PNM
2017-2036

Integrated Resource Plan

Balancing cost and reliability while reducing the impact on the environment

April 20, 2017
Public Comment Draft

PNM 100 ®
A NEW CENTURY OF SERVICE

Talk to us. PNM.com

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, which are often beyond their 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.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Background

Every three years, PNM is required to prepare an Integrated Resource Plan (IRP).[1] In this IRP, PNM has analyzed cost-effective power supply plans under two scenarios:

- San Juan Generating Station (SJGS) retires after the end of the current coal supply agreement, terminating on June 30, 2022
- SJGS continues to operate beyond 2022

The purpose of an IRP is to identify the most cost-effective resource mix that would meet the projected electricity demands of PNM's customers over the next 20 years, and to develop a four-year action plan that is consistent with that resource mix. PNM prepared this IRP for the period 2017 through 2036, examining all cost-effective resource options under a wide variety of possible futures for its energy portfolio. The four-year action plan is designed to test the assumptions in this report and maintain flexibility to adjust the mix of replacement supplies as the price and capabilities of renewable energy, natural gas, and energy storage technologies evolve over the next four years.

Key Findings

The most significant finding of the IRP is that retiring PNM's 497-MW share of SJGS in 2022 would provide long-term cost savings for PNM's customers. It's important to note that this finding assumes that PNM is able to recover the full cost of the remaining plant investment after SJGS retirement. This is consistent with what's known as the "regulatory compact," under which government regulators grant PNM the ability and obligation to serve as the sole supplier of electricity to all customers in a specific area. In return, PNM must provide reliable service, meet state and federal regulations, and work in the best interests of customers. In doing so, PNM has the right to recover prudent costs, including the opportunity to make a reasonable return on investments.

With this plan, PNM would be coal-free in 2031.

The results of the IRP illustrates that energy needs are changing and replacing coal supply with renewable energy and more flexible generators will save money in the long run. Accordingly, the analysis found that PNM exiting its 13% share in the Four Corners Power Plant (FCPP) after the coal supply agreement expires in 2031 would also save customer money. This action would eliminate coal from PNM's generating fleet.

[1] In accordance with 17.7.3 New Mexico Administrative Code, Integrated Resource Plan for Electric Utilities.

Retiring SJGS would result in the loss of jobs in the Farmington area. These high-wage positions will not be easily replaced. PNM will work with the most affected communities to mitigate the impact of these changes.

New Supply-Side Resources

PNM recognizes that renewable energy, natural gas, and energy storage technologies are rapidly evolving. The best mix of new resources currently includes solar energy and flexible natural gas-fired peaking capacity, which provides continuous reliability. The mix may also include energy storage, depending on the economics of the proposals PNM receives through a solicitation that the company will conduct as described in the action plan. Wind energy is also a possibility. However, the best wind conditions are in Eastern New Mexico, and transmission lines from that area are nearing maximum capacity. Only a limited amount of new wind energy can added to serve PNM's customers until new transmission capacity is developed.

Over the four-year action plan period, PNM will validate the assumptions in this report and rebalance the mix of replacement resources by monitoring and updating the analysis as price and capabilities of these technologies evolve.

Continuing Supply-Side Resources

Through 2022, PNM's existing supply-side resources, except for SJGS, will remain a part of the cost-effective resource base. These resources provide energy and capacity from renewable sources (wind, solar, and geothermal) as well as nuclear, coal, and natural gas-powered resources.

PNM owns 288 MW of PVNGS and leases another 114 MW, with leases of 104 MW expiring in 2023 and 10 MW expiring in 2024. Retention of this leased capacity beyond 2023 would preclude the need to replace it with carbon-emitting generation and would preserve the CO_2 emission reductions that result from the SJGS retirement. If carbon-emitting generation were to replace PNM's leased nuclear generation resources, it would offset at least some of those CO_2 emission reductions. Moreover, retention of the leased capacity preserves fuel diversity in the PNM portfolio, minimizes freshwater use, and serves as a balance against potential increases in natural gas prices.

Access to Power Markets

PNM also utilizes energy purchases and sales from the wholesale market to enhance reliability and reduce costs to customers. Power markets are changing rapidly. PNM's plan includes an assessment of how best to maintain real-time opportunities to purchase and sell energy by studying the costs and benefits of joining the California Energy Imbalance Market (EIM). Assess and Update Existing Systems

Assess and Update Existing Systems

As part of the IRP analysis, PNM studied its power transmission system to identify locations for new resources that would not require construction of additional transmission. Replacing SJGS and Four Corners will require replacement supplies in the Four Corners region. While some locations are preferable to others in terms of the cost to interconnect new resources and the need to maintain adequate energy supply throughout PNM's Balancing Area, sufficient transmission capacity exists to connect new resources to the existing transmission system. The existing transmission system from Eastern New Mexico, where the best potential for wind supplies exists, is currently fully subscribed. This limits the ability for new wind resources to meet energy supply needs until new transmission capability is built.

The four-year action plan includes an assessment of PNM's oldest power plant: the three-unit Reeves Generating Station. Maintaining energy supply at Reeves is a critical element of PNM's system reliability for Albuquerque. PNM will consider possible technology improvements to phase out the older generators and replace them with new, more flexible supplies or energy storage.

The Most Cost-Effective Portfolio

The Most Cost-Effective Portfolio (MCEP) is summarized in Figure 1. PNM recommends this plan because it best meets the objectives 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." This plan cost-effectively maintains a reasonable reliability expectation while achieving the lowest freshwater use and carbon emissions while meeting regulatory requirements.

Figure 1. MCEP Summary

BEFORE 2022	• Meet RPS and EUEA targets • Execute four-year action plan
IN 2022	• Retire PNM's SJGS capacity • Retain PVNGS leases • Replace SJGS with renewable resources, natural gas peaking capacity, and potentially energy storage
AFTER 2022	• Build new transmission to transmit wind energy from eastern New Mexico • Meet load growth with additional renewable energy, gas peaking, or energy storage • Replace existing wind purchase expiring in 2028 with renewable energy • Replace expiring Valencia purchase with renewable resources, natural gas peaking, or energy storage • Pursue replacement of Four Corners coal plant in 2031 with renewable resources, natural gas peaking capacity, and potentially energy storage

Four-Year Action Plan

The Recommendations Section of this IRP further details the four-year action plan. In summary, PNM will do the following over the plan period:

- Continue to develop and implement energy efficiency and demand management programs
- Add renewable energy resources to maintain compliance with the RPS
- 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 Generating Station to develop a plan for Reeves that coordinates with the need for replacement resources, assuming PNM retires SJGS in 2022
- File for SJGS abandonment with the New Mexico Public Regulation Commission
  - File for abandonment of SJGS no later than July 1, 2018
  - Secure the Palo Verde leased capacity
  - Issue Requests for Proposals for energy storage, renewable energy and flexible natural gas resources to validate the assumptions in this report and to further refine the mix of replacement resources assuming SJGS retires in 2022
  - Define SJGS replacement resource siting requirements by conducting a power flow study
  - Pursue securitization legislation to provide additional long term customer cost savings and to provide funds for replacement resources
- Identify the best opportunities to increase transmission capacity to Eastern New Mexico to allow for future expansion of wind energy resources

INTRODUCTION

TIMELINE

1882

A.A. Grant established the Albuquerque Gas Company and built a gas plant – manufacturing gas made from nitrogen, carbon monoxide, hydrogen, and coal or coke--for distribution to local businesses and residences. Perfecto Armijo established the Albuquerque Electric Light Company and immediately sold the company to A.A. Grant and Dennis Dennison. The company built a new power plant with a 250-kilowatt generator.

1917

The two Albuquerque companies: Albuquerque Electric Power Company and Albuquerque Gas, Electric Light and Power Company merge into a new organization, the Albuquerque Gas & Electric Company.

1922

New generation is needed and the Albuquerque Sawmill Power Plant adds Unit 4 capable of generating 2,500 KW.

1929

The first inter-city electric transmission line in New Mexico is completed and connects Albuquerque to Santa Fe ending the dependence of each city on its own town power plant. The construction crews worked in rough terrain and long hot summer days with only tents for shelter.

1939-1945

World War II stimulated the need to unite the geographically widespread distribution and transmission systems in New Mexico. Government defense and research installations like Kirtland Air Force Base, Sandia Laboratory, Los Alamos National Laboratory, and White Sands Missile Range led to increased power demands.

Public Service Company of New Mexico

1946

In 1946, the Albuquerque Gas and Electric Company changed its corporate name to the Public Service Company of New Mexico (PNM) and acquired the properties of New Mexico Power Company, Deming Ice and Electric Company, and Las Vegas Light and Power Company.

1964

WEST, an organization serving nine western states forms and plans to jointly build a power plant, the coal-fired Four Corners Plant in northwestern New Mexico. PNM also announced plans with Tucson Gas and Electric Company to build San Juan Generating Station, which would have state-of-the-art pollution controls.

1972

PNM lists on the New York Stock Exchange and the San Juan Generating Station begins operation.

1985

The firm acquires the Gas Company of New Mexico from Southern Union.

1994

The firm brings both its electric and gas operations under the PNM name.

2003

PNM begins purchasing power generated by the New Mexico Wind Energy Center near Ft. Sumner, establishing PNM as a leader among energy companies adopting wind into their portfolios.

2005

PNM buys TNP Enterprises, a privately owned holding company for Texas-New Mexico Power Company (TNMP) and First Choice Power (First Choice). The National Efficient Use of Energy Act and National Renewable Energy Transmission Authority Act helps PNM create energy efficiency programs and sets Renewable Portfolio Standards.

2008

PNM sells gas operations to New Mexico Gas Company. Pat Vincent-Collawn named PNM Resources president and chief operating officer.

2011

Leading in renewable energy science, the 500 kW PNM Prosperity Solar Energy Storage Project comes online south of Albuquerque. The Las Vegas solar facility begins operation, making it the first of 15 new solar farms to be constructed across New Mexico.

2016

Agreement reached for PNM to provide electricity through renewable resources for a new Facebook Data Center in Los Lunas. Energy will be provided through three new solar farms currently under construction.

2017

PNM celebrates 100 years of powering the energy needs of New Mexico and looks ahead to our next century of service.

FUTURE

INTRODUCTION

This integrated resource plan (IRP) identifies the types of resources that PNM will need in the future to continue to provide reliable, cost-effective electric service while also reducing environmental impacts caused by generating and transmitting electricity. PNM prepared the plan in accordance with several rules, regulations, and guiding principles. PNM based the recommendations and action plan items on 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 began with an assessment of the electric service its customers will need in the future to provide energy for their jobs and daily life. This assessment incorporated 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 and maintaining 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. This document presents the information considered, the analysis performed, and the recommendations that followed from that work.

IRP Process

In accordance with 17.7.3 New Mexico Administrative Code (NMAC), Integrated Resource Plan for Electric Utilities (IRP Rule), PNM has prepared this IRP. This is PNM's fourth IRP filing under the IRP Rule issued by the New Mexico Public Regulation Commission (NMPRC) on March 1, 2007, and amended on November 27, 2012.

The IRP Rule requires that New Mexico electric public utilities file an IRP that contains 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 resource portfolio and alternative portfolios
- A description of the public advisory process
- An action plan
- Other information that the utility finds may aid the NMPRC in reviewing the utility's planning processes

The rule requires New Mexico electric public utilities to file an IRP every three years. In addition to the requirements of the IRP rule, PNM agreed to present most cost-effective portfolios under two scenarios: (1) where San Juan Generating Station (SJGS) completely shuts down after the end of the current coal supply agreement, which terminates on June 30, 2022, and (2) where SJGS continues to operate beyond 2022. In addition, PNM has also committed to the following:

- After July 1, 2018, but no later than December 31, 2018, PNM shall make a filing with the NMPRC, and serve all parties to this case, to determine the extent to which SJGS should continue serving PNM's retail customers' needs after June 30, 2022.
- PNM shall provide participants in the IRP process and parties in the 2018 review reasonable access to inputs, assumptions, and constraints regarding Strategist®[2] runs, and will perform a reasonable number of Strategist runs using practical assumptions as requested by stakeholders engaged in the IRP process (Stipulation Paragraph No. 19).
- PNM will issue a Request for Proposal (RFP) as soon as practicable after the filing of the 2017 IRP. The RFP will request proposals for resources identified in the IRP as the most cost-effective portfolio (MCEP) using the assumption that SJGS does not continue to operate past 2022 (non-SJGS alternative).

The goal of the IRP process is to identify the most cost-effective resource portfolio that meets the projected electric demands of PNM's jurisdictional electric customers over the next 20 years and develop a four-year action plan that is consistent with the most-cost-effective portfolio.

