captures future technology advancements.

- Binary Geothermal: By far the most common geothermal utilizes two working cycles to produce energy from an underground reservoir. The primary cycle which employs a fluid to extract heat from a geothermal reservoir and a secondary cycle to which converts the extracted heat to produce energy via a steam turbine.
- Enhanced Geothermal: Deep Geothermal, takes binary geothermal and advances the extraction technology. By capturing advancements in drilling techniques to reach greater depths and using proprietary, patented thermally conductive slurry material surrounding the pipes embedded within the earth, heat transfer is improved. Enhanced geothermal energy promises greater transfer capabilities and subsequently greater generation than traditional binary geothermal technology.

Binary Geothermal cost and performance characteristics for new resource projects are summarized in Table [ ]. Capacity factors for traditional geothermal resources are based on information provided by the owners of the geothermal facility within PNM's resource portfolio. Cost assumptions for new resources, technology curves, and other characteristics can be found in Appendix X.

Subsequent internal PNM discussions recognized the importance of geothermal and extreme interests of many stakeholders. Rather than relying only on enhanced geothermal as the only candidate resource for geothermal, PNM decided to include binary geothermal in addition to the modeling database. Traditional geothermal has lower capital costs and is well positioned to compete with other technologies.

8.3 New Energy Storage Resources

Stakeholder Input: Storage Forced Outage Rates

During a review session, a stakeholder observed that the forced outage rates assumed for the candidate 4-hour and 8-hour lithium-ion battery resources differed from those assumed for PNM's existing battery storage facilities. This observation led PNM to conduct additional review and analysis. The original forced outage rate assumptions were obtained from EPRI TagWeb, a reliable industry source. However, after further evaluation and to better align the assumptions with PNM's SERVM analyses and the expected performance characteristics of lithium-ion battery technologies, PNM agreed and concluded that the forced outage rates for lithium-ion storage resources should be more consistent across similar technologies. Consequently, PNM revised the forced outage rate assumptions for the candidate battery storage resources, increasing them to more closely align with the assumptions used for PNM's existing and planned battery storage facilities.

Lithium-Ion Battery

Among the various forms of chemical storage, lithium-ion battery storage is the most competitive technology for short-duration applications (typically applications of up to four hours) with multiple installations on PNM's systems to date. Because there is no leading competitor in short duration storage, lithium-ion battery technology remains the best commercially available resource to meet PNM's dynamic balancing requirements. Under the Inflation Reduction Act, battery storage developers can claim an Investment Tax Credit (ITC) through 2033, with the credit phasing down through 2035 and expiring in 2036. Projects can receive a base rate adjustment which can raise the ITC to a full 30% if they can meet the Prevailing Wage and Apprenticeships requirements. To capture these benefits, PNM has included a full 30% ITC on all storage projects modeled until 2033, 22.5% in 2034, and 15% in 2035 effectively reducing the overnight capital costs used for modeling.

The IRP analysis models four-hour and eight-hour lithium-ion batteries as an option to meet future capacity and flexibility needs. These storage technologies share similar operating characteristics, with the primary distinction being their storage duration and energy capacity. Cost assumptions are explained in further detail in appendix XXX.

Flow Battery

Pumped Hydro Storage

Pumped Hydro storage (PHS) is a form of gravitational storage that uses hydraulic pumps to move water from a reservoir at lower elevation to one at higher elevation; water stored at the higher elevation can eventually be run through hydraulic turbines to generate electricity when needed. Pumped storage is a mature technology that has been widely deployed.

Several factors currently present barriers to widespread deployment of pumped storage. First, there are a limited number of sites that are suitable for pumped storage development from both a hydrological and permitting perspective. Second, potential projects are generally very large (sometimes described as “lumpy” investments), which makes it difficult for a single off taker to finance the plant. Third, the timelines for permitting and development of new pumped storage resources are typically longer than many other types of resources and therefore require advanced planning and commitment.

Despite development challenges, pumped storage is a proven mature option for longer duration storage whose long storage can provide both dependable capacity for resource adequacy and flexibility to balance renewable variability. In this IRP, pumped storage is included in all scenarios to help inform PNM’s strategy regarding planning for long lead time investments.

This IRP assumes a minimum project size of 100 MW and a 24-hour storage capability, reflecting the technology’s lack of modularity and the likely necessity that PNM take on a large share of a project to effectuate development. Given the relatively long lead time for new pumped storage development due to permitting, development, and potential coordination of joint ownership agreements, the IRP does not consider new pumped storage as an option prior to 2034. Similar to battery storage systems, federal tax incentives for pumped storage systems is largely dependent upon the Inflation Reduction Act which can range anywhere from 6% to 30% for total qualified capital and construction costs for projects, which effectively reduces the overnight capital costs used for modeling, placed in service throughout 2033. Beginning in 2034, the ITC rachets down over a period of two years.

The costs and characteristics of pumped storage facilities are highly site-specific and can vary considerably. The cost and operational assumptions for the representative plant modeled in this IRP can be found in appendix XXX. Table xXX summarizes the key resource cost and characteristics assumed for pumped hydro.

Compressed Air Energy Storage

Compressed air energy storage (CAES) is a form of long-duration storage that uses surplus electricity to compress air to high pressures for storage, usually in a subterranean geologic formation. The compressed air can later be withdrawn and, at high pressure, used to power a turbine to generate electricity. The requirement for a sizeable, enclosed volume in which to store the compressed air requires specific geological conditions, which inherently limits opportunities to develop CAES at scale; however, some potential sites have been identified in New Mexico. Numerous abandoned sites from the oil and gas industry in New Mexico offer favorable cavern sites where CAES could be potentially located. CAES has a lower round-trip efficiency than lithium-ion batteries but is more suitable for longer-duration storage. Although a small number of projects are currently operating to date, CAES has not been widely deployed globally or nationally. CAES systems qualify as energy storage under the Inflation Reduction Act and therefore can take advantage of ITC benefits. Like other storage technologies, a 30% ITC was applied for any CAES project until 2033 which effectively reduces the overnight capital costs used for modeling, with the credit phasing down over the following two years before expiring in 2036.

A compressed air energy storage facility with a 100 MW capacity and a storage duration of 10 hours. Table XXX summarizes the cost and performance characteristics for CAES. More information on costs and operating characteristics can be found in Appendix XXX.

Long Duration Energy Storage (Ion-Air Energy Storage)

Iron-air energy storage is a developing long-duration battery that utilizes the natural rusting process and is the most promising technology for long duration storage. Surplus electricity is used to reverse the process, converting rust to iron. The battery then takes in air from its surroundings, re-converting the iron to rust and releasing the stored energy as electricity. Iron-air batteries have a very low (less than 50%) round-trip efficiency and are slower to ramp up and down. However, iron-air batteries have the potential to provide upwards of 100 hours of storage. Iron-air storage is a relatively nascent technology that is steadily moving along the development stage and beginning to construct larger scale demonstration targets. Although a developing technology, Iron-air qualifies for federal tax incentives similar to all other energy storage technologies effectively reducing the overnight capital costs used for modeling.

Iron-air storage is the longest-duration storage option considered at a duration of 100 hours. This resource is included in the analysis beginning in 2029. Assumptions used to model this technology are summarized in Table xx. More information on present and future cost curves can be found in appendix XXXX.

Long Duration Storage Maturity

As PNM continues its transition toward a carbon-free portfolio, periods of prolonged low renewable output become increasingly important planning considerations. While wind and solar resources provide significant amounts of low-cost, carbon-free energy, historical operating experience has demonstrated that there are periods when renewable generation is reduced due to weather related factors, requiring the system to rely on dispatchable resources to meet customer demand. As more renewable resources are added to our system, the potential for multi-day periods of below-average solar and wind generation becomes an increasingly relevant reliability consideration. Long-duration energy storage technologies have the potential to help address these challenges by storing excess energy during periods of high renewable generation and discharging that energy when needed over extended durations, ranging from 24 hours to multiple consecutive days. By shifting energy across longer time horizons, long duration energy storage resources may help support reliability and improve utilization of carbon-free generation during periods of reduced renewable output.

PNM evaluated two energy storage technologies capable of storing and discharging electricity for 24 hours or longer. One of these technologies was pumped hydro storage (PHS), which is the oldest, most commercially mature, and most widely deployed utility-scale electricity storage technology in the world. However, its deployment is constrained by site-specific requirements, including sufficient elevation differences between reservoirs, suitable geology for dams, reservoirs, and tunnels, adequate water resources, and sufficient land area. These characteristics must also align with existing transmission infrastructure to help minimize cost to ratepayers

The second technology evaluated was iron-air energy storage. This emerging long-duration energy storage technology can provide up to 100 hours of storage. Several utility-scale projects are currently under development or deployment in the United States, representing some of the first commercial applications of the technology. Although iron-air energy storage remains in the early stages of commercial deployment and has relatively low round-trip efficiency, the technology offers several potential advantages. Iron-air systems are modular, utilize abundant and low-cost materials such as iron, and employ a water-based, non-flammable electrolyte. These characteristics may allow iron-air batteries to provide a potentially low-cost multi-day storage solution while offering potential safety advantages compared to some conventional battery technologies. While both technologies were evaluated as candidate resources, iron-air energy storage was selected in numerous modeled sensitivities, suggesting that multi-day storage may provide value under a range of future system conditions.

8.4 New Thermal Resources

Thermal resources are generating resources that produce electricity by using some form of heat – typically created through combustion of a fuel – to power a turbine. The options for thermal resources considered in this IRP represent potential innovative solutions that may contribute to PNM's transition to a carbon-free portfolio. These include both investments in new technologies and retrofits of existing fossil-fueled resources to reduce or eliminate their emissions.

8.4.1 Hydrogen-Ready Combustion Turbines

A promising pathway based on technology that exists today is the conversion of natural gas-fired generators to burn carbon-free fuel, such as green hydrogen produced through emissions-free resources, to provide peaking capacity. This IRP evaluates the option of building new hydrogen-ready combustion turbines to meet future resources needs, assuming the plants will initially operate using natural gas fuel but will be converted to operate using hydrogen by 2045. Only natural gas technologies that may be converted to burn 100% hydrogen fuel in the future are considered to increase likelihood that these investments can remain in use beyond 2045. This option builds upon the assumption that hydrogen could be purchased as a commodity by 2045, similar to how PNM purchases natural gas to fuel its natural gas generators today.

Combustion of hydrogen to produce electricity presents some engineering challenges in comparison with the operation of natural gas power plants. Namely, hydrogen's lower volumetric energy content necessitates a higher flow rate, which in turn requires that plants be designed with specialized equipment and accessories. Many modern aeroderivative turbines are capable of operating with a blend of hydrogen and methane fuel – some as high as 90% hydrogen by volume – but will require some limited component changes to enable direct combustion of 100% hydrogen.

While the capability to burn hydrogen is a prerequisite for consideration in the IRP analysis, it is worth noting that hydrogen is not the only carbon-free fuel that these types of plants could consume while transitioning toward a carbon-free portfolio. Renewable natural gas and synthetic hydrocarbons are also potential fuel sources, and the capability of these plants to combust any of these fuels helps preserve flexibility in any plan that includes combustion turbines as new resources.

8.4.2 Combustion Turbine (Aeroderivative)

The LM6000 is an aeroderivative combustion turbine derived from aircraft engine technology and adapted for electric power generation. It generates electricity by compressing air, combusting fuel, and using the resulting hot, expanding gases to spin turbine blades connected to a generator. The LM6000 can operate on a variety of fuels, including natural gas and diesel, and has been developed for operation with hydrogen blends. Due to its fast-start capability, the unit can reach full output in approximately 10 minutes, making it well-suited to provide contingency reserves and support grid reliability during unexpected events such as the loss of a generating unit or a transmission line outage.

PNM used EPRI as the source for the unit characteristics and adjusted the data for 4,500 feet above sea level. The cost and performance characteristics for an LM6000 turbine are summarized in Table XXX. If selected prior to 2045, new aeroderivative turbines operate using natural gas and are assumed to convert to hydrogen in 2045 (incurring a one-time capital upgrade cost to address the engineering challenges described above) and not amortized over the life of the equipment. This assumption effectively penalizes any aeroderivative technology during the planning period to prevent any possibility of creating a stranded asset. Information on future cost curves can be found in appendix XXXX.

8.4.3 Combustion Turbine (Heavy Frame)

Simple cycle heavy-frame gas turbines provide reliable, dispatchable generation when renewable resources such as wind and solar are not available or are insufficient to meet customer demand. This turbine operates by drawing air into a compressor, where the air is pressurized before being mixed with fuel and burned in a combustor. The resulting hot gases expand through the turbine, causing the turbine shaft to rotate. This rotating shaft drives a generator, which converts the mechanical energy into electricity. This technology can also provide reliability services, including voltage support and spinning reserve capability, to help maintain system reliability.

The cost and performance assumptions for a heavy frame turbine are summarized in Table XXX. PNM used EPRI as the source of the unit characteristics and adjusted the data for 4,500 feet above sea level. If selected prior to 2045, new heavy frame turbines operate using natural gas and are assumed to convert to hydrogen in 2045 (incurring a one-time capital upgrade cost) and not amortized over the life of the equipment. This assumption effectively penalizes any heavy frame technology during the planning period to prevent any possibility of creating a stranded asset. Information pertaining to the future cost curves for this technology can be found in appendix XXXX.

8.4.4 Combined Cycle

With average operating heat rates lower than those of traditional simple-cycle combustion turbines, combined-cycle facilities can generate electricity more efficiently than conventional heavy-frame gas turbine plants operating in simple-cycle mode. Compared to gas-fired peaking resources, combined-cycle plants generally require higher upfront capital investment but have lower operational costs per megawatt-hour of electricity produced. These facilities typically operate as baseload or intermediate-load resources, providing reliable capacity and energy when renewable resources such as wind and solar are unavailable or insufficient to meet system demand. Combined-cycle facilities equipped with carbon capture and sequestration (CCS) may also provide a pathway for reducing carbon emissions while continuing to supply firm, dispatchable generation.

- Combined Cycle (CC): This technology captures the thermal energy contained in the exhaust of a simple-cycle heavy-frame gas turbine that would otherwise be released to the atmosphere. This recovered heat is used to produce steam in a heat recovery steam generator (HRSG). The steam is then directed to a steam turbine, which generates additional electricity without requiring additional fuel combustion.
- Combined Cycle with Carbon Capture Sequestration (CC-CCS): This addition to a combined cycle facility allows the capturing and permanent storage of carbon dioxide emissions in underground geologic formations, this technology can substantially reduce the carbon emissions associated with electricity generation while continuing to provide firm, dispatchable power.

To minimize water usage and associated costs, PNM assumed this combined cycle gas turbine will utilize dry cooling technology, which is included in the capital cost estimates. PNM used the EPRI TAG database as the source of the unit characteristics and adjusted the TAG data for 4,500 feet above sea level. Table XXXX summarizes the cost and performance assumptions for CC and CC-CCS. These candidate resources are considered as options in all scenarios beginning in 2031. More information on cost curves can be found in Appendix XXXX

8.4.5 Linear Generator

Linear generators are a novel, firm thermal resource which offers an alternative to combustion turbines. Linear generators work by driving magnets attached to oscillators, which interact with surrounding copper coils. The constant back-and-forth motion of the magnets produces electricity. The magnets oscillate repeatedly as air and fuel are compressed in an inner chamber, pushing the magnets outward; followed by the compression of air in the outer chamber pushing the magnets back inward.

Linear generators possess multiple advantages over traditional combustion turbines: (1) they produce minimal criteria pollutants such as NOx, (2) they can switch between fuels (e.g. natural gas to hydrogen) without any significant capital expenditures or upgrades, and (3) they can be built in small, modular units to fulfill specific locational needs to mitigate need for new transmission, much like battery storage. Linear generators are currently more costly than traditional thermal generators and have only been deployed at a small scale to date.

The assumptions for the cost and performance characteristics of linear generators are summarized in table XXX. Present cost data and future cost curves are summarized in Appendix XX. Like hydrogen-ready combustion turbines, new linear generators are assumed to operate using natural gas fuel through 2044; however, no capital upgrades are needed to do so, as the linear generator technology is already technically capable of operating using hydrogen fuel. In all scenarios, linear generators are first included as an option in 2030.

8.4.6 NUCLEAR

Small Modular Reactors (SMRs) are nuclear power plants designed using modular construction techniques that allow major components to be factory fabricated and transported to a project site for installation. SMRs provide carbon-free electricity generation and, unlike variable renewable resources such as solar and wind, can generate electricity around the clock. In a light-water SMR, nuclear fission generates heat that is transferred to water. Heated water produces steam, which is directed through a steam turbine connected to an electric generator to produce electricity.

SMRs have the potential to support New Mexico's decarbonization goals while also enabling hydrogen production. Because SMRs can provide both electricity and steam, they may support hydrogen production through electrolysis. Studies5 have evaluated the use of electricity and process steam from SMRs for hydrogen production, and certain high-temperature steam electrolysis processes can utilize both electrical and thermal energy from the reactor, improving overall hydrogen production efficiency.

