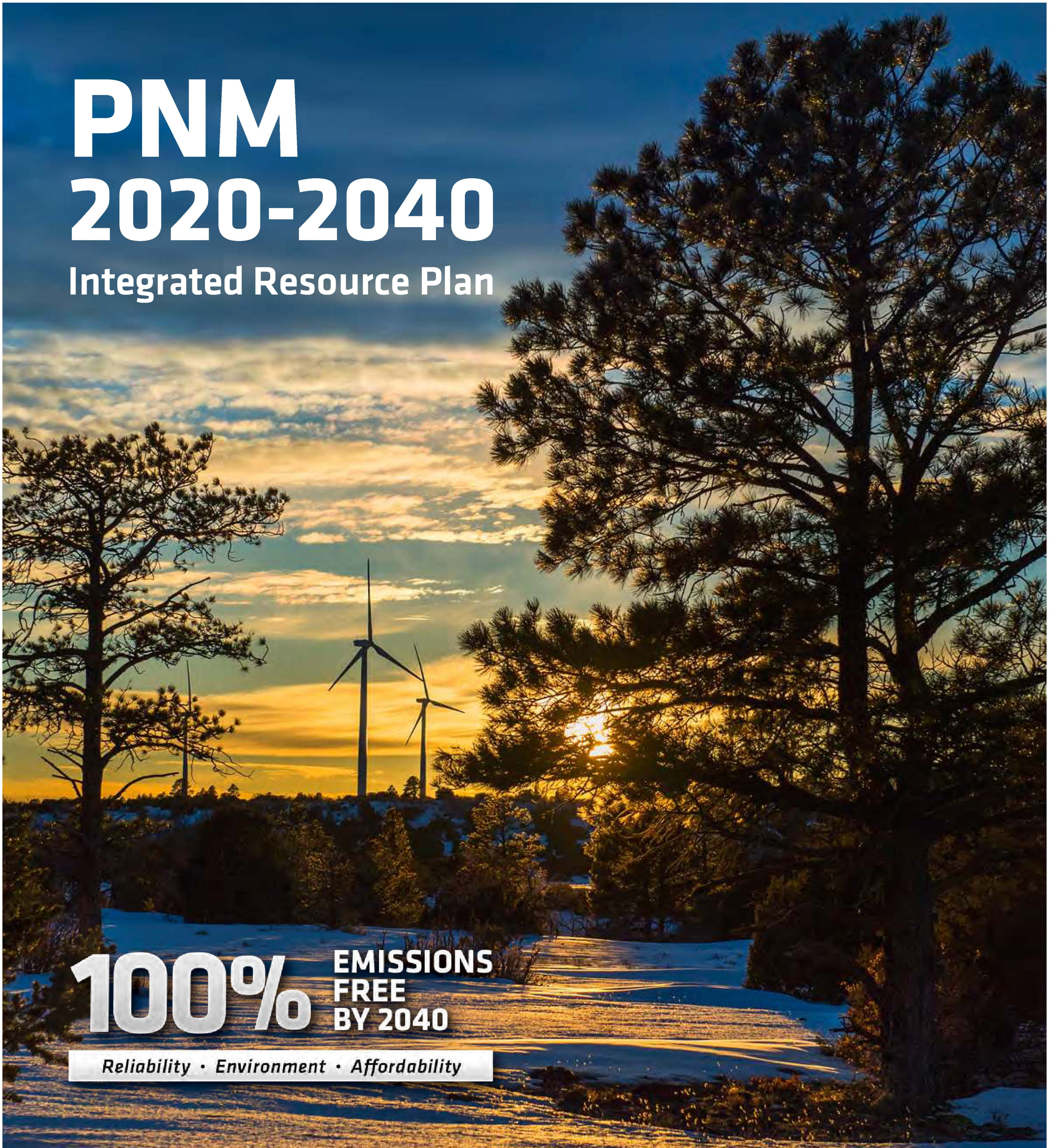
PNM
2020-2040
Integrated Resource Plan



100% EMISSIONS FREE BY 2040

Reliability · Environment · Affordability

Moving to the next decade of emissions-free electricity

January 29, 2021 **Corrected November 4, 2021**

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Patricia Vincent-Collawn
Chairman, President & CEO

A vision for carbon free electricity-
Bold solutions for our shared future.

Hello,

I am incredibly grateful for the people of our state who spent countless hours with our team to develop this PNM Integrated Resource Plan (IRP). We invited customers, stakeholders and advocates to join us on this journey as we looked at the next twenty years of electricity needs. We asked to hear your ideas, your voices and your solutions. Numerous meetings were held to ensure we had your insights before putting pen to paper. Thank you to those who walked with us through this process over the past eighteen months.

We are at the forefront of the energy industry's sustainability revolution. Policy, technology, and customer choice are dramatically reshaping the energy landscape. Here in New Mexico, the landmark Energy Transition Act set the state apart with a bold call for a 100-percent carbon-free electric system by 2045.

This IRP reflects these evolving policy priorities and our own PNM sustainability goals. The report underscores the criticality of environmental responsibility and stewardship alongside our core purpose of providing affordable and reliable electricity. This IRP is one of the first in the country to provide a roadmap for the transition to a carbon-free electricity portfolio.

In this IRP, we put forth a plan that calls for immediate and rapid action to enable our transition to a carbon-free goal that:

- Eliminates coal from our portfolio at the end of 2024 so that we can begin serving our customers with 100-percent coal-free electricity. This includes replacing the power from the San Juan coal plant in 2022 with a mix of approved carbon-free resources and divesting from the Four Corners coal plant by the end of 2024;
- Takes advantage of low-cost renewables and emerging technology to reshape our energy supply so that by 2025 nearly 75% of our customers' electricity needs will be supplied by carbon-free resources; and
- Remains steadfast in our commitment to reliability and identifies the resources needed to ensure that our transition to emissions-free electricity does not come at the expense of the high-quality service our customers deserve.

As we transition to a carbon-free portfolio, we will continue to collaborate with those who have engaged with us on this important discussion. We will work hard for our customers – from how we set rates and design programs to how we make new investments and operate our system. This commitment is emphasized further by the announcement of our merger with Avangrid, a leader in clean energy whose environmental and sustainability goals are well-aligned with our own.

In this plan, we offer a first look at how this transition could occur. This is not a path that we can walk alone. Conversations lead to action. We are committed to collaborating with stakeholders, research laboratories, academic institutions, and our regulators to continue progress.

We are excited about the clean and bright energy future and our continued partnership to advance the interests of the state of New Mexico.

With appreciation for this collaborative journey,

Pat Vincent-Collawn,
PNM Resources Chairman, President and CEO

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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 the 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 17.7.3.10 of the New Mexico Administrative Code.

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Acknowledgements

PNM would like to extend its sincere appreciation to the organizations and individuals that contributed to our 2020 Integrated Resource Planning process. We thank each and every one of you, without you this IRP would not be our best and most exciting IRP produced to date:

- First and foremost, our **Public Advisory Group** who spent countless hours at our Public Advisory Meetings learning about our process and providing input and feedback to help shape our Integrated Resource Plan.
- The **Technology Advisory Committee** (National Renewable Energy Laboratory, Sandia National Laboratory, New Mexico State University, State Land Office, Western Grid Group) who reviewed the Technology Request for Information and provided input regarding new and emerging technologies that could aid in the decarbonization of PNM's system.
- **Energy and Environmental Economics, Inc. (E3)** who provided invaluable contributions and guidance to the development of the IRP through their work and studies throughout the Western US in deep decarbonization of electric systems.
- **Astrapé Consulting** for their expertise and coordination in reliability modeling.
- **CDG Engineers, Inc.**, **Horizons Energy**, and **Anchor Power Solutions** for their technical and modeling support.
- **Applied Energy Group**, **PACE Global** and **Itron** for the contributions to the development of the Energy Efficiency, Commodities and Load Forecasts.
- The **California Independent System Operator** and **Sandia National Laboratory** for their guest presentations to our Public Advisory Group.

In order for PNM and the State of New Mexico to achieve its vision for a carbon free electric system, it will take the collective efforts and ideas from all of our stakeholders and experts. We are excited to continue our collaborative efforts to execute on this plan.

Thank you,

Nick Phillips
Director, Integrated Resource Planning

PNM Resource Planning Team:
Monique Reiman
Dean Brunton
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Executive Summary

This is PNM's fifth Integrated Resource Plan (IRP) filed with the New Mexico Public Regulation Commission ("Commission"), but it is our first plan since announcing our commitment to achieve a carbon emissions-free portfolio by 2040. Like our prior plans, this IRP identifies the most cost-effective portfolio of resources to meet projected electricity demands over the next twenty years. This year, it does so in the context of our new long-term goal, providing a vision for our transition to a carbon emissions-free portfolio and taking our previous environmental stewardship to a new level.

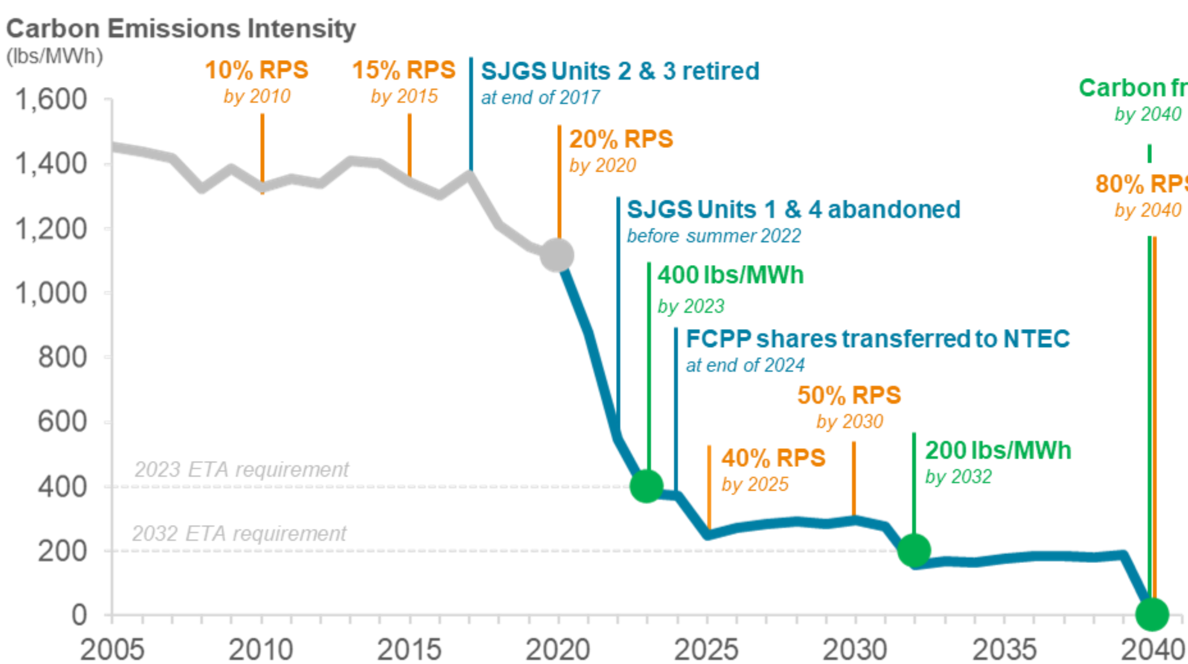
PNM's commitment to decarbonize aligns with the state of New Mexico's strong policy position to achieve deep reductions to its carbon footprint. In 2019, the governor signed into law the Energy Transition Act (ETA), which established significant long-term targets for utilities within the state:

- By 2040, all retail sales must be supplied by 80% renewable generation; and
- By 2045, all retail sales must be supplied by 100% carbon emissions-free generation.

Our governor also enacted Executive Order 2019-003, joining the US Climate Alliance in support of the 2015 Paris Agreement and establishing a goal to reduce economy-wide carbon emissions by 45% by 2030 (relative to 2005 levels). As the largest public utility in New Mexico, we recognize that we have a significant role to play in the effort to meet this goal and any others that may follow, and so this IRP takes on a scope and challenge beyond our previous IRPs by demonstrating our plans to eliminate a significant portion of the state's carbon emissions.

For this IRP, we have developed a twenty-year plan to transition our portfolio to meet our carbon-free goal and the requirements of the ETA. Figure 1 illustrates how our actions over this period will drive our emissions intensity to zero over the analysis horizon.

Figure 1. Historical and projected emissions intensity under our MCEP plans



Our plan to meet our customers' needs while facilitating a transition to a carbon-free portfolio comprises three main elements:

Transition away from aging baseload infrastructure: Since our 2017 IRP, we have developed plans to exit our shares of several of our largest legacy generation ownership resources. In 2019, under the terms of the ETA, we received approval from the Commission to abandon our 497 MW share of the San Juan Generating Station (SJGS) by June 2022. In 2020, we announced plans to return leased shares of the Palo Verde Nuclear Generating Station (PVNGS) in 2023 and 2024 and to exit our 200 MW share of the Four Corners Power Plant (FCPP) at the end of 2024, subject to Commission approvals. By 2025, PNM can be fully divested of coal generation, allowing us to reduce our emissions intensity below levels set by the ETA and paving the way for the long-term changes needed to meet our ultimate goal.

Invest in renewables, efficiency, and storage to decarbonize our energy supply: The investments that we make to replace our retiring resources will provide us with low carbon electricity far into the future, supporting our efforts to transition to a carbon emissions-free system by 2040. In 2019, our energy mix was roughly 44% carbon emissions free. With the replacement of SJGS with carbon-free resources this figure will increase to approximately 65% by the end of 2023 Meeting our goal of 100% by 2040 will require additional investments in a diverse set of resources, including renewables to supply carbon-free power, energy storage to balance supply and demand, and efficiency and other demand-side resources to mitigate load growth.

Retain and invest in firm capacity to maintain reliability: even as our portfolio transitions towards increased reliance on wind, solar, storage, and other emerging technologies, we envision a continued crucial role for traditional capacity resources. These resources, which include existing nuclear and natural gas plants that we may retrofit to operate on carbon-free fuels, are essential to maintaining resource adequacy due to their ability to serve as backstop resources when variable and energy-limited resources are not able to generate.

An Industry in Transition

This Integrated Resource Plan is set against a backdrop of an industry that is rapidly changing, creating a challenging and uncertain environment for resource planning. Our planning approach recognizes the unprecedented level of uncertainty we must consider while meeting short- and long-term needs. The most significant uncertainties that pose risks in our planning process are:

Changing customer needs & preferences: the nature of our service to customers is evolving in multiple ways: in our customers' preferences for clean energy and in the types of end uses we supply. Customers' demand for electricity will change with shifts and uncertainty in the economy.

Changing wholesale market dynamics: increasing retirements of firm generation throughout the West, coupled with significant investments in renewable generation across the region, are reshaping our opportunities to transact in wholesale markets.

Changing technology options: innovation and competition are continuing to drive cost reductions for existing technology and to bring new technologies into the market, including new options for energy storage, carbon-free fuels, and innovative demand-side resources.

Our planning process considers how these uncertain factors will affect our supply portfolio as we optimize our future energy mix.

Developing our Plan

The goal of our IRP is to produce a "Most Cost-Effective Portfolio" (MCEP) that minimizes cost to our customers while meeting or exceeding reliability and environmental objectives; Figure 2 illustrates the primary objectives of the IRP process. We evaluated a wide range of different scenarios and sensitivities to identify the MCEP that meets the needs of our customers at lowest costs. From this MCEP, we identify a four-year "Action Plan" that reflects the near-term outcomes.

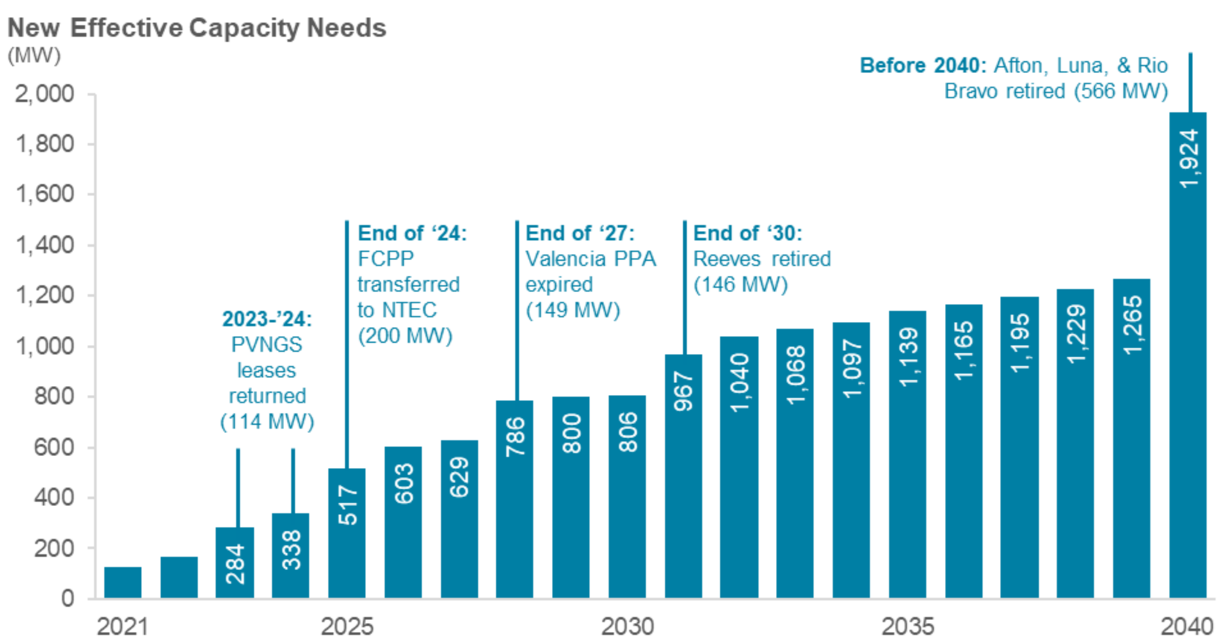
Figure 2. Pillars of our integrated resource planning process

Maintaining reliability	Minimizing cost	Mitigating environmental impact	Meeting other regulatory requirements

Among these goals, we view the preservation of reliability for our customers as a fundamental requirement; achieving this as we increase reliance on renewable generation will require paradigmatic shifts in how we plan the system. In the past, our resource adequacy planning has focused on ensuring that we have sufficient capacity to meet peak demand; in the future, changes to our resource mix will lead to reliability challenges outside of this traditional peak period. By 2023, our new solar resources will shift our greatest reliability challenge into the summer "net peak" period after sundown. To prepare for these changes, we must rethink our framework for resource adequacy. Doing so means revisions and updates to our approach to resource adequacy to better account for our needs across all hours of the year, not just during the periods of peak demand.

Maintaining reliability while our demand grows and fossil resources are transitioned will require increasing investments in new resources that contribute capacity to our resource adequacy needs. Figure 3 shows our cumulative capacity needs over the 20-year IRP analysis horizon.

Figure 3. Summary of PNM's cumulative new capacity needs over time.



To identify a portfolio of resources that meets these needs and our other objectives, we rely on sophisticated commercial software tools designed to address the industry's most pressing questions. The complexity of the questions that our plan must address has increased as the diversity of new technology options has expanded. To develop and evaluate portfolios, our planning process relies primarily on two modeling tools:

1. **EnCompass**, a capacity expansion and production simulation model that we use to optimize and simulate portfolios least-cost resources to meet our future needs; and

2. **SERVM**, a loss-of-load probability model that we rely on for detailed reliability analysis of our portfolios.

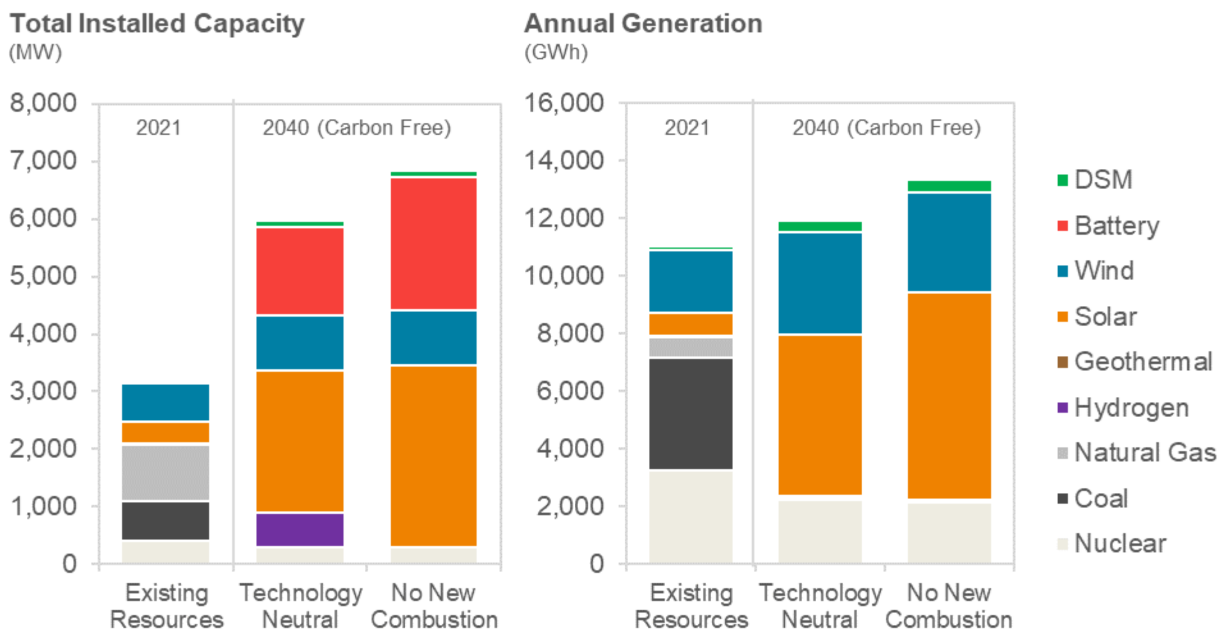
These two models provide complementary perspectives and together allow us to develop a plan that minimizes costs while meeting our reliability, regulatory, and environmental objectives.

Throughout this process, we have relied heavily on our stakeholders to provide valuable input, helping us establish the key questions within the scope of the IRP and develop reasonable inputs and assumptions. Since July 2019, PNM has hosted eleven public meetings to engage key stakeholders and solicit feedback to help inform our IRP. Through each of these meetings, our stakeholders have provided us with a diverse range of views and perspectives that have helped us refine the scope of our work and craft our plan to meet our key objectives.

Our Most Cost-Effective Portfolios

Our analysis in this IRP focused on a comparison of two primary paths to a carbon-free portfolio: (1) a **"Technology Neutral"** investment scenario that considers all possible technologies that could help meet our 2040 goals; and (2) a **"No New Combustion"** investment scenario that focuses on investments in renewables and storage. Figure 4 summarizes the portfolios of resources that achieve our 2040 carbon-free goals in each of these scenarios.

Figure 4. Summary of 2040 portfolios under Technology Neutral and No New Combustion portfolios



Higher annual generation in No New Combustion scenario offset by higher storage losses and off-system sales

In many respects, these two portfolios are very similar:

- Both portfolios require significant investments in new resources, roughly doubling the amount of installed capacity in our portfolio over the next 20 years;
- Both portfolios meet our 2040 energy needs with a carbon-free mix that is almost entirely supplied by nuclear, wind, solar, and DSM resources; and
- Both portfolios require significant investments in energy storage to meet balancing needs and to ensure resource adequacy.

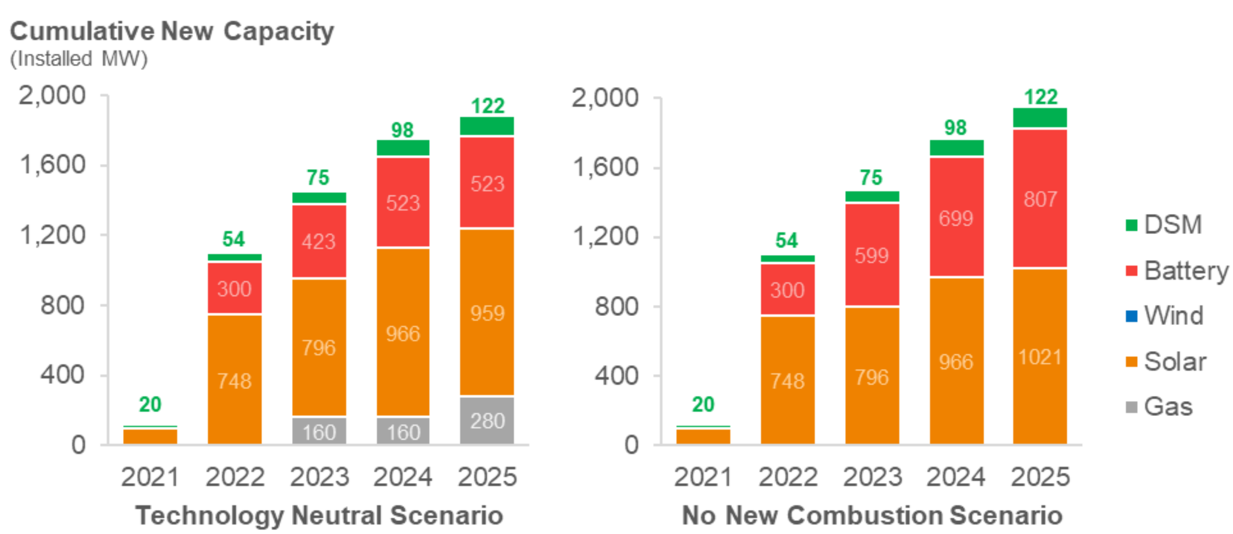
Where the two portfolios differ most significantly is in how we meet our resource adequacy needs:

- The Technology Neutral scenario relies on hydrogen-ready combustion turbines (CTs) to meet a portion of resource adequacy needs; these resources, which operate at low capacity factors throughout their lifetimes, are fueled by natural gas when brought online in the 2020s but are eventually converted to burn hydrogen by 2040.
- The No New Combustion scenario fills this same capacity need with incremental energy storage, requiring resources with increasing duration to offset storage's declining capacity value.

Based on the analysis conducted in this plan, both strategies can support our transition to carbon free while maintaining resource adequacy; however, there are a number of risks specific to a No New Combustion pathway that could lead to degradation of reliability below acceptable levels. While we recognize the appeal of storage as a non-fossil investment as well as the apparent risk of investing in new fossil asset before the viability of conversion to carbon-free fuels is certain, we will continue to prioritize reliability in our planning and procurement decisions.

Regardless of the pathway chosen, the next five years will require significant activity to enable progress towards our transition. Figure 5 shows the cumulative investments in each of these scenarios. Both will put us on a path to achieve a carbon emissions-free system by 2040.

Figure 5. Near-term investments in our Most Cost Effective Portfolios



Includes SJGS replacement resources (650 MW solar, 300 MW storage, and 15 MW DSM)

Our Four-Year Action Plan

As a first step towards this end point, our Action Plan comprises the following steps over the next four years:

Pursue abandonment and replacement of outstanding PVNGS lease interest and FCPP

- File for abandonment of the 114 MW of PVNGS leases and approval of replacement resources consistent with the identified MCEP paths.
- Issue an RFP for new capacity deliverable in 2025 to replace the FCPP capacity and file for approval of replacement resources by January 2022.

Complete annual filings for renewables and demand-side resources as required by the Commission

- Continue to develop and implement cost effective energy efficiency and demand management programs and file plans with the Commission.
- File Annual Renewable Energy Procurement Plans to demonstrate compliance with the RPS and request approval of new resources if needed.

Explore cost-effective options to maintain system supply and reliability

- Develop energy storage as a capacity resource and monitor its real-world performance in a resource adequacy context to better understand risks.
- Limit consideration of combustion-based resources to those that can be easily repurposed or retrofit to operate using carbon-free fuels, including hydrogen and renewable fuels.
- Continue to assess regional market depth and liquidity impact on resource planning decisions.
- Transition to the industry standard loss of load expectation of 0.1 days per year ("one day in ten years") to maintain best practices in reliability planning for our system.
- Explore rate design approaches that reflect customer use and load needs and evaluate energy efficiency and DSM program opportunities under the Efficient Use of Energy Act.

Continue to monitor and explore opportunities to advance transition to a carbon-free portfolio

- Monitor landscape of emerging technologies that could contribute to carbon-free goals, including generation resources, storage, and clean fuels.
- Utilize PNM's Wired for the Future program to pursue opportunities to modernize the grid and invest in transmission that supports the transition towards a carbon free system.
- Implement PNM's Transportation Electrification Program upon approval by the Commission.
- Assess potential load increases from economic development activities in PNM's service areas, in cooperation with state and local entities.

Conduct the 2023-2042 Integrated Resource Plan

- Address the implications of the expiration of supply contracts and any retiring resources.
- Consider the impacts of participation in the CAISO Energy Imbalance Market on our resource planning process and decisions.
- Apply co-optimization to generation, storage, and transmission as identified in this report to enhance coordinated planning efforts.
- Work with stakeholders in an ongoing collaborative public advisory process.

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1 Introduction

This IRP marks the first plan presented by PNM to study the path from today's portfolio to one that achieves the state's goal of generation that is carbon emissions free by 2045. Like our prior plans filed with the Commission, this IRP identifies the most cost-effective portfolio of resources to meet projected energy requirements over the next two decades. This year, our IRP does so in the context of our new long-term goal, providing a vision for our transition and taking our previous environmental stewardship to a new level.

PNM's commitment to decarbonize its generation portfolio aligns with the state of New Mexico's strong policy position to achieve deep reductions to its carbon footprint. In addition to supporting the passage of the landmark Energy Transition Act (ETA)[1], our governor also issued Executive Order 2019-003, joining the US Climate Alliance in support of the 2015 Paris Agreement and establishing a goal to reduce economy-wide emissions by 45% by 2030 (relative to 2005 levels). As the largest public utility in New Mexico, we recognize that our role in meeting this goal and others that may follow must be significant, and so this IRP takes on a scope beyond the traditional IRP by demonstrating our plans to mitigate a significant portion of the state's emissions.

The purpose of the IRP is to identify the types of resources that PNM will need in the future to continue to provide reliable, low-cost electric service to customers while meeting or exceeding regulatory and environmental objectives. PNM prepared the plan in accordance with several rules, regulations, and guiding principles. The recommendations and action plan items are based on a rigorous analysis of an extensive array of commercially available resource options that consider a wide variety of ideas of how the future may unfold.

PNM's analysis begins with an assessment of the electric service the customers will need in the future to provide energy for their jobs and daily life. This assessment revolves around three guiding principles: maintain reliability, provide service at reasonable costs, and reduce the impact to the environment below current levels. Reliability is the result of delivering electricity to customers when needed with a minimal probability of interruption or disturbance.

The electric grid is one of the largest and most complicated machines in the world. Building, maintaining, and evolving it has always been a capital-intensive endeavor. Recent technological advances, and expected advances in the future, are creating opportunities to add or replace existing resources at reasonable costs. New technologies also provide opportunities to maintain reliability while reducing air emissions and water use. Meanwhile, improvements in technology, automation, sensors, and communication create opportunities to empower customers and introduce better coordination between load and generation. This document presents the information considered, the analysis performed, and the recommendations that follow from that work.

[1] See Section 1.5.1

1.1 IRP Planning Framework

IRP Rule

PNM has prepared this IRP in accordance with 17.7.3 New Mexico Administrative Code (NMAC), Integrated Resource Plan for Electric Utilities (IRP Rule). The IRP Rule was originally issued by the Commission on March 1, 2007 and amended on November 27, 2012, August 29, 2017, and January 30, 2018. 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 our customers:

> "The purpose 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. For resources whose costs and service quality are equivalent, the utility should prefer resources that minimize environmental impacts."

– 17.7.3.6 NMAC

The IRP Rule further requires that New Mexico electric public utilities file an IRP every three years that includes the following information (17.7.3.9B 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 description of resource and fuel diversity;
- Identification of critical facilities susceptible to supply source or other failures;
- A determination of the most cost-effective portfolio and alternative portfolios;
- A description of the public advisory process;
- An action plan; and
- Other information that the utility finds may aid the Commission in reviewing the utility's planning processes.

The ultimate goal of the IRP process of identifying the "Most Cost-Effective Portfolio" (MCEP) results in a roadmap to meet the projected electric demands of PNM's customers over the next 20 years. This plan informs a four-year action plan that is consistent with the MCEP.

IRP Planning Process

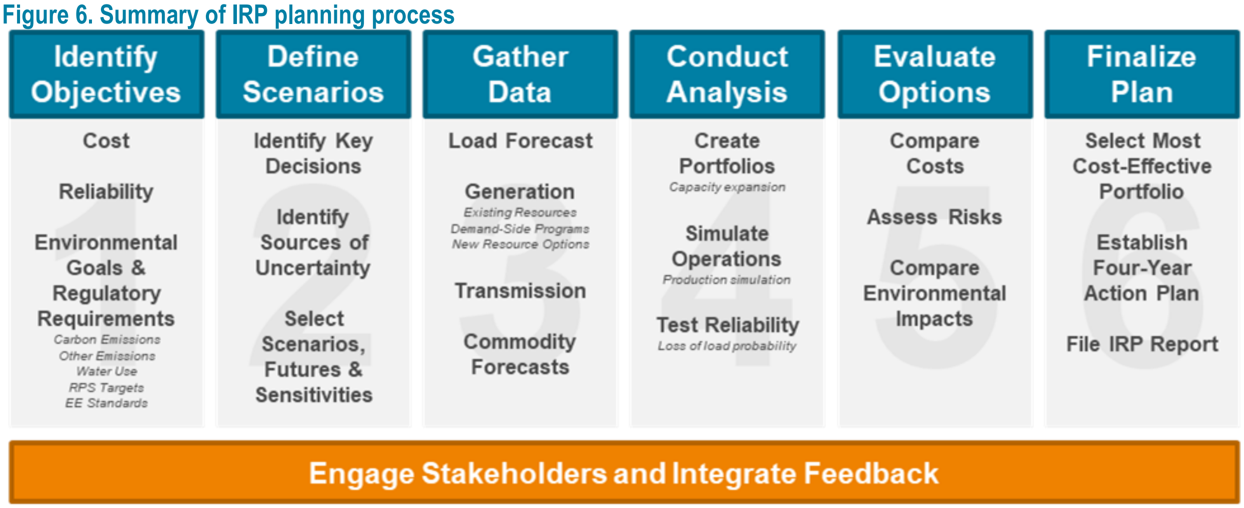
The IRP planning process is designed to identify the mix of resources that, together, will reliably meet system operational requirements, adhere to regulatory requirements, and mitigate environmental impacts, all while minimizing costs to our customers. This planning process allows PNM to respond to projected future events and ensure adequate resources are available to meet demand and maintain service reliability. The IRP is revisited every three years, with earlier notifications to the Commission and participants if material changes in assumptions would lead to a different course of action.

The IRP planning process spans a 20-year time horizon; for this IRP, the horizon we consider spans from 2021 through 2040. The endpoint of this plan is a uniquely significant milestone: it is the first year in which we have pledged to meet all our customer's energy needs with carbon emissions-free resources. By evaluating portfolios through the complete transition to our goal, we strive to demonstrate that the actions undertaken herein are not only in the best interests of ratepayers today but will enable our complete transition to a carbon emissions-free portfolio in twenty years.

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 has designed a multidimensional process for its IRP analyses to identify the MCEP for the 20-year period from 2021 through 2040. The process includes 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 6. Throughout the process, the PNM Integrated Resource Planning group worked to solicit input from participants in the IRP public advisory process, integrating comments, suggestions, and guidance into our planning process where possible. Key areas where stakeholders contributed valuable perspectives included in the design of scenarios, the choice and treatment of different technology options in technical analysis, and characterization of the potential of different demand-side resources.

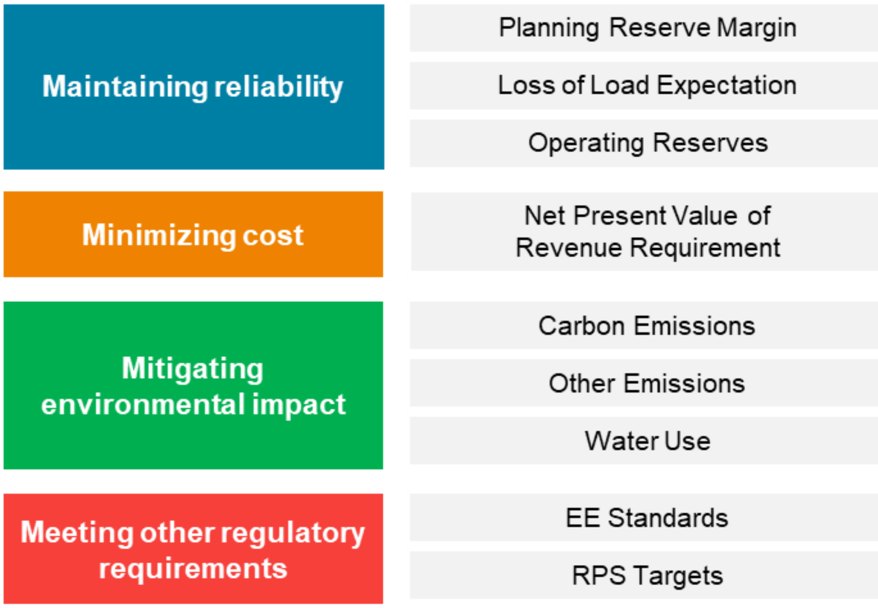
Figure 6. Summary of IRP planning process



1.2 Plan Objectives

Consistent with the objectives we have used in the past to develop and evaluate our IRPs, this IRP aims to identify a portfolio of resources that meet customer electricity supply needs reliably, with limited environmental impact, and at the lowest reasonable cost. Additionally, in this cycle our process faces a new test. In our 2020 IRP, we seek to create an MCEP that demonstrates a plausible transition plan to our goal of 100% carbon emissions-free generation by 2040. We recognize that our Action Plan will face additional scrutiny through a lens of how our actions will enable us to achieve these long-term goals. An additional objective of this IRP is therefore to study and communicate the challenges and uncertainties we expect to face as we pursue these ambitious goals to demonstrate how our Action Plan prepares us to meet those challenges.

Figure 7. Criteria considered in creation of the Most Cost Effective Portfolio



To meet these requirements, PNM analyzed a wide variety of resource combinations under numerous assumptions of the future and compared them against one another using metrics in four categories:

(1) Reliability: each plan we consider targets a planning reserve margin designed to meet a minimum standard for reliable electric service. Key plans are tested more rigorously via an analysis of Loss of Load Expectation (LOLE) – a measure of the probability of experiencing a reliability event in any given year. These practices align our standard for adequacy with standards accepted within the industry. As our portfolio transitions towards reliance on variable renewables, storage, and other emerging technologies, we will continue to prioritize our ability to meet customer needs. The MCEP must therefore meet several metrics for service quality:

- A minimum planning reserve margin across the planning period;
- An expected LOLE consistent with standards commonly in use throughout North America; and
- An ability to maintain operating reserves in every hour of every year.

(2) Cost to our customers: we compare potential plans against one another using the net present value of revenue requirements across a 20-year period (2021-2040) to identify the plan that meets reliability, environmental, and regulatory requirements at the lowest reasonable cost.

(3) **Environmental impact:** we strive to mitigate the impact of our portfolio on the environment, which we measure primarily through our emissions and water usage in this IRP. The New Mexico IRP rule allows us to use these metrics as tiebreakers among portfolios with similar costs. In this plan, our environmental impact plays a more central role in our process, as our plan is also designed to achieve our long-term goal of 100% carbon emissions-free generation by 2040 (as well as interim milestones for portfolio carbon intensity of 400 lbs/MWh by 2023 and 200 lbs/MWh by 2032 as required by the

ETA). We also anticipate that in the transition to a carbon-free portfolio, new environmental factors may merit consideration in our future planning as well – for instance, land use impacts of renewable development, mining for rare earth metals, and lithium disposal requirements for storage resources.

(4) **Other regulatory requirements:** our planning process is also informed by a number of other requirements established by the Commission and state legislature, most notably:

- Minimum requirements for the renewable portfolio standards (RPS) of 20% of retail energy sales no later than January 1, 2020, 40% in 2025, 50% in 2030, and 80% in 2040, all established by the ETA; and
- Energy efficiency spending of 3-5% of revenue requirements and annual savings goals of 5% of 2020 retail sales for the period 2021-2025.

The MCEP is the resource plan that performs most favorably against these criteria under the wide variety of futures analyzed through this planning process.

1.3 Public Stakeholder Process

Public participation in the planning process is critically important and supports the development of a strong integrated plan. As described in the IRP rule:

> "Public input is critical to the development and implementation of integrated resource planning in New Mexico. A utility shall incorporate a public advisory process in the development of its IRP. At least one year prior to the filing date of its IRP, a utility shall initiate a public advisory process to develop its IRP. The purpose of this process shall be to receive public input, solicit public commentary concerning resource planning and related resource acquisition issues."
>
> – 17.7.3.9H NMAC

Beginning in July 2019, PNM hosted a series of eleven public stakeholder workshops to share updates on the development of the IRP and seek stakeholder questions and comments. We have attempted to make this process as open and reciprocal as possible, using it as an opportunity to report out to stakeholders key developments and considerations in our IRP and to incorporate stakeholder concerns and perspectives into our approach to the IRP. These meetings were structured in accordance with the requirements for public participation in the IRP Rule. A list of stakeholder workshops and topics covered appears in Table 1.

As indicated by the topics covered, we have used this forum for a wide range of purposes: to discuss the technical details of our new IRP modeling tools; to provide transparency into the development of inputs and assumptions; to describe the key considerations that shape our planning landscape; and to gather feedback from stakeholders on our methods and assumptions. The issues and questions raised by our stakeholders have, in turn, helped shape this plan into its current form.

Among the key contributions of stakeholders throughout the IRP process are the recommendations for scenarios and sensitivities to study in the IRP analysis. Conversations with stakeholders have directly influenced the constructions of sensitivities such as the extension of tax policies, increased levels of EV adoption, uptake of building electrification, increased/decreased adoption of behind-the-meter solar, and institution of carbon pricing.

Table 1. Public Advisory Group meetings

Meeting Date	Key Topics
July 16, 2019	Kickoff, Overview, Timeline
August 20, 2019	ETA Roundtable, Utilities 101
August 29, 2019	Introduction to Resource Planning
September 6, 2019	Transmission & Reliability (Real World Operations),
September 24, 2019	Goals of the IRP, Modeling Tools of the IRP, Core Assumptions, Constraints, & Sensitivities, Audience Input to Scenarios
October 22, 2019	Energy Efficiency, Distributed Generation, Time-of-Day Rates
November 19, 2019	Battery and Energy Storage; Sandia National Laboratory Guest Presentation
January 14, 2020	Technology Review, RFI Results
August 25, 2020	Current Events, Commodities Forecast, Load Forecast, Modeling Updates, ELCC Study, Process & Scenario Updates
September 15, 2020	Resource Adequacy Deep Dive, Final Modeling Updates, Review of Stakeholder Scenarios Received
January 5, 2021	Current Events, ETA requirements, Modeling Framework & Approach, Draft Model Results, Reliability Analysis

Other stakeholder requests, including an earlier carbon emissions-free target, are shown among the additional portfolios studied of Section 8.7 (Additional Portfolios Studied). Some requests were deemed not possible under our existing modeling framework. These include looking at a “climate change future” and the possibility of additional DC interconnects. Though we cannot address these requests quantitatively, we note that they point to important qualitative considerations and areas for deeper future investigation. In particular, we share the stakeholders’ concern that the impact of extreme weather events such as long and geographically widespread heat waves may be underrepresented, especially in determining an appropriate planning reserve margin. We are developing methods to incorporate these considerations into future modeling and look forward to sharing this progress with the Public Advisory Group.

We are thankful for the participation of stakeholders that have contributed to shaping this plan. Going forward, we expect their continued engagement to help shape the future of our energy supply, and we invite any interested parties that wish to contribute to the process to notify us of their interest.

1.4 Review of 2017 IRP

The 2017 IRP identified PNM’s intended mix of future resources and laid out a four-year action plan capturing next steps in several key areas. This section provides an overview of the 2017 IRP and progress made on the four-year action plan.

Key Findings

The 2017 IRP was designed to evaluate the decision of whether to retain or abandon PNM’s share in the San Juan Generation Station – at 497 MW, our largest coal-fired resource – at the end of the current coal supply agreement in 2022. The 2017 IRP analyzed a range of portfolios under two primary scenarios: (1) SJGS retires after the end of the current coal supply agreement; and (2) SJGS continues to operate beyond 2022.

The most significant finding of the 2017 IRP was that retiring PNM's 497 MW share of SJGS in 2022 and replacing it with a portfolio of renewables, storage, and natural gas would provide long-term cost savings for PNM's customers. Similarly, the analysis performed in the 2017 IRP found that PNM exiting its 13% share in the Four Corners Power Plant (FCPP) in 2031 (following termination of the existing coal supply agreement) would further reduce costs to customers while fully eliminating coal from PNM's portfolio.

The 2017 IRP highlighted several additional topics of importance for PNM's future plans in the 2017 MCEP:

- **Retention of existing resources:** The 2017 IRP found that through 2022, all of PNM's existing supply-side resources, with the exception of SJGS, would remain a part of the resource portfolio. PNM's 288 MW ownership stake in Palo Verde Nuclear Generating Station (PVNGS) and leases that total an additional 114 MW are an important source of carbon emissions-free baseload power. Based on analysis completed in the 2017 IRP, PNM anticipated a potential renewal of these leases beyond their 2023 and 2024 expirations.

- **Access to power markets:** Wholesale power markets in the West, where we buy and sell electricity in order to reduce customer costs, are changing rapidly. The 2017 IRP established plans to assess opportunities to participate in real-time energy markets that might result from joining the Western Energy Imbalance Market (EIM)[2] and continue participating in regional transmission forums. This assessment led to a decision to join the Western EIM, which will occur officially in April 2021.

- **Transmission needs:** The ability to deliver generation to our load centers in northern and southern New Mexico is a key part of our planning process. The 2017 IRP identified potential geographic areas to locate new resources that would not require new investments in transmission. While some locations for new resources are preferable to others in terms of cost and system reliability, sufficient transmission capacity exists to connect new resources to PNM's existing transmission system. Removing SJGS and Four Corners from our portfolio will, however, require mitigation of voltage problems in the Four Corners region.

Four-Year Action Plan

The 2017 IRP included a four-year action plan that identified a number of strategic actions that would help PNM continue to meet its customers' needs reliably and at low cost. PNM has made significant progress towards the achievement of the 2017 Action Plan. Those action items not fully resolved between the 2017 and 2020 IRPs are revisited and explored within this plan.

[2] As further discussed in Section 1.5.5 (Western Energy Imbalance Market), the EIM is a subhourly energy market but does not affect PNM's resource adequacy needs.

Figure 8. Status of key actions from 2017 Action Plan

2017 IRP ACTION PLAN	STATUS
Continue to develop and implement energy efficiency and demand management programs	Ongoing
Add renewable energy resources to maintain compliance with the Renewable Portfolio Standard (RPS)	Ongoing
Explore options to maintain system supply and reliability • Assess the costs and benefits of joining the California Energy Imbalance Market • Participate in regional transmission planning groups • Complete an economic assessment of the Reeves Generation Station	Complete
File for SJGS abandonment with the New Mexico Public Regulation Commission • File with the NMPRC to determine the extent to which SJGS should continue serving PNM customer needs beyond 2022 • Issue an RFP for energy storage, renewable energy, and flexible natural gas resources to refine mix of replacement resources • Define SJGS replacement resource siting requirements by analyzing transmission system needs	Complete
Secure the PVNGS leased capacity	Revised
Identify the best opportunities to increase transmission capacity to Eastern New Mexico to allow future expansion of wind resources	In Progress
Conduct the 2020-2040 Integrated Resource Plan	Complete

1.5 Updates Since 2017 IRP

The time since the 2017 IRP has been eventful for PNM. New Mexico's passage of the Energy Transition Act, coupled with PNM's commitment to achieve a carbon-free portfolio by 2040, have reoriented our future plans towards a clean energy future. In addition to pursuing the goals laid out in the 2017 MCEP and Action Plan, we have filed for early abandonment of FCPP and will be submitting a filing for the abandonment and replacement of PVNGS leased capacity later this year. We use this section to provide context for and status of each of these developments.

1.5.1 New Mexico's Energy Transition Act and PNM's Decarbonization Goals

Subsequent to our filing of the 2017 IRP, lawmakers passed New Mexico's Energy Transition Act (ETA), a landmark piece of legislation establishing a bold vision for the state's energy supply.

Signed into law on March 22, 2019, the ETA has established a comprehensive energy policy for New Mexico electric utilities that provides for the orderly transition of the state's electricity supply needs away from fossil fuel generation to carbon emissions-free sources of energy. The key components of the ETA are:

- **The creation of a framework for utilities to transition away from coal-fired generation to lower carbon resources.** To encourage a transition away from reliance on coal generation, the ETA established mechanisms that allowed utilities filing for abandonment of existing coal plants to securitize any remaining undepreciated investment and to recover the costs of decommissioning and workforce transition by issuing energy transition bonds. Any utility that issues energy transition bonds must also comply with carbon intensity standards of 400 lbs/MWh by 2023 and 200 lbs/MWh by 2032.

- **Support for communities impacted by coal retirements.** The ETA also provides for economic support for the communities that will be most directly impacted by the closure of coal plants. This includes the creation and administration by the state of the Displaced Worker Assistance Fund and Economic Development Assistance Fund to support workforce training and local economic development, as well as a requirement that up to 450 MW of the replacement resources for SJGS be located in the Central Consolidated School District in San Juan County.

- **An increase to the state's current Renewable Portfolio Standard.** Under the ETA's amendments to the Renewable Energy Act, utilities in the state must comply with RPS targets of 40% by 2025, 50% by 2030, and 80% by 2040. The establishment of these aggressive targets and interim milestones provides a clear signal to the electric industry of the level of renewable development that will be needed within the state over the next two decades.

- **The establishment of a state goal to achieve a carbon emissions-free generation portfolio by 2045.** The ETA's final legislative contribution is the creation of an ultimate target for the state to eliminate greenhouse gas emissions entirely from its utilities' portfolios by 2045. The legislation also specifies that "reasonable and consistent progress shall be made over time toward this requirement". In establishing this goal, the ETA made New Mexico one of the first states to commit to eliminating carbon emissions from electricity generation within this timeframe.

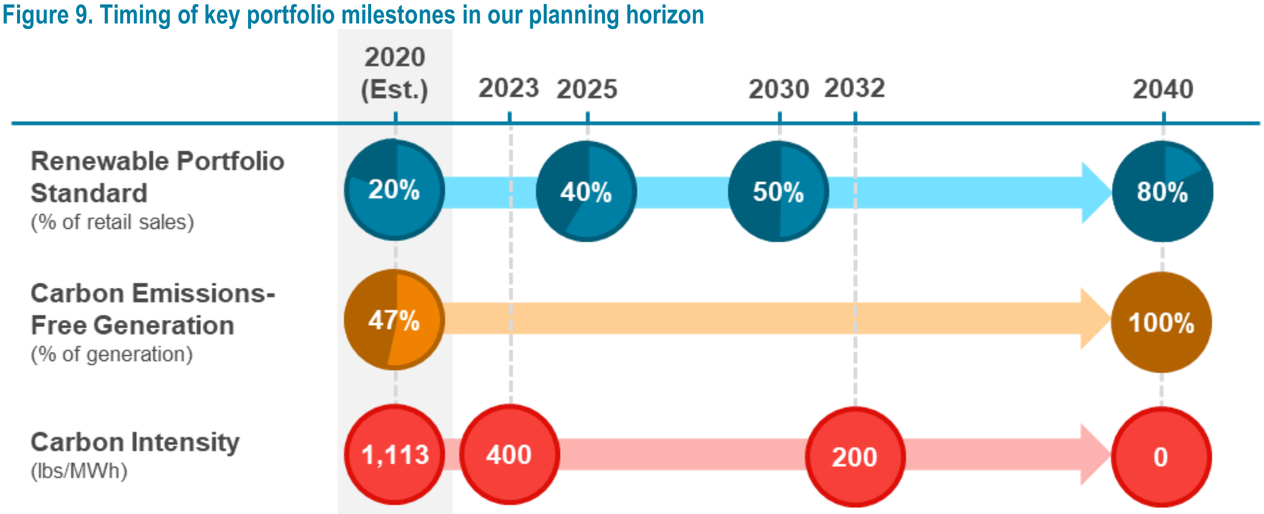
At PNM, we support the vision set forth by the ETA and have already undertaken significant steps to execute upon it. The ETA's provisions encouraging timely abandonment of coal plants allowed us to file for abandonment of SJGS by 2022 and FCPP by 2025; many of the resources that we procure to replace these resources will enable us to reduce costs to our customers and position our portfolio to achieve significant near-term reductions in carbon emissions.

While the ETA requires a carbon emissions-free electricity portfolio by 2045, we have committed to working towards achieving this milestone in 2040, five years sooner than required by statute. With the advances made by the industry in the past decade and the promise of continued technological innovation, we believe this transition is possible and will best serve the needs and preferences of our customers over the next two decades.

To comply with the 2040 target, our modeling assumes depreciation schedules for all carbon-emitting resources that complete by 2039, though this depreciation schedule has not been proposed or approved for rates at this time. This assumption is intended to prepare our portfolio for the final transition to a carbon-free supply, allowing our remaining fossil plants to cease operations after 2039 so long as we can maintain resource adequacy in their absence.

Together, the ETA and our own goals prescribe a roadmap of overlapping milestones for clean energy that guides our planning process. Our portfolios are designed to meet the statutory requirements prescribed by the ETA while also transitioning towards our goal of a 100% carbon emissions-free portfolio by 2040. Figure 9 highlights the key milestones that we consider in our planning process on the pathway to a carbon emissions-free portfolio.

Figure 9. Timing of key portfolio milestones in our planning horizon



Metrics for 2020 estimated based on PNM's current portfolio

1.5.2 SJGS Abandonment & Replacement Filings

On July 1, 2019, Public Service Company of New Mexico (PNM) filed its Consolidated Application for the Abandonment, Financing and Replacement of the San Juan Generating Station pursuant to the Energy Transition Act (Application). On July 10, 2019, the Commission issued an order separating the Commission's review of PNM's Application into two proceedings: one considering the abandonment and securitization issues for SJGS (Case No. 19-00018-UT) and a second focused on the replacement resources for SJGS (Case No. 19-00195-UT).

The application for abandonment of SJGS (Case No. 19-00018-UT) was approved by the Commission on April 1, 2020, providing for PNM's timely exit from plant ownership by July 1, 2022. At the same time, the Commission approved a financing order allowing PNM to issue bonds as allowed under the ETA to finance abandonment of the plant. These bonds were to be used to finance a total cost of $361 million (representing PNM's undepreciated costs, plant decommissioning costs, and workforce transition costs) to be collected through a non-bypassable charge on customer bills.

On July 29, 2020, the Commission issued a final decision in PNM's filing for replacement resources (Case No. 19-00195-UT), approving a portfolio of resources that includes 650 MW of solar PV, 300 MW of storage, 24 MW of demand response, and approximately 15 MW of additional energy efficiency. The replacement resources ordered by the Commission are summarized in Table 2.

Table 2. Replacement resources for SJGS ordered by the Commission

Resource		Capacity (MW)	Location
Arroyo Solar Project	Solar	300	McKinley
	Storage	150	
Jicarilla Solar Project	Solar	50	Rio Arriba
	Storage	20	
Rockmont Solar	Solar	100	San Juan
	Storage	30	
San Juan Solar Project	Solar	200	San Juan
	Storage	100	
Demand Response		24	System-wide
Energy Efficiency		15	System-wide
Total		**965**	

On August 14, 2020, we issued an RFP for 40 MW of demand-side resources to be online by June 1, 2022, in accordance with the Commission's decision in the SJGS replacement hearing. Responses were limited, and from the proposals that we received, we selected 15 MW of demand response resources. We are currently seeking approval of that resource from the Commission in Case No. 20-00182-UT; however, at the time of this IRP the Commission has not issued an Order regarding the DSM proposal.

1.5.3 PVNGS Lease Abandonment

PNM currently owns 288 MW of capacity in the Palo Verde Nuclear Generating Station (PVNGS) and leases 114 MW in PVNGS from financial investor lessors. Under the leases, PNM has an option to purchase the capacity at fair market value upon the expiration of the leases. On June 11, 2020, we announced our plan not to purchase our leased interests in PVNGS, that expire in 2023 and 2024. In our 2017 IRP, we had indicated our intention to renew these leases upon expiry. Since that plan was filed, we have continued to monitor industry trends and, in anticipation of the opportunity to procure additional low-cost carbon emissions-free replacement energy and flexible capacity resources, made a determination not to seek renewal.

Our ownership shares in PVNGS Units 1-3, a total of 288 MW that is capable of supplying approximately 20% of our customers' long-term annual needs, will continue to provide our customers with firm, carbon emissions-free power through at least the end of the current plant licenses (2045-2047). The potential extension or replacement of the 288 MW will be a consideration for future IRPs. Exiting our leases provides us with the opportunity to reduce customer costs and contemporaneously right-size our share in PVNGS as a percentage of PNM's portfolio used to meet our long-term needs as we transition towards a carbon emissions-free portfolio, while allowing us to take advantage of new market opportunities for the benefits of our customers.

On June 25, 2020, we issued a competitive RFP for replacement resources, and we intend to file with the Commission for approval of the abandonment of our leased shares and of corresponding replacement resources in Q1 2021.

1.5.4 Four Corners Abandonment

In PNM's 2016 rate case (Case No. 16-00276-UT), PNM and other intervenors entered into a stipulated agreement that was adopted and approved by the Commission, which included the following requirement:

> 10. PNM shall perform a cost-benefit analysis as part of its 2020 Integrated Resource Plan, on the impact of an early exit from Four Corners as a participating owner, as of 1) 2024, and 2) 2028, that includes an analysis of the cost recovery of and return on PNM's undepreciated investments in Four Corners together with full recovery of all existing contractual obligations, including default payments and penalty.

–Stipulated Agreement in Case No. 16-00276-UT

In accordance with the stipulation, PNM sought an opportunity to accomplish an early exit in 2024. An early closure and permanent shut down of Four Corners would require unanimous agreement of participants without an interest in the coal mine. Because the stated intent of other participants is to continue operating the plant, absent a transfer of its interest, PNM would be subject to default payments and penalty from an early exit. Without a potential alternative such as the transfer of ownership, it would not have been economically reasonable to exit Four Corners in 2024 or 2028.

On November 2, 2020, we announced a plan to transfer ownership of our share of FCPP to the Navajo Transitional Energy Company (NTEC) at the end of 2024. On January 8, 2021, we filed for abandonment of our minority share of FCPP in Case No. 21-00017-UT. This transaction is in the economic interest of our customers by bringing them significant cost savings and helps to accelerate our transition toward a carbon emissions-free portfolio by eliminating the most carbon-intensive resource in our portfolio earlier than the planned exit date of 2031.

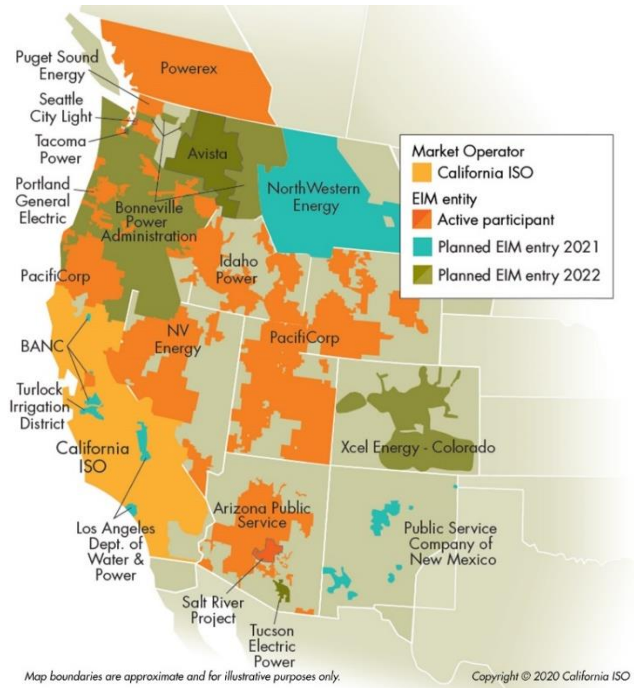
With the negotiation of the transfer of PNM's interests to NTEC and the avoidance of contractual default payments and penalties, the 2024 exit from Four Corners is more beneficial for customers than remaining a plant participant until 2031.

1.5.5 Western Energy Imbalance Market

The Western Energy Imbalance Market (EIM) is an effort to promote more formal and organized coordination among the various entities of the West. This coordination intends to harness the efficiencies of load and resource diversity across a broader geographic region, thereby reducing participants' system costs. The EIM allows utilities to exchange energy on a fifteen- and five-minute basis in an optimized manner across its footprint. This exchange enables more efficient system dispatch and mitigates curtailment of renewable resources. Since its inception in 2014, the footprint of the EIM has expanded to include large portions of the Western Interconnection, and by 2022, will include major utilities across every state in the West. To date, the EIM has produced benefits in excess of $1 billion for its participants.

As suggested by our 2017 Action Plan, we evaluated the costs and benefits of participation in the EIM. We expect the benefits of participation in the EIM to be $17-21 million per year, while the costs of joining the market would require one-time capital and O&M expenditures of $28 million and ongoing costs of $3-4 million per year. In light of the substantial savings opportunity for our customers, we filed with the Commission to join the Western EIM in Case 18-00261-UT and received approval to do so, along with an accounting order allowing PNM to seek recovery of EIM costs in future rate cases and requiring compliance reports on EIM costs and savings. We anticipate joining the EIM officially in April of 2021.

Figure 10. Current and planned EIM participants



While we expect the EIM to produce savings for our customers through more efficient operations of our resources, it will not contribute to or affect our resource adequacy needs. In fact, EIM entities are required to pass resource sufficiency tests in each hour as a prerequisite to participation to demonstrate that they are not inappropriately relying on capacity or flexibility from other EIM participants; those that cannot are excluded from the market until they can demonstrate sufficiency. Accordingly, while our participation is expected to allow us to operate our system more efficiently, it does not provide for increased or enhanced resource adequacy merely by becoming a participant.

1.5.6 Grid Modernization and the "Wired for the Future" Initiative

To modernize the service we provide to customers and aid in our transition to being carbon emissions-free by 2040, significant investments will be needed in the transmission and distribution systems. PNM will pursue focused initiatives to strengthen our existing systems and improve and modernize these systems to meet customers changing needs. At the Commission, PNM has filed its initial case for our transportation electrification plan in accordance with the Public Utility Act requirements. PNM is also evaluating grid improvements that meet the criteria of the Act's grid modernization statutes.

As one part of our efforts to provide quality service, PNM announced in July 2020 our "Wired for the Future" initiative to invest approximately $450 million from 2021 to 2025 with three goals: (1) enhancing customer satisfaction, (2) delivering clean energy, and (3) increasing grid resilience. Enhancing customer satisfaction entails leveraging grid modernization technologies to improve reliability and decrease outage restoration time, in addition to ensuring that the system has enough capacity to support growth from new and existing customers. Delivering clean energy requires making sure that our substations and lines are configured to deliver large amounts of renewable energy from generation pockets to load centers and making sure those resources are integrated seamlessly into power supply. We will increase grid resilience through updates that better support response to threats such as cybersecurity and wildfire. Focus on these goals will ensure that customer service only improves as we transition to a carbon emissions-free system.

2 Our Customers

Above all, PNM exists to provide service to our customers. Their usage patterns and preferences inform our resource planning and procurement decisions. As such, the portfolio of resources and programs that we identify in this IRP represents a system that is intended to evolve in concert with customer needs and preferences over the coming years. This section describes our customers, how they use electricity, and what they want from their electricity service. We also discuss our offerings to them through rates and programs, with attention to how these offerings can be designed to address both future resource planning needs and customer preferences.

Section Highlights

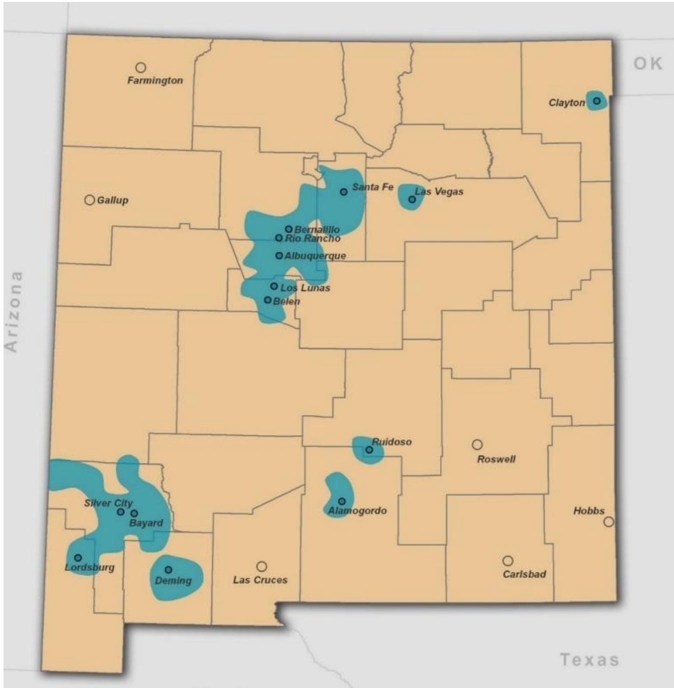
- PNM provides retail electric service to customers throughout the state of New Mexico; our customers include residential, commercial, industrial, and other end users of electricity.
- We tailor our services to meet our customers' needs and preferences, which requires us to understand what our customers value.
- We continue to refine our service offerings through the rates and tariffs we offer to our customers, which are designed to offer flexibility and optionality to our customers while also sending price signals that reflect the value of the service we provide.

2.1 Service Territory

Our 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.

PNM's retail service territory, shown in Figure 11, 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 we serve include Lordsburg, Silver City, Deming, Alamogordo, Ruidoso, Tularosa, Clayton, Las Vegas, several New Mexico Pueblo nations, and numerous unincorporated areas.

Figure 11. Map of PNM's electric service territory



2.2 Customer Usage and Trends

Our electricity customers number about 530 thousand and include many different types of users. For the purpose of providing retail electric service, we organize these customers into fourteen classes that reflect different sizes, applications, and patterns of consumption. Our classes of service are listed in in Table 3, along with breakdowns of total customers, annual load, contribution to peak, and revenue from these classes.

Table 3. PNM's customer counts, usage, and revenue

Customer Class	Customers (#)	Annual Load (GWh)	Coincident Peak (MW)	Revenue (M$)
Residential	471,935	3,230	861	392
Small Power	53,293	945	207	116
General Power	4,192	1,883	331	177
Large Power	186	1,035	130	78
Large Service	2	77	4	6
Private Lights	0	14	0	3
Irrigation	313	22	5	2
Water and Sewer	155	167	11	10
Universities	1	74	11	5
Street Lights	114	41	0	7
Large Manufacturing	1	360	44	22
Station Power	1	3	0	0
Large Power > 3MW	4	215	27	11
Special Service Rate	1	289	41	12
Total	**530,198**	**8,355**	**1,674**	**840**

Electrification

As New Mexico's economy moves towards decarbonization, electrification of building end uses and transportation will cause growth in PNM's per-customer load across most classes. While only 20% 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 13% of customers report electricity as their energy choice today. Similarly, though relatively few customers own electric vehicles (EVs) now or have expressed plans to own EVs in the next two years, electrification of the transportation sector is underway.

This anticipated load growth presents an opportunity. Much of this new load will be flexible and able to serve as a peak-reducing resource if managed through a combination of rate signals and automatic controls. On the customer side, this management and the grid modernization technologies that enable it will improve communications between us and our 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.