The IRP planning process, on a macro level, identifies the mix of resources that, together, will reliably meet system operational requirements, including delivery to customers that is consistent with applicable regulatory requirements. For planning purposes, PNM has used 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. This planning process will help to create a portfolio that allows PNM to respond to projected future events and ensure adequate resources are available to meet demand and maintain service reliability. The IRP is updated every three years or sooner, if material changes in assumptions would lead to a different course of action.

Approach

PNM designed a multidimensional process for its IRP analyses to determine the most cost-effective resource portfolio for the 20-year period from 2017 through 2036. The process included reviewing existing resources, forecasting future energy needs, examining future resource options, and designing scenarios, sensitivity analyses, and probabilities of risks and uncertainties to evaluate various resource portfolios. The goal is to meet customers' electric service needs in the most cost-effective manner while meeting all requirements for system reliability as well as security, safety, and environmental regulations. The PNM Integrated Resource Planning group worked with the IRP Public Advisory participants to consider their input in evaluating various factors. These included cost calculations and projections of future

[2] The Strategist model is described in the Analytical Tools section.

costs, current and potential environmental policy (their impacts and likelihood), and system reliability regulations today and how they might evolve as the electric grid changes.

Public Participation

PNM invited the public to participate in the planning process. The goals for public participation were two-fold. First, it provided information to interested stakeholders regarding the resource options available and, second, it allowed for feedback on the accuracy of the assumptions and calculations and affirmation of the breadth and focus of the process as well as the public's prioritization in resource planning. PNM considered these factors and the Public Advisory Group's input when analyzing different customer load and resource options under different future assumptions.

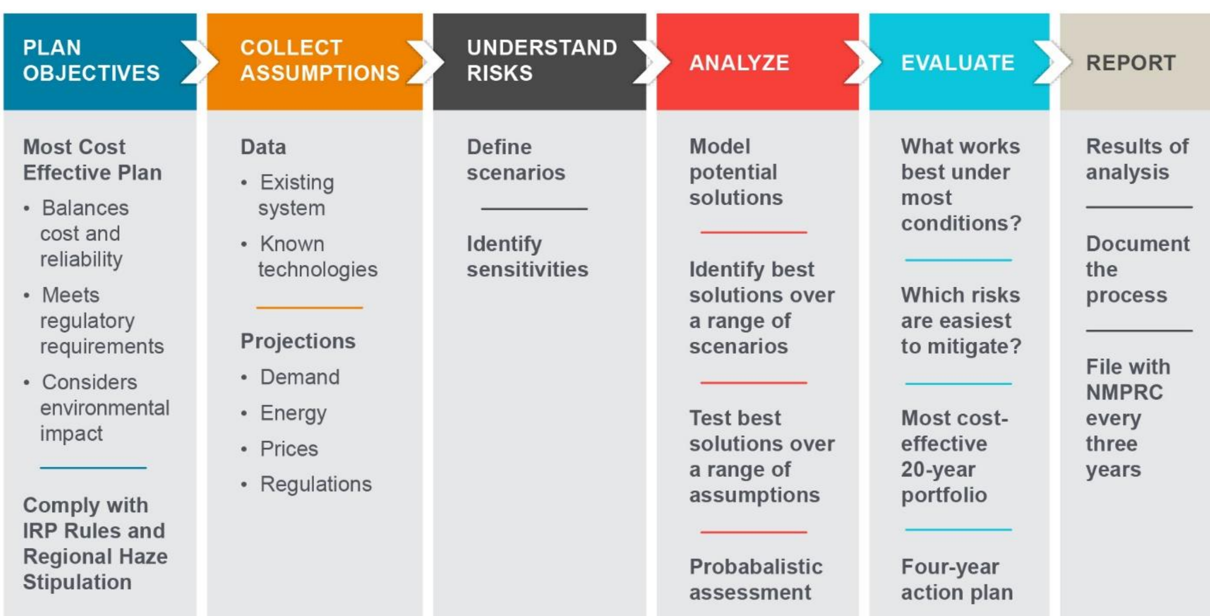
Determining the Most Cost-Effective Resource Portfolio

PNM identified the most cost-effective resource portfolios by considering a variety of factors including regulatory and environmental requirements, cost, environmental impact, and system reliability. Each factor was evaluated for potential financial risks and non-financial risks (such as reliability) and stakeholder impacts. The four-year action plan for the period from 2017 through 2021 outlines the near-term steps to implement the most cost-effective resource portfolio and ensure PNM is prepared for future transmission and emerging technology opportunities.

IRP Planning Process

PNM follows a structured six-stage process for determining the MCEP, which is shown in Figure 2 and detailed in this section.

Figure 2. Most Cost-Effective Portfolio Process



Plan Objectives

The planning process begins with defining the objectives that the resulting plan must meet. The IRP rules and other regulatory requirements set these objectives.

Collect Assumptions

Developing an IRP requires multiple assumptions. PNM collects data assumptions for use as inputs to the modeling. Table 1 provides a list of the data requirements.

Table 1. IRP Required Data

Data Types	Specifics
Load Forecast	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
Existing Generation	Additional capital improvement costs, O&M costs, heat rate, forced outage rate, maintenance schedules, fuel type, fuel price
Historical and Future Energy Efficiency Savings	Energy and demand savings
Demand Response	Available capacity, limits on use, contract costs and terms.
New Generation	Capital costs, O&M Costs, heat rate, forced outage rate, daily availability, maintenance schedules, fuel type, fuel price, interconnection costs, siting considerations, water needs, transmission costs
Fuel Price Forecasts	Price forecasts for natural gas, fuel oil, coal, and nuclear fuel, ranges
Regulations	Existing regulations and constraints, potential future regulations

Understand Risks

Given the inherent uncertainty of forecasts and possible future resource options, the next step of the IRP process is to understand the risks they represent to supplying power to customers in reliable, cost-effective, and environmentally acceptable ways. Using scenario and sensitivity analyses, the IRP process examines multiple versions of the future. PNM starts with the two overriding scenarios that look at whether SJGS continues to operate post 2022. Within those two scenarios, the alternate futures that vary load growth, fuel prices, and possible emissions charges are considered. Each individual scenario is a different picture of the future that, taken all together, explores the capability of different resources to provide energy services under combinations of load growth, fuel prices, and emissions charges.

Sensitivity analysis is used to test assumptions within a scenario. For example, solar installation costs have been declining and tax credits that affect installation costs are set to expire, so the future price of solar is uncertain. Testing a range of solar installation prices within a scenario will show if the MCEP is dependent upon future prices for solar.

Analyze

Using economic probabilistic dispatch modeling software, PNM can determine a least-cost resource portfolio for each of these scenarios for the future of SJGS. These scenarios are then analyzed and evaluated under a variety of future conditions to understand the impacts over the study period. The future is unlikely to look exactly like any one of the conditions analyzed; therefore, it is important to know how well each portfolio performs under varying assumptions of the future.

Evaluate

Through the IRP analysis processes, it is possible to learn the following:

- Which of these portfolios work best under most conditions, that is, have the flexibility to mitigate risks if actual conditions significantly vary from projections
- Which portfolios have the lowest net present value of costs over time, including capital and operating costs, and how they rank compared to other portfolios
- The environmental impacts of those portfolios in terms of air quality and water usage

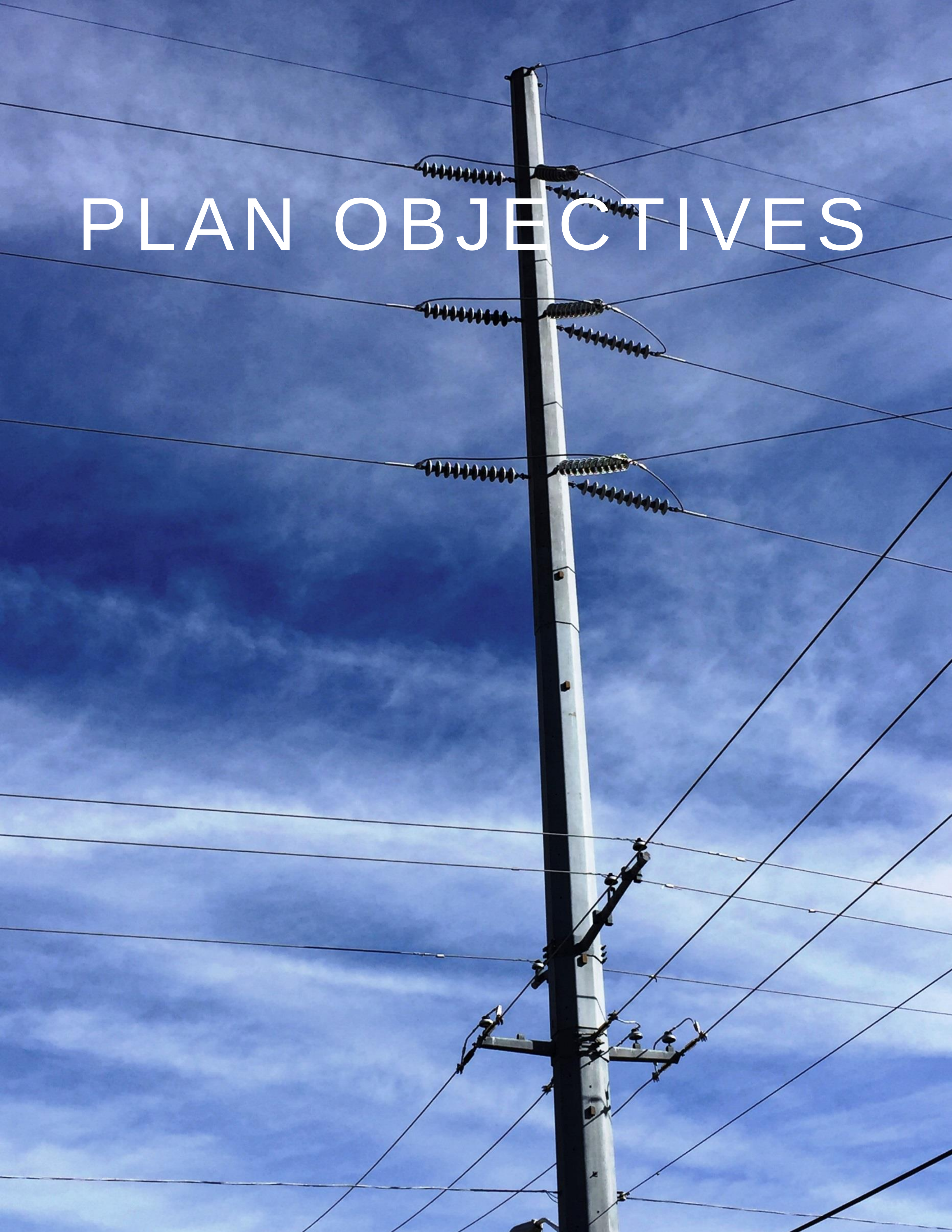
Throughout the IRP process, public participation is important to provide input for the assumptions used in the scenario analysis.

This IRP presents a four-year action plan that captures the actions PNM must take to create the most cost-effective portfolios and to take advantage of potential future opportunities identified in the MCEP creation process.

Report

The IRP process requires choosing one resource portfolio to pursue defined as the “most cost-effective portfolio,” and the development of a four-year action plan to begin implementing the portfolio. In the case of this IRP, PNM identifies a “most cost-effective resource portfolios” with an action plan based on the two SJGS scenarios and some alternate portfolios. PNM will follow this process with an RFP to solicit proposals for new resources before finalizing its decision regarding continued operation of SJGS.

PLAN OBJECTIVES



PLAN OBJECTIVES

The New Mexico IRP Rule states that the objective of the process is 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.” To meet these requirements, PNM analyzed a wide variety of resource combinations under numerous assumptions of the future.

The most cost-effective portfolios meet the following metrics for service quality:

- Sufficient reserves in every year
- Availability of operating reserves in every hour of every year
- Predicted Loss of Load Hours (LOLH) and Loss of Load Events (LOLE) measurements that meet national and regional grid requirements

Additionally, PNM ensured that every MCEP meets these other regulatory requirements:

- Energy efficiency spending of 3% of revenue requirements
- Minimum renewable portfolio standards of 15% of retail energy sales met through renewable energy resources through 2019, and 20% from 2020 thereafter

Then PNM compared plans to each other using the following metrics:

- **Net present value of revenue requirements:** the revenue requirements over the 20-year period for each resource plan under each set of future assumptions
- **Reliability metrics**: operating reserves, contingency reserves, and predicted loss of load events
- **Environmental impacts:** emission levels and water usage

The most cost-effective resource portfolios chosen under each of the SJGS scenarios are the resource plans that performed most favorably against the criteria shown in Figure 3, under the wide variety of futures analyzed through this planning process.