Table X summarizes the cost and performance assumptions for SMR. This technology is considered as an option in all scenarios beginning in 2035. More information on annual costs and performance characteristics for this technology can be found in Appendix XXX.

8.5 Accredited Capacity of New Resource Options

In addition to accrediting the existing fleet, as discussed in section ZZZ, ELCC values were developed for incremental additions of resources to inform the expansion planning process. Incremental ELCCs were calculated for wind, solar, 4HR storage, 8HR storage, pumped storage hydro, demand response, and energy efficiency resources.

As described in Appendix ZZZ, incremental ELCC was calculated by adding resource capacity to the 2029 base case and then adding load until LOLE returned to its original level. The load required to restore the base case LOLE, determined through interpolation, represents the accredited ELCC at that capacity level. Dividing this value by the resource's nameplate capacity yields the ELCC percentage.

Solar and storage resources were evaluated at increasing penetration levels to determine both cumulative (average) and incremental (tranche) ELCC values. Solar resources were assessed independently, while storage resources were paired with solar at a 2:1 ratio. Tranche ELCC results were used to develop continuous incremental ELCC curves for solar and storage technologies. Wind resources were evaluated at discrete penetration levels, while geothermal, demand response and energy efficiency were each assessed at a single increment.

Conventional thermal resources were accredited using an ELCC methodology applied across five resource categories: combined cycle, combustion turbine, nuclear, steam coal, and steam gas. The analysis was based on a 2029 system case calibrated to the 0.1 LOLE reliability target. Additional methodology details are provided in Appendix ZZZ.

For purposes of modeling candidate resource options, marginal ELCC curves were used to determine the appropriate accredited capacity to be applied to each new resource type depending upon the penetration level. Tables Z, Z, Z and Z show the marginal ELCC's of each resource type used in PNM's 2026 IRP modeling efforts.

Table Z – Marginal ELCC for new Solar resource additions

800	3%
1,600	<1%
2,400	<1%
3,200	<1%
4,000	<1%

Table Z – Marginal ELCC for new Wind resource additions

500	8%
1,000	2%

Table Z – Marginal ELCC for new Storage resource additions

400	42%	58%	74%
800	26%	42%	61%
1,200	22%	28%	43%
1,600	—	26%	37%
2,000	—	26%	38%

Table Z – Marginal ELCC for new gas, nuclear, geothermal, DR and Energy Efficiency resource additions

Resource	ELCC (%)
Combined Cycle	92%
Combustion Turbine	98%
Nuclear	94%
Geothermal	76%
Demand Response	63%
Energy Efficiency	50%

8.6 Zonal Transmission Adder for New Resources

(Being drafted)

8.7 Summary

Table 0-3 summarizes key assumptions in the EnCompass database for candidate resources which are included in all modeling runs.

Table 0-3. Cost & performance characteristics, all candidate resources

Resource	2026$	Performance Characteristics				
	Capital Cost	Fixed O&M	Variable O&M	Heat Rate	Investment Tax Credit	Operating Life
	$/kW	$/kW-yr	$/MWh	Btu/kWh	Yes/No	Years
Solar - Photovoltaic	1,477	15	N/A	N/A	No	30
Wind	2,306	47	N/A	N/A	No	25
Battery Storage (4 hr.)	1,661	13	N/A	N/A	Yes	20
Battery Storage (8 hr.)	2,386	85	N/A	N/A	Yes	20
CAES	4,056	29	8	N/A	Yes	40
CT (heavy frame)	1,922	14	8	10,236	No	30
CT (aero)	2,850	33	6	9,449	No	30
Combined Cycle	2,451	18	4	6,762	No	30
Combined Cycle with CCS	5,011	31	5	7,765	No	30
Linear Generator	2,996	7	7	7,582	No	30
Geothermal	7,959	185	1	N/A	No	30
Enhanced Geothermal	13,407	184	1	N/A	No	30
Iron Air Energy Storage	3,993	20	N/A	N/A	Yes	30
Pumped Hydro	3,331	31	N/A	N/A	Yes	50
SMR	6,333	107	9	10,900	No	30

8.8 Commodity Price Forecasts

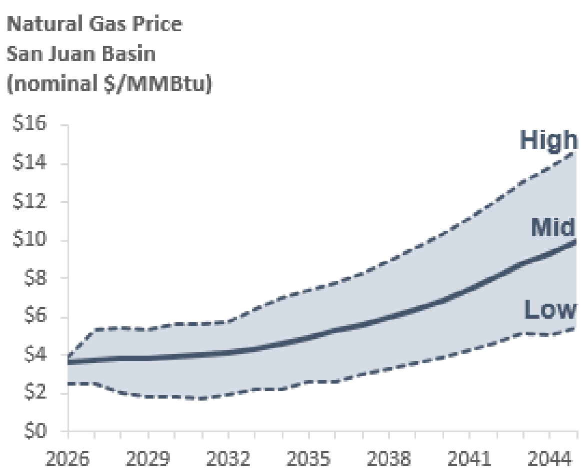
Historically, forecasted commodity costs have played a critical role in determination of which resources are selected in the preferred portfolio and longer-term planning. In this IRP, decisions around PNM's portfolio are primarily driven by emissions reduction, RPS targets, and maturity of long duration storage with commodity costs playing a smaller role. Still, the cost implications of these decisions are impacted by the expected prices for natural gas, hydrogen fuel, and the wholesale electricity throughout the IRP timeframe. The comparison between these variable costs and the upfront costs of renewables and storage helps to determine the optimal resource selection to be carbon reduction targets and meet customer need.

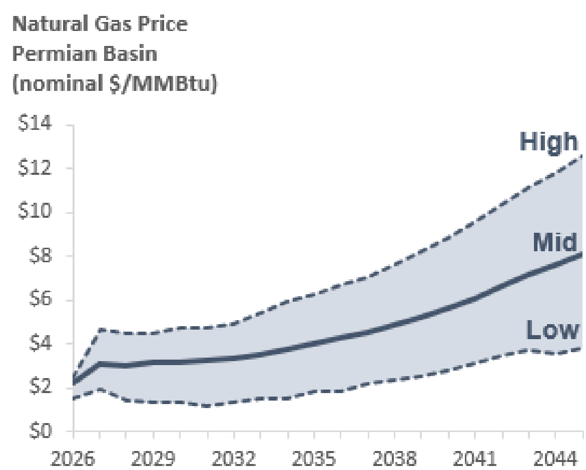
8.8.1 Natural gas Prices

PNM's natural gas supplies are sourced from two production basins: the Permian Basin in Texas and the San Juan Basin in the Four Corners region. The plants in the southern part of New Mexico are typically supplied from the Permian Basin via the El Paso Natural Gas (EPNG) Southern Mainline; plants in the north can also be supplied from the San Juan Basin via either New Mexico Gas Company's system or by either the EPNG Northern Mainline or the Transwestern Pipeline. Forecasts for natural gas commodity prices in each of these supply basins were developed by Siemens using fundamentals-based analysis of continental supply and demand for natural gas as well as forward prices up to October 2025.

Under the low natural gas pricing curve, negative pricing was forecasted for the winter of 2026 due to high production and low demand. This occurrence is expected to occur in the near term for only a short while. To mitigate any risks this imposed on the resource planning picture, PNM adjusted the near term of the forecast provided by Siemens with the natural gas forward pricing for the low case only. Thus, the low pricing case for natural gas is based on forward pricing for the first two years and a fundamental forecast thereafter.

These forecasts are shown in__; supporting data is provided in Appendix _.





In addition to the commodity cost of natural gas, PNM pays additional fees and taxes to deliver natural gas from the supply basins to the burner tip of PNM's generators. These fees and taxes include fuel surcharges, pipeline usage and transportation charges, and local gross receipts taxes. While these specific costs vary by plant based on its location and the pipeline transporting the fuel, they generally add between $0.82 to $2.06/MMBtu in additional costs to deliver natural gas to generators.

8.8.2 Hydrogen Prices

One of the potential options to meet a portion of future planning reserve needs in a carbon emissions-free portfolio is to repurpose natural gas generation infrastructure to operate using a "drop-in" carbon-free fuel. Since the passage of the IRA, commercial interest in hydrogen as an energy carrier has grown considerably. *The 45V tax credit for hydrogen production is expected to stimulate a nascent industry, and the Department of Energy (DOE) recently announced $7 billion in grant awards to seven proposed hydrogen hubs around the country.* As the industry begins to gain momentum, the prospect that some form of carbon-free fuel – hydrogen, renewable natural gas, or other synthetic fuels – may be available by 2040 is increasingly promising.

These fuels are appealing for numerous reasons: first, they would continue operations of some existing natural gas generation infrastructure beyond the 2044 time frame, allowing PNM to recover the costs of investments over a longer economic lifetime and thereby mitigating costs to customers; and second, they would provide an option for a firm, carbon-free resource, a crucial cornerstone of a reliable carbon-free portfolio. Present expectations suggest that these fuels would likely be costly to produce, deliver, and store; nonetheless, PNM would expect to use them infrequently and in small quantities much like peaking plants today.

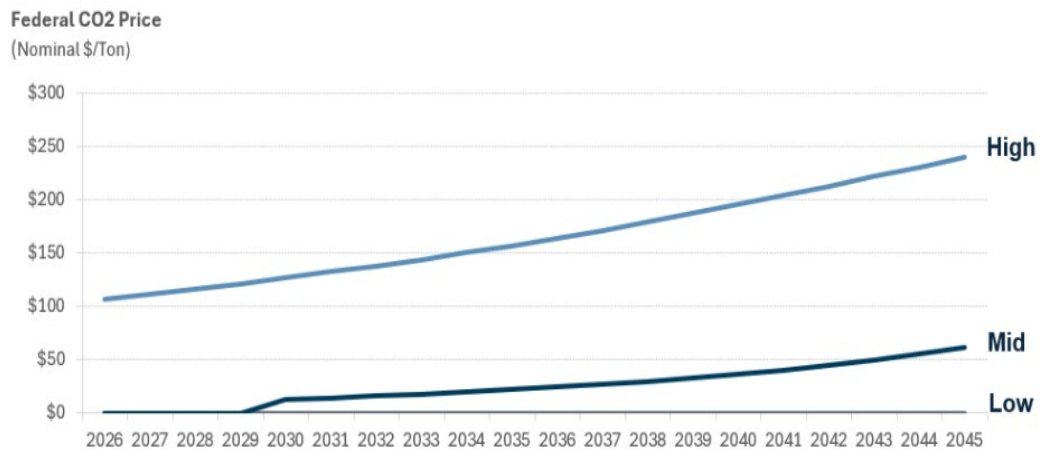
While these types of options would provide significant value to PNM's customers in the context of its 100% goal, the price at which these fuels may be offered in the future is a significant uncertainty. While many of the technologies needed to create these fuels exist today, the supply chains to produce and deliver these fuels at scale do not. Whether and at what scale these types of fuels are available will have particularly significant ramifications upon the nature of the challenges as PNM's portfolio approaches 100% carbon emissions-free energy. This IRP assumes a hydrogen fuel cost in 2045 of $21.36/MMBtu, a price intended to reflect the all-in cost of production of hydrogen using renewable energy, storage, and delivery of hydrogen within a 50-mile radius and does not include any federal tax incentives or credits.

8.8.3 Carbon Prices

This IRP analysis considers three forecasts of future carbon pricing derived from scenarios originally developed by Siemens. The lowest carbon price projection assumes no state or federal carbon pricing regimes throughout the planning period. For the CTP future, carbon pricing assumes no carbon tax which is reflective of the current policies. For the "Base" which begins in 2030 at about $11/ton and escalates over the planning period to $33/ton; in the "High" case, carbon pricing begins in 2025 and escalates at a higher rate to reach $129/ton by 2042.[1]

In addition to these scenarios, the standardized carbon Rule requires utilities to provide portfolio cost estimates using CO2 emission prices of $8, $20, and $40 per metric ton (starting price in 2010 dollars, escalating at 2.5% per annum). To implement these prices beginning in 2025 would make carbon pricing tremendously high to be considered useful. Rather than create unnecessary work, the carbon pricing scenarios that were developed by Siemens were the only carbon pricing used in scenario modeling.

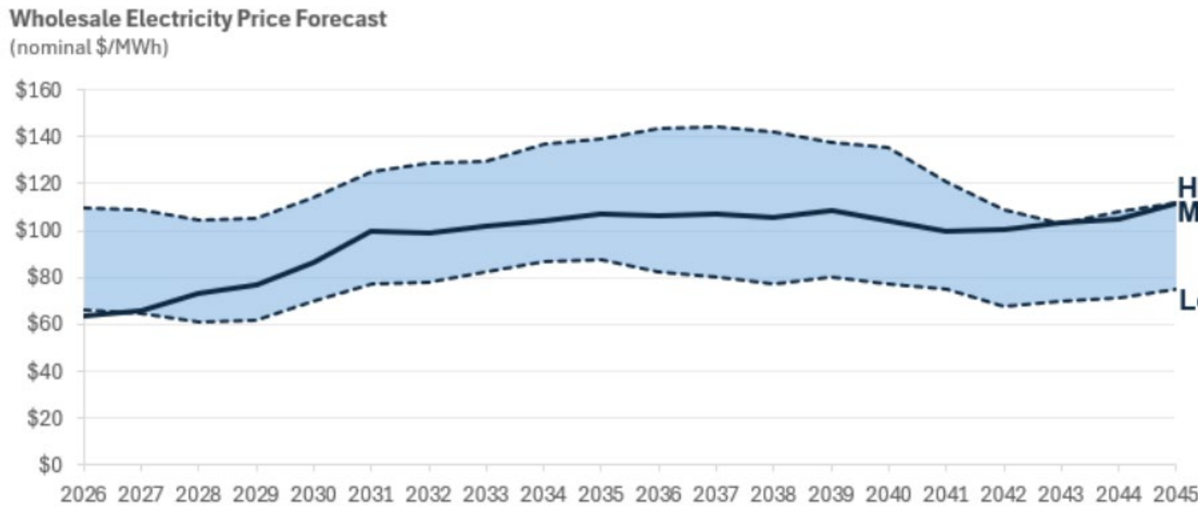
The full range of carbon pricing scenarios analyzed in the IRP is shown in Figure _.



8.8.4 Wholesale Electricity Market Prices

To capture the dynamics of PNM's interactions with the broader region within its planning process, this analysis incorporates projected wholesale market prices at the Palo Verde (PV), Four Corners (FC) and Southwest Power Pool (SPP) market hubs. Historically PNM has only included two market hubs; however, to ascertain any benefits that could be obtained through the nodal modelling of transmission alternatives the SPP market hub was included. These forecasts are also developed by Siemens using a fundamentals-based model of the Western electricity system and ?? (would this also be true for SPP hub? – ask Anuj) and reflect the same future commodity price forecasts for natural gas as PNM uses in its own analysis.

The wholesale market price projections used in this analysis are shaped on an hourly basis and reflect an expectation that continued investments in solar generation throughout the Western Interconnection will increasingly result in the lowest prices in wholesale markets during the daytime hours and the highest prices during the evening hours of sundown (exhibiting the same general shape as California's eponymous duck curve). Data for PV and FC market hubs were used explicitly in the zonal modeling. Nodal model also included SPP market hub to capture any market market interactions for the transmission alternatives sensitivities. Figure 63 shows the evolution of these patterns over the twenty-year analysis horizon as captured in the forecast provided by Siemens, in which the effects of solar saturation on daytime prices become increasingly pronounced.



8.8.5 Natural Gas Volatility Study

As part of PNM's ongoing efforts to improve the IRP process, many suggestions and improvements were made as part of the feedback for the 2023 IRP. These improvements serve to enhance the resulting reference portfolio by providing a robust analytical framework in which to understand all the implications of the results. One such request that was agreed to by PNM was to perform a natural gas volatility study in which the price swings for natural gas on a portfolio basis could be determined. As part of the 2026 IRP process, PNM contracted Siemen's to evaluate how these factors could affect natural gas prices over the planning horizon. In February of 2026, stakeholders were provided with an overview of how the study was to be conducted and were solicited for feedback. Receiving none, the study was performed as such:

1. analyze historical spot price data to calculate volatility, including short-duration market disruptions that create pricing anomalies;
2. apply this volatility to the forward curve through Monte Carlo simulation;
3. generate thousands of potential future price paths;
4. organize these paths into standard deviation bands around the forward curve;
5. apply the resulting price scenarios to forecasted monthly natural gas consumption from the IRP dispatch model to quantify gas exposure; and
6. estimate the variance between expected and unfavorable outcomes to assess potential risk to ratepayers.
7. Understand current utility practices regarding gas hedging
8. Make recommendations

To summarize, the quantitative and qualitative analyses presented in this study indicate that fuel cost variability associated with natural gas price volatility, while meaningful, can be prudently managed within the planning horizon. Simulations show that fuel cost deviations associated with natural gas price volatility remain within ranges consistent with historical market behavior, with annual variations of approximately $0.14 to $1.09/MMBtu around the forward curve. Under the high-gas-price scenarios evaluated by Siemens, this translates to an annual cost variance of approximately $26 million to $46 million, although these impacts can be substantially reduced through PNM's existing hedging program. Basis risk was estimated to contribute an additional exposure of approximately $10.8 million. While this exposure is not insignificant, the estimate does not reflect the risk reduction benefits provided by PNM's hedging program. When viewed in the context of overall portfolio fuel costs and the broader IRP planning horizon, this level of potential variance does not represent a structural threat to long-term rate stability, provided that it remains actively managed through ongoing risk-management practices. Ultimately the data concluded that the treatment of natural gas price risk within the 2026 IRP is reasonable and consistent with sound utility planning practices. The study and its findings are found in Appendix [ ].