We note here that while we are beginning to incorporate electrification-driven increases in load in long-term planning, our current forecasts do not include significant impacts from electrification within the timeframe of the planning period of this IRP. This is an area where we will continue to focus on developing modeling capabilities and sharpening our long-term view on the role of transportation and building electrification in meeting the energy needs of New Mexico's consumers.

New Large Loads

PNM currently provides service to one large data center load but has recently received a number of inquiries regarding the potential for new large economic development projects, typically either data centers or large industrial facilities. These types of projects could result in substantial increases to our future loads and associated resource needs.

2.3 Customer Preferences

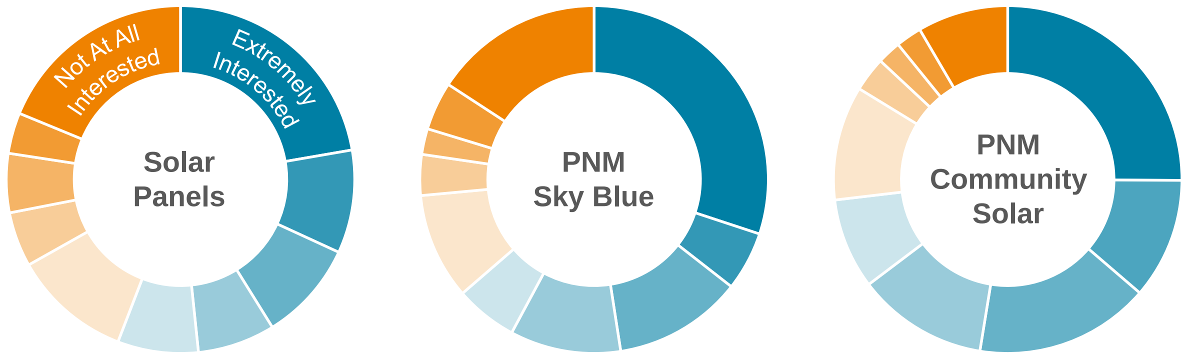
For customers who have an interest in energy supply that has more renewable energy than PNM's generation portfolio, we offer net metering and voluntary programs including PNM Sky Blue, PNM Solar Direct, and the PNM Green Energy Rider (Rider 47). These programs allow customers of all sizes to invest in their own on-site generation, or to procure renewable energy from utility scale resources. Because customers enrolled in these programs are voluntarily participating outside of PNM's standard service, the resources that serve the voluntary programs are not included in PNM's RPS accounting. This means that the actual fraction of renewable energy produced to serve PNM customers in a year will always be larger than the fraction reported for RPS compliance. We expect participation in these programs to continue growing, leading to a percentage of renewable generation higher than what is required by the RPS.

PNM conducts regular customer surveys on a variety of topics to understand the priorities of consumers and how to best serve them. A 2020 survey on PNM Customer Renewable Programs aimed to assess customer satisfaction with existing renewable options and to gain insights to guide design of future offerings. The survey included Residential customers, Low Income Home Energy Assistance Program (LIHEAP) customers, and Small Power customers.

In questions regarding satisfaction with current renewable offerings, over 47% of customers indicated satisfaction with PNM's current fraction of renewable resources serving energy needs. However, 31% thought that PNM should have a significantly larger share of renewables.

Currently, customers with preferences for renewable energy in their supply do so through one of two dominant avenues: purchasing privately owned solar photovoltaic (PV) systems installed on their property or participating in PNM Sky Blue, which is a REC purchase green tariff program. About a third of survey respondents already utilize one of these options, while another 40% indicated future interest in similar options. As indicated by Figure 12, customers indicating future interest showed a preference for streamlined utility-led programs over privately owned resources. The survey indicates that key drivers of program uptake are the desires to participate in the sustainability movement and to save money on electricity bills.

Figure 12. Self-reported interest of PNM's customers in renewable generation and associated programs.[3]



We recognize utility-led renewable energy programs as 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, in the IRP context, 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.

PNM Sky Blue

Customers who wish to contribute to raising the amount of renewable energy in PNM's portfolio may participate in the Sky Blue voluntary program. Enrolled customers contribute an amount above their monthly billing as a premium for renewable energy beyond the percentage in PNM's default portfolio. Those funds are then used to procure renewable energy above the amounts required by the RPS. We dedicate 1.5 MW of solar facilities to the Sky Blue program, the energy from which is blended with generation from New Mexico Wind Energy Center (NMWEC) to supply customers participating in the program.

PNM Solar Direct

We have also been working collaboratively with our larger customers to provide increased choice in energy supply. Under a program approved by the Commission 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.

2.4 Rates and Tariffs

An integral part of serving PNM's customers is providing a set of rates that accommodate customers' diverse usage patterns and desire for affordable power. Maintaining affordable prices entails encouraging customers to reduce total energy consumption and to align usage with the times of the day and times of the year during which energy production is cheapest. As PNM moves towards a carbon emission-free future, this calculus will need to include emissions as well; incentivizing customers to move their flexible loads to times when carbon emissions-free electricity is produced. Generally speaking, to maximize the efficiency of system investments and

[3] Based on responses to the survey question: "Based on your current knowledge about renewable offerings, how interested are you in subscribing to each of the following renewable options?" (Q20 n=644; Q28 n=569; Q36 n=538)

operations, customer rates should provide price signals to customers to encourage shifting usage to times when emissions are lowest.

Currently, PNM rates promote load management and load shifting through a variety of rate design mechanisms: seasonal rates, inverted block rates, time-of-day rates, demand rates, interruptible rates, and voluntary demand response programs. In compliance with IRP Rule Section 17.7.3.9 (F) (3), the rate designs that we offer are described below.

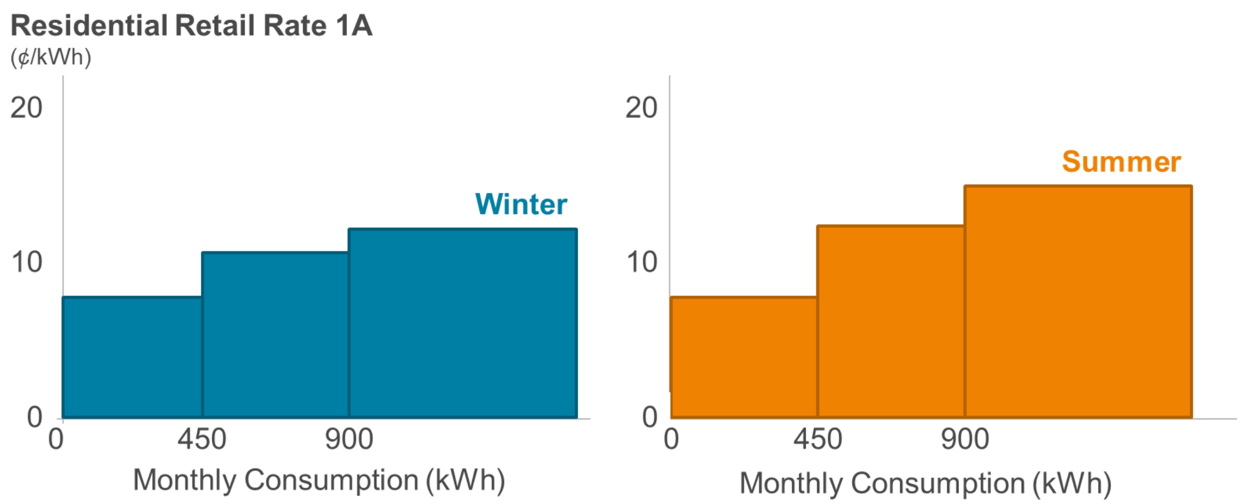
Seasonal Rates

For nearly all rates, summer rates are higher than winter rates. This seasonal rate design encourages customers to moderate usage during the summer months when demand on the system is greatest and utility generation costs and carbon emissions are highest. By discouraging usage during the peak season, seasonal rates can help to delay the need for new capacity resources and lower total carbon emissions.

Inverted Block

For most residential customers (Rate 1A), per-unit energy costs increase as usage increases. This discourages higher usage by increasing the rate at which customer bills increase as consumption increases. Figure 13 visualizes Rate 1A to highlight the Seasonal and Inverted Block components of the rate design.

Figure 13: The seasonal inverted block design of Residential rate 1A



Time-of-Day Rates

PNM offers time-of-day (TOD) rates for nearly all rate classes, including Residential, Small Power, General Power, and Large Power. These rates encourage customers to avoid usage during the time when the carbon emissions and cost to serve are highest (on-peak) and allow for greater efficiencies in generation resource utilization. TOD rates are required for all larger customers (greater than 50 KW). The remaining customers can choose TOD rates to lower their cost by shifting usage to off-peak periods.

Figure 14 shows the current TOD rate offered to the residential class, as well as a proposed future TOD rate for the residential class. The illustrative future rate is not meant to be regarded as a rate proposal, but merely an illustration of the likely evolution of TOD periods to match periods when we expect energy prices to be highest. With large amounts of solar generation, midday prices will be suppressed, and the current TOD period will not be appropriate. Instead, TOD peaks will be designed to align with the heating and cooling demands that arise during shoulder periods of the day when solar generation is low. An additional rate tier was proposed in our Transportation Electrification Plan for EV owners to encourage vehicle charging overnight when demand is otherwise low. Though not shown, PNM proposed in the Transportation Electrification Program a new TOD rate for separately metered commercial EV charging stations to encourage EV charging from workplaces during the solar peak and at night. The alignment of TOD periods with evolving hourly variation in cost of service will ensure that we utilize customer load flexibility to keep rates low as we build future resource plans.

Figure 14. Current TOD offering (1B) for Residential customers and an illustrative future rate with a narrower peak

Demand Rates

Demand rates charge for usage during a specific time window. Unlike energy rates that are based on a customer's total energy (kWh) usage, demand rates are based on a customer's maximum power (kW) that they demand from the grid during a given time period. A customer who uses a high rate of power for short periods requires the system to be ready with capacity at any time to provide that power. Demand rates encourage customers to reduce power usage during on-peak hours and to shift usage to off-peak hours, which improves system utilization and efficiency. In Section 8.4 (Implications for Resource Adequacy), we discuss the future need for carbon emissions-free firm capacity to meet resource adequacy needs in a renewable-dominated portfolio. The uncertainty and likely high cost of acquiring such resources indicates that there will be high future value of reducing peak load with demand rates and other tools.

Incremental Interruptible Power Rate

Five General Power and three Large Power customers have contracts for service under an interruptible power tariff (PNM's Rate Rider 8). In the event of a system emergency, PNM can call upon these customers to interrupt their incremental on-peak billed demand with 30 minutes' notice during the on-peak period from 8:00 a.m. to 8:00 p.m., Monday through Friday. Interruptions can extend for up to two hours into the daily off-peak period but have no limit in the total hours of interruption per year. This service allows a customer to bypass an interruption request and forgo the monthly discount, subject to potential removal from the rate. PNM will evaluate the effectiveness and need for this rate in its next general rate case.

Voluntary Demand Response Programs

Under the energy efficiency rider, residential and business customers (under the Power Saver program) and business customers with a demand greater than 150 kW (under the Peak Saver program) can volunteer to have portions of their load curtailed during summer peak events. The voluntary nature of these programs means that that customers can opt out of events if they choose. Load shifting achieved through the programs helps manage peak summer loads. More detail on our DR programs appears in Section 6.2.1 (Existing Demand-Side Resources).

Future Time-of-Day Rate Design

As our portfolio shifts to include more capital-intensive intermittent resources and fewer on-demand resources with high variable cost, we expect to be long on energy but short on capacity. This anticipated need for capacity results in the value of conservation decreasing and the value of temporal alignment of load with generation increasing. This shifting value means that moving more load onto Time-of-Day (TOD) rates is a critical part of our vision for future rate design.

Historically, all but the most basic TOD rates were considered too complex for residential customers, but this thinking has changed. Customer sophistication has increased, more and better tools facilitate communication between PNM and customers, "smart" appliances allow for load shifting with minimal customer intervention, and electrification of more end uses creates an abundance of flexible load. Accordingly, default residential rates with TOD components have been proposed, adopted, and implemented in nearby jurisdictions.

In the Transportation Electrification Program, we proposed a set of limited-enrollment TOD rates to improve alignment between the wholesale and retail cost of electricity at different times of day. These rates include a residential TOD EV rate and a Commercial EV Charging TOD rate. The Residential TOD EV rate structure has a super off-peak period that incentivizes overnight EV charging, as requested anecdotally by EV owners in PNM's service territory.

In an upcoming rate case, we plan to propose further expansion of TOD rates, including a Residential TOD rate and a Small Power TOD rate. Moving from the current rates to default service TOD pricing will not happen overnight. Currently we lack the Advanced Metering Infrastructure (AMI) required to collect and manage TOD data from all residential customers. However, we recognize that New Mexico's grid modernization legislation, House Bill 233, creates a pathway for AMI investment. To understand the approximate impact that TOD rates could have on long term plans, PNM includes a modeling sensitivity in which residential load is shifted in response to an example TOD rate.

2.5 Transmission System Customers

In addition to serving its retail customers, PNM also provides transmission customers with generator interconnection and transmission delivery services pursuant to its Open Access Transmission Tariff (OATT) as approved by the Federal Energy Regulatory Commission (FERC). PNM must plan to meet the needs of these customers along with retail customers, since OATT service accounts for approximately 50% of PNM's total transmission utilization. Transmission system customers fall into two categories: Network Integration Transmission customers and Point-to-point customers.

Network Integration Transmission Service allows integration of customer and PNM networks. This integration enables certain customers to dispatch and regulate their own resources and import energy purchases without additional charge. These customers include: Tri-State Generation and Transmission Association (Tri-State), Western Area Power Administration (WAPA) for Kirtland Air Force Base and Sandia National Laboratory, Los Alamos County, Navajo Tribal Utility Authority, Navopache Co-op, City of Gallup, Kit Carson Co-op, Jicarilla Apache Nation, and PNM Wholesale Power Marketing (for PNM retail).

Point-to-point customers use PNM's transmission network for both energy and capacity between specified points. These customers include: El Paso Electric, WAPA, High Lonesome Mesa Wind, Aragonne Mesa Wind, and Tri-State.

3 Planning Landscape

This year's plan is set against a backdrop of an industry that is rapidly changing, creating a challenging and uncertain environment for resource planning. These changes include significant shifts in the dynamics of Western wholesale electricity markets and the commercialization and evolution of new technologies, both of which have significant implications for our future resource plan. By identifying and monitoring these types of trends in the industry, we seek to design a plan that is anticipatory and that mitigates key risks associated with these uncertainties.

Section Highlights

- This year's plan is set against a backdrop of an industry that is rapidly changing, creating a challenging and uncertain environment for resource planning.
- Driven by a combination of economics and policy, the broader Western Interconnection is quickly transitioning towards increased penetrations of renewables while aging baseload generators are retiring; these changes are fundamentally shaping the nature of market dynamics and the availability of energy in the wholesale markets during different periods.
- Significant technological advances over the past decade have introduced new resource options to utility planning and procurement processes; the menu of options for future generation resources is continuing to expand as new technologies are brought to market to capitalize on utilities' increasing preferences for clean energy resources.

3.1 Changing Regional Dynamics

The Western Interconnection as a whole is undergoing significant and rapid changes driven by a combination of economics and policy. These changes are largely reflected in several broad themes: (1) tightening reserve margins due to retirement of aging baseload infrastructure, (2) a shift towards intermittent renewables and storage resources to meet new resource needs and policy goals, and (3) increased interest in centralized and organized market structures throughout the footprint. Each of these changes has notable implications for our future resource planning.

Shrinking Reserve Margins

One of the major issues considered in our planning process is the extent to which we can rely on the broader wholesale market of the West to support our reliability needs during times of stress on our system (i.e. system net peak). Throughout the year, our operators take advantage of our position in the Western Interconnection by purchasing power from the spot market to help meet our system's needs. The assumption of how much to count on regional markets to support our resource adequacy needs must consider the broader context of the regional balance of supply and demand and must balance the relative risks to system reliability associated with reliance on the wholesale market with the costs of investing in our own resources to meet our needs.

Most utilities in the Southwest experience the highest demands of the year in summer, when high temperatures result in significant cooling loads. The types of weather events that lead to the highest demands are typically regional in nature, so that when our system is experiencing peak demand conditions, many others throughout the region are at or near peak demand as well. What this means is that during our peak period, the amount of energy available on the wholesale market is relatively limited, as most utilities are focused on meeting their own needs with their own resources.

Over the past decade, we have observed material changes in the balance of loads and resources in the Southwest region (Arizona, New Mexico, and Nevada) that affect our ability to source energy during periods of peak demand – most notably, the retirement of aging firm resources. In the past five years, approximately 4,000 MW of coal capacity has retired within the region, and utility plans indicate that this pattern will continue, as an additional 1,000 MW of capacity may retire based on current utility plans in the next five years. These retirements are generally moving the Southwest from a position of surplus generation capacity to a very tight load-resource balance. At the same time, nearly 4,000 MW of natural gas generating capacity has retired in California since 2015, eliminating a surplus margin of capacity that had existed in the state since the Energy Crisis of 2001.[4] California's experience of rolling blackouts in the summer of 2020 – the first in the West since 2001 – presents stark evidence of the tightening balance between supply and demand.

Table 4. Major historical and future coal plant closures in the Southwest

Facility	Unit(s)	State	Capacity (MW)	Retirement/ Abandonment Year
Cholla	Unit 2	Arizona	260	2016
Reid Gardner	Unit 4	Nevada	257	2017
San Juan Generating Station	Units 2 & 3	New Mexico	836	2017
Navajo Generating Station	Units 1 - 3	Arizona	2,250	2019
Escalante Generating Station	Unit 1	New Mexico	253	2020
Cholla*	Unit 4	Arizona	380	2020
Subtotal, Historical			**3,976**	
San Juan Generating Station	Units 1 & 4	New Mexico	847	2022
Cholla	Units 1 & 3	Arizona	387	2025
Subtotal, Future			**1,234**	

** Retirement planned for 2020 but not retired as of January 2021*

The continued retirements of aging firm generation resources within the region and the corresponding reduction of the regional surplus are expected to exacerbate this dynamic, and we expect it will limit our ability to count on the wholesale market during the periods we need it most. The effect of this contraction is accounted for through our Planning Reserve Margin, which incorporates assumptions regarding the level of market support that the region can provide to support our reliability needs. This topic is discussed further in Section 4.1.1 (Resource Adequacy and Planning Reserves).

Changing Wholesale Market Dynamics

The widespread deployment of renewables – particularly solar resources – is a second notable trend that is reshaping the western grid. Over the past ten years, utilities in the Southwest and California have added over 20 GW of solar PV capacity to the electric grid, which has prompted the emergence of California's ubiquitous "duck curve:" an hourly "net load" shape that drops during the daytime during solar production and then rises steeply as the sun sets toward a net peak at sundown.

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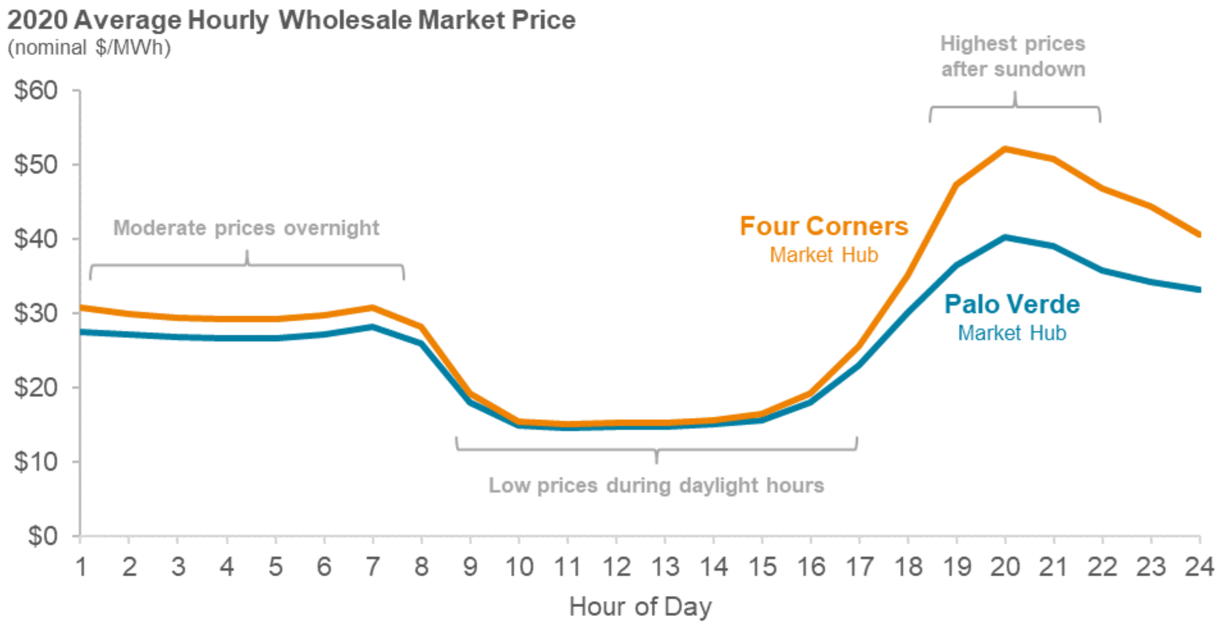
[4] Installed capacity of generation in California available from the California Energy Commission: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy

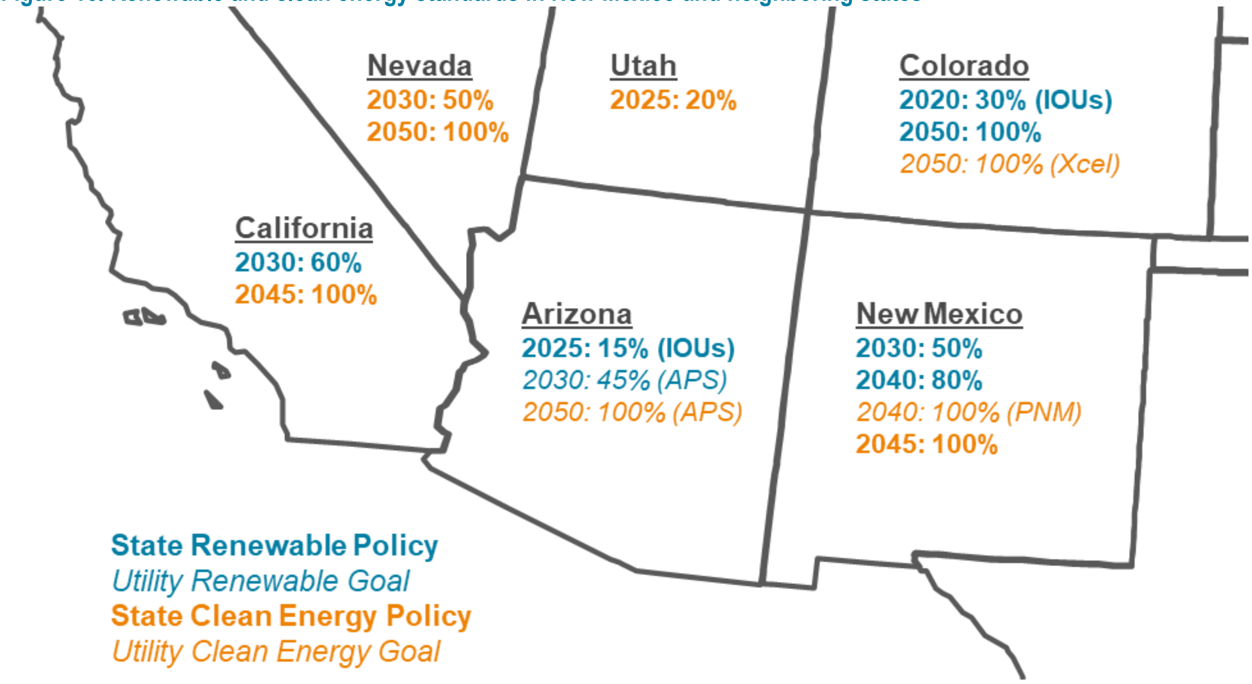
The shape of this curve has had profound impacts on the operations of the regional electric system and the dynamics of wholesale markets. For decades, the standard products traded in Western markets have been peak and off-peak blocks that generally allow utilities to exchange daytime energy at higher prices and nighttime energy at lower prices. The changing composition of supply in the West has upended this dynamic, as the wholesale market has generally realigned to follow the shape of the duck curve, exhibiting very low – sometimes negative – pricing during the daytime in the spring and very high prices during the evening ramp.

Figure 15. 2020 average hourly price shapes (based on PACE commodities forecast)



Going forward, we expect this trend to continue. Aggressive clean energy policies in neighboring states, summarized in Figure 16, will continue to drive investment in new renewable resources throughout the West, and the relative abundance of low-cost solar potential in the region should result in significant additions. While utilities are also beginning to invest in lithium ion batteries as a form of energy storage, these investments will only mitigate these pricing patterns – not eliminate them.

Figure 16. Renewable and clean energy standards in New Mexico and neighboring states



Regional studies of the impacts of these policies identify profound changes in the operations of the regional grid, indicating significant changes in trading patterns and transmission flows throughout the West. Our access to wholesale energy markets at Palo Verde and Four Corners positions us to take advantage of the opportunities presented by these changing dynamics, which in turn will impact our future investments. In particular, the low daytime prices in the wholesale markets due to regional solar surplus will tend to encourage diversification towards resources that are capable of producing energy outside of the daylight hours. In our analysis, we consider how participation in wholesale markets in the West will allow us to further optimize costs to our customers.

Increased Interest in Regional Coordination

The Western Interconnection exists today as a patchwork of balancing authorities and utilities, many of which have historically functioned largely independently in planning and operating their respective systems except through long-term contracting and bilateral wholesale trading. Many studies have identified the fragmented institutions of the Western Interconnection as a potential barrier to achieving high penetrations of renewable generation—and have highlighted the potential of greater regional coordination as a no-regrets opportunity to reduce system costs and accelerate the transition towards renewables.[5] Accordingly, recent efforts such as the Western EIM have been undertaken to explore enhancements to this bilateral status quo.

[5] See, for example, E3's *Western Interconnection Flexibility Assessment*, which found that "Improving regional coordination offers a low-hanging fruit among integration strategies", or Energy Strategies' *Western Flexibility Assessment*, whose observation that "In the long-term, results indicate that it will be very difficult, or at least extremely costly, to achieve Western policy targets without broad coordination of wholesale markets" suggests substantial benefits under high renewable penetrations.

The Western EIM has produced significant benefits for its participants to date, and we expect it to deliver savings to PNM's customers in the future after we have joined. However, its scope is limited when compared with more formal organized energy markets that could be possible with a centralized day-ahead market. Capitalizing on the success of the EIM to date, multiple participants, led by CAISO, have begun to explore the possibility of extending the same principles into the day-ahead timeframe through an "Extended Day-Ahead Market" (EDAM). The EDAM initiative would allow EIM entities to participate in a voluntary optimized day-ahead market, enabling greater coordination in unit commitment and dispatch on a timescale that could unlock latent flexibility within the Western Interconnection. This initiative is ongoing, and PNM will continue to monitor its progress as a stakeholder.

Utilities in some parts of the Western Interconnection have also begun to explore the possibility of a regional resource adequacy program. The Northwest Power Pool, which includes utilities across nine western states and two provinces, is currently in the early stages of establishing a regional program for resource adequacy. This effort has been motivated by a growing concern that a large number of plant retirements, coupled with excessive reliance on the market to meet individual utilities' resource adequacy needs, could lead to a regionwide capacity deficit. Such a program has not yet been contemplated or proposed within the Southwest but could have implications for how resource adequacy obligations are established and shared among utilities in the region in the future.

All of these examples point towards a broader recognition among Western utilities that as the interconnection as a whole transitions towards greater reliance on non-firm resources, exploring organized market structures has the potential to lower costs and produce benefits for participating utilities.

3.2 Technology Trends & Innovation

One of the foremost challenges of integrated resource planning is identifying a robust long-term plan notwithstanding the presence of significant long-term uncertainties. This challenge is particularly acute today, as our plan undertakes an effort to identify how we can transition towards a portfolio that is 100% carbon emissions-free when the very landscape of the technologies that could support that transition is diverse and rapidly changing.

Enumerating the various sources of uncertainty and how they affect our planning process and decision-making is a crucial step to charting a path towards a carbon emissions-free portfolio. Acknowledging these risks will better prepare us to design a flexible and adaptable plan that: (1) meets the near-term needs of our customers at reasonable costs, (2) enables material progress towards our goals, and (3) allows optionality and flexibility to take advantage of future changes in conditions as we move forward.

PNM's 2019 Technology RFI

Recognizing the challenges ahead as we continue our path towards a carbon-emission free future, we are actively monitoring the shifting technology landscape. In November 2019, PNM issued a Request for Information (RFI) seeking market intelligence on potential emerging technologies that could contribute to meeting our future energy, capacity, and flexibility needs. The RFI was developed by a Technical Advisory Team that included representatives from PNM, the National Renewable Energy Laboratory (NREL), Sandia National Laboratory, New Mexico State University, State Land Office, and Western Grid Group.

We received responses to the RFI from twelve companies, sharing details on a diverse range of potential resources that included storage technologies, demand-side management, microgrids, and several options for carbon emissions-free generation. Table 5 lists the companies that provided responses and the technologies they submitted.

Table 5. Responses to PNM's technology RFI

Respondent	Technology
Bright Energy	Concrete thermal energy storage and cryogenic carbon capture
Electriq	Customer side energy storage
Emera	Microgrid
Enbala	Distributed Energy Resource Management System (DERMS)
Energy Vault	Gravitational potential energy
ESS	Iron flow battery
Kinetic Power	Pumped hydro
NuScale	Small modular nuclear reactor
Microgrid Systems Laboratory	Microgrid
Packetized Energy	Demand response
Shifted Energy	Demand response

Respondents to the RFI were asked to provide information that would be useful to inform potential characterization of the resource for IRP purposes, including but not limited to:

- General information regarding the characteristics of the technology;
- Operating characteristics, including performance (e.g. nameplate capacity, ramp rates) and costs (e.g. capital, operations and maintenance);
- "Technology Readiness Level," as measured on a scale from 1 (basic principles developed) through 9 (commercially available and operational) developed by Sandia National Laboratory; and
- Information related to software capabilities to support system operations.

Each response was reviewed by the Technical Advisory Team. The outcome of the process was a series of recommendations to PNM regarding which technologies to consider in our IRP analysis. This process has helped inform our understanding of emerging technologies and has contributed to our development of assumptions in our plan.

3.2.1 Renewables

The emergence of low-cost renewable resources has been one of the most notable developments in the industry in the past decade. Reductions in technology cost and performance improvements have enabled rapid declines in the costs of developing new renewable resources to serve loads.

New Mexico's renewable resource potential is rich – and, unlike many states, offers both high quality solar and wind resources. Our location in the southwestern United States gives us some of the highest quality solar resources, and the wind resources in the eastern part of the state produce high capacity factors. Our proximity to such high-quality renewable resources is likely to be a key part of our transition to a carbon-free portfolio.

Solar PV

Over the past decade, the global solar PV industry has matured, and deployment across the United States has increased rapidly. According to a recent study by a recent study by completed by Lawrence Berkeley National Laboratory, , an average of over 6 GW of new utility-scale capacity has been added nationally each year since 2015, and projections indicate the market will continue to grow at 12-15 GW per year.[6] The deployment of solar resources at such scale has been enabled by increasingly favorable economics: the same study found that over the decade from 2009 through 2019, the capital costs of utility-scale solar decreased by 72% in real terms.[7] Solar PV resources are also eligible for the federal Investment Tax Credit (ITC), which was most recently extended in December 2020 such that:

- Projects that begin construction in 2021 and 2022 will be eligible for a tax credit of 26% of capital costs;
- Projects that begin construction in 2023 receive a 22% credit; and
- All systems beginning construction in 2024 or later receive a 10% credit.

Public projections developed by the National Renewable Energy Laboratory indicate a likelihood of continued cost reductions into the future.

In addition to reductions in cost, trends in plant design have enabled improved performance. New solar PV facilities today tend to use a single-axis tracking configuration instead of fixed tilt: in between 2015-2019, over 80% of new utility-scale solar PV systems were tracking (compared to under 50% between 2010-2014).[8] Over the same period, the average “inverter loading ratio” (ILR) – a measure of the ratio between the DC rating of the solar PV modules and the nominal capacity of the inverter – has increased from approximately 1.2 (2010) to 1.3 (2019).[9] Both of these trends have allowed new plants to achieve higher capacity factors, further reducing the cost of supplying renewable energy to the electricity system.

A third notable trend in the design of new solar PV facilities is the increasingly frequent pairing of solar PV with battery storage systems. Hybridizing solar PV and storage can improve performance – the ability to store variable renewables allows for the shaping of energy to better match load – while also presenting an economic opportunity: when paired with onsite solar, storage can be eligible for the federal ITC.

The assumptions that we use to characterize solar PV in our analysis are discussed in Section 6.4 (New Resource Options).

Wind

Over the past decade, the market for wind generation within the United States has also expanded considerably, growing by an average of 8 GW per year between 2015 and 2019; at the end of 2019, the US installed capacity of wind generation exceeded 100 GW.[10]

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[6] Lawrence Berkeley National Laboratory, *Utility Scale Solar 2020 Data Update*, available at: https://emp.lbl.gov/utility-scale-solar
[7] Same as above
[8] Same as above.
[9] Same as above.
[10] Lawrence Berkeley National Laboratory, *Wind Technologies Market Report 2020 Briefing*, available at: https://emp.lbl.gov/wind-technologies-market-report

Like solar, wind generation has experienced substantial reductions in cost and improvements in performance over this the past decade. From 2010 through 2019, the average capital costs of new wind projects decreased by over 40%.[11] At the same time, newer turbines with larger rotors and higher hub heights have allowed new turbines to achieve higher capacity factors than older turbines operating in the same regime. Both of these trends have driven down the effective cost of wind energy, similarly making it an attractive source of carbon-free power.

New Mexico's wind resource potential is significant and its high quality 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. Our assumptions for new wind resources are discussed in Section 6.4 (New Resource Options).

3.2.2 Energy Storage Technologies

The capability to store electricity and discharge to the grid when needed is essential to our achieving our clean energy goals. As our reliance on wind and solar grows, we will increasingly encounter periods when the total capability of our carbon emissions-free resources exceeds our demand for energy—during these periods, the capability to capture surplus electricity and store it for later use provides an important tool to align supply with demand. The exact nature of our ability to rely on energy storage will depend on two key questions: (1) what are the characteristics of various commercial storage options, and (2) what are their costs?

The remainder of this section describes the range of storage technologies that we are currently monitoring based on our procurement activity and the results of our technology RFI.

Lithium Ion Battery

Among the various forms of chemical storage, lithium ion batteries has quickly emerged as the most promising technology for short- to medium-duration applications (<1 hour to 4 hours). Lithium ion technologies have multiple advantages over competing battery chemistries, including a high energy density, better cycle life, and high round-trip efficiency. Because lithium ion batteries are used in multiple applications—most notably, in electric vehicles as well as stationary applications—competition among vendors and a rapid scale-up of manufacturing experience has helped to drive down costs significantly in the past few years. Many industry experts expect this trend to continue.

Despite its advantages, it is important to remember that this technology remains unproven at the scale contemplated in many forward-looking utility plans. Long-term operating experience is limited, and real-world performance and rates of degradation may deviate from assumptions used in planning studies. Safety is also a significant concern, as fires at lithium ion facilities are very dangerous. While these issues do not pose insurmountable barriers to the pursuit of grid-scale lithium ion storage development, more real-world operating experience will be needed to fully understand the capabilities of lithium ion storage.

Flow Battery

Flow batteries, named for the liquids that serve as working fluids and store electricity in tanks, may utilize a number of different chemistries. Relative to lithium ion batteries, flow batteries are typically more suitable for longer-duration storage applications (10+ hours), generally have a lower round-trip efficiency, and are more expensive per unit of storage capacity. Today, this is a

[11] Same as above

relatively nascent technology that has not been demonstrated at the scale needed to satisfy grid needs.

Pumped Storage Hydro

Pumped storage 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 present barriers to widespread deployment of pumped storage, technological maturity notwithstanding: (1) there are a limited number of sites that are viable from both a hydrological and permitting perspective; and (2) potential projects are generally of a size large enough to make it difficult to finance the plant with a single offtaker.

Despite these challenges, specific pumped storage projects may be valuable contributors to utilities' future capacity and flexibility needs. The costs and characteristics of pumped storage facilities are highly site-specific and can vary considerably. The duration of storage among existing pumped storage facilities varies between days and months of storage capabilities and is determined by the size of the reservoirs used for storage.

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. To date, CAES has not been widely deployed globally or nationally.

Aqueous Air Storage

Aqueous air storage uses surplus electricity to chill air to very low temperatures that allow for storage in a liquid phase; the significant increase in density due to the phase change allows the air to be stored in above-ground tanks until needed, at which point it is depressurized while running through a turbine. While several pilot projects exist, this technology has not yet been commercialized at a grid scale; nonetheless, advancements in this technology could present an attractive form of long-duration storage.

Gravitational Storage

A number of companies are exploring other means of using gravitational potential to store electricity. One such example that emerged from our Technology RFI uses cranes to stack (and unstack) concrete blocks; energy is "stored" by using electricity to lift the blocks and is generated when blocks are lowered to drive an electrical generator. This technology is currently precommercial, but based on proposed configurations, a single unit could produce between 4 and 8 MW with a duration between 8 and 16 hours.

3.2.3 Carbon Free Fuels

One of the potential options to meet a portion of our future planning reserve needs in a carbon emissions-free portfolio is to repurpose natural gas generation infrastructure to operate using a "drop-in" carbon emissions-free fuel. With growing commercial interest, the prospect that some form of carbon-free fuel – hydrogen, renewable natural gas, or other synthetic fuels – may be widely available by 2040 is increasingly promising.

In the context of our 100% goal, these fuels are appealing for numerous reasons: first, they would allow us to continue operations of some existing natural gas generation infrastructure beyond the 2040 time frame, allowing us to recover the costs of our investments over a longer economic lifetime and thereby mitigating costs to our customers; and second, they would provide us with an option for a firm, carbon emissions-free resource, a crucial cornerstone of a reliable carbon emissions-free portfolio. Present expectations suggest that these fuels would likely be costly to produce, deliver, and store; nonetheless, we 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 our 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 we encounter as our portfolio approaches 100% carbon emissions-free energy.

Hydrogen

In the past several years, interest in hydrogen as a possible synthetic carbon-free fuel for peaking applications in future low carbon electricity systems has grown substantially. The production of "green" hydrogen through electrolysis fueled by renewable electricity has been suggested as a medium for long-duration electricity storage. Electrolytic hydrogen production in alkaline electrolyzers using electricity and water inputs is a mature technology that has been used commercially in some applications for over a century; similarly, polymer electrolyte membrane electrolyzers are a mature, commercially available product.

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. Nonetheless, direct combustion of pure hydrogen for electricity production is a technically feasible option for a firm, carbon-free resource.

A number of western utilities with similarly aggressive clean energy ambitions are currently piloting efforts to introduce hydrogen-fueled generation into the energy mix as part of their transition towards goals of carbon emissions-free generation:

- One proximate effort to pilot the hydrogen production pathway and involves the Palo Verde Nuclear Generating Station. In 2019, the US DOE announced funding for an effort to demonstrate hydrogen production via electrolysis at three nuclear plants: PVNGS, one of Xcel Energy's nuclear plants in Minnesota, and the Davis-Besse nuclear facility in Ohio. The pilot program at PVNGS is being led by plant owner APS, who has also established a goal to eliminate carbon emissions by 2050, with technical support from Idaho National Laboratory (INL) and aims to begin production by 2022, producing hydrogen to blend with natural gas for combustion at nearby gas-fired power plants.
- The Los Angeles Department of Water & Power (LADWP) is another utility actively pursuing hydrogen generation solutions as part of a strategy of transitioning towards 100%

renewable energy. LADWP currently has plans to replace the Intermountain Power Project, an 1,800 MW coal plant in Delta, Utah, with an 840 MW combined cycle plant. Initially, this plant will burn 30% hydrogen with an expectation of eventually converting to 100% hydrogen fuel.

Most recently, the Western Green Hydrogen Initiative (WGHI), a public-private partnership jointly led by the National Association of State Energy Officials, the Western Interstate Energy Board, and the Green Hydrogen Coalition, was launched in November 2020 to support efforts within the region to develop hydrogen as part of the states' efforts to decarbonize. The WGHI aims to advance the industry by facilitating coordination among the research & development efforts taking place within the region; identifying and confronting regulatory, policy, and commercial barriers to hydrogen deployment; and assisting states in creating hydrogen roadmaps to spur innovation.

Renewable Natural Gas

Renewable natural gas (RNG), or biomethane, refers to a pipeline-quality substitute for natural gas that can be produced from a number of renewable feedstocks. Because of its purity, this fuel can be injected directly into existing natural gas pipelines (and burned in gas-fired power plants).

RNG is produced from biogas through a process of cleaning and conditioning to remove impurities. Production pathways for biogas are well-understood—indeed, biogas is produced at small scales today through anaerobic digestion using feedstocks from landfills, wastewater treatment plans, and a variety of other sources of organic waste. Biomass-derived RNG is currently being produced and injected to the natural gas grid in California.

The greater source of uncertainty with this fuel is whether it will be available at a scale significant enough to meet demands of the electric sector at a reasonable price. Increased efforts to decarbonize the broader economy may result in competition for biofuels across the various sectors of the economy. Competition from applications outside the electric sector may lead to higher costs and could ultimately limit the availability of the fuel to supply electric sector needs.

3.2.4 Advanced Demand Response & Flexible Loads

The transition to a supply portfolio that includes high amounts of renewable energy results in a decrease of supply-side flexibility to align generation with load. This can be countered with an increase in demand-side flexibility to align load with generation. We expect opportunities for demand-side flexibility to multiply in the coming years through proliferation of smart appliances, advanced metering, and other grid modernization technologies.

In time, we hope to install AMI throughout our service territory. We have already discussed how AMI deployment would allow for TOD rate designs which encourage customers to shift their flexible loads to off-peak hours. TOD designs can change over time in sophistication and in the peak period definition to ensure that load shifting avoids capacity and reduces the cost to serve all customers. As EV adoption increases and more smart appliances appear in homes and businesses, customers will have increased flexible load with which to take advantage of such rates.

Outside of rate signals, load flexibility can be achieved through grid modernization investments such as Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS). One function of these systems is to utilize the enhanced visibility provided by AMI for two-way communication between the grid and customer devices like

EVs, heat pumps, BTM PV, BTM energy storage, and other smart appliances. Programs leveraging this functionality are the natural successors to Peak Saver and Power Saver, but a modernized grid allows this communication to be continuous and dynamic instead of on a call basis.

Widespread deployment of sophisticated TOD rates and load management programs is a long-term process. Technologies in the space continue to evolve and many system impacts remain too uncertain to warrant inclusion in the IRP modeling. The only flexible load considerations in this IRP are the traditional demand response programs described in Section 6.4.1 (New Demand-side Resources) and the TOD rate sensitivity described in Section 5.1.3 (Sensitivities).

Efficient alignment of load to generation becomes increasingly important as we move towards our carbon emissions-free goal. In the coming years we plan to pursue technologies that enable flexible loads in our distribution planning process to ensure optimal benefit to customers and to our resource planning process; however, advanced metering infrastructure is a precursor to achieving these objectives.

3.2.5 Other Emerging Technologies

Nuclear Small Modular Reactors

Nuclear small modular reactors (SMRs) are an emerging technology option that is capable of producing baseload carbon emissions-free electricity. As implied by their name, one of the notable features of SMRs is their modularity: unlike traditional nuclear reactors such as the AP1000, SMRs can be installed in units of 50-60 MW to allow right-sizing for utility needs. An SMR plant design recently received safety approval from the Nuclear Regulatory Commission (NRC), marking an important milestone towards commercialization.

While SMRs and other nuclear plants produce carbon-free electricity, their production does not qualify for New Mexico's RPS requirements. As a result, within the policy paradigm established by the ETA, the role of SMRs in our portfolio is limited: between the 80% RPS requirement by 2040 and the output of our ownership share of PVNGS (roughly 20% of our long-term needs), opportunities to procure additional non-renewable carbon-free resources are likely small. Nonetheless, we will continue to monitor the technology's maturation.

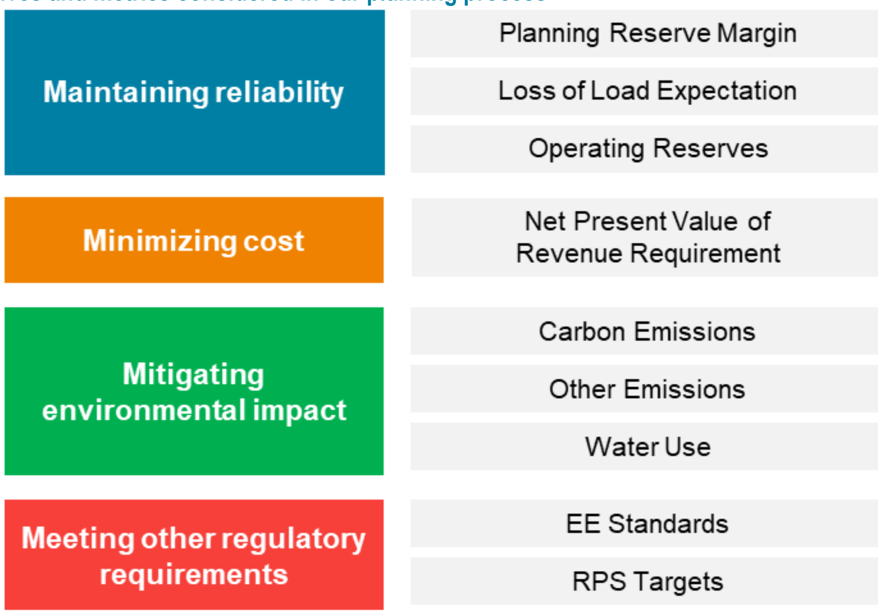
Microgrids

The term "microgrid" broadly describes a portion of the distribution grid that, in the event of a disturbance, can disconnect from the rest of the electric system and continue to supply local loads. Microgrids may comprise a range of different technologies, including fossil-fueled backup generators, small scale renewable resources, energy storage, and other distributed energy resources. Through the use of advanced electronic controls and software solutions, microgrids can improve local resilience and reliability under contingencies while providing customers and utilities value under normal operating conditions.

4 Planning Objectives

This chapter defines the objectives of our resource planning process. The development of our MCEP requires us to consider and balance multiple objectives: (1) maintaining reliability, (2) minimizing cost, (3) mitigating environmental impacts, and (4) meeting other regulatory requirements. These objectives, along with the metrics we track to monitor our performance in each area, is summarized in Figure 17.

Figure 17. Objectives and metrics considered in our planning process



Section Highlights

- This chapter defines the objectives of our resource planning process; developing a robust long-term plan requires careful consideration of these objectives and in some cases, will require tradeoffs among them.
- We strive to provide affordable electric service to our customers; while the IRP process balances multiple objectives, it is designed to yield the Most Cost Effective Portfolio.
- Our customers depend on a stable, reliable supply of electric service; our planning process prioritizes ensures reliability by requiring all potential plans meet a minimum planning reserve margin of 18% and NERC requirements for operating reserves.
- Our planning process accounts for the environmental impact of our generation portfolio, considering not only the stipulated requirements of the ETA and other legislation but options to further mitigate our environmental impact.
- Our plan is also subject to a number of other regulatory requirements, including New Mexico’s Renewable Portfolio Standard and Energy Efficiency rules.
- Across all of these objectives, we recognize that our plan is subject to a number of risks, particularly considering the pace at which many factors are changing; our process is designed to identify and characterize the most significant risk factors to ensure our decisions are as robust as possible.

4.1 Maintaining Reliability

Preserving reliable electric service for our customers under all but the most extreme conditions is of paramount importance. Our customers expect and rely on stable, reliable electric service for their homes and businesses, and our process is designed to achieve this outcome. This objective is consistent with the standards for electric service set forth in NM Rule 17.9.560.13C:

> 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.

-NM Rule 17.9.560.13C[12]

Our efforts to ensure reliability affect our planning and operations of our electric portfolio through two primary mechanisms:

1. To ensure that there are enough resources owned by or under contract to PNM, we maintain a **planning reserve margin** that determines the quantity of resources needed to ensure we have sufficient generation to meet all of our needs under all but the most stringent conditions.

2. In real-time operations, we balance our loads and resources while maintaining **operating reserves** to comply with reliability standards required by NERC.

The first of these requirements establishes the quantity of resources needed in our portfolio to ensure an acceptable level of reliability; the second impacts how the resources in that portfolio must be operated on a day-to-day basis. These two requirements are linked: by ensuring that our portfolio meets our minimum planning reserve margin in each year, we are able to maintain operating reserves to comply with NERC requirements without shedding load in all but the most extreme conditions. In this IRP, we take important steps forward to update our reliability planning to prepare our system to integrate high levels of renewables and storage. PNM ensures that both of these requirements are met in the MCEP.

4.1.1 Resource Adequacy and Planning Reserves

To meet our reliability objectives, we plan for and procure a portfolio of resources that is “resource adequate”—that is, a portfolio of generating resources that is capable of meeting our customers’ electric demands under all but the most exceptional circumstances. In the past, our efforts to plan a reliable portfolio have focused on meeting a 13% reserve margin during peak periods to meet our highest demands. The approach has historically been largely successful because we have relied predominantly on nuclear, coal, and gas resources, all of which are generally able to generate at full capacity when needed to meet summer peak.

The increasing penetration of intermittent renewable generation on our system has posed new challenges to this simple approach for several reasons. Because their output is intermittent and subject to variability due to meteorological conditions, wind and solar resources are often not available to produce at full capacity during peak periods. Further, due to their variability, increasing levels of renewable resources can lead to reliability concerns in periods outside of our traditional peak period. As this transition occurs, maintaining resource adequacy for our

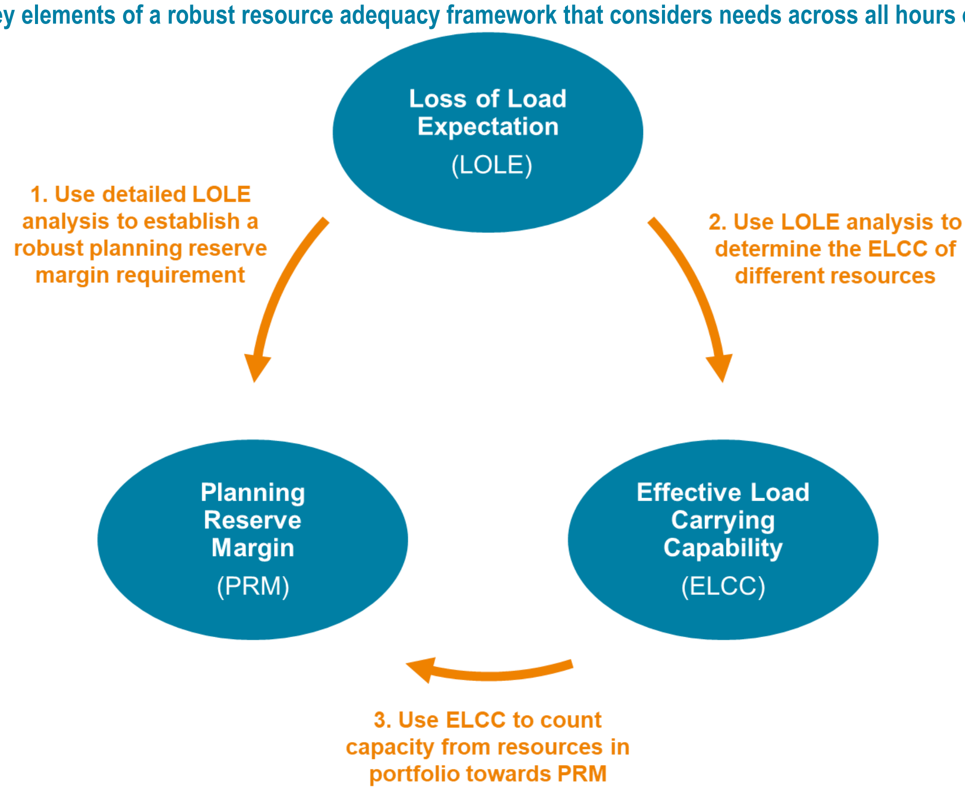
[12] http://164.64.110.134/parts/title17/17.009.0560.pdf

customers requires that we broaden our perspective to consider how to meet our customers' needs across all hours of the year with an increasingly intermittent supply of generation.

We have added a significant amount of renewable resources to our portfolio over the past decade, and yet our current renewable penetration is small compared to what we expect within two years due to our abandonment of SJGS. Modernizing our approach to planning for resource adequacy to account for our resource needs across all hours of the year is a prerequisite to integrating these resources while maintaining reliable service to our customers. As demonstrated by California's 2020 blackouts, failure to adjust planning practices to accommodate increasing quantities of variable and energy-limited resources may have serious consequences.

To strengthen our resource adequacy methodology, we rely on loss of load probability modeling, which uses Monte Carlo and statistical techniques to simulate loads and resources across hundreds of years of conditions. This approach allows us to examine resource needs across a broad range of conditions while considering extreme load events, renewable variability, unplanned outages, and other dispatch constraints. This approach measures the reliability of a portfolio of resources with robust statistical metrics such as **"loss of load expectation" (LOLE)**, which quantifies the expected frequency of loss of load events measured in number of days per year. These analytical methods are foundational to a robust and durable framework for resource adequacy, shown below in Figure 18.

Figure 18. Key elements of a robust resource adequacy framework that considers needs across all hours of the year



Establishing our reserve margin requirement based on rigorous technical analysis is a key first step to creating a durable, robust framework for resource adequacy. Instead of continuing to rely on an outdated reserve margin requirement, we use loss of load probability modeling to calibrate a PRM requirement that meets an LOLE standard of 0.2 days per year.[13] Meeting this LOLE standard an annual planning reserve margin of 18%, an increase from our previous reserve margin metric of 13%.

We must also ensure that each resource is counted appropriately towards this requirement. Different types of generation contribute differently to this requirement; in particular, the contributions of renewables, storage, and demand response must be measured based on how they help us serve load across all hours while accounting for their limitations. To measure their contributions towards this requirement accurately, we use the same modeling software to calculate the **"effective load carrying capability" (ELCC)** for renewables and storage resources. The use of ELCC, derived from loss-of-load-probability modeling, allows our plans to capture the dynamic impacts of variable and energy-limited resources as their penetrations increase on the system.

The analysis supporting our updated PRM and our incorporation of ELCC in our analysis are discussed in further depth below; additional technical detail on our approach to resource adequacy is provided in Appendix M.

Historical Context

Like most utilities, we rely on a planning reserve margin requirement, which specifies the amount of capacity needed in our portfolio relative to our system's expected peak. Historically, this approach has provided a simple and intuitive way to measure our portfolio's resource adequacy: by focusing on the resources needed to meet peak demand—plus some margin to account for potential extreme weather, unit outages, and operating reserve needs—we have been able to minimize the occurrence of reliability events resulting from insufficient supply in our portfolio with a portfolio comprising mostly nuclear, coal, and gas.

Before our 2017 IRP, we relied exclusively on a planning reserve margin requirement of 13% to ensure our portfolio has sufficient resources to meet our customers' needs. This target was the result of the stipulation approved in NMPRC Case No. 08-00305-UT. Section 9 of that stipulation states:

> Beginning with its 2011 Integrated Resource Plan ("IRP"), PNM will target a planning reserve margin of 13% of peak demand, but not less than 250 MW of planning reserve capacity, for resource planning purposes, instead of the 15% used in the current IRP and as agreed to in Paragraph 18 of the Merchant Plant Stipulation. The Signatories acknowledge that PNM's actual reserve margin may temporarily deviate from the planning reserve margin due to unexpected changes in load or imbalances caused by the magnitude of new resource additions to meet load growth, system requirements and renewable portfolio standards.

– NMPRC Case No. 08-00305-UT

Beginning in our 2017 IRP, recognizing that the traditional peak-hour planning approach was increasingly untenable with the addition of intermittent renewable resources, we expanded new tools and methods to support more advanced resource adequacy analytics. With the support of

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[13] While there is no formally established standard for resource adequacy, many utilities rely on a standard of "one day in ten years," which is frequently interpreted as requiring an LOLE of 0.1 days per year. The LOLE standard of 0.2 days per year used in this IRP is less stringent than the most widely used standard in the industry of "one day in ten years," commonly interpreted as 0.1 days per year. For this IRP, the use of 0.2 days per year balances historical continuity with a need to transition to industry best practices. In the future, we plan to transition to 0.1 days per year.

Astrapé Consulting, an industry leader in resource adequacy analysis, we used SERVM, a loss-of-load-probability model, to strengthen our analytics by incorporating Monte Carlo analysis across a broad range of conditions into our planning. This was a pivotal shift that allowed us to begin to consider the adequacy of our supply across all hours of the year, not just during peak periods. While we ultimately relied upon the same 13% reserve margin requirement for our 2017 MCEP, analysis using the SERVM model led to several notable conclusions highlighting the importance of revisiting PNM's planning reserve margin requirement in the future. The first notable finding was that a 13% reserve margin would be insufficient to meet a loss of load expectation standard of two days in ten years:

> PNM's loss of load probability using a 13% reserve margin is higher than two events in every 10 years. Reducing the loss of load probability to two events per year requires a reserve margin of about 17%. Achieving a one-in-10-year probability would require a reserve margin target in excess of 20%, which is much higher than the PNM's current target.

– PNM *2017 Integrated Resource Plan*, p.28[14]

The second finding of note was the observation that PNM has historically been able to carry a lower reserve margin while maintaining reliability due to a surplus of available capacity within the Western region – capacity that may not be available on a going-forward basis. Changes to the assumed level of available market assistance would directly impact our reserve margin requirement:

> Of additional concern, the market assistance PNM has long relied upon to help achieve shortfalls in resource adequacy is quickly drying up. This condition alone could force PNM to hold a higher reserve margin in order to maintain NERC compliance and shows that the current threshold for holding a 13% reserve margin is no longer adequate.

– PNM *2017 Integrated Resource Plan*, p.122

While the concerns raised in the 2017 IRP were not used to justify a change in our requirement at the time, they indicated a future need to revisit this topic. The use of a reserve margin requirement to determine our need for capacity is useful only insofar as it yields a level of reliability that is consistent with the standards our customers expect. Given the challenges identified in our 2017 IRP and the ETA's recognition of the need to continuously reassess resource adequacy, we have reassessed our planning reserve margin need.

Lessons from 2020

The Western heatwave of August 2020 provides useful case study for regional resource adequacy. The combination of recent changes in the composition of the region's resource mix and extreme weather conditions throughout the West pushed many utilities to the edge – and in some cases, over it. Between August 14 and August 19, ten different balancing authorities across the Western Interconnection experienced some level of Energy Emergency Alert, indicating their respective systems were operating near or at maximum capability; four experienced Stage 3 alerts (EEA 3), a condition in which the balancing authority operator interrupts firm load to preserve the reliability of the broader system.[15]

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[14] PNM 2017 IRP, p.28

[15] See WECC's presentation on the "Western Heatwave Event: 2020," available at: https://www.wecc.org/Administrative/Western%20Heatwave-WEB.pdf

Table 6. Definitions of energy emergency alerts (emphasis added)[16]

Stage	Description
Stage 1 (EEA 1)	• Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where ***all available resources are committed to meet firm load, firm transactions, and reserve commitments***, and is concerned about sustaining its required Operating Reserves, and • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
Stage 2 (EEA2)	• Balancing Authority, Reserve Sharing Group, or Load Serving Entity is ***no longer able to provide its customers' expected energy requirements***, and is designated an Energy Deficient Entity. • Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments.
Stage 3 (EEA 3)	• Balancing Authority or Load Serving Entity ***foresees or has implemented firm load obligation interruption***

One of the major causes of these events was a region-wide heatwave that led to high load conditions throughout the region. The potential increased severity and frequency of such extreme weather events due to climate change is a concern to PNM and poses a direct risk to our future reliability. Studying how we might incorporate the effects of a changing climate in our planning processes will require continuous efforts in the future to understand how these trends will affect our loads and resources.

Nowhere were the effects of this heatwave more acute than in California, where CAISO enacted rotating customer outages for the first time since the 2001 Energy Crisis in order to maintain the reliability of the grid on August 14 and 15. On January 13, 2021, CAISO, in partnership with the California Public Utilities Commission and California Energy Commission, published a final "root cause analysis" examining the confluence of factors that contributed to the outages in August. The conclusions of this report provide instructive lessons for utilities around the West that are transitioning towards increased reliance on renewables and storage resources.

One of the key conclusions of the root cause analysis was the need for a resource adequacy framework that fully considers how increasing renewables could contribute to reliability challenges outside of the traditional peak period. As described in the report:

> The construct for RA was developed around peak demand, which until recently has been the most challenging and expensive moment to meet demand. The principle was that if enough capacity was available during peak demand, there would be enough capacity at all other hours of the day as well, since most resources could run 24/7 if needed. With the increase of use-limited resources such as solar generation in recent years, however, this is no longer the case. Today, the single critical period of peak demand is giving way to multiple critical periods during the day, including the net demand peak, which is the peak of load net of solar and wind generation resources.

– CAISO *Final Root Cause Analysis*, p.44[17]

[16] Definitions from https://www.nerc.com/files/EOP-002-0.pdf

[17] CAISO's *Final Root Cause Analysis*, developed in collaboration with the California Energy Commission and California Public Utilities Commission, was released on January 13, 2021 and is available at: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

This finding highlights the need to reframe "resource adequacy" as less about meeting peak demands and more about having sufficient supply available across all periods of the year. Establishing an analytical foundation that is capable of meeting this challenge is therefore one of our goals in this IRP process; central to this approach is our use of **effective load carrying capability** to measure the contributions of renewables and storage towards our needs, discussed further below.

A second notable factor was the role of imports in contributing to California's resource adequacy needs during this period:

> The CAISO Balancing Authority Area (BAA) traditionally relies on electricity imports on peak demand days, meaning that while electricity trading occurs with the rest of the West, on net, the CAISO imports more than it exports. During the extreme heat wave, given the similarly extreme conditions in some parts of the West, the usual flow of net imports into the CAISO was drastically reduced.

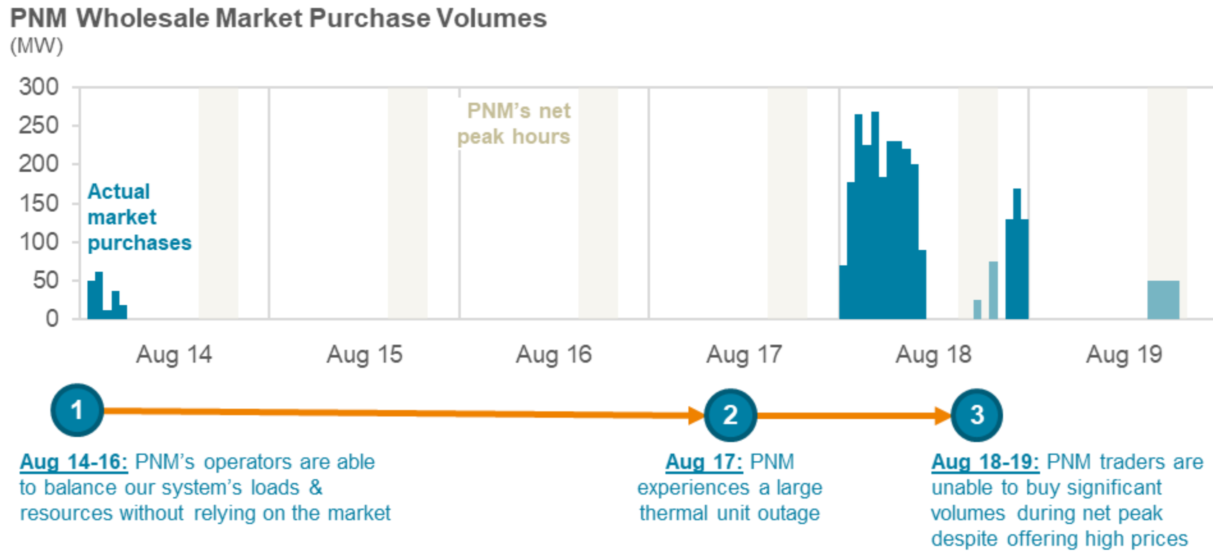
– CAISO *Final Root Cause Analysis*, p.22[18]

This observation is important because it demonstrates the realization of risk associated with excessive reliance on support from neighboring systems: namely, that conditions perceived as normal in historical experience may not be a good indication of the level of support that the broader Western market can supply during constrained periods, and further, that deviations from those historical norms could very well contribute to the occurrence of reliability events. These observations underscore the potential risks of relying excessively on market support from the broader region during the most constrained periods of operations.

PNM's operating experience during the heat wave also provides instructive evidence to inform our future resource adequacy planning. Between August 14-17, when conditions in the rest of the West were extreme, PNM operators were able to balance our system without relying on the market for support. However, towards the end of August 17, PNM experienced a large thermal outage. On these days, our resources were stretched to their limits, and during the net peak periods, our traders were unable to procure additional supplies from the wholesale market despite offering high prices. Figure 19, which shows our wholesale purchases over this period, highlights the lack of available market support during our net peak periods.

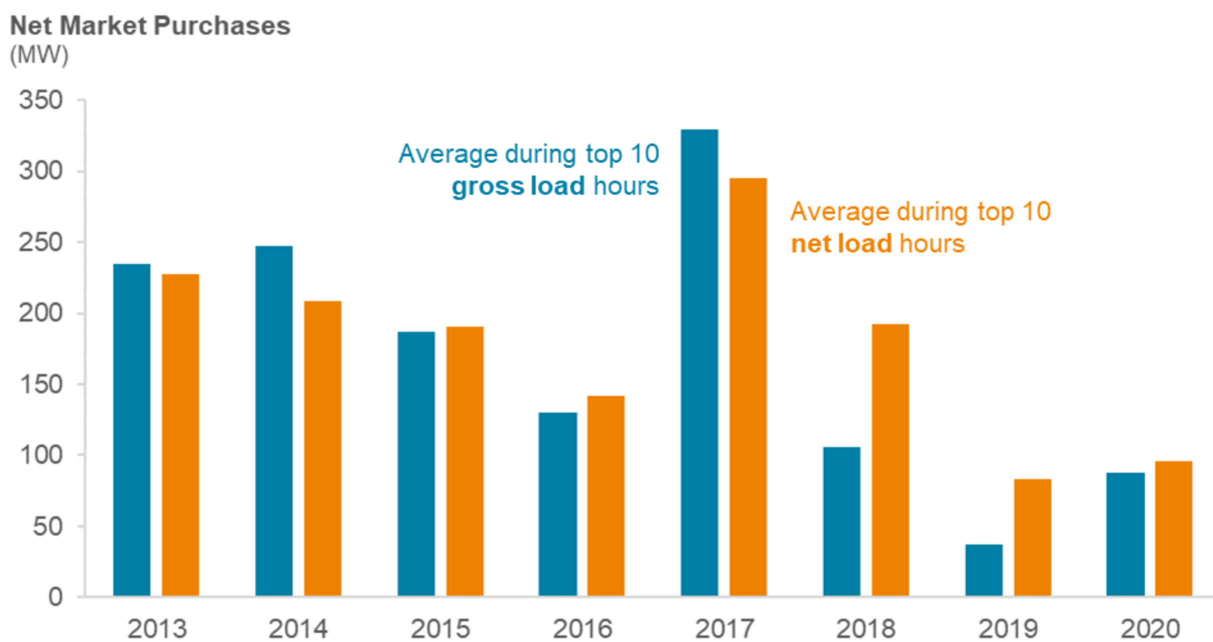
[18] Same as above

Figure 19. PNM's hourly wholesale market purchases during the August 2020 heatwave



This anecdote is broadly representative of the general dynamics that our wholesale power operations group have observed on a day-to-day basis the past several years: during the net peak period, the market is becoming increasingly illiquid, the number of counterparties is declining, and prices are rising sharply. This trend is clear in Figure 20, which shows how the amount of energy we have purchased in the wholesale market to meet our needs during our peak and net peak periods has steadily declined over the past three years. Our concern for resource adequacy leads us to conclude that excessive exposure to the market during this period could result in high energy costs, or worse, loss of load.