Figure 3. Plan Objective Criteria

COST	• Net Present Value of Revenue Requirements
RELIABILITY	• Peak Day Reserves • Hourly Operating Reserves • LOLH and LOLE
ENVIRONMENTAL IMPACTS	• CO_2 Emissions • Water Usage • Other Emissions
REGULATORY REQUIREMENTS	• Energy Efficiency Spending • Renewable Portfolio Standards • Regional Haze Stipulation Requirements

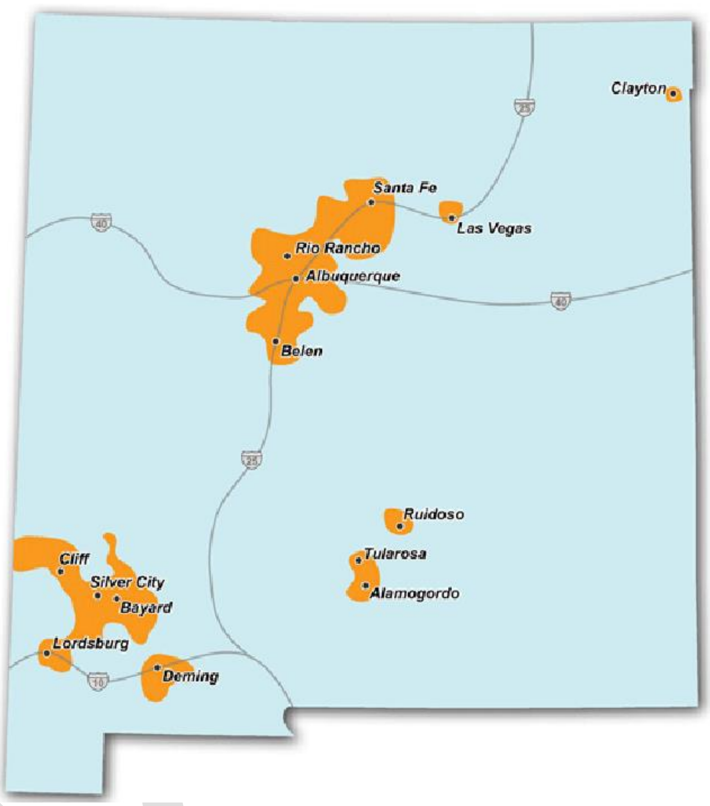
CUSTOMERS

CUSTOMERS

Service Territory

PNM has short- and long-term needs for resources that will provide capacity and energy to its customers, serving about 510,000 electricity customers statewide. As shown in Figure 4, PNM's electric service territory covers geographically diverse areas. Electric demand and energy usage varies based upon geography, customer mix, and climate, and recognition of these differences is important in preparing load forecasts.

Figure 4. PNM's Electric Service Territory Map



PNM is an electric utility that provides generation, transmission, and distribution service. PNM's retail service territory covers a large area of north central New Mexico, including the cities of Albuquerque, Rio Rancho, and Santa Fe and most of the area around the Rio Grande valley from Belen to Santa Fe. Other communities served include Lordsburg, Silver City, Deming, Alamogordo, Ruidoso, Tularosa, Clayton, and Las Vegas. PNM also serves a number of New Mexico Pueblo nations and numerous unincorporated areas.

Over the 20-year planning period, PNM faces growing peak demand. The retail load and energy forecast is developed by considering growth in customers, changing customer use, the economic trends in the region, changes in customer mixes, as well as projected energy efficiency and customer additions of solar and other distributed resources. PNM develops the resource plan to serve future system loads, maintain system reserve margins, and meet regulations for energy efficiency and renewable energy, as well as other applicable requirements. This section of the IRP reviews historical loads and discusses the methodology used to create the current load forecast and the load forecast scenarios used for the IRP analysis. Appendix A includes additional data on the load forecast.

Transmission System Customers

In addition to its retail customers, PNM provides generator interconnection and transmission delivery services pursuant to the terms and conditions of its Federal Energy Regulatory Commission (FERC) approved Open Access Transmission Tariff ("OATT"). PNM provides significant amounts of transmission service (40% to 45% of total transmission utilization) to other entities (network integration and point-to-point transmission service), as discussed below pursuant to its OATT, and PNM must plan its system to meet the needs of both its retail jurisdictional customers and its transmission customers.

Network Integration Transmission Service Customers

Network customers include these entities: Tri-State Generation and Transmission Association (Tri-State), Los Alamos County, Navajo Tribal Utility Authority, Western Area Power Administration (WAPA) for Kirtland Air Force Base, Sandia National Laboratory, City of Gallup, Jicarilla Apache Nation, and PNM-Wholesale Power Marketing (for PNM retail).

Point-to-Point Transmission Service Customers

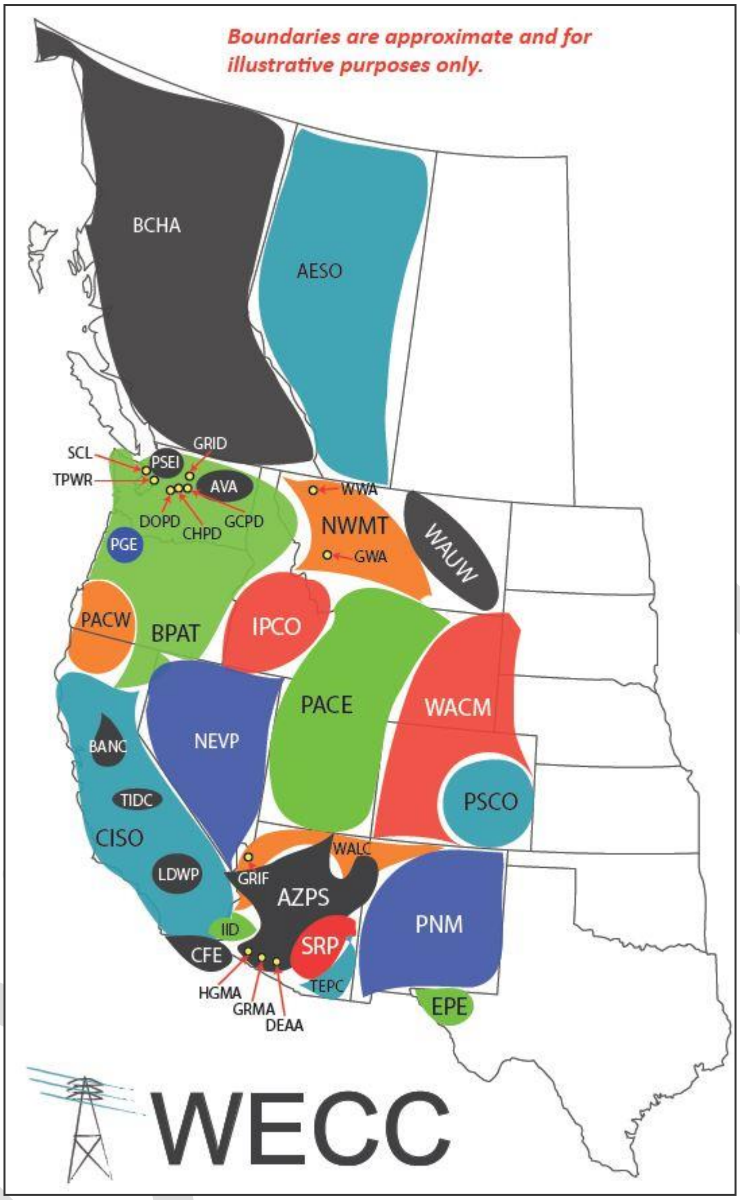
Point-to-point customers include El Paso Electric Company, High Lonesome Mesa, Aragonne Mesa, NextEra, WAPA, and Broadview Wind.

PNM Provides Power Balancing and Transmission Services

PNM ensures electric reliability in real time through balancing operations and transmission operations. Balancing operations ensures that the supply of power and the demand for power within the PNM system remains in balance to maintain 60-Hz power frequency. PNM has this responsibility within its operating footprint and shares grid balancing responsibility with approximately 38 other operating entities in the Western Electricity Coordinating Council (WECC), as shown in Figure 5. Transmission operators monitor power flow and voltage levels on transmission elements (switching stations, lines and transformers) and, if necessary to ensure reliability, adjust the dispatch of generation, switching of shunt devices, adjusting transformer tap settings and switching transmission elements. Adjustments have included these examples:

- Controlling the voltage profile on the transmission system
- Restoring a facility in response to forced outages because of events like weather or animal contact
- Managing planned outages for maintenance and construction activity

Figure 5. WECC Grid Map of Balancing Area Boundaries



PNM maintains continuous operations (24 hours a day, seven days a week) to assure reliability for its customers and prevent adverse effects on neighboring systems. PNM ensures reliability and alleviates problems by re-dispatching generators, switching facilities, adjusting interchange, curtailment of scheduled energy deliveries, and, if conditions require, shedding load (as a last resort). National and regional entities monitor and regulate virtually every aspect of utilities' real-time operations both for national security reasons and to ensure that each grid participant meets its obligations for maintaining reliability and efficient operation of the electric grid. These include:

- Balancing performance
- Mitigating generation and transmission disturbances
- Training system operators

- Developing procedures and requiring adherence to those procedures
- Providing emergency plans

PNM operates under the observation of two regional reliability coordination centers, one located in Loveland, Colorado, and the other in Vancouver, Washington. The regional grid regulatory entities have authority delegated from the FERC.

Load Forecast

For this IRP, PNM developed three load forecast scenarios—low, mid, and high—based on the most current assumptions available at the time of development. The low- and high-load forecasts are intended to incorporate various aspects of forecast uncertainty, such as the level of customer growth, the pace of efficiency gains because of different assumptions surrounding the costs/budgets of energy efficiency programs, and the variation in likely numbers of customers adopting distributed generation compared to the mid forecast. PNM developed the load forecast after the summer peak of 2016 to ensure it factored system peak demand for the most current year into the forecast. The load forecast also reflects load characteristics for a new large business customer, Facebook, which is now building a data center in PNM's service territory. The Facebook project was announced during the development of the forecast and its impact on loads and resources for the PNM system is included in the forecast.

PNM used each set of input assumptions to create a retail energy sales forecast and peak demand forecast. The load forecast scenarios discussed in the following sections include the energy sales forecast and a peak demand forecast on which the peak demand was based.

Methodology Overview

The system load forecast includes energy, customers, and peak demand and comprises three parts: retail loads (net of decrements to retail caused by energy efficiency programs, private solar, and new codes and standards), and distribution and transmission losses. Although PNM reports the results of its retail energy forecast by FERC customer class, it prepared the energy forecast at the more detailed rate-class level. PNM prepared the peak demand forecast in aggregate at the retail level, and then adjusted it for the impact of the same decrements described above.

PNM primarily relied upon statistically based time-series modeling to prepare retail load forecasts. This approach incorporated growth in customer loads over time, known customer-specific growth, and near-term impacts of economic activity in PNM's service area. Additionally, individual forecasts were prepared for a selected group of large customers whose loads are of sufficient size to call for individual review. Specific assumptions for the decrements and for each customer class are described in more detail in the following sections.

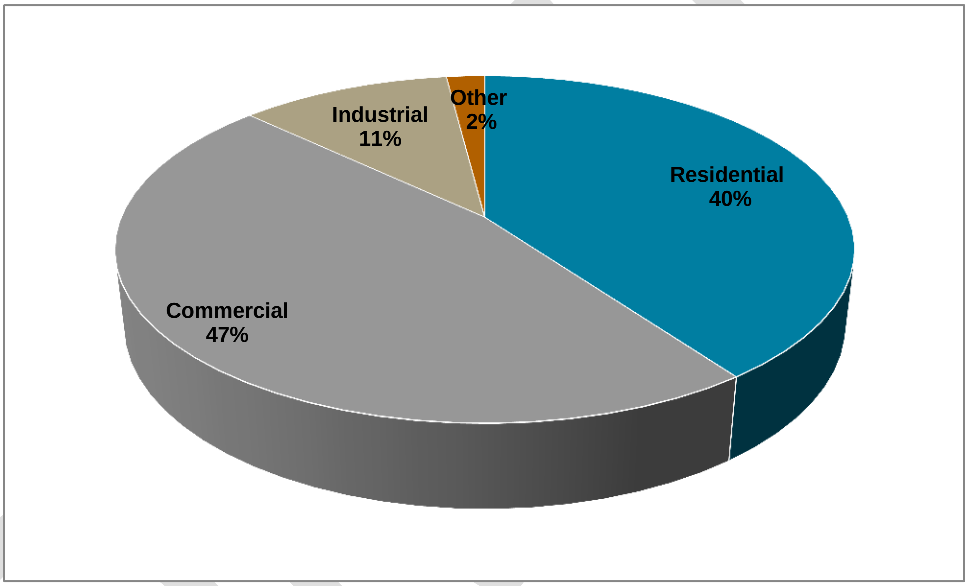
PNM used its most recently filed energy efficiency program to develop an energy efficiency decrement forecast, along with known and expected private solar applications, to develop a private solar decrement forecast. PNM also developed a codes and standards decrement forecast to capture higher appliance efficiencies and building standards that were not part of its energy efficiency programs.