9. Portfolio Analysis

9.1 Portfolio Analysis Overview

To evaluate future resource needs, PNM utilizes its capacity expansion model, EnCompass, to determine the lowest-cost combination of new resources that satisfies planning reserve margins and energy requirements, while meeting RPS and carbon reduction mandates at the lowest 20-year net present value (NPV).

9.2 Current Trends and Policy Modeling

9.2.1 Core Cases and Modeling Approach

To evaluate the robustness of the baseline future under varying operational, economic, and regulatory conditions, PNM analyzed twelve total core scenarios under the CTP framework, comprising the CTP Base Case and eleven alternative sensitivities. These sensitivities examine the impacts of key variables, including alternative technology costs, different rate structures, electric vehicle adoption rates, and transmission expansion, against the MCEP. Each scenario is described in Section [ ]

9.2.2 Resource Additions by Specific Technology Type

Table [ ] details the modeled capacity expansion ranges by technology type and functional resource category across all CTP core sensitivities. These ranges reflect intra-tier elasticity, capturing portfolio sensitivity to key input variables such as technology cost trajectories, natural gas price volatility, and transmission availability.

- **Focus Period (2033–2036):** Over the Focus Period, carbon-free resources, primarily new utility-scale solar PV and energy efficiency, are largely sufficient to reliably satisfy system needs. The modeling selects between 353 MW and 608 MW of solar PV alongside 196 MW of expanded energy efficiency programs. New demand response programs contribute an additional 15 MW to 45 MW of dynamic peak reduction. In select scenarios, a targeted addition of long-duration storage (100 MW of either LDES or pumped hydro) is also deployed to support system reliability.
- **Planning Period (Through 2045):** Substantial resource additions are required over the remainder of the planning horizon to achieve statutory decarbonization goals. Utility-scale solar PV increases to between 849 MW and 1,638 MW, up to 129 MW of wind capacity is selected, and 420 MW of energy efficiency programs are integrated across all core cases. To support higher renewable penetration, dynamic balancing requirements are met through 517 MW to 803 MW of short-duration battery energy storage (BESS) along with expanded demand response. The most impactful additions are firm, dispatchable carbon-free technologies needed to satisfy New Mexico's zero-carbon mandate, with the model selecting between 548 MW and 2,108 MW of firm dispatchable capacity across sensitivities, utilizing diverse technology mixes depending on scenario assumptions.

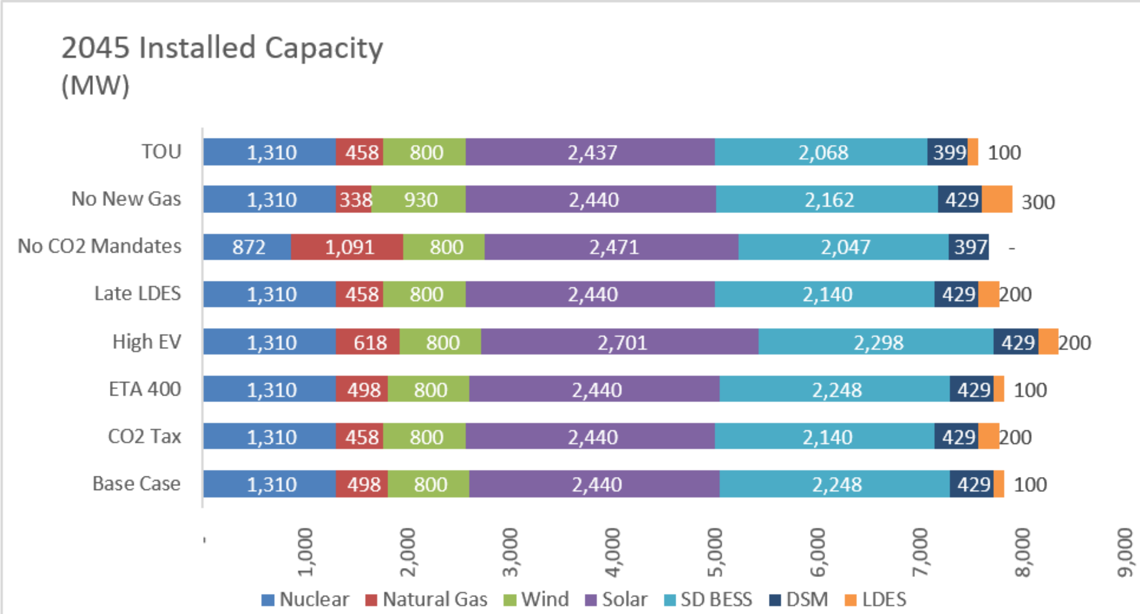
TABLE [ ]: CTP CORE CASE RESOURCE ADDITIONS BY TECHNOLOGY TYPE (MW NAMEPLATE)

Technology Type	Through 2036		Through 2045	
	Low	High	Low	High
Solar PV (Utility-Scale)	353	608	849	1638
Wind Generation	0	0	0	129
Energy Efficiency	196	196	420	420
Carbon-Free Energy	**549**	**804**	**1269**	**2188**
Battery Energy Storage (BESS - 4hr)	0	0	517	803
Demand Response (DR)	15	45	19	52
Dynamic Balancing	**15**	**45**	**536**	**855**
Long-Duration Energy Storage (LDES)	0	100	0	300
Combustion Turbines / Peakers (Gas/H_2)	0	0	0	179
Advanced Generator	0	0	0	360
Geothermal	0	0	0	0
Nuclear	0	0	584	1168
Pumped Hydro	0	100	0	100
Firm Dispatchable	**0**	**200**	**584**	**2,108**

The 'Low' and 'High' columns within each individual load scenario do not represent low or high economic growth; rather, they represent the optimization bounds driven by variations in cost, policy, and other sensitivities within that specific load track.

Figure [ ] summarizes the total nameplate capacity (MW) across all CTP core cases in 2045, reflecting cumulative candidate additions alongside existing and planned assets, net of scheduled unit retirements and contract expirations.

FIGURE [ ] CTP CORE CASES – INSTALLED CAPACITY MW (2045)



9.2.3 Portfolio Costs

As shown in Figure [ ], 20-year net present value (NPV) portfolio costs range from $13,703 million to $14,989 million across all modeled scenarios. Excluding the High EV sensitivity (which includes incremental load to serve) and the non-ETA compliant scenario narrows this range to between $13,822 million and $14,605 million NPV.

As illustrated in Figure [ ], annual revenue requirements remain relatively stable across scenarios through 2040. However, between 2040 and 2045, annual costs rise significantly and scenario outcomes diverge as portfolios expand to meet statutory clean energy and zero-carbon mandates.

These results reflect the widely recognized reality of electric sector decarbonization: while achieving the initial 80% to 90% clean energy threshold remains relatively cost-effective and provides revenue requirement stability through 2040, eliminating the final 10% to 20% of emissions requires significant capital investment in clean firm and long-duration technologies. The post-2040 cost inflection across all policy-compliant scenarios directly illustrates this dynamic, showing that achieving full zero-carbon compliance is the primary driver of long-term portfolio costs.

FIGURE [ ] CTP CORE CASES – 20 YEAR NPV

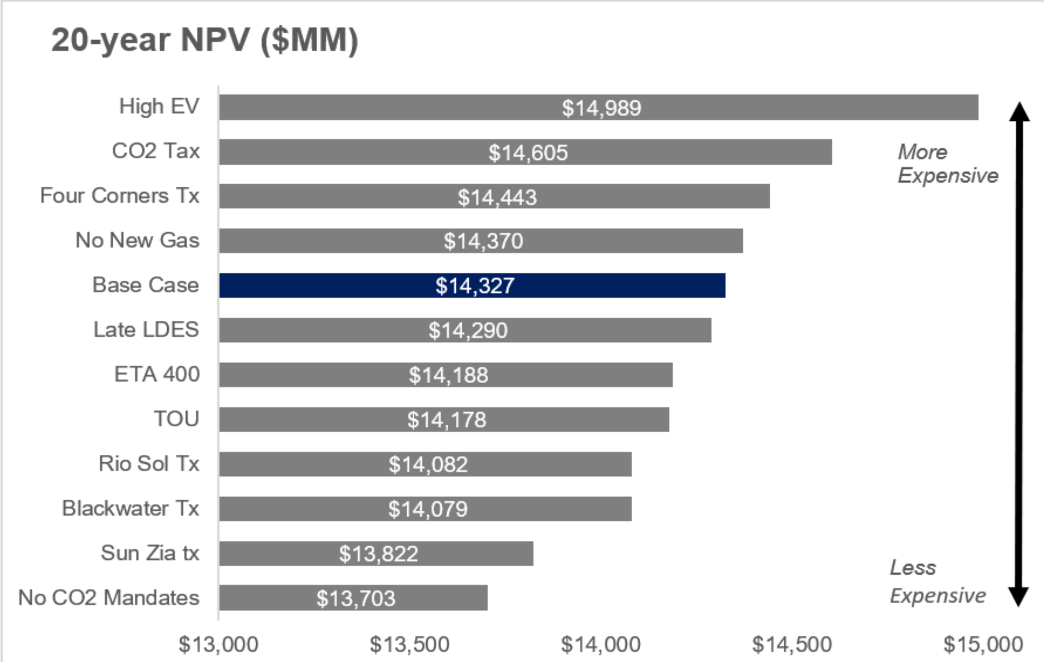
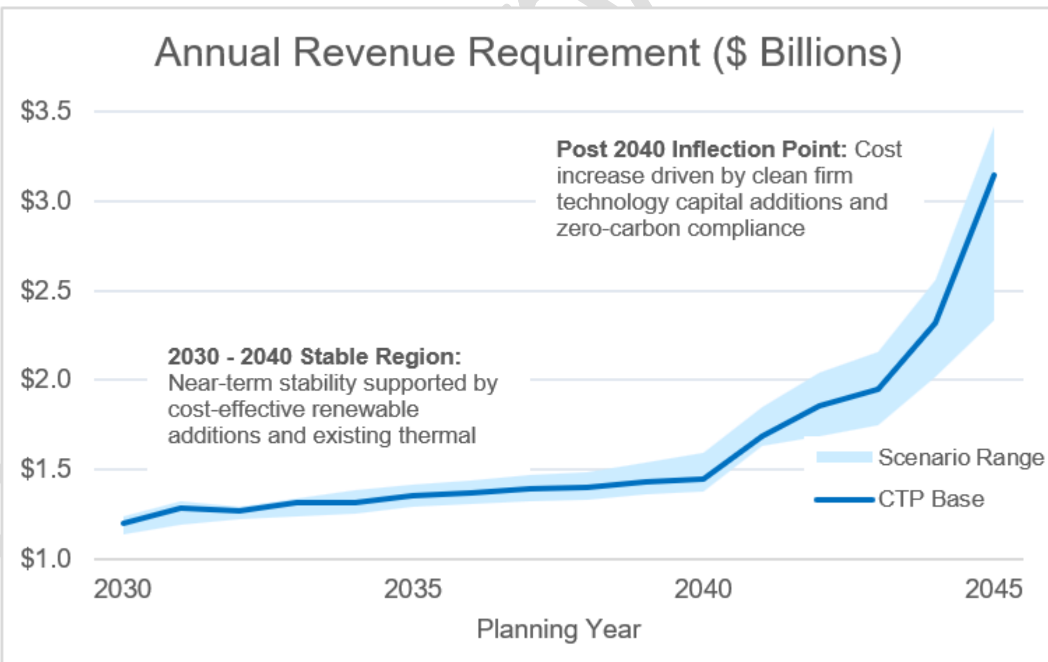


FIGURE [ ] CTP CORE CASES – ANNUAL REVENUE REQUIREMENT (2030-2045)



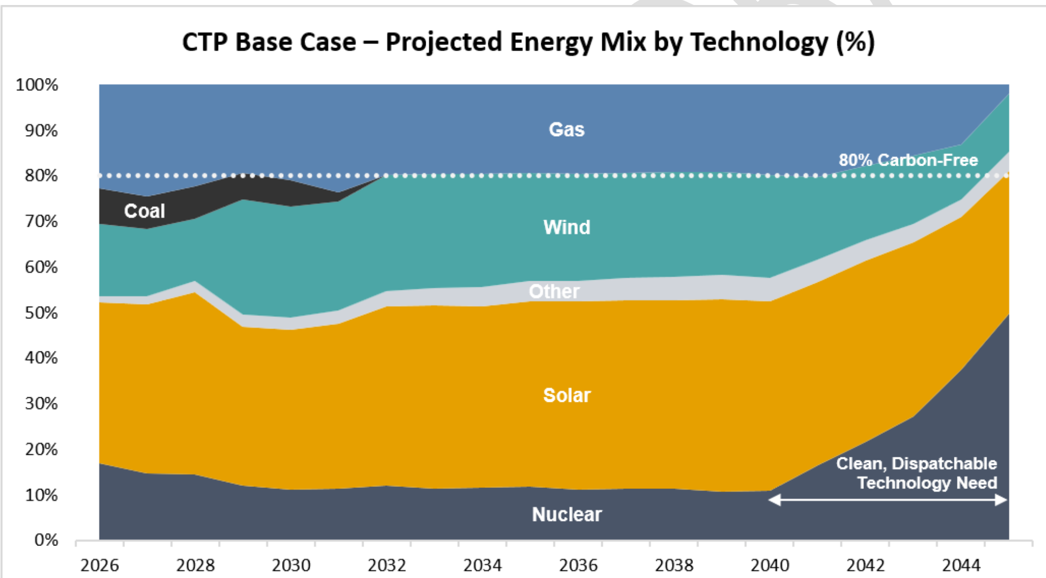
9.2.4 ENERGY GENERATION MIX

While nameplate capacity (MW) establishes system resource adequacy and peak demand, energy generation mix (GWh) illustrates how resources dispatch in practice to serve customer load throughout the year. Across all CTP core cases, the energy trajectory reflects a structural shift towards zero-carbon generation, driven by RPS targets and ETA mandates:

- **Focus Period (2033–2036):** Following the retirement of PNM's remaining coal capacity at the Four Corners Power Plant (which fully eliminates coal from PNM's portfolio) carbon-free resources supply approximately 80% of total system energy. Additionally, short-duration battery energy storage plays a critical balancing role during this period, absorbing mid-day solar overgeneration and discharging during the evening net-peak to minimize curtailments and reduce reliance on natural gas-fired generation.
- **Remainder of Planning Period:** By 2045, 100% of customer energy requirements are met by zero-carbon resources. Emerging clean firm assets (e.g., small modular nuclear reactors or advanced geothermal) serve as the zero-carbon baseload foundation, while hydrogen-fueled combustion turbines operate strictly in a targeted peaking capacity - accounting for under 1% to 3% of total annual system energy.

These energy trajectories directly mirror the financial patterns observed in the annual revenue requirements, illustrating how physical generation shifts drive long-term portfolio costs.

FIGURE [ ] 2026-2045 CTP BASE CASE - PROJECTED ENERGY MIX BY TECHNOLOGY (%)



Figures [ ] and [ ] illustrate the energy generation mix across all modeled CTP core sensitivities in 2036 and 2045, respectively. As shown below, the generation mix remains largely consistent across sensitivity in 2036 due to the closely aligned expansion plans through 2040. In 2045, portfolio energy mixes remain closely aligned across almost all runs as they ramp to meet zero-carbon targets between 2040 and 2045, diverging only in the sensitivity evaluated without CO2 mandates.