Figure 20. Historical market purchases by PNM during peak and net peak periods



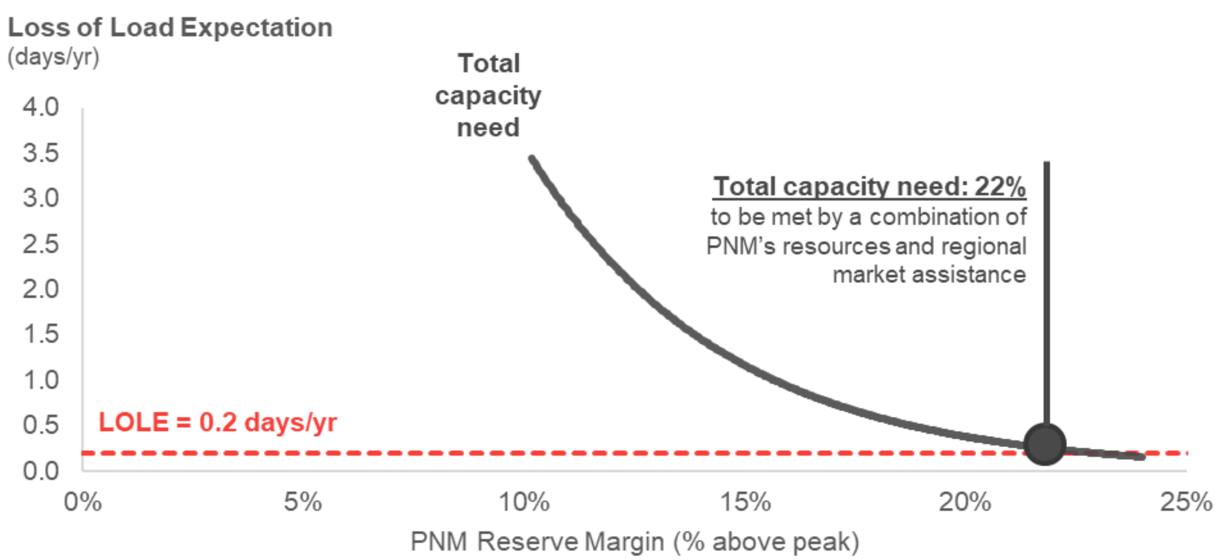
A final issue of note raised by CAISO's root cause analysis was the concern that California's current 15% PRM requirement may be insufficient to provide adequate supply to meet the state's reliability needs. To prepare the system for summer 2021, the California Public Utilities Commission has opened a proceeding exploring policies and processes to enhance the state's resource adequacy program. In this proceeding, experts from CAISO have testified that increasing the state's PRM requirement to 17.5% would be needed to maintain reliability.[19] While the CAISO's recommendations cannot be applied directly to PNM, California's move to reconsider its standard in light of the events of 2020 underscore the importance of regularly reviewing and updating our standard and managing our exposure to the market.

Total Capacity Needs

To identify our current and future resource adequacy needs, we begin by determining the total capacity needed to meet our resource adequacy targets. Our needs will be met by a combination of our own resources and some level of assistance from the broader market, but in this step, we do not distinguish between these two. Studying our system in this way provides a means to understand the total capacity needs of the system – a portion of which may be provided by market assistance from neighboring entities.

Figure 21 illustrates the characteristic relationship between the system's LOLE and its reserve margin under this modeling construct: increasing the system's reserve margin will result in continued reductions in the expectation of lost load. In order to meet PNM's LOLE standard of 0.2 days per year, the total amount of capacity needed before factoring in market assistance (i.e., considering our system as an "island") is 22% above expected peak demand.[20]

Figure 21. Relationship between our reserve margin and LOLE when PNM is considered as an island



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[19] Opening testimony of Jeff Billinton in CPUC Rulemaking 20-11-003, available at: http://www.caiso.com/Documents/Jan11-2021-OpeningTestimony-JeffBillinton-ReliableElectricService-ExtremeWeatherEvent-R20-11-003.pdf

[20] The calculation of our reserve margin needs also depends on how we count capacity from different resources. To establish our requirement, we use unforced capacity (UCAP) and ELCC accounting conventions for firm and non-firm resources, respectively. These conventions are discussed below.

Reliance on Market Assistance

PNM's position in the Western Interconnection – and our transmission ties to neighboring utilities and balancing authorities – can contribute towards meeting the total capacity requirement identified above, subject to (a) limits on the transmission system, and (b) the availability of surplus supply. This assumed "market assistance" allows us to carry a lower reserve margin on our system while still adhering to the LOLE standard of 0.2 days per year. However, unlike our own resources, which we can plan for and operate to meet our needs, the availability of market assistance is a significant source of uncertainty in our reliability planning.

For this plan, we assume that the level of market assistance that we can count upon during the most constrained "net peak" hours is limited to 50 MW, consistent with recent operating experience. In previous plans, we have assumed that the market would be able to supply 200-300 MW of energy when needed. However, recent experience during the summer of 2020, coupled with the anticipation that reserve margins throughout the region are shrinking, have prompted us to reconsider this assumption. Our latest assumption represents the level of imports that our planners and operators have a reasonably high degree of confidence will be available when needed. Because of our obligation as a utility to maintain a reliable portfolio for our customers, it is crucial that we do not overstate the capabilities of factors that are fundamentally uncertain and outside our control as a utility. Considering that the LOLE standard that we plan to meet (0.2 days per year) is already less stringent that the "one day in ten year" standard used by many utilities and RTOs, overestimating the level of available market assistance could result in reliability well below commonly accepted standards.

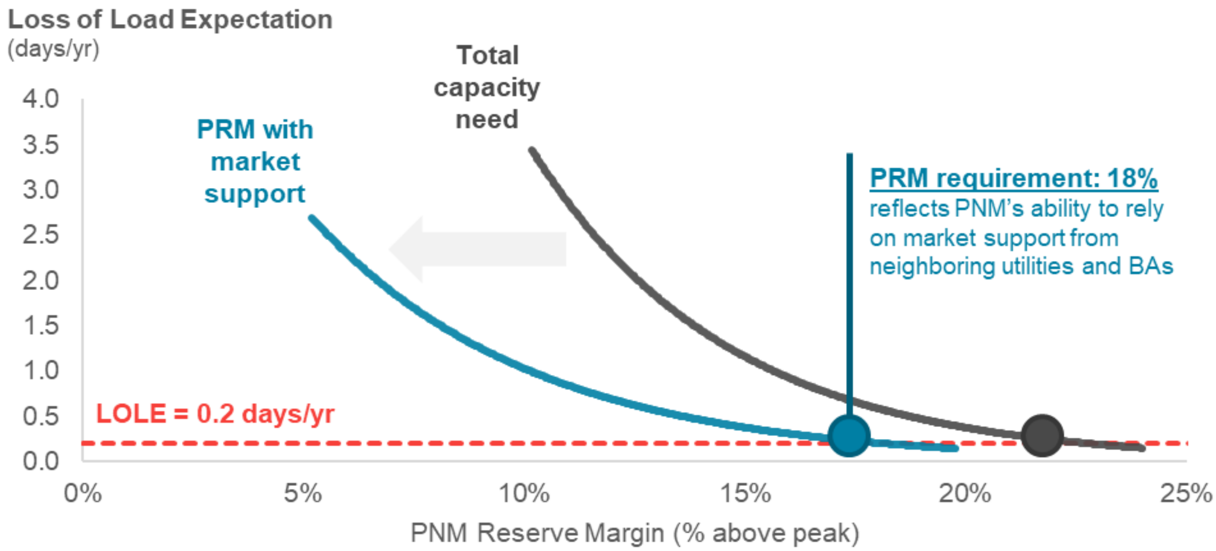
Planning Reserve Margin Requirement

The assumed availability of this level of market support contributes to our total capacity needs, allowing us to maintain a lower reserve margin while still meeting our LOLE standard. Based on this assumed level of market support, Astrapé Consulting conducted an analysis that found an 18% reserve margin would be needed to meet an LOLE standard of 0.2 days per year.[21] Figure 22 shows the relationship between our reserve margin and the expected frequency of reliability events.

This requirement increases our capacity needs from the previously stipulated 13% requirement; however, we believe that this level of reserves is reasonable and necessary to ensure reliable service to our customers.

[21] Compared with analysis conducted in the 2017 IRP, which identified a 17% reserve margin to meet a 0.2 LOLE standard, the increase in the requirement found here is primarily the result of the reduction in assumed market assistance.

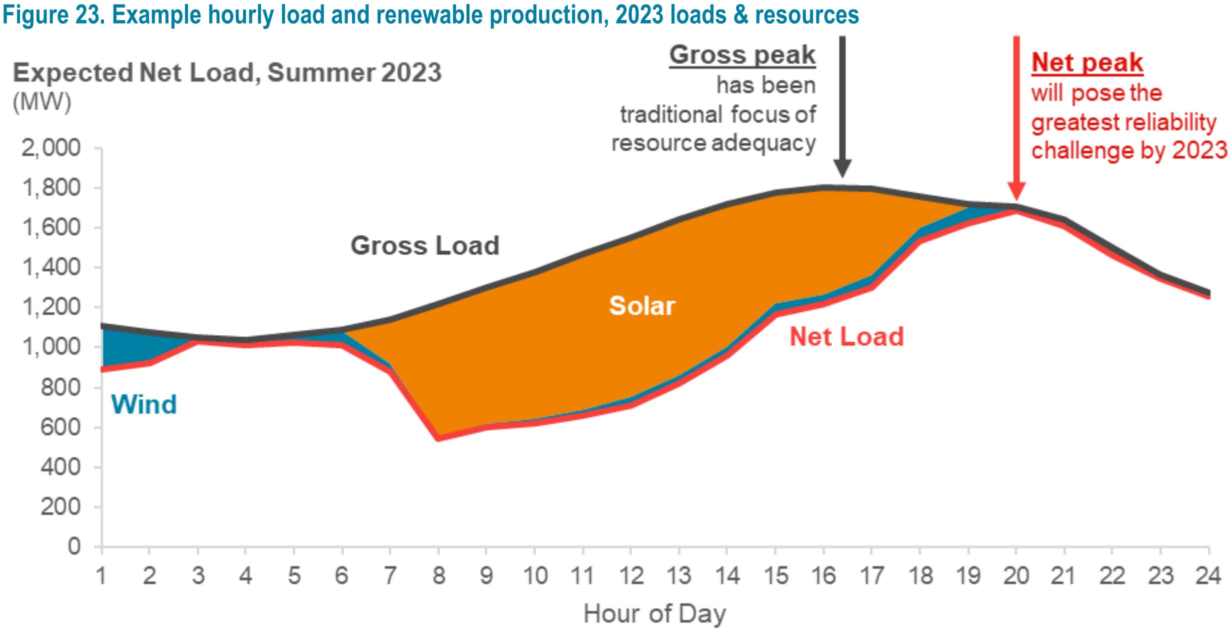
Figure 22. Relationship between planning reserve margin and loss of load expectation



Effective Load Carrying Capability (ELCC) for Renewables & Storage

Our increasing reliance on wind and solar poses a challenge to the traditional peak-focused paradigm of the planning reserve margin. Unlike "firm" resources—resources that can be dispatched on demand to full capacity whenever and however long is needed—wind and solar cannot produce at full capacity. Further, the addition of wind and solar resources to our portfolio causes the timing of our reliability needs to shift due to the changing shape of our "net load"—load minus the output of variable renewable resources. By 2023, with the significant amount of new solar added as part of the San Juan replacement portfolio, our net peak will have shifted into the evening hours when solar no longer produces. As we continue towards our goal of a carbon emissions-free portfolio by 2040, the timing of greatest need could shift further to other seasons.

Figure 23. Example hourly load and renewable production, 2023 loads & resources



As this transition continues, we must update our framework for measuring resource adequacy to take these complex dynamics into account. We seek to establish a durable, robust framework for resource adequacy that will allow us to continue to execute upon this goal even as we increase reliance on non-firm resources. Doing so requires an approach to resource adequacy that accounts for our needs across all hours of the year, not just during the periods of peak demand.

The application of ELCC to count renewables and storage is a cornerstone of a robust resource adequacy accounting framework that can account for our needs across all hours of the year.

To integrate renewables and energy storage effectively into our PRM accounting framework, we apply an ELCC methodology to determine the most appropriate capacity credits. While utilities use a variety of methods to count the capacity of these resources towards their reserve margins, use of ELCC is quickly becoming the consensus best practice within the industry.[22] This method has been adopted by numerous other utilities throughout the West, as well as in a number of regional resource adequacy programs and organized capacity markets. The application of ELCC to count renewables and storage is a cornerstone of a robust resource adequacy accounting framework that can account for our needs across all hours of the year.

A resource's ELCC is defined as the amount of "perfect capacity" that provides the same contribution to a utility's needs; that is, a 100 MW resource with a 50% ELCC provides the same contribution to a utility's needs as a 50 MW resource that is available at full capacity at all times throughout the year. Accurately quantifying the ELCC of a resource (or a combination of resources) is a computationally intensive process; we rely on the SERVM loss-of-load-probability model for this purpose to generate ELCC assumptions for our portfolio optimization.

The derivation of ELCC from the fundamentals of loss-of-load-probability modeling allows it to capture several dynamics crucial to maintaining resource adequacy with high levels of renewables and storage:

1. Any specific non-firm technology generally exhibits a declining marginal ELCC with increasing penetration. The most obvious example of this phenomenon is the decreasing capacity value of solar: while the first increment of solar is relatively coincident with the demand profile, increased levels of solar will cause the net peak to shift into the evening, when additional solar provides limited to no additional capacity value. While solar provides the most obvious example of this phenomenon, this is generally true of all non-firm resources to some extent.

2. Multiple technologies can produce total ELCCs that are greater than (or less than) the sum of their individual parts. This phenomenon, often described as a "diversity benefit" when positive, can be attributed to interactive effects between specific technologies. Solar and

[22] Utilities and regulators that currently rely upon ELCC for capacity accreditation in the West include: the California Public Utilities Commission, El Paso Electric, Northwestern Energy, NV Energy, Portland General Electric, Puget Sound Energy, Sacramento Municipal Utilities District, and Xcel Energy

storage are one common example of a resource combination that produces diversity benefits. [23]

By capturing these dynamics in its determination of capacity value, ELCC underpins a robust framework for resource adequacy even in a portfolio that relies heavily on non-firm resources. By using ELCC to account for the capacity contribution of these resources, our planning process is able to continue to utilize the PRM accounting framework to a productive result. Additional detail on the methods used to calculate ELCC are discussed in Appendix M.

Unforced Capacity (UCAP) for Thermal Resources

As part of our effort to strengthen our resource adequacy framework, we have also adjusted the accounting conventions used to count thermal resources towards the PRM requirement: instead of counting the full nameplate capacity of each thermal unit towards the requirement, we derate its contribution according to its expected forced outage rate to calculate its "unforced capacity" (UCAP). This approach has several advantages:

- It harmonizes our treatment of thermal resources with renewables and storage in our PRM accounting by measuring each resource according to its expected contribution to resource adequacy. Derating each thermal plant by its forced outage rate better reflects the value that resource provides towards resource adequacy.[24] When considering new investments, this approach allows a more appropriate comparison of the relative resource adequacy benefits of thermal, renewable, and storage resources.

- It allows us to establish a more stable reserve margin that is less sensitive to changes in our resource portfolio. One of the notable consequences of the harmonization discussed above is the fact that by treating all resources on a comparable basis, our resource adequacy needs as reflected in the PRM will not vary as much with changes in our portfolio. The outage rates of specific units, previously reflected entirely in the PRM requirement itself, are now captured in unit-specific capacity derates. This, in turn, reduces the sensitivity of the requirement itself to the specific outage rates on the system.

It is worth noting that this accounting change commensurately impacts the contributions of the individual thermal resources as well as the requirement itself;[25] that is, relative to our previous approach, it has no impact on the quantity of new resources needed to achieve a certain LOLE standard.

[23] We fully account for these synergistic interactive effects among our existing resources (including the SJGS Replacement Resources) as described in Appendix M; however, as discussed in more detail in more detail in Section 5.4.1 (EnCompass), our current modeling framework does not allow us to capture this effect yet when producing long-term capacity expansion results. See Appendix M for more detail on ELCC methodology.

[24] For instance, a hypothetical 50 MW plant with a 5% outage rate provides a higher resource adequacy value than the same hypothetical plant with a 10% outage rate.

[25] In other words, our adoption of the UCAP convention will allow us to maintain a PRM requirement that is more consistent with the capabilities of our units than if we had maintained the convention of counting thermal resources at their installed capacity.

Additional Reliability Metrics

In addition to ensuring that the portfolio meets PNM's 18% PRM requirement, we use loss-of-load-probability modeling to calculate and report a number of supplemental reliability statistics for each portfolio that measure if a portfolio is reliable. These include:

- **Loss of Load Expectation (LOLE, days/yr):** the expected number of days per year experiencing a loss-of-load event;
- **Loss of Load Hours (LOLH, hrs/yr):** the expected number of hours per year experiencing a loss of load event; and
- **Expected Unserved Energy (EUE, MWh/yr):** the expected amount of load that cannot be met due to insufficient supply.

Each of these metrics is probabilistic and reflects an expected value across a wide range of conditions rather than a prescription for each year; for example, a system with an LOLE of 0.2 days/yr may experience an outage in two years and then go eight years with no outages.

4.1.2 Operational Reliability & Flexibility Needs

Our approach to resource adequacy described above ensures that our long-term plan will include enough capacity so that we can meet customer needs under a broad range of conditions; however, preserving reliability is also a matter of operating that portfolio of resources to match the needs of our customers on a day-to-day basis.

Each day, our operators are responsible for operating our system reliably by balancing loads and resources in real time. PNM's operators follow a number of steps to ensure we can serve our customers while adhering to these requirements. Our operators first develop a unit commitment plan to fully supply that day's projected hourly loads. The first step is to commit (i.e., schedule) all "must-take" (non-dispatchable) resources, which include nuclear, wind, solar, and geothermal, as well as the minimum output of any generation unit that is expected to be needed that day, including any "must-run" resources needed for reliability and N-1 contingency planning purposes. PNM then schedules all other generation using economic dispatch principles. This generally means the lowest cost generation unit being the first dispatched. Once projected hourly load is met, PNM commits additional generation needed to meet all operating reserve requirements needed to manage uncertainties and contingencies.

Operating Reserves

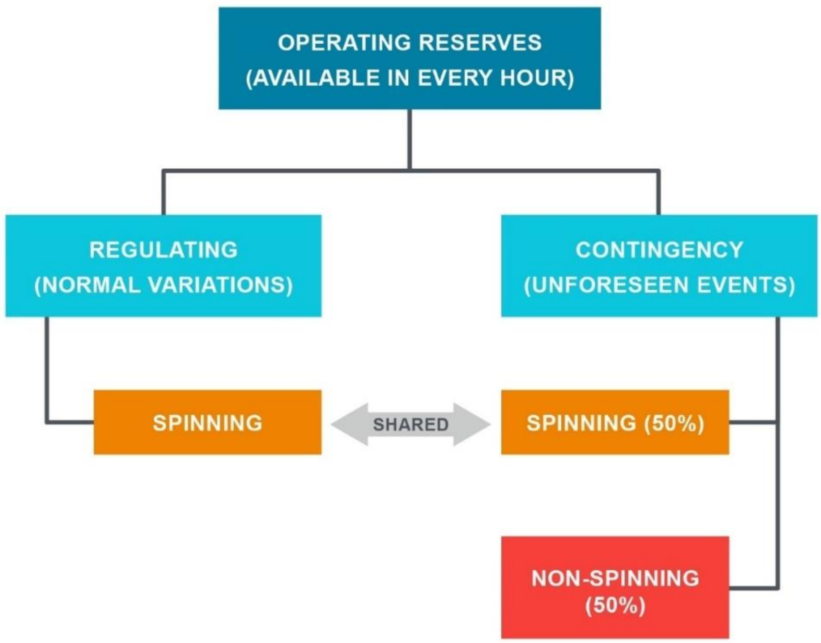
The term "operating reserves" refers to generating capacity that is used by the Balancing Authority (BA) system operator to respond quickly to disruptions or perturbations in demand or supply – for example, when a variable energy resource ramps down or a generator goes offline. To comply with NERC and WECC reliability criteria, PNM carries the following reserves:

- **Contingency reserves**, which allow the system operator to respond to unexpected events (e.g. generation or transmission outages); and
- **Regulation reserves**, which our operators use to respond to variations in load and renewable output on a second-to-second basis.

As mandated by NERC, the PNM BA carries contingency reserves equal the greater of: (1) 3% of the BA's load plus 3% of its online generation, or (2) the single largest contingency on the PNM system. Today, the single largest contingency on the PNM system is often San Juan Unit 4 (392 MW). Beyond 2022, once SJGS is no longer part of our portfolio, the Afton Combined Cycle (235 MW) will become PNM's single largest contingency when operating. In the future, as the composition of our portfolio changes, the single largest contingency may be determined by different elements in the system.

Our contingency reserve requirement can be further decomposed into "spinning" and "non-spinning" reserves. "Spinning reserves" are resources that are synchronized to the grid and can respond instantaneously; "non-spinning reserves" are not synchronized but can be brought online within a ten-minute period. Figure 24 illustrates the different types of operating reserves.

Figure 24. Operating reserves used by PNM to maintain day-to-day reliability



PNM meets a portion of these requirements through voluntary participation in the Southwest Reserve Sharing Group (SRSG), a group that includes fifteen utilities in the southwestern United States, The SRSG provides opportunities for cost savings to member utilities through more efficient dispatch by enabling a sharing of contingency reserves.[26] It should be noted that the actual level of shared reserves available will vary depending on what loads and resources from SRSG members are committed at the time and what unit within the PNM BAA is forced out of service that requires assistance from SRSG. So while the table below presents some indicative amounts of capacity that PNM could receive, these levels are just an example. Additionally, PNM

[26] This allows the members of the SRSG to share the single largest hazard requirement within the SRSG proportionally rather than having to carry reserves for individual single largest hazards of the respective BAs. For example, PNM's share of a full Palo Verde Unit 2 ~1340 MW hazard results in lower reserve requirements then if we were to try to meet our own single hazard by ourselves. At minimum PNM still has to keep 5% of BA load or resources as reserve per that agreement. The SRSG arrangement results in PNM typically needing to carry a minimum of 40-120 MW of reserve at any given time which is equally split between spinning and non-spin.

is only able to receive assistance from the SRSG for at most one hour and within that hour the PNM BA must restore balance to the PNM BAA system as well as restore its reserves including its required contribution to the SRSG.

Table 17 summarizes PNM's largest hazards; how much assistance it can expect from its reserve sharing group (though as discussed above, actual values will vary), the Southwest Reserve Sharing Group (SRSG); and how much capacity is required to be available within 15 and 60 minutes.

Table 7. Inputs to Operating Reserves Requirements at Time of Summer Peak

Site of Single Largest Hazard	Size of Hazard (MW)	SRSG Assistance	15-Minute Requirement	60-Minute Requirement
SJGS Unit 4	392	160	232	70
Afton	235	160	70	25

Regulating reserves represent an incremental amount of reserve above this, sufficient to follow load and respond to fluctuations in the output of generating units, primarily renewable resources. Regulating reserves change hourly based on system variables such as changes in load, renewable generation output, and unscheduled generation changes. The need for frequency response currently is driven by NERC Standard BAL-003-1[27]. PNM currently estimates that 13.8 MW of fast frequency response is needed to maintain compliance with the standard.

Subhourly Flexibility Needs & the Western EIM

In addition to the operating reserves that PNM holds to comply with NERC and WECC operating standards, PNM's upcoming entry into the EIM will also require our operators to meet flexibility reserve requirements when establishing our day-ahead schedules for generation dispatch. These reserves are designed to ensure that our portfolio will have sufficient flexibility to respond to load and renewable forecast error and subhourly variability; a daily showing of sufficient flexibility reserves is a prerequisite to participation in the EIM.

PNM's flexibility reserve requirements will be reviewed prior to each operating hour by CAISO. These requirements are based on CAISO's load forecasts, forecasts of variable energy resources and an assessment of the PNM BA area to meet forecast uncertainty/variability and resource diversity associated with the broad geographic footprint covered by the EIM.

Overgeneration and Renewable Curtailment

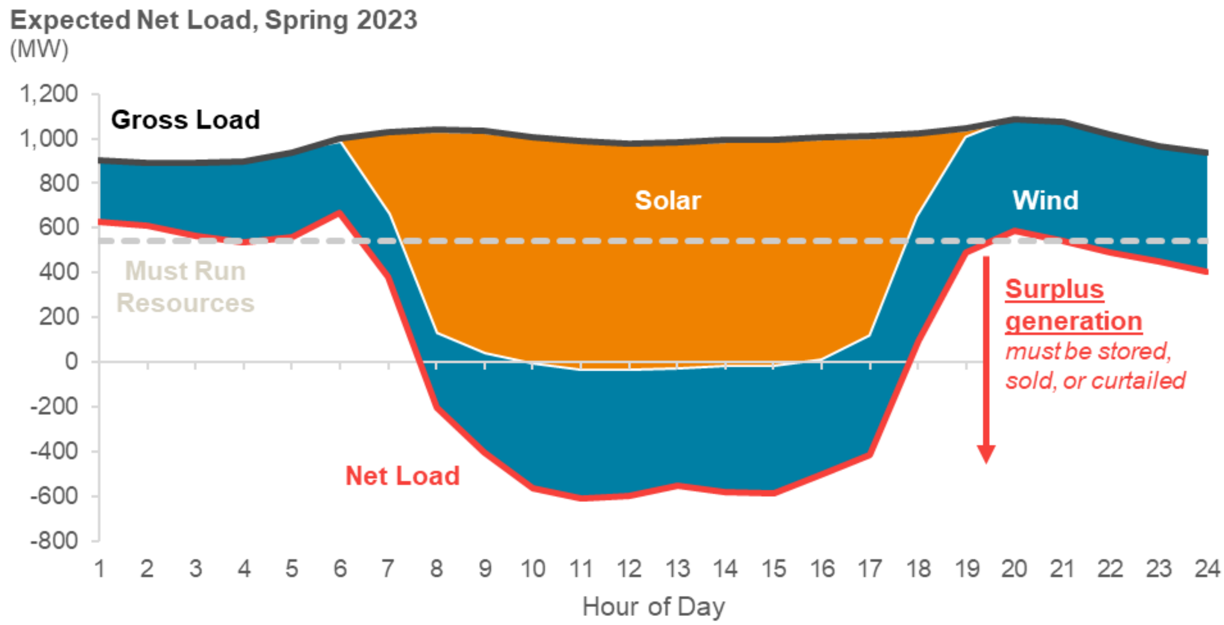
With significant amounts of new solar resources anticipated in the next few years, our operators will increasingly face challenges that arise due to overgeneration conditions. "Overgeneration" describes a condition when the available generation from inflexible and renewable resources exceeds our demand.

The transition to higher levels of reliance on variable renewable resources will increase the frequency of these types of events. By 2022, our portfolio will include over 1,000 MW of solar generation, which, if producing at full capacity, may actually exceed our daytime load during the spring. When combined with generation from our wind resources and the baseload output of

[27] This standard and other relevant standards are described in Appendix D

PVNGS, the amount of available energy during the daytime may significantly exceed our needs. Figure 25 shows an example of what may be a typical spring day in PNM's system.

Figure 25. Illustrative example of spring overgeneration conditions resulting from high levels of renewables



In order to manage the system under such circumstances and ensure continued balance of supply and demand, our traders and operators have several options for recourse:

- **Use surplus to charge storage resources.** The capability to store surplus renewables and discharge when needed represents a significant share of the anticipated value of our future energy storage resources. The storage resources that we expect to be online by 2022 will allow us to store up to 300 MW of surplus renewables, provided that the storage resources are not already fully charged; additional investments in storage may expand this potential. However, our battery resources' four-hour duration will not always match the overgeneration events which is why PNM will need to pursue increased duration storage facilities as we continue to add more renewables to the system.

- **Look for opportunities to sell surplus in wholesale markets.** If we can find a willing counterparty within the region, we may be able to reduce overgeneration through off-system sales. However, depending on the timing and conditions of our surplus, these opportunities may be limited – development of solar resources across the region will often mean that the occurrence of overgeneration will be a regional issue, rather than a utility-specific one.

- **Curtail renewable resources.** If surplus generation can be neither sold nor stored, our operators will curtail renewable resources to maintain reliability.

In our transition to a highly renewable, carbon emissions-free portfolio, some amount of curtailment will be inevitable as part of a least-cost reliable portfolio; especially as the costs of renewables decline, it will not make sense to invest in storage to mitigate all our overgeneration.

The analytical methodology we use to develop our plan is designed to consider the amount of curtailment we will experience along other economic tradeoffs. However, as PNM starts to experience higher levels of curtailment this will factor back into the price of new renewable contracts as the solar and wind developers are now calculating the potential for limited curtailments as part of their pricing offers.

As discussed through this document, additional investments in storage and transmission have many benefits, one of which would be to reduce the number of curtailments from renewable generators and optimize the efficient use of the system. However, prudent planning requires PNM to plan the system as a whole – to reasonably assure resource adequacy while balancing environmental impacts and customer costs. No decision in resource planning can be viewed or made without consideration of all factors.

4.1.3 Critical Facilities and Infrastructure

PNM does not have a single facility that is critical to reliable service because we have back-up capabilities should any single supply source fail. However, as we move toward a system that is more dependent on renewable and storage the system will become less susceptible to a fuel supply event. Generally, system risks will shift as we transition away from carbon emitting resources. To address system risks, PNM has a designated Crisis Management and Resilience function to establish and maintain a capability that plans for and effectively manages rapidly evolving crises that pose a strategic or operational threat to PNM's system reliability, infrastructure, personnel, or customers. This is to implement an enterprise "All Hazards" response plan and business continuity program to establish the framework for how the utility responds to and maintains operational resilience during any emergency. We currently maintain hazard and business area-specific response and continuity plans, focusing on areas that present unique challenges, such as storms and other severe weather events, wildfires, cyberattacks, and pandemics. We perform hazard and impact assessments of our infrastructure based on industry standards, best practices, and a tiered approach focusing on greatest risk to safety, security, and service reliability. Further, PNM works with the utility industry in support of State & Federal efforts to prepare for possible disruption of electric systems. This includes disaster planning, coordination of grid recovery & resilience, generation resource adequacy and fuel supply security.

4.2 Minimizing Cost

Each portfolio we model is built through an optimization 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.

In prior IRPs, we have developed and evaluated large numbers of potential resource plans to identify a single fully determined MCEP. The changing landscape for resource planning has added complexity to this process as the design criteria for a portfolio is greatly emphasized by environmental requirements in concert with resource adequacy attributes more than ever. The number of resource options under consideration is larger than ever, and different technologies carry unique characteristics and operating constraints to be considered in optimizing a portfolio. As commercialization of new resources occurs in New Mexico and elsewhere, capital costs are expected to change over time and can change resource's cost risk profiles.

A portfolio that optimizes cost while considering reliability and environmental impact within this complex and rapidly changing technological landscape must be flexible. The resource pathway that appears least cost now is not guaranteed to remain the lowest cost path as costs and risks evolve. As a result, we caution against determining a single 20-year resource plan based solely on the present-day evaluation of cost and risk that we are able to quantify today. Maintaining a certain amount of flexibility in resource selection allows for re-optimizations at key decision points in the future when more information is available on the technologies that are only beginning to see widespread adoption now. This flexibility ensures that customer affordability takes advantage of the changing technology landscape instead of being threatened by it.

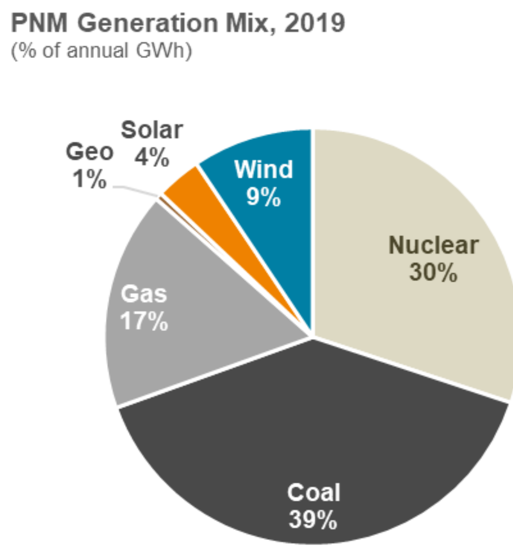
4.3 Mitigating Environmental Impact

Evaluating portfolio's current and future impact on the environment is a key factor we use to develop our plan. In developing our plan, we focus on the following factors:

- Greenhouse gas emissions;
- Criteria pollutants and other emissions;
- Water consumption.

Our progress to reduce our environmental impact as reflected by these metrics is largely a result of our energy mix. Figure 26 shows our 2019 generation mix by fuel; as we replace coal resources and invest in renewables and storage, the share of our needs met by carbon-free resources will increase. Our transition away from fossil fueled generation resources will generally improve our performance in each of the metrics we examine.

Figure 26. PNM's 2019 annual generation mix



While not considered directly in this plan, we recognize that other environmental impacts of our portfolio may merit further consideration in the future. Factors such as the land use impact associated with renewable and transmission development and lithium disposal may become future considerations in our development of resource plans and procurement decisions.

4.3.1 Greenhouse Gas Emissions

The consideration of our greenhouse gas footprint figures more prominently in this IRP than in any of our prior plans. Achieving deep emissions reductions at a rapid pace is a priority for the state, for many of our stakeholders and customers, and for PNM as a company that strives to uphold principles of corporate responsibility and sustainability. Over the twenty-year horizon of this IRP, we develop a plan that prioritizes rapid carbon emissions reductions to comply with the requirements of the ETA and to meet our own corporate goals of achieving a carbon-free portfolio by 2040.

Our Current Carbon Footprint

Table 8 summarizes the greenhouse gas emissions from resources owned by and under contract to PNM for the 2019 historical year. Nearly 80% of our current emissions can be attributed to

SJGS and FCPP, the two remaining coal plants in our portfolio; our plans to exit our interests these plants in 2022 and 2025, respectively, will significantly reduce our carbon footprint within five years. beyond that point, continued investments in renewables, storage, efficiency, and other carbon emissions-free resources will be necessary to continue further reducing the carbon intensity of our portfolio.

Table 8. 2019 historical greenhouse gas emissions from PNM generation resources

Facility	Total CO2 Emissions (short tons)	Annual Net Generation (MWh)	Share of Annual Generation (%)	Carbon Intensity (lbs/MWh)
Nuclear	-	3,255,777	30%	-
Palo Verde Generating Station	-	*3,255,777*	*30%*	-
Coal	5,200,079	4,262,223	39%	2,440
Four Corners Power Plant	*1,256,760*	*1,205,885*	*11%*	*2,084*
*San Juan Generating Station**	*3,943,319*	*3,056,338*	*28%*	*2,580*
Natural Gas	997,127	1,840,249	17%	1,084
Afton Generating Station	*422,541*	*876,416*	*8%*	*964*
La Luz Energy Center	*12,027*	*19,460*	*<1%*	*1,236*
Lordsburg Generating Station	*13,057*	*19,906*	*<1%*	*1,312*
Luna Energy Center	*161,793*	*383,389*	*4%*	*844*
Reeves Generating Station	*144,290*	*188,048*	*2%*	*1,535*
Rio Bravo Generating Station	*187,837*	*269,483*	*2%*	*1,394*
Valencia Energy Facility	*55,582*	*83,547*	*1%*	*1,331*
Geothermal	-	57,638	1%	-
Wind**	-	1,017,995	9%	-
Solar**	-	383,524	4%	-
Total	**6,197,206**	**10,817,406**	**100%**	**1,146**

** Includes 65 MW of PNM merchant capacity*
*** Individual renewable facilities not listed in this table, but detailed information is available in Appendix H*

Carbon Intensity Requirements of the ETA

Section 62-18-10(D) of the ETA establishes certain requirements for the carbon intensity that apply to our portfolio as a condition of our financing the abandonment of our coal plants through the issuance of Energy Transition Bonds. By 2023 and 2032, our portfolio must achieve a carbon intensity of 400 lbs/MWh and 200 lbs/MWh, respectively. These levels of carbon intensity represent dramatic reductions in our near-term and long-term carbon footprint and will be achieved through both the elimination of coal generation in our portfolio and continued development of renewable and demand-side resources.

To capture these requirements in our modeling, we create a constraint based on the carbon emissions from PNM generation divided by retail sales that are grossed up for losses. We believe this to be a conservative interpretation of the ETA requirements. The ETA requirement divides carbon emissions by total generation, which is larger than retail sales due to off-system sales and energy losses from storage charge/discharge inefficiency. Additionally, we enforce the constraint on an annual basis, whereas the ETA calls for measurement and verification of average compliance every three years.

PNM's Carbon-Free Goal

In addition to the carbon intensity requirements described above, the ETA also established an ultimate goal for the state of New Mexico to achieve a carbon-free electricity supply by 2045:

> …no later than January 1, 2045, zero carbon resources shall supply one hundred percent of all retail sales of electricity in New Mexico. Reasonable and consistent progress shall be made over time toward this requirement.

–New Mexico Energy Transition Act, Section 29

While the ETA requires public utilities in New Mexico to achieve a carbon-free portfolio by 2045, PNM has established a corporate goal to meet this standard five years sooner, by 2040. This goal similarly serves as a constraint in our planning process, and all portfolios that we consider are designed to complete this transition over the twenty years of the planning horizon. To achieve this goal, our analysis includes the following considerations when we design our portfolios:

- We incorporate the approved abandonment of SJGS (2022) and proposed transfer of FCPP to NTEC (end of 2024) to eliminate coal in all our portfolios by 2025.
- In addition to capturing the ETA's interim carbon intensity requirements, we apply a constraint that prohibits any combustion of fossil fuels by 2040, designing a portfolio capable of meeting all our needs throughout the year with carbon-free resources.
- To prepare for our final transition, we assume all existing gas plants will be fully depreciated by 2039, allowing for timely shutdown of any plants that are not capable of continuing operations using carbon-free fuels so long as we can ensure resource adequacy.

These design principles provide the foundation for our framework for a transition to a carbon-free energy mix.

The Paris Agreement and Executive Order 2019-003

The United Nations Framework Convention on Climate Change (UNFCCC) is an international environmental treaty that was negotiated at the 1992 United Nations Conference on Environment and Development (informally known as the Earth Summit) and was enforced in March 1994. The objective of the treaty is to "stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." Parties to the UNFCCC, including the United States, have been meeting annually in Conferences of the Parties (COP) to assess progress in meeting the objectives of the UNFCCC. This assessment process led to the negotiation of the Kyoto Protocol in the mid-1990s. The Protocol, which was agreed to in 1997 and established legally binding obligations for developed countries to reduce their greenhouse gas emissions, was never ratified by the United States. At the COP meeting in 2011, participating nations, including the United States, agreed to negotiate by 2015 an international agreement involving commitments by all nations to begin reducing carbon emissions by 2020. On December 12, 2015, the Paris Agreement was finalized during the 2015 COP. The agreement between more than 190 nations requires that countries submit Nationally Determined Contributions (NDCs) reflecting national targets, actions arising from national policies, and elements relating to oversight, guidance, and coordination of actions to reduce emissions by all countries.

In 2017, the Trump Administration withdrew support from the Paris Agreement, reversing the United States' prior commitment. In response, governors from several states established the U.S.

Climate Alliance, a bipartisan coalition of governors committed to reducing greenhouse gas emissions through action at the state level. In 2019, New Mexico's governor enacted Executive Order 2019-003, joining the U.S. Climate Alliance in support of the Paris Agreement and establishing a goal to reduce economy-wide emissions by 45% by 2030 (relative to 2005 levels). More recently, the Biden Administration issued an executive order renewing the United States' original commitment to the Paris Agreement, signaling renewed federal policy support for greenhouse gas emissions reductions.

While New Mexico's state greenhouse gas reduction goals and state and federal commitments to the Paris Agreement do not establish formal requirements for our future resource plan, they do influence our philosophy, approach, and priorities within the process:

- First, these commitments underscore the importance of the ETA and our pledge to achieve a 100% carbon emissions-free portfolio. As the largest electric utility within the state of New Mexico, PNM serves approximately 36% of the state's retail load. PNM's 2005 emissions of 7.7 million short tons represent a significant portion of the state's historical 2005 baseline. Meeting aggressive decarbonization targets will invariably require significant direct emissions reductions in our resource portfolio. Under our current plans, we expect to reduce our emissions by over 80% relative to 2005 levels by 2030.
- Second, we understand that New Mexico's commitment to a carbon-free economy may eventually lead to an increased role for PNM as an electric utility. Many studies of economy-wide decarbonization highlight transportation and building electrification as core to a successful transition strategy. While these measures can reduce emissions across the economy, they will require electric utilities like PNM to take on an even more central role in the economy-wide decarbonization effort by supplying low or zero carbon electricity to an increasingly broad selection of end uses. At the time of this plan, there is little existing direct policy support for electrification in New Mexico, so our plan reflects a moderate level of electrification. However, we also recognize that future policies implemented to enable the state's progress towards its goal may result in increases in new types of electric loads that will present both new opportunities and challenges.

The renewal of federal support for climate action may be accompanied in more direct regulation of emissions and/or clean energy in the electric sector. President Biden's climate plan includes a goal to supply 100% of electricity demands with carbon-free power by 2035. While this goal would be more ambitious than PNM's, we believe that the organization of our plan to meet ETA requirements and our own 2040 commitment will put us in a favorable position to adapt to future federal climate policy.

Methane Emissions

Methane emissions from new oil and natural gas sources are subject to Environmental Protection Agency (EPA) regulation. The regulations generally apply to production, processing, transport, and storage of those fuels. This may be of some impact as it could affect the cost or availability of gas supplies.

The ETA targets methane reductions by allowing generation resources to count as zero carbon resources if they reduce methane emissions by an amount equal to at least one-tenth the tons of carbon emitted from electricity production. We do not utilize this definition of carbon emissions-free in our modeled portfolios. However, we acknowledge that sourcing natural gas with lower upstream methane leakage could be a valuable aspect of our transition to carbon emissions-free generation.

4.3.2 Other Emissions

Electric utilities are subject to stringent laws and regulations for protection of the environment by local, state, federal and tribal authorities. Included in these regulations is compliance with the National Ambient Air Quality Standards (NAAQS). PNM's natural gas plants are subject to the NAAQS as are the coal plants through their remaining operating lives. PNM's natural gas-fired electric generating units operate in compliance with Clean Air Act (CAA) Title V Operating Permits issued by the applicable agencies as determined by the location of the plants. New Mexico currently does not have any non-attainment areas, although Dona Ana County may reach a small area of non-attainment due to cross-border transport of air emissions.

Gas plants generally have lower emissions levels of NOx, SO2, and CO2 when compared with coal plants. Gas plants' NOx emissions are controlled by low-NOx burners and/or selective catalytic reduction. Catalytic reduction is also used to control carbon monoxide emissions. Ozone control is a potential future emission regulation. Table 9 shows 2019 emission rates for selected NAAQS at PNM's coal and gas fuel plants.

Table 9. 2019 emissions rates for other NAAQS at PNM's coal and natural gas generation facilities

Facility	NOx lbs/MWh	CO lbs/MWh	SO2 lbs/MWh	PM2.5 lbs/MWh	Mercury lb/TWh
Coal					
*Four Corners Power Plant**	*0.597*	*n/a*	*0.390*	*n/a*	*5.3*
San Juan Generating Station	*2.755*	*2.271*	*0.618*	*0.054*	*0.9*
Natural Gas					
Afton Generating Station	*0.196*	*0.113*	*0.005*	*0.062*	
La Luz Energy Center	*0.123*	*0.012*	*0.006*	*0.037*	
Lordsburg Generating Station	*1.095*	*0.875*	*0.007*	*0.073*	
Luna Energy Center	*0.077*	*0.023*	*0.004*	*0.022*	
Reeves Generating Station	*3.072*	*0.841*	*0.008*	*0.094*	-
Rio Bravo Generating Station	*0.384*	*0.013*	*0.007*	*0.046*	-
Valencia Energy Facility	*N/A*	*N/A*	*N/A*	*N/A*	-

** Four Corners emissions rates based on 2018 operations*
N/A indicates data was not available to PNM

4.3.3 Water Consumption

In the arid Southwest, water is a scarce natural resource. Historically, we have taken a number of steps to reduce the water consumption of our existing portfolio, including:

- Use of gray water from the City of Deming at Luna Energy Facility in Deming to reduce freshwater use by one-third;
- Use of gray water from the City of Phoenix and other nearby communities for all cooling purposes at the PVNGS;
- Addition of parallel cooling at the Afton Generating Station to reduce freshwater consumption by 40 to 70%, depending upon operating conditions;
- Implementation of water recycling measures at SJGS that condense the turbine-turning steam back into water, allowing intake water to be reused at least 10 to 15 times (in some

plant processes, water is reused as many as 50 to 100 times before it is ultimately evaporated);

- Completion of an extensive water use study at San Juan that identifies in further detail how water is used in the plant and opportunities to increase water efficiency; and
- Planned shutdown of SJGS (2022) and exit from FCPP (end of 2024), which in 2019 accounted for 87% of all freshwater consumption in PNM's portfolio.

Table 10 shows the water consumed by each plant in PNM's portfolio for the 2019 historical year. In the future, our continued transition to renewable resources is expected to significantly decrease our water consumption, but we will continue to prioritize actions to further limit our footprint. The looming threat of climate change may increase the severity and frequency of extreme drought conditions within the region, meaning that our efforts to conserve water will become doubly important in the future.

Table 10. 2019 freshwater consumption at PNM generation facilities

Facility	Total Water Use (000 gallons)	Annual Net Generation (MWh)	Share of Annual Generation (%)	Water Use (gal/MWh)
Nuclear	68,697	3,255,777	30%	21.1
Palo Verde Generating Station	*68,697*	*3,255,777*	*30%*	*21.1*
Coal	2,615,779	4,262,223	29%	613.7
Four Corners Power Plant	*696,399*	*1,205,885*	*11%*	*577.5*
*San Juan Generating Station**	*1,919,380*	*3,056,338*	*28%*	*628.0*
Natural Gas	297,694	1,840,249	17%	161.8
Afton Generating Station	*61,875*	*876,416*	*8%*	*70.6*
La Luz Energy Center	*1,135*	*19,460*	*<1%*	*58.3*
Lordsburg Generating Station	*3,653*	*19,906*	*<1%*	*183.5*
Luna Energy Center	*78,940*	*383,389*	*4%*	*205.9*
Reeves Generating Station	*148,859*	*188,048*	*2%*	*791.6*
Rio Bravo Generation Station	*1,294*	*269,483*	*2%*	*4.8*
Valencia Energy Facility	*1,938*	*83,547*	*1%*	*23.2*
Geothermal	-	57,638	1%	-
Wind**	-	1,017,995	9%	-
Solar**	-	383,524	4%	-
Total	**2,982,168**	**10,817,406**	**100%**	**275.7**

** Includes 65 MW of PNM merchant capacity*
*** Individual renewable facilities not listed in this table, but detailed information is available in Appendix H*

4.4 Meeting Other Regulatory Requirements

4.4.1 Renewable Portfolio Standard

New Mexico's RPS targets have played a significant role in shaping our portfolio today and will continue to influence our decisions into the future. 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):

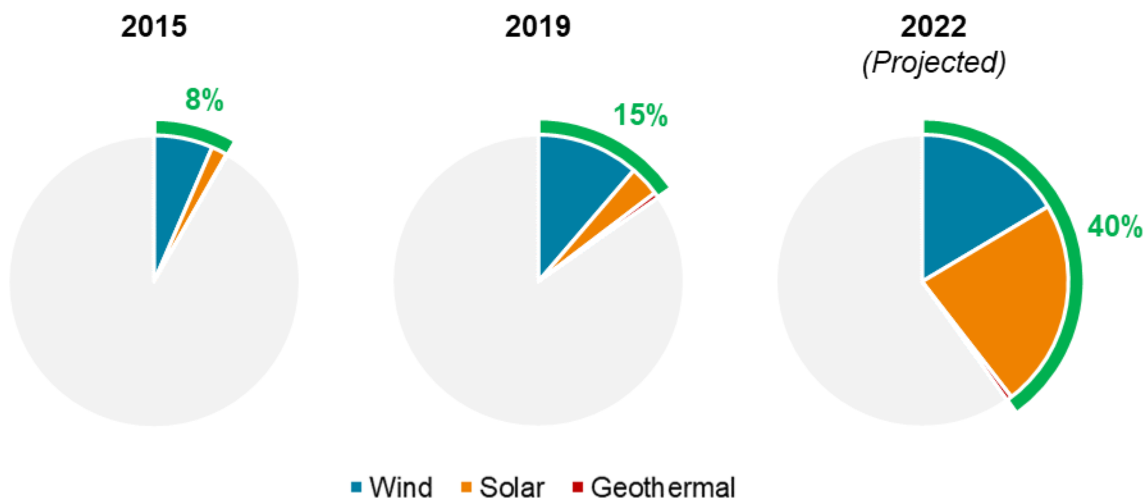
- 5% of retail sales by 2006
- 10% of retail sales by 2011
- 15% of retail sales by 2015
- 20% of retail sales by 2020

The ETA made significant changes to New Mexico's future RPS requirements, adding targets beyond 2020 to facilitate the state's transition to a carbon emissions-free electricity system:

- 40% of retail sales by 2025
- 50% of retail sales by 2030
- 80% of retail sales by 2040

With the portfolio of replacement resources for SJGS approved by the Commission, PNM is well-poised to meet statutory RPS compliance requirements over the next five-year period. Beyond that time frame, additional investments in renewable generation will be required to keep pace with the increasing requirements of the program (as well as to provide sustained carbon reductions for our portfolio). We note that renewable resources whose output is earmarked for PNM Solar Direct and Sky Blue programs, as well as renewables directly contracted to large customers, are not included in the RPS calculation. As a result, the actual penetration of renewable resources in our system portfolio exceeds the reported values in our RPS compliance reports.

Figure 27. PNM's supply of RPS-eligible resources as a share of retail sales



4.4.2 Efficient Use of Energy Act

Under the Efficient Use of Energy Act (EUEA), PNM is required to implement load management and energy efficiency programs subject to cost effectiveness as measured using the Utility Cost Test (UCT). The EUEA and subsequent amendments have established energy savings goals for these programs:

- The original EUEA established a 2014 goal of 5% of PNM's 2005 retail sales, or 411 GWh;
- Amendments in 2013 established a 2020 goal of 8% of 2005 retail sales, or 658 GWh; and
- The most recent amendments in 2019 established goals for 2021-2025 of 5% of 2020 retail sales, or approximately 400 GWh.

As of year-end 2019, PNM's approved EE programs achieved cumulative annual net energy savings of about 672 GWh. Meeting our goals for 2021-2025 will require achievement of roughly 80 GWh of new savings each year.

Our new programs are developed according to the specifications included in the Act and the Rule, which include passing the UCT cost-effectiveness test at a portfolio level, and meeting or exceeding the EUEA goals. (Net savings are determined by applying reductions to gross savings that account for free rider impacts and the effective useful life (EUL) of the programs, as determined by the independent evaluator).

4.4.3 Nuclear Regulations

PVNGS is subject to the jurisdiction of the Nuclear Regulatory Commission (NRC).

5 Analytical Approach

To achieve the objectives outlined above, we have developed a robust analytical framework that builds upon and enhances the methods used in previous IRPs. The focus of this year's plan on our 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 our answers to this and other questions is robust, we employ sophisticated software to optimize our portfolio while accounting for our resource adequacy needs. This section describes these components we use to help determine out MCEP from the modeling results.

Section Highlights
• This chapter presents the analytical approach used to develop the MCEP, including a discussion of the scenario approach, the inputs and assumptions needed for analysis, and the tools used to complete the analysis. • Our IRP analysis uses a scenario-based framework to study the performance of several different options for meeting our future needs under a wide range of conditions; scenarios are designed to highlight different technology pathways and carbon intensity trajectories to achieve our 2040 goals while maintaining reliability. • The scenario analysis completed to inform this IRP builds upon analysis conducted to support several separate filings before the Commission, including our application for abandonment of FCPP and abandonment and replacement of our PVNGS leased shares. • Our increasing reliance on intermittent renewables and storage to meet future needs has brought additional complexity to our planning process; the types of models that have long been used by utilities as the engines for IRP development are not fully capable of capturing these nuances and complexities. • To improve our modeling capabilities and address these technical deficiencies, we rely on EnCompass, a capacity expansion model designed specifically to address the challenges of planning a highly renewable system; as well as SERVM, which provides us with the capability to evaluate the resource adequacy

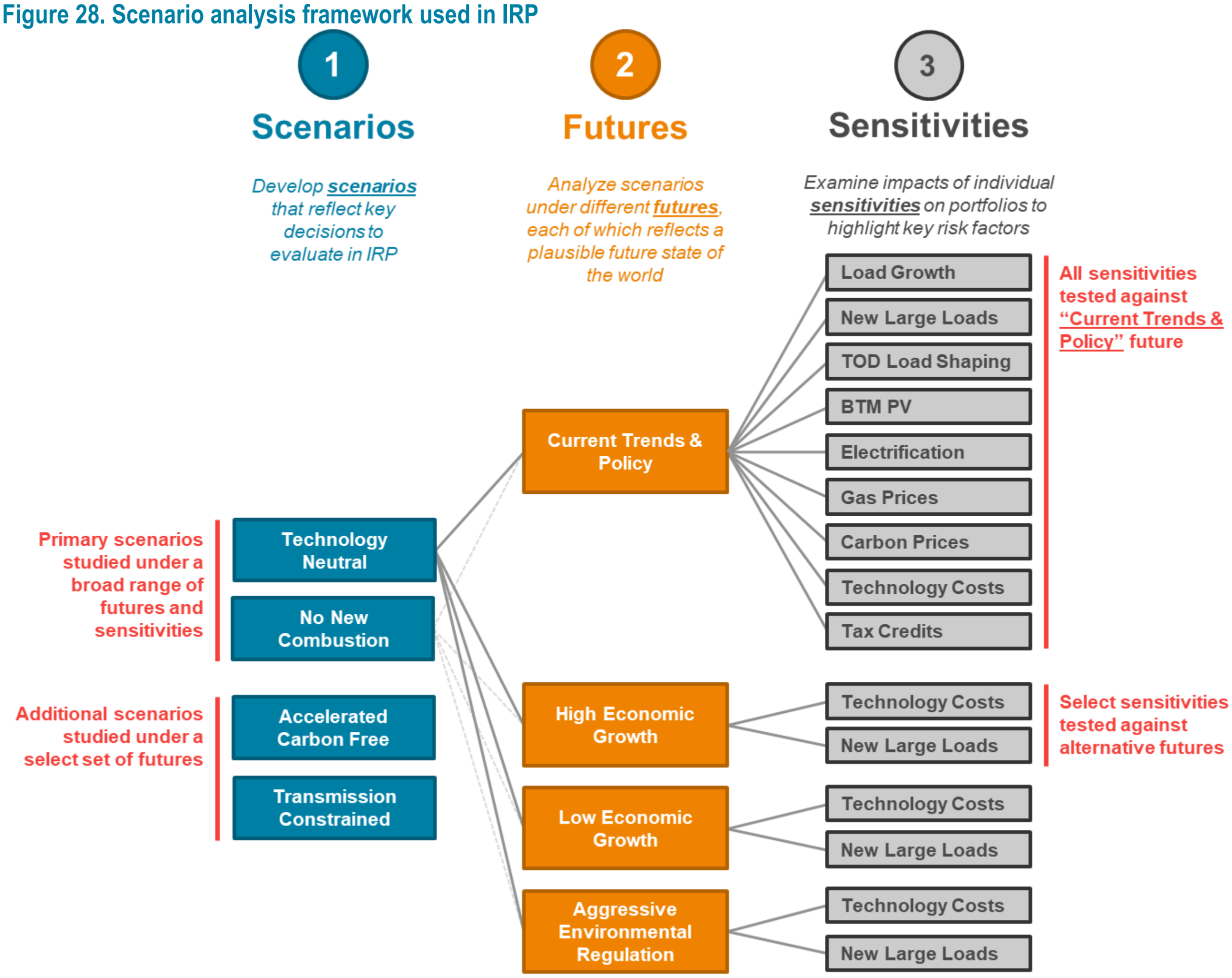
5.1 Scenario Analysis Framework

Our future generation portfolio will be largely determined by the resources that are considered for replacement when existing resources leave PNM's portfolio. To capture two possible replacement paths, we model two **scenarios** to explore how decisions around replacement options impact resource builds and our ability to achieve our IRP objectives. Given that data forecasts also impact this decision-making, the scenarios are modeled under several sets of forecast assumptions or **futures**.

In addition to identifying scenarios and futures, we design **sensitivities** in which a single forecast element is changed from an existing scenario/future. Sensitivities provide analysis of risk by revealing the forecast components to which results are most sensitive and the extent to which costs and portfolio builds change given changes in the forecasts. The framework of scenarios, futures, and sensitivities ensures that the choice of MCEP is robust to a variety of futures and minimally affected by sensitivities.

The framework of scenarios, futures, and sensitivities serves to focus the analysis so that modeling results provide insight to the most important questions. Here we describe how each of these pieces fits into the analysis, and what specific scenarios, futures, and sensitivities we choose to test.

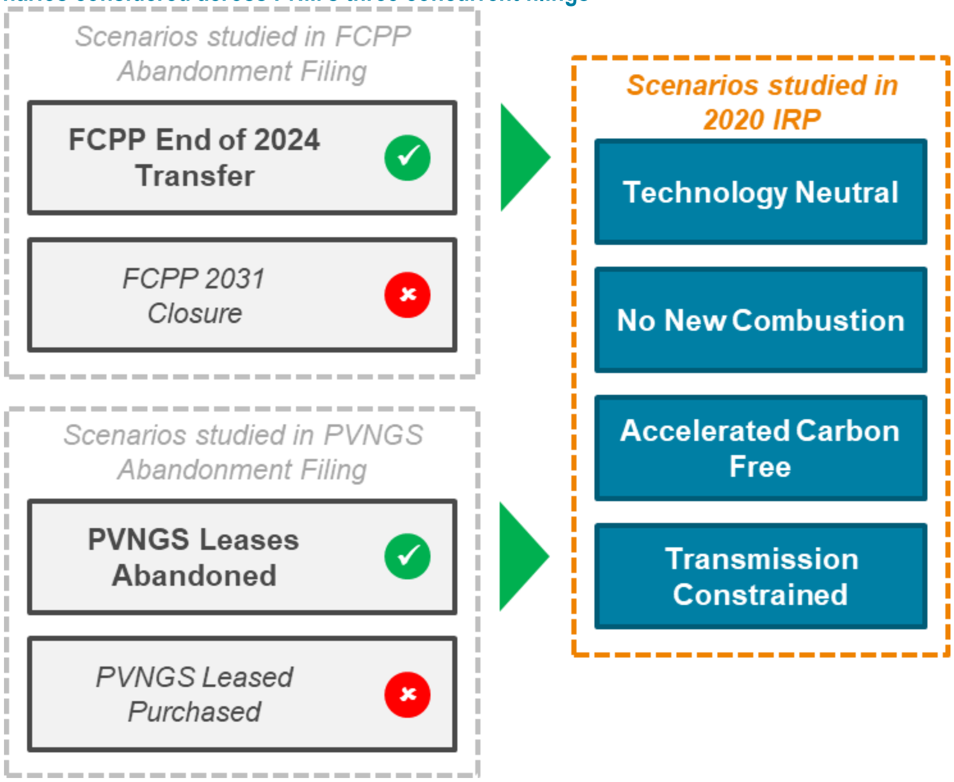
Figure 28. Scenario analysis framework used in IRP



Relationship to FCPP and PVNGS Filings

Across three separate filings—FCPP Abandonment, PVNGS Abandonment and Replacement, and the Integrated Resource Plan—we have examined a wide range of scenarios to inform our future energy supply. The scenario framework we have developed is best understood holistically, despite the independent nature of each of those filings. As indicated in Figure 29, the scenarios we consider in our IRP are directly informed by the analysis supporting the respective filings for FCPP and PVNGS abandonment. We apply the same modeling techniques and assumptions across all three filings, ensuring consistency in our decision making across these filings.

Figure 29. Scenarios considered across PNM's three concurrent filings



Because the questions of whether to renew the PVNGS leases and whether to transfer ownership of FCPP before its eventual closure are explored in these separate filings, the scope of our IRP focuses on establishing a roadmap towards our 2040 goals and some of the key portfolio decisions facing us.

5.1.1 Scenarios

To identify an MCEP that meets our objectives, we examine two "primary" **scenarios** which focus on the types of investments we consider in our transition to a carbon-free system. Namely, these scenarios focus on the decision to consider all technologies for replacement or to prohibit new combustion resources. We also examine a set of "additional" portfolios designed to probe paths to 2040 that are less likely to materialize but hold valuable information.

The "primary" scenarios are studied under the broadest range of potential future conditions, while the "additional" scenarios are studied under a more limited set of future conditions. The "primary" scenarios are selected to highlight the most significant and imminent choice facing PNM in our efforts to transition to a carbon-free portfolio; the other scenarios generally relate to choices that may be deferred for more thorough investigation in future IRPs.

The scenarios investigated in this IRP are shown in Table 11, along with brief descriptions of their assumptions and purposes. The key assumptions that define each of the Primary IRP scenarios are shown in Table 11; A further description of each primary scenario follows.

Table 11. Scenarios considered in IRP analysis

Scenario	Description	Purpose
Primary IRP Scenarios		
Technology Neutral	Considers all technologies (renewables, demand-side resources, storage, and hydrogen-ready CTs) in optimization of future resource mix	Identify the least-cost resource plan to meet statutory requirements and PNM's goals
No New Combustion	Considers only non-combustion resources in optimization of future resource mix	Evaluate potential to meet the same set of requirements and goals without reliance on new combustion resources
Additional IRP Scenarios		
Accelerated Carbon Free*	Achieves a carbon-free portfolio by 2030; includes a minimum of 1,500 MW of pumped storage	Study implications of accelerating PNM's carbon emissions-free goal and the role of pumped storage
Transmission Constrained	Includes more explicit representation of transmission system and candidate projects/upgrades in model	Validate conclusions from simpler transmission representation. Explore possibility of using this modeling method in the future

* *Based on scenario requests submitted by stakeholders*

Technology Neutral

The Technology Neutral scenario is designed to meet the requirements of the ETA and our own environmental goals at least cost to our customers. Accordingly, this scenario considers only as constraints the legal requirements of the ETA, our own established 2040 goal, the need to preserve reliability, and the engineering limits that govern the operations of the grid. This scenario is intended to demonstrate the lowest cost options to supply the needs of our customers while still achieving the aggressive interim carbon intensity milestones of the ETA as well as meeting the carbon emission-free target of the ETA five years ahead of the statutory schedule. The plan presented by this scenario optimizes our portfolio considering all potential investments that we expect could play a role in meeting our needs in a 2040 carbon emissions-free portfolio, including renewables, storage, energy efficiency, demand response, and hydrogen-ready combustion turbines. Additional emerging technologies may also provide the solutions that would support our transition; we plan to monitor these developments and look for opportunities to incorporate new options in future IRP cycles.

Figure 30. New resource options considered in the Technology Neutral scenario

- **Solar** ✓
- **Wind** ✓
- **Battery Storage** ✓
- **Pumped Storage** ✓
- **Incremental DSM** ✓
- **H_2-Ready CTs** ✓

No New Combustion

In the No New Combustion scenario, we create a plan that excludes new investments that would generate electricity through combustion. The difference between the No New Combustion scenario and the Technology Neutral scenario is the exclusion of hydrogen-ready combustion turbines as an option for investment from the portfolio. As a result of this constraint, in these scenarios, all future needs are met by a combination of renewables, storage, and demand-side resources.

Like the Technology Neutral scenario, this scenario is designed to meet the requirements of the ETA and our own environmental goals.

Figure 31. New resource options modeled in the No New Combustion scenario

Solar	✓
Wind	✓
Battery Storage	✓
Pumped Storage	✓
Incremental DSM	✓
H_2-Ready CTs	✗

5.1.2 Futures

A **future** consists of a set of forecasts that describe the state of the world. The different forecast components that define a future can be found in the first column of Table 12. These range from customer-related factors including load forecast and adoption of end use electrification to broader factors such as the prices of gas, electricity, CO2, and technology capital costs.

Generally, PNM has little to no ability to influence which future becomes reality. The *Current Trends & Policy* future is defined by what PNM believes to be the most likely set of forecasts. Alternative futures take plausible forecast combinations that could be the result of deviations from assumed economic growth or more aggressive climate-based regulation. In a future with stronger emphasis on environmental impacts, the costs of renewable resources and battery storage become more critical.

Table 12. Definitions of futures based on key assumptions

	Current Trends & Policy	High Economic Growth	Low Economic Growth	Aggressive Environmental Regulation
Load Forecast	Mid	High	Low	Mid
BTM PV Forecast	Mid	High	Low	High
EV Adoption Forecast	Mid	High	Low	High
Building Electrification Forecast	Mid	Mid	Mid	High
Gas Price Forecast	Mid	Mid	Low	High
Carbon Price Forecast	Mid	Mid	Mid	High
Technology Cost Forecast	Mid	Mid	Mid	Low

Current Trends & Policy

The "Current Trends & Policy" future reflects our best estimates of the future state of the world based on the information we have at the time of the IRP's development. Specifically, in this future, we assume:

- Continued economic and population growth within our service territory consistent with trends as forecast by Woods and Poole, as well as modest levels of incremental customer solar and electrification;
- Future commodity pricing assumptions based on projections provided by PACE Global that are intended to represent a most likely outcome in gas and electric markets;
- Technology pricing and future technology cost declines developed based on recent bids provided to PNM and NREL's latest 2020 Annual Technologies Baseline (ATB); and
- Expiration of federal tax credits for renewable generation based on current sunset dates in the early 2020s.

High Economic Growth

Our "High Economic Growth" future is based on the assumption of more aggressive future growth of the New Mexico economy. In addition to driving an increase in the growth of our electric demands, we would expect a rapidly growing economy to support greater levels of customer adoption of solar resources and electric vehicles. In combination, these factors increase demand while reshaping its daily patterns.

Low Economic Growth

Our "Low Economic Growth" future assumes a persistent lower level of growth in the New Mexico economy. In contrast to the High Economic Growth future, we would expect lower levels of growth to dampen customer adoption of solar and electric vehicles. In addition, we assume that a lower growth environment would indicate sustained low natural gas prices through the horizon of our analysis.

Aggressive Environmental Regulation

Under an "Aggressive Environmental Regulation" future, we analyze scenarios under a plausible future set of conditions that represents increased state and federal commitments towards environmental regulation.

Through its commitment to the Paris Agreement, the state of New Mexico has already signaled the priority of achieving deep economy-wide reductions. Numerous studies of economy-wide reductions, including analyses specific to the state of New Mexico, indicate that electrification is a key pillar of meeting such aggressive goals. While specific policies do not yet exist in New Mexico to drive such aggressive levels of electrification, this future presumes increases in load due to accelerated electrification of both vehicles and buildings.