Sales by Customer Class and FERC Class

The FERC classes categorize customers by type (residential, commercial, industrial, etc.), whereas PNM rate classes correspond to the PNM rate schedules under which customers receive service. For example, residential customers may receive service under two PNM rate schedules. Similarly, commercial and industrial customers receive service under one of several PNM rate schedules, which are typically based on the amount of energy the customer uses each month or the customer's peak demand.

In 2016, residential sales accounted for 40% of total retail sales, commercial sales accounted for 47%, and industrial sales accounted for 11% of total retail sales. The remaining two FERC classes (other public authorities and street lighting) represented only about 2% of retail sales, as shown in Figure 6.

Figure 6. Total Retail Sales by FERC Classes (2016)



Residential Forecast Methodology

PNM based the residential energy sales forecast on forecasts of customer growth and forecasts of per-customer usage. Specifically, the forecast of energy sales equals the forecast of customers multiplied by the forecast of usage per customer.

PNM prepared separate forecasts for each of its two residential rate schedules based on statistical analyses of historical growth in the number of customers and usage per customer, combined with exogenously forecasted macroeconomic variables.[3]

---

[3] PNM contracts with the Bureau of Business and Economic Research at the University of New Mexico for macroeconomic forecasts of the state and local economies as well as for some research tailored to PNM's service territory.

To calculate growth in the number of customers over time, PNM relied on the population forecasts used to determine growth rates for residential customers. Historical population at the county levels was gathered that matched PNM's service territory and growth of these counties was then estimated based upon historical trends, beginning with 2001 data.

To calculate usage per customer, PNM identified three data inputs: (1) the seasonal differences within a year, (2) responses to weather, and (3) changes in usage patterns over time that result from lifestyle changes, price, and historical appliance efficiency improvements. The use-per-customer forecast assumed normal weather derived from a 10-year average (2006 to 2015) of heating and cooling degree days.

Commercial Forecast Methodology

The FERC commercial class contains 10 PNM rate classes. The forecasts of the small power and general power classes were prepared in the same way as the two residential rate classes, by multiplying forecasts of the number of customers by forecast per customer use. Historical trends and employment estimates from the Bureau of Business and Economic Research at the University of New Mexico were used as an input in the commercial customer forecast equation to help capture economic conditions.

PNM prepared forecasts of the larger customers within the commercial class differently. Forecasts for the largest commercial customers, managed by internal account managers, were prepared on an individual basis. PNM's internal account managers routinely contacted these customers and provided updates on their expected energy use. The account managers also helped to identify if any new large customers anticipated starting service in the forecast period.

Industrial Forecast Methodology

Like the commercial FERC class, the industrial class may receive service under several PNM rate classes. PNM serves just under 250 industrial customers, the largest 40 making up the majority of total industrial segment energy sales. The largest industrial customers receive service under four rates (rate schedules 4B, 5B, 30B, and 33B). PNM forecasts for these customers reflect information obtained directly from the account managers, who are in contact with these customers in the same manner as that for the commercial class. PNM, through its quarterly update process, continually evaluated the forecasts for these large customers.

PNM prepared forecasts for the remaining industrial customers, those served under either small power or general power rate schedules, in the same way it prepared the forecasts for their counterparts in the commercial class—by aggregating all customers within a rate class and performing statistical time-series analyses. PNM prepared autoregressive statistical models based upon the historical relationship between time, weather, and non-weather monthly variations and usage. For the large power customers that did not receive individual forecasts, PNM forecasts aggregate use for that group rather than use per customer multiplied by a customer count forecast. Change in industrial use per customer is not as easily predictable from historical data as the other classes. Industrial customer usage is directly dependent on the size and nature of industrial customers entering or exiting PNM territory, more so than the economic trends used to predict residential sector growth. Industrial load is affected by weather, but not to the extent that weather-driven space heating and cooling affect the residential and commercial classes' load.

Separate load forecasts for firm wholesale customers were prepared using recent history and known contract changes for the future.

Transmission and Distribution Line Loss Estimate Methodology

Transmission and 46 kV and 69 kV Demand and Energy Loss Calculation Methodology
Forecast demand losses for the PNM control area transmission (115 kV through 345 kV) and 46 kV and 69 kV facilities are derived from powerflow analysis based on historical measurements. The PNM control area transmission and 46kV and 69kV energy losses are derived from metered data. The transmission losses for jointly owned facilities located outside of PNM's control area are determined separately.

Distribution (4.16 kV through 13.8 kV) Demand and Energy Loss Calculation Methodology
The methodology used to calculate the distribution system losses is derived from historical meter data.

PNM Energy Efficiency Programs, Rooftop Solar, and Codes and Standards Decrement Forecasts Methodologies

Incorporated into the load forecast are reductions in energy consumption caused by PNM's energy efficiency programs under the EUEA requirements, estimates for rooftop solar adoption by PNM's customers (private solar), and projections for increased energy efficiency based on future codes and standards. PNM developed an energy and demand savings forecast of PNM's energy efficiency and load management programs (EE Forecast) over the 20-year IRP planning period. Energy and demand savings are a function of the level of spending on the programs and the savings achieved per dollar spent. The level of spending is proscribed by the EUEA and is equivalent to 3% of PNM's retail revenues. Historically, the savings achieved per dollar spent have been decreasing. In other words, it is becoming more expensive to achieve a given level of savings because of a number of factors, including saturation of low-cost measures. The EE Forecast was developed by estimating the annual spending level and estimating a rate of increase in the cost of delivering savings over time based on historical trends. The EE Forecast was developed by dividing historical results kWh of savings per dollar into the required EUEA spending of the future.

PNM developed the rooftop solar energy decrement forecast by multiplying the historical capacity of the system across photovoltaic (PV) customers with the total effective sun hours of a fixed-tilt south-facing solar panel in Albuquerque during each month (solar resource information was provided by the National Renewable Energy Laboratory). PNM determined the historical capacity of the system (prior to 2016) by the total kW AC of all interconnected customers at that time. The forecasted interconnections assumed continued growth at the same rate as interconnections seen at the time of forecast until 2021. The impact then grows at an annual percentage increase of 1.4% starting in 2022.

PNM prepared the codes and standards decrement forecast using LoadMAP, an end-use model developed and maintained by the Applied Energy Group.[4] LoadMAP addresses a variety of forecast drivers, including appliance standards, by computing electricity consumption for each major appliance category for residential and commercial customers. As an end-use or bottom-up model, LoadMAP gathers information on how many appliances of each efficiency level are in the existing stock of homes and how many appliances of each efficiency level are in the new market, consisting of replacements and new construction. It then computes the energy used by all the existing and new appliances, assuming that the appliances run for a specified number of hours per year under designated weather conditions.

Load Forecast Scenarios

Table 2 shows the average 20-year growth rates for the low-, mid-, and high-load forecast sensitivities developed for this IRP. Note that all forecast scenarios presented here predict slowed growth compared to the baseline presented in the 2014 IRP. This expectation is caused, in part, to the slow rate of economic recovery in New Mexico as well as increased energy efficiency and conservation within PNM's service territory because of a combination of PNM's programs and the impacts of new codes and standards. The adoption of plans for increased efficiency gains, such as building code revisions, results in changes above and beyond those directly related to PNM's energy efficiency programs. Although some energy efficiency gains are inherent in the historical data, for the IRP process, PNM has treated incremental gains in energy efficiency programs as a separate component.

Table 2. Load Forecast Net Growth Rates

Growth Segments	Low	Mid	High
Residential Sector			
Residential Customers	0.00%	0.89%	1.40%
Residential Use Per Customer	-0.98%	0.39%	0.65%
Residential Energy Sales	-0.98%	1.10%	2.06%
Commercial/Industrial Sectors			
Commercial & Industrial Energy Sales	0.05%	1.01%	2.26%
Retail Energy Sales	-0.34%	1.01%	2.12%
Peak Demand			
System Peak Demand	0.51%	1.50%	2.40%

Low-Load Forecast

The low-load forecast represents a combination of zero customer growth and reduced loads across all sectors. The forecast scenario predicts decreasing loads almost continuously through 2036.

[4] Information about the Applied Energy Group's LoadMAP tool is available at the Applied Energy Group website at http://www.appliedenergygroup.com/load-and-revenue-forecasting.

For the low-load forecast, PNM assumed negative growth in use per customer for both residential and commercial customers. This was attributed to increases in energy efficiency and increases in rooftop solar installations. Finally, PNM assumed the industrial energy load would only grow through the addition of a single datacenter customer, with that customer's load forecast at the low end of its projected range. Table 3 illustrates the low-load forecasts for the years 2017, 2022, and 2036.

Table 3. 2017 IRP Low-Load Forecasts

Forecasts	2017	2022	2036
Demand (MW)			
PNM Forecasted Load Total	1,906	1,963	2,261
EE (incremental)	(23)	(91)	(145)
PV-DG (incremental)	(18)	(45)	(62)
Net System Total	**1,865**	**1,827**	**2,055**
Energy (GWh)			
PNM Forecasted Load Total	8,998	9,460	9,352
EE (incremental)	(197)	(706)	(1,042)
PV-DG (incremental)	(47)	(210)	(251)
Net System Total	**8,754**	**8,544**	**8,059**

Mid-Load Forecast

PNM developed the mid-load forecast using normalized weather and the Bureau of Business and Economic Research at the University of New Mexico's mid scenario for projected economic conditions. The mid scenario of the economic forecast predicts a steady improvement in economic conditions. Industrial energy sales will be positively impacted by the addition of the single datacenter customer at its target load projection.

For the mid-load forecast, moderate residential and commercial customer increases are assumed, driven by with customer count growth of about 0.8%. Customer growth does not climb to some of the higher growth rates seen in the 1990s for the New Mexico service area. The forecast projects use per customer decreasing until about 2030 because of energy efficiency and rooftop solar effects. Table 4 illustrates the mid-load forecasts for the year's 2017, 2022, and 2036.

Table 4. 2017 IRP Mid-Load Forecasts

Forecasts	2017	2022	2036
Demand (MW)			
PNM Forecasted Load Total	1,911	2,163	2,650
EE (incremental)	(23)	(89)	(122)
PV-DG (incremental)	(18)	(33)	(48)
Net System Total	**1,871**	**2,041**	**2,480**
Energy (GWh)			
PNM Forecasted Load Total	9,040	10,475	11,671
EE (incremental)	(197)	(695)	(881)
PV-DG (incremental)	(47)	(153)	(194)
Net System Total	**8,796**	**9,627**	**10,597**

High-Load Forecast

The high-load forecast predicts sustained customer growth of 1.4%. PNM broadly based its assumptions for this scenario as matching customer growth rates observed in PNM Resources' Texas-New Mexico Power Company utility and the scenario assumption that New Mexico's economy catches up to the recovery experienced in neighboring Texas. Consistent with a clustering effect of datacenters, this forecast also includes increases in industrial energy sales because of the addition of a second datacenter. This scenario also includes a slight uptick in use per customer because of reduced impacts of energy efficiency and reduced rooftop solar interconnections. Table 5 illustrates the mid-load forecasts for the year's 2017, 2022, and 2036.

Table 5. 2017 IRP High-Load Forecasts

Forecasts	2017	2022	2036
Demand (MW)			
PNM Forecasted Load Total	1,915	2,361	3,076
EE (incremental)	(23)	(85)	(100)
PV-DG (incremental)	(18)	(20)	(34)
Net System Total	**1,875**	**2,257**	**2,943**
Energy (GWh)			
PNM Forecasted Load Total	9,088	11,339	13,924
EE (incremental)	(195)	(660)	(726)
PV-DG (incremental)	(47)	(96)	(137)
Net System Total	**8,847**	**10,583**	**13,061**

Historical Comparison of Load Forecasts

Table 6 and Table 7 show historical load forecasts compared to actual load. The columns represent forecast cycle and the rows represent the year forecasted. For example, row 2015, column 2016, represents 2016's demand as forecasted in 2015. Each year of historical forecast in this table was prepared in the year shown at the top of each column.