FIGURE [ ] 2036 PROJECTED ENERGY MIX BY TECHNOLOGY (%) BY CTP SENSITIVITY

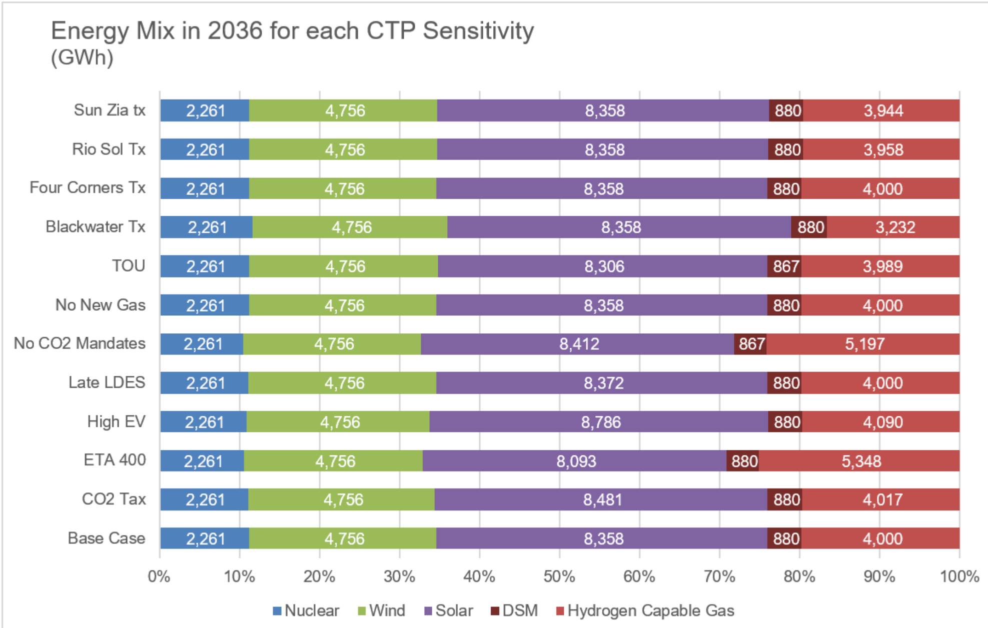
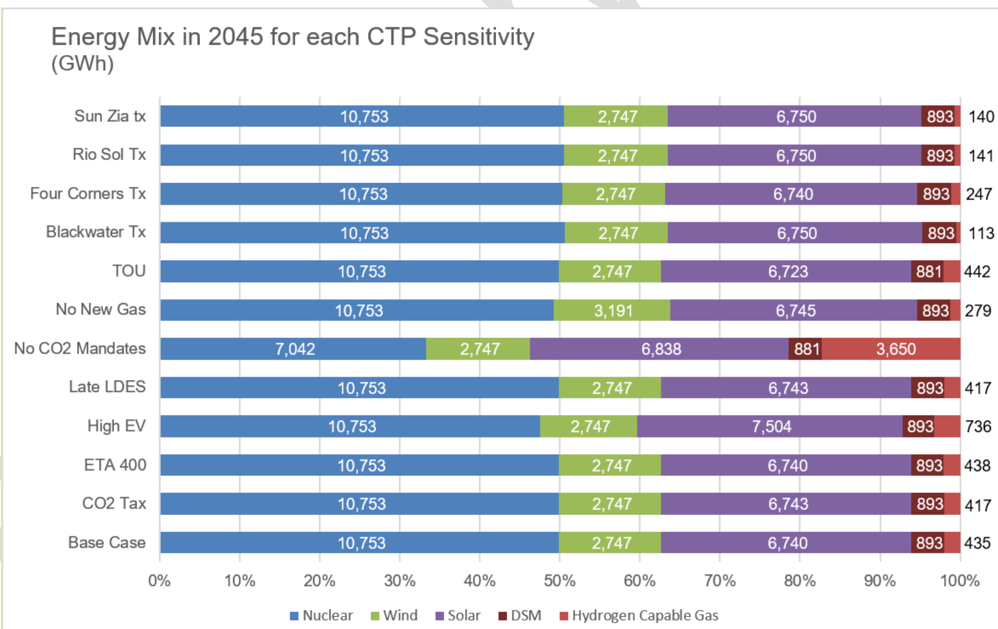


FIGURE [ ] 2045 PROJECTED ENERGY MIX BY TECHNOLOGY (%) BY SENSITIVITY



9.3 Most Cost-Effective Portfolio (MCEP)

In accordance with the IRP Rule, PNM identifies a Most Cost-Effective Portfolio (MCEP), which PNM has anchored to the CTP Base Case. This baseline case represents the expected forecast trajectories and central reference point for system planning. However, while the IRP Rule requires the utility to designate a primary MCEP, it also mandates that the IRP demonstrate how the resource plan adapts under shifting supply and demand dynamics.

Because modern utility planning involves multi-dimensional uncertainties, including evolving technology commercialization timelines, fuel price volatility, transmission expansion, and dynamic load growth trajectories, relying solely on a single static portfolio creates substantial long-term ratepayer risk. Therefore, PNM's modeling framework expands beyond the point-estimate MCEP to evaluate how portfolio choices adapt across a broad suite of sensitivity analyses.

Rather than treating the MCEP as a rigid, exclusive blueprint, PNM synthesizes the common analytical denominators across all three futures to establish tiered planning ranges. These ranges capture the baseline's underlying elasticity, providing PNM and stakeholders with transparent insight into how the MCEP dynamically evolves in response to real-world market conditions. This approach maintains essential commercial flexibility, supports prudent near-term execution during the Action Plan Period, and prevents premature capital commitments to specific emerging technologies before they achieve commercial or economic maturity.

FIGURE 0-1. INSTALLED CAPACITY ADDITIONS FOR THE MOST COST-EFFECTIVE PORTFOLIO

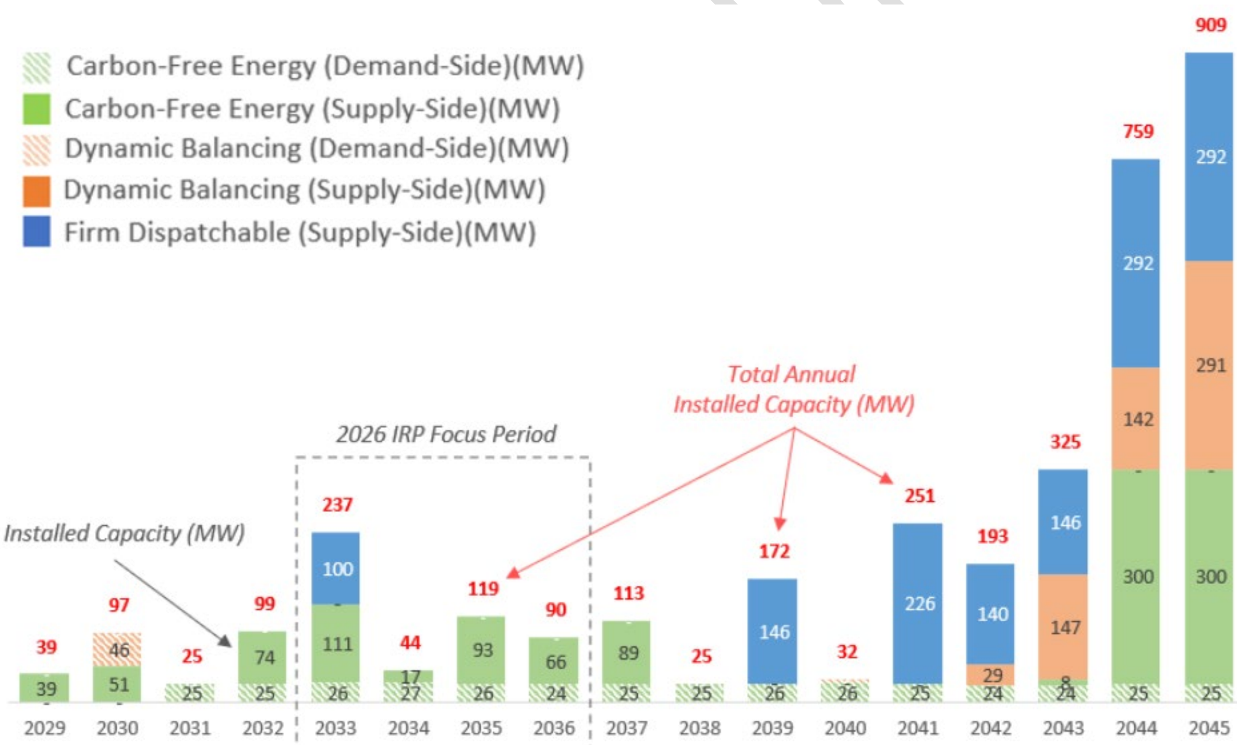


Figure [ ] outlines the volume, timing, and functional categories of proposed new resources required to reliably serve customer demand across the 20-year planning horizon while fulfilling state statutory policies.

Crucially, the resource additions included in the MCEP reflect the deterministic optimization of the single CTP Base Case prior to stress-testing against alternative market and policy sensitivities. Consequently, the formal Statement of Need (Section [ ]) integrates both the foundational MCEP baseline and the boundary variations established by the sensitivity analyses. Expressed through flexible procurement tiers and functional resource attributes, the Statement of Need ensures system resource adequacy, maintains planning reserve margins, and fulfills state environmental mandates under a least-cost, risk-managed framework.

9.4 Low Economic Growth Cases

To establish a lower-bound demand boundary and evaluate portfolio requirements under reduced demand conditions, PNM analyzed four core scenarios under the LEG framework. This boundary scenario tests system resource additions if economic conditions dampen customer demand below reference projections.

9.4.1 Resource Additions by Specific Technology Type

To test portfolio robustness against downside load risk, the Low Economic Growth (LEG) scenario models system requirements under reduced energy consumption and peak demand. Evaluating this trajectory establishes the minimum baseline of resource additions necessary to maintain reliability and fulfill statutory mandates if economic growth falls below reference case expectations.

- **Focus Period (2033–2036):** Over the Focus Period, existing and near-term committed solar and battery storage resources fully satisfy PNM's planning reserve margin requirement, eliminating the nee for uncommitted, candidate supply-side capacity additions during this timeframe. The model does still add 163 MW of energy efficiency and 9 MW of demand response programs.
- **Planning Period (Through 2045):** Even under suppressed demand growth, the structural retirement of legacy natural gas assets post-2035 creates a persistent capacity deficit. Consequently, a baseline addition of [ ] MW to [ ] MW of clean firm and dispatchable capacity is required by 2045. This core foundation is supported by between [ ] MW and [ ] MW of solar PV additions, expanding energy efficiency programs, and incremental dynamic balancing resources, including both energy storage and demand response, to maintain grid reliability during net peak periods.

TABLE [ ]: LEG CORE CASE RESOURCE ADDITIONS BY TECHNOLOGY TYPE (MW NAMEPLATE)

Technology Type	Through 2036		Through 2045	
	Low	High	Low	High
Solar PV (Utility-Scale)	0	0	778	894
Wind Generation	0	0	0	0
Energy Efficiency	163	163	369	381
Carbon-Free Energy	**163**	**163**	**1147**	**1275**
Battery Energy Storage (BESS - 4hr)	0	0	268	364
Demand Response (DR)	9	9	18	20
Dynamic Balancing	**9**	**9**	**286**	**384**

Long-Duration Energy Storage (LDES)	0	0	0	0
Combustion Turbines / Peakers (Gas/H_2)	0	0	0	0
Advanced Generator	0	0	0	40
Geothermal	0	0	0	0
Nuclear	0	0	146	584
Pumped Hydro	0	0	0	0
Firm Dispatchable	**0**	**0**	**146**	**624**

9.4.2 LEG Portfolio Costs

As shown in Figure [ ], 20-year net present value (NPV) portfolio costs range from $10,485 million to $10,802 million across all modeled scenarios. Excluding the non-ETA compliant scenario narrows this range to between $10,766 million and $10,802 million NPV.

Similar to the CTP core cases shown in Figure [ ], annual revenue requirements remain relatively stable across scenarios through the early 2040s, though this cost stability extends slightly longer than in the CTP cases due to reduced near-term load pressure. However, between 2043 and 2045, annual costs rise significantly and scenario outcomes diverge as portfolios deploy capital to meet statutory clean energy and zero-carbon mandates.

FIGURE [ ] LEG CORE CASES – 20 YEAR NPV

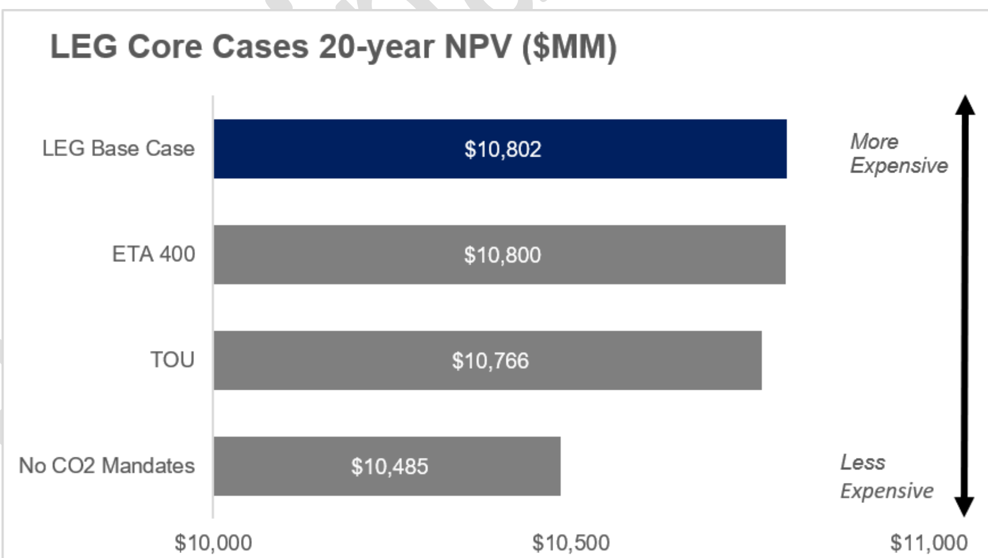
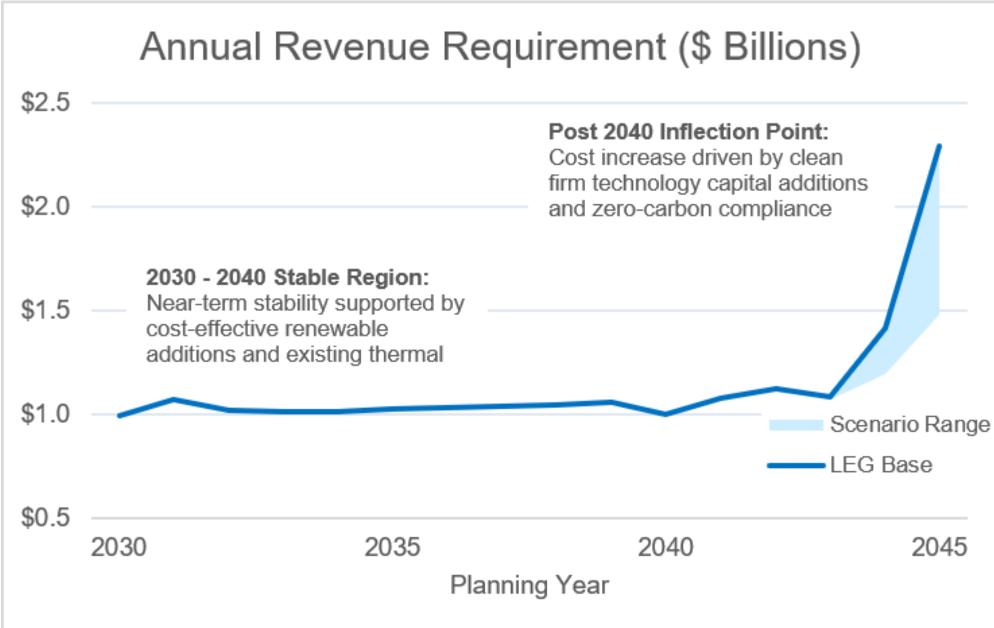


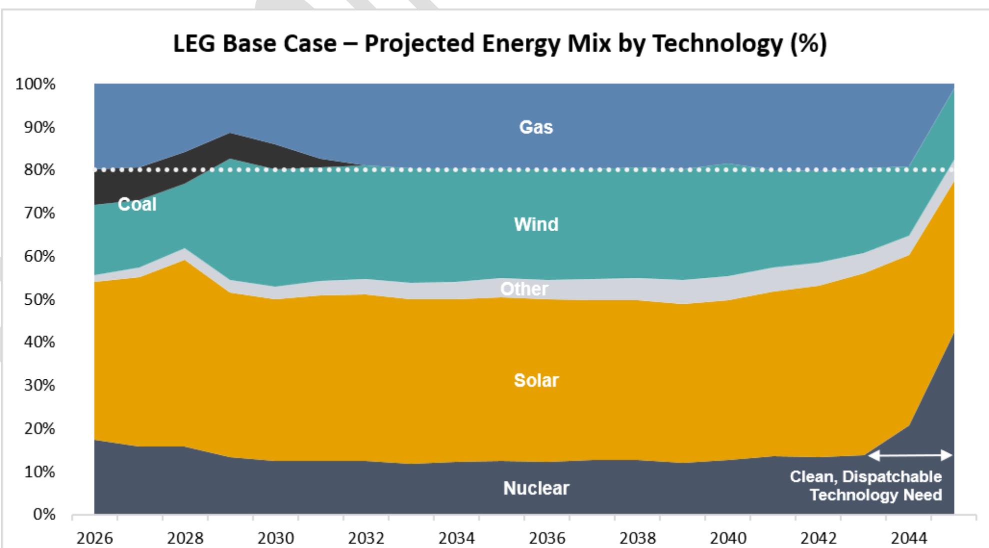
FIGURE [ ] LEG CORE CASES – ANNUAL REVENUE REQUIREMENT (2030-2045)



9.4.3 LEG Energy Generation Mix

As shown in Figure [ ], lower demand provides a slight early-period advantage in the energy mix, allowing existing and planned zero-carbon resources to easily carry the system. In fact, the portfolio maintains a steady ~80% carbon-free energy share across most of the planning horizon. In alignment with the revenue requirement trends, the final push to replace the remaining ~20% gas margin is slightly delayed, concentrating the rapid ramp in clean, dispatchable technology between 2043 and 2045 to satisfy full zero-carbon mandates.