With respect to future commodity pricing, this future incorporates a higher natural gas price forecast intended to capture the plausibility that future restrictions on natural gas fracking could restrict production and lead to upward pressure upon the low prices in today's highly competitive markets. This future also includes a high carbon price forecast, reflecting the eventual possibility of regional or national carbon pricing schemes.

Finally, this future assumes aggressive technology cost declines for wind, solar, and battery storage. The rationale for this assumption is that under aggressive environmental regulation, a combination of policy-driven decisions – increased R&D spending, extensions of tax credits, accelerated learning due to deployment of technology on a larger scale – could drive cost reductions at rates beyond the level assumed in the "Current Trends & Policy" future.

5.1.3 Sensitivities

A **Sensitivity** describes the variation of a single input assumption within a defined future. By adjusting a single assumption, we seek 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. Figure 32 lists the variables examined in our sensitivity analysis and the default assumptions for each under the Current Trends & Policy Future.

Figure 32. Assumptions varied in sensitivity analysis

Assumption	Current Trends & Policy	Sensitivity Options		
New Large Loads	None	High	Very High	
Load Growth	Mid	Low	High	
TOD Load Shaping	Limited	Widespread		
Customer Solar	Mid	Low	High	No Incremental
Electrification (Vehicles)	Mid	Low	High	
Electrification (Buildings)	Status Quo	High		
Gas Prices	Mid	Low	High	
CO2 Prices	Mid	Low	High	$8/20/40 per ton
Technology Costs	Mid	Low	High	
Tax Credits	Expired	Extended		

The number of potential sensitivities that could be considered across all scenarios and futures is extensive. To meet the IRP Rule's requirement to analyze risks, we carefully select which sensitivities to analyze under each different future. Under the "Current Policy & Trends" future, we analyze all possible sensitivities to ensure that we understand the magnitude and direction of the impacts of different risk factors. Under the alternative futures, we analyze a select subset of sensitivities chosen to highlight the most significant sources of uncertainty whose impact on our pathway to a carbon emissions-free portfolio could be significant: namely, the future cost trajectories of emerging and nascent technologies.

5.2 Consideration of Risk

In our past IRPs, our risk assessments have focused on ensuring that our investments and portfolio decisions are robust despite uncertainties in commodity costs and load patterns. In these plans we have used stochastic analysis of these uncertainties to ensure that our portfolio does not expose our customers to undue risks.

As a utility transitioning towards a carbon emissions-free portfolio, the most significant sources of risk in our planning process are fundamentally shifting, and our approach to assessing risk must also adjust. The types of investments we consider in our plan are generally heavily weighted towards up-front investment costs—either because they are zero-marginal cost resources like wind and solar, or because we would operate them only when needed for reliability needs—which in turn means that our decisions of what resources to choose have limited impact on our exposure to risks around fuel and carbon costs. Instead, the most significant risks we face are related to the following uncertainties:

- **Load growth:** many uncertain factors will impact the level of load growth in our service area, including economic growth, the changing climate, levels of future electrification, and the future arrival of new large customers in New Mexico. The implications of under- or over-forecasting future demand are different: under-forecasting may lead to circumstances where our portfolio does not have sufficient resources to meet our customers' needs reliably; over-forecasting may result in procurement of more generation than needed to supply our customers' needs, imposing additional costs upon them.

- **Technology performance:** in our transition to a carbon-free portfolio, we recognize the likelihood that new and emerging technologies will play a significant role in enabling that transition. At the same time, we must be cautious not to transition too quickly to technologies not proven at the scale and penetration we may eventually need. Reshaping our portfolio too quickly could lead to unintended consequences – higher costs, reliability events – if real-world performance of emerging technologies deviates from planning assumptions.

- **Technology cost:** our analysis indicates storage resources will be principal selections in nearly all cases. There is risk however, that today's battery choice will be displaced by cheaper, better performing or longer lasting batteries as the technology progresses.

- **Broader regional conditions:** PNM actively participates in wholesale electricity markets in the Western Interconnection, and our planning process relies on certain assumptions regarding the future dynamics of wholesale markets and the availability of regional support during constrained periods. The regional grid is trending toward prominence of solar energy supply and low prices in daylight hours but scarcity during the evening hours. We want to be prepared to be self-reliant when the region is unable to support our system.

- **Regulatory changes:** future state or federal regulatory changes could impact how the costs of our decisions today are borne by our customers over time. In the past several decades, regulatory changes have generally served to accelerate the transition away from fossil fuels and towards cleaner energy sources – most recently with the ETA, but previously through the establishment of the RPS program and the EUEA. Our planning process considers how changes in the future regulatory environment would affect the costs of various plans.

- **Climate change impacts:** New Mexico has already begun to experience direct impacts of climate change, and in spite of increasingly widespread efforts to mitigate its effects, these trends are likely to continue. In addition to the negative impacts that changes in climate have upon society at large, our changing climate has implications for our long-term planning efforts as a utility. Higher temperatures and more frequent extremes will change our load patterns and could require additional resources to maintain reliable electric supply for our customers. While it is difficult to project the localized impacts of global climatological shifts, this is an area that we will continue to monitor, and where possible, incorporate into our forecasting processes in the future.

- **Open position market risk:** We describe in this IRP that more sophisticated analytical techniques reveal a need to increase our planning reserve margin. One of the key drivers of this increase is the decreasing ability to rely on market purchases during potential loss-of-load events. Lagging approval or rejection of resources needed to meet this PRM would leave PNM relying on a shrinking market for reserves. Over-reliance on the imports during peak events exposes PNM customers to increased risk of high market prices and risk of lost load.

- **PPA deliverability and operational flexibility:** As we transition towards a portfolio of resources whose operations will grow increasingly complex, the choice between utility ownership and PPAs has implications for how efficiently we will be able to operate our resources to meet our customers' needs. Utilities have the obligation to serve and ensure system reliability. If new resources fail to meet a specified Commercial Operation Date, utilities can face penalties from regulators and NERC; however, outside of liquidated damage clauses, the utility has little control to ensure develops meet expected online dates leading to increased deliverability risk. Under utility ownership, our operators will have full control of our assets and can operate them to maximize value to our customers within their technical and engineering limits. While we generally structure PPAs to afford as much flexibility in operations as possible, contract terms can in some instances inhibit the dispatch or use of a resource in the most efficient way for our customers.

In this plan, we address these broader set of risk factors through extensive sensitivity analysis, testing how our optimized plan would change under different future assumptions. These sensitivity analyses include traditional risk factors – for instance, levels of load growth and commodity pricing – but also allow us to examine how factors like how the long-term cost declines for renewable and storage technologies should affect our near-term investment choices.

5.3 Inputs & Assumptions

The modeling effort requires data from two broad categories: resource data and forecast data. Resource data includes specifications for PNM's existing demand-side resources, supply-side resources, and transmission capabilities and obligations. Also, this category includes speculative information on future resources and transmission projects that may be used to meet load and relieve congestion. Forecast data includes projections of customer energy and demand, commodity prices, technology costs, and technology adoption. Forecast data also includes anticipated regulations that would affect any of these forecasts or how the PNM system is run.

Existing resources and transmission are discussed in Sections 6.2 and 7.1, while Sections 6.4 and 7.2 contain descriptions of possible future resources and transmission projects. Forecasts of load appear in Section 6.1.

Inputs required for the IRP analysis and selection process are numerous and wide-ranging. This section describes the essential inputs, their sources, and why they matter in the IRP process. Table 13 provides a list of the IRP data requirements, which are covered in this section.

Table 13. IRP Required Data

Input Data	Details	Location(s)
Load Forecasts	Existing customer counts and load by rate class, historical and projected population growth, assumptions around growth in use per customer or customer class, large customer changes, wholesale contracts	Section 2.2 Section 6.1 Appendix C
Commodity Forecasts	Price forecasts (with sensitivity ranges) for natural gas, hydrogen, fuel oil, coal, and nuclear fuel costs	Section 6.5 Appendix G
Existing demand-side resources	Energy and demand savings from EE. For DR, available capacity, limits on use, contract costs and terms. Historical data and plans for future programs	Section 6.2.1 Appendix L
Existing Generation	Additional capital improvement costs, operation and maintenance (O&M) costs, heat rate, forced outage rate, fuel type, fuel price, emissions rates, water needs	Section 6.2.2 Appendix H
New Generation	Capital costs, O&M costs, heat rate, forced outage rate, fuel type, fuel price, roundtrip efficiency of storage, emissions rates, water needs	Section 6.4 Appendix I
Transmission	Headroom on existing lines, typical availability during peak hours, proposed new projects with cost, associated resources, and timing expectations	Section 7
Regulations	Existing regulations and constraints, potential future regulations	Section 4 Appendix F

5.4 Modeling Tools and Methods

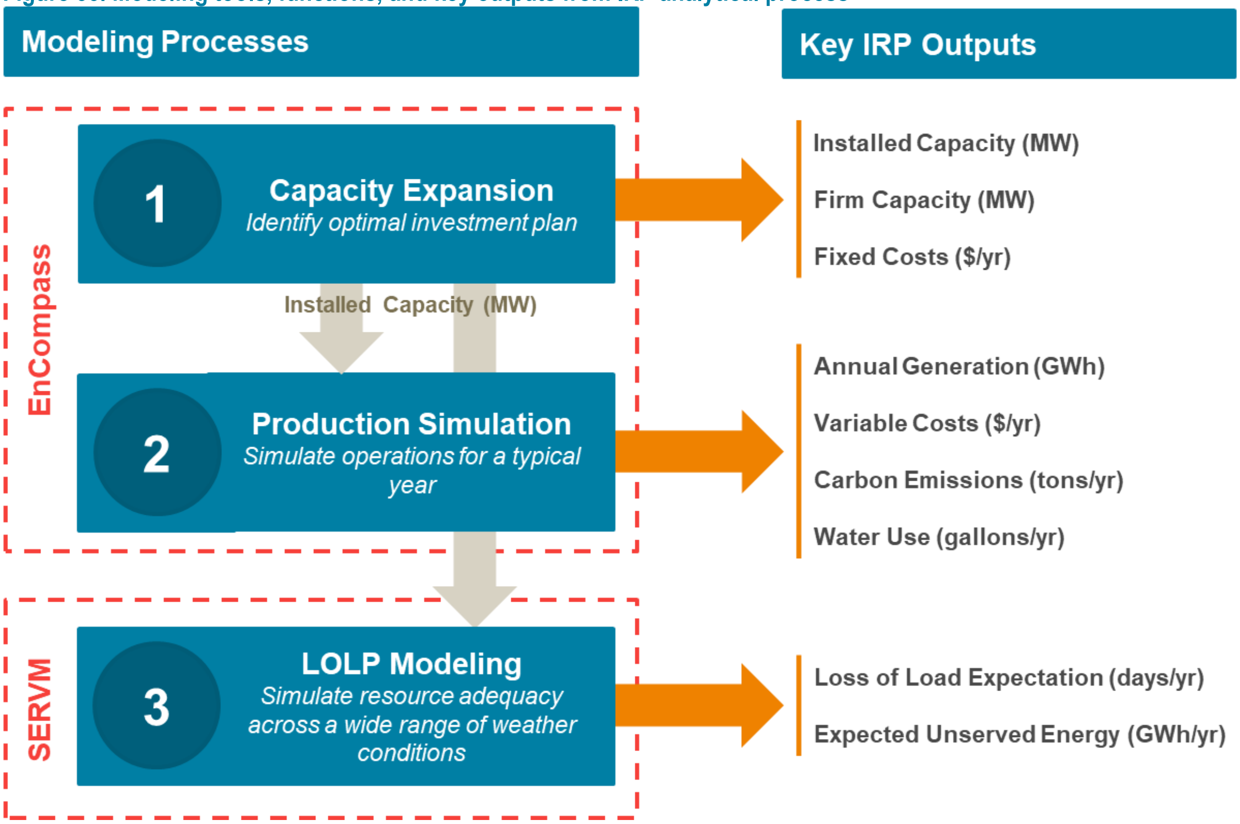
In this cycle, we have upgraded our modeling toolkit to take advantage of commercial software tools on the cutting edge of the industry's most pressing questions. Our modeling framework relies primarily on two tools:

1. **EnCompass**, an optimal capacity expansion and production simulation model created by Anchor Power Solutions, which we use to identify and simulate portfolios least-cost resources to meet our future needs; and

2. **SERVM**, a loss-of-load probability model developed by Astrape Consulting, which we rely on for detailed reliability analysis of our portfolios.

Both of these tools are necessary to obtain a robust result that achieves our objectives. To produce optimized portfolios, EnCompass incorporates a representation of how our system will operate across a sampling of representative days; however, due to the computational complexity of the optimization problem, it is not practical to include direct simulation of all possible conditions within the optimization itself. At the same time, our reliability standards dictate that our portfolio result in no more than two days of lost load in ten years; accurately characterizing whether a portfolio meets that standard and the extent to which different types of resources can contribute to it requires a tool that can quickly simulate thousands of years' worth of conditions. By pairing these tools together, we are able to identify and evaluate a range of portfolios that meet our environmental goals and reliability standards. Using one without the other jeopardizes the ability to select long-term portfolios that are sufficient to meet load while also addressing factors of cost, environmental considerations and regulatory requirements.

Figure 33. Modeling tools, functions, and key outputs from IRP analytical process



Limitations of Previous Models

In our 2017 IRP and previous plans, we used three models to generate and evaluate portfolios: (1) ABB's Strategist for capacity expansion; (2) AuroraXMP for production simulation; and (3) SERVM for reliability analysis. Our transition to use of EnCompass as the primary analytical tool to support this plan enhances our capabilities to address a number of the emergent challenges in highly renewable electricity systems that these previous tools were not as well-equipped to study.

ABB's Strategist uses heuristics to identify optimal portfolios that are not well-suited to address the planning challenges we face as we transition towards a carbon emissions-free portfolio. Specifically, Strategist uses a "load duration curve" to approximate the costs of dispatching resources to serve loads when identifying new investments. This traditional approach served the industry well when planning processes focused on comparisons of thermal generators with different costs and efficiencies. However, older models are becoming inadequate for analysis of electricity systems with changing customer energy requirements, increasing penetrations of variable renewable resources, and the anticipated deployment of storage resources at scale. As the penetration of these resource types grows, it becomes increasingly important to capture the chronological operations of the system endogenously within the capacity expansion model for several reasons. Chronological simulation of operations allows the model to capture the dynamics of different types of resources on the system, including:

- The impacts of increasing levels of wind, solar, and demand side resources on the shape of our net load;

- Frequent cycling of thermal units with unit commitment and ramping constraints to balance renewable output;
- Charging and discharging of storage resources to shift energy throughout the day.

Secondary but also notable is the benefit of consolidating the capacity expansion and production simulation functions within a single modeling platform, which has provided our team with the opportunity to improve our process efficiency. This consolidation eliminates a step in our process of manually transferring information between models, which helps our team ensure consistency in assumptions among the various modeling processes within the IRP.

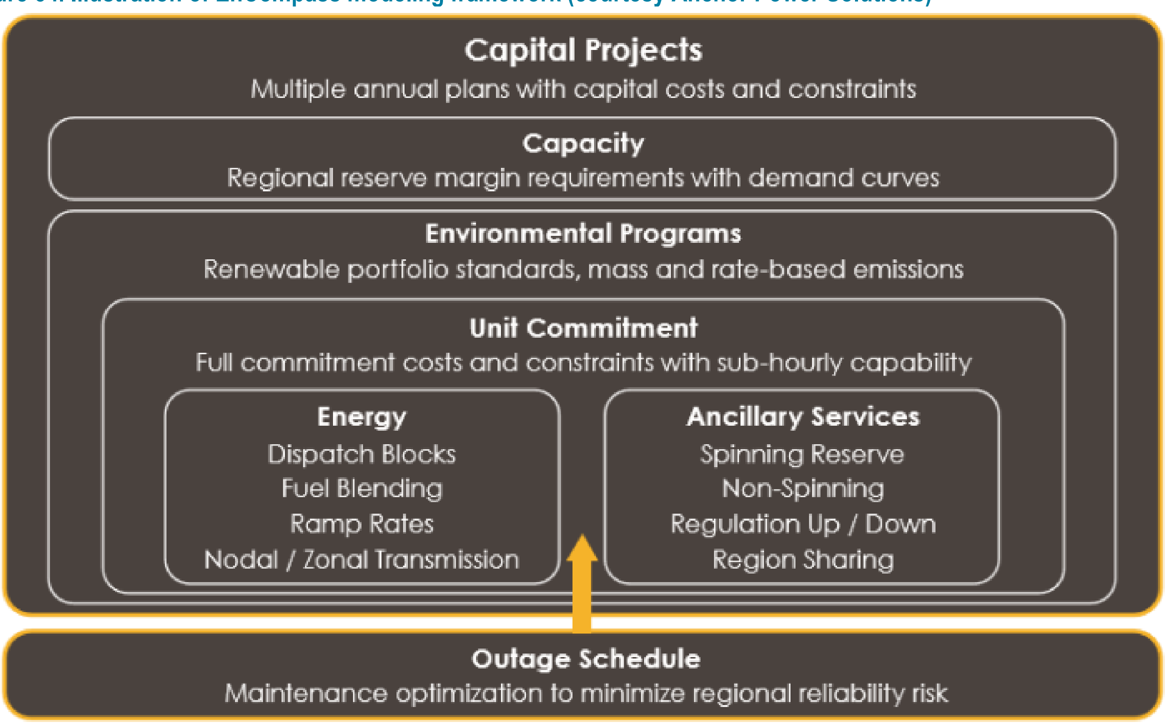
5.4.1 EnCompass

EnCompass, developed and maintained by Anchor Power Solutions, is an optimal capacity expansion and production simulation model designed for long-term integrated resource planning. In our IRP, we use EnCompass for two functions:

- **Capacity expansion:** EnCompass produces least-cost portfolios of resources to meet future needs, subject to resources operating parameters, constraints on reliability, and the various environmental and regulatory requirements established by our planning processes; and
- **Production simulation:** EnCompass simulates the hourly operations—and the associated cost of serving our loads—of each portfolio across the full planning horizon, capturing detailed unit commitment dynamics, dispatch constraints, and transmission limitations of our system.

Figure 34, reproduced here with the permission of Anchor Power Solutions, illustrates EnCompass' modeling framework.

Figure 34. Illustration of EnCompass modeling framework (courtesy Anchor Power Solutions)



For our planning process, we configure EnCompass' capacity expansion module to identify least-cost portfolios of resources 2021 through 2040 while meeting a number of constraints. The model's **"objective function"** – the sum of all costs included in the optimization – approximates the net present value of our revenue requirement, including all costs related to our generation portfolio (existing and new resources) and new transmission investments. EnCompass minimizes this objective function subject to a number of **"constraints"** – certain requirements that the portfolio must meet in order to be considered a valid solution. The components included in the model's objective function and the key constraints that govern the possible solutions are shown in Figure 35.

Figure 35. Objective function and key constraints implemented in EnCompass

Objective Function

Net present value (2021-2040) of:
- Generation carrying costs
- Contract expense
- DSM program costs
- Fixed O&M costs
- Variable O&M costs
- Fuel costs
- Carbon costs

Annual Constraints

- Planning reserve margin
- Carbon intensity
- Renewable portfolio standard

Hourly Constraints

- Power balance
- Operating reserves
- Unit-level operating constraints

EnCompass' modeling functionality is foundational to our identification of a robust plan and represents a significant step forward in our planning capabilities since our last IRP. Several of the most important features of EnCompass that we use to develop our plan are described below.

Endogenous Hourly Dispatch

Within the context of the capacity expansion optimization, EnCompass includes a representation of the hourly system dispatch of our portfolio to meet our loads. As our capacity mix shifts towards renewable and energy storage resources, hourly system dispatch allows us to model dynamic operational decisions we expect to make in the future. Unlike dispatchable thermal generation that can be brought online as needed to match energy demand, generation from renewable resources is subject to availability limitations. For example, solar resources can generate power only during the day and wind speed varies by location, time of day and season. In Encompass, renewable resources are represented using hourly profiles which capture the temporal variation in renewable generation required for hourly system dispatch. Operation of energy storage resources, such as daily charging and discharging patterns are also better represented using hourly system dispatch.

Utilizing the hourly production cost representations in EnCompass lends robustness to our capacity expansion modeling, especially regarding thermal fleet operations and representation of renewable and energy storage operations.

Dynamic ELCC Curves

Another key feature of Encompass for our analysis is the capability to represent ELCC curves for each technology dynamically; that is, given an ELCC curve for a specific technology, Encompass can track how the marginal ELCC of that resource changes as the magnitude of that technology scales with the portfolio. This enables the modeling to account for saturation effects inherent to resources like solar and storage and is key to our ability to optimize a portfolio while meeting resource adequacy needs.

Currently, EnCompass does not include logic to capture the synergistic effects between resources explicitly. However, PNM understands this functionality may be added in future releases of the software.[28]

Emissions Constraints

EnCompass allows us to optimize a portfolio of resources according to constraints on carbon emissions (or emissions intensity), a key feature needed to ensure that our portfolio can comply with the future requirements of the ETA.[29] We apply yearly emissions intensity constraints in all scenarios modeled beginning with the ETA's 2023 requirement of 400 lbs/MWh.

According to the requirements set forth by the ETA:

> "…the qualifying utility's generation and sources of energy procured pursuant to power purchase agreements **with a term of twenty-four months or longer**, and that are dedicated to serve the qualifying utility's retail customers, shall not emit, on average, more than four hundred pounds of carbon dioxide per megawatt-hour by January 1, 2023, and not more than two hundred pounds of carbon dioxide per megawatt-hour by January 1, 2032 and thereafter."
>
> – ETA Section 10D (emphasis added)

Under this accounting regime, short-term wholesale market transactions are not directly considered in determining our carbon intensity. In order to design portfolios that we believe comply with the spirit and requirements of the ETA and do not rely excessively on short-term purchases, we do not allow for market purchases or sales in the capacity expansion step of our analysis. This approach ensures that our portfolio includes enough resources to serve our own loads while also complying with the requirements of the ETA. A key element in the design of our portfolios is that they all are designed such that they can meet the objectives of the ETA as well as PNM 2040 Carbon Free goal before considering market interaction.

Co-optimization of Generation & Transmission

EnCompass includes functionality that allows co-optimization of transmission and generation investments. Jointly selecting generation and transmission would allow our planning process to identify areas for development with high quality renewable resources where transmission costs may not be prohibitive. Further, this approach would allow our analysis to better capture the inherent lumpiness of transmission investments, treating potential transmission upgrades as

[28] The effect of not capturing the synergies embeds some conservatism into the portfolios and increases resource adequacy approximation resulting from the EnCompass simulations. As shown in Section 8.4 and Appendix M, the near term LOLE analysis (2025) yields results very close to the calibrated 0.2 metric. However, the 2040 LOLE analysis results in portfolios well below the 0.2 threshold. One potential reason for this is the implicit diversity benefit captured in the SERVM model that is not captured by EnCompass.

[29] EnCompass also allows us to model the RPS requirements of the ETA, but we generally observe that these constraints do not drive portfolio decisions due to the significant level of renewables included in our existing portfolio and the more stringent carbon constraints we impose. Nonetheless, all portfolios are also designed to meet year-by-year RPS requirements.

binary decision. Doing so would allow our analysis to right-size investments in generation to match the delivery capabilities of realistic options for transmission expansion identified by our planners.

The co-optimization of transmission and generation adds significant complexity to the capacity expansion modeling. In developing the analysis in support of the 2020 IRP, we tested this functionality, exploring the potential to represent transmission upgrades discussed in Section 7.2 (Transmission Planning) as explicit choices. The additional complexity was significant enough to make model runtimes untenably long. In this IRP, we include in the model a transmission adder – based on the identified upgrade choices – for resources that require new transmission for delivery to load. We will continue to investigate the functionality to include explicit transmission representation in our next IRP as part of an effort to better integrate transmission and generation planning.

8760 Production Simulation

While the capacity expansion run approximates our system operations based on a sample of conditions – and associated metrics including energy mix, carbon emissions, and operating costs – the hourly analysis provides a richer view of our system's operations over the course of the year. Some differences in the representation of operations between the limited sample in the capacity expansion model and the full production simulation run due to the broader set of conditions studied. In addition, in the production simulation runs, we allow for interactions with neighboring wholesale markets to reflect our opportunities to reduce customer costs with short-term transactions. Under the ETA's rules, short-term market purchases do not count towards our carbon intensity, and so in circumstances where the production simulation model chooses to buy from the market instead of dispatching our own natural gas resources, the apparent emissions intensity of our portfolio may appear lower than in our capacity expansion model runs.

5.4.2 SERVM

Under a consulting agreement with Astrapé Consulting, PNM used the SERVM model to update reserve margin and reliability metrics from the loss of load probability analysis. SERVM is a combined resource adequacy and production cost simulation model. The Southern Company originally developed SERVM in the 1980s and has enhanced it several times over the ensuing decades. It has been used in studies that have been filed with state regulatory commissions in Mississippi, Florida, Georgia, Alabama, Kentucky, South Carolina, North Carolina, and California to support target reserve margins and other resource adequacy related planning decisions. In addition to its use in regulatory proceedings, SERVM is used by many other planning organizations to inform resource adequacy decisions.

SERVM has capability to perform reliability risk assessments. As recommended in the *NERC Generation and Transmission Reliability Planning Models Task Force Final Report on Methodology and Metrics*, resource adequacy assessments should adhere to minimum simulation requirements such as hourly chronological load modeling, accounting for load forecast uncertainty and random forced outages of generation capacity, and transmission modeling that recognizes major transmission constraints. SERVM fully meets all these requirements. While the above recommendations are for a specific nationwide resource adequacy assessment, the industry generally follows these recommendations. Most planning organizations in the United States use either SERVM or the GE MARS software for determining target reserve margin levels and resource adequacy planning needs and additional models to determine long-term expansion plans.

6 Loads & Resources

One of the first steps in developing our long-term plan is to compile a comprehensive set of assumptions to characterize our future loads, our existing resources, and our options for new resources. Each potential plan will balance a combination of existing and new resources to meet the obligations established by our load. This chapter summarizes our demand forecast, provides details on the characteristics of our existing resources, identifies the residual need for new resources to meet reliability needs, and introduces the menu of options considered as new resources.

Section Highlights

- PNM's weather-normalized peak demand, 1,929 MW in 2020, is expected to grow at a rate of 0.9% per year over the 20-year IRP analysis horizon; under alternative conditions, our growth rate could be as low as 0.2% per year or as high as 2.6% per year depending on broader economic and demographic trends and a variety of other factors.
- To meet these future needs, PNM will rely upon a combination of our existing resources, investments in new generation, and demand-side programs.
- PNM's existing portfolio of resources comprises a mix of nuclear, coal, natural gas, renewables, and demand-side resources. By the end of 2022, PNM will have abandoned our share of the San Juan Generating Station (SJGS) and plans to replace it with a combination of solar, storage, and demand-side resources.
- To meet growing future resource needs and achieve our long-term carbon goals, significant new investments in new generation will be required; options for new resources considered in the planning process include incremental energy efficiency and demand response, wind, solar, battery storage, pumped storage, and hydrogen-ready combustion turbines.

6.1 Load Forecast

The load forecast is a foundational part of the IRP. Higher or lower loads will impact the timing of generation additions and retirements, as well as the transmission and distribution infrastructure needed to carry electrons between generation and load. In determining the possible futures in which PNM may be operating, the load forecast is arguably the most critical contributor.

The load forecast and associated sensitivities are essential inputs to our resource planning efforts – especially in times of dramatically changing load possibilities. Historically, PNM's load over the past half century saw periods of such dramatic shifts. Load grew rapidly and steadily in the post-war period as U.S. demographics saw growth in Sunbelt regions like New Mexico. In addition, New Mexico experienced a huge investment in defense infrastructure with our national laboratories and military bases. This unprecedented increase in the need for electricity brought forth the construction of large baseload plants like FCPP, SJGS and PVNGS. Later, PNM in particular was affected by the rise and fall of uranium mining in New Mexico. The industry was PNM's largest customer group in terms of energy; either directly 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.

Today, we may be approaching another time of potential sea change in the demand for electricity. PNM has recently seen a large load increase with a single data center customer's move to the state. New Mexico appears to be a likely location for future development of other data centers and large industrial loads. Also, most policy prescriptions for dealing with greenhouse gas emissions now include electrification of the economy. The conversion of transportation, space heating and other energy uses to electricity would have great impacts on the demand for utility service.

We develop forecasts of load at the rate level. For residential, small power, and general power classes, we create forecasts of usage per customer and number of customers in the rate class. For large power customers, whose loads are large enough to merit individual review, we prepare individual forecasts.

Forecasted loads are based on historical load data, which are grossed up to exclude the impact of behind-the-meter generation and are then normalized by weather metrics from those historical periods. This data feeds into statistically adjusted end use models, which then predict future load levels based on forecast factors like economic growth, changes in end-use saturation and efficiency, and adoption of new technologies such as electric vehicles, rooftop PV, and heat pumps. As we explore the impacts of climate change in future analysis, this approach would allow us to incorporate climate change-adjusted weather years into the load forecast.

Key drivers of the forecasts include population, household size, non-manufacturing employment, and income per capita. Forecast customer-level load is also grossed up by loss factors over the distribution and transmission systems to arrive at retail load. The distinction between load at the customers delivery point or load at the point of generation allows the analysis to evaluate the value of resource location; whether demand-side or generation.

Our demand forecast also reflects the cumulative effect of prior years' energy efficiency programs. These programs and the reductions to our load are further discussed in Section 6.2.1 (Existing Demand-Side Resources). The potential impacts of future energy efficiency programs, including those required by the EUEA and additional programs, are modeled as explicit resources and are discussed in Section 6.4.1 (New Demand-side Resources). A more detailed discussion of the load forecasting methodology appears in Appendix C.

6.1.1 Load Forecast Components

Economic and Demographic Changes

Macroeconomic and demographic are a key driver of PNM's future load growth. Our demand forecasts are based on projections of three factors: (1) population growth in our 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, are used as inputs to statistical models that predict our future

Table 14. Economic & demographic assumptions used in IRP

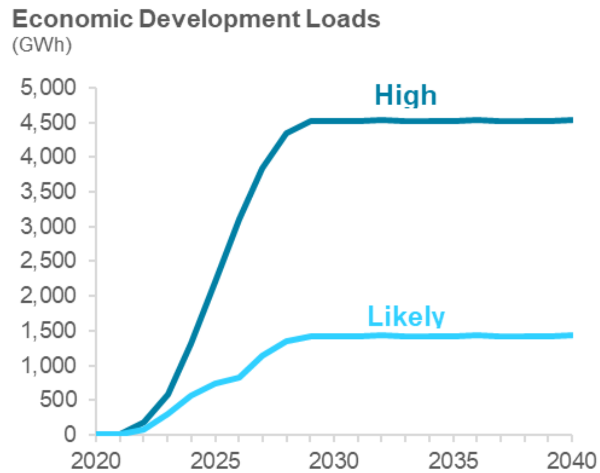
Input Data	Low	Mid	High
Population Growth *(# per year)*	4,800	9,800	15,800
Non-Manufacturing Employment Gains *(# per year)*	3,500	6,500	10,000
Real Per Capita Income Growth *(% per year)*	0.6%	1.0%	1.3%

load based on historically observed relationships. The assumptions for each of these parameters are shown in Table 14.

New Economic Development Loads

There is potential for a number of new large economic development projects to be built within PNM service territory. These loads are associated with industrial and data center customers that tend to have high load factors. We create two forecasts of energy and demand that can be added to the mid, low, or high load forecast to account for a range of possible impacts should some amount of new economic development load materialize. However, load forecasts used in this IRP assume no new economic development load unless otherwise specified.

Figure 36. New economic development loads considered in the IRP

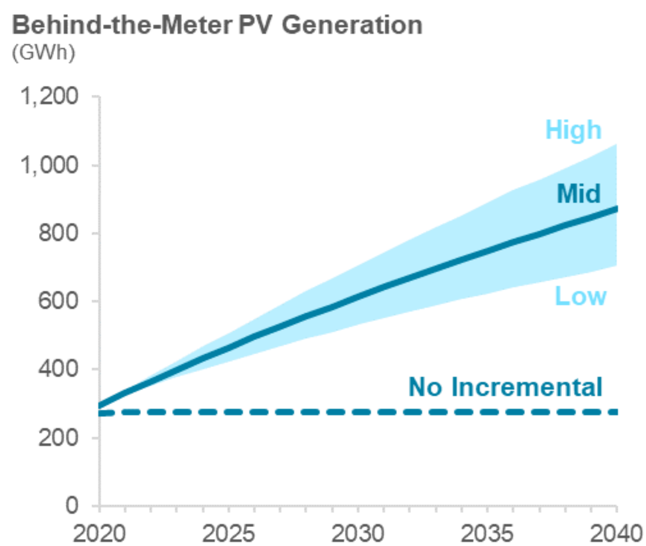


The first level uses a probability-weighted sum of potential new loads. Though the resulting load does not correspond to an actual set of discrete projects, we say that this demand represents the “likely economic development loads”. The second level of additional load, denoted “high economic development loads”, assumes that all potential economic development projects materialize. While unlikely, this presents a useful high bookend. Once fully realized in 2029, these loads add either 183 MW or 547 MW to peak demand and either 1,426 GWh or 4,521 GWh to annual load.

Behind-the-Meter PV

Our IRP analysis considers a range of future adoption of behind-the-meter PV, reflecting the continuation of a trend of our customers’ increasing interest in renewable energy. Our projections reflect a range that is generally consistent with levels of adoption that have been observed over the past several years and is shown in Figure 37.

Figure 37. Range of BTM solar PV generation studied in IRP

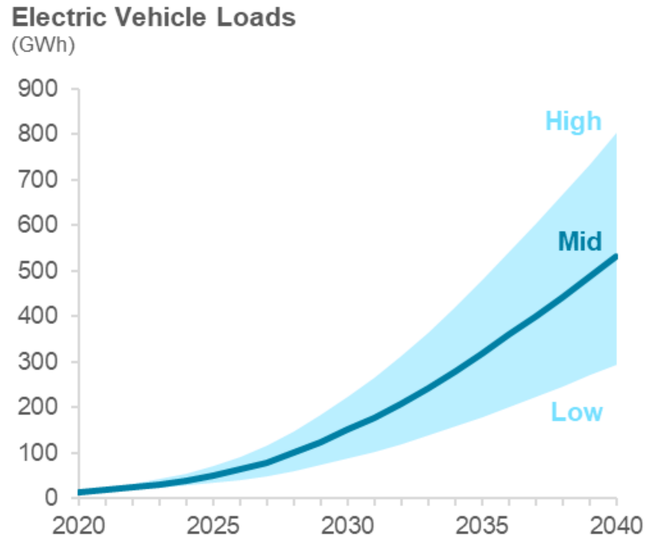


In addition to the range of scenarios reflecting continued growth of BTM solar PV, our analysis also considers (a) a scenario in which no incremental BTM solar PV is added beyond 2020, and (b) a counterfactual scenario in which no BTM solar PV exists on our system. These scenarios are not studied as plausible outcomes but instead provide us with useful information on the value that existing and future BTM solar PV resources provide to our system.

Electric Vehicle Adoption

Currently, demand from electric vehicles represents a small share of our annual retail loads (less than 1%); as of 2020, the number of electric vehicles in PNM's service territory is estimated at approximately 3,400. Looking forward, we expect this segment of our loads to begin to grow significantly with more widespread adoption of new electric vehicles. Our "Mid" electric vehicle adoption scenario assumes that by 2030, this figure will have increased by an order of magnitude to 37 thousand vehicles; by 2040, it will increase to 127 thousand. The implied increases in load in this "Mid" case, as well as in "High" and "Low" scenarios, are shown in Figure 38. Because of the projected acceleration of electric vehicle adoption over the forecast period, transportation electrification loads become an increasingly significant component of our future loads.

Figure 38. Range of electric vehicle loads considered in IRP



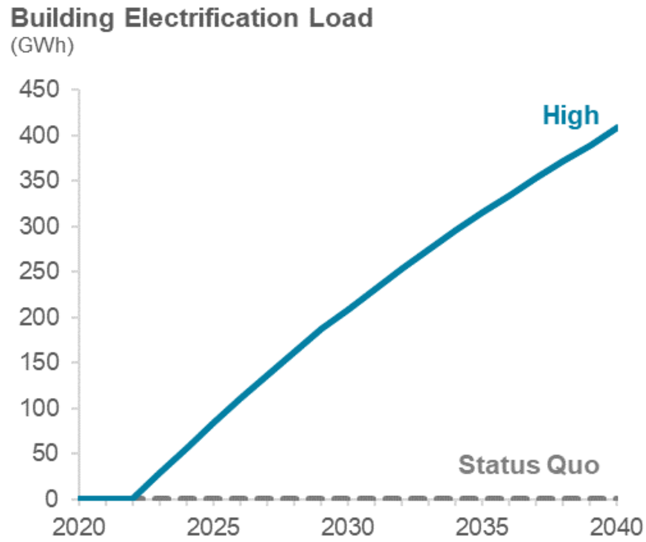
While the projections developed for this IRP are based on plausible ranges of market growth, state and national policy may also play a role in the rate of electric vehicle adoption. In studies of economy-wide decarbonization, transportation electrification has commonly been recognized as a significant potential source of carbon reductions. The state's plans to encourage decarbonization, as reflected in a recent report by the *New Mexico Interagency Task Force*[30], recognize the potential role of transportation electrification as a source of carbon mitigation as well as the need for continued policy and regulatory support. We will continue to monitor this landscape as it evolves and ensure our planning efforts remain aligned with the state's policy priorities.

[30] New Mexico Interagency Climate Change Task Force, *New Mexico Climate Strategy: 2020 Progress and Recommendations*, available at: https://www.climateaction.state.nm.us/documents/reports/NMClimateChangeReport_2020.pdf

Building Electrification

Another potential source of future load growth is the electrification of building end uses. This cycle, our IRP considers two levels of incremental building electrification: "Status Quo", which reflects historical trends; and "High," which assumes that beginning in 2023, new homes rely on electric space heating instead of natural gas and oil. The resulting impact on our loads is shown in Figure 39.

Figure 39. Range of building electrification loads studied in IRP



Like transportation electrification, building electrification has been identified in many studies as an effective strategy to support economy-wide carbon reductions. Thus, while the level of load impact considered in this IRP is relatively low, we will continue to explore opportunities to support the state's economy-wide decarbonization efforts.

6.1.2 Load Forecast Summary

Table 15 lists the four considered futures and the differentiating components that determine the load served by PNM in each future: load forecast, BTM PV adoption, EV adoption, and the BE forecast. We note that these futures do not aim to create the most extreme high and low load forecasts possible (i.e., there is no line with a high end use forecast, low BTM PV, high EVs, and high building electrification). Instead, the futures are crafted to be realistic combinations of economic and policy possibilities.

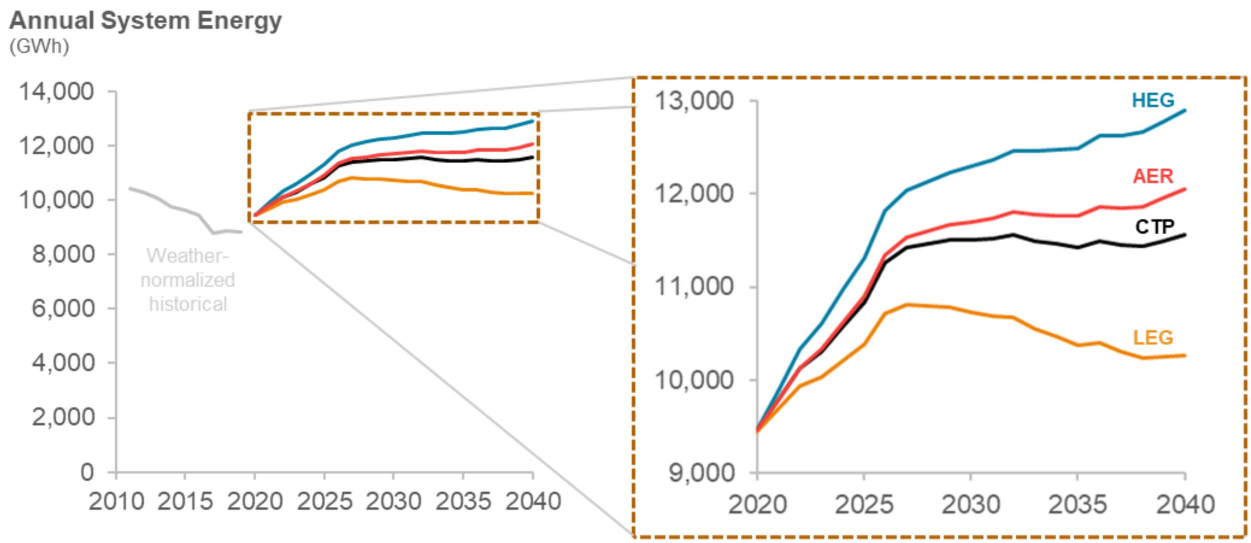
Table 15. Settings for load forecast components of futures analyzed

Future	Economic & Demographic Growth	BTM PV Forecast	EV Adoption Forecast	Building Electrification Forecast
Current Trends & Policy	Mid	Mid	Mid	Mid
High Economic Growth	**High**	**High**	**High**	Mid
Low Economic Growth	**Low**	**Low**	**Low**	Mid
Aggressive Environmental Regulation	Mid	**High**	**High**	**High**

High economic growth couples with higher end use loads and with increased disposable income. We assume that increases in disposable income increase discretionary spending by customers on items like solar cells and electric vehicles. This future can be pushed further by adding load from a new data center to ensure a high load bookend is analyzed. Similarly, low economic growth implies lower end use loads, less discretionary spending, and slower uptake of generation and electrification technology in homes. While the long-term impact of COVID-19 is yet unknown, we explain below that these impacts should be captured by the low economic growth future.

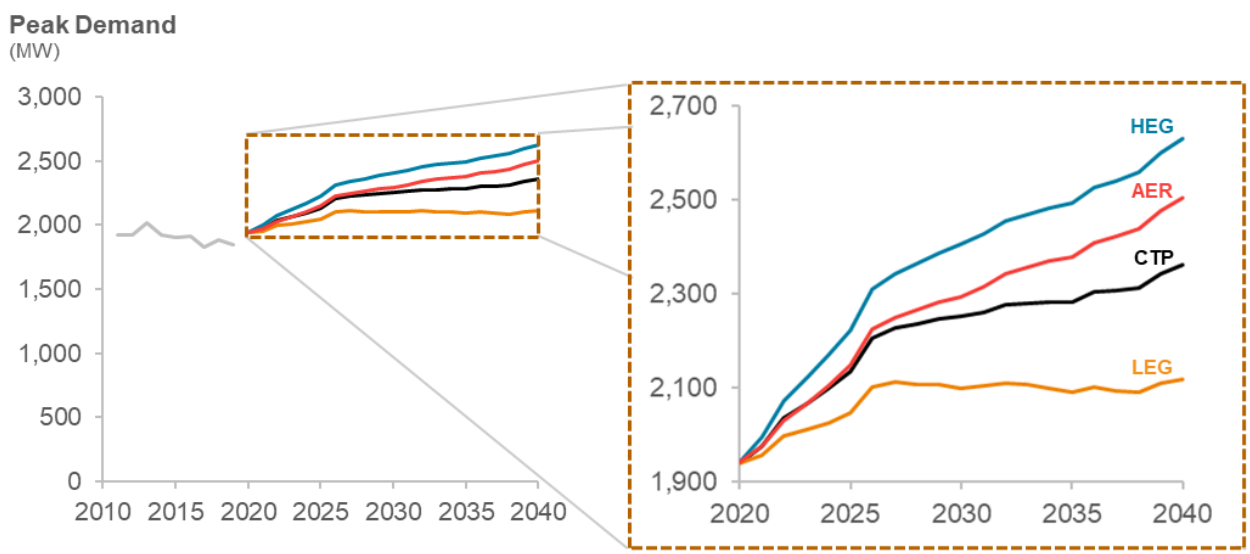
Given the statewide push for cleaner energy, we also consider a future in which policy exists to spur adoption of customer PV, EVs, and building electrification. The presence of such policy need not link to any economic outcome, and so mid-level end use customer loads are assumed in this future. Because the New Mexico heat pump market remains far from mature, we assume that only the presence of aggressive policy would promote high levels of building electrification. Accordingly, futures that focus on the economic state do not consider alternative building electrification trajectories. Figure 40 and Figure 41 display the annual system energy and peak demand for each of the futures from Table 15.

Figure 40. Forecasts of annual energy demand under different futures



CTP = Current Trends & Policy; AER = Aggressive Environmental Regulation; HEG = High Economic Growth; LEG = Low Economic Growth

Figure 41. Forecasts of peak demand under different futures



CTP = Current Trends & Policy; AER = Aggressive Environmental Regulation; HEG = High Economic Growth; LEG = Low Economic Growth

Impacts of the COVID-19 Pandemic

Based on a small amount of billing data since the start of the COVID-19 pandemic hit New Mexico, we have observed some usage changes. In April and May of 2020, residential sales averaged about 7% above historically based expectations. In concert, commercial sales decreased by 10% and 20% respectively in the two months. Sales from the LS15 rate class dropped over 50% in May, but other industrial sales were not impacted strongly.

During the pandemic, the traditional connections between usage and the economy have not held. Although employment and incomes have dropped, residential use per customer is up due to stay-at-home policies. Employment has dropped significantly, but the number of commercial customer accounts have not yet declined. Non-residential sales have declined due to stay-at-home policies, but this trend is reversing as the state reopens. In the near term, these impacts can be tracked, but cannot be predicted with great confidence.

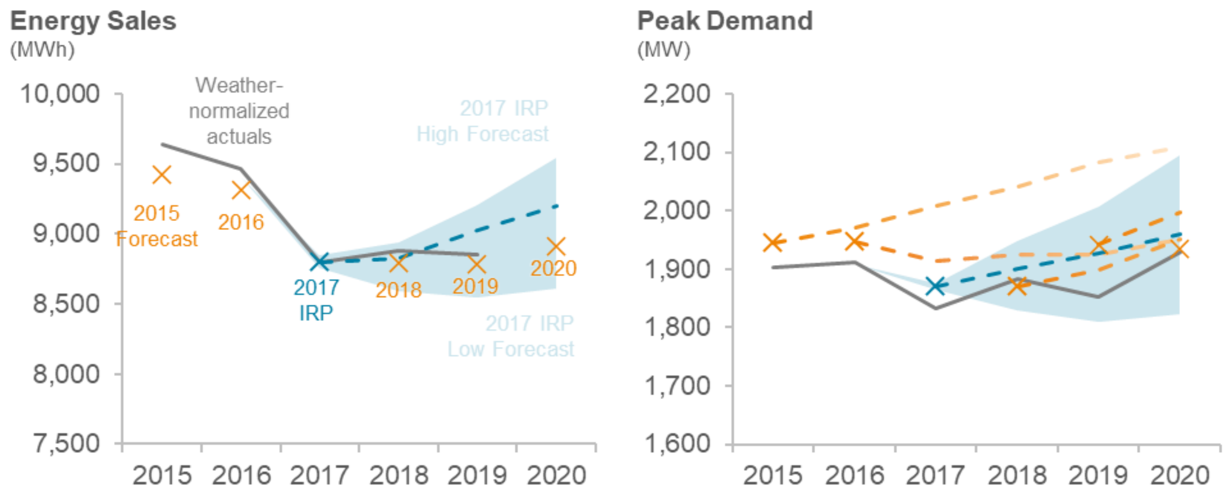
In the longer term, there is not yet strong evidence to suggest that usage will look markedly different from the pre-COVID world. This remains the case so long as the outlook for the key drivers of sales per customer (efficiency, solar generation, and electric vehicles) have not been altered. If customer growth continues its course, and use per customer returns to previous patterns, there should be no reason to adjust a long-term load forecast for the pandemic. Still, the negative effect of COVID-19 on the economy may turn out to be a long-term impact – we believe that this possibility is captured by the low economic growth future.

Historical Forecast Accuracy

We have reason to believe the actual load will fall within the range defined by these forecasts. Our past forecasts, shown in Figure 42 alongside the weather-normalized actual load, have done well to predict system load growth. At the start of each year, we prepare an energy sales forecast for that single year and a peak demand forecast for the next 10 years – these points are shown by the orange X-marks and lines in the figure. For the 2017 IRP, the forecast process was more thorough, including a multi-year forecast with high and low bounds – these are shown by the blue line and shaded regions.

It is worth noting that the scale of the vertical axes in Figure 42 has been selected to emphasize differences between forecasts and actuals. No single year energy forecast has an error greater than 2%, and the difference between the 2015 forecast of 2020 peak demand and actual 2020 peak demand is only 9%. The discrepancies that do exist owe to a variety factors: New Mexico’s slow economic recovery in the wake of recessions, loss of co-op loads, fast uptake of efficiency measures, and cuts by large companies including defense labs and bases.

Figure 42. Historical energy and demand forecasts



6.1.3 Load Forecast Sensitivities

Along with the futures listed by Table 15, additional load forecasts are prepared to conduct sensitivity analysis. These forecasts are not intended to represent realistic projections of overall load outcomes, but instead exist so that the impact of individual forecast elements on analysis results can be understood. The load forecasts prepared specifically for sensitivities appear in Table 16.

Table 16. Settings for load forecast components for sensitivity analysis

Sensitivity	Economic & Demographic Growth	TOD Pricing	BTM PV Forecast	EV Adoption Forecast	Building Electrification Forecast
High Load Growth	**High**	Status Quo	Mid	Mid	Status Quo
Low Load Growth	**Low**	Status Quo	Mid	Mid	Status Quo
High BTM PV	Mid	Status Quo	**High**	Mid	Status Quo
Low BTM PV	Mid	Status Quo	**Low**	Mid	Status Quo
No New BTM PV	Mid	Status Quo	**Zero Inc.**	Mid	Status Quo
High EV Adoption	Mid	Status Quo	Mid	**High**	Status Quo
Low EV Adoption	Mid	Status Quo	Mid	**Low**	Status Quo
High Building Elec	Mid	Status Quo	Mid	Mid	**High**
TOD Pricing	Mid	**Widespread**	Mid	Mid	Mid

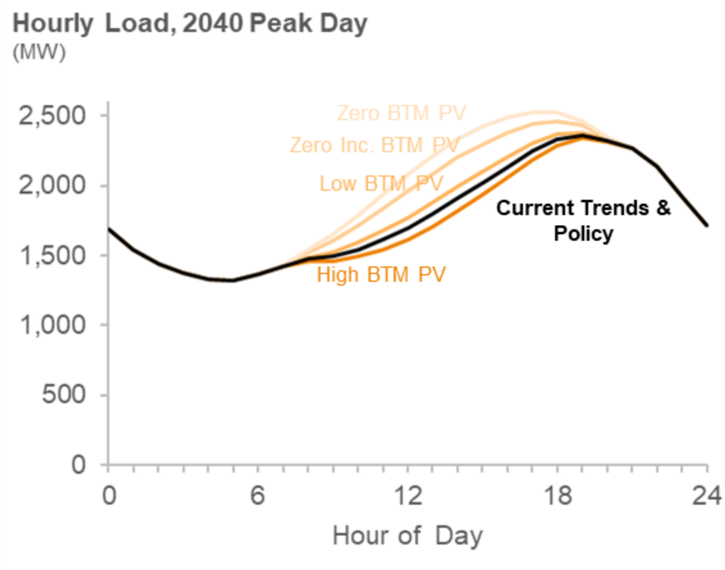
Sensitivities upon our load forecast help inform our future plan in several important ways. First, sensitivity analysis on load helps us understand how robust our plan is in spite of the significant uncertainties that will affect our future loads (e.g. levels of economic growth. Second, sensitivity analysis on our loads can help inform our actions and strategies in areas where we can work with our customers to control loads (e.g. TOD pricing and other rate design considerations).

Brief discussions of the impact of each of these sensitivities upon our demand follow; additional detail showing the impact of each sensitivity on our demand is provided in Appendix C.

Behind-the-Meter PV Sensitivities

Sensitivities on BTM PV adoption reflect a plausible range of outcomes given increasing consumer preferences for customer-owned solar PV. BTM PV sensitivities range from eliminating BTM PV entirely, to a high forecast in which PV production peaks at 541 MW in 2040. We note that while BTM PV additions initially decrease and shift the peak, this impact is muted at any levels of penetration above that of the low BTM PV forecast. This declining impact is expected and aligns with the declining impact of supply-side solar described in Section 6.4.2 (New Supply-side Resources). In 2019, PNM's solar distributed generation programs produced 225,572 MWh of energy with 129 MW of installed capacity. These are customer-sited solar systems; usually rooftop, but some customers have larger systems sometimes ground-mounted.

Figure 43. Impacts of behind-the-meter solar PV sensitivities on load shape and peak demand



Impact on Peak Demand (MW)

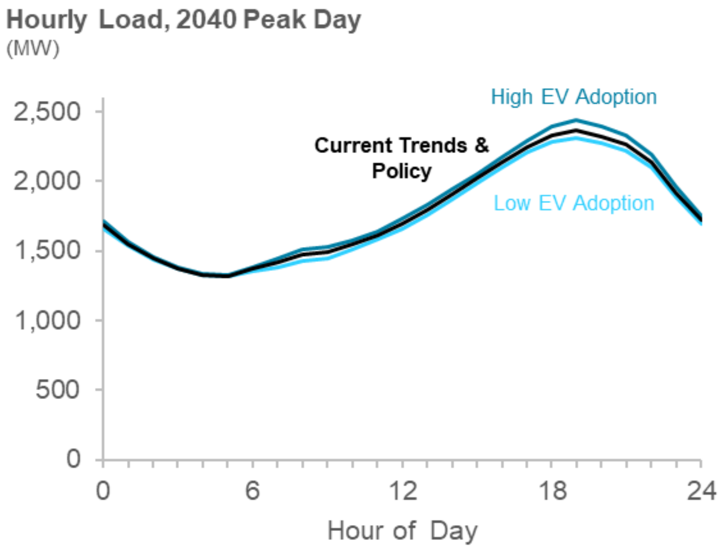
Sensitivity	2025	2040
Zero BTM PV	+148	+165
Zero Inc BTM PV	+60	+101
Low BTM PV	+11	+20
High BTM PV	-10	-22

Relative to Current Trends & Policy

Electric Vehicle Sensitivities

Electrification of transportation represents a potential source of load growth – especially in the long term as the state pursues decarbonization goals. Today, EV adoption and charging behaviors are mostly driven by customer preferences. Our sensitivity analysis considers a range of potential impacts shown in Figure 44.

Figure 44. Impacts of electric vehicle adoption sensitivities on load shape and peak demand



Impact on Peak Demand (MW)

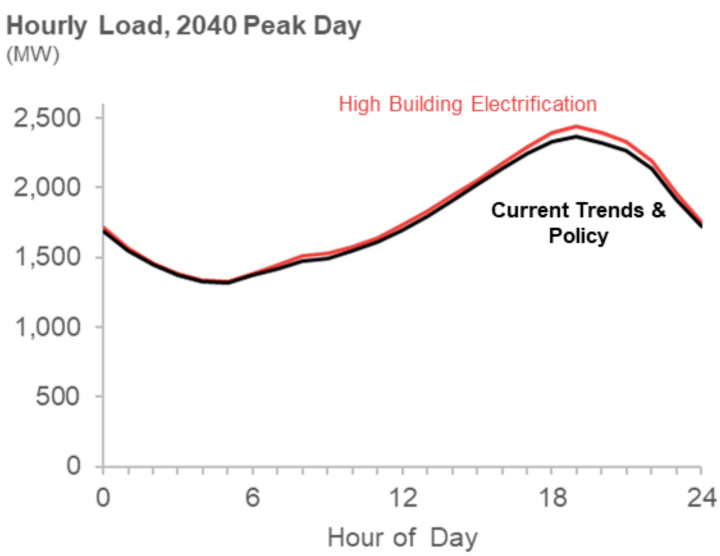
Sensitivity	2025	2040
High EV Adoption	+5	+75
Low EV Adoption	-4	-55

Relative to Current Trends & Policy

Building Electrification Sensitivities

In Figure 45 we show the impacts of the High Building Electrification sensitivity. Building electrification increases electrical load during heating hours but results in overall energy and carbon savings across the economy due to reduced consumption of heating fuels. During cooling hours, the impact on load is a balance between increases from more buildings having cooling capabilities and decreases from the efficiency improvement of heat pumps over other cooling technologies. The shown 2040 summer peak impact of 4% is less than the winter peak impact of 15%, but the summer peak remains about 400 MW larger than the winter peak.

Figure 45. Impacts of building electrification sensitivities on load shape and peak demand



Impact on Peak Demand (MW)

Sensitivity	2025	2040
High BE	+17	+90

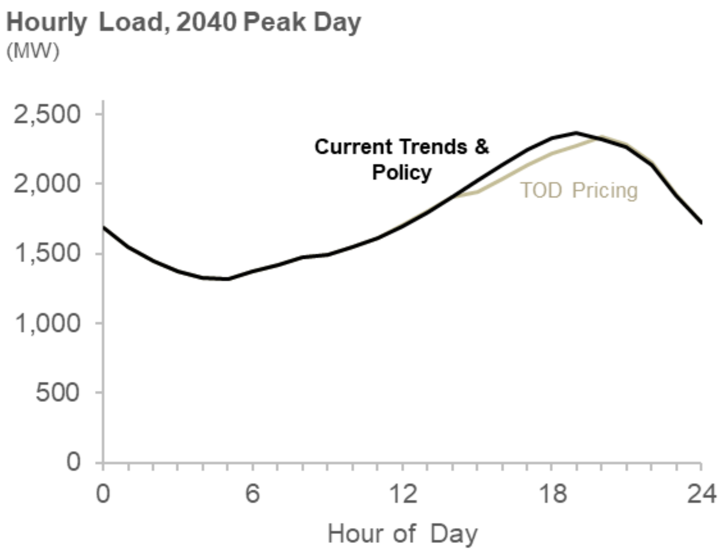
Relative to Current Trends & Policy

TOD Pricing Sensitivity

As discussed in Section 2.4 (Rates and Tariffs), we are currently considering expansion of TOD pricing to new customer classes in the future. By better aligning our customers' retail costs with our own underlying cost of supply, TOD pricing can enable reductions in consumption during the peak period and reduce our need for investments in new infrastructure for resource adequacy. To characterize the potential benefits of the implementation of TOD pricing, we examine a sensitivity that captures the expected effect of TOD pricing on our load shape.

Our sensitivity analysis is based on a TOD pricing scheme in which the highest cost hours occur during a six-hour block in the summer afternoon and early evening, which we expect to align with periods of most constrained supply in the near term. The impact that this has upon our peak day load shape is illustrated in Figure 46. The impact that this TOD pricing has upon our peak demand will vary by year due to growth and changes in the shape of our retail load; by 2025, we estimate that TOD pricing could reduce peak demand by up to 87 MW.

Figure 46. Impacts of TOD pricing sensitivities on load shape and peak demand



Impact on Peak Demand (MW)

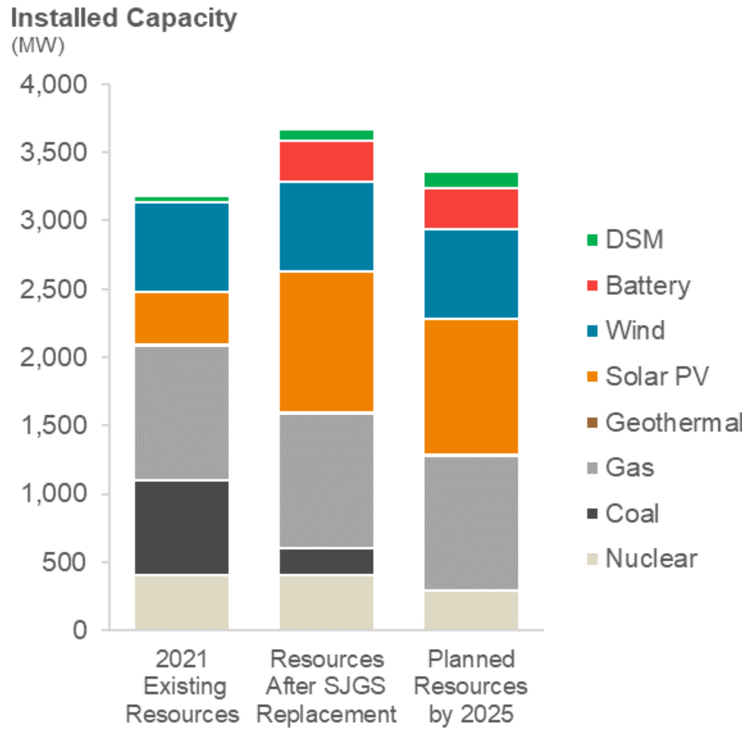
Sensitivity	2025	2040
TOD Pricing	-87	-26

Relative to Current Trends & Policy

In the long term, it may be prudent to further adjust TOD periods to maintain alignment with the underlying cost of supply. For simplicity, we do not alter the peak period during the course of this analysis, but we recognize that getting the most out of a TOD pricing program will require continuous reevaluation of the peak period definition and how it aligns with customer net loads.

6.2 Existing Resources

Figure 47. Installed capacity of existing resources in PNM portfolio



Includes SJGS replacement resources & future energy efficiency required by EUEA; does not include impacts of past EE programs embedded in load

Today, our supply portfolio today includes a diverse mix of nuclear, coal, natural gas, solar, and wind generation resources. In the next two years, our existing resource portfolio will undergo significant changes with the abandonment of SJGS and the addition of replacement resources. In order to replace the 497 MW of capacity currently provided by SJGS, we expect to add a portfolio of resources that includes 650 MW of new solar PV, 300 MW of co-located energy storage, and the 24 MW of previously mentioned demand response. This portfolio of replacement resources was approved by the Commission in 19-00195-UT. In the years beyond, our portfolio will continue to evolve. Figure 47 shows the composition of our existing resource portfolio at three key points in time: (1) today, (2) at the end of 2022, after the replacement of SJGS, and (3) in 2025, after our exits from our PVNGS leases and our minority ownership share of FCPP.

6.2.1 Existing Demand-Side Resources

As defined by the IRP Rule, demand-side resources consist of two types: energy efficiency and load management. Energy efficiency refers to reductions in energy use by customers that have a benefit/cost ratio greater than one from the overall utility system viewpoint. Load management programs, such as demand response, reduce customer demand at times of peak load or during generation supply shortages. This section describes the impact of existing and planned energy efficiency and demand response programs on the load forecast. We also describe historical program performance and program descriptions as a response to the requirements of the IRP Rule Section 17.7.3.9(C)(9).

PNM’s existing resource portfolio includes EE and DR programs approved by the Commission pursuant to the Efficient Use of Energy Act (EUEA). These programs were determined to pass the utility cost test, which compares program costs to benefits. Benefits include avoided generation costs (e.g. fuel and emissions) along with avoided or delayed cost of capacity additions.

Amendments to the EUEA in 2013 require utilities to invest 3% of retail sales revenues in energy efficiency and load management programs. Between 2015 and 2019, our annual budgets for efficiency and demand response were between $24 and $26 million per year. Of this total, we spend a minimum of 5% of total program budget on programs targeting low income customers (historically, an average of 8% of spending has been on low income programs). These requirements provide consistency in the level of spending that can be expected over time.

Energy Efficiency

We promote energy efficiency programs and efficient energy-use incentives through bill inserts, direct mail advertising, radio, television, print advertising, and community education programs. The PNM website also provides information on these programs.

Our energy efficiency programs including the following incentives:

- Instant rebates for the purchase of light emitting diode (LED) bulbs;
- Rebates for recycling older refrigerators;
- Residential incentives for efficient lighting, 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 saving kits provided to fifth-grade and high school students along with an inter-active instructional presentation on energy efficiency; and
- Incentives that specifically target energy efficiency improvements for lower-income customers.

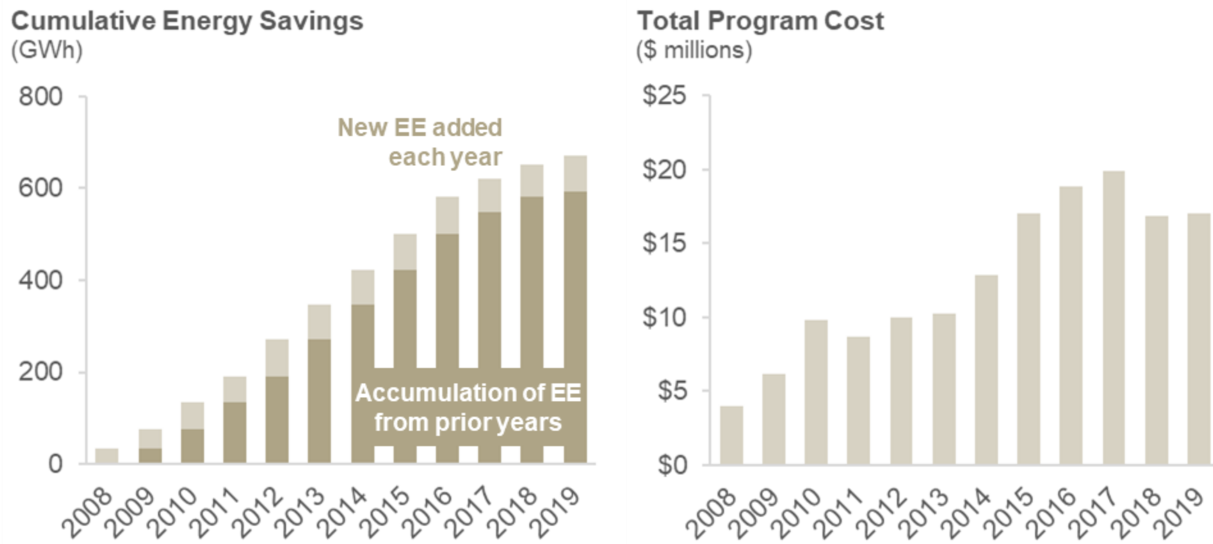
Once approved by the Commission, energy efficiency programs remain in effect until modified or canceled by the Commission. Descriptions of the specific programs offered appear in Appendix L.

Every year, we review the demand and energy savings from the energy efficiency programs using the results from an annual independent third-party measurement and verification process. The process is conducted by a Commission selected independent evaluator and reports metrics including quantified customer adoption rates as well as energy savings for energy efficiency and demand response programs.

Annual incremental energy savings from PNM energy efficiency have been consistently between 70 GWh and 80 GWh since 2012, with the exception of 2016 when savings were calculated to be 82 GWh. Figure 48 shows the annual energy savings in each year atop the growing base of ongoing savings from programs in previous years.[31] This cumulative view shows that we exceeded the 2014 cumulative goal of 411 GWh (5% of 2005 retail sales) by achieving cumulative savings of 421 GWh. Similarly, we expect to meet this goal of 658 GWh (8% of 2005 retail sales) in 2020 as well. The figure also shows the annual program cost for the efficiency measures added in each year. Year-to-year relationships between cost and achievement vary based on factors including date of implementation, customer participation, verified savings, and marketing efforts.

[31] To account for the finite life of energy efficiency measures, we only include savings in the cumulative total for the portfolio's "effective useful life." Cumulative savings in 2019 reflect savings from 2011-2019 but do not account for savings from 2010 or prior.

Figure 48. Savings and costs provided by historical energy efficiency programs



The effects of these historical programs are captured directly in our load forecast. In forecasting load, we assume that programs will be replaced as they expire, so that demand and energy savings continue throughout the plan period.

Looking forward, our energy efficiency programs will continue to meet the requirements of the EUEA. In April 2020, we submitted our 2021 Energy Efficiency and Load Management Plan to the Commission for approval, which establishes funding for our efficiency programs through 2023. Our analysis considers the resource approved in this plan, as well as the EUEA resources needed to meet goals in 2024 and 2025, as part of our existing portfolio.