Table 6. PNM System Peak Demand Comparison

Forecasted Peak Demand (MW)	2013	2014	2015	2016	Actual
2013	1,978				2,008
2014	1,984	1,983			1,878
2015	2,000	1,991	2,088		1,889
2016	2,012	1,997	1,970	1,945	1,908

Table 7. PNM System Energy Comparison

Forecasted Energy Sales (GWh)	2013	2014	2015	2016	Actual
2013	10,158				10,130
2014	10,191	9,832			9,702
2015	10,245	9,853	9,427		9,580
2016	10,317	9,863	9,377	9,317	9,403

PNM's past demand forecasts tended to over-forecast system peak demands on a weather-normalized basis. A key factor contributing to this has been declining sales growth in the aftermath of the recent economic recession. The overriding factor has been the poor performance of the New Mexico economy relative to the national and regional recoveries since the recession. Figure 7 and Figure 8 show each year's forecast in comparison to other years, along with the actual loads for that year.

Figure 7. PNM's Historical Energy Forecasts

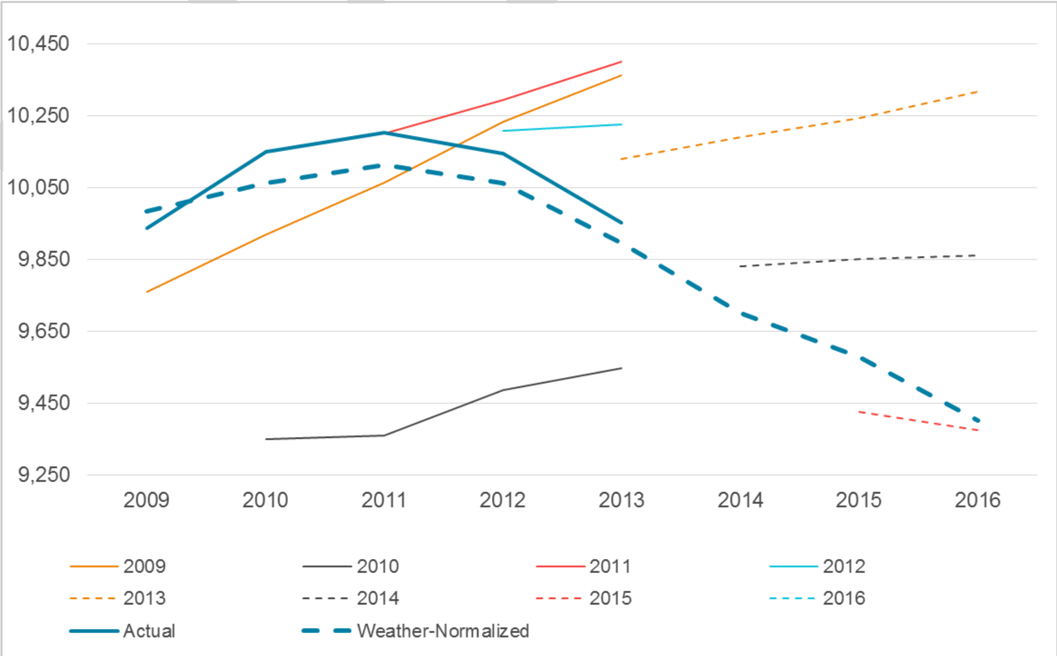
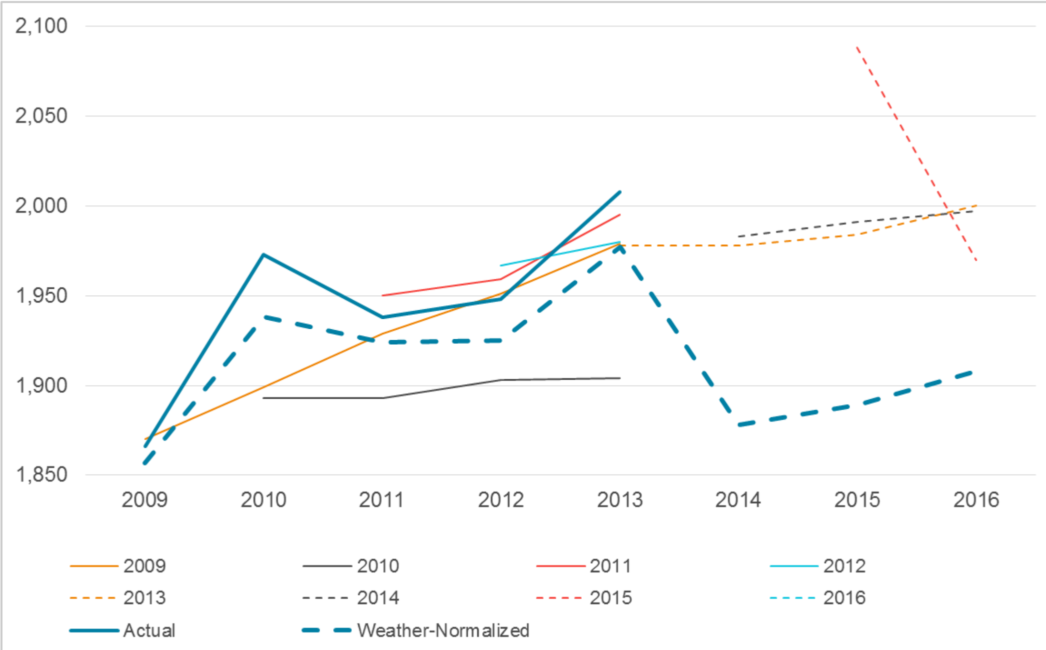


Figure 8. PNM's Historical Demand Forecasts



Load Factor

Load factor is a measure of average customer demand divided by peak customer demand. It represents an expectation of the amount of time that resources necessary to meet peak customer load is likely to be required for non-peak load, thereby affecting the selection of the type of generation resource that PNM may develop as peak demand grows over time.

As shown in Table 8, PNM has seen a deteriorating load factor for both the total system and the retail portion of PNM's load. PNM attributes this trend to two factors: (1) residential customers replacing evaporative space cooling with refrigerated air conditioning, thereby increasing summer peak demand, and (2) PNM's energy efficiency programs, which are reducing energy use across all hours.

Table 8. PNM System Load Factor Summary

Year	Actual
2006	63.60%
2007	62.70%
2008	63.00%
2009	60.80%
2010	58.70%
2011	60.10%
2012	59.30%
2013	56.60%
2014	58.97%
2015	57.90%
2016	56.26%

The system load factor has fallen below 60% in several recent years, which represents a significant decrease from averages of around 63% seen in the early 2000s. Whether this deterioration will continue is difficult to predict for the forecast period. Although recent history would infer continuing deterioration, PNM's demand response programs "shave" peak demand, whereas rate structure encourages load shifting from on-peak hours to off-peak hours. These programs and rate structure are designed to encourage increases in load factor or mitigate decreasing load factors.

The current forecast assumes a moderately decreasing system load factor absent development of further initiatives to improve it.

Demand and Energy Forecast

PNM developed the forecast using an econometric time-series regression to estimate peak demand combined with explanatory variables including weather and energy sales. The outcome is a peak demand forecast that grows at a rate slightly higher than energy sales. This is partially because increases in energy efficiency and rooftop solar affect annual energy consumption more than peak demand.

The peak demand forecast is especially important for resource planning because it is one of the primary drivers of the amount of capacity that must be installed. It is important to note that although PNM is a summer-peaking utility, the winter peak is generally 70% to 85% of summer peak. This may influence timing decisions for resource additions because a resource may need to be available, not only for the next year's summer peak, but also for the previous winter peak. Figure 9 shows a comparison of the range of peak demand forecast and Figure 10 provides the range of energy forecast considered in the IRP analysis.

Figure 9. Comparison of PNM's Demand Forecast Sensitivities (MW)

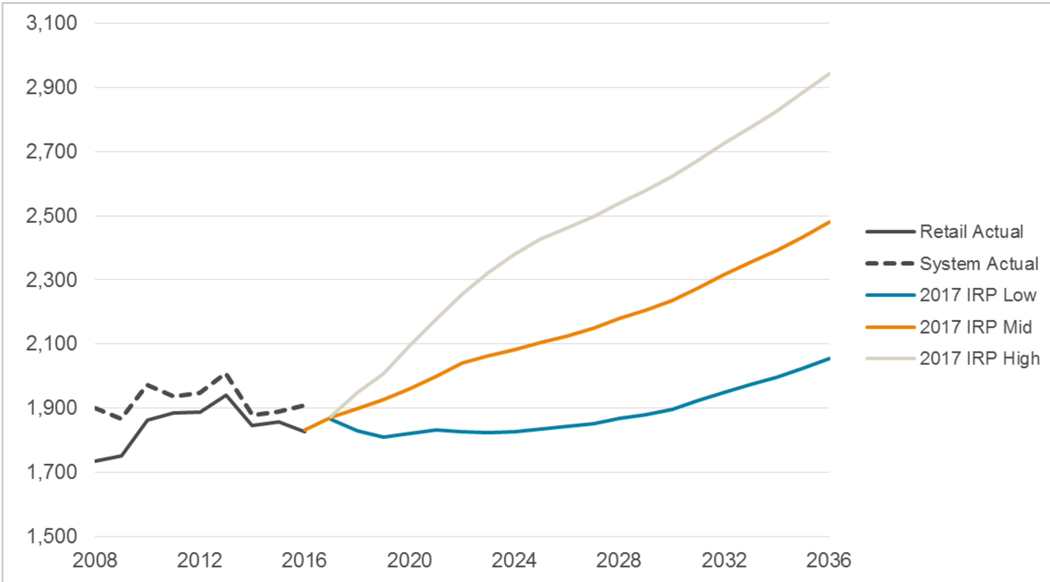
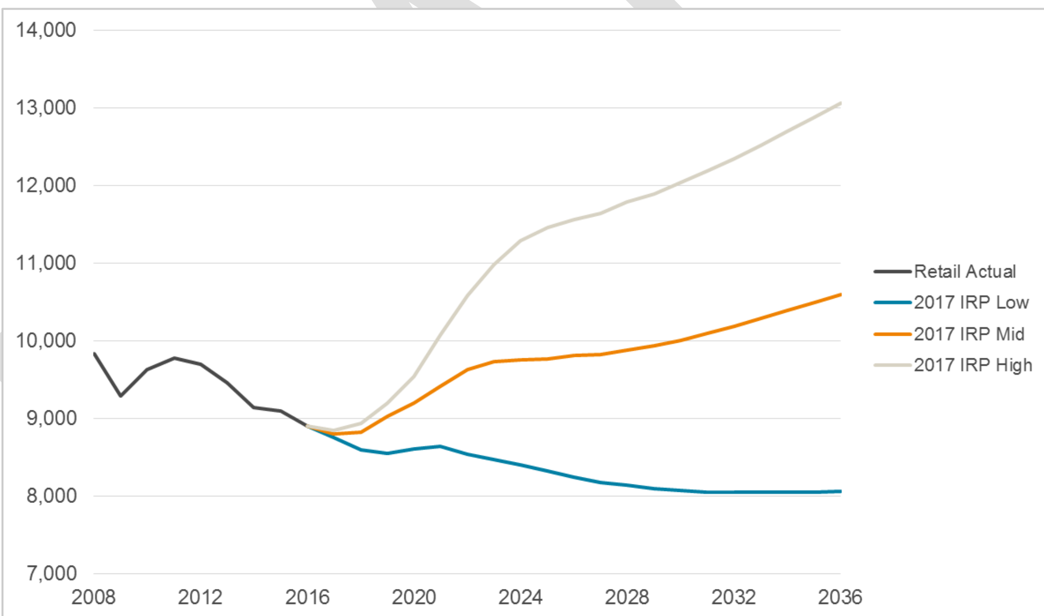


Figure 10. Comparison of PNM's Energy Forecast Sensitivities (GWh)



Private Distributed Generation (DG)

Customers on PNM's system, or third parties contracting with the customer, are eligible to construct solar photovoltaic (PV) systems behind PNM's electric meter at their place of residence or business. They also receive energy bill savings when the customer's generation exceeds their consumption. By participating in PNM's solar DG program, customers may also sell the Renewable Energy Certificates (RECs) generated by their solar system to PNM, which uses the RECs for New Mexico Renewable Portfolio Standard (RPS) compliance. The interconnection of these facilities to PNM's system, the administration of the private credits program, and the purchase of the RECs by PNM from solar facilities sized up to 1 MW are subject to the requirements of applicable PNM tariffs that have been reviewed and approved by the NMPRC.

Private solar PV installations are a small but fast-growing resource on PNM's system. Customers who choose to install a qualified solar PV or solar thermal electric system at their homes or businesses (or that are installed and owned by third parties) are eligible for PNM programs that allow customers to receive private credits and to sell the RECs associated with the energy to PNM. Although these customer-sited systems decrease net system demands, PNM provides backup service to interconnected customers, which ensures the customer still has electricity service if their solar system is temporarily out of service for any reason.