Figure [ ] 2026-2045 LEG Base Case - Projected Energy Mix by Technology (%)



9.5 High Economic Growth Cases

The High Growth scenario evaluates portfolio needs under expanded demand conditions to determine how accelerated system energy and peak demand trajectories impact long-term resource selection. Analyzing this trajectory establishes the incremental capacity, infrastructure, and procurement timing required to preserve system reliability and fulfill statutory zero-carbon mandates if load growth exceeds baseline projections.

9.5.1 Resource Additions by Specific Technology Type

To test portfolio robustness against upside load risk, the High Economic Growth (HEG) scenario models system requirements under energy and peak demand expansion. Evaluating this higher trajectory reveals how increased load growth accelerates the need for new capacity into the near-term Focus Period, defining the advanced procurement required to preserve system reliability and fulfill statutory zero-carbon mandates.

- **Focus Period (2033–2036):** Unlike the LEG cases, incremental load growth eliminates near-term capacity margins, accelerating candidate supply-side additions directly into the Focus Period. To satisfy planning reserve margins and maintain peak reliability, the model brings forward between [ ] MW and [ ] MW of utility-scale solar PV, up to 199 MW of wind, alongside between [ ] MW of short-duration BESS. These additions are reinforced by expanded demand-side management, including energy efficiency and demand response programs. Importantly, there's an established need for firm and dispatchable resources in in the focus period.
- **Planning Period (Through 2045):** Sustained demand growth, combined with the retirement of legacy natural gas assets, significantly compounds long-term capacity requirements. Satisfying final zero-carbon mandates while serving higher peak loads requires an aggressive expansion of clean firm dispatchable resources ([ ] MW to [ ] MW), supported by extensive solar PV additions ([ ] MW to [ ] MW), [ ] MW of energy efficiency, large-scale BESS deployment, and expanded dynamic balancing resources across the remainder of the planning horizon.

Table [ ]: HEG Core Case Resource Additions by Technology Type (MW Nameplate)

Technology Type	Through 2036		Through 2045	
	Low	High	Low	High
Solar PV (Utility-Scale)	716	1199	1185	2333
Wind Generation	0	199	0	207
Energy Efficiency	196	196	420	420
Carbon-Free Energy	**912**	**1595**	**1605**	**2959**
Battery Energy Storage (BESS - 4hr)	1	674	201	1482
Demand Response (DR)	15	46	21	53
Dynamic Balancing	**16**	**720**	**222**	**1535**
Long-Duration Energy Storage (LDES)	0	400	0	400

Combustion Turbines / Peakers (Gas/H_2)	0	0	0	358
Advanced Generator	0	80	0	720
Geothermal	0	0	0	0
Nuclear	0	0	584	1314
Pumped Hydro	0	200	0	300
Firm Dispatchable	**0**	**680**	**584**	**3092**

The 'Low' and 'High' columns within each individual load scenario do not represent low or high economic growth; rather, they represent the optimization bounds driven by variations in cost, policy, and other sensitivities within that specific load track

9.5.2 HEG Portfolio Costs

Evaluating the economic outcomes across the HEG scenario suite illustrates the financial impact of accelerated demand growth and advanced procurement timing. Total 20-year Net Present Value (NPV) system costs across HEG sensitivities range from $16,263 billion to $16,861 billion, reflecting the front-loaded capital investments and expanded capacity additions required to reliably serve higher peak loads. Crucially, while total utility expenditure increases under higher growth, these elevated system costs are offset by higher overall energy sales -offsetting the overall impact on per-unit customer rates.

Figure [ ] HEG Core Cases – 20 Year NPV

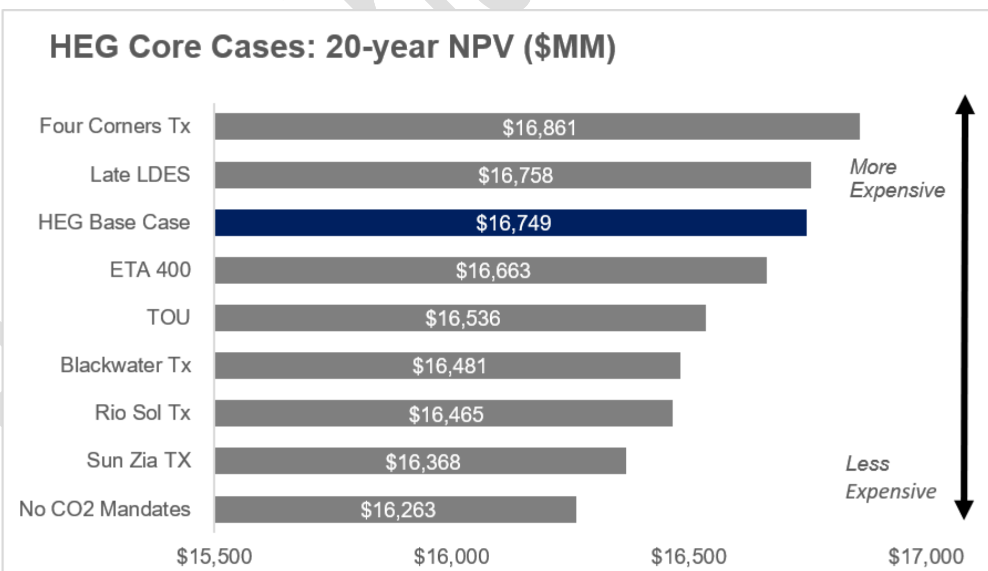
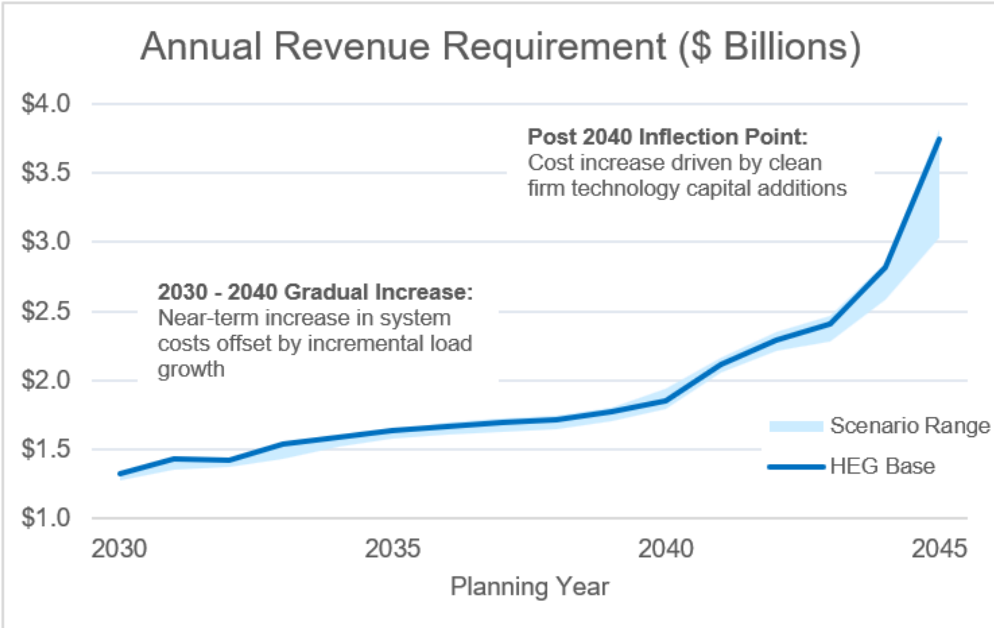


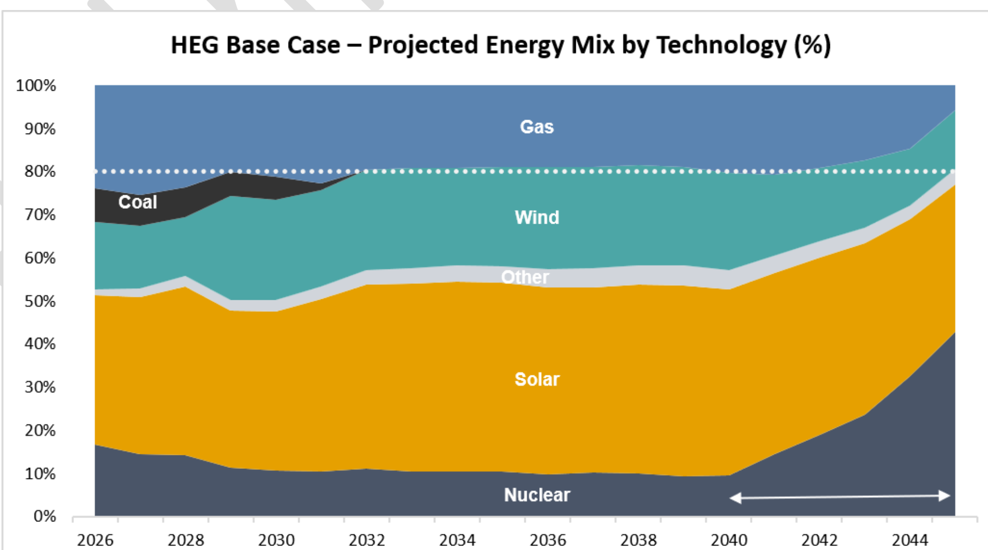
FIGURE [ ] HEG CORE CASES – ANNUAL REVENUE REQUIREMENT (2030-2045)



9.5.3 HEG ENERGY GENERATION MIX

Despite higher load growth, the expanded buildout of variable renewables and early storage ensures the system continues to supply ~80% carbon-free energy across most of the planning horizon. To meet escalating RPS and carbon-intensity targets under higher overall energy burn, additional zero-carbon energy generation must be integrated into the mix alongside near-term additions.

FIGURE [ ] 2026-2045 HEG BASE CASE - PROJECTED ENERGY MIX BY TECHNOLOGY (%)



9.5.4 Extreme Economic Development Case

To capture the full spectrum of potential demand growth, PNM evaluated system performance under the Extreme Economic Development Load Growth case. Examining this boundary scenario illustrates the severe stress placed on grid infrastructure by substantially accelerated load expansion—driven by rapid data center development and concentrated industrial load additions—and identifies the aggressive capacity procurement required to maintain grid stability and statutory compliance.

Key Findings

[Currently being drafted]

9.6 Stakeholder Requested Scenario Analysis

In addition to the core futures, PNM evaluated a series of alternative sensitivity cases to incorporate specific stakeholder-requested constraints and inputs. While built upon the same foundational baseline assumptions as the primary futures described above, these sensitivities adjust key operational and policy parameters to model specific stakeholder perspectives.

9.6.1 Stakeholder Scenario #1: Fusion & Small Modular Reactor (SMR)

Scenario Purpose

To evaluate the long-term potential of emerging technologies within PNM's resource portfolio, PNM conducted a sensitivity analysis examining the integration of commercial nuclear fusion generation within the *HEG* future. The primary objective was to evaluate whether fusion would be selected in a least-cost capacity expansion plan, including the optimal timing, scale, and economic performance of potential additions.

Additionally, this scenario assessed broader portfolio impacts, specifically evaluating fusion's potential to accelerate carbon emissions reductions relative to the baseline trajectory and quantifying the resulting impact on total revenue requirement.

Modeling Adjustments & Assumptions

Based on stakeholder input, the following cost parameters were incorporated as candidate resources starting in 2040:

Adjustment	Description	Stakeholder
Commercial Fusion Candidate Parameters	Added Fusion starting in 2040 with parameters (2040$): • Capital Cost: $6,137 / kW • Fixed O&M: $75 / kW-year • Variable O&M / Fuel: $1.50 / MWh	Stakeholder

SMR Candidate Parameters	Added SMRs starting in 2040 with parameters (2040$): • Capital Cost: $8,402 / kW • Fixed O&M: $162 / kW-year • Variable O&M / Fuel: $14.00 / MWh	Stakeholder

Results and Key Findings:

Under these cost assumptions, the capacity expansion model selected 300 MW of fusion capacity per year from 2040 through 2045, building a cumulative total of 1,800 MW. The introduction of firm, low-cost fusion completely displaced all SMR capacity previously selected in the HEG base case. Because of its high-capacity factor and firm zero-carbon profile, the 1,800 MW fusion addition reduced the need for several other buildouts across the system, including 200 MW of hydrogen-capable gas, 300 MW net of pumped hydro, 262 MW of short-duration battery storage, 572 MW of solar PV, 199 MW of wind, and 32 MW of energy efficiency.

Overall, system NPV decreased from $17,237 million to $16,387 million, delivering $850 million in portfolio cost savings while driving a substantial acceleration in system-wide carbon emissions reductions.

Conclusion and PNM Takeaway:

The scenario highlights that a low-cost, firm, dispatchable zero-carbon resource can significantly reduce the requirement for variable renewables and short-duration storage while simultaneously reducing system costs and accelerating decarbonization. While the sensitivity demonstrates that a firm, low-cost zero-carbon resource can displace variable renewables and lower system costs, commercial fusion remains in early stages of development. PNM will continue to track technological progress and market maturity, but notes that the commercial availability, firm pricing, and performance parameters modeled in this scenario cannot be verified until such resources are submitted and evaluated through future competitive solicitations.

9.6.2 Stakeholder Scenario #2: Updates to Geothermal Cost Assumptions

Scenario Purpose

To evaluate whether conventional or enhanced geothermal generation would be selected in a least-cost expansion plan under updated, lower capital cost assumptions, PNM modeled a dedicated sensitivity within the CTP framework. The primary objective was to determine the economic competitiveness, optimal timing, and portfolio impacts of incorporating firm geothermal capacity into the future resource mix.

Modeling Adjustments & Assumptions

Adjustment	Description	Suggested By

Conventional Geothermal Candidate Resource	Added up to 50 MW of conventional geothermal capacity starting at $5,100/kW (2026$), escalated at 3% annually thereafter.	Stakeholder
Enhanced Geothermal Candidate Resource	Added unlimited enhanced geothermal capacity starting in 2030 at $6,100/kW (2030$), escalated at 3% annually thereafter.	Stakeholder
Geothermal Transmission Cost Adder	Applied a transmission interconnection and reinforcement cost adder of $286/kW (2026$).	PNM

Key Findings & Portfolio Dynamics

In the initial unconstrained optimization run, the model did not select either conventional or enhanced geothermal as part of the least-cost expansion portfolio. To evaluate the economic and operational impacts of integrating these firm resources, PNM conducted three constrained sensitivities forcing geothermal into the portfolio in 2033:

- Sensitivity 1: Forced selection of 50 MW of conventional geothermal.
- Sensitivity 2: Forced selection of 50 MW of enhanced geothermal.
- Sensitivity 3: Forced selection of 250 MW total geothermal (50 MW conventional + 200 MW enhanced).

Across these forced-build runs, integrating firm geothermal capacity drove consistent portfolio reconfigurations:

- **Resource Shifts:** The addition of firm geothermal capacity enabled the system to incorporate 100 MW of Long-Duration Energy Storage (LDES). These additions were counterbalanced by displacing 98 MW to 117 MW of short-duration battery storage, 8 MW to 19 MW of utility-scale solar PV, and 80 MW of hydrogen-ready gas generation. In the 250 MW combined sensitivity, geothermal capacity also displaced 146 MW of nuclear capacity.
- **System Cost Impacts:** Forcing geothermal resources into the portfolio *increased* total 20-yearNPV system costs by $144 million to $292 million.
- **Break-Even Cost Analysis:** Holding all other operational and cost assumptions constant, PNM calculated the break-even capital cost needed for unconstrained model selection to be approximately $4,350/kW for conventional geothermal and $5,930/kW for enhanced geothermal.

Conclusion and PNM Takeaway:

While geothermal resources were not selected in the unconstrained least-cost optimization, the relatively narrow cost delta between the approximate break-even point and stakeholder costs demonstrates that geothermal represents a potential promising candidate resource for meeting future firm zero-carbon capacity requirements. As geothermal technologies mature, PNM will continue to evaluate their commercial viability, capital costs, and resource availability, and will observe market-tested pricing as proposals are submitted through future competitive solicitations.