In addition to the minimum requirements for efficiency set forth by the EUEA, our analysis considers additional energy efficiency measures as a new resource option. The characterization of these additional bundles is discussed in Section 6.4.1 (New Demand-side Resources).

Demand Response

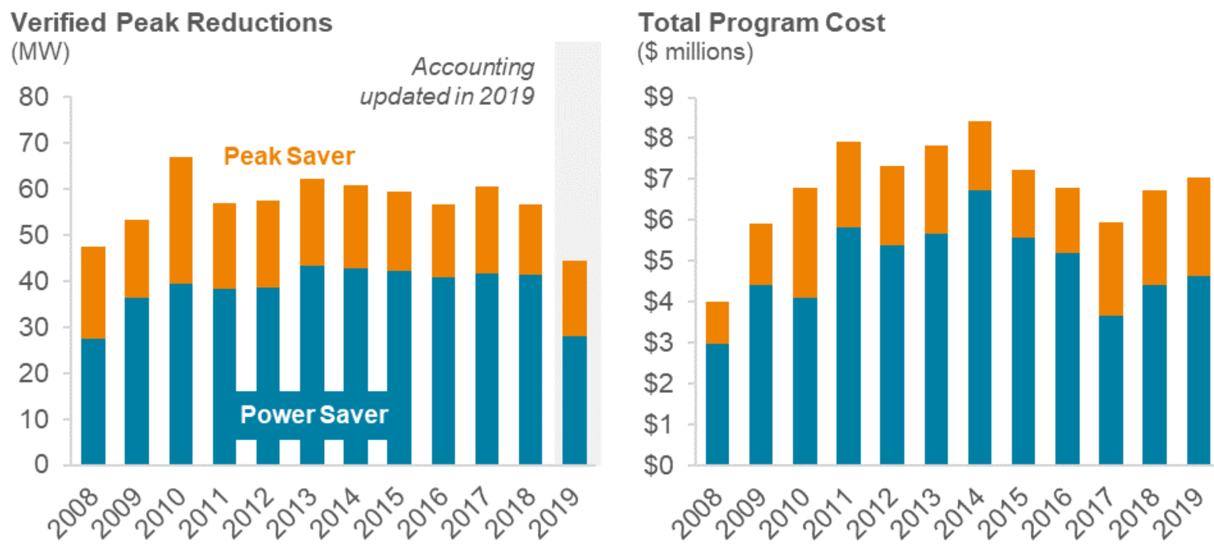
Demand response programs reduce customer demand at times of peak load or during generation supply shortages. PNM customers can volunteer to have portions of their load curtailed through the Power Saver and Peak Saver programs:

- The **Peak Saver** load management program is designed to help medium and large commercial customers with demand greater than 50 kW reduce the amount of energy they require during peak demand periods.
- The **Power Saver** load management program controls refrigerated air conditioning units in participating homes and small businesses during periods of peak demand.

These programs were approved by the Commission in Case No. 07-00053-UT and reauthorized in Case No. 16-00096-UT. PNM selected the demand response program contractors through a competitive bid process. Each program operates from June to September to help PNM manage peak summer loads. Participants may be curtailed up to 100 hours with a maximum duration of four hours. Customers receive a minimum 10-minute notice for each curtailment event (though notice is typically provided farther in advance), and these curtailment events cannot be called on weekend days or on the first weekday following a holiday weekend. These rules allow for 25 or more calls per year, but the actual number of calls in a year has typically been between five and fifteen.

The top panel of Figure 49 shows the peak reductions achieved through the Peak Saver and Power Saver programs. Prior to 2019, we determined the peak demand savings from Power Saver program participants with a statistical sampling method that derived kW savings per installed unit. However, more robust counting employed in 2019 and beyond indicates that this method overstated the savings from the nearly 48,000 participants, as indicated by the decrease of the blue bar size in the final year of the figure. Peak savings from the approximately 90 Peak Saver participants is available through hourly meter data. Should we deploy smart meters in the future, peak savings from residential customers would be easier to measure, which would give planners more confidence that those reductions are available when needed.

Figure 49. Peak reductions from DR and EE programs and total program costs[32]



The demand response programs are governed by 5-year contracts that expire in 2023. At that time, we have the option to renew for another 5-year term. Our current directives from the Commission include a comprehensive evaluation of these programs.

In addition to the Peak Saver and Power Saver programs, an additional 24 MW of demand response was approved by the Commission in Case No. 19-00195-UT as part of our replacement resource portfolio for SJGS. For the purposes of our IRP analysis, we consider this additional demand response capacity part of our existing portfolio. However, at the time of this IRP, the contract for the resource to fulfill this need is under review by the Commission in Case No. 20-00182-UT.

6.2.2 Existing Supply-Side Resources

PNM's supply portfolio consists of diverse generating resources that are owned by PNM or that generate power purchased by PNM through a PPA. PNM constructs or contracts supply resources to serve customer loads, to replace expiring contracts or retiring facilities, and to meet

[32] Allocation of reductions to Peak Saver and Power Saver in 2011 is estimated based on 2012 ratio

public policy requirements such as the RPS. Appendix H includes cost and performance data for PNM's existing resources.

The IRP Rule Section 17.7.3.9 (C) (1-3, 5-7) requires a description of the resources used by the utility to meet jurisdictional retail load at the time of filing. Table 17 provides this information for PNM-owned and contracted supply-side resources.

The capacity listed in the tables is expected to be fully available to meet PNM's system load and reserve margin requirements after the identified in-service date. For renewable and storage resources, each resource's contribution to peak is measured using ELCC, which allows us to capture the dependable amount of capacity they provide towards our resource adequacy needs, and these peak contribution capacity values are used for reserve margin planning.

The amount of generation capacity from existing resources can change over time because of events such as the expiration of leases and PPAs. PNM's resource plan accounts for such developments and assumes that the resource will either be extended or replaced with a new resource through an RFP and competitive bid process.

Table 17. Existing & pending supply side resources owned by and under contract to PNM

Facility		Location	Ownership	In-Service Date	Retirement/ Expiration Date	Total Summer Net Dependable Capacity (MW)	PNM Summer Net Dependable Capacity (MW)	PNM Share (%)	Duty Cycle
Nuclear									
Palo Verde Generating Station	Unit 1	Wintersburg, AZ	Owned	1986	2045	1,311	30	10.2%	Baseload
			Leased		2023		104		
	Unit 2		Owned	1986	2046	1,314	124		
			Leased		2024		10		
	Unit 3		Owned	1988	2046	1,312	134		
Coal									
San Juan Generating Station	Unit 1	Waterflow, NM	Owned	1976	2022	340	170	50%	Baseload
	Unit 4			1982		507	327	64%	
Four Corners Power Plant	Unit 4	Fruitland, NM	Owned	1969	2025	770	100	13%	Baseload
	Unit 5			1970		770	100		
Natural Gas									
Afton Generating Station		La Mesa, NM	Owned	2007	2039	235	235	100%	Intermediate
La Luz Gas Turbine		Belen, NM	Owned	2015	2055	41	41	100%	Peaking
Lordsburg Generating Station	Unit 1	Lordsburg, NM	Owned	2002	2042	43	43	100%	Peaking
	Unit 2					43	43		
Luna Energy Facility		Deming, NM	Owned	2006	2039	570	190	33%	Intermediate
Reeves Generating Station	Unit 1	Albuquerque, NM	Owned	1960	2030	42	42	100%	Peaking
	Unit 2			1959		41	41		
	Unit 3			1962		63	63		
Rio Bravo (Delta) GT		Albuquerque, NM	Owned	2000	2039	141	141	100%	Peaking
Valencia Energy Facility		Belen, NM	PPA	2008	2028	149	149	100%	Peaking
Geothermal									
Dale Burgett		Animas, NM	PPA	2014	2043	11	11	100%	Baseload
Wind									
Casa Mesa Wind			PPA	2018	2043	50	50	100%	Intermittent
NM Wind Energy Center		House, NM	PPA	2018	2028	200	200	100%	Intermittent
La Joya	1	Torrance, NM	PPA	2020	2040	165	165	100%	Intermittent
	2		PPA	2020	2040	140	140	100%	Intermittent
Red Mesa Wind		Cibola County, NM	PPA	2010	2046	102	102	100%	Intermittent
Solar									
Existing Solar Resources (Total)*		Various	Owned/PPA	Various	Various	385	385	100%	Intermittent
Arroyo Solar**		McKinley, NM	PPA	2022	2042	300	300	100%	Intermittent
Jicarilla 1 Solar**		Rio Arriba, NM	PPA	2021	2042	50	50	100%	Intermittent
Rockmont Solar**		San Juan, NM	PPA	2022	2042	100	100	100%	Intermittent
San Juan Solar**		San Juan, NM	PPA	2022	2042	200	200	100%	Intermittent
Storage									
Arroyo Storage**		McKinley, NM	ESA	2022	2040	150	150	100%	Storage
Jicarilla 1 Storage**		Rio Arriba, NM	ESA	2022	2042	20	20	100%	Storage
Rockmont Storage**		San Juan, NM	ESA	2022	2042	30	30	100%	Storage
San Juan Storage**		San Juan, NM	ESA	2022	2042	100	100	100%	Storage

* A full list of PNM's existing solar facilities is provided in Appendix H; this entry is inclusive of facilities expected to come online in 2021

** Indicates resources with a CCN approved by the Commission as replacement resources for SJGS

Nuclear Generation

Palo Verde Nuclear Generating Station (PVNGS)

PVNGS is a three-unit nuclear power plant located west of Phoenix in Wintersburg, Arizona, that went into service between 1986 and 1988 and is operated by APS. The plant is jointly owned by a number of western utilities, whose shares are reported in Table 18. Under its current licenses, granted by the Nuclear Regulatory Commission in 2011, the units will remain in operation through 2045 (Unit 1), 2046 (Unit 2) and 2047 (Unit 3).

Table 18. Current PVNGS capacity rights by unit*

Owner	Unit 1 (MW)	Unit 2 (MW)	Unit 3 (MW)	Percentage
Arizona Public Service	382	382	382	29.1%
Salt River Project	229	230	230	17.5%
El Paso Electric	207	208	207	15.8%
Southern California Edison	207	208	207	15.8%
PNM (Owned)	**30**	**124**	**134**	**7.6%**
PNM (Leased)	**104**	**10**	**-**	**2.6%**
SCPPA (SoCal Public Power)	77	78	77	5.9%
LADWP (Los Angeles)	75	75	75	5.7%
Total	**1,311**	**1,314**	**1,312**	**100.0%**

** Capacities listed correspond to net dependable summer capacity*

PNM's current capacity rights total 10.2% of the rated output of each of the three units. Our current capacity rights originated as follows:

- In 1985 and 1986, PNM undertook sale/leaseback financing of Unit 1 (134 MW) and Unit 2 (134 MW) holdings. These units were placed in service during 1986. Since then, PNM has reacquired ownership rights to 154 MW of this lease-financed capacity (30 MW in Unit 1 and 124 MW in Unit 2).

- The remaining leases for PVNGS Unit 1 (104 MW) and Unit 2 (10 MW) originally had terms that expired in 2015 and 2016. PNM exercised options to extend the leases for Units 1 and 2 to January 15, 2023 and January 15, 2024, respectively.

- PNM owns the full 134-MW share of PVNGS Unit 3, with no lease provisions. In Case 13-00390-UT, the Commission granted PNM a Certificate of Convenience and Necessity (CCN) to provide that resource as a supply resource to serve New Mexico retail customers. We anticipate this capacity will be available to meet jurisdictional customer demand into 2047.

To deliver electricity from PVNGS to retail loads in New Mexico, we rely on jointly owned transmission facilities and contracted transmission rights. The fuel supply for PVNGS is procured by APS under multiple agreements for uranium concentrate, conversion, enrichment, and fuel assembly fabrication. Suppliers are selected through a competitive bid process. These contracts are with five separate suppliers to ensure diversity of sources and to mitigate supply reliability risks. Our transmission rights and long-term fuel contracts are expected to extend throughout the planning period.

Under the leases, PNM has an option to purchase the capacity at fair market value upon the expiration of the leases. In June 2020, we announced our plan not to purchase our leased interests in PVNGS Units 1 and 2. This determination was made on the basis of a comparison of the going-forward costs and risks of the leases and potential alternative resource options. In early 2021, we plan to submit a filing to the Commission seeking approval of our decision not to exercise the purchase option as well as of a portfolio of replacement resources identified through competitive solicitation. In this filing, we will show how a scenario without the purchase of the lease interests (“PVNGS Leases Expired”) produces more favorable cost outcomes for our customers when compared with a scenario in which the capacity is purchased (“PVNGS Leases Retained”). This analysis is performed using the same methods and underlying assumptions as those used to develop this IRP.

This IRP’s forward-looking plan reflects our decision not to purchase the remaining leased capacity. Accordingly, in this analysis, our capacity rights to the PVNGS plant decrease from 402 MW today to 288 MW by the end of 2024.

Coal Generation

San Juan Generating Station (SJGS)

The SJGS is a coal-fired plant that consists of four units. Located in Waterflow, New Mexico, SJGS is about 18 miles west of Farmington, New Mexico. The SJGS units were constructed under the following timeframes: Unit 1 in 1976, Unit 2 in 1973, Unit 3 in 1979, and Unit 4 in 1982. Units 2 and 3 were retired at the end of 2017. In 2020, the Commission approved PNM’s application to abandon its ownership share of SJGS Units 1 and 4 in 2022; after this point, SJGS is no longer included in our portfolio.

PNM is currently the plant majority owner and is the plant operator. Table 19 shows the current ownership shares by generating unit. The coal needed to fuel SJGS is purchased from an adjacent underground coal mine owned by the Westmoreland Coal Company under a contract that runs through June 30, 2022. Currently, PNM’s share of Unit 4 represents the largest single resource (327 MW) in PNM’s balancing area. This unit, including the additional 65 MW of merchant capacity it serves, represents the single largest contingency on our system when in operation.

Table 19. 2020 SJGS Ownership by Unit*

Owner	Unit 1 (MW)	Unit 4 (MW)	Total (MW)	Percentage
PNM	**170**	**327**	**497**	**58.7%**
Tucson Electric Power	170	-	170	20.1%
City of Farmington	-	43	43	5.1%
Los Alamos County	-	37	37	4.3%
UAMPS	-	36	36	4.2%
PNM Merchant	-	65	65	7.7%
Total	**340**	**507**	**847**	**100.0%**

** Capacities listed correspond to net dependable summer capacity*

Four Corners Power Plant (FCPP)

The FCPP in Fruitland, New Mexico, consists of two coal-fired units (Units 4 and 5) that are operated by Arizona Public Service Company (APS). FCPP is located on Navajo Nation reservation land. The two units are supplied with coal from the Navajo Mine adjacent to the plant under a long-term fuel supply agreement with the NTEC that expires in 2031. PNM’s 13% share of these units, which it acquired in 1969 and 1970, respectively, amounts to a total of 200 MW of baseload capacity. PNM relies upon the transmission system to deliver this power into the northern New Mexico system to deliver to New Mexico loads. Table 20 shows the ownership by generating unit at the FCPP.

Table 20. Current FCPP ownership shares*

Owner	Unit 4 (MW)	Unit 5 (MW)	Total (MW)	Percentage
Arizona Public Service	485	485	970	63%
PNM**	**100**	**100**	**200**	**13%**
Salt River Project	77	77	154	10%
Tucson Electric Power	54	54	108	7%
Navajo Transitional Energy Company	54	54	108	7%
Total	**770**	**770**	**1,540**	**100%**

** Capacities listed correspond to net dependable summer capacity*

*** PNM is currently seeking Commission approval to transfer its 13% share to NTEC at the end of 2024*

On November 2, 2020, we announced a plan to transfer ownership of PNM's share of FCPP to the NTEC. We filed for approval of this transaction with the Commission on January 8, 2021. In that filing, we demonstrated that this transaction is in the economic interests of our customers and helps to accelerate our transition toward a lower carbon emissions portfolio – the latter by both eliminating the most carbon-intensive resource in our portfolio and prompting the need for procurement of new resources largely composed of carbon emissions-free generation.

To support our filing for abandonment of our share of FCPP, we analyzed two alternative scenarios: one that retains FCPP in our portfolio through the end of its contract term in 2031 and a second in which we assume the transfer of the plant to the NTEC at the end of 2024. Both scenarios adhere to the requisite environmental and reliability criteria of our planning processes. Our analysis across a broad range of sensitivities indicates that transferring our ownership share to NTEC at the end of 2024 will save customers a net present value of between $30 and $300 million dollars. Building upon the results of this filing, our IRP scenario analysis assumes our ownership share of FCPP is transferred to NTEC at the end of 2024, resulting in a coal-free generation portfolio beginning in 2025.

Natural Gas Generation

Our portfolio of natural gas generators includes six utility-owned units and one under long-term contract. These gas generators are generally located in two parts of the state: in the south along the El Paso Natural Gas southern mainline, which provides direct access to the low-cost gas supplies of the Permian Basin; and close to our largest load center in Albuquerque, where they provide crucial reliability support services to allow us to meet loads in a constrained load pocket.

We assess natural gas requirements for natural gas-fired generating plants on a monthly basis, taking into consideration the anticipated load, weather, and other events, such as outages in the generating fleet, and makes purchases of gas for the upcoming month that can be supplemented with a spot purchase as necessary during the month.

In our current planning, we anticipate the closure of most of these plants by the end of 2039 to enable the final transition to a carbon emissions-free generation portfolio. Two of these plants, Lordsburg and La Luz, use modern aeroderivative turbines and are candidates for eventual conversion to hydrogen fuel. In anticipation of the need for a firm source of carbon emissions-free capacity, our analysis assume these plants remain in service beyond 2040 but are converted to consumption of a carbon emissions-free fuel in the Technology Neutral scenarios. For planning purposes, we assume that all gas plants will be fully depreciated by 2039, allowing us to retire them by 2040 – if conversion to a carbon-free fuel is not economic or viable– as long as we are confident we can preserve resource adequacy in their absence.

Afton Generating Station

The Afton Generating Station is a 235 MW natural gas-fired generating plant. Afton is located near La Mesa, New Mexico, within PNM's southern New Mexico load pocket and consists of one General Electric (GE) Frame 7 gas turbine, a heat recovery steam generator, and a steam turbine. The plant can be operated either in a simple cycle mode using a combustion turbine or as a combined cycle generating facility. Energy generated at Afton Generating Station can be delivered to southern New Mexico loads or to northern New Mexico loads via contracted transmission rights. Natural gas is transported and delivered to the Afton facility via the El Paso Natural Gas Company's southern main line.

La Luz Energy Center

The La Luz Energy Center (La Luz) is the newest thermal generator in PNM's portfolio and came online in 2016. The plant is located in Valencia County, directly west of PNM's Belen Substation. A single GE LM6000 combustion turbine, La Luz can deliver 41 MW of capacity into the northern New Mexico load center. It is equipped with selective catalytic reduction and carbon oxidation air emission control systems and can provide full power within 10 minutes to meet operating reserve requirements.

Natural gas supply for La Luz is delivered through Transwestern's interstate pipeline. The plant is also close to the El Paso Natural Gas Company's interstate pipeline. In the future, the aeroderivative turbine in use at La Luz is a possible candidate for conversion to combustion of hydrogen, and in scenarios that are designed to include hydrogen as a carbon-free fuel, we assume full conversion to operations with hydrogen can be achieved by 2040.

Lordsburg Generating Station

Lordsburg Generating Station (Lordsburg) is a natural gas-fired peaking facility located near Lordsburg, New Mexico. Lordsburg has two GE LM6000 aeroderivative units that can deliver a total of 85 MW of quick-start peaking capacity. PNM needs the quick-start capability of Lordsburg for system load balancing and regulation. Located in the southern New Mexico load pocket, energy from Lordsburg can be delivered directly to southern New Mexico loads or can be delivered via contracted transmission rights to PNM's northern load. PNM has contracted with NAES to operate and maintain Lordsburg under a service agreement.

Lordsburg currently receives natural gas supply via the El Paso Natural Gas southern main line. Like La Luz, Lordsburg's aeroderivative turbines present the potential option for conversion to hydrogen. In our analysis, we assume this conversion is possible by 2040.

Luna Energy Facility

The Luna Energy Facility (Luna) is a natural gas combined cycle plant constructed in 2006 near Deming, New Mexico. This facility is configured with two GE heavy-frame 7FA gas turbines, each connected to a HRSG steam generator. PNM owns one-third, or 190 MW, of Luna. Tucson Electric and Samchully Power & Utilities 1, LLC each also own one-third interests in Luna. In 2008, the Commission granted a CCN to make PNM's share of Luna a jurisdictional resource. Unlike Afton Generating Station, Luna can only operate in combined cycle mode. Luna can deliver to southern New Mexico loads directly or, via contracted transmission rights, to PNM's northern load. PNM oversees the plant operation and maintenance on behalf of the owners through a long-term service agreement with NAES, which operates and maintains the plant. Luna receives natural gas supply via the El Paso Natural Gas southern main line in New Mexico. Each owner purchases its own fuel supply.

Reeves Generating Station

The Reeves Generating Station is located southwest of the intersection of Paseo del Norte and Jefferson streets in the city of Albuquerque. The 146 MW[33] facility is a natural gas steam electric plant with three units. Units 1 & 2, 42 and 41 MW steam turbine generators, became operational in 1958 and 1962, respectively; Unit 3, a 63 MW steam turbine, became operational in 1962. It operates on natural gas supply delivered through the New Mexico Gas Company. PNM operates the Reeves Generating Station not only to meet generation requirements, but also to relieve transmission constraints and provide system voltage support.

During 2010 and 2011, PNM overhauled Units 1 and 2 and installed new distributed control systems to increase reliability and prolong the life of these units. PNM is addressing the aging of this facility through ongoing maintenance programs and has factored in required maintenance costs needed to reach an assumed end of life in 2030.

Rio Bravo Generating Station

Rio Bravo Generating Station (Rio Bravo; formerly called Delta-Person) is a natural gas-fired generating plant with a capacity of 141 MW[33] located on the south side of Albuquerque off Interstate 25. This station consists of a GE 7F combustion turbine that went into service in 2000. In June 2013, the Commission approved a CCN for PNM to acquire the plant from its previous owner.

Because of Rio Bravo's location within the northern New Mexico load center, it is an important PNM load-side generating resource for load to relieve transmission system constraints and to provide voltage support. Rio Bravo is a dual-fuel facility. It operates on natural gas supply delivered through the New Mexico Gas Company; however, when required, the plant can operate on fuel oil stored on-site and supplied under a delivery service agreement. PNM anticipates that Rio Bravo will be available to meet customer load through 2039, when we plan to retire the plant prior to meeting our carbon-free goal as long as we are able to meet resource adequacy requirements.

Valencia Energy Facility

The Valencia Energy Facility (Valencia) is located south of Belen, New Mexico. Its generator is a heavy-frame GE 7FA gas turbine that began commercial operations on May 30, 2008. It supplies PNM with approximately 149 MW[33] of peaking capability under a 20-year PPA with Southwest Generation, LLC. The PPA expires in 2028. PNM will review options to replace the power as the expiration date nears. Valencia receives its natural gas fuel supply through a four-mile-long pipeline interconnection to Transwestern's interstate pipeline.

Geothermal Generation

The Dale Burgett Geothermal Facility (formerly known as Lightning Dock) generates electricity using geothermal resources and is located in the Animas Valley in Hidalgo County, about 20 miles southwest of Lordsburg, New Mexico. PNM purchases the energy and associated RECs under a 20-year PPA. PNM began purchasing power from this facility in January 2014. Initially, operations began at the 4-MW level, with the facility more recently increasing its net capacity up to 11 MW.

[33] Net dependable summer capacity

The plant uses a closed-loop binary system where geothermally heated groundwater is pumped from a deep reservoir to a heat exchanger. Heat is transferred to a working fluid with a low boiling point in a separate closed-loop system. The working fluid flashes and powers the turbine expander, generating electricity, and is then cooled and condensed back into a liquid to be used again. The groundwater is re-injected into the same deep reservoir to be naturally reheated without ever coming into contact with the secondary working fluid or being exposed to air.

Wind Generation

PNM currently has power purchase agreements for 658 MW of total wind capacity spread across five facilities: the New Mexico Wind Energy Center (NMWEC), Red Mesa, Casa Mesa, and La Joya 1 & 2. In an average year, these resources are capable of producing an average annual output of 2,200 GWh, enough to meet 23% of our 2021 energy needs. The output of wind resources can fluctuate significantly on a year-to-year basis due to natural variability in meteorological patterns. For instance, since 2003, NMWEC's annual capacity has averaged 29% but has ranged as low as 23% and as high as 35%. Table 21 shows historical generation from the three wind facilities that were operational at the beginning of 2019. We note that the jump in capacity factor for NMWEC in 2019 is due to repowering of the facility that coincided with PNM signing a new contract.

Table 21. Historical wind generation and capacity factors from 2003–2019

Year	NMWEC		Red Mesa		Casa Mesa		Total	
	MWh	Capacity Factor	MWh	Capacity Factor	MWh	Capacity Factor	MWh	Capacity Factor
2003	211,931	N/A					211,931	N/A
2004	514,414	29.3%					514,414	29.3%
2005	513,019	29.3%					513,019	29.3%
2006	528,567	30.2%					528,567	30.2%
2007	500,420	28.6%					500,420	28.6%
2008	577,506	32.9%					577,506	32.9%
2009	533,289	30.4%					533,289	30.4%
2010	552,242	31.5%					552,242	31.5%
2011	579,900	33.1%					579,900	33.1%
2012	546,321	31.1%					546,321	31.1%
2013	493,949	28.2%					493,949	28.2%
2014	489,442	27.9%					489,442	27.9%
2015	404,765	23.1%	184,297	21.0%			589,062	22.4%
2016	492,427	28.0%	214,030	24.4%			706,457	26.8%
2017	496,778	28.4%	215,606	24.0%			712,384	23.1%
2018	485,108	27.7%	212,754	23.7%			697,862	22.6%
2019*	610,138	34.8%	220,073	24.5%	187,441	42.8%	1,017,652	33.0%

** Increased output from NMWEC in 2019 due to repowering*

While output from PNM's wind resources varies from hour to hour and day to day, these resources do typically exhibit some notable trends. Figure 50 shows the average hourly production pattern for each month of the year. For instance, our wind resources tend to generate less output in summer than in other seasons, and more output in the evening and nighttime than during the day. During the hours of our typical peak period, our wind resources often generate at capacity factors between 10-20%, which heavily impacts the ELCC that we ascribe to these resources for reliability planning.

Figure 50. Historical average capacity factor by month and time of day for PNM's wind resources (2013-2019)

	Hour of Day (MST)																							
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
1	33%	32%	33%	33%	32%	32%	32%	31%	29%	28%	28%	30%	31%	32%	33%	34%	34%	35%	37%	39%	38%	38%	36%	35%
2	39%	38%	38%	36%	35%	35%	33%	31%	27%	28%	29%	32%	35%	39%	41%	42%	43%	41%	41%	41%	42%	41%	41%	39%
3	38%	36%	34%	33%	33%	32%	29%	26%	27%	28%	29%	30%	33%	35%	36%	39%	41%	41%	40%	41%	41%	41%	40%	40%
4	38%	37%	36%	34%	32%	30%	28%	26%	27%	27%	29%	32%	35%	37%	39%	42%	44%	43%	40%	42%	45%	44%	44%	40%
5	34%	32%	31%	29%	25%	22%	19%	19%	19%	20%	22%	25%	27%	31%	34%	35%	36%	38%	36%	36%	38%	39%	39%	37%
6	33%	31%	28%	25%	24%	21%	17%	16%	14%	14%	14%	15%	17%	20%	21%	24%	25%	27%	28%	29%	33%	34%	34%	36%
7	24%	22%	21%	20%	19%	17%	14%	12%	12%	11%	10%	10%	11%	12%	14%	17%	20%	21%	24%	25%	27%	27%	26%	24%
8	21%	19%	19%	19%	18%	16%	13%	11%	10%	10%	10%	9%	10%	12%	13%	16%	19%	21%	21%	22%	24%	25%	24%	23%
9	23%	21%	20%	18%	17%	17%	16%	14%	14%	14%	15%	16%	17%	19%	21%	24%	24%	23%	24%	28%	30%	29%	28%	26%
10	29%	28%	27%	27%	25%	25%	25%	22%	21%	23%	24%	26%	28%	30%	31%	33%	33%	32%	33%	35%	35%	34%	32%	31%
11	34%	33%	32%	31%	30%	30%	30%	29%	27%	28%	30%	31%	34%	35%	37%	37%	35%	34%	36%	37%	38%	37%	36%	34%
12	33%	32%	32%	31%	31%	31%	30%	30%	27%	26%	26%	27%	29%	31%	33%	33%	31%	33%	36%	36%	35%	35%	34%	33%

Descriptions of each of the facilities under contract to PNM follows.

New Mexico Wind Energy Center

The New Mexico Wind Energy Center (NMWEC) is a 200-MW wind energy generation facility located near House, New Mexico. It interconnects to the PNM transmission system at the Taiban Mesa station interconnected to the Blackwater-BA 345-kV line and can deliver up to 200 MW into PNM's system. Since 2003, PNM has purchased the renewable energy and the associated RECs generated by the NMWEC from its owner and operator, NextEra Energy, Inc. In 2019, this facility was repowered to increase output, and we extended our PPA through 2044.

Red Mesa Wind

Red Mesa Wind, LLC, is a 102-MW wind energy generation facility located about 50 miles west of Albuquerque in Cibola County, New Mexico. Owned by NextEra Energy, Inc., the facility interconnects to PNM's 115 kV transmission facilities at the Red Mesa station west of Albuquerque. PNM has purchased the energy and associated RECs generated by this facility since January 1, 2015, under a 20-year PPA that expires in 2035.

Casa Mesa

The Casa Mesa wind facility is a 50 MW facility located in De Baca and Quay Counties, New Mexico. Owned and operated by NextEra Energy, Inc., the facility is adjacent to NMWEC, and the total output from both Case Mesa and NMWEC are limited by the 200 MW transmission interconnection with the PNM system. PNM has purchased the energy and associated RECs generated by this facility since January 1, 2018, under a 25-year PPA that expires in 2043.

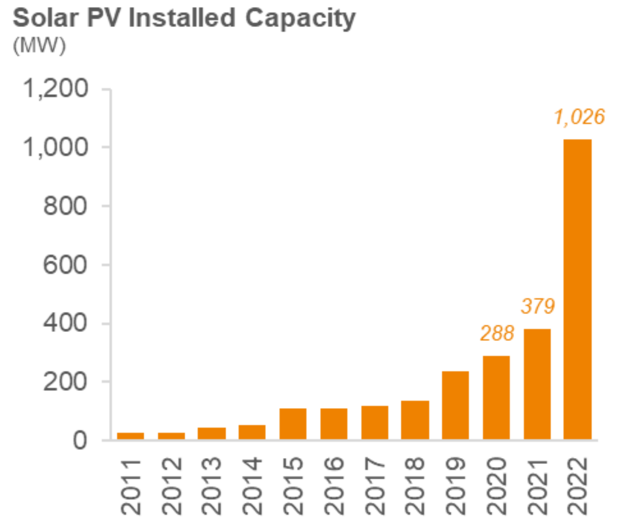
La Joya Wind 1 & 2

La Joya 1 & 2 are 166 MW and 140 MW facilities, respectively, located in Torrance, New Mexico. These plants are anticipated to be brought online in early 2021 by Avangrid Renewables, who sells the output to PNM under two separate long-term PPAs that expire in 2040. Output from La Joya 1 is used to meet voluntary customer renewable programs and therefore is not considered an RPS-eligible resource for compliance with the ETA; output from La Joya 2 serves our retail customers' system loads and provides RECs that contribute to our statutory RPS obligations.

Solar Generation

By the end of 2021, PNM will have 379 MW of solar PV-generating facilities in service; wees expect these resources to produce over 700 GWh, sufficient to meet approximately 8% of our 2020 energy needs. By 2022, between resources already in development and additional resources procured to replace SJGS, the total generating capacity of our solar resources will exceed 1,000 MW. Our solar PV resources consist of a mix of fixed-tilt and single-axis tracking arrays near various communities in PNM's service area: Alamogordo, Albuquerque, Deming, Los Lunas, Las Vegas, Rio Rancho, Bernalillo County, Cibola County, Otero County, Santa Fe County, and Valencia County. A list of all the existing solar PV facilities under PNM ownership and long-term contract is provided in Appendix H.

Figure 51. Growth of solar PV generating capacity over time



Like wind, solar is an intermittent resource whose output varies hourly and seasonally as a function of meteorological conditions. While the daily production pattern for our solar resources is more regular than wind, its variability and steep ramps in output during sunrise and sunset hours nonetheless pose a challenge for our system operators on a day-to-day basis. Typical output patterns for our portfolio of solar resources based on historical data from 2013-2019 are shown in Figure 52.

Figure 52. Historical average capacity factor by month and time of day for PNM's solar resources (2013-2019)

	Hour of Day (MST)																							
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
1	0%	0%	0%	0%	0%	0%	0%	2%	32%	57%	69%	74%	75%	70%	62%	46%	16%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	12%	45%	67%	77%	80%	79%	78%	71%	57%	33%	3%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	2%	29%	58%	75%	83%	84%	83%	81%	73%	61%	41%	11%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	14%	46%	64%	78%	85%	86%	85%	81%	74%	61%	44%	18%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	3%	26%	53%	68%	81%	87%	87%	86%	82%	74%	61%	46%	24%	3%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	4%	28%	52%	67%	81%	88%	89%	86%	81%	72%	60%	46%	26%	5%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	2%	22%	48%	65%	78%	85%	86%	83%	77%	68%	55%	40%	22%	4%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	14%	44%	62%	76%	84%	85%	82%	78%	68%	54%	38%	17%	1%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	8%	41%	61%	75%	83%	84%	82%	79%	69%	55%	35%	8%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	2%	33%	59%	73%	80%	80%	79%	75%	67%	51%	22%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	16%	47%	63%	70%	72%	71%	68%	59%	40%	8%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	4%	33%	56%	65%	69%	69%	66%	57%	36%	6%	0%	0%	0%	0%	0%	0%	0%

PNM also has distributed generation solar energy on our system. These are customer-sited solar systems; usually rooftop, but some customers have larger systems which are sometimes ground-mounted. While these behind-the-meter systems affect our load, their impact follows the output patterns of the utility scale solar resources. In 2019, PNM's solar distributed generation programs produced 225,572 MWh of energy with 129 MW of installed capacity. The distributed generation on our system is discussed further in Section 6.1 (Load Forecast)

Energy Storage

PNM's existing energy storage resources comprise two small projects: (1) the Prosperity Energy Storage facility described above, and (2) a 1 MW battery storage project co-located with the Casa Mesa Wind Project. Our reliance on energy storage will grow substantially in the next few years with the approval of replacement resources for SJGS. Specifically, the Commission's approved replacement portfolio includes 300 MW of energy storage capacity, all co-located with solar PV generation facilities. Each of these storage facilities will be contracted to PNM, allowing us to optimize the use of the storage to balance our loads and resources (subject to restrictions related to the need to charge from on-site solar to be eligible for the ITC and limited to 365 equivalent cycles per year). Additional detail on these facilities is provided in Appendix H.

While we are committed to maximizing the value of these resources to the greatest extent possible, we are also aware that lithium ion battery storage has not yet been widely commercialized at this scale, nor has a single utility relied on such a significant portion of it to meet its reliability needs. The 300 MW that we anticipate in our portfolio by the end of 2022 represents approximately 15% of our peak demand, a figure that will make us among the most heavily reliant upon energy storage among utilities in the country. As we bring these resources online and begin to gain experience operating them, we will monitor their performance closely to ensure that their contributions are in line with expectations.

6.3 Summary of Resource Needs

The combination of expected load growth and the planned abandonments and retirements of a number of plants results in a growing need for new resources to maintain reliability. The growth of our resource need over time, along with key retirements and abandonments, is shown Figure 53. This figure does not specify what mix of resources are needed to supply this need; however, ensuring that our new resources can fill this need is crucial to our resource adequacy.

Figure 53. PNM's growing need for new capacity over time

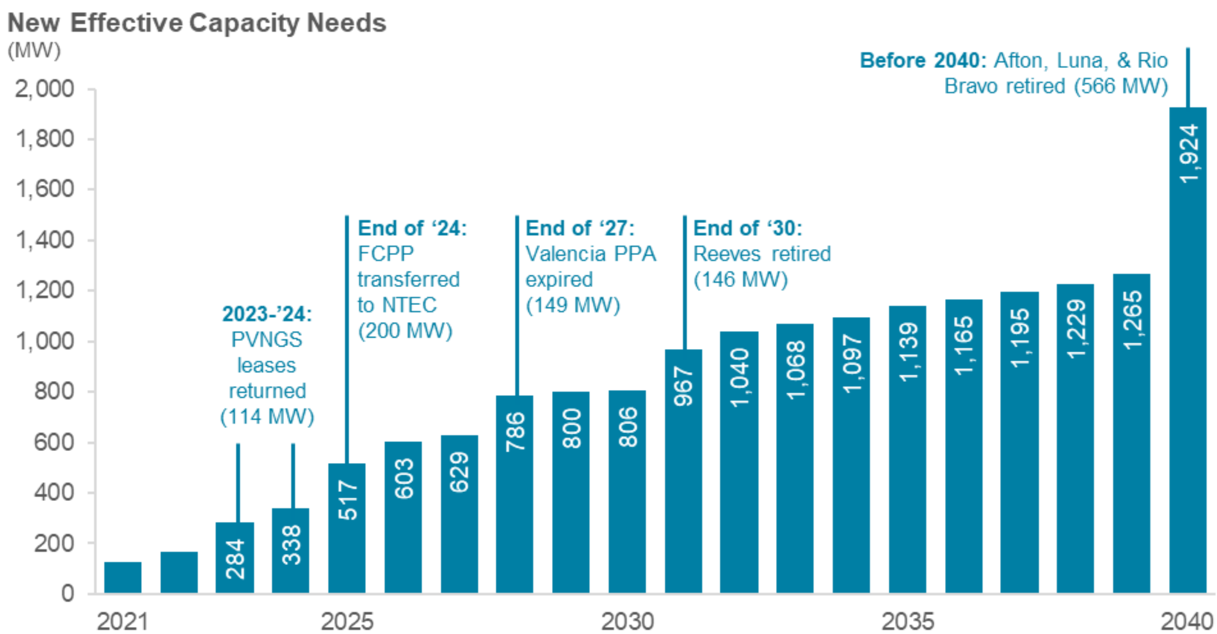


Table 22 provides a detailed breakdown of the effective capacity of our existing resources compared with the total resources needed to meet our planning reserve margin requirement.

Table 22. Existing resource dependable capacity & incremental resource needs (Current Trends & Policy future)

Year		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand	MW	1,976	2,035	2,066	2,098	2,135	2,206	2,228	2,237	2,248	2,252
EE*	MW	-20	-39	-60	-81	-102	-102	-102	-102	-102	-102
Net Peak	MW	1,956	1,996	2,006	2,017	2,032	2,104	2,125	2,135	2,145	2,150
PRM	%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Total Need	**MW**	**2,308**	**2,355**	**2,368**	**2,380**	**2,398**	**2,483**	**2,508**	**2,519**	**2,532**	**2,537**
Nuclear	MW	394	394	292	282	282	282	282	282	282	282
Coal	MW	568	160	160	160	-	-	-	-	-	-
Gas CCGT	MW	408	408	408	408	408	408	408	408	408	408
Gas CT	MW	403	403	403	403	403	403	403	259	259	259
Gas ST	MW	141	141	141	141	141	141	141	141	141	141
Geothermal	MW	5	5	5	5	5	5	5	5	5	5
Solar**	MW	54	171	167	166	165	164	162	161	160	159
Wind	MW	181	181	181	181	181	181	181	181	181	181
Storage**	MW	0	287	284	284	284	284	284	284	284	284
DR**	MW	30	42	42	12	12	12	12	12	12	12
Total Gen	MW	**2,184**	**2,192**	**2,084**	**2,042**	**1,881**	**1,880**	**1,879**	**1,733**	**1,732**	**1,731**
Net Need	MW	**125**	**165**	**284**	**338**	**517**	**603**	**629**	**786**	**800**	**806**
Year		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Peak Demand	MW	2,262	2,277	2,280	2,283	2,284	2,305	2,308	2,314	2,344	2,363
EE*	MW	-102	-102	-83	-63	-43	-43	-21	-	-	-
Net Peak	MW	2,160	2,174	2,197	2,220	2,241	2,262	2,287	2,314	2,344	2,363
PRM	%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Total Need	**MW**	**2,549**	**2,566**	**2,592**	**2,619**	**2,645**	**2,669**	**2,698**	**2,731**	**2,766**	**2,788**
Nuclear	MW	282	282	282	282	282	282	282	282	282	282
Coal	MW	-	-	-	-	-	-	-	-	-	-
Gas CCGT	MW	408	408	408	408	408	408	408	408	408	-
Gas CT	MW	259	259	259	259	259	259	259	259	259	122
Gas ST	MW	-	-	-	-	-	-	-	-	-	-
Geothermal	MW	5	5	5	5	5	5	5	5	5	5
Solar**	MW	158	156	155	154	153	152	151	149	148	83
Wind	MW	181	138	138	138	124	124	124	124	124	124
Storage**	MW	277	277	277	276	275	275	275	275	275	248
DR**	MW	12	-	-	-	-	-	-	-	-	-
Total Gen	MW	**1,581**	**1,526**	**1,524**	**1,523**	**1,506**	**1,504**	**1,503**	**1,502**	**1,501**	**864**
Net Need	MW	**967**	**1,040**	**1,068**	**1,097**	**1,139**	**1,165**	**1,195**	**1,229**	**1,265**	**1,924**

**Reflects future EE programs approved by Commission & required to comply with EUEA through 2025*
***Includes SJGS replacement resources*
****More detailed loads and resources tables appear in Appendix K*

6.4 New Resource Options

6.4.1 New Demand-side Resources

Energy Efficiency

In keeping with our carbon emissions-free goal, we target new approaches in this IRP to include and evaluate energy efficiency. In addition to the minimum requirements for efficiency established by the EUEA discussed in Section 6.2 (Existing Resources), we consider additional EE beyond the planned amounts required by statute. The EE beyond planned amounts is bundled into similarly priced groups that can be considered by the model alongside supply-side resources. Allowing this EE to be chosen by the optimization algorithm indicates the extent to which we should pursue EE above and beyond the statutory amount as a lower cost solution than adding supply-side resources.

To enable modeling EE as a resource, we commissioned a study performed by Applied Energy Group to develop hourly supply curves representing program potential. Their process consisted of the following steps:

1. Calculate "achievable technical" potential for EE within PNM service territory. This potential incorporates achievability rates but does not screen for measure benefit/cost ratios.

2. Define a statutory EE bundle based on requirements to meet the EUEA from 2021-2025. This bundle is the planned incremental EE category to which we refer above.

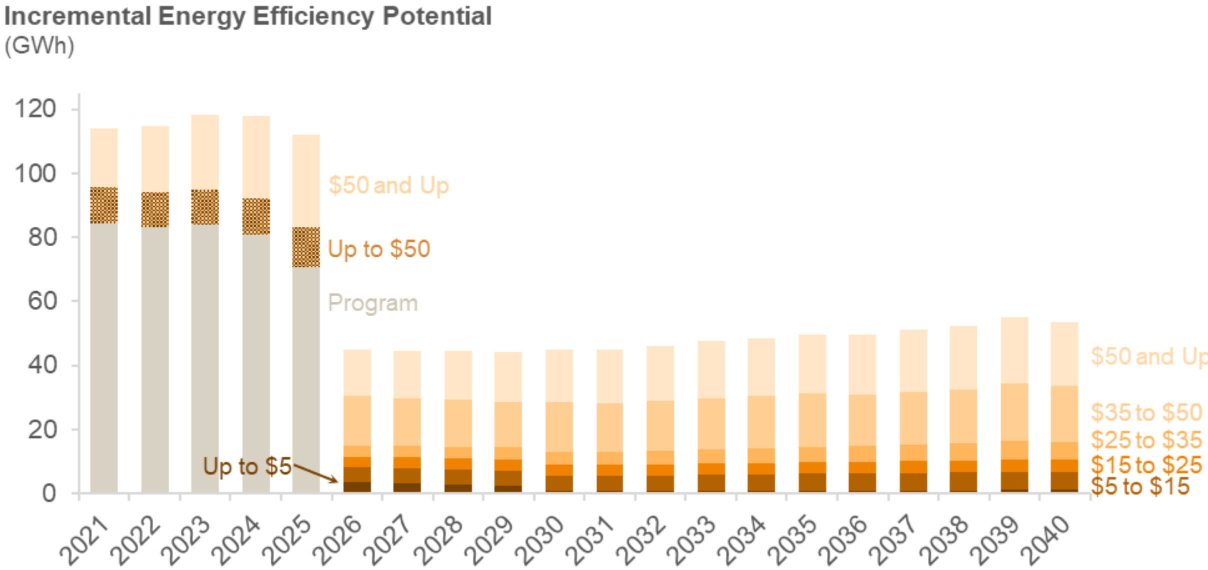
3. Define bundles of EE measures beyond the EUEA's minimum requirements by grouping measures with similar levelized costs of conserved energy.

4. Calculate annual incremental energy savings, weighted average cost, and measure life for each bundle based on included measures.

5. Develop hourly impacts for each bundle by spreading measure-level impacts over calibrated end use load shapes.

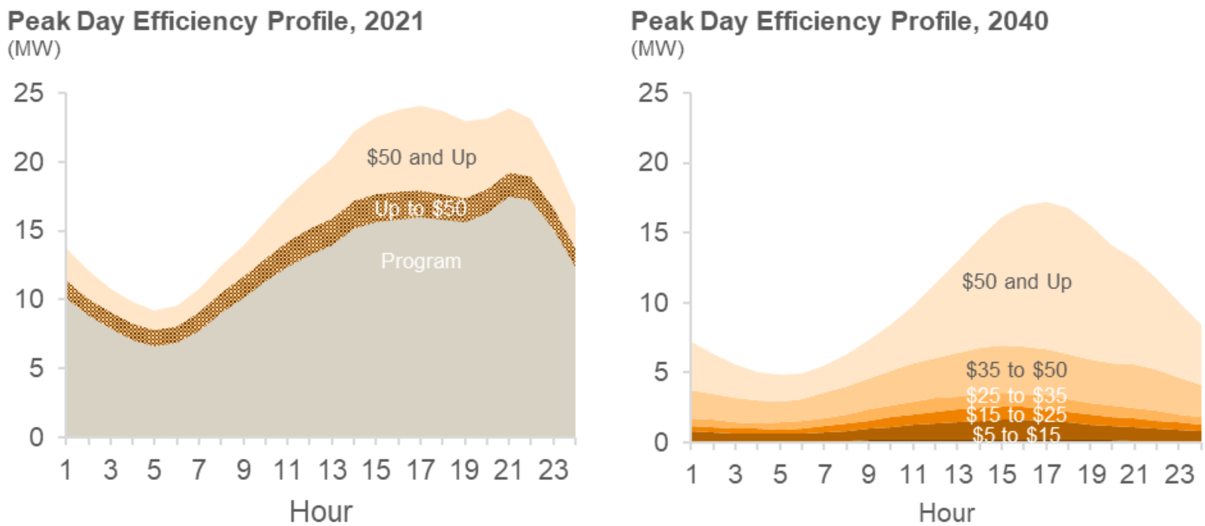
The results of this process are shown in Figure 54 and Figure 55; additional details on the characteristics of the bundles are provided in Appendix I. These respectively show the resulting EE bundles and two examples of their hourly impact in different years. We note that the gray "Program" EE is planned efficiency required by statute – this EE is included in all scenarios. In any given simulation year, the model may select from the available non-program efficiency bundles shown in Figure 54. If a bundle is selected, its effects persist throughout the bundle lifetime. The undefined upper bound of the "$50 and Up" bundles results in an average levelized cost of over $500/MWh for the bundles, so this tier is very unlikely to be selected. PNM will continue to evaluate and refine this approach in future IRPs, likely including an adjustment to add resolution within the "$50 and Up" bundle tier.

Figure 54. Energy efficiency bundles*



* *Impact at shown at load and not grossed up for transmission & distribution losses*

Figure 55. Example hourly impacts by EE bundle on a peak day in 2021 and 2040*

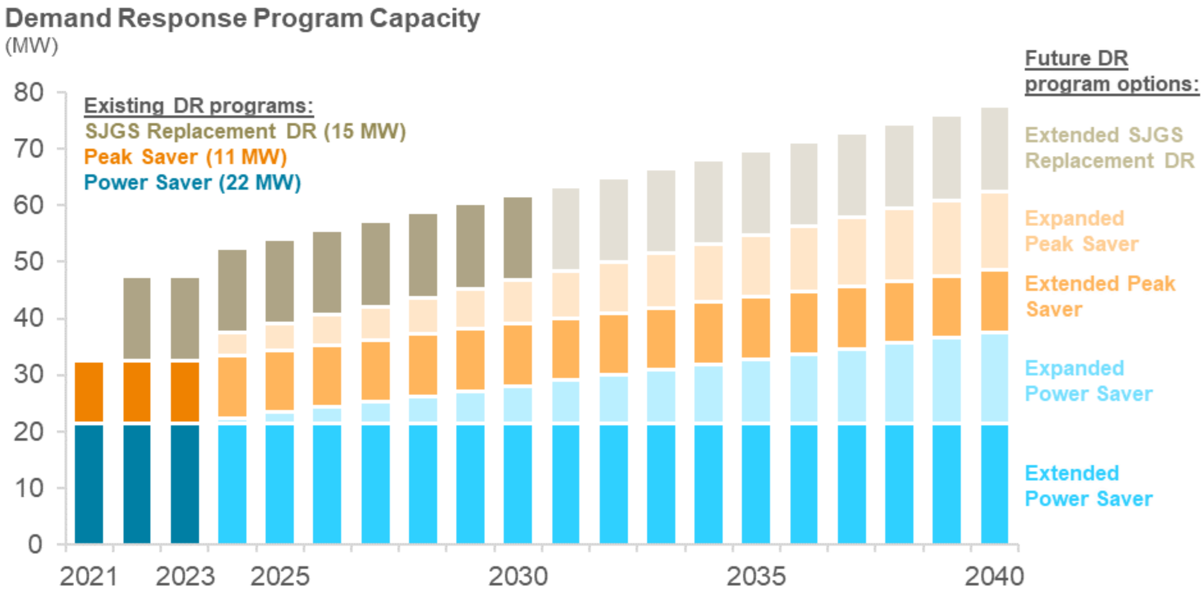


* *Impact at shown at load and not grossed up for transmission & distribution losses*

Demand Response

Like energy efficiency, DR is modeled with existing/planned programs included in all scenarios, and programs beyond these planned amounts (including extensions of the existing programs) can be selected. The DR options are shown in Figure 56: existing Peak Saver and Power Saver programs will run through 2023 and appear in all forecasts. In 2024 the model can choose to discontinue these programs, extend them, or extend and expand them. Alongside these programs, PNM is currently seeking Commission approval of 15 MW of additional DR resources as part of the replacement portfolio of SJGS. While this resource has not been approved by the Commission at the time of this analysis, we include it in our IRP as part of our existing portfolio. In 2031, the model has a choice to extend this 15 MW through the end of the model horizon.

Figure 56. Options to extend and expand existing demand response programs

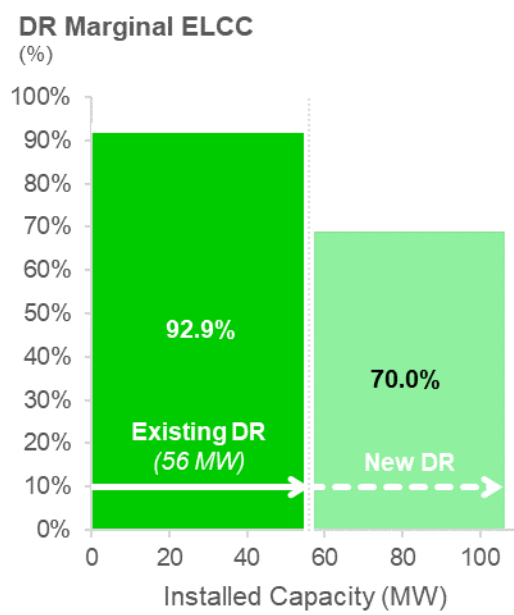


Due to the voluntary nature of the DR programs, rules dictating call schedules, and historical underperformance of enrolled MW, it is important to consider DR in the context of the reliability discussion of Section 4.1.1 (Resource Adequacy and Planning Reserves). The success of a DR program depends on the shape and timing of the system peak relative to the structure of the DR program. For example, the current DR programs which have 4-hour call durations cannot mitigate longer peaks. These programs have a limited ability to mitigate fast ramps too: Power Saver has historically provided no contribution to 10-minute response. The presence of more storage may create opportunities for effective optimization of DR and storage discharge, but the value of such optimization declines with program constraints on DR call schedules.

Other program rules further reduce DR's reliability value. The prohibition of weekend calls means that we cannot count on demand response when high loads occur on the weekends. In 2020, our second highest load occurred on a Saturday; since 2013, an average of twelve of the top 100 load hours of each year have fallen on weekend days. The voluntary nature of the programs means that customers that have historically participated can opt out of the program with little warning – an event that transpired in July of 2020, resulting in a sudden drop of 10 MW from the DR portfolio and an additional 4 MW in August.

Experience from the Peak Saver and Power Saver programs indicates that, on average, we need to contract for 1.25 MW of DR to get 1 MW. However, this ratio grows when we move from considering average performance to performance during

Figure 57. Declining capacity credit assigned to new DR resources



system peak. The results of our ELCC analysis (see Appendix M) of DR appear in Figure 57 and show declining capacity value from 92.9% for the first 56 MW to 70.0% for the next 50 MW assuming weekend calls are prohibited. These findings conceptually align with recent analysis from California suggesting that the state may be overvaluing the resource adequacy of DR by 40% or more.[34] Design of future DR programs should prioritize flexibility to get the most value from DR.

6.4.2 New Supply-side Resources

Technology is rapidly evolving, and we are closely monitoring these changes. As part of our public IRP process, we enlisted the support of Sandia National Laboratory to help assess the landscape of available and emerging energy storage technologies, and our Technology RFI from late 2019 was targeted specifically towards learning more about the anticipated viability of a broad range of potential storage technologies. As the demand for utility-scale energy storage continues to grow, we expect the list of promising technologies to continue to expand as competition drives innovation.

For the purposes of inclusion in our IRP, we limit the set of technologies we model based on two criteria: (1) a technology must have achieved a minimum level of commercial viability as determined by our Technology RFI review panel, and (2) its expected cost and performance characteristics must compare favorably with alternative technologies with similar operating characteristics. While we narrow the set of technologies considered in the analysis, we will continue to monitor the market across all offerings, and our procurement processes for energy storage will be designed to be agnostic to specific technologies, allowing the most cost-competitive storage technologies to compete to meet our needs.

This section provides detail on the resources available for selection by the model. Given the focus of this IRP on achieving a carbon-free portfolio by 2040, we pay special attention to renewable and other low- or zero-carbon-emitting resources.

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 PPA. Each of these options has specific benefits, but each also presents risks and uncertainties worth consideration when making procurement decisions. For the purposes of long-term resource planning, we do not evaluate specific ownership structures.[35] Instead we compare and evaluate all resources under a framework that is agnostic to ownership. In order to efficiently evaluate projects, a utility ownership finance structure is utilized, but unlike utility ownership, we assume that the projects can take full advantage of tax credits. This approach is not meant to show a preference for utility ownership, but rather to allow for utilizing tax benefits while ensuring that all technologies are considered on a level playing field using a consistent set of financing assumptions in our optimization procedure.

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[34] http://www.caiso.com/InitiativeDocuments/E3Presentation-EnergyStorage-DistributedEnergyResourcesPhase4-May27-2020.pdf

[35] Project specifics, including ownership structures are determined during RFP evaluations.

Wind

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 a number of other offtakers elsewhere in the Western Interconnection.

Wind resources were characterized in generic 400 MW increments with a 43% capacity factor based on bids we recently received in response to competitive solicitations. Cost assumptions for new wind resources are based on the results of PNM's most recent competitive RFPs and incorporate future technology cost declines based on NREL's 2020 ATB. Key cost assumptions for new solar PV resources are shown in Table 24.

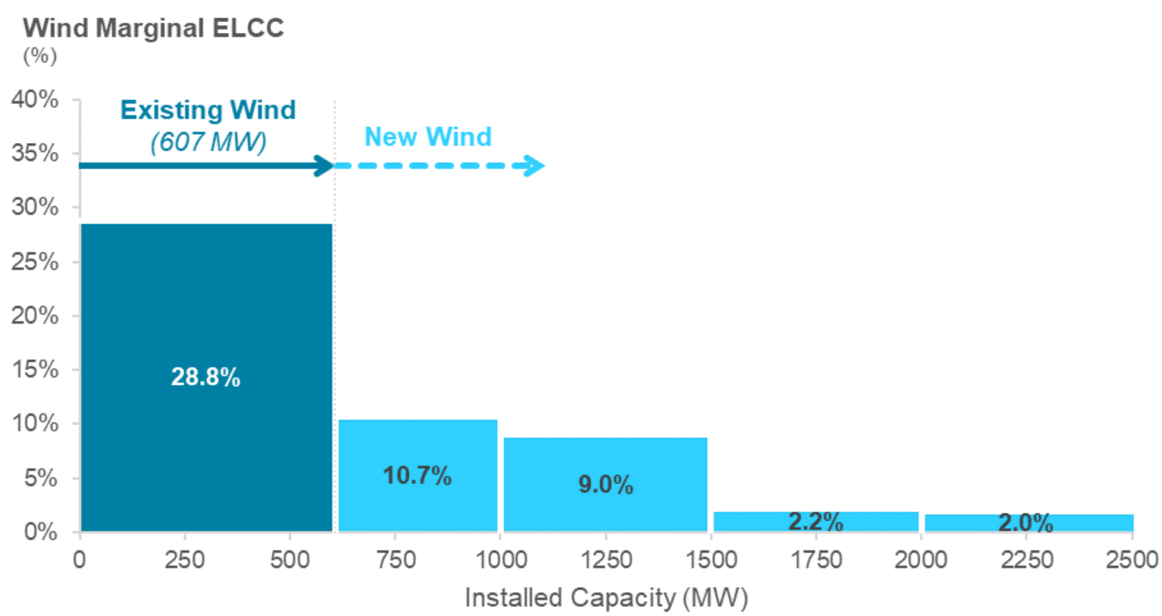
Table 23. Key input assumptions for new wind resources

Installation Year	Capital ($/kW)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	Production Tax Credit ($/MWh)	Economic Life (yrs)
2022	**$1,751**	**$35**	**43%**	**$21**	**30**
2025	$1,682	$34	43%	–	30
2030	$1,554	$33	43%	–	30
2035	$1,484	$32	43%	–	30
2040	$1,431	$30	43%	–	30

We also examine several sensitivities on future wind costs that reflect differences in future capital cost assumptions and the extension of the federal Production Tax Credit (PTC).

New wind resources are modeled with a declining capacity credit as their penetration increases, a dynamic that is directly captured in the calculation of ELCC. The capacity credits we assign to new wind resources are shown in Figure 58. Beyond the 607 MW of wind in our portfolio, wind has a relatively limited capacity value; because of its intermittency and high variability, its coincidence with the periods that are most constrained for resource adequacy is limited. Additional details on the determination of these capacity credits is provided in Appendix M.

Figure 58. Declining capacity credit assigned to new wind generation resources



Developing new wind resources to supply PNM's needs also has implications for our transmission system. Namely, because the transmission system between eastern New Mexico wind production and Albuquerque is fully subscribed, additional investment in transmission will be needed to deliver new wind resources to our loads. Our analysis captures this need by including an incremental transmission cost associated with new wind resources in our model based on the characteristics of potential new projects discussed in Section 7.2 (Transmission Planning), where we present detail on the specific transmission projects that could enable our access to increased amounts of eastern New Mexico wind.

Solar PV

Cost assumptions for new solar PV resources are based on the results of PNM's recent competitive RFPs and incorporate future technology cost declines based on NREL's 2020 ATB. Key cost assumptions for new solar PV resources are shown in Table 24.

Table 24. Key input assumptions for new solar PV resources

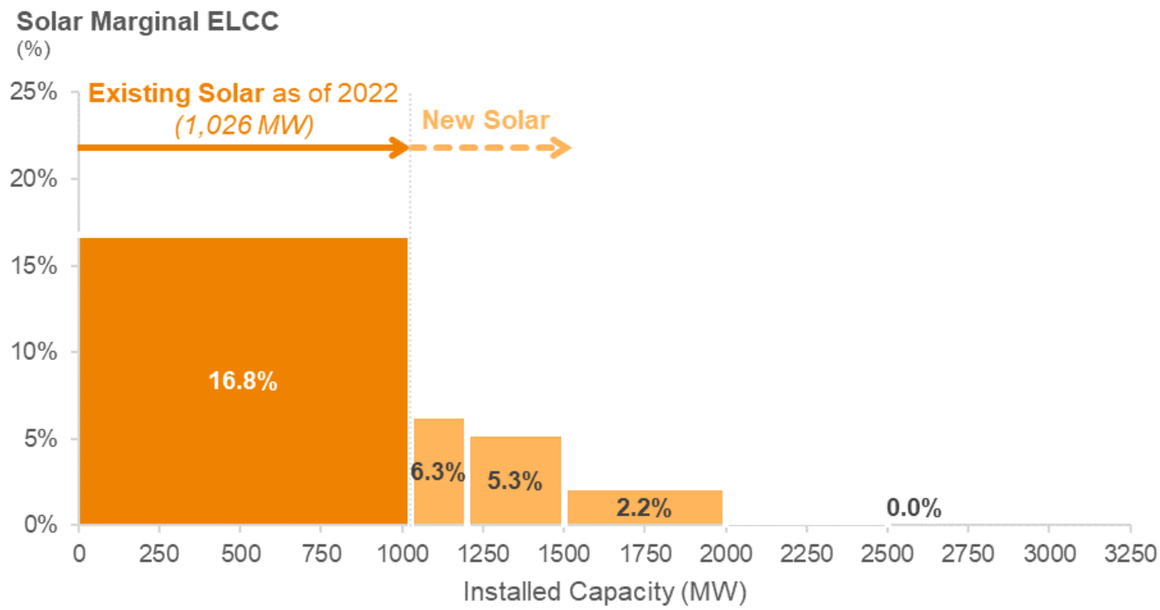
Installation Year	Capital ($/kW)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	Investment Tax Credit* (%)	Economic Life (yrs)
2022	**$1,416**	**$15**	**32%**	**30%**	**30**
2025	$1,251	$13	32%	26%	30
2030	$991	$10	32%	10%	30
2035	$919	$9	32%	10%	30
2040	$886	$9	32%	10%	30

** ITC timing based on assumed construction start date*

We examine a number of sensitivities on future solar PV resource costs, which include variations in the rate of cost declines and the possibility for an extension of the federal Investment Tax Credit.

New solar PV resources are modeled with a declining capacity credit as their penetration increases, a dynamic that is directly captured in the calculation of ELCC. The capacity credits we assign to new solar resources are shown in Figure 59. Beyond the 1,026 MW of solar PV in our portfolio (including the San Juan replacement resources), solar PV has a relatively limited capacity value. This is because by 2022, the timing of our net peak period will have shifted nearly entirely into the evening hours when solar resources will not be available to produce. Additional details on the determination of these capacity credits is provided in Appendix M.

Figure 1. Declining capacity credit assigned to new solar resources



Unlike wind resources, the performance of solar PV generation does not vary considerably based on its location in the state, as the underlying patterns of solar insolation. Accordingly, our plan considers solar PV resources in multiple locations, including areas to the north, west, and south of Albuquerque. In each of these areas, new transmission will be needed to accommodate increased levels of solar PV. Additional detail on the specific transmission projects that would allow development of additional solar is provided in Section 7.2.

Battery Storage

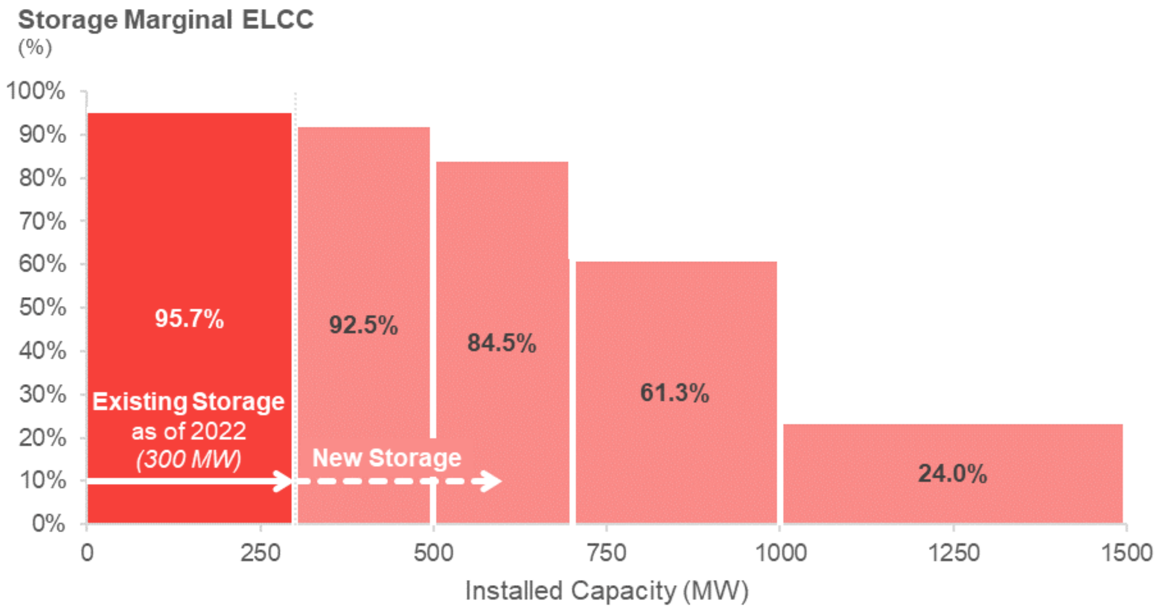
Our analysis considers four-hour lithium-ion batteries as options to meet future capacity and flexibility needs in our portfolio, both as standalone projects and paired with solar PV as hybrid projects. Our assumptions on the present and future cost of battery storage installations are based on a combination of recent bid data provided to PNM and NREL's 2020 ATB and are summarized in Table 25.

Table 25. Key input assumptions for new four-hour battery storage resources

Installation Year	Capital ($/kW)	Fixed O&M ($/kW-yr)	Duration (hrs)	Economic Life (yrs)
2022	$1,569	$32	4	20
2025	$1,278	$25	4	20
2030	$1,043	$20	4	20
2035	$990	$19	4	20
2040	$938	$18	4	20

New storage resources are modeled with a declining capacity credit as the level of penetration increases, a dynamic that is directly captured in the calculation of ELCC. The capacity credits we assign to new storage resources are shown in Figure 60. Beyond the 300 MW in our portfolio (including San Juan replacement resources), energy storage provides a high but declining capacity value. The reason for the decline is due to the fact that as storage progressively flattens the shape of our net load, it must extend its output across broader and broader time horizons. This results in a reduction in the value of a resource with fixed duration (e.g. four-hour storage) but can also be understood as a need for longer duration storage to retain higher capacity credits. Additional details on the determination of these capacity credits is provided in Appendix M.