Customer installations continue to grow both in number and in the size of systems. This is attributable to federal and state tax incentives, the current downward trend in the cost of PV systems, private credits, and REC payment incentives offered by PNM. Table 9 shows the number of customers participating in the private solar programs, the installed capacity, annual RECs, and the peak-hour generation for each year since 2006.

Table 9. Private Renewable Distributed Generation

Year	Cumulative Number of Participants	Cumulative KWAC Installed	Annual RECs (MWh)	Peak Hour Generation KWAC (55% of capacity)	Percentage of Growth over Previous Year
2006	93	164	413	90	
2007	187	348	1,593	191	112%
2008	368	748	3,525	411	115%
2009	708	2,124	7,132	1,168	184%
2010	1,342	6,165	13,611	3,391	190%
2011	2,192	14,208	26,767	7,814	130%
2012	2,994	19,894	41,914	10,942	40%
2013	3,777	31,441	56,366	17,293	58%
2014	5,071	39,372	85,239	21,655	25%
2015	5,422	42,550	93,577	23,403	8%
2016	8,710	62,830	119,574	34,557	48%

Although these installations are the responsibility of the system owners, PNM assumes that these installations will be maintained because customers receive net-metering and REC payments. For IRP purposes, it was assumed that existing distributed generation installations will continue to operate to offset system load for the entire planning period.

The PNM rates and tariffs that govern customer-sited renewable development include the following:

- **Photovoltaic Renewable Energy Certificate Procurement Rates (Rate 24, Rate 31, and Rate 32):** These rates incentivize customers to install solar facilities on their premises and sell the RECs to PNM for RPS compliance. Rates 24 and 31 are closed to new participants because those programs were superseded by Rate 32.

- **Cogeneration and Small Power Production Rate (Rate 12):** This rate, based on PNM's energy costs in the corresponding month of the prior year, is offered to qualifying facilities that provide net-excess renewable generation to PNM.

PLANNING CONSIDERATIONS

PLANNING CONSIDERATIONS

Reliability and Reliability Standards

The most cost-effective resource portfolio must provide sufficient reserve capacity to maintain system reliability. PNM reviews the ability of the MCEP to provide two categories of reserves: planning reserves and operating reserves. Planning reserves are forecasted generation capacity over and above the amount required to serve the projected peak-hour demand of the year. Operating reserves provide the ability to respond to supply and demand imbalances within the actual operating hour, occurring either as normal variations in system loads or resource ramping or in response to unforeseen events that change the loads and resources balance. Planning reserves are necessary in the event that one or more of PNM's generation resources are unavailable or cannot run at full capacity at the time of system peak. Planning reserves also account for uncertainties in demand forecasting and resource availability. As illustrated in the Load Forecast section of report, actual net-system peaks can vary from the forecasted net system peaks by hundreds of MWs.

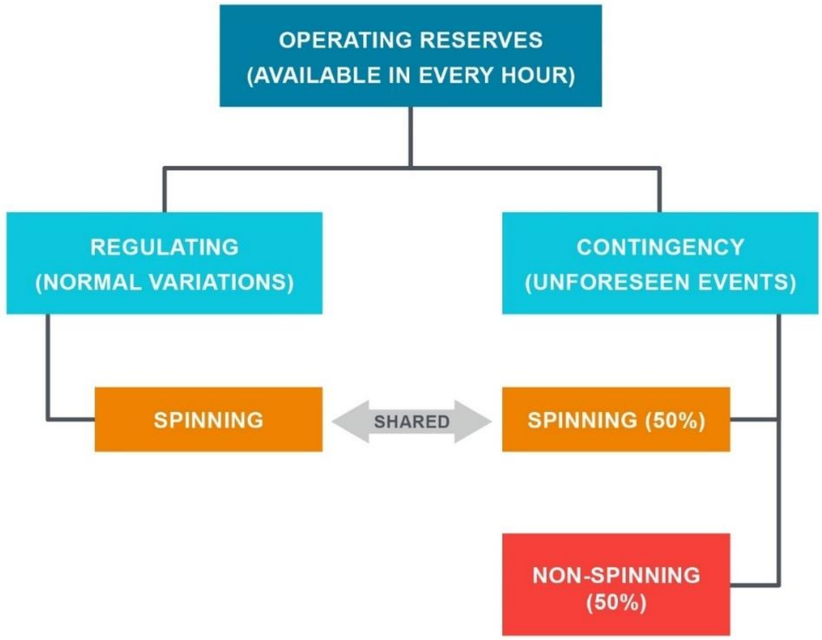
For resource planning, operating reserves and planning reserves must be considered conjunctively in determining a system's resource needs and how best to supply those needs to maintain reliability.

Operating Reserves

Operating reserves, which include contingency reserves (that respond to unforeseen events) and regulating reserves (that respond to normal load variations) are generating capacity available to the BA system operator to quickly satisfy system requirements when there is a disruption in demand or supply (e.g., a variable energy resource ramping down or a generator tripping offline). Contingency reserves are optimally comprised of spinning and non-spinning reserves (which must be able to respond within 10 minutes) in approximately equal amounts.

The total contingency reserve requirement is based on the utility's single largest generator, also known as the single largest hazard, or associated with either generator or transmission capacity. Non-spinning contingency reserves must be able to respond to cover losses within 10 minutes. PNM also requires regulating reserves, which are typically supplied by spinning resources, to continuously maintain system balance. Figure 11 illustrates the different types of operating reserves needed to respond within any given hour.

Figure 11. Operating Reserves



The MCEP must ensure sufficient resources to meet system operational demands, which can vary by location within PNM's service territory. Operational standards for the industry are established by North American Electric Reliability Corporation (NERC) and the WECC. PNM is a NERC-registered BA, ensuring in real time that power system demand and supply are balanced, and includes managing transfers of electricity with other BAs and must maintain adequate operating reserves to comply with NERC and WECC reliability standards. PNM considers the following primary standards for the MCEP:

- BAL-002-1: Disturbance Control Performance Standard
- BAL-002-WECC-2: Contingency Reserves
- BAL-003-1: Frequency Response Requirement

PNM must meet these requirements every day around the clock. NERC, WECC, and PNM's reserve sharing group, the Southwest Reserve Sharing Group (SRSG), can assess monetary penalties for noncompliance. The WECC reliability coordinator (Peak RC) can order the utility to shed load if required for the BA to reestablish compliance with these standards.

For a detailed explanation of these standards, refer to Appendix D: Detailed Explanation of Primary MCEP Standards.

Planning Reserves

Planning reserves are the amount of resource capacity available (as a percentage of total capacity), above and beyond the projected peak loads at the highest demand of the year. Planning reserves are not required to be spinning or non-spinning (available within 10 minutes), and, therefore, can be any type of available capacity. For the MCEP, PNM targets a minimum

13% planning reserve margin as a 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 use 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.

As the stipulation makes clear, the prescribed 13% reserve margin is a target, not a hard and fast rule, and the actual reserve margin may temporarily differ from the target for a variety of reasons, including the need to add resources in increments that do not precisely match immediate on-peak requirements and the need to add resources to meet other system requirements. Due to the impact of more variable energy and variable demand on the system, reserve margin is an insufficient metric to consider system reliability and must be supplemented by other reliability assessments

Typically, industry standards set reliability targets that should produce a system reliability expectation that the utility will experience a loss in firm load event no more than once in every 10 years. This is a common standard and has been widely used in the electric industry for 50 years. Traditionally, the simplest planning metric for modeling this reliability objective has been the reserve margin. Setting a planning reserve margin at a high level will result in a higher level of reliability, which generally implies greater investment in resource or demand-side capacity.

PNM's loss of load probability using a 13% reserve margin is about two events in every 10 years. Achieving a one-in-10-year probability would require a reserve margin target of 20%, which is much higher than the 13% target PNM currently uses. The results of a reserve margin study PNM conducted in 2013 indicate that a good balance between the cost of additional capacity and the desire to reduce loss of load events results in a planning reserve margin of 16%, reducing the loss of load events to one and a half events every 10 years. PNM is continuing to use the 13% reserve margin target in its capacity expansion modeling and has supplemented that analysis with an analysis of loss of load probability.

Reserve Needs

PNM's existing portfolio includes nuclear, coal-fired, natural gas-fired, and renewable energy resources. Diversity of resources and fuel sources is beneficial to ensuring system reliability because variabilities in one resource compensate for others. Each of these resource types has different operating characteristics that must be accounted for when PNM is planning system operations on a day-ahead and hourly basis. Each day, PNM develops a unit commitment plan to fully supply projected hourly loads during the day. The first step in the plan is to commit (i.e., schedule) all non-dispatchable or must-take resources including nuclear, wind, solar, geothermal, and the minimum outputs of any base load or other generation unit projected to be needed to serve the daily projected load (e.g., coal-fired generation plus natural gas generation during expected high-load periods). PNM schedules all other generation using economic dispatch principles with the lowest cost generation unit being the first dispatched.

Once the projected hourly load profiles are met using this process, PNM commits additional generation needed to meet all ancillary service requirements including the spinning reserves that provide load following, regulation, voltage support, frequency response requirements, and the contingency reserve obligations of both spinning and non-spinning reserves. Table 10 describes PNM's largest hazards, the amount of SRSG assistance available, and how much capacity is required to be available within 15 and 60 minutes.

Table 10. Inputs to Operating Reserves Requirements at Time of Summer Peak

Size of Single Largest Hazard	Size of Hazard in MW	SRSG Assistance	15-Minute Requirement	60-Minute Requirement
SJGS Unit 4	392	160	232	70
Afton	230	160	70	25

PNM is required to maintain a minimum level of operating reserves (that is, regulating and contingency reserves) that meets NERC and WECC criteria. The required amount of contingency reserves is based on 3% of the BA's load and 3% of the BA's online generation, which is measured and calculated every four seconds. Within the contingency reserve calculation, at least half of the contingency reserves must be carried by generators that are online, unloaded, and able to respond to immediate changes to interconnected system frequency. The required amount of contingency reserves changes hourly, but, generally in the peak-load hour, PNM must maintain the current mandated SRSG spin and non-spin quota of approximately 125 MW, plus enough additional contingency reserves to recover from a failure of PNM's single largest hazard. Regulating reserves are an incremental amount of spinning reserve above this, sufficient to adequately follow load and respond to fluctuations in the output of generating units, most importantly 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. PNM currently estimates that 15 MW of fast frequency response is needed to maintain compliance with the standard.

Environmental Impact and Anticipated Regulations

PNM has a long-standing record of environmental stewardship. Emission rates for each of PNM's existing generation facilities are listed in Table 11.

Table 11. 2015 Emission Rates by Plant

Facility	Generation	NOX	CO	SO2	Particulates	CO2	Mercury
	PNM's MWh	lbs/MWh	lbs/MWh	lbs/MWh	lbs/MWh	lbs/MWh	lbs/MWh
Afton Generating Station	646,765	0.152	0.157	0.005	0.065	958.5	0
Four Corners Power Plant	1,294,866	4.750		1.343	0.087	2,025.0	17.2 lbs per million MWh
La Luz Gas Turbine	6,053						0
Lightning Dock Geothermal	10,450	0.000	0.000	0.000	0.000	0.0	0
Lordsburg Generating Station	20,319	1.250	0.626	0.007	0.144	1,396.7	0
Luna Energy Facility	284,121	0.615	0.779	0.028	0.146	924.9	0
NM Wind Energy Center	404,765	0.000	0.000	0.000	0.000	0.0	0
Palo Verde Generating Station	3,316,500	0.000	0.000	0.000	0.000	0.0	0
PNM-Owned Solar	155,290	0.000	0.000	0.000	0.000	0.0	0
Red Mesa Wind	184,297	0.000	0.000	0.000	0.000	0.0	0
Reeves Generating Station	136,707	3.158	0.403	0.008	0.097	1,565.0	0
Rio Bravo (Delta) GT	73,410	0.512	0.015	0.008	0.053	1,423.4	0
San Juan Generating Station	4,120,239	6.770	6.713	1.691	0.094	2,150.7	1.5 lbs per million MWh
Valencia Energy Facility	108,782	0.397	0.147	0.007	0.191	1,367.1	0

PNM has long been committed to the environment through the efficient SJGS plant design, sourcing its fuel with low-sulfur coal, implementing emission control improvements as they became available, and following low-impact operating practices. Currently, SJGS complies with EPA's public health standards in accordance with the National Ambient Air Quality Standards (NAAQS). Although the challenge of greenhouse gas (GHG) emissions and climate change remains, PNM's record of improving its total emissions levels will continue with the 2017 retirement of two units at SJGS. Table 12 lists the most recent emission control upgrades installed at SJGS.