9.6.3 Stakeholder Scenario #3: Accelerated Decarbonization

Scenario Purpose

This scenario served a dual purpose. First, it evaluated a more gradual, stepped reduction in the carbon intensity of PNM's resource portfolio between the 200 lbs/MWh regulatory target in 2032 and New Mexico's zero-carbon mandate in 2045. Second, stakeholders sought to determine whether implementing a smoothed interim trajectory would mitigate the concentrated capacity additions and associated capital investment requirements modeled in 2045.

Modeling Adjustments & Assumptions

To test this approach, the following carbon intensity reduction trajectory was modeled:

Adjustment	Description	Suggested By
Incremental carbon intensity reduction	2026 – 2031: 400 lbs/MWh	Current Requirement
	2032 – 2034: 200 lbs/MWh	Current Requirement
	2035 – 2037: 155 lbs/MWh	Stakeholder
	2038 – 2040: 110 lbs/MWh	Stakeholder
	2041 – 2044: 65 lbs/MWh	Stakeholder
	2045: 0 lbs/MWh	Current Requirement

Results and Key Findings:

Implementing an accelerated decarbonization schedule induced specific timing and resource adjustments across the portfolio:

- **Resource Displacements and Additions:** While total installed capacity through 2045 remained largely unchanged, the model selected an additional 100 MW of LDES and 53 MW of wind capacity. These additions were offset by displacing 82 MW of short-duration BESS, 40 MW of hydrogen-ready gas generation, and 30 MW of demand response.
- **Portfolio Acceleration:** The primary impact of the accelerated schedule was pulling forward clean capacity additions to meet near-term carbon intensity limits. Most notably, this required advancing 292 MW of nuclear generation by three to five years, alongside earlier commercial operation dates for solar PV and short-duration storage assets.

- **Cost Impacts:** On a PVRR basis, accelerating the decarbonization schedule *increased* total NPV system costs by approximately $350 million due to the near-term capital requirements of advancing firm zero-carbon and renewable capacity.

Conclusion and PNM Takeaway

Meeting an optional interim clean energy trajectory under current market conditions presents clear cost and procurement challenges. However, PNM's historical performance demonstrates a track record of exceeding interim carbon reduction milestones, and the company will continue evaluating opportunities to accelerate decarbonization provided ratepayer affordability and grid reliability are preserved.

9.6.4 Stakeholder Scenario #4: High Natural Gas Price Forecast

Scenario Purpose

Initially Requested: Stakeholders proposed evaluating a scenario reflecting continued geopolitical disruption in the Persian Gulf, associated oil price escalation, and supply chain constraints on natural gas turbines driven by rapid data center expansion.

Refined Scope: Following consultation with stakeholders, the scope was focused specifically on evaluating the impacts of a sustained High Natural Gas Price Forecast within the CTP modeling framework.

Modeling Adjustments & Assumptions

Adjustment	Description	Suggested By
Gas Price Sensitivity	Applied PNM's High Natural Gas Price Forecast across the planning horizon in the CTP base	Stakeholder
Gas Price Sensitivity	Applied PNM's Low Natural Gas Price Forecast across the planning horizon in the CTP base case.	PNM

Results and Key Findings:

When higher natural gas prices are introduced, the capacity expansion model shifts to insulate the portfolio from elevated fuel costs by accelerating non-emitting resources, though the final long-term resource mix remains virtually identical to the base case. To mitigate higher operational expenses, the model accelerates the addition of 146 MW of nuclear capacity by 4 years relative to baseline timing. Similarly, near-term deployments of solar PV and short-duration energy storage are moved forward significantly to offset fuel burn during high-cost hours. Consequently, the entry of hydrogen-capable natural gas generators is deferred by 2 to 4 years, though these resources are still ultimately constructed in the same total capacity volumes by the end of the planning horizon. Applying higher underlying fuel prices *increases* the overall system revenue requirement, raising total portfolio costs by $1,028 million NPV. For comparison, PNM also evaluated a Low Natural Gas Price Forecast sensitivity, which demonstrated a corresponding portfolio cost *reduction* of $1,281 million NPV.

Conclusion and PNM Takeaway:

This sensitivity demonstrates that while sustained high gas prices adjust the near-term timing of capacity additions, pulling clean resources forward and deferring gas investments, they do not fundamentally alter the ultimate destination of the resource mix. PNM will continue to evaluate fuel price volatility across a range of market forecasts and observe actual market responses through upcoming competitive solicitations.

9.6.5 Stakeholder Scenario #5: High Behind-the-Meter (BTM) Solar & TOU

Scenario Purpose

To evaluate how customer-side resources and dynamic time-of-use structures influence utility-scale procurement, PNM modeled two distinct scenarios built on the CTP baseline with a high behind-the-meter (BTM) solar forecast.

- **Scenario 5A (High BTM Solar Only):** Replaces the reference BTM solar adoption forecast with an aggressive high-growth trajectory.
- **Scenario 5B (High BTM Solar + TOU / Managed EV Charging):** Combines the high BTM solar forecast with widespread Time-of-Use (TOU) rate adoption and managed electric vehicle (EV) charging.

Modeling Adjustments & Assumptions

Adjustment	Description	Suggested By
High BTM Forecast	Replaced reference BTM solar adoption with the High BTM Solar forecast trajectory in the CTP framework.	Stakeholder
Default TOU rate sensitivity	Applied a default TOU rate structure starting in 2039, assuming approximately 85% customer participation.	Stakeholder
Managed EV charging sensitivity	Assumed 85% to 90% of all light-duty EVs are enrolled in either an EV Time-of-Day (TOD) rate or a managed charging plan by 2030.	Stakeholder
Two-scenario extensions	Modeled the adjustments both as a standalone High BTM Solar case and as a combined High BTM + TOU / Managed EV case.	Stakeholder

Key Findings & Portfolio Dynamics

Expanding customer-side solar and active load management flattens system net demand, enabling PNM to defer or avoid both utility-scale thermal capacity and clean energy builds.

- In Scenario 5A (High BTM Solar Only), customer-sited generation reduces utility-scale buildouts by avoiding 40 MW of hydrogen-capable natural gas and 66 MW of utility-scale solar PV. Assuming no additional administrative or program implementation expenses, this shift yields $160 million in NPV cost savings.
- In Scenario 5B (High BTM Solar + TOU / Managed Charging), active load shifting further reduces system peak requirements. This combined approach avoids a cumulative 80 MW of hydrogen-capable gas, 87 MW of energy storage, 62 MW of utility-scale solar, and 46 MW of utility Demand Response (DR) programs. Total system cost savings increase to $282 million NPV (excluding program costs).

Comparing the two runs demonstrates that adding high-participation TOU rates and managed EV charging delivers an *incremental* $122 million in NPV savings (excluding program costs) while displacing 46 MW of traditional utility demand response during the focus period.

Conclusion & PNM Takeaway

These sensitivities illustrate that expanded distributed solar, high TOU participation, and managed EV charging can meaningfully reduce bulk system peak requirements, lowering total supply-side capital commitments and overall net present value costs. Because these estimates do not account for the administrative, marketing, or infrastructure expenses required to achieve 85%+ rate adoption, PNM will continue to evaluate the full cost-effectiveness of these customer programs and monitor real-world adoption trends through future rate dockets and market solicitations.

9.6.6 Stakeholder Scenario #6: Incremental Demand Response Programs

Scenario Purpose

To evaluate the capacity value and cost-effectiveness of expanded demand-side management, PNM modeled a scenario testing the extension and expansion of existing direct load control programs. Specifically, this sensitivity examines the portfolio and financial impacts of extending PNM's Power Saver program through 2045 alongside a 25% increase in program magnitude across both Power Saver and water heater load control portfolios, combined with high behind-the-meter (BTM) solar adoption and Time-of-Use (TOU) rate design.

Modeling Adjustments & Assumptions

Adjustment	Description	Suggest by
High BTM Solar Forecast	Replaced reference BTM solar adoption with the High BTM Solar forecast trajectory.	Stakeholder
Time-of-Use (TOU) Sensitivity	Applied the default TOU rate design and managed EV charging assumptions established in Scenario #5.	Stakeholder
Power Saver Extension & Expansion	Forced in the Power Saver program through 2045 and	Stakeholder

	expanded total achievable potential magnitude by **25%**.	
Water Heater Program Expansion	Forced in smart water heater load control programs through 2045 with a **25% increase** in achievable potential magnitude.	Stakeholder

Key Findings & Portfolio Dynamics

Forcing in the extended and expanded Demand Response (DR) programs adds 39 MW of incremental demand response capacity to the portfolio.

The addition of this controllable demand-side capacity primarily shifts the utility-scale storage expansion plan. The incremental DR enables the system to avoid 100 MW of Long-Duration Energy Storage (LDES). To complement the shifted load profiles and maintain intra-day balancing, the model selects a modest addition of 20 MW of short-duration battery storage and 10 MW of utility-scale solar PV.

Overall, incorporating this expanded DR portfolio yields $233 million in total NPV savings across the planning horizon, assuming zero incremental administrative, equipment, or customer incentive program costs.

Conclusion & PNM Takeaway

This sensitivity highlights that expanding direct load control programs like Power Saver and water heater management can effectively displace higher-cost long-duration utility storage assets while lowering overall portfolio net present value costs. However, because these model runs assume zero incremental program delivery expenses, PNM notes that the net economic benefit in practice will depend on actual program administration costs, technology enablement expenses, and customer enrollment rates, which PNM will continue to evaluate through future demand-side management filings and market solicitations.

9.6.7 Stakeholder Scenario #7: VPP Integration & Direct Load Control

Scenario Purpose

To evaluate the impact of rapidly developing distributed energy resources on utility capacity expansion, PNM modeled a sensitivity examining aggressive Virtual Power Plant (VPP) growth. This scenario builds upon the high BTM solar, TOU rate design, and expanded Demand Response (DR) baseline established in Scenario #6 by layering on high battery storage attachment rates for residential solar installations and enrolling those customer batteries into a direct load control (DLC) VPP program.

Modeling Adjustments & Assumptions

Change	Description	Suggested By
High BTM Solar Forecast	Replaced reference BTM solar adoption with the High BTM Solar forecast trajectory.	Stakeholder

Time-of-Use (TOU) Sensitivity	Applied the default TOU rate design and managed EV charging assumptions established in Scenario #5.	Stakeholder
Expanded Demand Response	Retained the extended Power Saver and smart water heater expansions (+25% magnitude through 2045) from Scenario #6.	Stakeholder
VPP / Battery-DLC Deployment	Updated Battery-DLC potential assuming: • New Solar: Starting in 2030, 50% of new BTM solar includes a 4-hour battery, with 90% enrolled in VPP (up to 60 dispatch events/year). • Retrofit Solar: Starting in 2029/2030, 1% of existing BTM solar retrofits a 4-hour battery annually, with 90% enrolled in VPP.	Stakeholder

Key Findings & Portfolio Dynamics

The aggressive adoption and dispatch of customer-sited batteries provides 58 MW of incremental dispatchable capacity to the system via the VPP program.

This additional firm, distributed capacity significantly alters the timing and mix of utility-scale additions. The aggregate VPP contribution enables the portfolio to defer 100 MW of Long-Duration Energy Storage (LDES) and reduce utility-scale solar PV additions by 108 MW. To maintain energy balance across off-peak and overnight hours, the model compensates by increasing utility-scale wind capacity by 75 MW.

Economically, adding the VPP battery program generates an incremental $100 million in NPV cost savings beyond Scenario #6, bringing total portfolio cost savings to $333 million NPV (assuming zero program or customer incentive costs).

Conclusion & PNM Takeaway

This analysis demonstrates that customer-sited battery VPPs can serve as an effective substitute for utility-scale solar and long-duration storage while enhancing overall portfolio value. However, capturing these savings depends on customer willingness to attach batteries, high enrollment retention across 60 annual dispatch events, and manageable utility administrative costs. PNM will monitor customer adoption metrics and test distributed storage capabilities through future demand-side management filings and market solicitations.

9.6.8 Stakeholder Scenario #8: Geothermal Generation & LDES Requirements

Stakeholders requested a scenario to test whether adding geothermal generation would eliminate the need for Long-Duration Energy Storage (LDES). PNM and stakeholders agreed that this evaluation was already fully captured within the modeling framework of Scenario #2.

9.6.9 Stakeholder Scenario #9: Impact of EDAM on PRM

Stakeholders initially requested a scenario evaluating whether participation in the Extended Day-Ahead Market (EDAM) could reduce PNM's Planning Reserve Margin (PRM). Following technical discussions, both parties agreed this scenario was unnecessary and was not modeled.

9.7 Rate Impacts

A potential measure of affordability associated with IRP findings is the rate impact to customers of the candidate portfolios. This section provides a very brief discussion of potential revenue requirements and rate impacts based on the technologies and quantities selected for the CTP and HEG futures studied in the IRP. The analysis does not consider how the various sensitivities applied to each future would potentially impact results.

PNM recently filed the 2029 to 2032[31] resource application with the NMPRC. The resource plan proposed new resources to serve substantial increases in load as well as addressing existing resource retirements or abandonments. The load increases were driven mostly by large load customers. The plan included the resource additions identified in Section [ ] and were modeled as part of the pending resources for purposes of the 2026 IRP. The resource application included illustrative information on the potential revenue requirements and customer rate impacts of the proposed application resources.

Based on PNM's last approved general rate case, base rates are designed to collect $866.1 million in non-fuel revenue requirement[32]. Within the 2029-2032 resource application, the total revenue requirement for new resource additions was estimated at $501.3 million. PNM provided illustrative class allocations designed to collect the total revenue requirement shown in Table X, Line No. 4.

---

[31] Docket No. 26-0000114

[32] Case No. 24-00089-UT: PNM's last approved general rate case.

Line No.	Category	Value	
1	24-00089-UT Approved Stip. Non-Fuel Revenue Requirement	$866,083,648	
2	2030 Forecasted Fuel Revenue Requirement	$239,111,642	
3	Docket No. 26-0000114: 2031 TY Revenue Requirement	$501,291,244	
4	Total Revenue Requirement	$1,606,486,534	Line No. 4 = Line No. 1 + 2 + 3

The average total system $/kWh, based on Line No. 4 from PNM Table-1, is $0.09525 per /kWh. The resource application provided additional information indicating a residential average rate of $0.1456 per kWh. A new large load tariff is proposed as part of the illustration. The resource filing determined a large load, average all in rate of approximately $0.1164 per kWh which plays an important role in avoiding large load cost impacts to other rate classes. The illustrative information in the filing does not account for any distribution system cost changes, or any transmission system cost changes that are not associated with interconnecting and delivering the resources requested in the filing.

CTP

Using the resource filing rate impact illustration as a starting point, PNM evaluated the potential rate impact of the technologies and amounts identified in the CTP base case (case defining the MCEP). The analysis is based on the incremental revenue requirement for resources added through 2036 over the 2029-2032 resource application. The revenue requirement increase from addition of these resources was $229M with a total increase in energy sales of 1,780,000 kWh. The resulting system average 2036 rate is $0.09845 per kWh which represents a 3.4% increase over the illustrative 2031 rate in the 2029-2032 resource filing.

HEG

The rate impact associated with the HEG base case was also evaluated for illustrative purposes. The total resources in the HEG base case by 2036 are considerable higher than with the CTP. The incremental revenue requirement for the HEG resources over the resource application was $519M (vs $229M for the CTP resources) with additional sales of 3,932,000 kWh. This yielded a new system average 2036 rate of $.1022 per kWh which represents an increase of around 11% over the 2031 estimated rate in the 2029-2032 resource application.

Overall Affordability Indication

The system average rate used in this discussion is largely indicative of the degree of rate impact for the system as a whole. Individual rate class impacts will potentially differ from the system average. The results generally show customer impacts should be manageable based on resource needs through 2036 with the potential increase ranging from 3% to 11% depending on the degree and nature of future load growth.

9.8 Key Findings of Portfolio Results

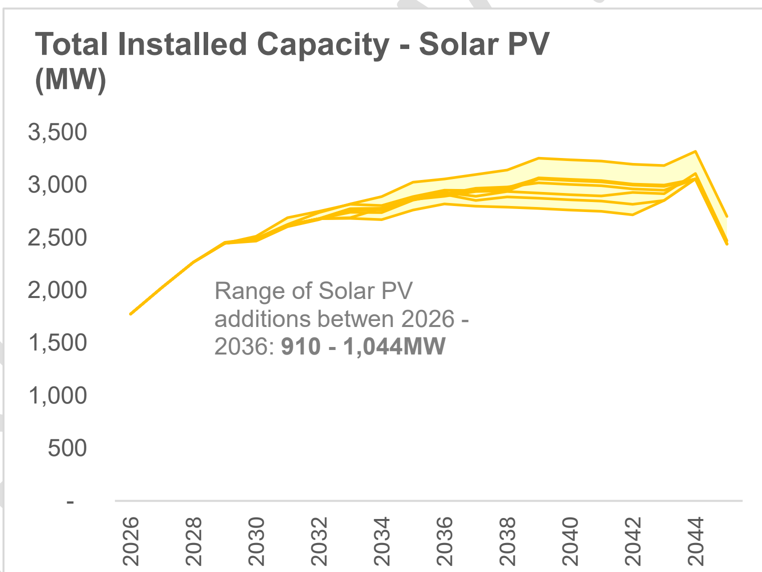
Examining the results across all core cases under each future and stakeholder sensitivities highlights key trends in PNM's baseline system requirements and points toward the most cost-effective resource strategies to meet them:

Key Finding 1. Solar PV Serves as Core Resource Across CTP All Portfolios

New renewable generation plays a foundational role in meeting near-term system needs and supporting progress toward PNM's long-term clean energy goals:

New renewable generation plays a foundational role in meeting near-term system needs and driving long-term clean energy progress. Across all CTP sensitivity cases, total installed solar capacity grows by 910 MW to 1,044 MW between 2026 and 2036, continuing to build through 2040. This growth includes 629 MW of near-term planned solar additions, supplemented by 281 MW to 415 MW of uncommitted, generic solar selected on an economic basis. Even as federal tax credits expire, solar remains a cost-effective resource for meeting RPS compliance targets.