Figure 60. Declining capacity credit assigned to new four-hour energy storage resources



Pumped Storage Hydro

The cost and performance characteristics of new pumped storage hydro are highly site-specific. In our IRP we consider two specific options for new pumped storage facilities whose characteristics are based on information provided in our Technology RFI.

Several factors make pumped storage a more challenging option in comparison to other options we consider in our integrated resource plan. First is its lack of modularity: the options for new pumped storage facilities that have been identified (1,500 MW and 600 MW) are much larger than our potential need for new capacity over this twenty-year time frame, and in general these types of projects are not easily scalable to meet smaller specific capacity needs. This “lumpiness” presents a challenge to incorporating this type of resource into our plan.

One potential strategy to address this challenge would be to pursue a joint ownership agreement of a new large pumped storage project with other utilities or offtakers within the region. Considering the regional trends we expect to see—significant new investments in solar generation coupled with retirements of aging firm resources—it is reasonable to expect that other utilities may be in a similar position by 2030, in search of both dependable capacity for resource adequacy and the storage capability to integrate increasing levels of solar. This type of arrangement would no doubt present its own unique challenges but might provide an avenue for right-sizing a share of a major infrastructure project to meet our specific needs.

Because of the coordination required for such a joint ownership agreement, as well as the typical long lead times for permitting and development of pumped storage, we do not include these facilities as options in our portfolio until 2030, which represents the soonest possible date we would expect the plants to achieve commercial operations if developed. This development timeline is generally supported by industry responses to our RFI, which provided information assuming commercial online dates between

Hydrogen-Ready Combustion Turbines

Ensuring that any of our future investments will remain used and useful through their economic lifetimes – which will extend beyond 2040, when PNM aspires to reach a 100% carbon emissions-free portfolio – is a priority within this IRP cycle. While long-term technology uncertainty makes it difficult to prescribe the technology mix of our portfolio by 2040, one of the most promising pathways based on our knowledge of technology today is the repurposing of natural gas fired generation to provide peaking capacity while using a carbon emissions-free combustible fuel. To preserve optionality for such a transition, we only consider new natural gas technologies that may, in the future, be repurposed to run on 100% hydrogen. This optionality helps to ensure that costs in the near-term will remain manageable for our customers while still allowing our portfolio of resources to reach our carbon emissions-free goal by 2040.

The cost and performance assumptions that we model are based on a GE LM6000 combustion turbine and are summarized in Table 26. In addition to the costs shown below, we assume a nominal one-time conversion cost of $154/kW for all new combustion turbines, treated as an expense in 2040, to allow combustion of 100% hydrogen.

Table 26. Key input assumptions for new combustion turbines

Installation Year	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Economic Life (yrs)
2022	$847	$20	$1.51	8,212	40
2025	$812	$20	$1.51	8,212	40
2030	$789	$20	$1.51	8,212	40
2035	$772	$20	$1.51	8,212	40
2040	$760	$20	$1.51	8,212	40

While the capability to burn hydrogen is a prerequisite for consideration in our plans, it is worth noting that hydrogen is not the only carbon emissions-free fuel that these types of plants could consume beyond our 2040 goal. 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 optionality and flexibility in any plan that includes these plants as new resources.

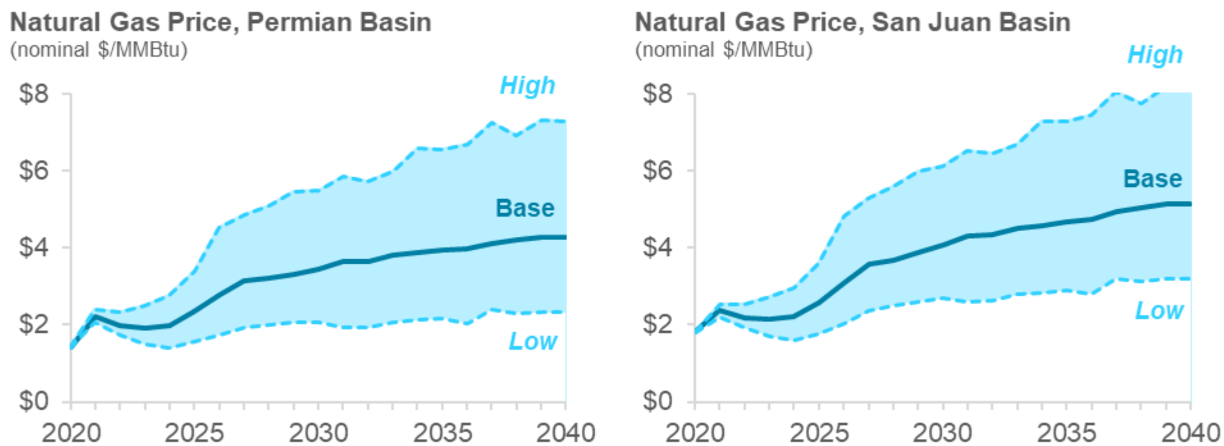
6.5 Commodity Pricing

Historically, commodity costs have played a critical role in determination of the MCEP and longer-term vision of IRPs. In this IRP, this role is reduced: decisions around resource retirements and additions are driven primarily by carbon policy and RPS mandates and only secondarily by energy cost. Still, understanding the cost implications of these carbon-driven decisions remains important and depends on the prices we expect to pay for natural gas, hydrogen fuel, and the wholesale electricity throughout the IRP timeframe. Also, the comparison between these variable costs and the upfront costs of renewables and storage helps to determine resource selection under the constraint of the carbon targets.

Natural Gas Prices

Our natural gas supplies are sourced from two production basins: the Permian Basin in Texas and the San Juan Basin in the Four Corners region. Our 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 PACE Global using fundamentals-based analysis of continental supply and demand for natural gas. These forecasts are shown in Figure 61 and are summarized in greater detail in Appendix G.

Figure 61. Natural gas commodity price forecasts



In addition to the commodity cost of natural gas, we pay additional fees and taxes to deliver natural gas from the supply basins to the burner tip. These fees and taxes vary depending on the location of the plant and the pipeline used to deliver gas and 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 providing transportation service, they generally add between $0.50 to $1.00/MMBtu in additional costs to deliver gas to our plants.

Hydrogen Fuel Cost

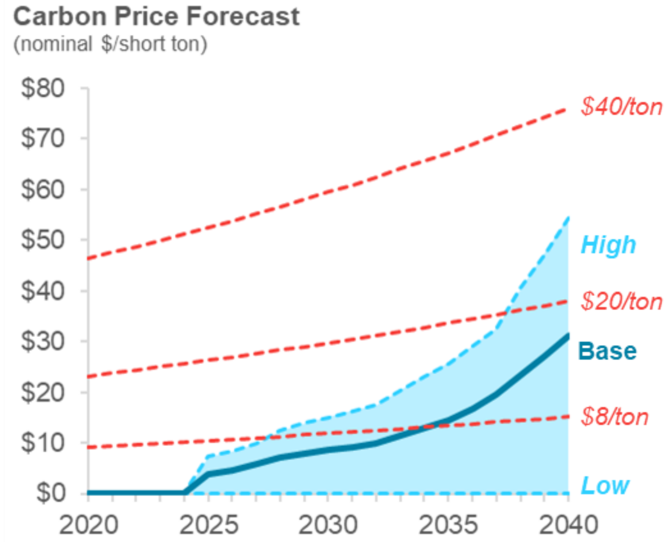
One of the options we consider in developing a resource plan to achieve a carbon-free portfolio is the conversion of natural gas combustion turbines to operate running exclusively on green hydrogen fuel by 2040. Our analysis assumes an exogenous price for the delivered cost of hydrogen to our plants. This all-in cost is intended to include costs of production (including costs of electrolyzers, renewable generation, and other infrastructure necessary), transportation, and storage. This study assumes a delivered cost of $40/MMBtu for hydrogen in 2040. This cost assumption has been developed based on a literature review of studies of the present and future cost of hydrogen production; it is intentionally chosen as a conservative assumption so as to avoid biasing our model in favor of a technology that has not yet been widely deployed.

Carbon Prices

Our IRP analysis considers three forecasts of future carbon pricing based on scenarios developed by PACE Global. The lowest carbon price projection assumes no state or federal carbon pricing regimes throughout the analysis horizon. The mid carbon price forecast is based on a scenario in which national carbon pricing begins in 2025 at a low level (roughly $4/ton) and escalates over the planning period to reach $31/ton (in nominal terms) by 2040. The highest carbon price scenario reaches $55/ton by 2040.

In addition to these scenarios, our IRP analysis also considers the range of carbon pricing as required by the final order in Case No. 06-00448-UT. This order requires regulated 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).

Figure 62. Carbon price projections used in IRP analysis

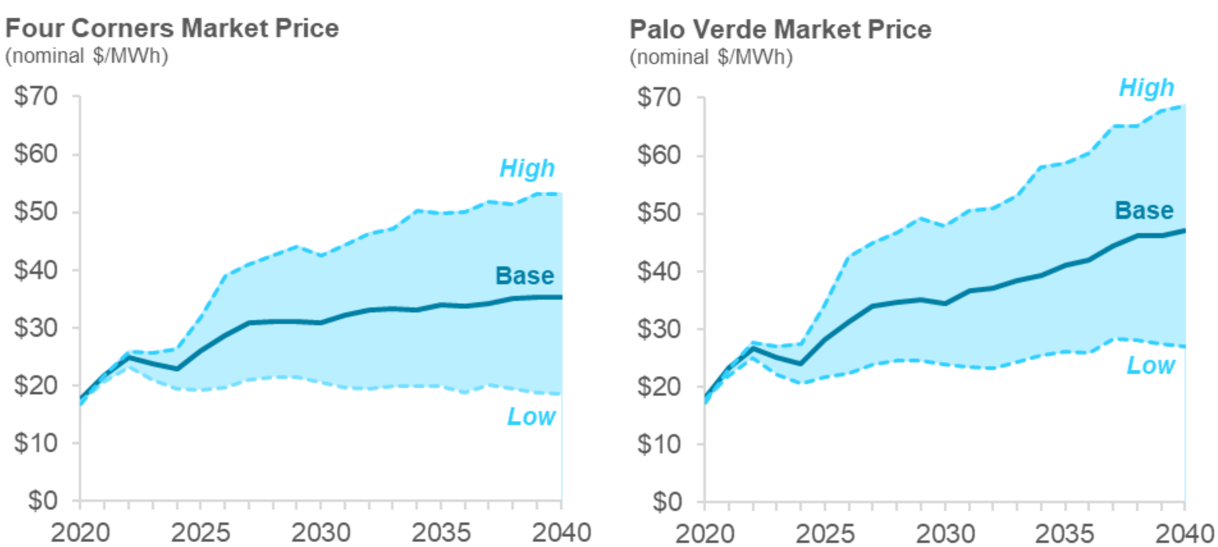


The full range of carbon pricing scenarios analyzed in the IRP is shown in Figure 62.

Wholesale Electricity Market Prices

To capture the dynamics of our interactions with the broader region within our planning process, our analysis incorporates projected wholesale market prices at the Palo Verde and Four Corners market hubs. These forecasts are also developed by PACE Global using a fundamentals-based model of the Western electricity system and reflect the same future commodity price forecasts for natural gas as we use in our own analysis.

Figure 63. Wholesale market price projections used in IRP 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). Figure 64 shows the evolution of these patterns over the twenty-year analysis horizon as captured in the forecast provided by PACE Global, in which the effects of solar saturation on daytime prices become increasingly pronounced.

Figure 64. Changes in wholesale market pricing dynamics incorporated in IRP analysis

2021 Average Palo Verde Market Price by Month & Time of Day
nominal $/MWh

Month	Hour of Day (MST)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	18	18	18	18	17	20	25	26	22	18	17	16	15	15	16	17	22	29	29	29	29	28	23	22
2	16	16	16	16	16	20	26	26	21	17	17	16	15	15	15	16	21	28	31	30	29	28	24	21
3	16	15	15	15	15	19	22	22	17	12	11	11	11	11	11	12	14	19	27	29	27	24	21	19
4	8	7	7	7	8	13	17	13	6	5	5	5	5	5	5	6	9	15	22	28	27	22	18	16
5	10	9	9	9	9	11	13	10	7	5	6	7	8	10	11	13	16	19	22	28	27	23	19	17
6	15	14	13	13	13	15	16	14	13	13	13	13	14	16	17	20	21	23	25	31	32	26	22	20
7	25	25	24	24	25	26	28	26	26	26	28	29	31	33	36	40	40	41	44	52	51	40	32	28
8	25	25	24	24	25	26	29	29	28	28	29	29	32	33	35	38	41	44	51	64	54	39	31	27
9	23	22	22	22	22	23	25	25	21	19	19	19	20	20	21	22	26	29	36	40	36	29	27	25
10	19	19	19	19	19	21	23	24	19	15	15	15	15	15	16	16	20	27	34	33	30	25	22	21
11	16	16	16	16	16	18	23	23	20	16	16	16	16	16	16	21	29	34	36	34	32	29	25	23
	24	23	23	23	23	25	28	30	27	23	22	21	21	20	21	23	29	32	33	31	30	30	27	26

2030 Average Palo Verde Market Price by Month & Time of Day
nominal $/MWh

Month	Hour of Day (MST)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	37	37	38	37	37	38	40	40	32	25	22	21	19	20	21	24	36	43	44	44	43	43	43	41
2	33	33	33	32	33	34	35	32	24	20	20	19	19	20	20	21	30	41	42	41	41	40	40	38
3	33	32	33	33	33	32	32	31	23	9	8	8	8	8	8	8	9	23	37	39	37	35	35	34
4	26	25	25	25	25	26	27	23	6	3	3	3	3	3	4	5	6	16	33	38	36	34	33	33
5	30	30	30	29	29	30	30	24	8	5	6	6	6	6	7	8	10	21	36	41	41	38	37	37
6	34	33	33	33	33	33	33	27	15	15	16	16	16	16	17	19	21	28	39	42	44	40	40	39
7	38	37	37	36	36	36	36	32	27	27	29	29	29	29	30	32	35	41	48	54	55	48	47	46
8	34	33	31	30	30	30	30	30	26	28	31	31	32	32	32	34	39	44	45	52	49	44	43	41
9	39	38	38	37	37	37	38	37	24	21	22	22	22	22	23	25	29	42	48	52	48	46	46	45
10	33	33	32	33	33	33	34	34	24	13	13	14	14	14	14	14	21	44	46	45	45	45	43	42
11	32	31	31	31	31	34	37	37	24	22	22	23	22	23	23	40	48	49	49	49	49	47	44	42
12	37	36	37	36	36	39	41	41	34	29	27	28	27	27	28	33	44	45	45	45	45	45	44	43

2040 Average Palo Verde Market Price by Month & Time of Day
nominal $/MWh

Month	Hour of Day (MST)																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	41	40	38	38	38	38	39	39	28	13	11	11	11	11	11	11	31	42	45	45	45	45	45	44
2	33	32	32	30	31	32	34	30	17	15	15	15	15	13	13	15	22	37	39	38	37	39	39	37
3	26	28	28	28	27	26	26	24	11	5	4	4	4	4	4	4	5	12	38	39	37	35	34	34
4	28	28	26	25	25	25	28	14	1	1	1	1	1	1	1	1	2	7	36	42	41	40	40	40
5	43	43	43	43	43	43	44	11	0	0	0	0	0	0	1	1	2	6	41	55	52	50	49	49
6	47	47	46	46	46	46	45	13	7	7	7	7	7	7	8	9	10	18	39	53	58	53	51	50
7	64	63	62	61	61	61	61	45	24	25	26	26	25	26	28	30	32	46	73	95	100	88	88	87
8	59	58	57	56	56	55	55	50	29	28	29	30	30	30	32	35	38	49	71	86	85	76	75	75
9	59	58	55	56	56	56	56	53	16	13	14	14	14	14	15	17	21	47	76	87	82	76	75	72
10	43	43	43	43	42	42	43	43	12	4	4	4	4	4	4	4	6	54	61	60	59	59	55	55
11	45	44	44	44	44	45	44	42	16	15	15	15	15	15	17	30	64	69	69	70	70	69	70	68
12	44	44	44	43	43	45	49	46	28	22	20	20	19	20	21	26	52	53	52	54	52	53	52	54

7 Transmission

PNM is one of over 60 transmission service providers in the Western Interconnection. As a transmission operator and transmission owner, we provide open access transmission service under a standard FERC tariff and operate the transmission system within a NERC-certified balancing authority area (BAA), the PNM BAA. PNM monitors key transmission paths within the BAA and our interconnections to other BAAs to ensure the transmission system is operated safely and reliably. Established path limits identify maximum flow levels for safe and reliable operation, allowing for the loss of a major element (e.g., line, transformer, and tie point) to occur without disrupting service to customers. In most cases, customers never know when a transmission system element is out of service.

The configuration of our transmission system today, largely designed to deliver power from baseload generators in northwest New Mexico to load centers in the north and south, allows us to meet our customers' needs on a dynamic basis. In the future, we expect significant changes in the utilization of the transmission system as our portfolio and those of our neighboring utilities transition away from baseload generation resources and towards reliance on intermittent renewables. Maintaining, operating, and expanding the transmission system will be crucial to delivering new renewable resources to loads and to enable enhancements and more dynamic participation in the wholesale markets of the Western Interconnection. The importance of planning for this maintenance, operation, and expansion is acknowledged by our "Wired for the Future" initiative described in Section 1.5.6 (Grid Modernization and the "Wired for the Future" Initiative), which plans to invest approximately $450 million in the transmission and distribution systems by 2025.

In this chapter, we discuss the current dynamics of our transmission system, how we expect those dynamics to change over the next several years, and how we will consider new expansions to transmission as part of our long-term planning efforts.

7.1 Existing Transmission System

PNM's existing transmission system is shown in Figure 65 below.[36] The key elements of PNM's existing system are (1) the high voltage backbone between Four Corners and the northern load center, (2) the high voltage transmission lines that link Four Corners with the southern portion of PNM's service territory, and (3) the Eastern Interconnection Project, which has recently been expanded to facilitate delivery of wind resources to PNM's system and beyond.

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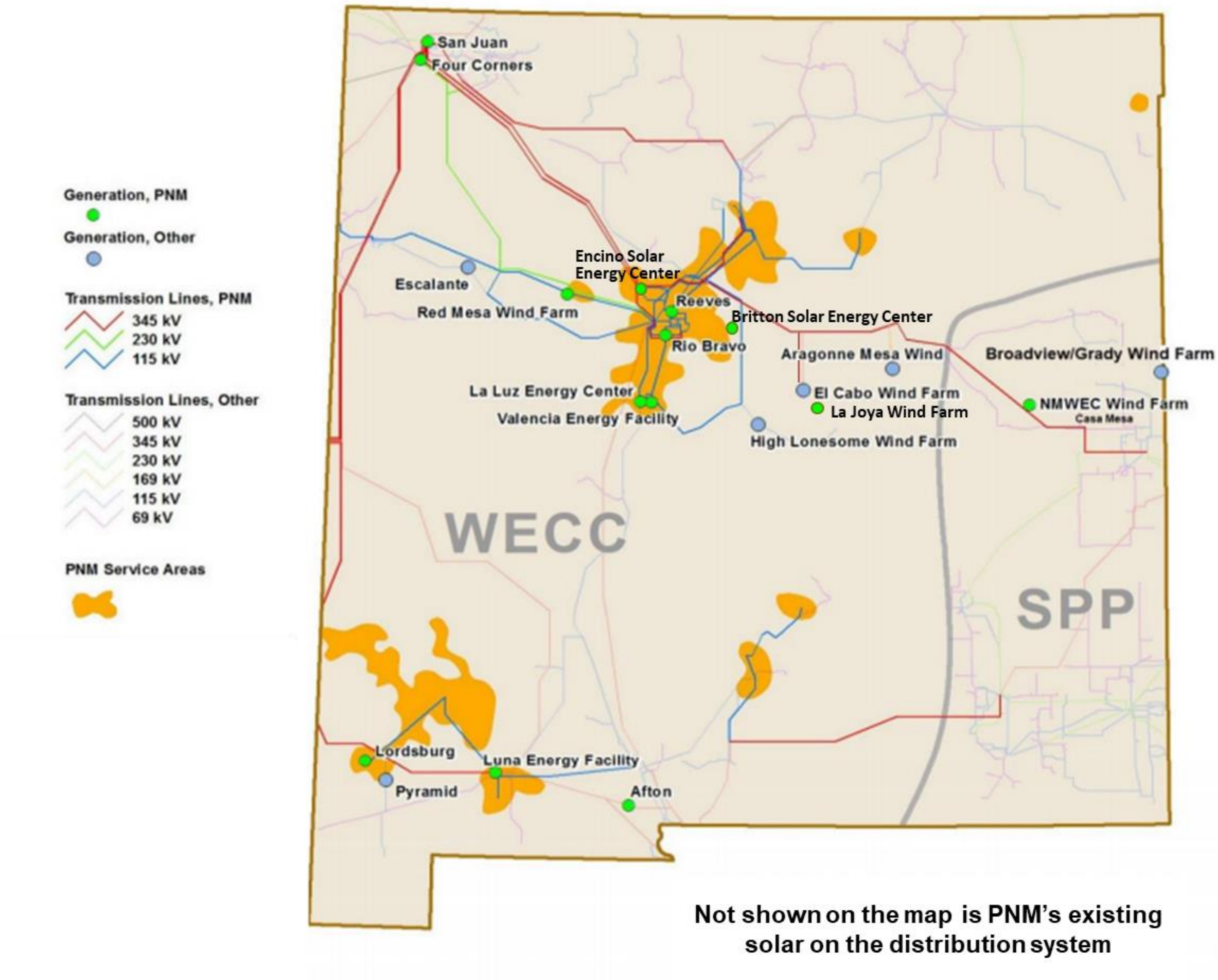
[36] A full list of PNM transmission lines and switching states appears in Appendix E

Figure 65. Map of PNM's existing transmission system



PNM's transmission system has undergone dramatic changes in its configuration and uses since its inception. The initial system consisted of 46 kV and 115 kV lines used to deliver "locally" generated energy to "local" loads. In the 1950s and 1960s, some lines between the cities were built so local generators could provide backup support to each other, and an associated increase in reliability of service was attained. PNM's first tie to the "outside world" was a 230 kV line to Four Corners built in 1962, concurrent with the construction of the original FCPP.

The basic 345 kV transmission system that is in place today was developed in the late 1960s and early 1970s as New Mexico's load grew and as the larger coal-fired generating units at FCPP and SJGS were constructed. This shifted large baseload generation from local to remote resources away from load centers, partly because of environmental, economic, water, and fuel availability considerations, whereas smaller and less efficient intermediate and peaking units were located within the load centers. The availability of remote resources with a mix of low-cost coal and nuclear fuel resulted in the dispatch of generating plants near the load centers being limited to peak hours of the summer or when transmission system import limits would otherwise be exceeded.

The last PNM backbone transmission line was completed in 1984, when PNM constructed the Eastern Interconnection Project. This line, a 216 mile, 345 kV line from the Placitas area north of Albuquerque located at BA 345 kV Switching Station to Clovis, New Mexico, connected PNM with Southwestern Public Service (SPS) in the Eastern Interconnection through the Blackwater AC-DC-AC converter station. During the 1990s, PNM pursued the Ojo Line Extension (OLE) project to complete a third 345 kV path from the Four Corners area to the major load centers to reinforce the 345-kV backbone transmission system and increase import capability into the northern New Mexico system. Ultimately, the CCN for permission to build the OLE project was denied and PNM focused its efforts on transmission reinforcements that maximized the use of the existing northern New Mexico system transmission lines and location of resources near the load centers in Northern New Mexico.

Today, the “backbone” of the system consists of the 345 kV lines and 230 kV line built in the 60’s and 70’s that connect the Four Corners area in northwest New Mexico to load centers in the Southeast and South. Power flow on these lines is typically from north to south due to the location of baseload generation resources in the Four Corners area and in Arizona. In southern New Mexico, PNM is a joint owner in two 345 kV lines that run from eastern Arizona to the Southeast and East towards El Paso, Texas. Historically, power has flowed in an easterly and southerly direction on these 345 kV lines. Large autotransformers located at load centers are used to step down the system voltages to the 115 kV level. Substations located on 115 kV, 69 kV and 46 kV lines further step the voltages down to distribution system voltages for delivery to end users.

In addition to these resources, PNM purchases transmission service from a number of other transmission service providers within the region to allow for the delivery of our generation to serve our loads. PNM has the right to continue taking long-term firm transmission service in accordance with FERC policy. These agreements are summarized in Table 27.

Table 27. Transmission service agreements with neighboring transmission service providers

Service Provider	Transmission Service Description
Arizona Public Service	PNM contracts with APS for point-to-point service to deliver output from PVNGS to PNM’s system: • Non-OATT bilateral contract for 130 MW from Phoenix to Four Corners • OATT transmission service for a total of 145 MW from 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 (a load of approximately 3.5 MW)
El Paso Electric	PNM contracts with EPE for point-to-point services to facilitate transfers between northern and southern New Mexico: • 295 MW to deliver resources from south to north • 25 MW to deliver resources from north to south
Western Area Power Administration	PNM and WAPA have a transmission exchange agreement under which: • WAPA provides 134 MW of service between Phoenix and Four Corners to deliver output from PVNGS to PNM system • PNM provides 247 MW of service from Four Corners to various New Mexico delivery points

Because of the configuration of the New Mexico system (i.e., the locations of the loads, generation, and major transmission lines), a large portion of the power used to serve PNM and its transmission customers' load flows across the northern New Mexico system, independent of where it is generated. All generation transmitted to PNM load in North Central New Mexico, from the Four Corners area and the western grid, flows on the northern New Mexico system. Generation resources in southern New Mexico are also delivered to customers in the northern New Mexico system across Path 47.

Figure 66. Diagram of key transmission constraints in PNM system

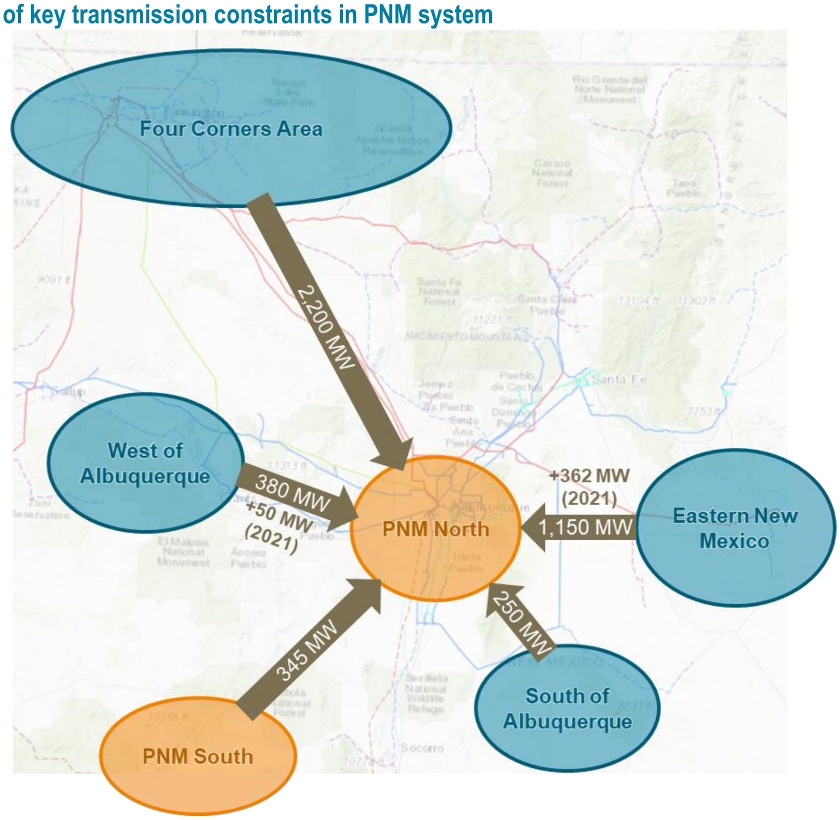


Figure 66 highlights the key resource and load zones. The arrows in the figure indicate the firm transmission capacity from each zone into the PNM North load center, with planned expansion indicated just above and below relevant connections. As described in the following subsections, the transmission capacity into PNM North is nearly fully subscribed today. Given this level of transmission, 498 MW of capacity must be available within the load center to ensure reliability. Keeping this capacity available, or replacing it with firm transmission, in the face of a changing resource mix is a key challenge of our transmission planning during the IRP window.

PNM's Northern Load Center

Our ability to meet demands reliably within the northern load area depends on both our transmission system and the generation resources we currently have within the load pocket. The existing bulk transmission system alone is not designed with the capability to meet our highest demands with resources from outside the load pocket. Accordingly, despite the low capacity factors of load-side resources, Reeves Generating Station, Rio Bravo, and the Valencia PPA provide crucial capability to ensure reliability, both during peak demand periods and in the event of transmission outages.

Notwithstanding the typically low capacity factors of load-side resources, the ability to produce electricity at a predictable level across extended periods as needed makes such resources crucial for maintaining local reliability. At the same time, our plan assumes that the Valencia PPA will expire in 2028 and that we will retire Reeves by the end of its depreciable life in 2030. With the loss of the capabilities provided by these units, maintaining the ability to serve loads reliably in the north will require investment in new load-side resources, new transmission, or a combination of the two.

Southern Transmission System

PNM's southern New Mexico system delivers power to a combination of jurisdictional service territories which include Deming, Silver City, Lordsburg, Alamogordo, Ruidoso, and Northern New Mexico. The southern New Mexico system also contains three solar facilities and three natural gas fired generation facilities at Afton, Luna, and Lordsburg that are integrated into PNM's resource portfolio to effectively dispatch and serve load while minimizing overall utility costs. In addition to our ownership share in Path 47, we purchase transmission service over EPE's system to deliver power to a portion of the load served in the Alamogordo area and from TEP for a portion of the load in the Deming and Silver City areas. We also purchase transmission service from EPE and TEP to move a portion of southern New Mexico generation to northern New Mexico.

Afton, Luna, and Lordsburg generation resources provide a total of 510 MW of capacity. Because they are located inside the Path 47 transmission boundary, these resources can adequately serve loads in southern New Mexico. Power delivery rights over a combination of PNM, Tri-State, and EPE assets combine for 345 MW of transmission rights from southern New Mexico to northern New Mexico that allow this generation to serve loads in the north when needed.

Currently, there are ample generation resources in southern New Mexico to serve all PNM loads in the southern New Mexico system. In addition, PNM has rights to approximately 75 MW of transmission resources for delivering power from northern New Mexico to southern New Mexico across the Path 47 transmission boundary.

Four Corners Area

The transmission lines connecting the Four Corners area to our load center in Albuquerque has been the historical backbone of the PNM transmission system. This part of our system was designed to transmit the baseload output from SJGS, FCPP, and PVNGS to PNM's largest load center in Northern New Mexico.

While the capacity provided by these lines remains crucial for meeting our peak demands reliably, the utilization of this part of our transmission system has changed notably with recent additions of intermittent renewable resources in northern and eastern New Mexico. Increased delivery of renewable energy into the northern New Mexico load pocket has led to reduced flows on the system between Four Corners and Albuquerque – and, in some instances, the prevailing historical direction of flow has reversed during periods of high renewable production. We expect this trend to continue.

Over the next five years, our plans include abandonment of a total of 811 MW of capacity that are delivered to Albuquerque loads from the Four Corners region: SJGS (497 MW), FCPP (200 MW), and the expiring leases of PVNGS (114 MW). These abandonments free up a similar amount of capacity from the transmission system that can be repurposed to enable development of future resources in the northwestern part of the state.

The headroom on the transmission system created by abandonment of SJGS will largely be exhausted by the portfolio of solar and storage replacement resources approved by the Commission in Case No. 19-00195-UT. However, the future abandonments of FCPP and leased shares of PVNGS will create additional headroom on the transmission system. Our planning efforts assume that these abandonments enable up to 314 MW of existing transmission to be repurposed for new resource development by 2025.

Eastern New Mexico

Development of wind resources in eastern New Mexico has resulted in the expansion of the transmission capacity out of eastern New Mexico. The high-quality resources present in the eastern part of the state have attracted interest from developers and offtakers outside the state of New Mexico, and a significant amount of the new capacity contemplated would contribute to the clean energy goals of neighboring western states. To date, PNM and merchant transmission developers have together undertaken significant expansions to the Eastern New Mexico transmission system to enable interconnection of these resources.

In New Mexico, wind resources in the eastern portion of the state currently include 250 MW connected at Taiban Mesa serving PNM loads, 90 MW connected at Guadalupe serving Arizona loads, and approximately 790 MW connected at Blackwater and Clines Corners serving California loads. These resources interconnect to PNM's 216-mile 345 kV transmission line from the BA 345 kV switching station (north of Albuquerque) to PNM's Blackwater 345 kV Station (in the Clovis-Portales area of eastern New Mexico), known as the Eastern Interconnect Project (EIP). An additional wind farm will be connected and injecting 306 MW of generation at Clines Corners by the end of 2020. This wind farm was dependent on the completion of a second 345 kV line between Clines Corners and PNM's BA Switching Station, known as the BB2 line. The addition of this wind farm, along with the existing wind farms, has resulted in 1362 MW of firm transmission service between Clines Corners and BA Station.

Figure 67. Eastern Interconnect Project

By the end of 2021, the most ambitious transmission project in New Mexico since the mid-1980's is expected to be completed. This project, known as the Western Spirit Transmission Project, will allow for the interconnection of an additional 800 to 950 MW of wind resources. The project is being developed by Pattern Energy and will be acquired by PNM upon completion. The project is expected to be fully subscribed upon initial energization and will allow total wind resources in eastern New Mexico to be expanded to approximately 2300 MW.

West of Albuquerque

To the West of Albuquerque, roughly 350 MW of existing generation rely on PNM's transmission system to meet PNM and Network Transmission Customer loads in Northern New Mexico. With the anticipation of an additional 50 MW in 2021, this portion of our transmission system will be nearly fully subscribed.

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 system. Like other parts of our transmission system, this area is fully subscribed.

7.2 Transmission Planning

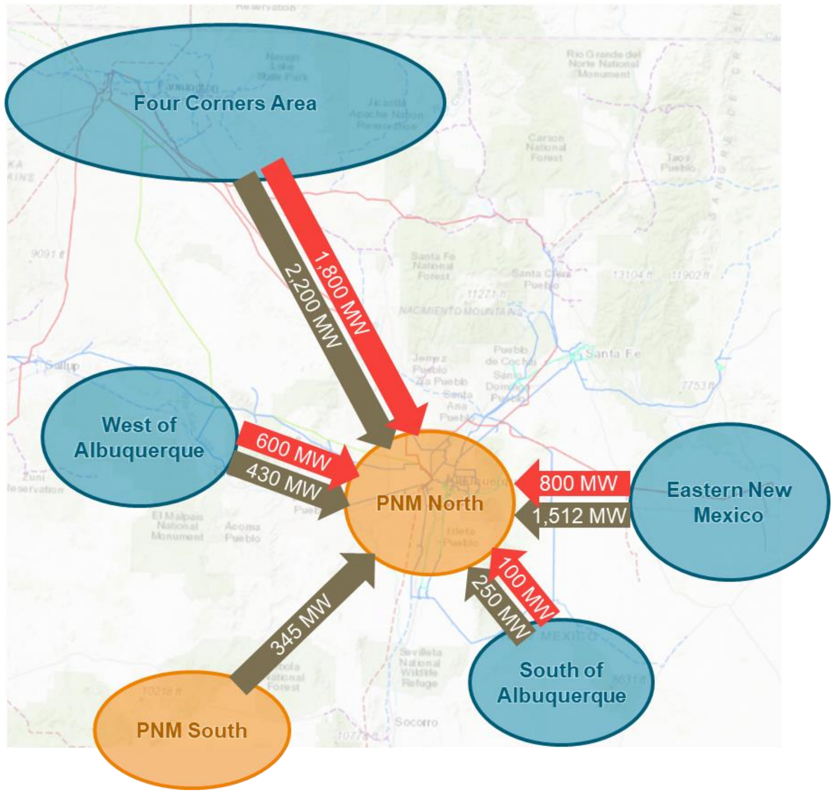
7.2.1 New Transmission Projects

While New Mexico is endowed with significant amounts of high-quality wind and solar resource potential, many of the most suitable sites are located far from our load centers and require transmission. The scale of renewable development needed to achieve our long-term goals will require significant new investments in the transmission system to allow the delivery of renewable energy resources to PNM and Network Transmission Customer loads.

Some of the conceptual transmission projects under consideration represent reinforcements and upgrades to existing transmission corridors to increase the capacity to deliver renewables to loads. While these types of projects are smaller in scope than projects requiring new corridors and right of way, they nonetheless require significant up-front planning, as the permitting and construction processes together can still take up to a decade in some cases. Transmission is inherently a lumpy investment, and siting, permitting, cost, and construction timelines for new transmission line projects will continue to be a challenge. It is accordingly incumbent upon our IRP process to provide an early indication of the types, locations, and scale of transmission investments needed to complement the future generation portfolio long in advance of the time they are needed.

Figure 68 shows a simplified representation of the existing transmission system with red arrows indicating the areas where considerable major new investments in transmission may be needed. Generally, transmission projects enable access to resources in the same five parts of the state discussed above: to the west (1) and immediately south (2) of Albuquerque, where solar resources are highest quality; in the Four Corners area (3) of the state, where solar is suitable for development; in the east (4) of the state, where the highest capacity factor wind resources are located; and in southern New Mexico (5).

Figure 68. Primary transmission expansion projects considered in IRP analysis.

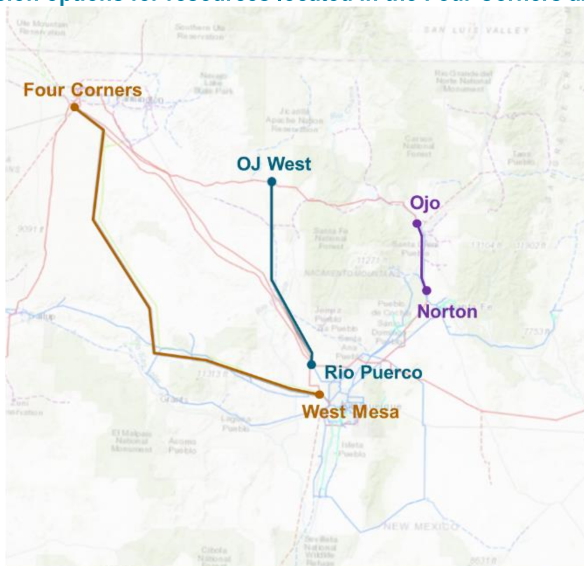


The remainder of this section provides some high level conceptual transmission expansion options that could unlock access to increased quantities of renewables in the various regions of the state.

Four Corners Area

PNM has identified three conceptual transmission projects that could increase transmission capacity for the renewable potential in the Four Corners area of the state. PNM would expect a single project to provide about 600 MW of transmission capacity. These conceptual projects are shown in Figure 69. The projects are expected to require permitting processes with long lead times and in some cases could lead to high costs.

Figure 69. Transmission expansion options for resources located in the Four Corners area of New Mexico

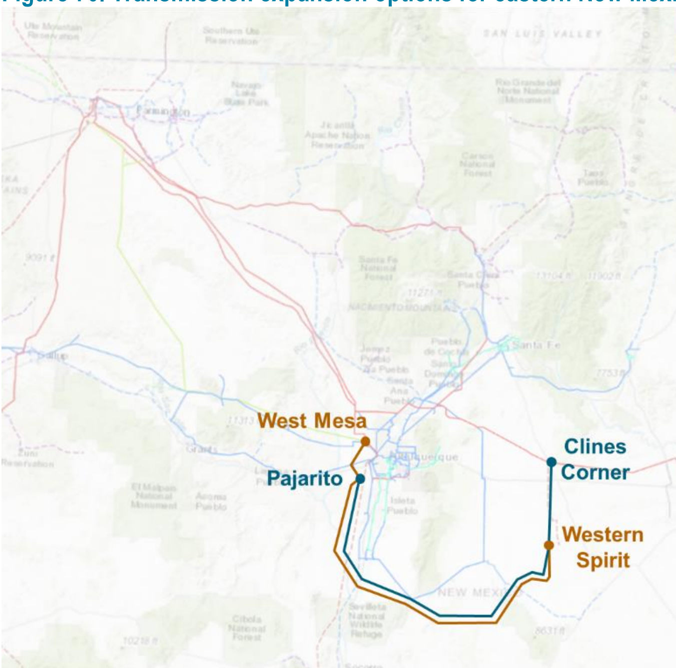


Project Name	Four Corners-West Mesa Expansion	Rio Puerco-OJ West Transmission Project	Ojo-Norton Transmission Project
Project Size	600 MW	600 MW	600 MW
Project Cost	$400+ million	$200+ million	$100+ million
Permitting / CCN Timing	5 years	5 years	5 years
Generation Options	Solar, Pumped Storage, Combustion Turbines		Solar, Pumped Storage, Combustion Turbines
Project Elements	• Expand Four Corners and West Mesa 345 kV substations • Install 345 kV stations and 345/230 kV transformers at Pillar, Bista, and Ambrosia • Install two 345 kV switchable shunt reactors • Rebuild Four Corners-West Mesa 230 kW to 345 kV line (180 miles)	• Expand Rio Puerco and OJ West 345 kV substations; • Install two 345 kV switchable shunt reactors; • Build OJ West-Rio Puerco 345 kV line (80 miles)	• Expand Ojo and Norton 345 kV stations • Build Ojo-Norton 345 kV line (34 miles)

Eastern New Mexico

We expect that significant new resources in eastern New Mexico will require addition of transmission beyond the Western Spirit Project. Options are limited but several have been reviewed in recent transmission studies. Lead times can be considerable. One of the options is shown in Figure 70 which assumes a project along the same corridor and of similar scope to the Western Spirit Project.

Figure 70. Transmission expansion options for eastern New Mexico resources

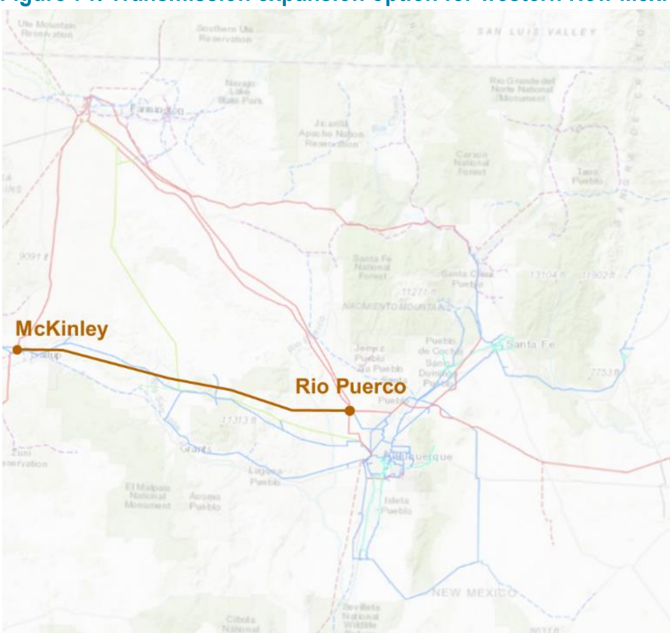


Project Name	Western Spirit-Pajarito Expansion
Project Size	800 MW
Project Cost	$360 million
Permitting / CCN Timing	5 years
Generation Options	Wind
Project Elements	• Expand Western Spirit & Pajarito 345 kV stations • Build Western-Spirit Pajarito 345 kV (135 miles) • Install 345 kV series compensation • Install two 345 kV switchable shunt reactors

West of Albuquerque

The area West of Albuquerque has considerable potential for solar resources and includes wind resources that have potential for expansion. Transmission facilities in the area include two 115 kV lines with capacity that is fully committed to existing resource obligations. Resource additions on Albuquerque's West Mesa can potentially be accommodated with addition of 115 kV transmission between northern Sandoval County and southern Bernalillo County. Resources further west may require more extensive transmission including 345 kV transmission additions extending from the Arizona border to Albuquerque. A conceptual project that could accommodate approximately 600 MW of resources west of Albuquerque is shown in Figure 71.

Figure 71. Transmission expansion option for western New Mexico resources

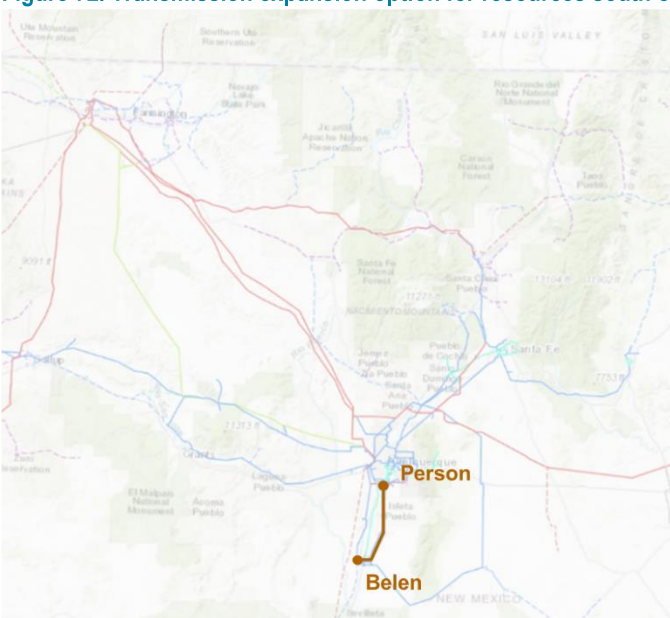


Project Name	McKinley-Rio Puerco Transmission Project
Project Size	600 MW
Project Cost	$170 million
Permitting / CCN Timing	5 years
Generation Options	Solar
Project Elements	• Expand McKinley and Rio Puerco 345 kV substations • Build McKinley-Rio Puerco 345 kV (125 miles) • Install two 345 kV switchable shunt reactors • Install 345/115 kV transformer and new 345 kV & 115 kV stations

South of Albuquerque

Numerous solar projects have been proposed which are south of the Albuquerque metropolitan area in Valencia county. Gas resources and recent distribution connected solar projects in the area have resulted in fully subscribed transmission capacity between Belen and Albuquerque. Transmission enhancements will be needed to locate additional resources in Valencia County. PNM has an existing 115 kV line operating at 46 kV which shares poles with an existing 115 kV line to Tome. Conversion of this line to 115 kV operating will provide approximately 100 MW of additional capacity. This plan is shown in Figure 72. Studies performed for interconnection requests have also shown that capacity could be added by rebuilding existing circuits south of Huning Ranch. Such efforts would be expected to have at least a 3-year lead time.

Figure 72. Transmission expansion option for resources south of Albuquerque



Project Name	Belen-Person Expansion
Project Size	100 MW
Project Cost	$25 million
Permitting / CCN Timing	2 years
Generation Options	Solar
Project Elements	• Convert BP 46 kV line to 115 kV • Expand Belen and Person 115 kV stations • Reconductor existing Person-Prosperity-KAFB 115 kV line

Southern New Mexico

Specific projects have not been proposed for expansion of transmission between Northern and Southern New Mexico. Projects would be expected to have high costs and long lead times. Past studies have looked at possible means of connecting or enhancing existing 345 kV facilities running from Albuquerque to Las Cruces and approximately Saint John, Arizona to Deming to provide for better utilization of the facilities. These assets are primarily owned by El Paso Electric Company. PNM may have some limited remaining opportunity to move resources to Northern New Mexico from areas around Lordsburg or Deming by purchasing wheeling from neighboring transmission providers. It is expected that PNM will continue to need resources located in southern New Mexico to serve existing loads in the area.

7.2.2 Treatment in Modeling

As discussed in Section 5.4 (Modeling Tools and Methods), Encompass includes capability to optimize generation and transmission expansion jointly with an explicit zonal representation of the transmission network; while we explored this functionality during the development of the IRP, its complexity ultimately proved prohibitive for incorporation in this IRP. Rather than modeling transmission upgrades explicitly as decisions in the model, we apply transmission adders to specific resources located outside of our load zones based on the characteristics of the projects discussed above.

In an effort to support harmonization of our generation and transmission planning efforts, we will continue to refine the co-optimization functionality offered within Encompass. To illustrate the potential insights that this approach could provide, we present and discuss results from several select model runs using this functionality in Section 8.7 (Additional Portfolios Studied).

7.2.3 Regional Transmission Planning

Numerous organizations are involved in planning coordination of the western grid. In addition to the planning meetings that PNM sponsors twice per year, PNM also participates in the WECC Planning Coordination Committee, WestConnect Planning Committee, and the Southwest Area Transmission Planning Oversight Committee (SWAT).

This is important to the IRP process because developments within WECC that affect PNM's transmission operations will have the potential to affect or influence future resource selections. PNM participates in these committees and transmission groups to stay informed and to protect the interests of customers served from our utility-owned transmission assets. New operating ideas or concepts start in small regions of the system and, as they are tested and evaluated, they are shared with neighboring utilities. It is important that PNM continues its participation because it allows the company to leverage lessons learned from others.

WECC Planning Committees

PNM is a member of WECC and its mission is to coordinate and promote electric system reliability. In addition, WECC works to support efficient competitive power markets, ensure open and nondiscriminatory transmission access, provide a forum for resolving transmission access disputes, and provide an environment for coordinating the operating and planning activities of the Western Interconnection. WECC is one of eight electric reliability councils in North America. Membership in WECC is open to all entities with an interest in the operation of the bulk electric system in the Western Interconnection.

PNM participates in the planning functions of WECC through the Planning Coordination Committee (PCC). PNM has membership in several of the PCC subcommittees and workgroups that focus in varying degrees on transmission planning and coordination activities. The PCC is chartered to do the following:

- Recommend criteria for the guidance of the members, for adequacy of power supply, and for such elements of system design that affect the reliability of the interconnected bulk power systems
- Accumulate necessary data and perform regional studies of the operation of the interconnected systems necessary to determine the reliability of the western regional bulk power network
- Evaluate proposed additions or alterations in facilities in relation to established reliability criteria
- Identify the types and investigate the impact of delay on the timing and availability of power generation and transmission facilities

- Review reports and recommendations prepared by subcommittees and others concerning reliability and adequacy of power supply and then forward reports or recommendations with comments and/or recommendations to the Board of Directors in a timely manner
- Prepare appropriate reports and maps of planning information for governmental regulatory agencies, reliability councils, and others, as required.

WestConnect Planning Committee

WestConnect is composed primarily of utility companies providing transmission of electricity in the southern portion of the Western Interconnection. Members work collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to the western wholesale electricity market. WestConnect is committed to coordinating its work with other regional industry efforts to achieve as much consistency as possible in the Western Interconnection. In 2007, WestConnect executed the WestConnect Project Agreement for Subregional Transmission Planning (STP Project Agreement), of which PNM is a signatory. The agreement establishes the terms for developing a coordinated transmission expansion plan within the WestConnect footprint that covers the desert southwest as well as utilities and stakeholders in Colorado, Wyoming, Nevada, and parts of California. The transmission studies are typically performed under one of the WestConnect STP groups and feed into the coordinated plan. PNM is a member of the SWAT STP group listed next.

Southwest Area Transmission Planning Oversight Committee

SWAT includes transmission regulators/governmental entities, transmission users, transmission owners, transmission operators, and environmental entities. The goal of SWAT is to promote regional planning in the Desert Southwest. The SWAT regional planning group includes several subcommittees, which are overseen by the SWAT Oversight Committee. PNM chairs the New Mexico subcommittee of SWAT, which focuses on stakeholder coordination of transmission expansion among the utilities and market participants in New Mexico.

Other Transmission Planning Committees

PNM has established a Network Integration Transmission Customer Operating Committee that meets twice a year. The meetings are used to provide direct communications with PNM's network customers. The transmission system improvement needs within the PNM control area including PNM's transmission expansion plans are standard topics for discussion at these meetings.

From time to time, PNM participates in planning efforts where parties may wish to look at a common solution for multiple interests. Although these activities are not directly under the WECC or WestConnect committees, results of analyses and stakeholder input are frequently shared in WECC and WestConnect forums.

7.3 Merchant Transmission Projects

New Mexico’s high quality renewable resources has attracted significant commercial interest from offtakers throughout the West, which has in turn led to proposals for a number of merchant transmission projects to deliver those resources to various load centers in the region. Today, a number of new regional transmission projects are in various stages of development within New Mexico. These projects, summarized in Figure 73, include the following:

- **Lucky Corridor (345 kV) and the Mora Line (115 kV):** projects under development by Lucky Corridor LLC that would enable increased transfer capability towards the Four

Corners area from northeastern New Mexico and southeastern Colorado. This area has significant wind resources but extremely limited transmission infrastructure due to the rural lightly populated nature of the area and its location at the far eastern edge of the Western transmission grid.

- **Southline (345 kV):** a project under development by Southline Transmission LLC consisting of a new right-of-way and an upgrade of an existing corridor linking New Mexico to wholesale markets in Arizona.
- **SunZia (500 kV):** a new high voltage line under development by the Southwestern Transmission Group from central New Mexico to Arizona.
- **Western Spirit (345 kV):** a new line between Eastern New Mexico and Albuquerque under development by Pattern Energy that will be transferred to PNM after completion. This project was discussed above.
- **Integration of Generation Ties (345 kV):** Wind developers in eastern New Mexico have built several radial 345 kV lines in order to connect wind resources to PNM's transmission system. Depending on additional resource needs in eastern New Mexico it is possible that some of these additions could be integrated into the looped system enhancing transfer capability.

Figure 73. Merchant transmission projects in development in New Mexico

A number of these projects are designed to transmit renewable electricity out of New Mexico to utilities in California, Arizona, and potentially elsewhere. The configuration of these lines –

particularly SunZia and Southline – does not present a significant opportunity to PNM to develop and deliver resources to our own loads under currently planned configurations. Additional studies may show opportunities to better integrate the facilities to serve New Mexico load. Nonetheless, PNM will continue to monitor new opportunities presented by merchant transmission developers (or other potential partners) as we pursue our own plans to develop renewables within the state.

8 Portfolio Analysis

In this section, we review the model results for the analysis framework described in Section 5.1. We begin with an overview of portfolio results that outlines for each scenario the installed capacity, cost, carbon emissions, resource adequacy, and typical hourly operations. Following this, we discuss uncertainty and risk in the portfolios through analysis of different futures and sensitivities, as well as through qualitative discussion of key hard-to-quantify factors. Finally, we provide results of additional portfolios that fall outside the main analysis framework. These portfolios are a combination of suggestions from stakeholders, analyses done to answer specific but tangential questions, and early tests of new model functionality that might be brought into future IRP models.

Section Highlights
• Our analysis identifies multiple plausible plans to achieve the transition to a carbon-free portfolio by 2040 while preserving reliability. All portfolios will require PNM to make significant investments in solar, storage, and demand-side resources; portfolios without technology restrictions also include hydrogen-ready combustion turbines for resource adequacy. All of these potential plans meet the requirements of the ETA. • As we transition to higher penetrations of renewables, the most challenging periods for maintaining reliability will shift from the afternoon peak period to the evening after sunset. Resources that can provide stable and sustained output during non-daylight hours are essential to maintaining resource adequacy under these conditions. • The way our system operates will also change dramatically under all cases: whereas today's system relies predominantly on the load-following capabilities of our coal and gas resources to balance load, in the future, we will rely on storage, flexible gas, and renewable curtailment to manage "net load" dynamically. • Scenarios that impose restrictions upon our investment choices generally result in higher costs to our customers; this finding holds true across a wide range of futures and sensitivities and is considered a robust result. These scenarios also present different risks to our customers; the most substantial risk we foresee is the failure of storage resources to provide the resource adequacy value expected in this analysis, which could result in a lower level of reliability than acceptable.

8.1 Portfolio Results

The following results show installed capacity and energy mix for the two scenarios introduced in Section 5.1 (Scenario Analysis Framework):

1. The **Technology Neutral** scenario, which does not constrain resource choices;
2. The **No New Combustion** scenario, which prohibits additions of any new combustion resources, including hydrogen-ready CTs.

The contrast between these two scenarios provides useful insights to inform our future planning and procurement choices.

Technology Neutral

The Technology Neutral scenario represents a least-cost portfolio that complies with the ETA, meets our reliability standards, and achieves our own environmental goals. This portfolio comprises a mix of new resources that include solar, wind, various storage technologies, incremental demand-side resources, and hydrogen-ready CTs. Highlights include:

- In 2022, abandon our share of SJGS and bring online the ordered replacement resources, comprising solar, storage, and incremental DSM[37];
- Between 2023 and 2025, meet growing loads and replace capacity from PVNGS leases and FCPP with a mix of solar (240 MW), hydrogen-ready CTs (280 MW) and lithium ion batteries (223 MW) while continuing to expand incremental DSM programs (68 MW);
- Between 2028 and 2031, meet growing loads and replace the expiring Valencia PPA and our retiring Reeves Generating Station with battery storage (211 MW), hydrogen-ready CTs (120 MW), and incremental DSM programs (27 MW);
- By 2040, retire Afton, Luna, and Rio Bravo plants; convert La Luz, Lordsburg, and new CTs to run on hydrogen, and add significant additional quantities of wind, solar, and various energy storage resources.

Figure 74 shows the total installed capacity of resources in this scenario over the twenty-year analysis horizon; Table 28 shows the specific new investments and retirements made over the first five years of the plan. Figure 75 shows the portfolio's energy mix at several key milestones as our portfolio transitions towards our 2040 goal of eliminating carbon emissions.[38] By 2025, after our exit from coal, nearly 75% of our annual energy needs are supplied by carbon emissions-free resources. By 2040, our portfolio no longer includes any carbon-emitting resources. At this point, nuclear, wind, and solar are the predominant sources of energy in our generation mix; hydrogen is burned in combustion turbines when needed for reliability but represents a very small share of our annual energy mix.

[37] DSM resources still pending approval at the time this IRP is filed

[38] Note that storage is not reflected in our generation mix since it does not produce energy; rather, it serves as a balancing resource to help match supply and demand.

Figure 74. Total installed capacity by year in the Technology Neutral scenario

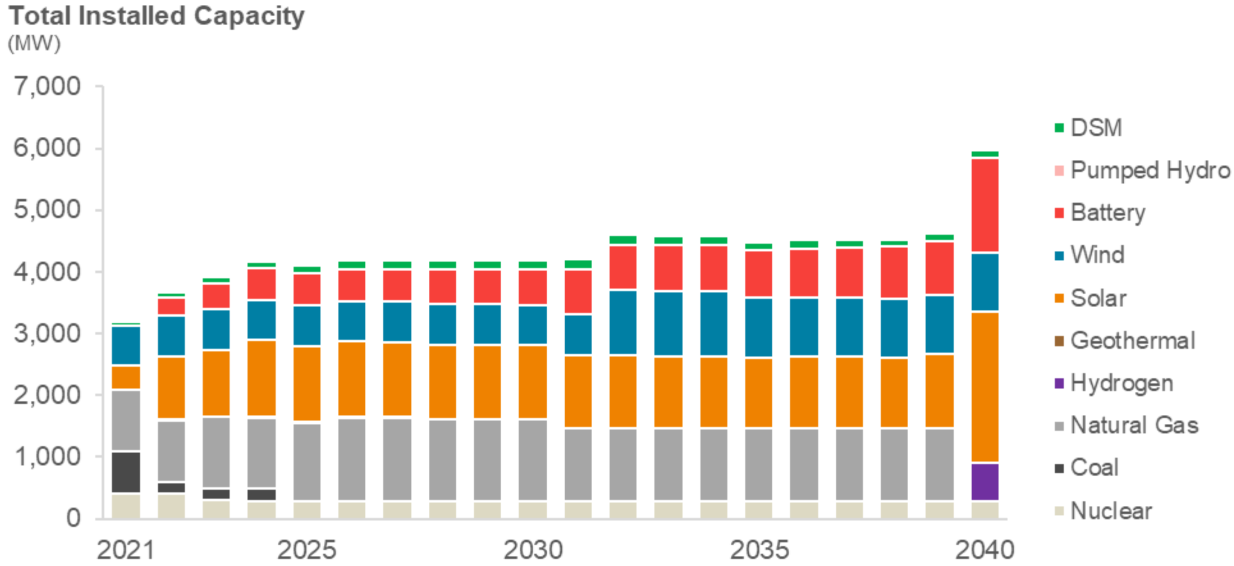
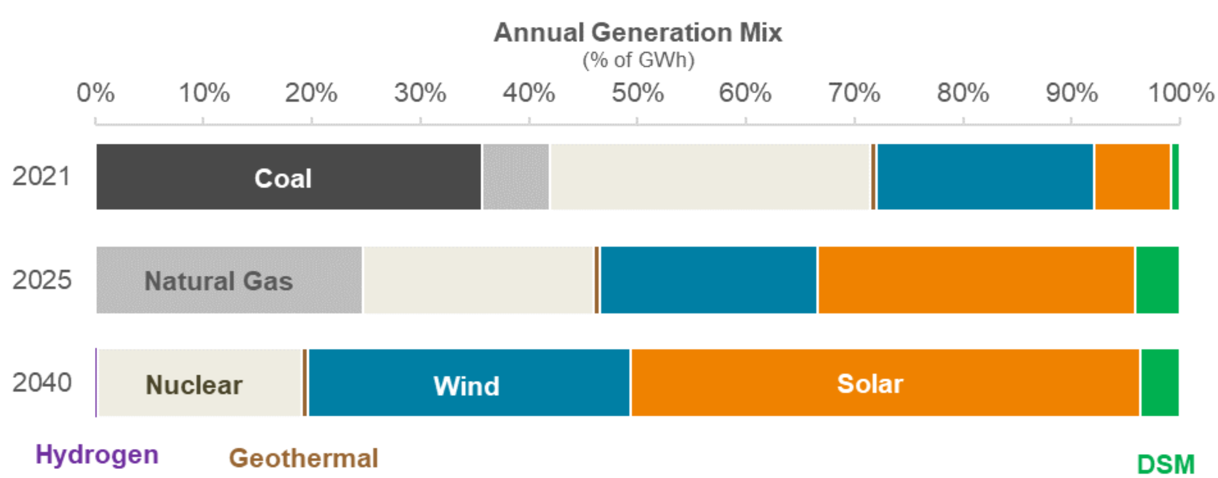


Table 28. Annual installed capacity additions and retirements between 2021-2025 (Technology Neutral scenario)

	Technology	2021	2022	2023	2024	2025
Additions	Solar	99	650	50	190	-
	Wind	-	-	-	-	-
	Battery Storage	-	300	123	100	-
	Pumped Storage	-	-	-	-	
	H_2-Ready CTs	-	-	160	-	120
	DSM	20	35	20	24	24
Retirements	Nuclear	-	-	-104	-10	-
	Coal	-	-497	-	-	-200

Figure 75. Generation mix at key milestones in the Technology Neutral scenario



No New Combustion

Our analysis finds that we may also be able to meet the IRP's environmental and reliability objectives if investments in new resources are restricted to renewables, storage, and incremental DSM. The No New Combustion scenario restricts resource additions accordingly. Again, this portfolio complies with the ETA, meets our reliability standards, and achieves our own environmental goals. Highlights include:

- In 2022, abandon our share of SJGS and bring online the ordered replacement resources, comprising solar, storage, and incremental DSM[39];
- Between 2023 and 2025, meet growing loads and replace capacity from PVNGS leases and FCPP with solar (302 MW) and lithium ion batteries (507 MW) while continuing to expand incremental DSM programs (68 MW);
- Between 2028 and 2031, meet growing loads and replace the expiring Valencia PPA and our retiring Reeves Generating Station with solar (220 MW) and battery storage (375 MW) and incremental DSM programs (27 MW);
- By 2040, retire remaining gas plants and add significant additional quantities of wind, solar, and various energy storage resources.

Figure 76 shows the total installed capacity of resources in this scenario over the twenty-year analysis horizon; Table 29 shows the specific new investments and retirements made over the first five years of the plan. In the No New Combustion scenario, our energy mix scenario is similar to the mix in the Technology Neutral scenario throughout the twenty-year analysis horizon: the portfolio reaches approximately 75% carbon emissions-free generation by 2025 and transitions over the next fifteen years to 100% carbon emissions-free by 2040.

The similar energy mix observed in the two scenarios result from the fact that the main factor differentiating them is how they satisfy resource adequacy requirements. Whereas the Technology Neutral scenario includes a combination of hydrogen-ready CTs and a variety of storage resources, the No New Combustion scenario requires increased investments in energy storage. Both reliance on development of a carbon emissions-free fuel for CTs and reliance on energy storage have their own associated risks; these risks are discussed throughout Sections 8.4 (Implications for Resource Adequacy), and 8.5 (Implications for Operations), and 8.6 (Alternative Futures & Sensitivities).

[39] DSM resources still pending approval at the time this IRP is filed

Figure 76. Total installed capacity by year in the No New Combustion scenario

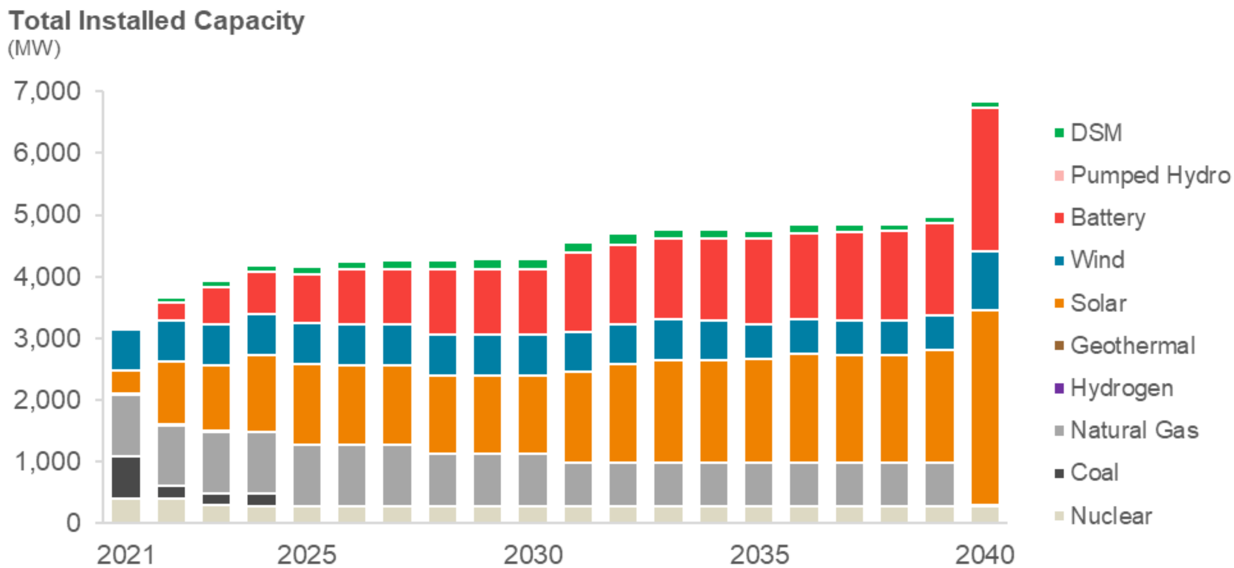
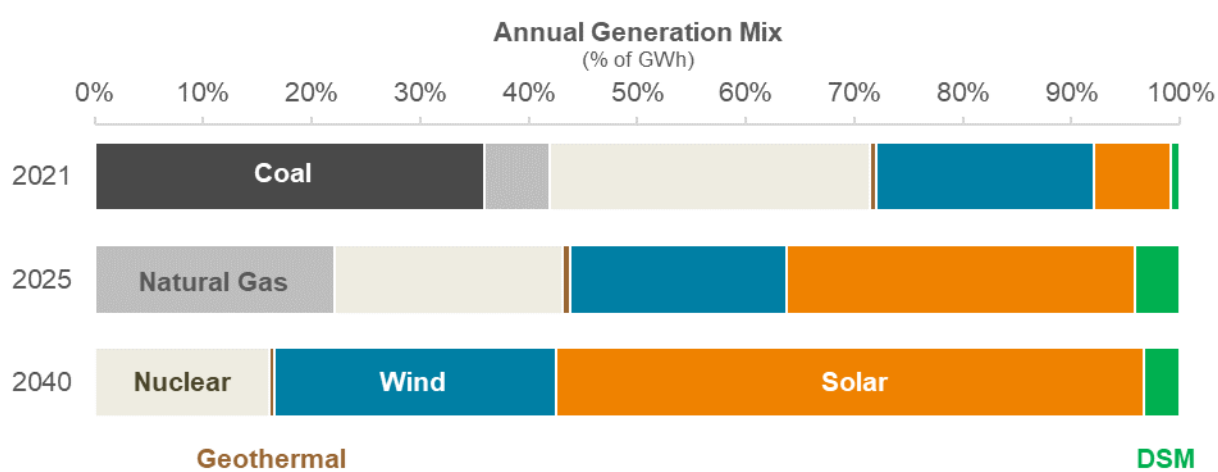


Table 29. Annual installed capacity additions and retirements between 2021-2025 (No New Combustion scenario)

	Technology	2021	2022	2023	2024	2025
Additions	Solar	99	650	50	190	62
	Wind	-	-	-	-	-
	Battery Storage	-	300	299	100	107
	Pumped Storage	-	-	-	-	-
	H_2-Ready CTs	-	-	-	-	-
	DSM	20	35	20	24	24
Retirements	Nuclear	-	-	-104	-10	-
	Coal	-	-497	-	-	-200

Figure 77. Generation mix at key milestones in the No New Combustion scenario

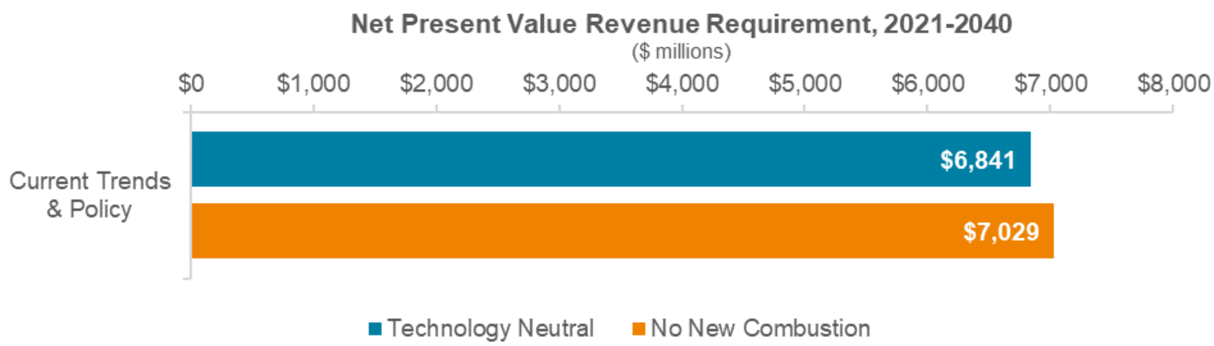


8.2 Cost Impacts

The primary cost metric we use to evaluate our portfolios is the **net present value revenue requirement**, which measures the cumulative discounted costs of the generation resources in our portfolio.