Table 12. Impact of Recent Emission Control Upgrades at SJGS

SJGS	NOx	SO2	Particulate Matter	Mercury*	CO2*
Emission Reductions after 2009 Environmental Pollution Control Upgrades	44% ↓	71% ↓	72% ↓	99% ↓	N/A
2012 Emissions ** (tons/year)	21,000	10,500	2,380	0.005	11,906,236
Emission Reductions from 2012 to 2018 (two-unit shutdown)	62% ↓	67% ↓	50% ↓	50% ↓	47% ↓
Permitted Emissions in 2018 (tons per year)	8,011	3,483	1,184	0.002	6,359,750

* Mercury and CO_2 numbers are based upon actual emissions since there are currently no required permit limits for these constituents.
** 2012 chosen as base year to match the base year of EPA's Clean Power Plan for reduction of CO_2 emissions for fossil generation.

Other Environmental Regulations

PNM's natural gas-fired electric generating units operate in compliance with Clean Air Act Title V Operating Permits issued by the New Mexico Environment Department. 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. New Mexico currently does not have any non-attainment areas, although Dona Ana County may reach a small area of non-attainment because of cross-border transport.

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 PVNGS is licensed and inspected by the Nuclear Regulatory Commission (NRC). Currently, there are no pending new or revised environmental regulations anticipated during the planning period. PVNGS does not emit GHGs and uses treated sewer effluent for cooling water.

Coal ash (coal combustion residuals) at PNM's coal plants are regulated as non-hazardous waste. Ash at SJGS is returned to the adjacent surface mine for use in reclamation. Water intake structures are subject to rules to protect fish and wildlife in surface water supplies. SJGS is a zero-discharge facility, but is also subject to regulations protecting against stormwater runoff or other potential contamination of neighboring waters.

PNM has a current environmental focus in three key areas:

- Meeting regional haze rules at the coal-fired SJGS as cost-effectively as possible while providing additional environmental benefits including a significant reduction in CO_2, nitrogen oxides, sulfur dioxide, particulate matter, and other emissions from existing power plants
- Meeting New Mexico's increasing renewable energy requirements as cost-effectively as possible and complying with the RPS requirements
- Increasing energy efficiency program savings and complying with the EUEA requirements

All three of these efforts result in a significant CO_2 emissions reductions from historical levels and limit CO_2 emissions going forward. PNM's 2017 IRP considers CO_2 emissions from future portfolios by assigning a range of potential future CO_2 costs and by quantifying potential total emissions from MCEP options. This method of assessing potential carbon costs is supported by the reasonable anticipation of future carbon emission regulations and is required by the IRP rules. The form and stringency of potential future carbon emission regulations or targets are uncertain. Regulation could follow something similar to the pending Clean Power Plan issued in 2015 or the Paris Accords. This IRP considers potential Clean Power Plan requirements as well as the CO_2 targets established by the Paris Accords.

Federal CO_2 Emission Regulations

In April 2007, the U.S. Supreme Court held that the EPA has the authority to regulate GHG under the Clean Air Act (CAA). In December 2009, EPA released its endangerment finding stating that the atmospheric concentrations of six key GHGs (CO_2, methane, nitrous oxides, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride) endanger the public health and welfare of current and future generations.

On June 25, 2013, former President Obama announced his Climate Action Plan, which outlined how his administration planned to cut GHG in the United States, prepare the country for the impacts of climate change, and lead international efforts to combat and prepare for global warming. The plan proposed actions that would lead to the reduction of GHG by 17% below 2005 levels by 2020. The former President also issued a Presidential Memorandum to EPA to continue development of the GHG New Source Performance Standards (NSPS) regulations for electric generators. The Presidential Memorandum established a timeline for the proposal and issuance of a GHG NSPS for new sources under section 111(b) of the CAA and a timeline for the proposal and final rule for developing carbon pollution standards, regulations, or guidelines for GHG reductions from existing sources under Section 111(d) of the CAA. The Presidential Memorandum further directed EPA to allow the use of "market-based instruments" and "other regulatory flexibilities" to ensure standards will allow for continued reliance on a range of energy sources and technologies, and that the standards are developed and implemented in a manner that provides for reliable and affordable energy. The Presidential Memorandum required EPA to undertake the rulemaking through direct engagement with states, “as they will play a central role in establishing and implementing standards for existing power plants,” and with utility leaders, labor leaders, nongovernmental organizations, tribal officials, and other stakeholders.

EPA met the former President’s timeline for issuance of carbon pollution standards for new sources under Section 111(b) and for existing sources under Section 111(d) of the CAA. On August 3, 2015, EPA issued its final standards to limit CO_2 emissions from power plants. The final rule was published on October 23, 2015. Three separate but related actions took place: (1) the final Carbon Pollution Standards for new, modified, and reconstructed power plants were established (under Section 111(b)); (2) the final Clean Power Plan was issued to set standards for carbon emission reductions from existing power plants (under Section 111(d)); and (3) a proposed federal plan associated with the final Clean Power Plan was released.

Carbon Pollution Standards for New, Modified, and Reconstructed Power Plants

EPA’s final rule to limit GHG from new, modified, and reconstructed power plants establishes standards based upon efficient natural gas combined cycle technology. Newly constructed or reconstructed base load natural gas-fired stationary combustion turbines are limited to 1,000 lbs CO_2/MWh-gross or 1,030 lbs CO_2/MWh-net. A new source is any newly constructed fossil fuel-fired power plant that commenced construction after January 8, 2014.

Clean Power Plan

The Clean Power Plan rule sets the first compliance date in 2022 and adopts emission targets. The rule establishes two numeric emission standards: one for fossil-steam units (coal- and oil-fired units) and one for natural gas-fired units (combined cycle only). The emission standards are based on emission reduction opportunities that EPA deemed achievable using technical assumptions for three building blocks: efficiency improvements at coal-fired electric generating unit (EGU), displacement of affected EGUs with renewable energy, and displacement of coal-fired generation with natural gas-fired generation. The final standards are 1,305 lbs/MWH for fossil-steam units and 771 lbs/MWH for gas units, both of which phase in over the period from 2022 to 2030. To facilitate implementation, EPA converted the emission standards into state goals. Each state’s goal is based on the weighted average of each state’s unique mix of affected units. Note: the status of this rule is changing, this section will be revised in the final report.

Table 13 summarizes the New Mexico emissions goals laid out by EPA. The analysis section illustrates CO2 emissions from PNM’s operation compared to these goals.

Table 13. New Mexico CO_2 Emissions and EPA Standards

Year	CO_2 Emission Rate (lb/MWh)	CO_2 Emissions (tons)
New Mexico Current State		
2012	1,798	17,339,683
EPA Standard for New Mexico		
2022	1,325	13,815,561
2030	1,146	12,412,602

Paris Accords

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 GHG, 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 November 2014, former President Obama announced the United States’ commitment to reduce GHG, on an economy-wide basis, by 26% to 28% from 2005 levels by the year 2025. Further, the U.S. NDC is targeting an 80% economy-wide CO_2 reductions by 2050. The Climate Action Plan is a key element of the U.S. NDC.described above.

Modeling Carbon Cost

The near-term outlook for explicit carbon costs has been altered by the 2016 presidential election. Implementation of the Clean Power Plan is on hold for judicial review and the key provisions are being unwound by the EPA under a new executive order. Nonetheless, PNM is continuing to model a cost for each ton of CO2 emitted in each portfolio’s projected operation. PNM expects that a replacement for the CPP is likely to be implemented at some point in response to continued international calls that carbon emissions should be addressed.

The replacement regime for the CPP is assumed to again take the form of a per-unit cost (emission tax or cap and trade allowance). A legislative program could address the legal challenge of administrative taxation and also address the other problematic features of the CPP. Such a new program could be politically acceptable, especially if the carbon cost burden is less severe than under the CPP.

PNM also considered several other potential regulations including National Ambient Air Quality Standards (including ozone and nitrogen oxide regulations), natural gas and methane rules that may affect oil and natural gas production, EPA Rule 316(b) addressing cooling water intake structures, the 2015 Waters of the U.S. rule potentially addressing water discharge, and coal combustion residual (aka coal ash) disposal rules.

Cost to Customers

PNM measured “cost to customers” of the IRP portfolio options using the metric required and described in the IRP rule: net-present value of costs required to meet retail customer loads over the 20-year planning period. PNM’s calculation of this metric includes the following:

- Cost to operate and maintain existing resources from 2017 through 2036
- Cost to build, operate, and maintain any resources added between 2017 and 2036
- Costs associated with retiring any resources between 2017 and 2036

While these costs contribute to the overall revenue requirements PNM uses to calculate customer rates, they do not include any credits that might occur from PNM’s off-system sales.

Public Advisory Process

PNM conducted a robust public advisory process as part of this IRP. The primary goal of the public advisory process is to solicit public comment and information to improve the overall process.

PNM placed newspaper advertisements and sending notifications in customer bills to create public awareness in the spring of 2016. On April 28, 2016, PNM notified the NMPRC and stakeholders in accordance with the IRP Rule. The public advisory process provides transparency of PNM’s resource planning process and results by inviting public participation in community meetings. Representatives from the general public and various interest groups attended these meetings along with PNM staff. During these meetings attendees actively engaged in the planning process by discussing the planning assumptions and approach, providing comments, sharing concerns, and by proposing alternative scenarios, assumptions, and methodologies for consideration.

Public Advisory Meetings

At the meetings, PNM presented and discussed the data and analytic techniques used in this IRP and provided hardcopy handouts of related reports and analyses to all meeting participants, encouraging an open discussion of the topics and related issues. The meetings were well attended by representatives of the NMPRC, other government entities, and other groups involved in utility regulation. Customers, renewable energy developers, advocacy groups, and interested citizens also took part. The meetings were broadcast as on-line webinars for those who could not attend in person. Meeting presentation materials for each meeting were posted on the IRP website. Table 14 lists the IRP public advisory meetings, including dates and topics discussed.

Table 14. Topics of Public Advisory Meetings

Date	Topics
June 30, 2016	**IRP – Kick-off meeting** • Describe process and goals • Preliminary list of scenarios and sensitivities • Illustration of assessment of need for resources • Process for SJGS that includes IRP • Schedule • Establish communication
Jul 27, 2016	**Reliability Day** • Grid modernization • AMI • Batteries • EV • Demand response
Aug. 11, 2016	**Baseload Resources** • Coal SJGS FCPP • Palo Verde leases • Financial impacts • Asset recovery
Sept. 1, 2016	**Transmission and Generation Day** • Existing transmission • Projects PNM can model • Renewable energy • Energy efficiency
Sept. 22, 2016	**Fuel and Carbon** • Natural gas • Environmental regulation risks • Water issues
Nov. 10, 2016	**Load Forecast** • Rates and Tariffs
	Models Used **IRP Analysis Preliminary Plan**
Mar. 28, 2017	**IRP Process Update**
Apr. 18, 2017	**Draft Report Discussion**
May 23, 2017	**Advisory Group Comments**
Mar. 28, 2017	**Distribute Report & Wrap-up**

The public advisory process resulted in significant contributions to PNM's planning process, with participants providing substantial feedback including prioritization recommendations regarding what areas had been covered adequately and which required more analysis. Examples of how PNM has responded to public comments in this process are:

- This report includes a discussion of how resource planning affects PNM's business
- PNM provided information explaining why PNM is not considering replacing coal with natural gas as a fuel supply to SJGS
- The alternate portfolios considered includes higher levels of renewable supply than included in the MCEP
- PNM looked into battery and other storage technologies, not just as near-term resources, but also to assess its potential for long-term transformation

Some advisory group participants requested data so that they could perform independent analysis. Data files on hourly customer load and hourly renewable energy production were provided. Also, there was interest in PNM's solar-battery demonstration project – the Prosperity Solar-Battery Project. Solar and battery performance at 1-minute and 5-minute intervals was provided in response. PNM has also made modeling data, assumptions, and outputs available. Participants were very interested in the key question of continuing vs. retiring SJGS in 2022. Many other topics were cited by participants as areas of interest or concern such as:

- Impacts of resource planning decisions on customers and local economies,
- Environmental impacts of decisions made,
- Advanced technology and the potential to address resource planning challenges, and
- In particular, the potential for energy storage (specifically batteries) to reduce the electric system's dependence on fossil fuels.

PNM made an effort to deliver the initial findings of the analysis and the preliminary MCEP early in the process to allow time for review and feedback by participants and other stakeholders. PNM posted its preliminary draft report on April 20, 2017.

The issue of most concern was whether continuing SJGS operation past 2022 is cost-effective. While the final decision may be affected by subsequent developments, changes in economic conditions or decisions by the NMPRC, the preliminary finding is that a 2022 closure of SJGS is a key component of the MCEP.