FIGURES [ ] CTP CORE CASES – RANGE OF SOLAR PV INSTALLED CAPACITY ADDITIONS



Key Finding 2. Meeting Load Uncertainty Requires a Flexible Procurement Framework

Like utilities nationwide, PNM faces unprecedented load uncertainty and volatility at a time when bringing new generation and transmission online requires multi-year lead times. PNM must proactively manage this uncertainty – hedging against potential demand growth without overcommitting capital. Under the Low Economic Growth (LEG) scenario, PNM's existing and committed supply-side resources are sufficient to satisfy system needs through the focus period. Conversely, under the High Economic Growth (HEG) and Extreme Economic Development cases, accelerated demand necessitates incremental supply-side resources within the focus period to maintain grid reliability.

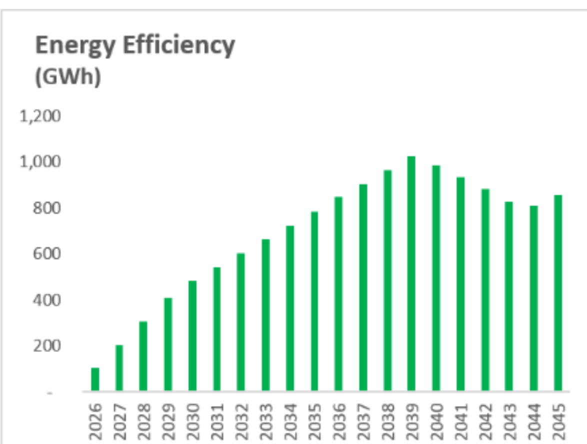
[Insert chart showing supply-side resource additions through 2036 in LEG, CTP, HEG and XEG base cases]

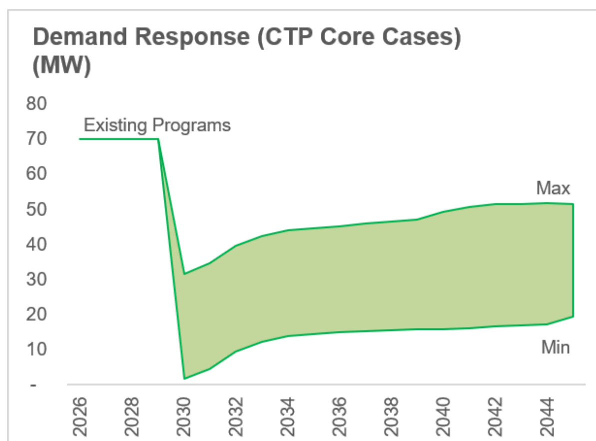
Key Finding 3. Demand-Side Resources Expand to Provide Energy and Peak Capacity Reductions

Rather than treating demand-side management as a fixed reduction to the load forecast, Demand Response (DR) and Energy Efficiency (EE) are modeled as candidate resource options within EnCompass. This allows demand-side bundles to compete directly on a least-cost basis against supply-side alternatives. Across all core CTP scenarios, the model selected maximum achievable levels of energy efficiency and consistently selected expanding DR programs to defer utility-scale peaking buildouts.

Stakeholder Feedback: As shown in Figure [ ] below, all CTP core cases selected incremental DR as an economic candidate resource. However, the core analysis also accounted for the expiration of existing DR programs, resulting in a net reduction of total DR capacity over the planning period. At the request of stakeholders, PNM modeled alternative scenarios incorporating additional DR capacity beyond baseline levels. As detailed in Section [ ], these stakeholder-requested scenarios yielded overall portfolio cost reductions.

FIGURES [ ] AND [ ] MODELED DEMAND-SIDE MANAGEMENT (DSM) EXPANSION – ENERGY EFFICIENCY AND DEMAND RESPONSE ADDITIONS ACROSS CTP CASES



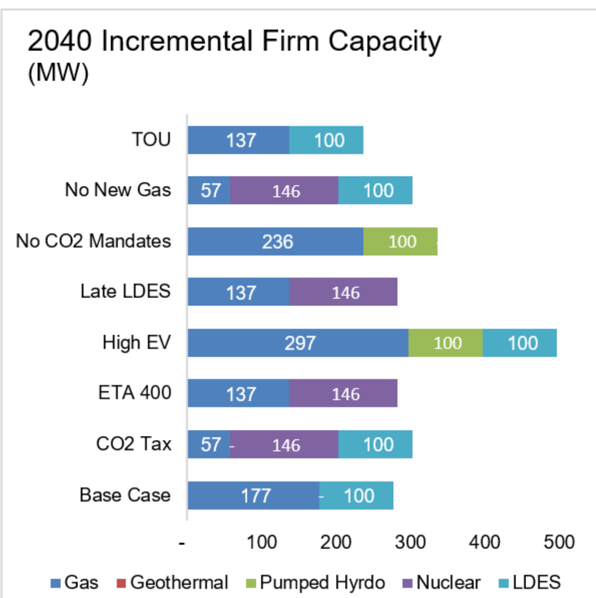


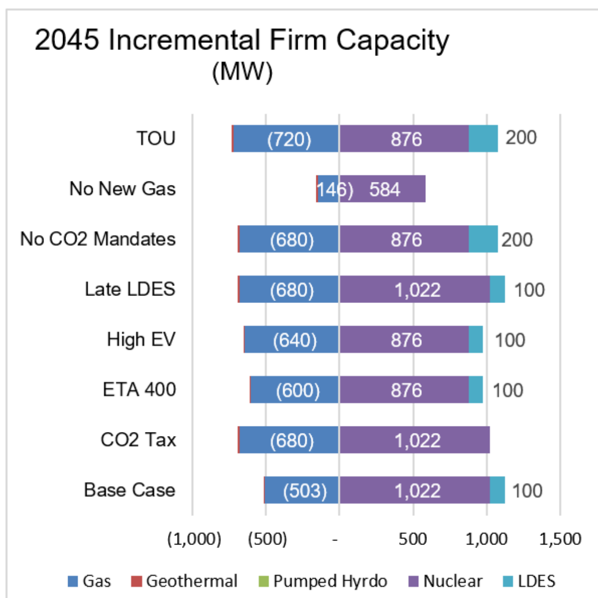
Key Finding 4. Firm, Dispatchable Resources Are Essential for Grid Reliability in a Clean Energy Portfolio

As PNM advances toward a 100% clean energy portfolio, capacity expansion modeling demonstrates a growing structural requirement for carbon-free firm, dispatchable resources. While renewable resources (wind and solar) deliver most of the annual energy generation and daily peak system balancing relies heavily on shifting energy delivery with battery energy storage, firm capacity remains essential to maintain resource adequacy, bridge multi-day renewable lulls, and support system resiliency during periods of extreme weather or grid stress.

- **Through 2035 - 2040:** Across all core scenarios, the model resulting expansion plans adds between 237 MW and 497 MW of new firm, dispatchable capacity, comprising options such as hydrogen-capable gas turbines, geothermal, pumped hydro storage, nuclear, and long-duration energy storage (LDES). Excluding the High EV Forecast sensitivity (which drives higher overall load), the underlying resource need spans a narrow range of 237 MW to 336 MW. This consistency demonstrates that despite variations in technology operating characteristics, the overarching requirement for firm capacity is critical and invariant.
- **Elevated Growth Upside (HEG & Extreme Cases):** While the CTP core cases establish this baseline, firm capacity requirements accelerate and expand substantially under the High Economic Growth (HEG) and Extreme Economic Development scenarios to maintain reserve margins against higher peak demand.
- **Through 2045:** As existing natural gas capacity retires to comply with New Mexico's Energy Transition Act (ETA) mandates, the requirement for firm capacity expands significantly. To replace retiring gas assets while maintaining reliability, the model selects incremental nuclear capacity in all scenarios, complemented by additional LDES in most cases. However, as evaluated further in this section, adjusting market availability and cost assumptions for emerging zero-carbon technologies (e.g., geothermal) alters the specific technology mix without diminishing the total firm capacity required.

FIGURES [ ] AND [ ] INCREMENTAL FIRM CAPACITY ADDITIONS 2040 AND 2045 CTP CORE CASES

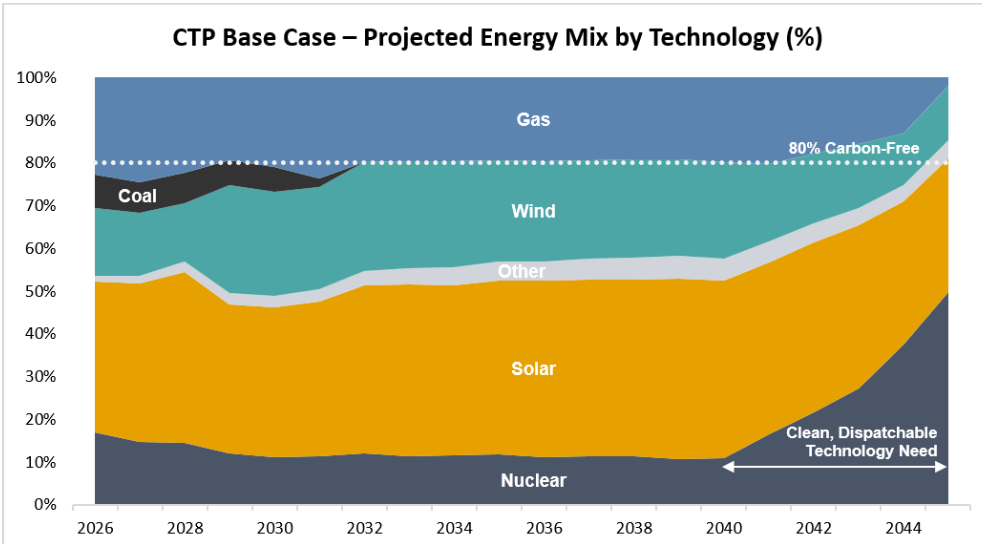




Key Finding 5. Renewables and Clean Firm Generation Anchor the Energy Transition

Across all evaluated scenarios, carbon-free resources supply approximately 80% of total system energy by the early to mid 2030's, with natural gas meeting the remaining demand. As the portfolio transitions toward New Mexico's 2045 zero-carbon mandate, system adequacy requires emerging technologies such as nuclear generation or advanced geothermal, complemented by expanding renewable resources and demand-side management (DSM). Under the 2045 zero-carbon requirement, any remaining gas-capable assets (converted to operate on zero-carbon fuels) transition to a targeted, peaker-oriented role, supplying only a minor fraction of total system energy.

FIGURE [ ] CTP BASE CASE – PROJECTED ENERGY MIX BY TECHNOLOGY (%)



Key Finding 6. Portfolio Economics Are Primary Drivers of Ratepayer Value

System cost screening across the CTP suite demonstrates that achieving an ~80% carbon-free energy platform is cost-effective using proven, commercially mature technologies like solar, wind, and short-duration storage. However, replacing the remaining 10–20% of firm thermal generation to achieve full zero-carbon compliance presents significant cost and operational challenges. Eliminating this final margin without inflating ratepayer costs requires the commercialization and cost decline of emerging clean firm and long-duration technologies (e.g., advanced nuclear, clean fuels, advanced geothermal, and LDES) that are not yet commercially available at scale today.

Key Finding 7. Expanded Transmission Connectivity Potentially Provides Substantial Net Savings for Ratepayers

Evaluating targeted transmission expansion sensitivities demonstrates that enhancing regional transfer capability can potentially lower system costs. Three of the four transmission scenarios evaluated yield significant customer savings relative to the CTP Base Case by increasing off-peak market sales, reducing renewable curtailments, and optimizing overall portfolio dispatch. The inclusion of the SunZia transmission line delivers the largest cost reduction, lowering the 20-year NPV by $504 million. Similarly, the Blackwater DC and Rio Sol expansion projects yields net savings of $247 million and $245 million, respectively. Conversely, the Four Corners transmission expansion increases total NPV by $116 million, indicating that transmission additions must be strategically located to deliver net economic benefits.

TABLE [ ] 20-YEAR PORTFOLIO NPV AND CUSTOMER NET SAVINGS ACROSS TRANSMISSION SCENARIOS ($ MILLIONS)

Scenario Name	20-Year NPV ($ millions)	Delta from CTP Base Case ($ millions)
SunZia Transmission line included	$13,822	$(504)
Blackwater DC Transmission line included	$14,079	$(247)
Rio Sol Transmission line included	$ 14,082	$(245)
Four Corners Transmission line included	$14,443	$116

The results of the transmission NPV impacts are highly preliminary, driven by modeled price differences between markets and the limitations of zonal modeling transfer limits in the production costing tools. Substantial addition analysis is needed to quantify the benefits of each proposed interconnection.

9.9 Transmission Nodal Analysis/Portfolio Comparison/Discussion

9.9.1 ZONAL CAPACITY EXPANSION TO NODAL MODELING PROCESS

Initial capacity expansion portfolios are developed without transmission cost adders. This is a deliberate methodological refinement from the 2023 IRP. In 2023, PNM baked zonal transmission cost adders directly into the first (and only) capacity expansion run — meaning the model's resource selection was already influenced by assumed transmission costs from the start. In the 2026 IRP, PNM instead runs the initial Encompass Zonal Capacity Expansion Model "clean," with no locational cost penalty applied at all.

The output of this first pass is a Candidate Portfolio that specifies only:

- Technology type (e.g., solar, battery storage, wind, long-duration storage)
- Amount (MW)
- Year added

Critically, at this stage the portfolio is not location-specific — the model has determined what to build and when, but not where. The illustrative example from Workshop 3 shows exactly this kind of output: 200 MW solar in 2033, 100 MW battery storage in 2033, 400 MW wind in 2035, 200 MW long-duration storage in 2038, and 300 MW solar in 2040 — with no node or zone attached.

Resource Location assumptions by Technology

Once the zonal, location-neutral candidate portfolio exists, PNM moves to a Location Assignment step:

Specific real-world nodes on the New Mexico transmission system are selected to interconnect each technology in the portfolio (e.g., the 200 MW solar block is assigned to Four Corners 345 kV; the 400 MW wind block to Western Spirit 345 kV; the long-duration storage to Pajarito 345 kV).

Historical siting patterns guide these initial assignments — resources of a given technology type tend to be mapped to the same nodes where similar resources have historically interconnected, since that's usually a decent starting proxy for where developers would actually propose such projects.

Siting assumptions used for the 2026 IRP cycle

Siting assumptions for each resource technology reflect PNM's transmission system characteristics and historical development patterns:

- Solar: Albuquerque, San Juan/Four Corners, Belen and Los Lunas, and Eastern NM.
- Wind: Eastern NM (Torrance/Guadalupe); Union, Quay, Curry, and Roosevelt counties will have higher associated transmission costs.
- Geothermal: Potential locations remain to be determined. Facility size is a factor, but optimal geothermal sites are generally not located near existing PNM transmission facilities.
- Pumped Storage: Assumed to be sited in the San Juan/Four Corners area.
- Compressed Air Energy Storage (CAES): Southeast New Mexico, which carries significant transmission cost implications.

These node-assigned resources are then added to the nodal model database, which contains a full electrical connection model of the transmission system — every line, transformer, and node, not just PNM's own aggregated zones.

Outputs that are used to evaluate performance

This produces four specific outputs used for "review":

- Losses
- Resource curtailment
- Congested hours
- Congestion costs

This is the step that answers a question the zonal model structurally cannot: given where these resources reside on the transmission system, do neighboring transmission system operations adversely affect the proposed portfolio? Do the Transmission Alternative Scenarios modeled make the specific future lower-cost by providing access to remote markets that allow for more efficient dispatch of the portfolio identified in capacity expansion modeling? This is arguably the single most important structural upgrade nodal analysis provides, rooted in the fact that over 50% of PNM's transmission utilization is used for wholesale wheeling by external customers. The nodal model closes this modeling gap by representing the broader WECC grid, including known neighboring load-serving entities and their constructed resources.