Figure 78 compares the net present value cost of these two scenarios under the "Current Trends and Policy" future. That the Technology Neutral scenario produces the lowest cost outcome for our customers across the twenty-year analysis horizon is expected; this scenario is the least constrained in terms of technology.

Figure 78. Comparison of NPV revenue requirement (2021-2040) across scenarios



Compared to the Technology Neutral scenario, the No New Combustion scenario results in additional costs to customers of $188 million over the twenty-year IRP period. The incremental cost is driven by additional investments needed to ensure reliability. Specifically, in the No New Combustion scenario:

- Additional investment in wind and solar is needed to supply carbon emissions-free energy in spite of their intermittency and variability; and
- Additional investments in storage resources are necessary to ensure resource adequacy; longer duration storage resources, which generally have higher investment costs than four-hour lithium ion batteries, are needed to compensate for the declining ELCC of storage at increasing scale.

8.3 Environmental Impacts & Regulatory Requirements

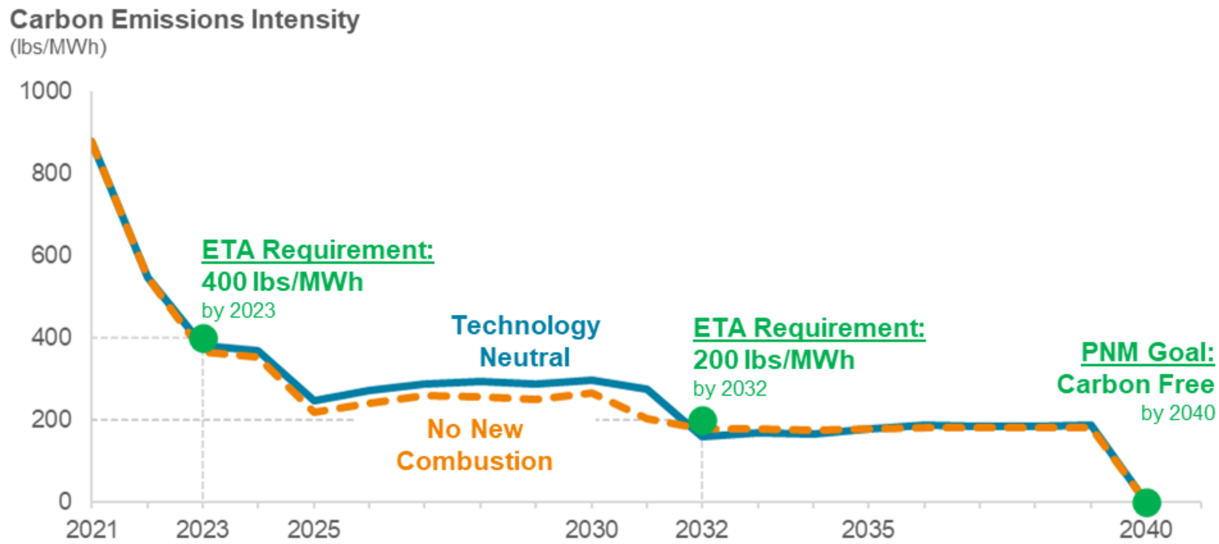
One of the key criteria we consider while identifying the MCEP is the performance of the various portfolios against key environmental metrics and regulatory requirements. The following sections discuss and present the two key regulatory requirements (re)defined in the Energy Transition Act; namely carbon emission intensities for PNM's system and Renewable Portfolio Standards, as well as implications for freshwater use and the future of our DSM programs.

Carbon Emissions

Figure 79 compares the carbon intensity of our generation mix in the Technology Neutral and No New Combustion scenarios. Both portfolios comply with the intensity requirements set forth by the ETA and reach our goal of a carbon-free portfolio by 2040. Relying more heavily on energy from solar, the No New Combustion achieves a slightly lower carbon emissions intensity from

2025 to 2032, but the difference is slight. With respect to carbon emissions, the two portfolios produce similar results:

Figure 79. Carbon intensity in the Technology Neutral & No New Combustion scenarios[40]

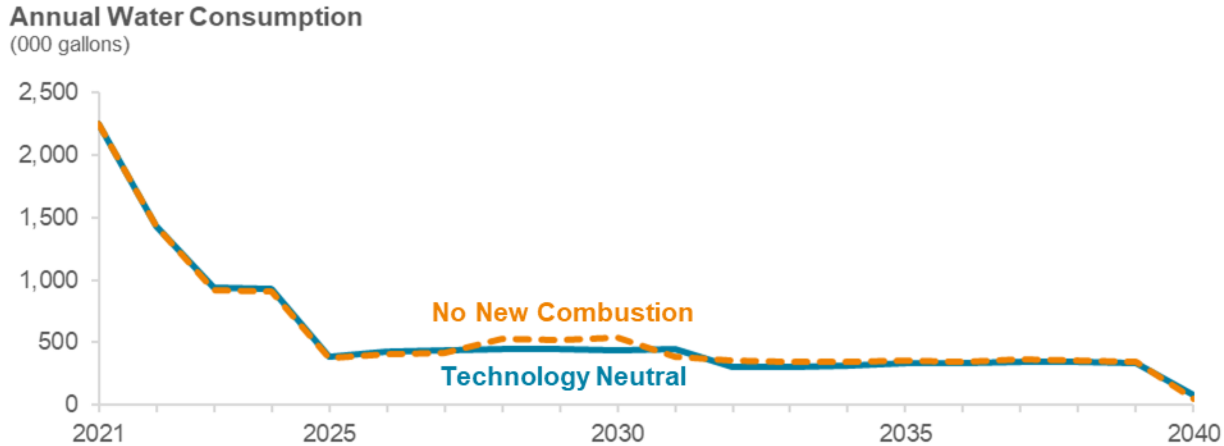


Water Consumption

Figure 80 shows the change in freshwater consumption associated with our generation resources over the planning horizon. Because our coal resources account for the majority of our current freshwater use, both scenarios show a significant decline in water consumption over the first five years of the plan. As we continue our transition away from fossil-fueled energy, our freshwater consumption will continue to decline.

[40] The carbon emissions intensity reported in this figure are based on the results of our capacity expansion modeling without market optimization. As previously discussed in Section 5.4.1 (EnCompass), we design our portfolios to meet the ETA's carbon intensity requirements without relying on short-term market purchases. In actual operations (and in the production simulation modeling), short-term market purchases may reduce our needs to rely on our own natural gas resources, resulting in an emissions intensity for our own resources that is below the ETA's requirements.

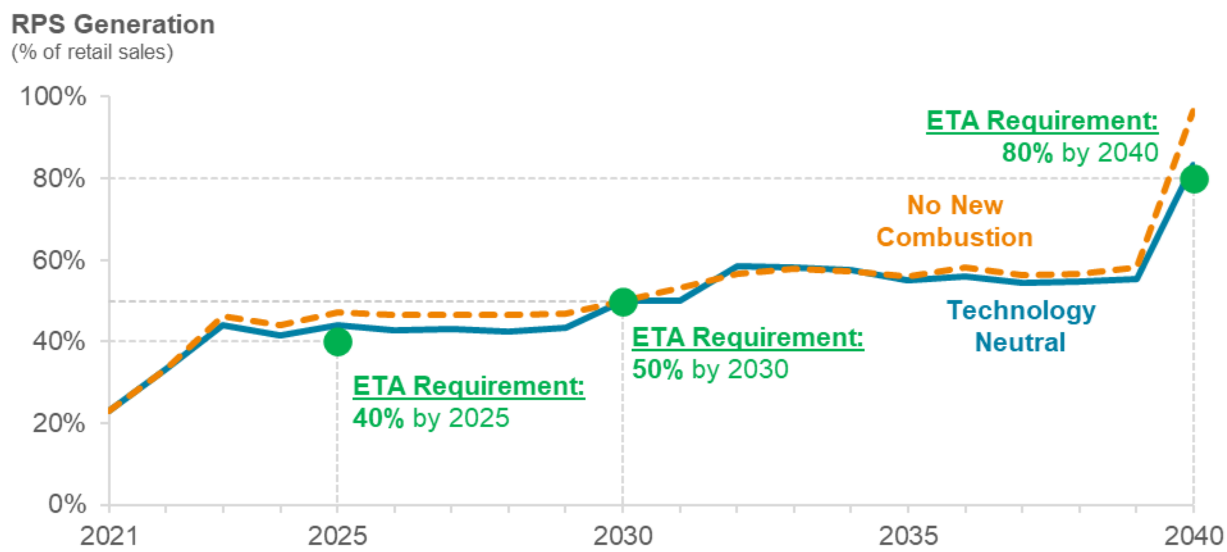
Figure 80. Water consumption in the Technology Neutral & No New Combustion scenarios[41]



RPS Compliance

Both portfolios also comply with the RPS targets set forth by the ETA. In near-term years, plans exceed the requirement instead of simply meeting it because the carbon intensity goals set forth by the ETA, coupled with the SJGS replacement resource plan, reflect more stringent environmental standards. Similar to our findings on carbon intensity, we do not observe a meaningful difference between the Technology Neutral and No New Combustion portfolios in this measure.

Figure 81. RPS penetration achieved in the scenarios[42]



DSM Programs

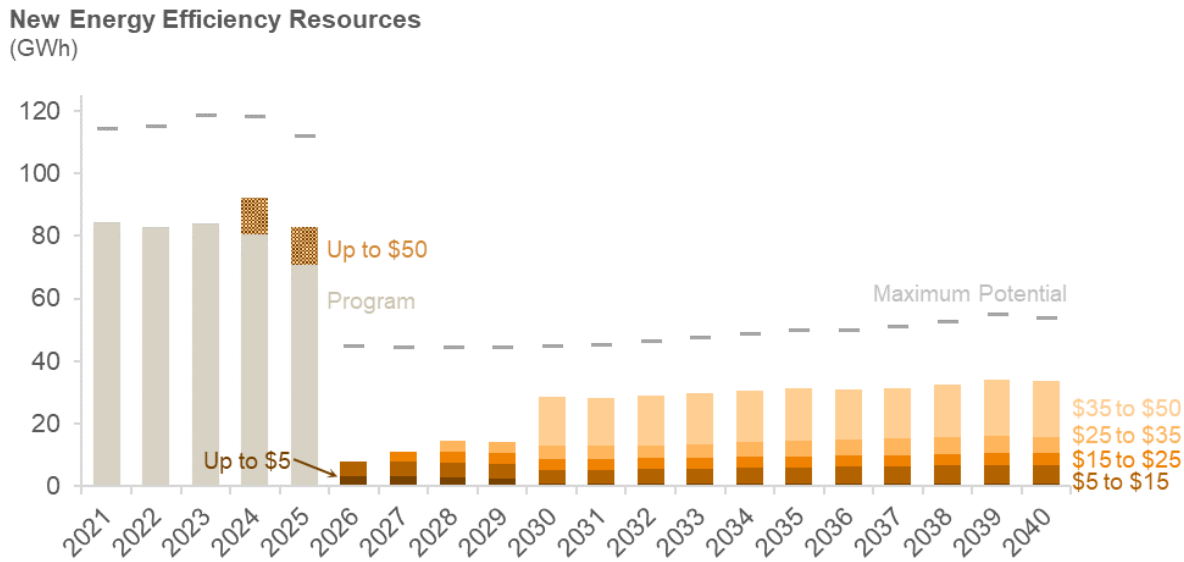
The EUEA establishes minimum requirements for our DSM programs over the next five years; Our analysis finds that in addition to those resources required to meet the standards of the EUEA,

[41] Water consumption shown in this figure is based on capacity expansion modeling for consistency with the previous figure. Some usage of banked RECs is included to ensure meeting compliance targets.

[42] RPS generation shown in this figure is based on capacity expansion modeling for consistency with the previous figure. Some usage of banked RECs is included to ensure meeting compliance targets.

additional energy efficiency resources are selected as part of the optimal resource portfolio in both the Technology Neutral and No New Combustion scenarios. In fact, across nearly all futures and sensitivities studied, all but the most expensive energy efficiency bundles are selected as part of an optimized portfolio. The specific combination of efficiency bundles selected in the Technology Neutral and No New Combustion scenarios appears in Figure 82 – only the "$50 and Up" bundles remain unselected from 2030 to the end of the analysis period.

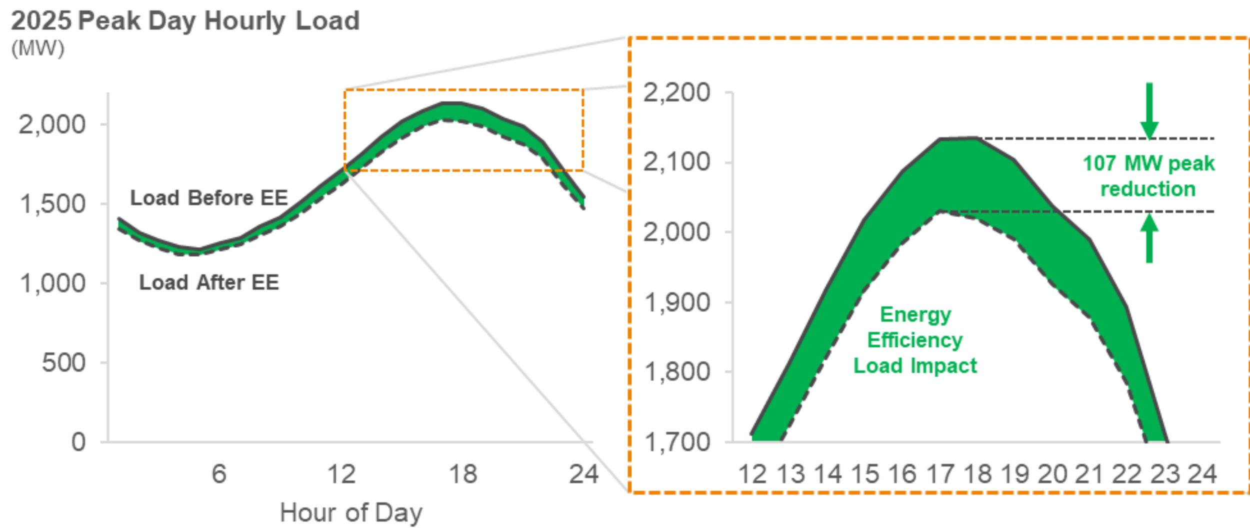
Figure 82. Energy efficiency bundles selected in the Technology Neutral and No New Combustion scenarios



This agreement across nearly all cases indicates a high value of demand-side efficiency measures as we transition to a carbon emissions-free system. This result encourages us to continue investing in cost-effective DSM resources beyond statutory requirements to continue reducing costs for our customers. This result also indicates that the value of energy efficiency will increase over time – and as we approach our carbon-free goal.

One of the principal benefits of our energy efficiency programs is the reduction in peak demand that allows us to defer or avoid investments in new generation resources for resource adequacy. By 2025, the cumulative reduction of our peak due to efficiency programs implemented between 2021 and 2025 in the Technology Neutral and No New Combustion scenarios is 107 MW, roughly 5% of peak demand. This reduction is the effect of both programs required to meet EUEA requirements and additional efficiency identified as cost-effective. The resulting 2025 peak day load shape is shown in Figure 83.

Figure 83. Peak demand reduction due to energy efficiency in 2025



Our analysis also provides some useful lessons to inform our future demand response programs. In both scenarios, the Peak Saver and Power Saver programs are discontinued after 2023, when the current programs are set to expire. These results implicate the limited value of the current design of these programs. At the same time, our portfolios choose to renew the more flexible and less constrained demand response resource included as part of the SJGS replacement portfolio at the end of its proposed life. This contrast highlights the importance of modernizing the design of future demand response programs to ensure that their characteristics are aligned with the needs of our system. As new sources of flexible load are added to the system (e.g. electric vehicles) and we modernize the grid with more advanced electronics, we will continue to pursue demand-side resource options that can help manage our customers' costs.

8.4 Implications for Resource Adequacy

One of the core objectives of our planning process is to identify a portfolio of resources that meets our standards for reliability, allowing us to provide our customers with continuous and consistent service. Maintaining the standard for reliability that our customer expect will become increasingly complex as we transition towards reliance on resources whose capabilities depend on uncertain meteorological patterns.

In each year of the planning process, we ensure that our portfolio meets our minimum reserve margin requirement (18%) using an accounting framework that relies on ELCC to measure the contributions of renewables, storage and demand response. Utilizing ELCC allows us to capture the declining value of such resources.

Meeting our Planning Reserve Margin

Table 30 shows how we meet our resource adequacy needs in 2025 in both the Technology Neutral and No New Combustion scenarios. In both scenarios:

- Our remaining existing firm resources (nuclear and natural gas) account for nearly 1,200 MW of effective capacity, accounting for roughly 50% of our resource adequacy needs.

- Energy efficiency, including programs required under the EUEA and a small amount of incremental efficiency, contributes to roughly 5% of our need.
- Our variable resources (wind and solar), measured using ELCC, provide only 400 MW of effective capacity (or about 15% of our resource adequacy needs), an amount significantly lower than their installed capacity of approximately 2,000 MW due to their intermittency and variability.

The difference in how we meet our remaining resource adequacy needs, roughly 750 MW, is reflected by the installed capacity needed for each portfolio:

- The Technology Neutral scenario meets this need with a combination of firm hydrogen-ready CTs (280 MW installed capacity) and energy storage (523 MW installed capacity).
- The No New Combustion scenario meets this need exclusively with storage resources, requiring a total installed capacity of 807 MW of battery storage by 2025.

Table 30. 2025 loads and resources, Technology Neutral and No New Combustion scenarios*

Loads	Units	Technology Neutral			No New Combustion		
Gross Peak	MW			2,135			2,135
Energy Efficiency	MW			-107			-107
System Peak	MW			**2,027**			**2,027**
Resources		**Installed Capacity (MW)**	**Effective Capacity (%)**	**Effective Capacity (MW)**	**Installed Capacity (MW)**	**Effective Capacity (%)**	**Effective Capacity (MW)**
Nuclear	MW	288	98%	282	288	100%	282
Coal	MW	–	–	–	–	–	–
Natural Gas	MW	987	96%	952	987	96%	952
Gas (H_2-Ready)	MW	280	97%	271	–	–	–
Wind	MW	658	29%	181	658	29%	181
Solar	MW	1,233	17%	205	1,295	16%	213
Geothermal	MW	11	47%	5	11	47%	5
Battery (4 hr)	MW	523	95%	497	800	92%	737
Battery (8 hr)	MW	–	–	–	7	96%	6
Battery (10 hr)	MW	–	–	–	–	–	–
Demand Response	MW	15	81%	12	15	81%	12
Total Resources	MW	**4,103**		**2,404**	**4,169**		**2,388**
Reserve Margin	**%**			**19%**			**19%**

** More detailed loads and resources tables appear in Appendix K*

In our transition to 2040, how we meet our resource adequacy needs changes dramatically. In both portfolios, we assume most of our remaining natural gas resources are retired to enable the final transition to a carbon-free portfolio.[43] While additional renewable resources are needed in each scenario to decarbonize our energy supply, their contributions to resource adequacy are very small. New investments are needed to replace this retiring capacity and meet load growth, and the differences in the portfolios already apparent by 2025 become larger in the long term:

[43] In the Technology Neutral scenario, our existing combustion turbines at Lordsburg and La Luz are converted to hydrogen operations.

- The Technology Neutral portfolio includes additional investments in hydrogen-ready CTs to meet a portion of this need; we add a cumulative total of 480 MW by 2040. This portfolio also relies heavily on storage to meet a large share of resource adequacy needs: in addition to 1,100 MW of four-hour batteries, 435 MW of ten-hour flow batteries are installed by 2040. The longer duration helps offset the declining ELCC of four-hour storage.
- The No New Combustion scenario, in the absence of hydrogen-ready CTs, relies even more heavily on storage for the bulk of our resource adequacy needs. In total, this portfolio includes over 2,300 MW of battery storage resources. These resources include a mix of four-, eight-, and ten-hour batteries; increasingly longer durations of storage will be needed in the absence of new firm resources.

Table 31 compares how we meet our needs in the long term in each of these scenarios. It is worth emphasizing the significant role energy storage plays in both portfolios' ability to serve loads reliably in a carbon-free portfolio – even in the Technology Neutral case, storage accounts for roughly 50% of our resource adequacy needs. This result underscores the importance of emerging technologies in enabling our transition towards a carbon-free portfolio.

Table 31. 2040 loads and resources, Technology Neutral and No New Combustion scenarios

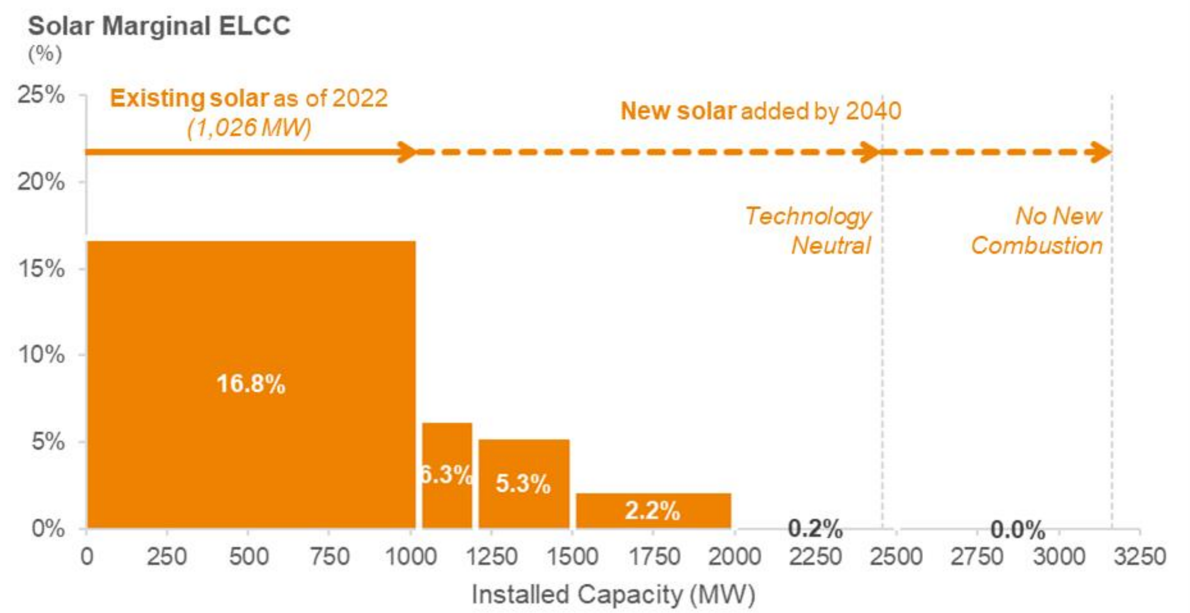
Loads	**Units**	**Technology Neutral**			**No New Combustion**		
Gross Peak	MW			2,363			2,363
Energy Efficiency	MW			-95			-95
System Peak	MW			**2,267**			**2,267**
Resources		**Installed Capacity (MW)**	**Effective Capacity (%)**	**Effective Capacity (MW)**	**Installed Capacity (MW)**	**Effective Capacity (%)**	**Effective Capacity (MW)**
Nuclear	MW	288	98%	282	288	98%	282
Coal	MW	–	–	–	–	–	–
Natural Gas	MW	–	–	–	–	–	–
Hydrogen	MW	606	97%	586	–	–	–
Wind	MW	956	22%	213	956	22%	213
Solar	MW	2,456	10%	245	3,165	8%	246
Geothermal	MW	11	47%	5	11	47%	5
Battery (4 hr)	MW	1,100	84%	921	1,325	74%	975
Battery (8 hr)	MW	–	–	–	391	96%	374
Battery (10 hr)	MW	435	96%	416	590	96%	564
Demand Response	MW	15	81%	12	15	81%	12
Total Resources	MW	**5,867**		**2,680**	**6,741**		**2,671**
Reserve Margin	%			**18%**			**18%**

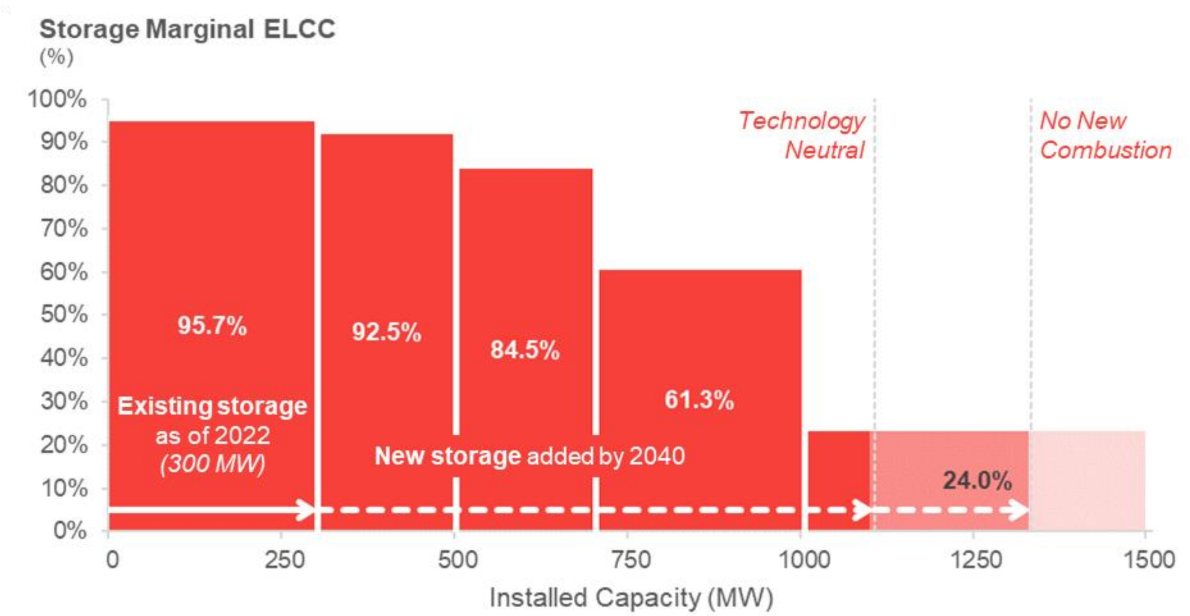
** More detailed loads and resources tables appear in Appendix K*

ELCCs of New Resources

The ELCCs reported for renewables and storage in these tables reflect the average ELCCs of each technology. The marginal ELCC for each – that is, the incremental capacity value of the last unit of capacity added – is in many cases smaller. Figure 84 shows marginal ELCC curves for solar and four-hour storage to the levels selected in the two portfolios. At the 2040 levels, the marginal ELCC of zero is effectively zero; that is, additional solar resources would provide negligible value towards our resource adequacy needs; at this penetration, our net peak has shifted entirely into the evening hours beyond sunset. Four-hour battery storage also exhibits declining ELCCs at the level of penetration in both portfolio. In both the Technology Neutral and No New Combustion scenarios, the marginal ELCC of four-hour storage declines to 24% due to saturation effects. As a result, the optimized portfolios begin to prefer storage with longer durations (and consequently higher ELCCs) by 2040. The need to use longer duration storage to serve resource adequacy is evident from the No New Combustion portfolio's selection of much more eight-hour storage than the Technology Neutral portfolio to make up for the lack of hydrogen CT capacity in 2040.

Figure 84. Marginal ELCC curves for solar & four-hour storage resources in the 2040 portfolios





Analysis of Loss of Load Expectation

To further ensure our plans adhere to our standards for reliability, we also conduct loss of load probability analysis on the resulting portfolios in a number of select years to evaluate the expected frequency of reliability events, which we can compare against our standard of 0.2 events per year. This analysis indicates that our portfolio is able to meet this standard in 2025 – once SJGS, FCPP, and our PVNGS leases are no longer in our portfolio – in both scenarios.

The detailed results of LOLE analysis of our portfolios sheds further light on the changing nature of the reliability challenges we will face. Figure 85 below shows the timing of expected unserved energy events in our 2023 portfolio based on loss-of-load-probability modeling. As demonstrated in this figure, over 90% of the expected unserved energy is observed after HE19 (8 PM MDT) in the summer months after the sun has set.

Figure 85. Timing & seasonality of reliability events by 2025

Share of Expected Unserved Energy by Month & Time of Day, Technology Neutral Scenario, 2025

	Hour of Day (MST)																							
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
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.4%	3.3%	5.8%	0.7%	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3%	1.5%	1.4%	17%	37%	14%	3.1%	0.3%	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3%	0.2%	5.5%	9.2%	0.6%	0.0%	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Greatest risk of loss of load occurs after sundown

Approximate sunset (hours with typical solar capacity factors <5%)

We also test the performance of our 2040 portfolios using analysis of LOLE. Over this time period, we expect regional market conditions to change dramatically due to economics and policy as discussed in Section 3.1 (Changing Regional Dynamics); we expect the general trends towards solar & storage and away from baseload firm resources to lead to (1) abundant supplies of energy during daylight hours, (2) highly constrained supplies during net peak hours, and (3) lower levels of energy available during nighttime/off-peak hours. Because of the significant level of uncertainty in how regional market conditions will change this far into the future, our analysis considers a range of levels of market support in our analysis of 2040:

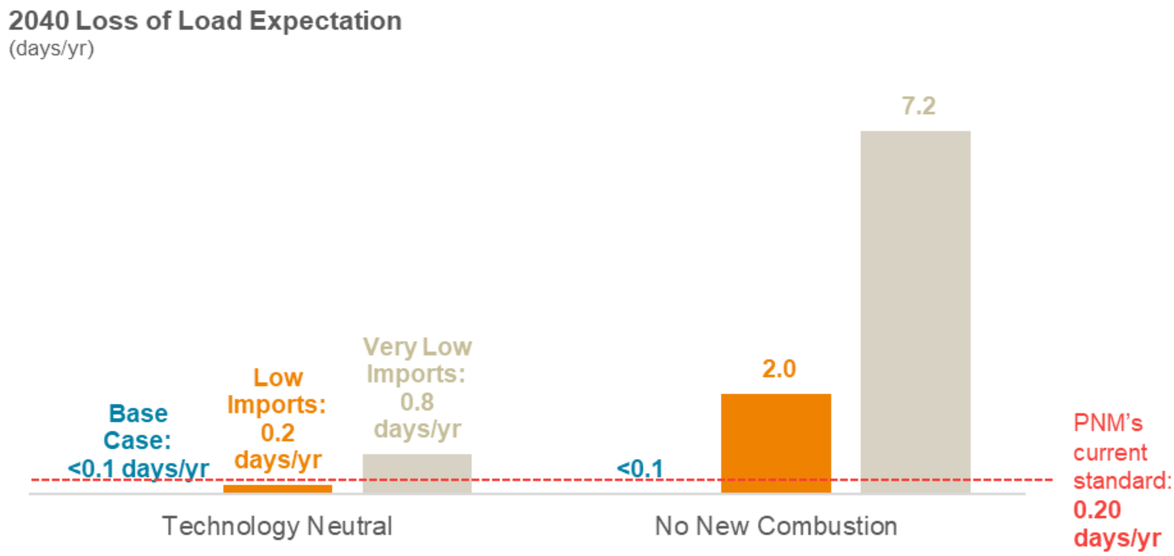
1. Our "Base Case" assumptions[44] used in our 2025 reliability assessment;
2. A "Limited Imports" scenario that constrains imports during nighttime hours to 200 MW; and
3. A "Very Limited Imports" scenario that further constraints imports during nighttime hours to 50 MW.

The LOLE outcomes for the Technology Neutral and No New Combustion scenarios under each of these three variations in regional market conditions are summarized in Figure 86. This analysis is important due to the way the market dynamics are modeled. As more fully described in Appendix M, the SERVM analysis estimates available market support by explicitly simulating

[44] Our Base Case assumptions allow up to 50 MW of imports during summer net peak hours (HE 19-22), between 100-150 MW prior to this net peak period (HE 16-18), between 200-300 MW in all other hours within 85% of gross peak demand, and up to our transmission limits, subject to availability of resources in other areas, at all other times of year.

neighboring loads and resources; however, PNM does not know how the neighboring loads and resources will change over time. Consequently, the neighboring systems are held static overtime which leads to roughly the same amount of excess capacity available for purchase throughout the planning horizon. While this is a reasonable assumption for the near term, the characteristics of Western wholesale markets – depth, liquidity, and pricing – are increasingly uncertain far into the future. The 2040 simulations demonstrate increased variance and uncertainty with respect to the ability to meet reliability requirements when market access during non-daylight hours is stressed. The sensitivities that reduce the amount of market depth during non-daylight hours can be thought of as representative of a highly correlated western system heavily reliant on solar and storage, perhaps in response to climate change, that would require individual BAs to increase reserves to account for this risk, or require broader regional planning and increasing reliance on regional transmission.

Figure 86. 2040 loss of load expectation under a range of assumptions



"Low Imports" limits imports during nighttime hours to 200 MW; "Very Low Imports" limits imports during nighttime hours to 50 MW

- Under "Base Case" assumptions, both portfolios are able to meet our standards for resource adequacy.
- If external factors limit our ability to import from external markets, it is possible that both portfolios would fail to meet our standard, and additional investments would be needed.
- Portfolios that rely more heavily on energy storage are significantly more sensitive to our assumptions on the conditions in external markets, which represents a material risk to our long-term reliability.

While both portfolios meet our standard for resource adequacy, the No New Combustion portfolio relies more heavily on purchases from wholesale markets to meet this standard. Compared with the Technology Neutral portfolio, the No New Combustion portfolio has a lower quantity of firm resources and a larger quantity of energy storage resources. Whereas the firm resources in the Technology Neutral portfolio can operate at full capacity on a sustained, round-the-clock basis when needed for reliability, storage resources portfolio are limited by duration. When their state of charge is exhausted, the assumed market purchases provide the energy needed to ensure reliability. As a result, our ability to maintain resource adequacy in a No New Combustion portfolio world is more sensitive to the availability of imports from other entities in the region.

The difference between the portfolios is worth noting because of the inherent uncertainty that exists in our ability to predict the conditions that will exist in the Western wholesale market beyond the next few years. As the mix of resources continues to shift towards greater levels of renewables and storage across the region, it is difficult to quantify exactly when and how much surplus will be available for purchase. In the event that the available levels of market support do not align with modeled assumptions, a No New Combustion portfolio would either experience significant reliability risks or would require more investments, above and beyond those identified in our portfolio analysis, to reach an appropriate LOLE standard.

Figure 87, which shows the timing and seasonality of unserved energy in 2040 in the No New Combustion (Limited Imports) scenario, illustrates the nature of the resource adequacy challenge resulting from heavily relying on storage in the absence of firm resources. In this scenario, the timing of loss of load events shifts from our net peak period to night and early morning, and from summer to other seasons as well. While storage provides an effect means of meeting our net peak needs, it is less effective if needed to sustain production through the night. In this scenario, the limits on our ability to purchase energy from the market overnight, coupled with finite limits on the duration of the storage resources, results in loss of load events that occur during the nighttime and early morning hours in most months of the year.

Figure 87. Timing and seasonality of reliability events, No New Combustion (Low Imports) scenario, 2040

Share of Expected Unserved Energy by Month & Time of Day, No New Combustion (Low Imports), 2040

	Hour of Day (MST)																							
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
1	0.4%	0.5%	0.8%	1.1%	1.6%	2.8%	5.6%	1.8%	0.0%	-	-	-	-	-	-	-	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.3%	0.5%
2	0.0%	0.1%	0.1%	0.1%	0.3%	0.6%	1.3%	0.3%	0.0%	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%	0.0%	0.0%	0.1%
3	-	-	-	0.0%	0.0%	0.2%	0.3%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	0.1%	0.1%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	0.3%	0.4%	0.5%	0.8%	1.4%	1.2%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%	0.0%	0.1%	0.2%
7	1.1%	1.9%	2.9%	4.5%	7.7%	7.8%	0.7%	0.0%	-	-	-	-	-	-	-	-	-	0.0%	0.1%	0.1%	0.2%	0.3%	0.7%	1.1%
8	1.0%	1.5%	2.3%	3.3%	5.2%	7.5%	1.8%	0.0%	-	-	-	-	-	-	-	-	-	0.0%	0.0%	0.1%	0.2%	0.4%	0.7%	0.9%
9	0.1%	0.1%	0.2%	0.3%	0.6%	1.2%	0.5%	0.0%	-	-	-	-	-	-	-	-	-	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.1%
10	0.0%	0.0%	0.1%	0.2%	0.6%	1.5%	1.4%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
11	-	-	-	0.0%	0.0%	0.1%	0.3%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	0.2%	0.3%	0.4%	0.8%	1.6%	2.9%	5.4%	1.4%	-	-	-	-	-	-	-	-	-	-	0.0%	0.1%	0.1%	0.1%	0.2%	0.3%

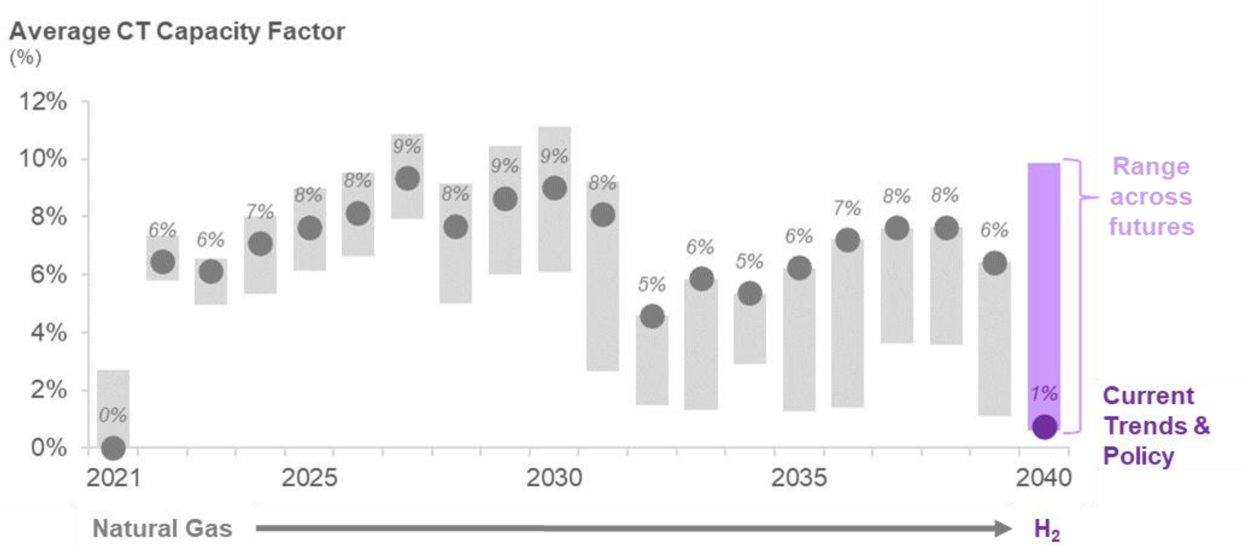
This dynamic has multiple implications for our future resource planning:

(1) It highlights the high value of firm resources capable of sustaining output around the clock (and the corresponding risk of overreliance on battery storage) in a fully decarbonized portfolio.
(2) It affirms the notion that our resource adequacy planning needs to consider our ability to supply loads across all seasons and time of day, not just summer peak.
(3) It underscores the importance of continuing to monitor and adapt to changing regional conditions through adjustments to our resource adequacy assumptions over time to ensure our portfolio is not relying on market assistance that will not be available.

Role of Gas & Hydrogen Resources

In all scenarios, our natural gas resources will play an important role in meeting our resource adequacy needs. Our existing peaking resources and any new investments we make in hydrogen-ready combustion turbines (specific to the Technology Neutral scenario) provide value through their ability to dispatch on demand across any number of hours to ensure we can meet customer needs under the most extreme conditions. This capability is particularly valuable in the context of the resource adequacy challenges highlighted by Figure 87 above. At the same time, we expect these resources to operate at low capacity factors by design. Figure 88 shows the range of capacity factors for our CTs (existing and new) observed across all futures in the Technology Neutral scenario, which generally fall in a narrow range between 5-10%. The low capacity factors belie the importance of these resources to our resource adequacy needs.

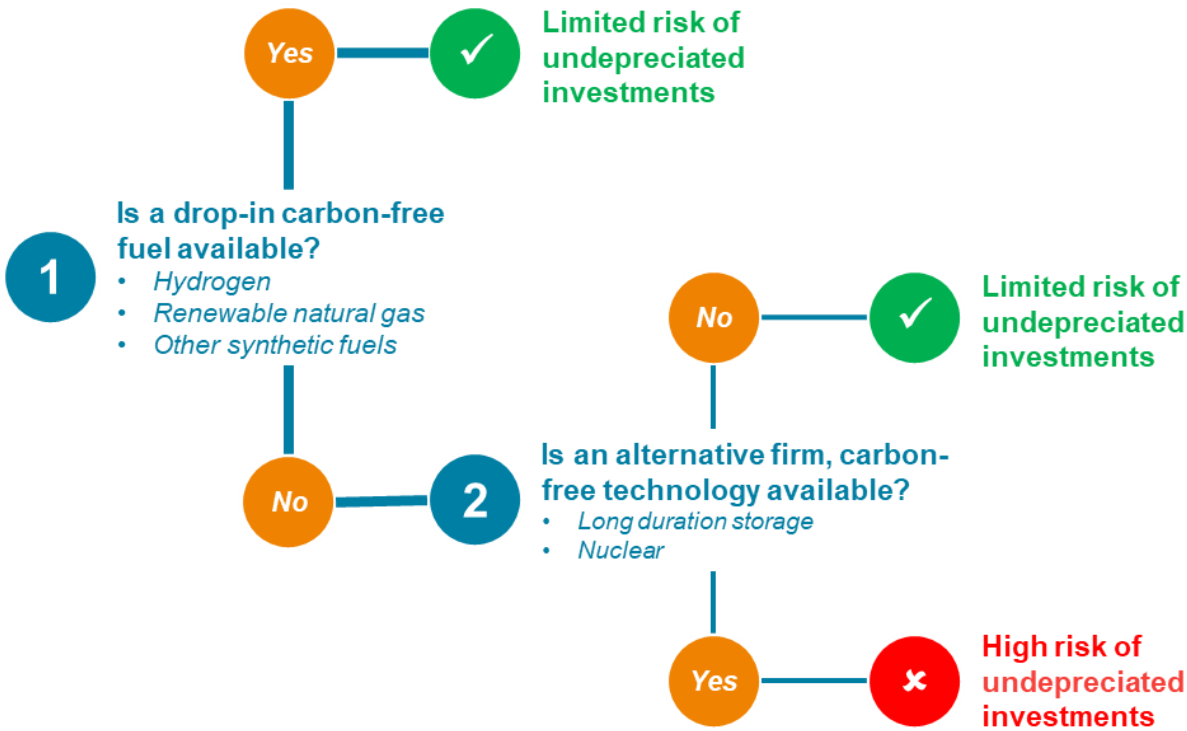
Figure 88. Annual capacity factors for combustion turbines, Technology Neutral scenario



One of the concerns specific to the Technology Neutral portfolio is the risk that investments in hydrogen-ready CTs could result in undepreciated fossil investment costs when the ETA requires utilities to achieve a 100% carbon emissions-free portfolio. To understand the nature of that risk, we considered the circumstances under which this risk would materialize. In our framework for considering this risk, illustrated in Figure 89, the realization of this risk depends on two questions:

- **Is a drop-in carbon emissions-free fuel available?** Our analysis is oriented around the idea that our investments in new CTs could be repurposed to operate 100% on hydrogen by 2040, but any carbon emissions-free fuel would allow these units to continue operating as part of a carbon emissions-free portfolio even once the legal requirements of the ETA take hold in 2045. Since new CTs would have a low going-forward costs, this condition alone would be sufficient to secure their position as part of a least-cost, carbon emissions-free portfolio.
- **Is an alternative firm carbon emissions-free technology available?** If a drop-in carbon emissions-free fuel is not available, the risk of stranded costs will depend on whether the CTs can be replaced in our portfolio while maintaining reliability without excessive costs. This would require an alternative firm carbon emissions-free resource, a need that could be fulfilled by long duration storage or nascent technologies like small modular nuclear reactors.

Figure 89. Framework for considering risk of undepreciated investments associated with new H2-ready CTs



If a drop-in carbon-free fuel does not become available and alternative firm carbon emissions-free technologies are available, there is a risk of undepreciated costs. Given the lack of commercialization of either carbon-free fuels or long duration storage, the possibility of the lowest branch of Figure 89 materializing must be considered.

Technology Risk & Resource Adequacy

One of the notable risks that distinguishes the Technology Neutral scenario from the No New Combustion scenario is the degree of reliance on lithium ion battery storage to meet our needs. Despite its growing commercialization, lithium ion battery storage has not yet been widely deployed at grid scale. The 300 MW of storage capacity brought online as part of the San Juan replacement portfolio represents roughly 15% of our peak demand, a level of penetration that will number among the most aggressive in the industry. From this point, the Technology Neutral and No New Combustion scenarios diverge:

- By 2025, the Technology Neutral scenario includes 523 MW (25% of peak) of total storage capacity, whereas the No New Combustion scenario includes 807 MW (38%); and
- By 2030, the Technology Neutral scenario includes 569 MW (25% of peak), whereas the No New Combustion scenario includes 1,070 MW (48%).

While we are committed to integrating significant amounts of storage into our portfolio, we are also cognizant of the risks that accompany such a rapid transition to an emerging technology. Relying so heavily on a technology that has not been deployed at such scale poses multiple risks:

- **Technical risks:** as with any technology that has not been widely commercially deployed, utility-scale battery storage systems are subject to some technical risks, including potential failures of electrical equipment or degradation in performance. While we attempt to mitigate this risk by incorporating financial penalties for non-performance in energy storage agreements, these penalties will not protect our customers from the consequences of unexpected failures to perform.

- **Operational risks:** our resource adequacy accounting uses ELCC to measure potential contributions of storage to meet our needs, which assumes batteries are dispatched optimally to meet our needs. In reality, multiple factors prevent operators from achieving perfectly optimal dispatch. To the extent that these real-world factors preclude use of storage in the ways assumed in the ELCC studies, the level of reliability achieved could be lower than modeled.

Failure of energy storage systems to perform as modeled in our planning process could have numerous adverse impacts upon our customers, which could include failure to meet our resource adequacy standard (i.e. increased frequency of reliability events) and increased levels of renewable curtailment, both contributing to higher costs than anticipated for customers.

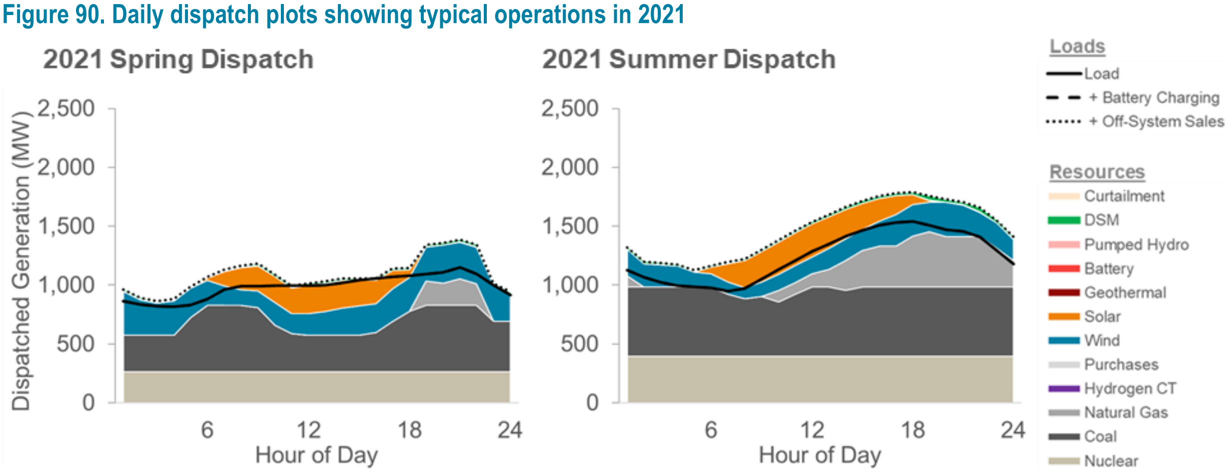
None of these risks would prevent PNM from pursuing battery storage as a resource to meet a portion of our resource adequacy and renewable integration needs, yet recognizing these risks is key to preserving optionality and flexibility in our approach to achieving the multifaceted objectives of our planning process. The realization of one or more of these risks as we gain real-world experience with increasing levels of storage may require us to adapt our approach to meeting our customers' needs.

8.5 Implications for Operations

All of the scenarios we have examined that meet the targets prescribed by the ETA and our own carbon goals result in profound changes in the way our system operates on a day-to-day basis. While the specific patterns of operations vary to some degree from one scenario to the next, the nature of these changes is generally consistent across them. To illustrate these changes, we show examples from the Technology Neutral and No New Combustion scenarios.

Historically, we have relied largely on nuclear, coal, and gas resources to dispatch on demand when needed and to follow loads throughout the day. While the penetration of renewables on our system has increased notably over the past decade, our current portfolio still largely relies on this combination of resources. Figure 90 shows a typical day of operations at two times of year: during the spring, when loads are lowest, and during summer, when loads are highest.

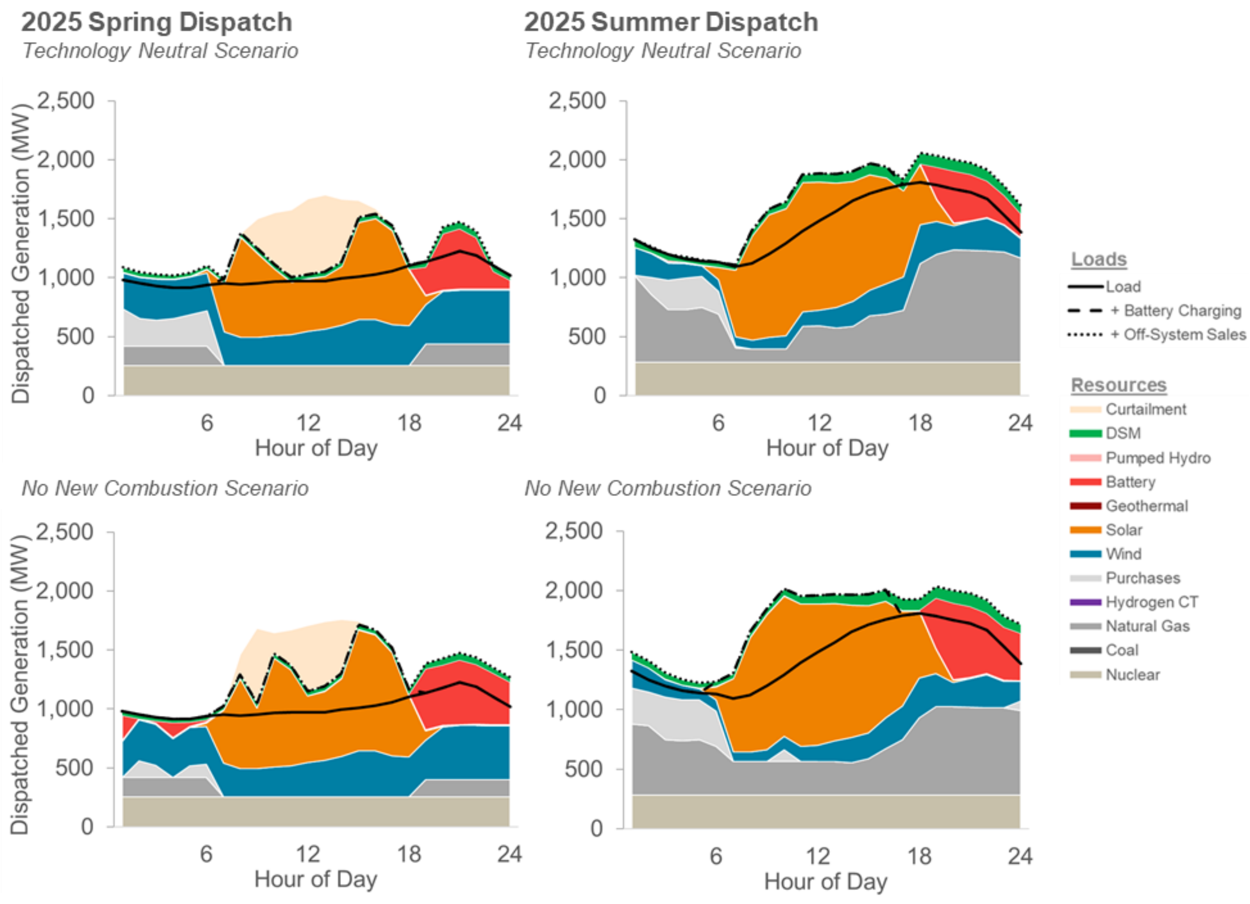
Figure 90. Daily dispatch plots showing typical operations in 2021



By 2025, the abandonment and replacement of SJGS, FCPP, and PVNGS leases will prompt major changes in the composition of our portfolio – and, by extension, how it operates. We highlight these operational differences by showing the same two representative days in 2025 in Figure 91. At this point in time, our portfolio of wind and solar resources will provide approximately 45% to 50% of our annual energy needs. At higher penetrations of variable resources, our operators will operate our system more dynamically, using gas and storage resources to balance the inherent variability of net load throughout the day.

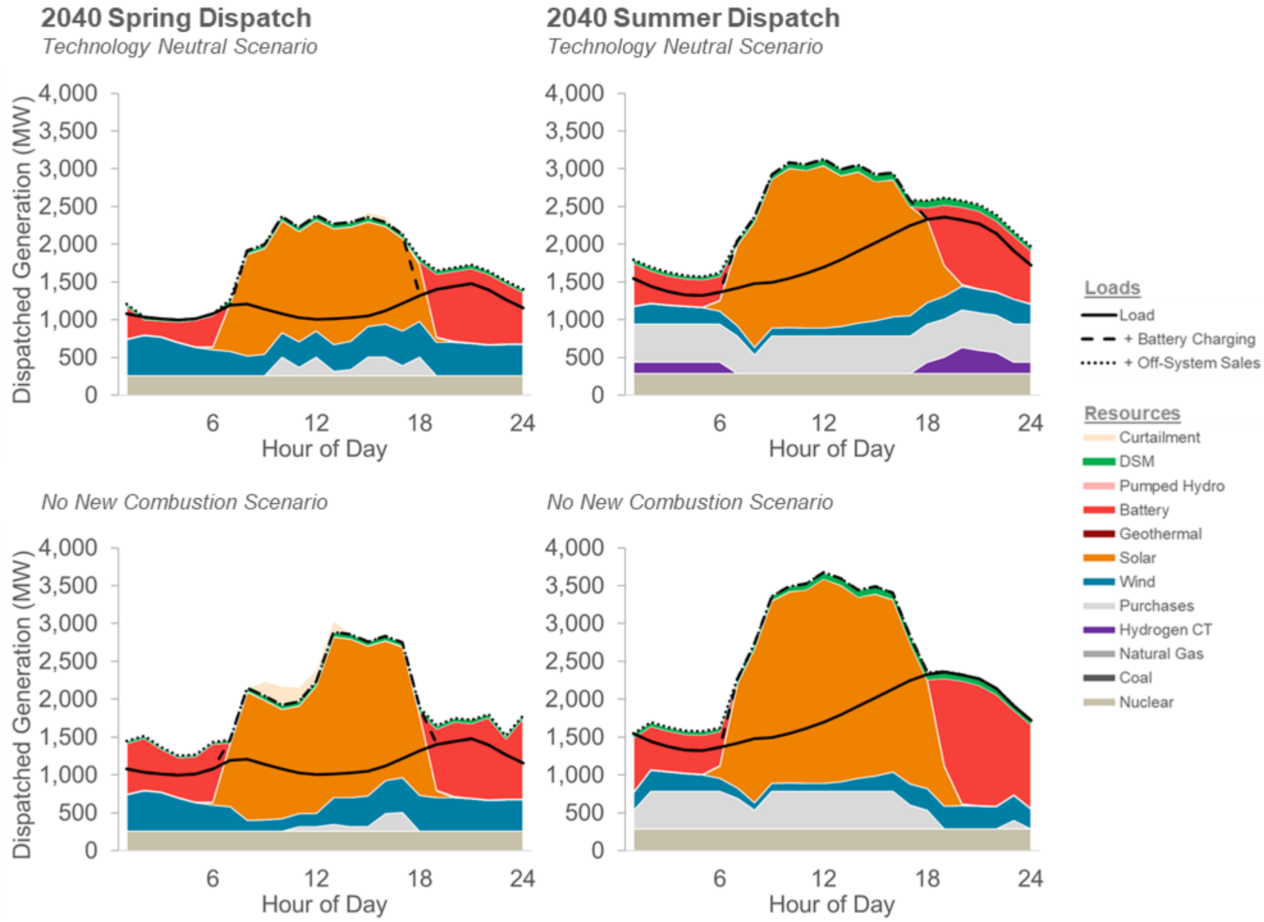
In 2025, we anticipate a moderate level of curtailment due to the large amount of solar in our portfolio, investments in storage notwithstanding. During the spring months, high levels of solar and wind output coupled with low load conditions will likely result in some level of curtailment during daytime hours. This is the same integration challenge that has manifest in other parts of the west with significant amounts of solar capacity.

Figure 91. Daily dispatch plots showing typical operations in 2025



Our ultimate transition to a fully carbon emissions-free portfolio will result in further changes to how our system operates. While we will continue to invest in renewable resources – likely solar – whose variability will continue to challenge our operators, additional investments in energy storage will mitigate some of the balancing challenges we expect in the near term. Our operations for the same two representative days in 2040 are shown in Figure 92. To meet the highest loads of the year, the Technology Neutral portfolio relies on firm capacity resources in the form of hydrogen-fueled combustion turbines whose operations will be infrequent but whose capabilities are essential to our reliability. The No New Combustion scenario relies on storage to achieve this same goal.

Figure 92. Daily dispatch plots showing typical operations in 2040



Role of Curtailment

Renewable generation is intermittent in nature, driven by daily and seasonal patterns of solar insolation and wind speed. Nuclear generation is a base load resource with limited ramping capability. These resources contrast with flexible dispatchable resources like gas turbines that can be ramped up and down to meet load. As a result, balancing load using renewables and nuclear generation can be challenging, particularly at high penetration of renewables.

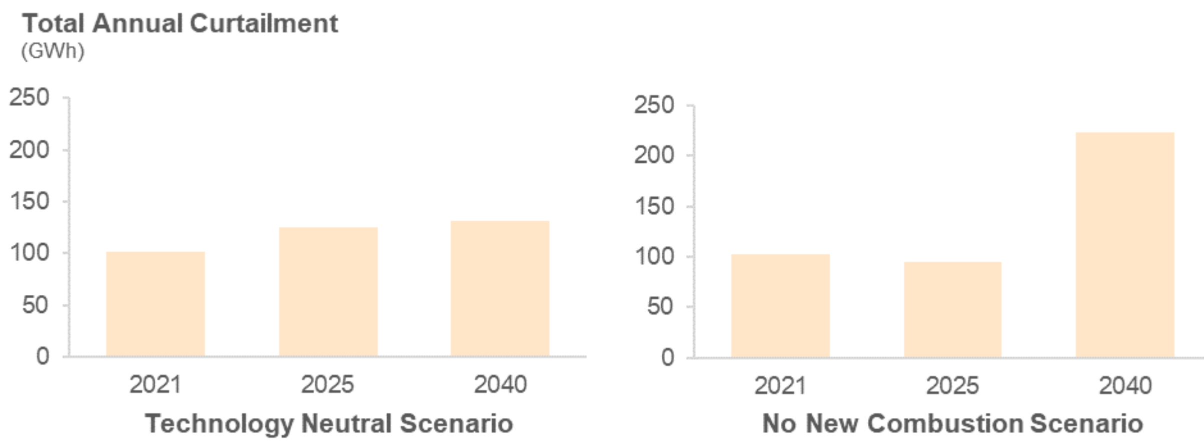
Energy storage resources present one solution for renewable integration. By charging during excess generation and discharging during low generation, energy storage resources smoothen the generation profile and enable a higher renewable penetration. Storage is particularly synergistic with solar generation which has a clear diurnal generation profile by charging during mid-day and discharging in the evening when the sun goes down, as seen in the graphs above.

Another option available to grid operators for large scale renewable and inflexible unit integration is curtailment. By curtailing some or all generation, otherwise intermittent and inflexible generators can better align with the energy demand. One illustrative example that shows the economic benefit of using curtailment occurs when generation exceeds load, i.e., during overgeneration. As renewables become cheaper, overbuilding renewables to ensure reliability in low renewable production hours, alongside curtailment during overgeneration hours often result in cost savings.

The amount of curtailment is affected by the operational flexibility of the generation portfolio. Energy storage and flexible resources generally reduce curtailment, whereas inflexible resources, like nuclear units and coal units with low ramp rates, generally tend to increase curtailment.

Figure 93 shows the total curtailment under the Technology Neutral and No New Combustion scenarios. Across both scenarios, curtailment is observed even in 2021 for balancing as the due to a combination of renewable generation and output from must-run resources. Similar amount of curtailment is observed in 2025 even as more solar resources come online as our system becomes more flexible with storage additions and without coal. By 2040 when we reach a 100% carbon emissions-free portfolio, significant solar and storage additions result in slightly higher curtailment especially in the No New Combustion scenario.

Figure 93. Total annual curtailment in the Technology Neutral and No New Combustion portfolios



8.6 Alternative Futures & Sensitivities

8.6.1 Alternative Futures

As described in Section 5.1.2, we consider four futures in this IRP: Current Trends and Policy (CTP), Aggressive Environmental Regulation (AER), High Economic Growth (HEG), and Low Economic Growth (LEG). Comparative analysis of each portfolio across the different futures is useful for two reasons: (1) it allows us to understand the extent to which alternative futures would indicate a different portfolio of investments would achieve lowest costs, and (2) it shows us the relative cost impacts of various factors outside our control.

Table 32 shows the installed capacity of new resources online through 2025 across the four futures considered. Across the futures, the combination of new investments varies little over the first five years in both scenarios. Differences in load among the futures result in slightly higher or lower needs for capacity resources, which are generally met by hydrogen-ready CTs (if available) and storage. These ranges are shown visually in Figure 94. Several observations are apparent:

- Across all futures and scenarios, a large amount of solar and storage is added by 2025.
- The level of DSM resources included is consistent across the scenarios and futures, indicating that the incremental bundles selected have value under a range of conditions.

- When new hydrogen-ready CTs are allowed, at least 200 MW are added as part of a least-cost portfolio across the futures.

Table 32. Installed capacity of new resources in 2025

	Technology Neutral (MW)				No New Combustion (MW)			
	CTP	AER	HEG	LEG	CTP	AER	HEG	LEG
Solar	959	984	959	959	1,021	1,222	1,013	959
Wind	-	-	-	-	-	-	-	-
Battery Storage	523	519	593	486	807	814	932	703
H_2-Ready CTs	280	280	320	200	-	-	-	-
DSM	122	122	122	122	122	122	122	122

CTP = Current Trends & Policy; AER = Aggressive Environmental Regulation; HEG = High Economic Growth; LEG = Low Economic Growth

Figure 94. 2025 range of new installed capacity across futures

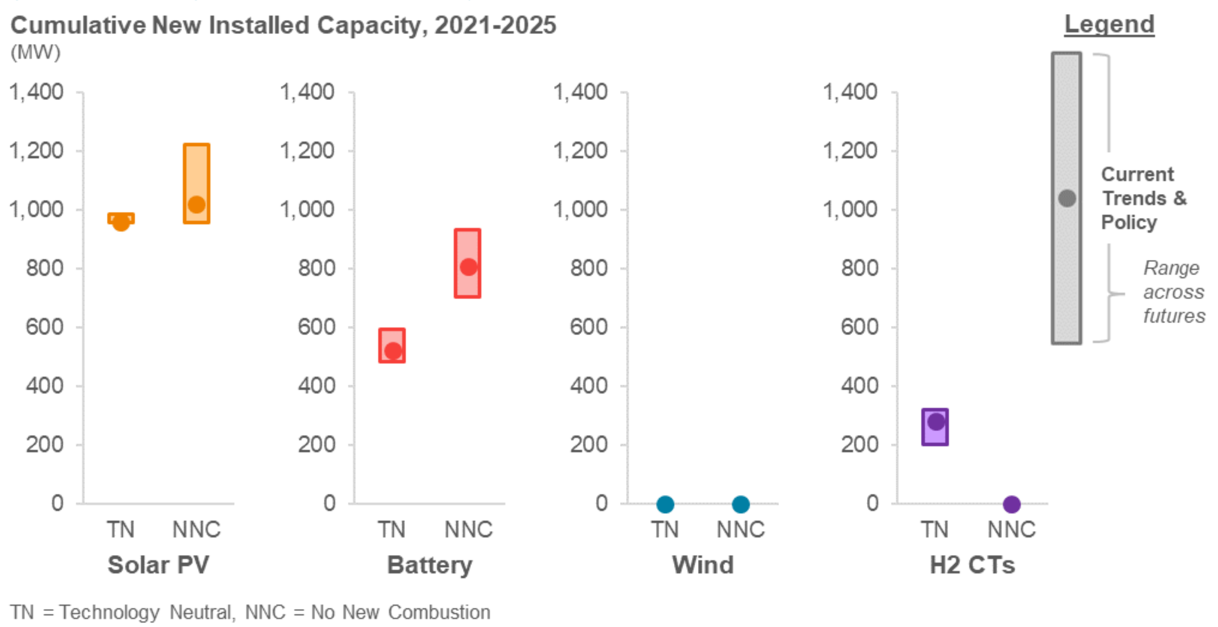


Table 33 and Figure 95 show the installed capacity of new resources online through 2040 under the same futures. Over the full twenty-year horizon, we see more variation in across the futures. This increased variation is no surprise: forecasts of load and technology cost continue to diverge in the years from 2025 to 2040. The range in peak load forecasts is nearly 700 MW (with load over 3,000 GWh) in 2040 compared to less than 200 MW (with load under 1,000 GWh) in 2025.

The widening uncertainty in the long term supports several conclusions:

- In both scenarios, the ranges for new solar and storage capacity are the largest, indicating the general scalability of these resources to meet a significant portion of our future needs. The modularity of solar and storage installations should allow us to adjust our plan in response to changing load conditions throughout the horizon.
- New wind resources are added by 2040 in both scenarios under all futures. The complementarity of wind's production profile and its ability to supply energy during the nighttime hours makes its value robust across a wide range of assumptions.

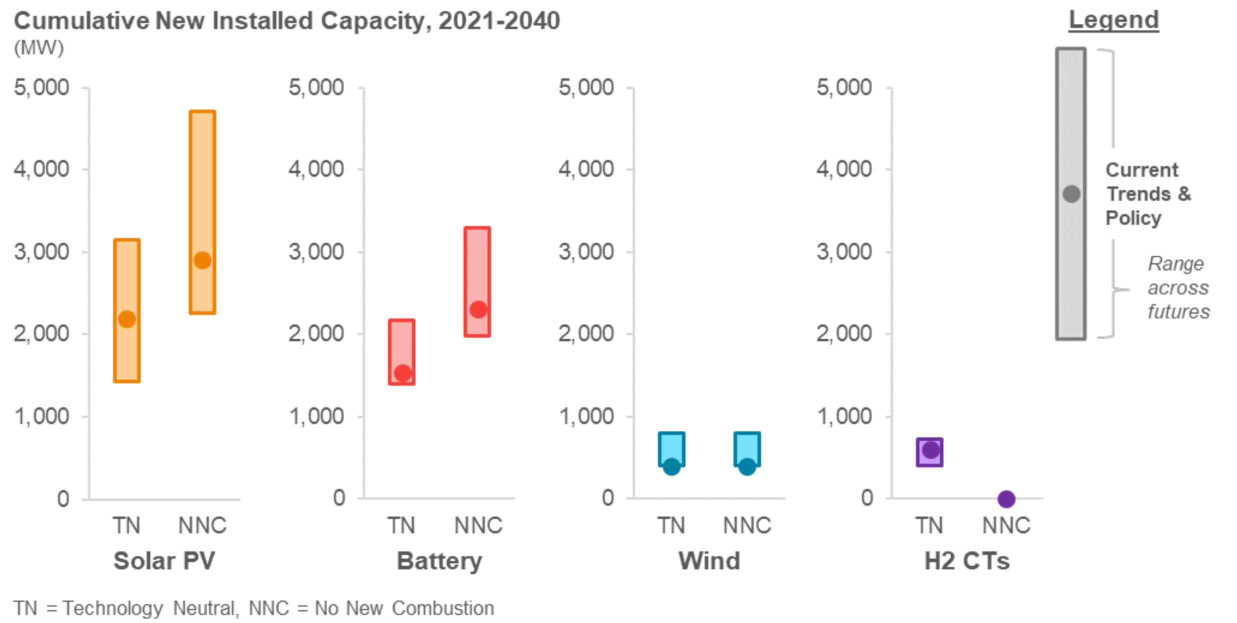
- The range of new hydrogen CTs added in the Technology Neutral scenario across the futures is relatively narrow in comparison to the other resources. This result underscores the notion that a least-cost pathway to a carbon-free portfolio would include some amount of carbon-free firm resources.

Table 33. Installed capacity of new resources in 2040

	Technology Neutral (MW)				No New Combustion (MW)			
	CTP	AER	HEG	LEG	CTP	AER	HEG	LEG
Solar	2,204	1,581	3,156	1,434	2,913	2,675	4,719	2,266
Wind	400	800	400	400	400	800	400	400
Battery Storage	1,535	1,797	2,165	1,396	2,307	2,310	3,297	1,983
H_2-Ready CTs	480	360	600	280	-	-	-	-
DSM	110	110	110	110	110	110	110	110

CTP = Current Trends & Policy; AER = Aggressive Environmental Regulation; HEG = High Economic Growth; LEG = Low Economic Growth

Figure 95. 2040 range of new installed capacity across futures



The differences in the long-term portfolios confirms that the futures we consider differ enough to serve as bookends in the analysis. Meanwhile, the consistency between portfolios in the short-term gives us confidence that investment decisions we make now should not result in stranded assets regardless of which future is realized.

Table 34 shows the NPV cost breakdown of the two portfolios selected under each of the four futures. Generally, total cost scales with the load forecast; accordingly, higher NPV costs under higher load scenarios do not imply higher costs on customer bills. The finding that the Technology Neutral scenario produces lower costs for our customers persists across all futures we considered. As shown by Table 34, No New Combustion portfolios have higher costs than Technology Neutral portfolios by 2% to 5% in every future.

Table 34. NPV revenue requirement 2021-2040 across different futures

Future	Technology Neutral ($ millions)	No New Combustion ($ millions)	Difference ($ millions)	Difference (%)
Current Trends & Policy	$6,841	$7,029	+$188	+3%
Aggressive Environmental Regulation	$6,939	$7,081	+$142	+2%
High Economic Growth	$7,673	$8,053	+$380	+5%
Low Economic Growth	$6,142	$6,278	+$135	+2%

8.6.2 Sensitivity Analysis

As described in Section 5.1.3, we use a series of sensitivities to quantify the uncertainty associated with possible variation among key drivers of MCEP determination. We conduct sensitivities by varying a single forecast element at a time and allowing the model to re-solve. Comparison of the resulting portfolio back to the original portfolio indicate the impact of the changed element. We repeat this process over a range of forecast elements to assess how different scenarios may be sensitive to different forecast variables. It is important to note that the model constraints remain in place during these sensitivity runs. As a result, all portfolios produced meet the reliability and environmental standards required of any MCEP candidate portfolio.

The sensitivities we test fall into two broad categories: load uncertainty and price uncertainty. Sensitivities exploring load uncertainty come from changes to the load forecast. These include:

- Higher or lower load growth based on economic and demographic factors,
- Higher or lower adoption of BTM PV adoption,
- Higher adoption of building electrification measures,
- Higher or lower adoption of electric vehicles, and
- Additional load shifting out of the peak period due to widespread use of TOD rates.

The details of how the high and low forecasts compare to the CTP forecasts for each element can be found in Section 6.1 along with demonstrations of each forecast on an example summer day.

Sensitivities exploring price uncertainty come from changes to forecasts of resource or commodity prices. These include:

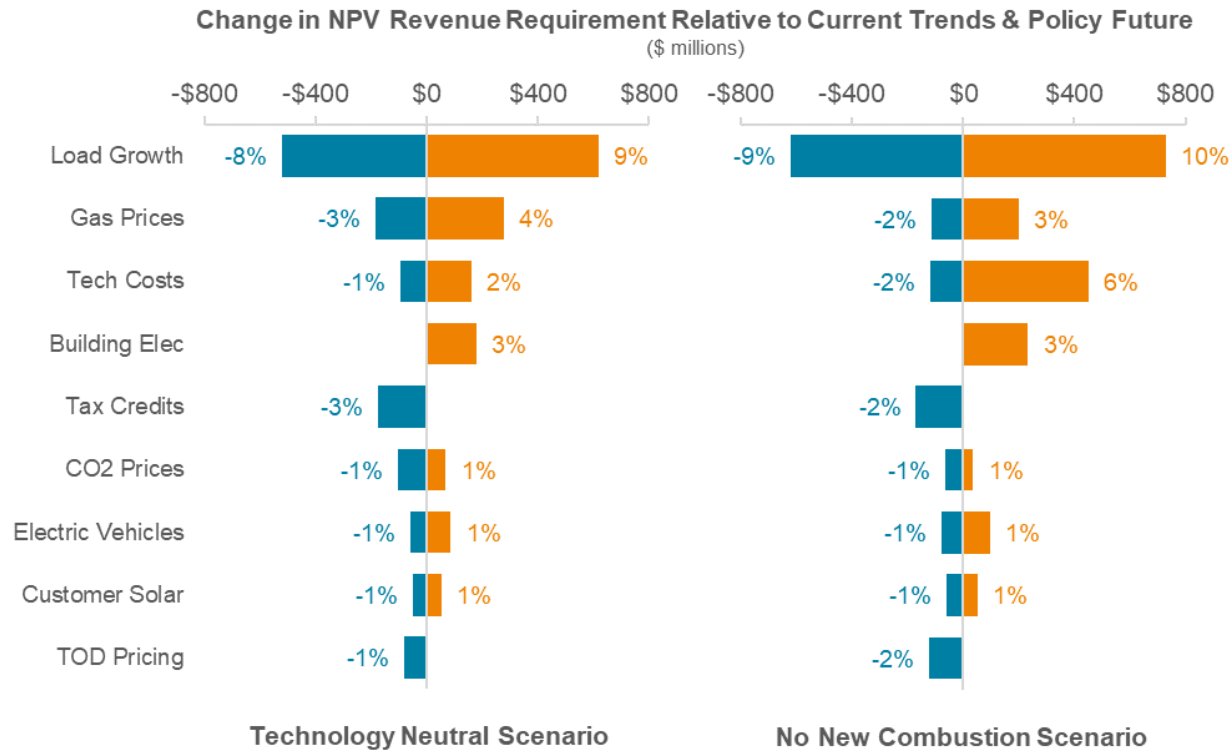
- Higher or lower gas (and therefore electricity market) prices than in our CTP forecast,
- Higher or lower CO2 prices than in our CTP forecast,
- Higher or lower projections of cost reductions for new technologies including batteries, wind, solar, and hydrogen fuel, and
- Extension of ITC and PTC tax credits at current levels throughout the analysis timeframe.

The details of how the high and low forecasts compare to the CTP forecasts for each element can be found in Section 5.2.

In addition to the full set of sensitivities run off of the CTP future, we run two more sensitivities across all four futures. The first of these is the sensitivity on technology cost that has been mentioned above. Combining low costs of new technology with the specifications of each future tests the conclusion that the Technology Neutral scenario is less expensive than the No New Combustion under the most favorable conditions for investment in new technologies. The second is a sensitivity in which new economic development loads are added into the load forecast. Adding this load to the High Economic Growth future creates a still higher load forecast that tests PNM's ability to achieve environmental goals at any load level.

Figure 96 shows how the sensitivities we consider impact the total NPV cost of the Technology Neutral and No New Combustion scenarios. The bars show the difference in costs from the sensitivity to the CTP future, while percentages paired with each bar give the difference as a fraction of the total cost of the CTP future for the given scenario.

Figure 96. Range of sensitivity impacts on NPV revenue requirement



The load forecast itself is the largest source of uncertainty in determining cost for both scenarios. It comes as no surprise that changes to the economic and demographic indicators that drive the load forecast result in a change in total costs up to about 10% above or below the cost of our base forecast. With only one exception, no other sensitivity results in a cost increase or decrease in excess of 4%. Generally, we notice slightly higher levels of uncertainty in the No New Combustion scenario. This comes in the form of higher dollar amounts at risk – in absolute terms and as a percentage of the CTP portfolio NPV – under the same set of sensitivities.

In addition to cost, the sensitivity analysis also has implications for the types and quantities of new resources needed. Figure 97, Figure 98, Figure 99 show how the sensitivities on the Current Trends & Policy future affect the amount of new capacity additions over the full 20-year horizon for the three technologies most impacted by the sensitivities: solar, battery storage, and hydrogen-ready CTs.[45] These figures affirm that changes in load conditions – due to growth, electrification,

[45] Wind and DSM are not shown in these charts because with select exceptions, sensitivity analysis does not result in different levels of investment.

or other factors – will be the biggest driver of a need to adjust our plans. Other sensitivities generally result in smaller adjustments to the least cost plan in the Current Trends & Policy case.

Figure 97. 2040 range of new solar installed capacity across sensitivity analysis

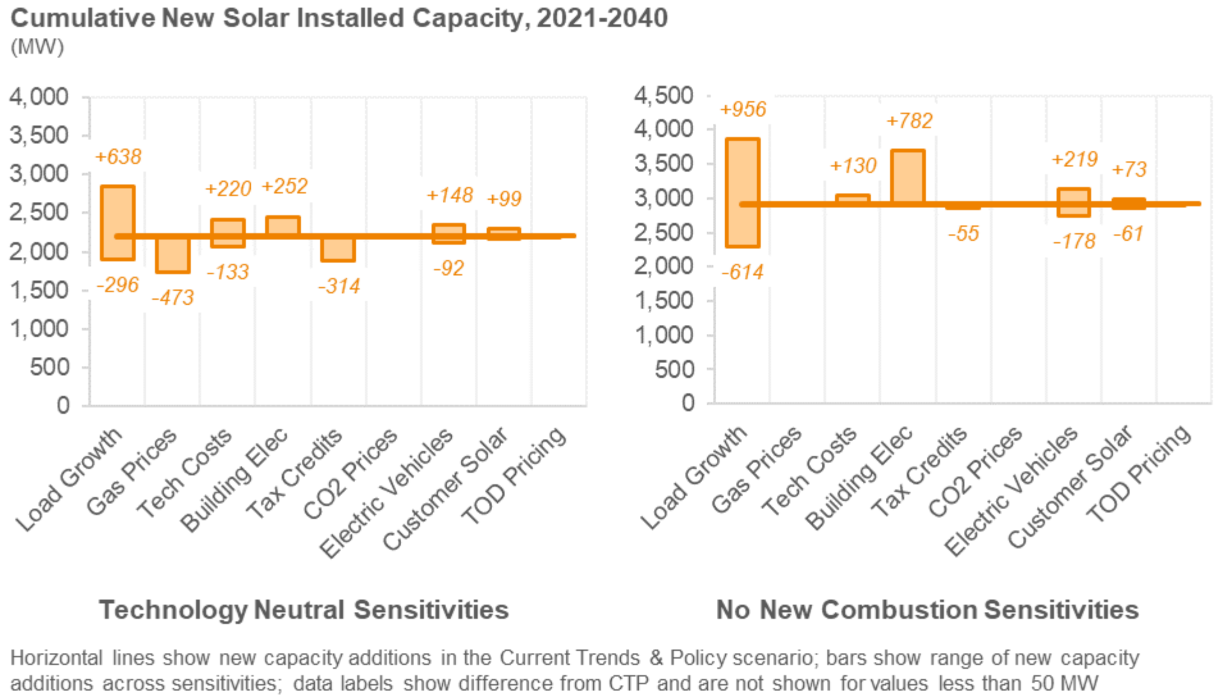


Figure 98. 2040 range of new battery installed capacity across sensitivity analysis

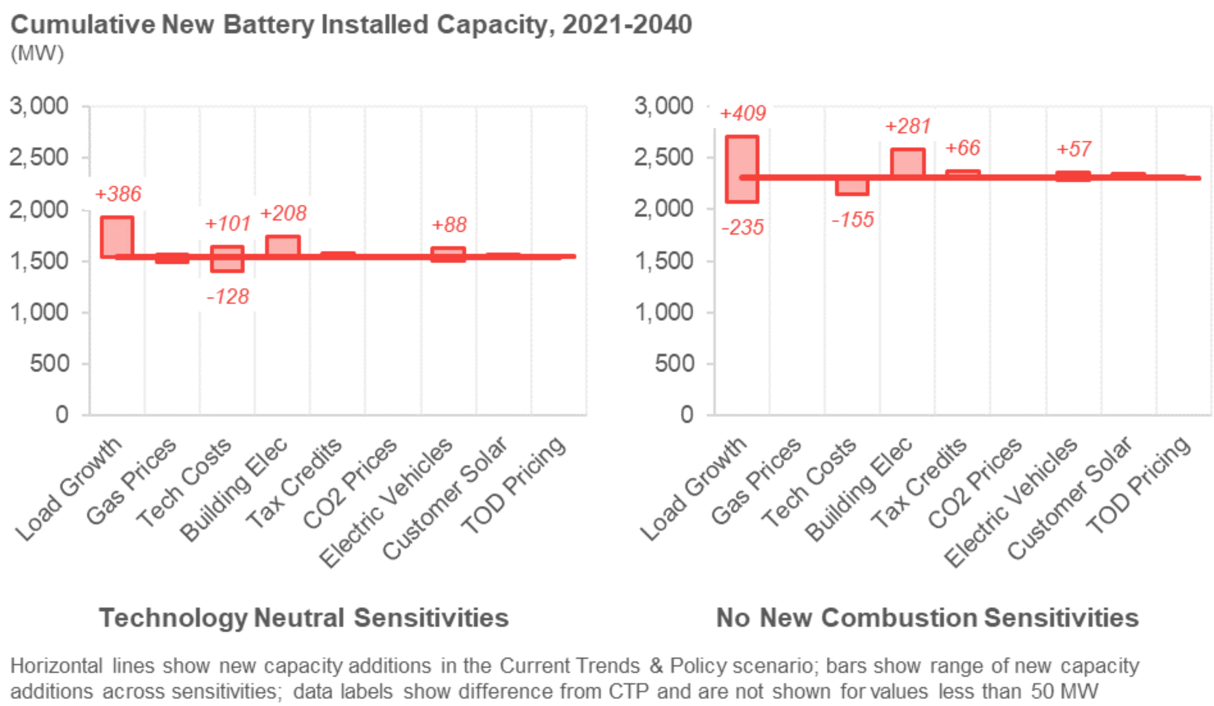
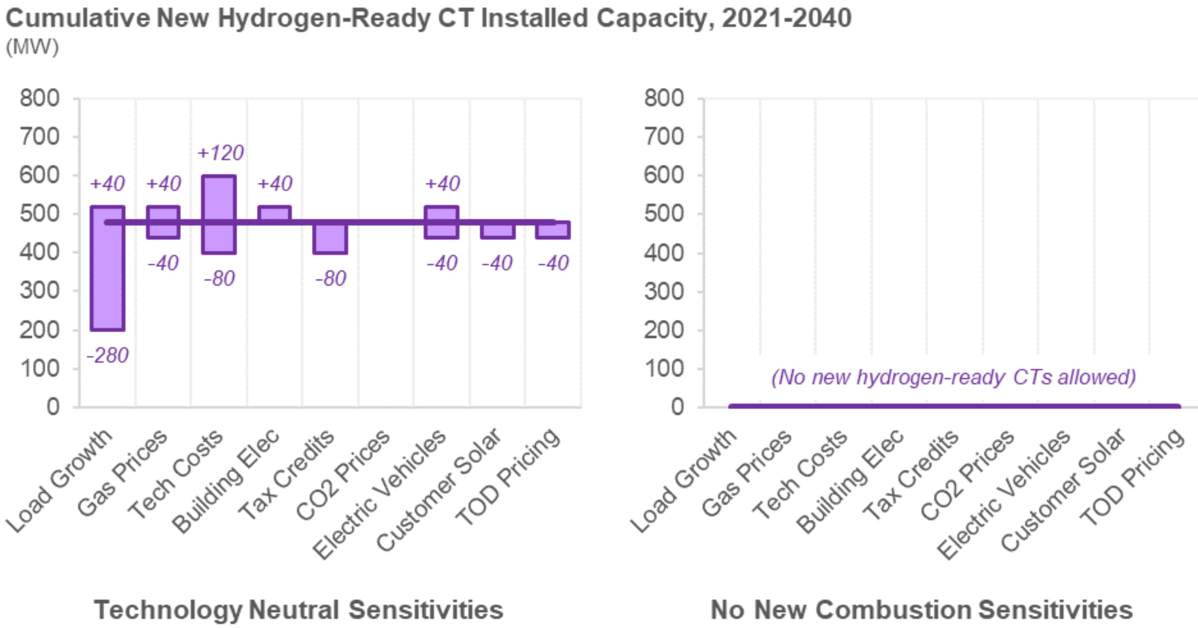


Figure 99. 2040 range of new hydrogen-ready CTs installed capacity across sensitivity analysis



Horizontal lines show new capacity additions in the Current Trends & Policy scenario; bars show range of new capacity additions across sensitivities; data labels show difference from CTP

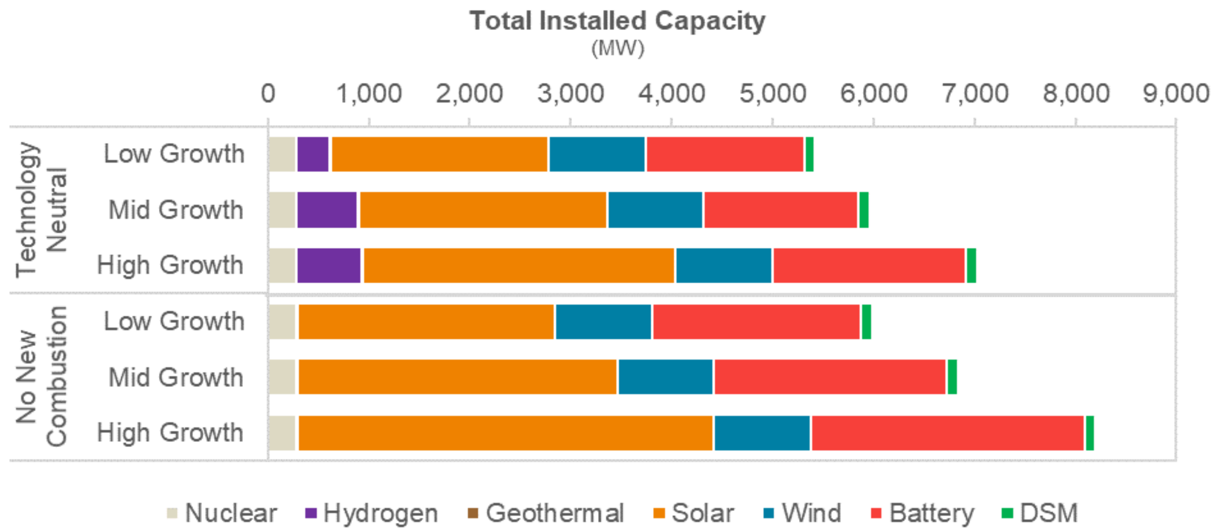
The following subsections discuss the implications of some of the specific sensitivities we consider.

Load Growth Sensitivities

While our sensitivity analysis on load growth yields the highest range of NPV revenue requirement, this does not translate to the same range of outcomes for customer bills. Along with changes to our revenue requirement, the load growth sensitivities also result in a change in sales to end users, so the cost per unit of energy supplied varies less across our load growth sensitivities.

These sensitivities do provide useful insights into the scale of investment needed to achieve our carbon-free goals under a range of load growth outcomes. Figure 100 shows the amount of total installed capacity needed to serve our 2040 loads across load growth sensitivities. The range is significant: under lower growth scenarios, our portfolios will include between 5-6 GW of total installed capacity; under high economic development sensitivities, the amount of total installed capacity needed ranges from 7-8 GW. Most of this incremental resource need is met by a combination of solar and storage, whose modularity should allow for scalability to meet load growth.

Figure 100. 2040 total installed capacity across load growth sensitivities



Technology Cost Sensitivities

The Technology Cost sensitivities shows how technology cost uncertainty has become one of our more significant risk factors in the context of our plan to achieve a carbon-free portfolio. While the potential range of cost outcomes is broad across both scenarios, the No New Combustion scenario exhibits a larger range of potential cost impacts (-2% to +6%) than the Technology Neutral Case (-1% to +3%), largely due to its increased reliance on battery storage.

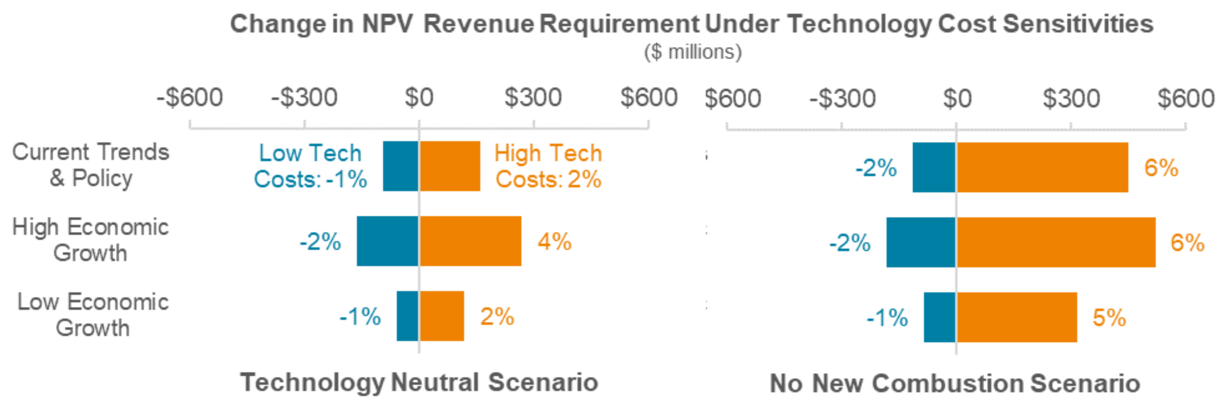
The difference between these two results highlights an observation that is axiomatic in nature: that consideration of a more expansive set of technologies in our planning and procurement can help to mitigate the risk of future technology cost uncertainties. Table 35 shows how, in the Technology Neutral scenario, we could adjust our long-term portfolio decisions in response to different future technology costs: in the “Low Technology Costs” sensitivity, our portfolio takes advantage of cost reductions by including additional solar and storage; in the “High Technology Costs,” our portfolio relies more heavily on proven technology (hydrogen-ready CTs) to avoid investments in higher cost storage resources. This same flexibility is not possible under a No New Combustion scenario, where the buildout of new resources does not vary significantly in spite of the underlying variations in technology cost. In other words, establishing an *ex ante* preference for (or against) a specific technology or type of resource may pose cost risks to our customers, both by reducing the competitiveness of solicitation process and by ignoring lower cost alternative options.

Table 35. Total 2040 installed capacity under technology cost sensitivities

Resource	Technology Neutral (MW)			No New Combustion (MW)		
	Low Tech Costs	Current Trends & Policy	High Tech Costs	Low Tech Costs	Current Trends & Policy	High Tech Costs
Nuclear	288	288	288	288	288	288
Coal	-	-	-	-	-	-
Natural Gas	-	-	-	-	-	-
Hydrogen	526	606	726	-	-	-
Geothermal	11	11	11	11	11	11
Wind	956	956	956	956	956	956
Solar	2,676	2,456	2,323	3,295	3,165	3,272
Battery	1,635	1,535	1,407	2,152	2,307	2,173
DSM	110	110	110	110	110	143
Total	**6,093**	**5,852**	**5,711**	**6,701**	**6,727**	**6,700**

The relative sensitivity of the Technology Neutral and No New Combustion portfolios to technology costs persists under different levels of growth as well. Figure 101 shows how the NPV revenue requirement changes when technology cost sensitivities are tested against different futures; across all futures, the No New Combustion portfolio exhibits a larger range of cost outcomes. As shown below, the effect of technology cost sensitivities also scales slightly with the level of load growth: because higher levels of growth will generally require more investments in new resources, our portfolio is more sensitive to future technology costs.

Figure 101. Impacts of High & Low Technology Cost sensitivities on NPV revenue requirement under different futures



TOD Pricing Sensitivity

The results of the TOD pricing sensitivity sharpen our observations of TOD rate design. In 2025, this sensitivity reveals strong potential to reduce total capacity; the load impact is large enough to defer investments in 120 MW of new CTs. However, its impact is reduced by 2040 since the TOD window was not assumed to adjust with the changing timing of the 2040 system net peak. This highlights the need to update TOD periods as load and generation hourly profiles evolve, but also hints that appropriately designed TOD rates could continue to have a substantial system benefit in the near and long terms. Given that cost savings of 2% can be achieved with a simple design, potential for savings from more ambitious TOD designs may be substantial. As previously stated, widespread adoption of TOD rates would be enabled by investment in advanced metering infrastructure – an initiative that PNM intends to pursue.

Electrification Sensitivities

Our sensitivities on vehicle and building electrification could together increase costs by a combined 4%, but like our other sensitivities on load forecasts, this cost increase would not necessarily translate to an impact on bills due to the associated increase in sales. This analysis also ignores the potential value of the large amount of potential flexible load that this electrification could provide under future demand response and pricing programs. Load shapes assigned to future EVs and building electrification in the model are based on historical shapes that are inflexible. But with adequate price signals or load management programs (both of which could be enabled with appropriate grid modernization investment), EV load in particular could be more of an asset than a burden. With this in mind, we recognize the need to promote EV charging rates and other mechanisms to manage transportation and building electrification load in the coming years.

Behind-the-Meter PV Sensitivities

As indicated by the figures, applying high or low projections of BTM PV adoption by customers does not have a large impact on the total cost. Not pictured are the sensitivities we conducted in which we assumed zero incremental BTM solar PV after 2020. As previously stated, we do not view these as plausible, but use them to understand the value provided today and in the future by BTM PV resources. These sensitivities find that current levels of BTM PV adoption will cause savings from $245 million to $520 million between now and 2040; however, this reduction in system cost does not mean that all customers will benefit from lower rates. Due to credits paid to the customers with BTM resources and the reduction in energy served by the utility, its possible that the rest of the system will pay higher rates due to BTM PV. Adding in incremental adoption that is expected to occur between now and 2040 increases the range of value to $495 million to $580 million. As indicated by the small impacts of fluctuations around the BTM PV adoption forecast, however, this value diminishes once the system net peak is pushed later into the evening. This diminishing value is evident from the daily load shape of Figure 43.

Gas & Carbon Pricing Sensitivities

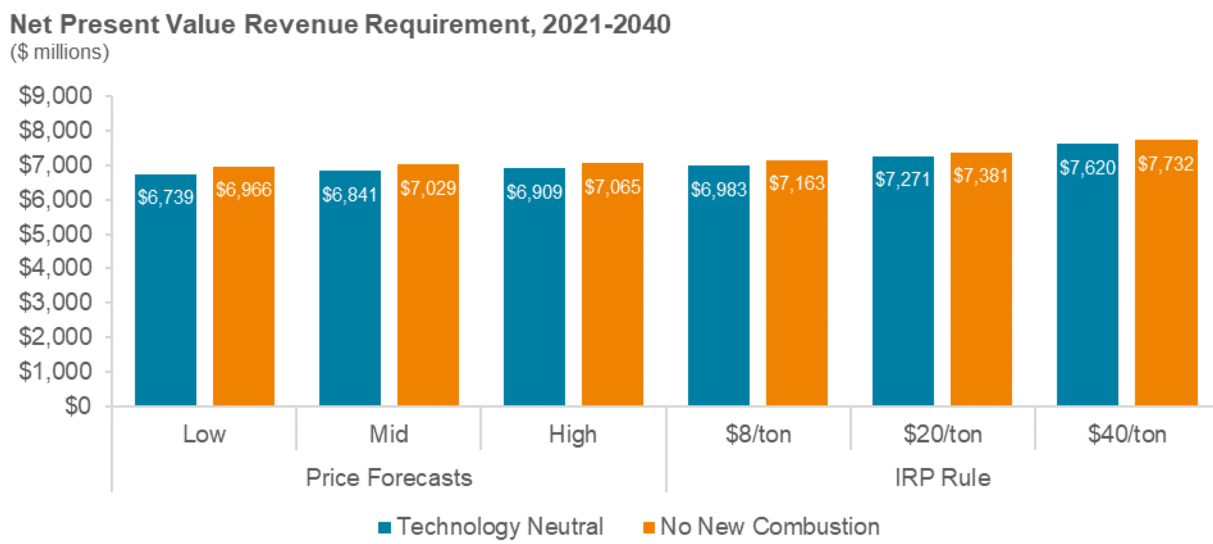
Our sensitivity analysis incorporates a range of different gas and carbon prices to examine risks related to fuel price and potential future environmental regulations. Both uncertainties result in a range of cost outcomes: the range of gas prices we study may increase costs by as much as 4% or reduce costs by 3%; the range of carbon prices generally result in cost variance of +/-1% (both measured on an NPV basis).

While these uncertainties will impact our costs to our customers, they have a limited impact on the decisions we make as we transition to a carbon-free portfolio. Across all gas and carbon price sensitivities, the composition of the Technology Neutral and No New Combustion portfolios notably does not change substantially: regardless of gas or carbon prices, our long-term plan includes generally the same mix of solar, storage, wind, hydrogen-ready CTs, and DSM programs. This is a significant but intuitive finding: as we transition towards a carbon-free portfolio, our exposure to commodity price and carbon price uncertainty shrinks. This is notable in its implications for risk in our long-term planning: in the context of a plan that fully transitions our portfolio aggressively away from fossil fuels and carbon-emitting resources, the costs of those fuels become secondary considerations in our choice of technology when compared with other uncertainties – for instance, technology cost.

One finding of note specific to the Technology Neutral scenario is that the level of investment in new hydrogen-ready CTs is relatively insensitive to both gas prices and carbon prices: high and low gas prices result in a range of 440 to 520 MW of new additions by 2040, and high and low carbon prices have no effect. This stability is a result of the fact that the choice to add these plants is driven mainly by their ability to meet resource adequacy needs at low costs. Because these plants would be expected to run at low capacity factors for resource adequacy, their operational costs (including gas and carbon) are small relative to their fixed costs.

In addition to the carbon price forecasts provided by PACE Global, we also examine how the carbon price trajectories required by the IRP rule impact the cost of our portfolio. The results are shown in Figure 102. The NPV revenue requirement appears higher in the IRP Rule carbon price trajectories due to their higher starting points in 2021.

Figure 102. Range of NPV revenue requirements observed across sensitivities

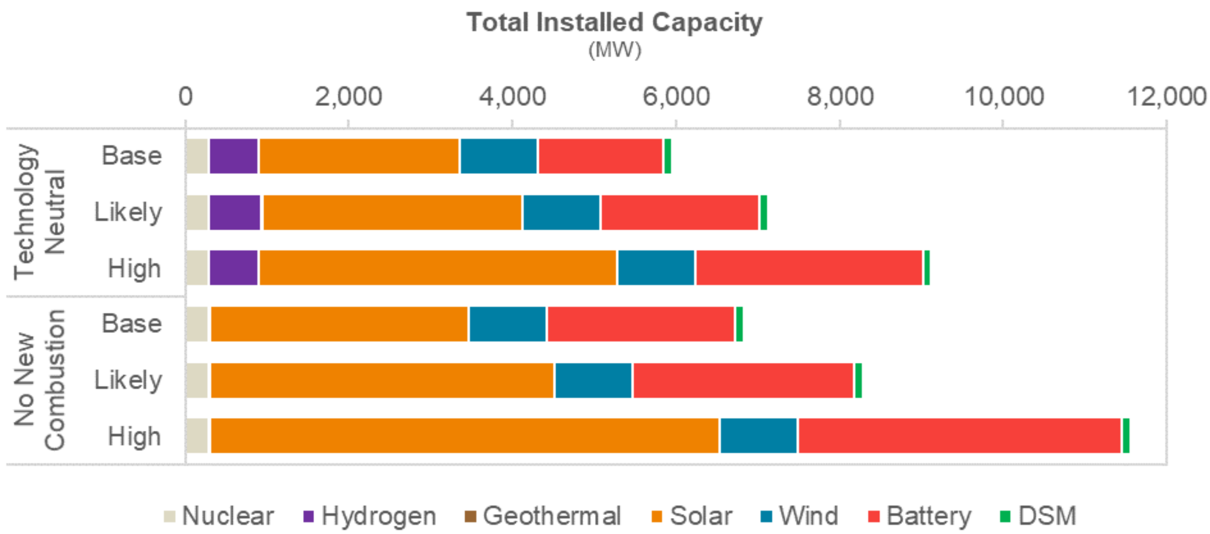


Economic Development Load

PNM has recently received a number of inquiries regarding the potential for new large economic development projects. Given that these projects could result in large increases to our future loads and associated resource needs, we find it necessary to understand how the inclusion of some or all of these loads in the load forecast would change our expected portfolios and costs. Here we test the “likely economic development loads” and the “high economic development loads” introduced in Section 6.1.1 across each of our four futures.

Figure 103 shows the 2040 portfolio builds that the model selects under our base forecast as well as with likely and high economic development load sensitivities within each future. These results are useful to illustrate the possible scale of new resources needed to serve potential new large customers, which could require anywhere from 1,000 to 4,000 MW of additional solar and storage. In general, the higher loads will pose a greater strain upon our resource adequacy, requiring significant additional investments in new capacity resources. Across all economic development load sensitivities, this additional resource adequacy need is met by incremental storage resources. This effect is most pronounced in the No New Combustion case, where the absence of a firm resource apart from our share of PVNGS means that significant additional investments in batteries will be needed to offset their rapidly declining capacity value. Additionally, new economic development loads require additional investments in carbon-free resources (in this case, solar) to supply energy to serve those loads.

Figure 103. Total installed capacity in 2040 across new economic development load sensitivities



"Base" = Current Trends & Policy; "Likely" = Likely Economic Development Loads; "High" = High Economic Development Loads

Not surprisingly, total system costs also increase significantly; however, this increase in costs does not mean that our existing customers' bills would increase. In general, by negotiating individualized rate agreements with new large customers, we are able to protect our existing customers from rate increases that might result from the additional costs resulting from additional infrastructure needs.

8.7 Additional Portfolios Studied

Accelerated Targets

PNM has committed to achieving the carbon emissions-free goal of the ETA in 2040, five years before the law requires. Based on a stakeholder request, this scenario examines the implications of accelerating that goal to 2030 and investing in a significant quantity of pumped storage to enable the transition. In this model run, we look at the possibility and cost implications of accelerating that target an additional 10 years to 2030. Figure 104 shows that the model achieves this by building out a large amount of solar and pumped hydro in 2030, while also converting remaining CT capacity to use hydrogen fuel. Since a 2030 carbon emissions-free target would be voluntary, some combined cycle gas turbines are maintained after 2030 for reliability purposes. However, these resources are not run at all from 2030 through the end of the analysis period.

Figure 104. Total installed capacity by year in the Accelerated Targets scenario

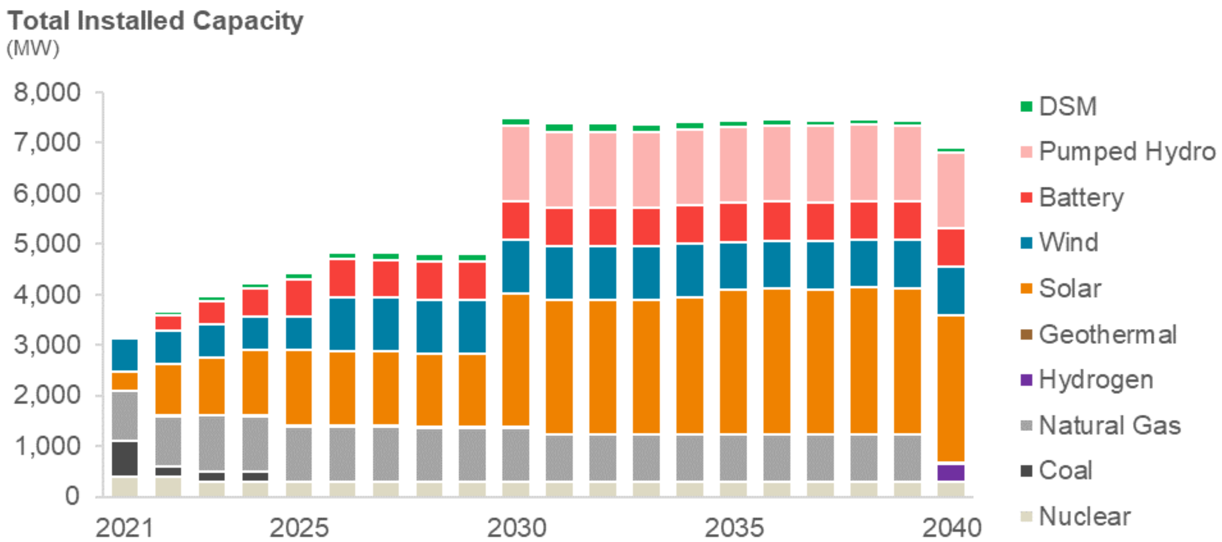
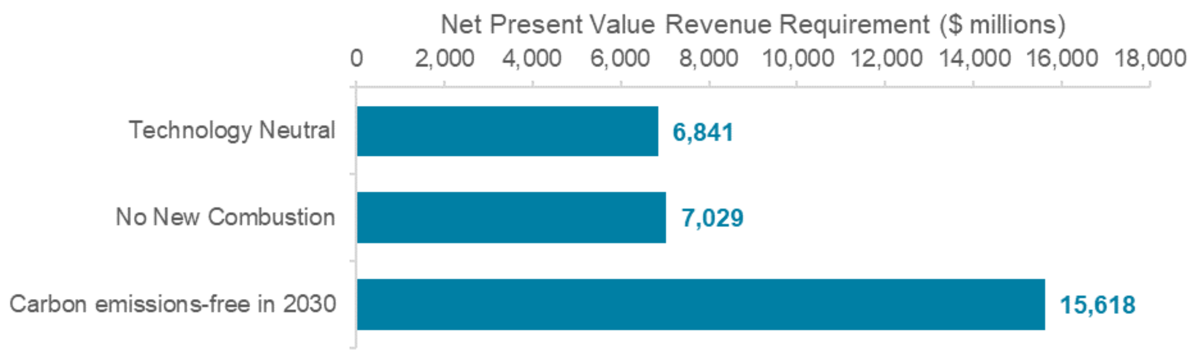


Figure 105 compares the cost of this scenario to the Technology Neutral and No New Combustion scenarios that achieve carbon emissions-free generation in 2040. The cost to reach the emissions goal a full ten years earlier more than doubles the NPV cost of either main scenario. This cost premium would be even larger if we accelerated depreciation of all combined cycle units to retire them in 2030 instead of keeping them to help meet resource adequacy. Given PNM's responsibility to provide affordable power to ratepayers, we do not consider this to be a viable option.

Figure 105. NPV cost of portfolio that achieves carbon emissions-free generation in 2030 relative to main scenario costs



Transmission-constrained Portfolio

The ability to deliver electricity from the point of generation to our loads is critical to our ability to meet our customers' needs. As our portfolio shifts increasingly towards renewable resources whose locations may not necessarily allow delivery over our existing transmission system, investments in new transmission will likely be needed as part of a comprehensive plan to meet our customers' needs reliably with carbon emissions-free electricity.

Previous and current models have been limited in their consideration of transmission within the optimization process. In this IRP, transmission is captured through model constraints on resource potential meant to reflect line limits and transmissions adders applied to select resources that can only be accessed by new transmission projects. Recent versions of EnCompass include functionality that allows co-optimization of transmission and generation investments. We have tested this functionality and present some results of that test here as a proof of concept. We plan to continue testing this functionality so that it can be fully incorporated into future filings.

Jointly selecting generation and transmission would allow our planning process to identify areas for development with high quality renewable resources where transmission costs may not be prohibitive. Further, this approach could capture the inherent lumpiness of transmission investments by regarding each potential transmission project as a binary decision. This enhancement would allow our plan to right-size investments in generation to match the delivery capabilities of realistic options for transmission expansion identified by our planners, such as the options discussed in Section 7.2.

Results of our proof-of-concept test cases appear in Figure 106, which shows the timing of transmission expansion investments in the Technology Neutral and No New Combustion scenarios. We note that, without reliance on new combustion resources, the expansion to the north occurs in the near term. Also, we confirm in the timeline that the Technology Neutral scenario does not build the expansion to the west during the model horizon. Given that these results are only for proof-of-concept, more testing would be required before considering these findings for selection of the MCEP.

Figure 106. Example timing of transmission buildout from model test cases

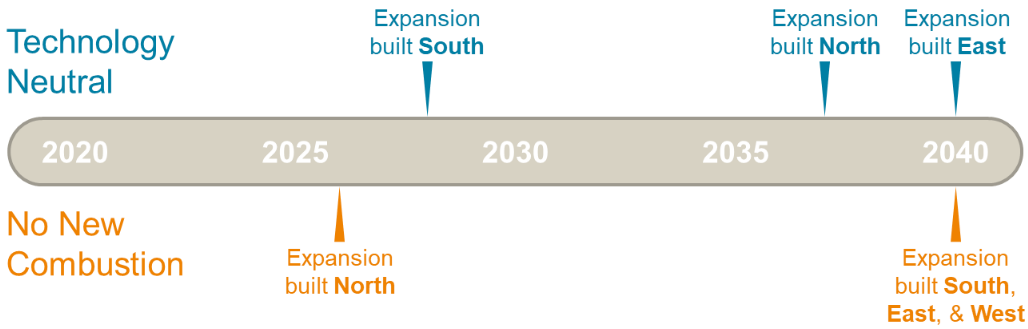
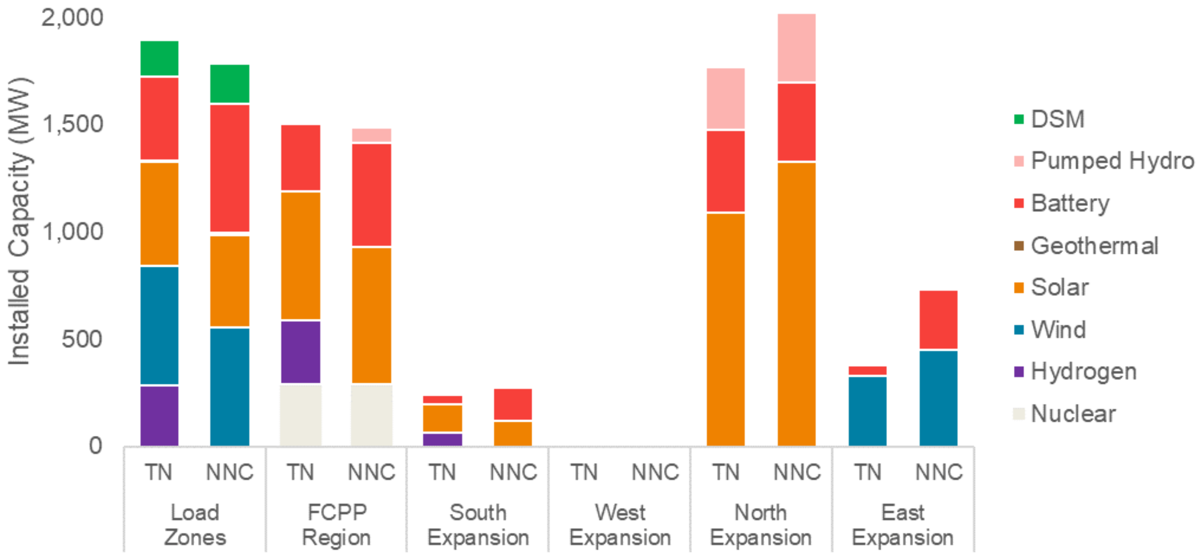


Figure 107 shows 2040 portfolio buildouts for the Technology Neutral (TN) and No New Combustion (NNC) scenarios broken out by the zone in which resources are built. This view highlights the importance of the North transmission expansion and the known resource potential strengths of each zone (i.e. wind in the east).

Comparing total resource builds in these test cases to the candidate MCEP portfolios gives us confidence that exclusion of explicit transmission constraints does not invalidate the candidate MCEP results. Changes to model inputs from the test case runs to the candidate MCEP runs means that we cannot isolate the impacts of the transmission treatment alone. However, we note that for either representation of transmission, the Technology Neutral portfolio relies on about 600 MW of hydrogen-ready CTs, plus 2,300 to 2,500 MW of solar and about 1,500 MW of energy storage. No New Combustion portfolios also show consistency: 2040 builds include 2,500 to 3,200 MW of solar plus about 2,300 MW of energy storage.

Figure 107. Example resource build in 2040 by zone from model test cases



Energy Purchases Allowed

During the stakeholder process, we ran a scenario through the capacity expansion portion of the model that focused on model interaction with the electricity market. The intention of the scenario was to explore if interaction with the wholesale market would change the resources selected in candidate MCEP profiles. The presence of the market could influence resource choices because the market provides some amount of on-demand capacity and because the market can provide energy that does not count towards the ETA carbon emissions targets (see Section 5.4.1).

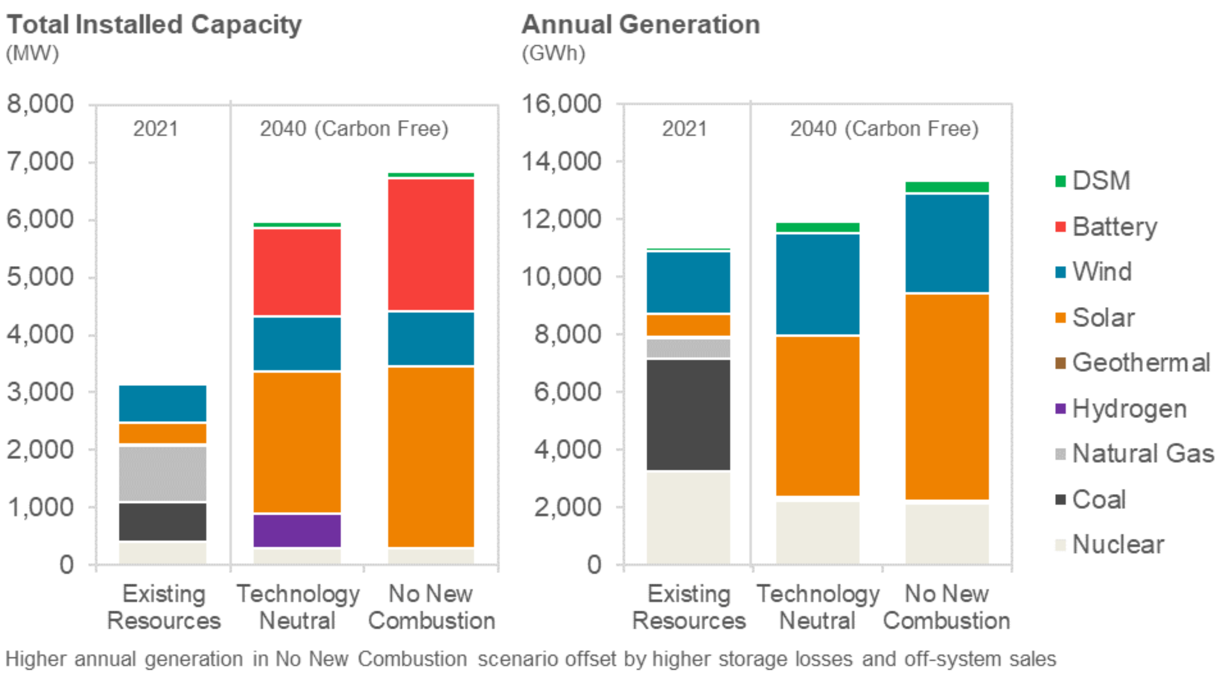
Running our full modeling process – which includes capacity expansion, production simulation, and LOLP modeling – obviates the need for a scenario dedicated to market interactions as they are endogenous to this modeling process. Assumptions about the amount of market support that PNM can rely during a peak event are included in the LOLP modeling that establishes our PRM. Insisting that capacity be built to meet the PRM in each year ensures that limited purchasing capability observed during peak events will not cause reliability issues. We also explore how changing the assumptions of market availability alter LOLP for each candidate MCEP. Meanwhile, hourly dispatch within the production simulation has access to wholesale markets, allowing PNM to import and export energy to neighbors as a simulation of market dynamics. Because these market considerations are included in our full modeling process, we do not include a specific “energy purchases allowed” scenario here.

9 Conclusion

9.1 Our Most Cost-Effective Portfolios

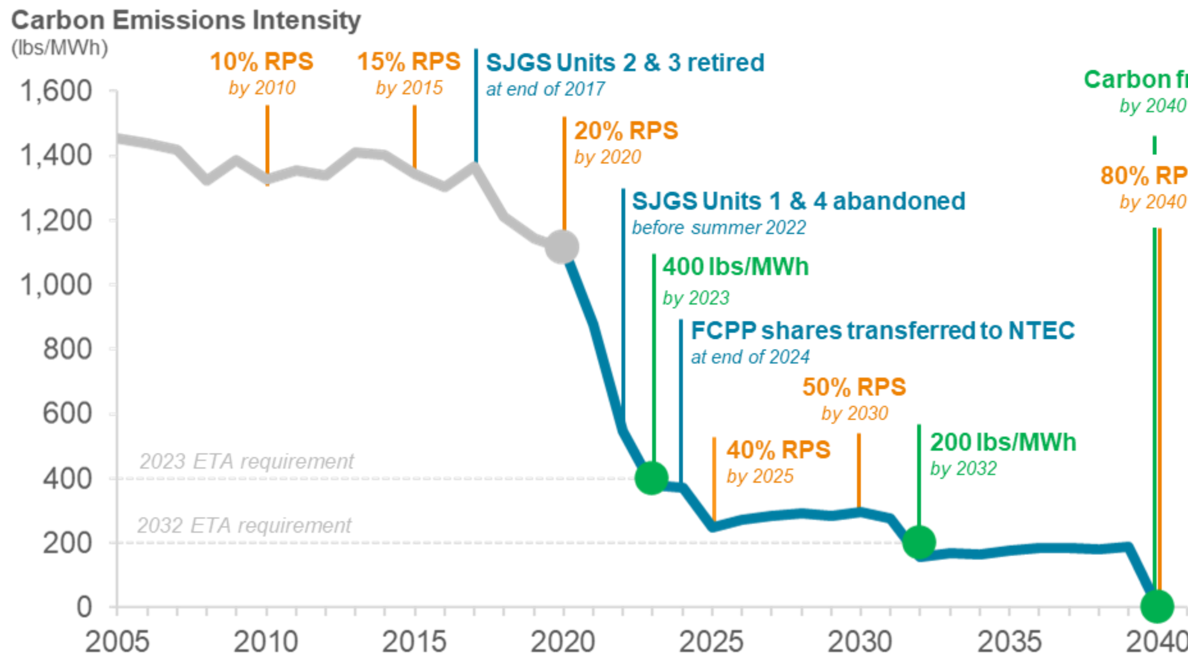
Our analysis in this IRP focused on a comparison of two primary options for future resource procurement: (1) a **"Technology Neutral"** investment scenario that considers all possible technologies that could help meet our 2040 goals; and (2) a **"No New Combustion"** investment scenario that focuses on investments in renewables and storage. Figure 108 summarizes the portfolios of resources that achieve our 2040 carbon emissions-free goals in each of those scenarios.

Figure 108. Portfolios achieving PNM's 2040 carbon-free goal



The Technology Neutral and No New Combustion portfolios are far more similar than they are different. Both portfolios represent approximate doubling of the current installed generation capacity; an increase driven by maintaining reliable service in the face of steady load growth and declining capacity value of renewable and storage resources. Both portfolios meet 2040 energy needs with a mix primarily composed of nuclear, wind, solar, and some DSM resources. Both portfolios require significant investments in energy storage to meet balancing and resource adequacy needs and renewables to supply carbon-free energy. And in both portfolios, our achieved carbon emissions intensity over the 20-year analysis horizon follows a similar path. Our MCEPs achieve carbon emissions intensities of 400 lbs/MWh and 200 lbs/MWh in 2023 and 2032 as required by the ETA. The trajectory of carbon emissions intensity implicit in the MCEPs, along with key milestones, is shown in Figure 109.

Figure 109. PNM emissions intensity, 2005-2040

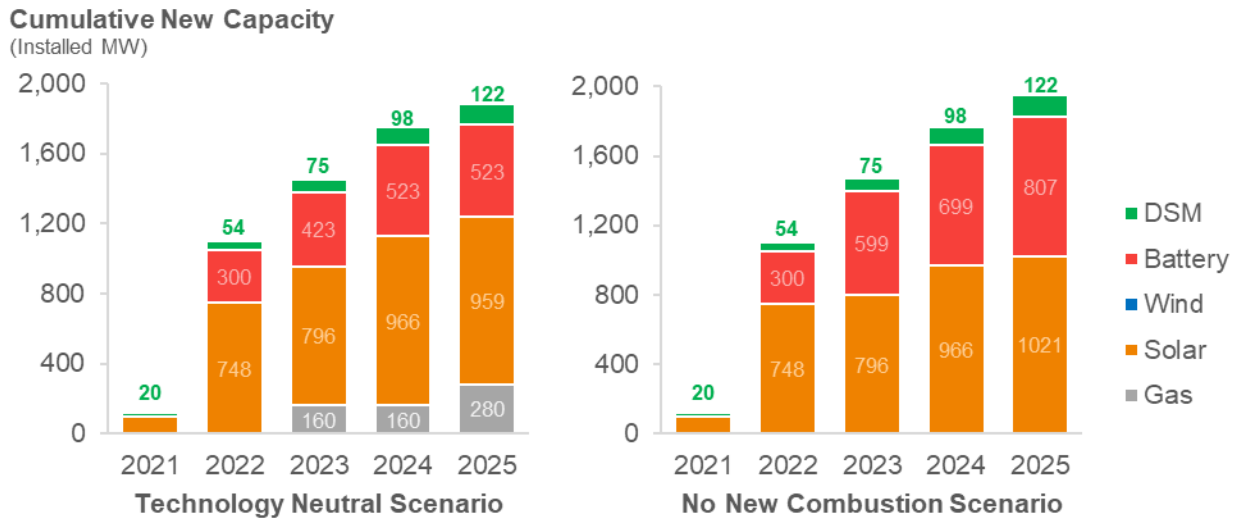


The key factor that differentiates these two portfolios is the reliance of the Technology Neutral portfolio on hydrogen-ready combustion turbines to meet a portion of our resource adequacy needs. Excluding new combustion resources, the No New Combustion portfolio relies on longer duration storage to meet this same need. The tradeoffs between these paths are multifaceted: the Technology Neutral pathway generally exhibits lower costs, relies on proven technology, and provides greater certainty of resource adequacy; and yet, in a policy and regulatory environment that favors investments in carbon-free resources, the No New Combustion portfolio offers an alternative that limits the risk of undepreciated investments along the pathway to our carbon-free goal.

While we present these two portfolios as independent parallel pathways to our 2040 goal, the flexibility to adjust our plan as conditions evolve will be a key strategy to manage the risks we face. The decisions of whether and how much to invest in hydrogen, storage, or other emerging technologies not considered in these two paths to meet our resource adequacy needs will generally be made in small steps throughout our transition, allowing us to revisit tradeoffs among these risks with the continued reshaping of our portfolio. The Commission's most recent policy decisions have implicitly set us upon the path of the No New Combustion scenario, and to the extent that concerns for cost and reliability do not unduly hinder our progress, it will remain a feasible pathway. We also acknowledge that changes to the technology landscape, regional market conditions, and our own loads may require us to adjust this plan.

While the specific resource choices differ in our two MCEPs, our transition will occur in several phases over the coming two decades. The key decision points are marked by the abandonments and replacements of resources from our existing portfolio. In the near term, our analysis indicates that both MCEPs can meet our reliability needs while positioning our portfolio for the long-term transition to our carbon-free goal. Further, both are consistent with the requirements set forth by the ETA. The key specific milestones and phases of our transition to a carbon-free portfolio are discussed further below, with the MCEP options in the nearest years shown by Figure 110.

Figure 110. Cumulative new investments between 2021 and 2025 in the Technology Neutral and No New Combustion MCEPs



Includes SJGS replacement resources (650 MW solar, 300 MW storage, and 15 MW DSM)

San Juan Replacement (2022)

As established by Commission decisions in Case No. 19-00018-UT and Case No. 19-00195-UT, our MCEP incorporates our planned abandonment of SJGS and the corresponding replacement portfolio of resources approved by the Commission (650 MW of solar PV, 300 MW of storage, and 15 MW of demand response[46]). The replacement of SJGS with carbon emissions-free resources will prompt a dramatic and immediate shift in our portfolio; in the two years between 2021 and 2023:

- Our carbon intensity will decrease by more than 50%, from over 800 lbs/MWh to 400 lbs/MWh;
- The penetration of renewables will increase from 31% to 43% of annual energy needs; and
- We will add 300 MW of storage to our portfolio, equivalent to roughly 15% of our peak demand.

These changes lay the foundation for the 20-year transition towards a carbon emissions-free system. This presents an opportunity to better understand how our system will operate when relying heavily on energy storage. In fact, with storage capacity equivalent to 15% of peak demand, PNM's reliance on battery storage to meet resource adequacy needs will be among the most in the nation.

Palo Verde Lease Replacement (2023-2024)

Between 2023 and 2024, the expiration of our leased shares of PVNGS requires 114 MW of firm capacity replacement. The replacement of this capacity represents our first choice to continue

[46] Demand response is subject to Commission approval in Case No. 20-00182-UT

reliance on batteries or to build new hydrogen-ready CTs for resource adequacy. Our MCEPs demonstrate how we could replace the leases with mix of solar, battery storage, and hydrogen-ready combustion turbines; the specific resources we propose will be determined in our filing for PVNGS abandonment and replacement. Regardless of whether the replacement resources include hydrogen-ready CTs or rely exclusively upon carbon-free resources, the low composite emissions intensity of the replacement portfolio will allow us to maintain the 400 lbs/MWh requirement set forth by the ETA.

Four Corners Replacement (2025)

At the end of 2024, we intend to transfer our share of FCPP (200 MW) to NTEC; another significant loss of firm capacity that will require investment in new resources to remediate the impact on system resource adequacy. This transaction will eliminate coal-fired generation – by far the largest source of emissions today – from our portfolio. Our MCEPs demonstrate multiple feasible pathways to replace this capacity in our portfolio, which either rely heavily on energy storage for resource adequacy or include limited quantities of new hydrogen-ready CTs. In either case, our plan continues to expand our portfolio of renewable resources in this period.

Valencia & Reeves Replacement (2028-2031)

Our current PPA with Valencia Energy Facility expires in 2028, and Reeves Generating Station is currently scheduled to retire in 2030. Despite operating at low annual capacity factors, both of these plants are currently crucial to meeting loads reliably within the Northern load pocket, where our peak loads can exceed the capability of the transmission system to deliver generation from other parts of the state. Whether through reinforcement of the transmission system, investment in new resources within the load pocket, or a combination of the two, the loss of these two resources will require careful and detailed planning to ensure our resources can meet customer needs even under the most constrained conditions.

Given that replacement resource decisions for FCPP and PVNGS will be made in 2021 and 2022, the replacement capacity for natural gas generation marks a significant decision point between battery storage, hydrogen-ready CTs, or other new resources capable of meeting our resource adequacy needs. Several years of experience operating a system with high levels of storage and renewables, monitoring the commercialization of zero-carbon fuels, and following technology cost trajectories for longer duration storage will help inform our choice. In our MCEPs, we identify either battery storage or hydrogen-ready CTs within the load pocket as the least-cost combination of resources to replace Valencia and Reeves. Both these resources and their replacements are chosen specifically for their ability to provide capacity when it is needed most but have a negligible impact on our generation mix and carbon footprint. Accordingly, our emissions intensity over this period remains relatively stable just above 200 lbs/MWh.

Transition to 100% Carbon emissions-free (2032-2040)

Over the subsequent decade, our MCEP identifies a series of additional investments in carbon emissions-free resources needed to achieve a 200 lbs/MWh carbon intensity by 2032 and to transition fully to a 100% carbon emissions-free system by 2040. We foresee the need to add substantial amounts of additional renewable generation and energy storage to eliminate fossil fuels from our portfolio. In our MCEPs, we identify the following ranges resource additions between 2032-2040:

- Between 1,300 to 1,700 MW of solar depending on whether any combustion resources will be maintained after 2039;

- At least 400 MW of wind, accompanied by investment in new transmission to Eastern New Mexico to allow delivery to loads along a corridor that is today fully subscribed; and
- Between 800 to 1,000 MW of storage, including resources with increasing duration (eight hours and beyond) to offset the declining capacity value of four-hour batteries at higher penetrations.

At the same time, our plan assumes a transformation of our remaining natural gas generation fleet, namely:

- We will plan to depreciate our combined cycle plants (Afton and Luna Energy Facility) and Rio Bravo CT through 2039, allowing for plant retirements so long as resource adequacy can be maintained;
- In the case that we maintain combustion resources after 2039, we will convert our remaining existing resources (Lordsburg and La Luz) and the new hydrogen-ready CTs to burn carbon emissions-free fuel, allowing us to retain those resources for reliability purposes beyond our 2040 goal.

Together, these steps provide us with a balanced and nimble foundation to achieve our long-term goals and to eliminate carbon from our portfolio by 2040. While our MCEPs present specific paths to a carbon-free portfolio that rely largely on technologies commercial today, we also recognize the importance of adaptation in response to the ever-changing technology landscape. Especially in the long-term, we will continue to explore options to provide the key attributes embodied in these plans: low-cost reliable carbon-free electricity.

9.2 Our Action Plan

As a first step towards this end point, our Action Plan comprises the following steps over the next four years:

Pursue abandonment and replacement of outstanding PVNGS lease interest and FCPP

- File for abandonment of the 114 MW of PVNGS leases and approval of replacement resources consistent with the identified MCEP paths.
- Issue an RFP for new capacity deliverable in 2025 to replace the FCPP capacity and file for approval of replacement resources by January 2022.

Complete annual filings for renewables and demand-side resources as required by the Commission

- Continue to develop and implement cost effective energy efficiency and demand management programs and file plans with the Commission.
- File Annual Renewable Energy Procurement Plans to demonstrate compliance with the RPS and request approval of new resources if needed.

Explore cost-effective options to maintain system supply and reliability

- Develop energy storage as a capacity resource and monitor its real-world performance in a resource adequacy context to better understand risks.

- Limit consideration of combustion-based resources to those that can be easily repurposed or retrofit to operate using carbon-free fuels, including hydrogen and renewable fuels.
- Continue to assess regional market depth and liquidity impact on resource planning decisions.
- Transition to the industry standard loss of load expectation of 0.1 days per year (“one day in ten years”) to maintain best practices in reliability planning for our system.
- Explore rate design approaches that reflect customer use and load needs and evaluate energy efficiency and DSM program opportunities under the Efficient Use of Energy Act.

Continue to monitor and explore opportunities to advance transition to a carbon-free portfolio

- Monitor landscape of emerging technologies that could contribute to carbon-free goals, including generation resources, storage, and clean fuels.
- Utilize PNM’s Wired for the Future program to pursue opportunities to modernize the grid and invest in transmission that supports the transition towards a carbon free system.
- Implement PNM’s Transportation Electrification Program upon approval by the Commission.
- Assess potential load increases from economic development activities in PNM’s service areas, in cooperation with state and local entities.

Conduct the 2023-2042 Integrated Resource Plan

- Address the implications of the expiration of supply contracts and any retiring resources.
- Consider the impacts of participation in the CAISO Energy Imbalance Market on our resource planning process and decisions.
- Apply co-optimization to generation, storage, and transmission as identified in this report to enhance coordinated planning efforts.
- Work with stakeholders in an ongoing collaborative public advisory process.