9.9.2 Portfolios used for Nodal in the 2026 IRP

Portfolios used for Nodal analysis in the 2026 IRP were the three futures Current Trends and Polices (CTP), High Economic Growth (HEG), Low economic growth (LEG). The four transmission scenarios are then folded into those three futures to see how they perform. For the purposes of discussion in this write up metrics will be shown for the base future and across the CTP future for comparison.

9.9.3 Losses

Losses GWh			
Year	CTP GWh	HEG GWh	LEG GWh
2029	687.0	708.0	640.0
2035	710.0	756.0	665.0
2040	742.0	768.0	681.0

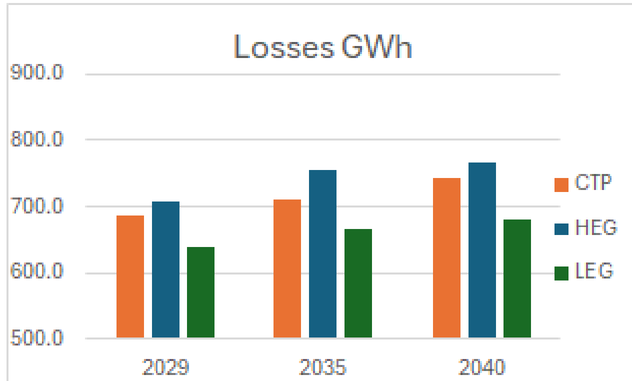


Figure [] Loses for Base Futures

Figure [] shows the losses over the study period generally increase as load increases for the three futures model for this analysis.

CTP Losses					
Year	GWh	Rio Sol GWh	Sun Zia GWh	Black Water GWh	Four Corners GWh
2029	687.0	687.0	687.0	687.0	687.0
2035	710.0	697.0	702.0	844.3	674.6
2040	742.0	731.0	735.0	784.0	706.0

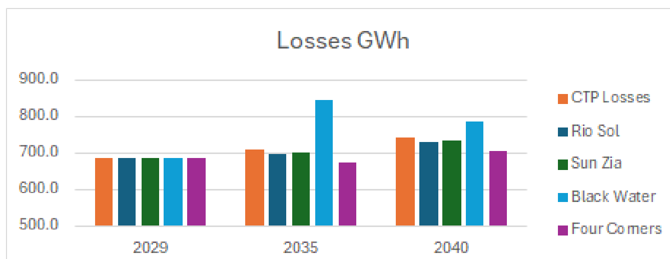


Figure [] Transmission Alternative Losses based upon the CTP Future

Figure [] show mixed loss results across the four transmission expansion alternatives. While more connectivity, usually reduces network impedance and therefore losses generally are reduced, some network alternatives (Black Water transmission Alternative) creates more transactions and increases losses relative to the three other scenarios.

9.9.4 Resource Curtailment

Curtailments GWh			
Year	CTP GWh	HEG GWh	LEG GWh
2029	0.0	0.0	4.1
2035	28.0	51.0	77.0
2040	212.0	417.0	633.0

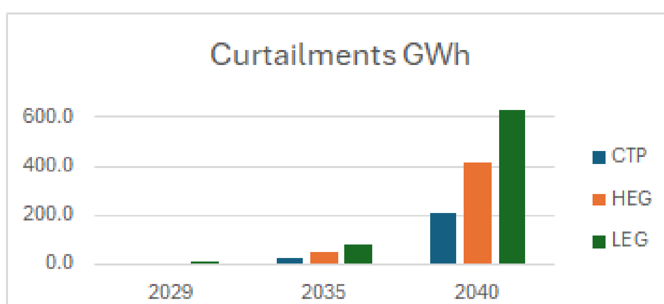


FIGURE [] CURTAILMENTS FOR BASE FUTURES

Curtailments across the Base Future, Figure [] remain minimal in the near-term horizon. The lack of near-term curtailments would indicate that existing transmission and capacity expansion plans don't create huge amounts of resource curtailments.

CTP Curtailments GWh					
				Black	Four
		Rio Sol	Sun Zia	Water	Corners
Year	GWh	GWh	GWh	GWh	GWh
2029	0.0	0.0	0.0	0.0	0.0
2035	28.0	26.7	7.7	6.0	27.0
2040	212.0	209.0	48.1	38.5	204.5

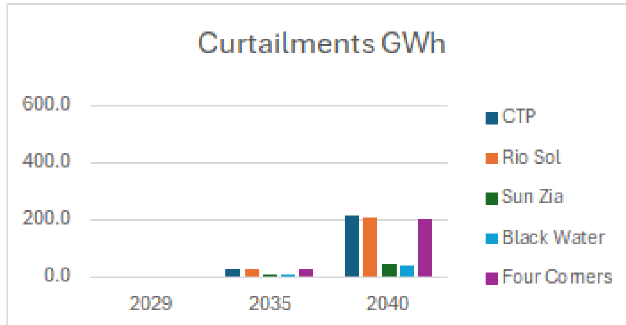


FIGURE [] TRANSMISSION ALTERNATIVE CURTAILMENTS ACROSS THE CTP FUTURE

Figure [] Shows that all transmission alternatives decrease curtailments over the study period. This matches the expectation that additional access to markets reduces curtailments because resources can continue to operate rather than to curtail.

9.9.5 CONGESTED HOURS

Congestion Hours			
	CTP	HEG	LEG
Year	Hours	Hours	Hours
2029	898.0	1007.0	733.0
2035	943.0	1064.0	776.0
2040	1013.0	1138.0	902.0

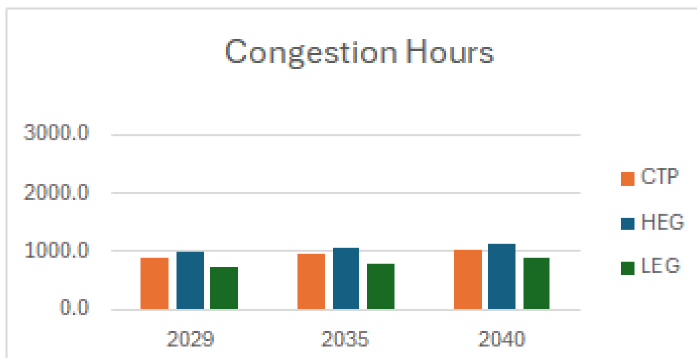


FIGURE [] PATH 48 CONGESTION HOURS ACROSS BASE FUTURES

As shown in Figure [] and similar to curtailments, congestion hours across the base futures vary across study period from 700 hours to 11000 hours respectively.

CTP Congestion Hours					
				Black	Four
		Rio Sol	Sun Zia	Water	Corner
Year	Hours	GWh	GWh	GWh	GWh
2029	898.0	898.0	898.0	898.0	898.0
2035	943.0	596.0	2967.0	1637.0	170.0
2040	1013.0	627.0	2769.0	2039.0	224.0

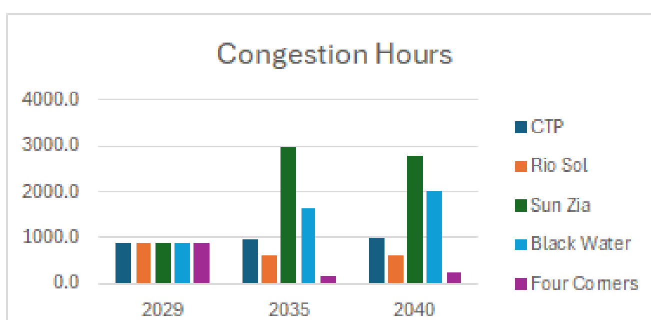


FIGURE [] - TRANSMISSION ALTERNATIVE PATH 48 CONGESTION HOURS ACROSS CTP FUTURE

Similar to transmission losses across the CTP future, Congestion hours across the transmission alternatives varies over the period despite having the same capacity expansion portfolio. Congestion hours represent the flow across path 48 when it is at a limit in either direction. So the higher the number of hours congested, the less the system can optimize purchases and sales to further reduce to total production cost.

9.9.6 CONGESTION DOLLARS

	Congestion $		
	CTP	HEG	LEG
Year	M$	M$	M$
2029	11.8	16.8	5.9
2035	18.7	36.6	6.0
2040	24.1	120.3	25.0

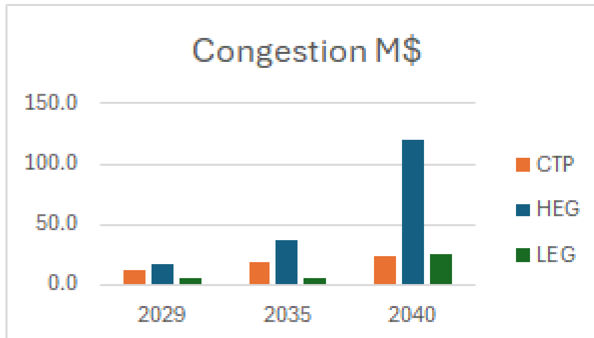


FIGURE [] CONGESTION DOLLARS FOR PATH 48 OVER THE BASE FUTURE

Figure [] Shows congestion Dollars increase slightly over the study period. HEG case shows additional congestion in 2040 tied to a different capacity expansion plan.

	Congestion M$				
				Black	Four
	CTP	Rio Sol	Sun Zia	Water	Corner
Year	M$	GWh	GWh	GWh	GWh
2029	11.8	11.8	11.8	11.8	11.4
2035	18.7	7.8	119.6	23.3	0.7
2040	24.1	8.8	126.0	43.4	1.8

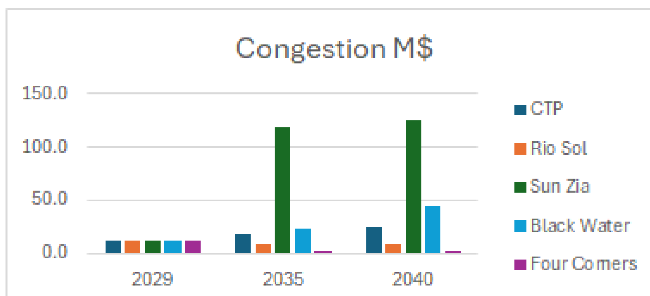


FIGURE [] TRANSMISSION ALTERNATIVE CONGESTION DOLLARS FOR PATH 48 OVER THE CTP FUTURE

As seen in Figure [] congestion costs vary significantly across the transmission alternatives, based on differing market assumptions and portfolio dispatch. Because each alternative provides access to a different market, dispatch patterns and congestion settlement outcomes differ accordingly. Congestion dollars suggest that Four Corners and Rio Sol projects reduce Congestion cost to the system over the study period.

In summary, further analysis is warranted for transmission alternatives that provide access to an external market, as both the Nodal and Zonal models show promising cost reductions. However, while these results are directionally useful in identifying which alternatives merit further study, they should not be treated as conclusive. PNM will need to consult with external market experts experienced in SPP, CAISO, and the broader Arizona wholesale market to better understand the specific dynamics of each connecting market, and to confirm whether a more detailed and rigorous accounting of those market interactions would continue to support the cost savings suggested by this preliminary transmissional alternative analysis.

10. STATEMENT OF NEED

[See draft Statement of Need provided for Workshop 8 https://www.pnm.com/documents/d/pnm.com/pnm-draft-son-revised]

(Statement of Need is being redrafted to reduce overall length as much of the information for Workshop 8 was to provide for context and can be found in other sections of the IRP report. Ranges of need are being checked for clarity and accuracy.)

11. ACTION PLAN

1. PNM will continue to pursue the necessary regulatory approvals and advance construction efforts to support the timely commercial operation of resources included in the Application for 2029-2032 System Resources and Abandonment of Four Corners Power Plant.

2. PNM will take the necessary steps to advance the 2029-2032 All-Source Generation Resource RFP Supplement issued on May 1, 2026, proceeding with the evaluation and selection of resources to meet 2029-2032 system needs identified in PNM's 2023 IRP.

3. PNM will issue an All-Source RFP seeking both supply-side and demand-side resources to meet its 2033 – 2036 system needs. Given the long development timelines for generation and transmission infrastructure, initiating procurement well in advance provides the necessary lead time and could broaden the pool of potential bidders.

   PNM will provide the draft RFP, which will be open to new and revised demand-side management options, for stakeholder review. The RFP draft documents will identify how PNM will evaluate these projects, include accredited capacity, and avoided or deferred system costs that will be assessed.

4. Note: PNM must finalize its resource selections from the 2029-2032 All-Source Generation Resource RFP Supplement before issuing a subsequent RFP. Consequently, this dependency, along with the need to solidify other critical inputs and assumptions, such as the load forecast, may require a variance to the IRP procurement schedule.

5. PNM will form a working group to evaluate strategic public and private partnerships, policies and funding mechanisms or tax credits, including new state and federal incentives, to support the deployment of emerging clean energy resource development including fusion and enhanced geothermal and transmission expansion in New Mexico, with the goal of benefiting customers by reducing development risk and managing associated costs.

   A focus of the working group will include identifying potential solutions to challenges of seeking emerging and long-lead technologies under the current RFP processes outlined in the IRP rule.

6. PNM will further analyze the four IRP-evaluated transmission alternatives that would connect PNM's system to neighboring systems: the Rio Sol transmission facilities, the

SunZia AC transmission facilities, the SPP system near the existing Blackwater HVDC facility, and the expanded interconnection with neighboring utilities at Four Corners. These analyses will focus on validating the underlying economic findings on customer value and clarify the potential benefits of increased access to external regional markets. Depending on the outcomes of these evaluations, PNM may seek regulatory approval for specific transmission projects. PNM will provide appropriate information justifying the basis for any facilities sought under a regulatory filing.

7. PNM is participating in the development of a western regional resource adequacy program for EDAM participants and will assess its potential to enhance reliability and deliver PNM customer value. As a sponsor and active member of the stakeholder working group, PNM will assist in advancing a final resource adequacy proposal for the EDAM/WEIM footprint to the new ROWE Board by the end of Q1 2027 for program development. Based on the final program framework, PNM will evaluate whether there are impacts to its long-term reliability planning metrics that should be incorporated into its next IRP and will report its evaluation in its annual action plan status updates.

8. PNM will continue to support the expansion of demand side options including demand response and energy efficiency initiatives through its triennial Energy Efficiency and Load Management program filings and Grid Modernization Plan development and timelines.

    a. PNM will continue efforts for expanding demand response programs that leverage Grid Modernization AMI technologies. The development timeline is dependent on the deployment of AMI meters and infrastructure. This includes development of specifications for a Behavioral Demand Response Pilot program.

    b. Contingent on a final contract with DOE, PNM will leverage small, distributed energy resources to improve grid reliability and reduce customer electricity bills through its recently awarded DOE VPP grant.

    c. PNM will provide a visual representation of the various demand-side programs and their progression.

    d. PNM will continue to advance energy efficiency and demand response initiatives thorough existing and planned pilot programs:

        i. An All-Electric Homes Pilot to encourage all-electric home construction by supporting homes with electric cooking, space heating, and water heating systems through enhanced incentive offerings.

ii. PNM Manufacturing Facilities Glow-Up Program: Helping qualifying manufacturing customers reduce energy costs by combining tax-saving opportunities with energy-efficiency upgrades.
iii. PNM Business Uplift Pilot: Supporting small businesses in designated redevelopment areas by providing enhanced incentives for energy-efficient equipment upgrades and facility improvements.
iv. Low Income Residential Heat Pump Pilot: Promoting the adoption of high-efficiency heat pumps among low-income customers through enhanced rebates and financing options.
v. PNM will actively recruit customers for the EV Active Managed Charging Pilot Program which was recently initiated.

9. PNM recognizes that IRP stakeholders support opt-out time-of-day rates and will continue to work through the Pricing Advisory Committee (PRAC) on its Roadmap to default TOD rates as a part of the grid modernization plan.
    a. PNM will continue to provide status updates on its roadmap to establish an opt out TOD rate.
    b. Based on data from the TOD pilot program initiated in 2024, PNM will propose modifications to the pilot program to improve potential benefits to lower-use customers.
    c. PNM will propose in its next general rate case modifications to the pilot program to add a super off-peak period.
    d. Using data collected from the pilot program, PNM will develop a residential TOD program as the default residential rate with an opt-out provision. The changes will be proposed in the next general rate case following full deployment of AMI. At that time, PNM will roll out education to the residential customer class.
    e. PNM will continue to seek stakeholder input on the TOD rate development through the PRAC.

10. PNM will file annual reports to demonstrate the progress of its Action Plan.

11. PNM will file a Large Load Tariff to establish rates, service conditions, and cost-responsibility provisions applicable to large loads seeking service on PNM's system. The tariff will be designed to support economic development opportunities while protecting existing customers from cost shifting, stranded investment risk, and adverse reliability impacts. PNM will evaluate and incorporate, as appropriate, customer protection mechanisms including minimum load commitments, contract demand obligations, exit provisions, collateral requirements, and infrastructure cost assignment methodologies.

12. PNM will complete the 2029 IRP in accordance with NMAC 17.7.3.