Regulated Utility Considerations

PNM is an investor-owned vertically integrated regulated monopoly, meaning that PNM is owned by private shareholders, is the sole provider of electricity in its service territory, owns most of the generation, transmission, and distribution assets utilized to serve its customers, and must file rate reviews with the NMPRC in order for its shareholders to receive recovery of and a return on investments made to serve its customers. PNM must meet requirements to ensure its investments are cost-effective and prudent. The IRP is one of the requirements to ensure the public has an opportunity to provide input and review the analysis used to decide upon future electricity supply plans.

While the IRP process and resulting plan provides documentation to support building or retiring units, the IRP, once accepted by the NMPRC, does not provide permission for the resource decisions. PNM must file for a Certificate of Public Convenience and Necessity (CCN) in order to obtain approval to place a new generating facility into service. Applicable IRP regulations provide that in any CCN proceeding relating to a NMPRC-accepted IRP, "[e]vidence that the resource is consistent with the IRP, and that there have not been material changes that would warrant a different course of action by the utility, will constitute prima facie evidence that the resource type, but not the particular resource being proposed, is required by the public convenience and necessity." Accordingly, the accepted IRP and its findings may be relevant in the CCN proceeding, depending upon the facts and circumstances. To retire a unit, PNM must file an abandonment application. Once the NMPRC approves PNM's application to build or retire a generation facility, PNM must have the costs approved through a rate case in order to adjust customer's rates. When new PNM rates are set, the operational costs of the facility such as fuel and ongoing labor are directly passed through to the customer without any markup. Customer bills get credited if PNM is able to sell any excess power or ancillary services at a profit into wholesale markets.

Generation Ownership Considerations

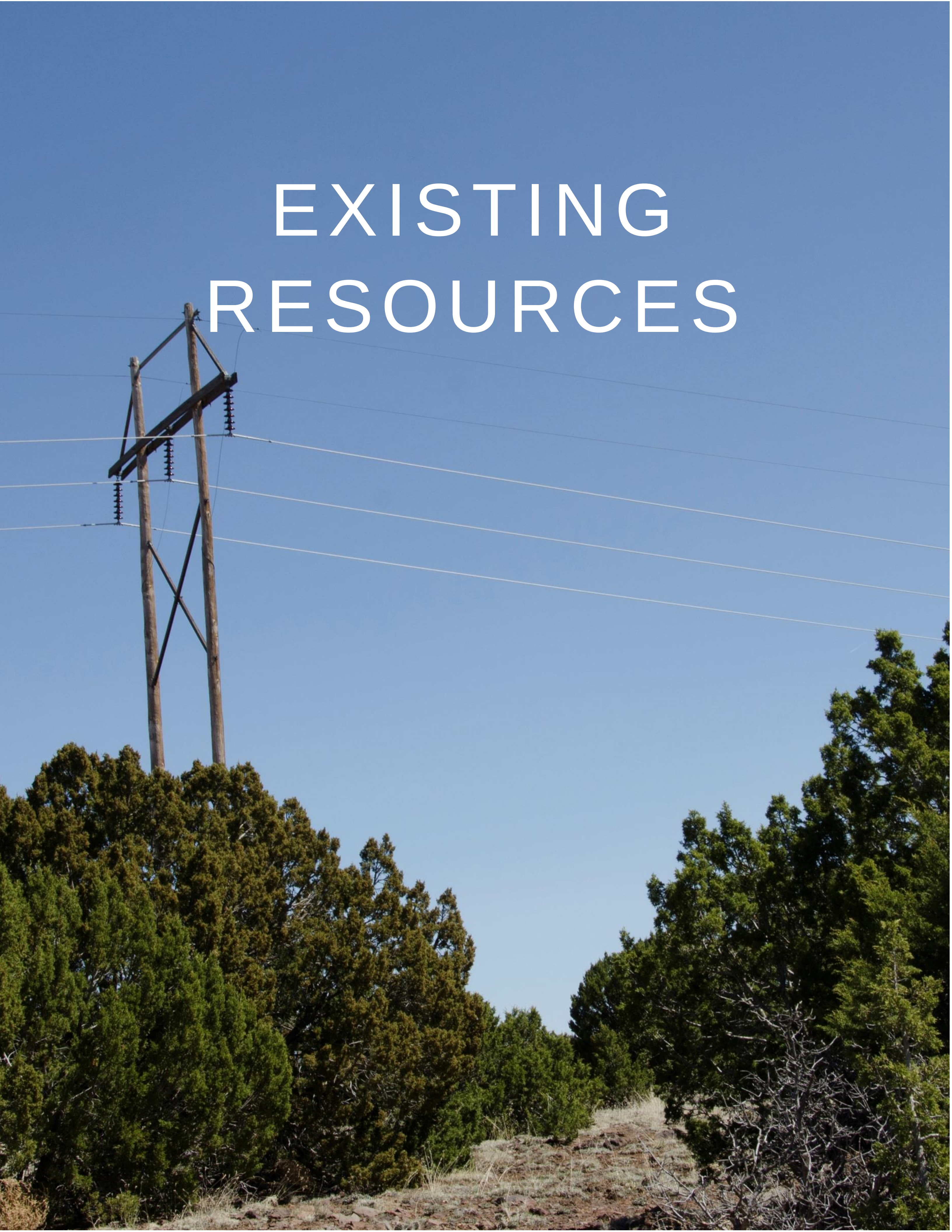
The IRP process requires identification of the "most cost-effective portfolio" based on the net present value of revenue requirements to reliably meet customer demand within regulatory constraints while considering risks and uncertainties.

Providing resources to meet electricity demand can take different forms. The analysis completed in this IRP does not assume any particular ownership form. PNM calculated present value of revenue requirements for new resources based on the best information available for resource costs in PNM's BA. Whenever possible, the information is based on recent bids for new resources, whether the bids were for turnkey utility ownership under a turnkey or for IPP ownerships with PPA pricing. PNM accepts bids for either structure in its competitive RFPs. For example, a "utility self-build" approach occurs when the utility constructs and operates the project on its own. A "build-transfer" or "turnkey" approach occurs when the project is developed to a particular stage or constructed in its entirety by a third party, often an IPP, then sold to the utility to own and operate over the useful life of the generation resource. The third parties can benefit from this approach through the competitive resource procurement process. A third alternative is purchasing the output from a generator or set of generators over a contract period. Each of these options, while they may have equivalent net present value of revenue requirements based on the assumptions in this IRP, have different risks and uncertainties that should be considered. These are described in Table 15.

Table 15. Generation Ownership Benefits, Risks, and Uncertainties

Ownership	Benefits	Risks and Uncertainties
Utility-Owned	• Lower cost of capital • Construction control and full knowledge to ensure reliability requirements met • Flexibility to respond to changing regulations over time • Ownership and use of depreciated asset available at end of life • Passes cost savings on to customers	• Construction risk • Operational risk
Build-Transfer or Turnkey	• Limited construction risk, but maintains reliability risk	• Higher cost of capital • Operational risk
Power Purchase Agreements	• Price and operational certainty per contract for the contract period • Limited construction and operational risks	• Limited flexibility once the contract is signed • No access to residual asset

EXISTING RESOURCES



EXISTING RESOURCES

Existing Demand-Side Resources

As defined by the IRP Rule, demand-side resources consist of two types: energy efficiency and load management. Energy efficiency generally refers to reductions in energy use by customers that are cost-effective from the overall utility system viewpoint. Load management programs reduce customer demand at times of peak load or during generation supply shortages. PNM's existing resource portfolio includes cost-effective energy efficiency and load management programs approved by the NMPRC pursuant to the EUEA. Amendments to the EUEA in 2013 also require utilities to invest 3% of retail sales revenues in energy efficiency and load management programs. This provides consistency in the level of spending that can be expected over time.

This section describes PNM's existing demand-side energy efficiency and demand response resources. Demand response is a form of load management. This information generally responds to the requirements of the IRP Rule Section 17.7.3.9(C)(9). The customer-owned distributed generation is addressed in the supply-side resource section.

Energy Efficiency Programs

PNM's energy efficiency programs currently consist of a portfolio of offerings that provide incentives to encourage customers to be more energy efficient:

- 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 the customers' business
- 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
- Incentives that specifically target energy efficiency improvements for lower-income customers

Once approved by the NMPRC, energy efficiency programs remain in effect until modified or canceled by the NMPRC.

The NMPRC determined these programs were cost-effective using the utility cost test, which calculates a ratio of program benefits to program costs. To be cost-effective, the ratio of benefits to costs must be greater than one. Program benefits include the value of the lifetime avoided energy and capacity, which include avoided cost of energy production, such as fuel costs and avoided air emissions associated with electricity generation, and avoided or delayed cost of capacity additions.

The level of energy efficiency savings achieved becomes a function of the effectiveness of each program and rate of increase in cost to procure incremental savings. Every year PNM reviews the demand and energy savings from its energy efficiency programs using the results from an annual independent third-party measurement and verification process, and estimates the customer participation in current and future programs.

In its load forecast, PNM only counts savings from current energy efficiency programs through their estimated lifetime, but assumes that as the lifetimes of programs expire they will largely be replaced with new programs so that demand savings and energy savings will continue throughout the plan period.

Demand Response Programs

Demand response programs reduce customer demand at times of peak load or during generation supply shortages. Existing demand-side resources include two voluntary demand response programs originally approved by the NMPRC in Case No. 07-00053-UT and reauthorized in Case No. 16-00096-UT. The Power Saver program is for residential and small commercial customers with less than 150 kilowatt (kW) load, and the Peak Saver program is for commercial customers with 150 kW of load or greater. PNM selected each of the demand response program contractors through a competitive bid process. The demand response programs are governed by 10-year professional services contracts that began in 2007 and expire in 2017. PNM has filed for reauthorization of the programs in its most recent energy efficiency and load management program plan filing.

Power Saver Program

The Power Saver program is designed for customers with refrigerated air conditioning. PNM hired a third-party contractor, Comverge, Inc., to manage this program through 2017. Comverge installs a device on customers' refrigerated air conditioners that PNM uses to remotely control the units when they cycle. During peak periods, PNM can reduce peak demand by remotely cycling the air conditioners, which reduces the collective electricity demand from the air-conditioning units. The program runs during the summer peak period of June through September, and this resource can be dispatched within 10 minutes as a peak-shaving resource for up to 100 hours each year.

Peak Saver Program

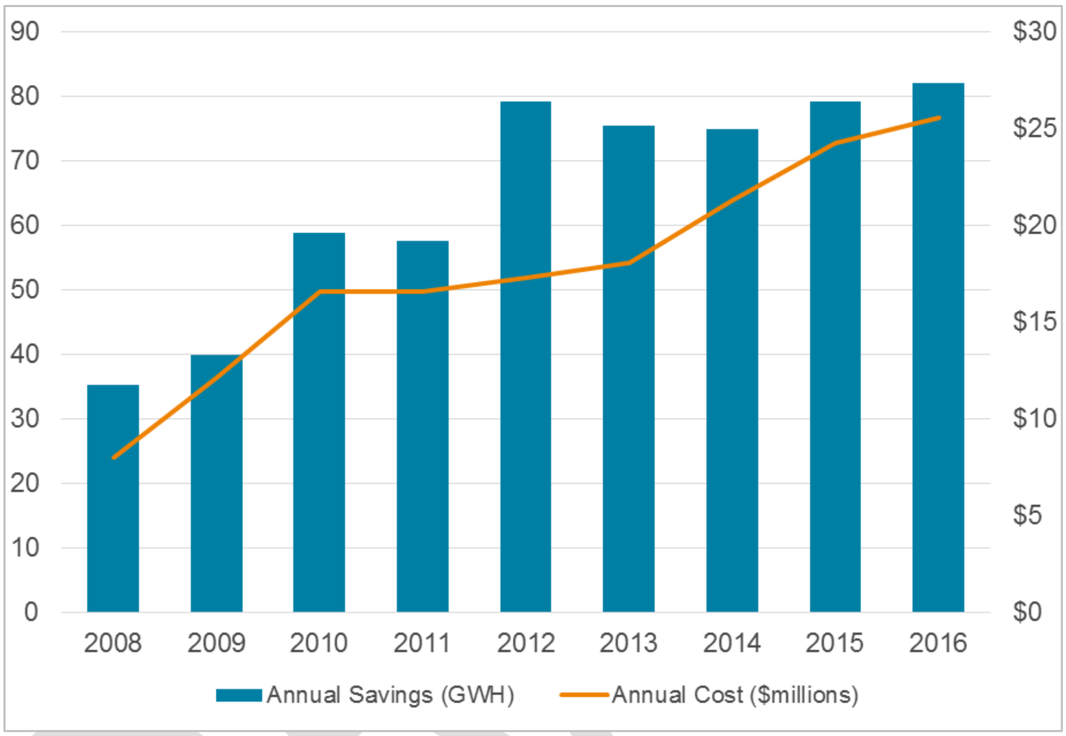
PNM's Peak Saver program is for larger commercial and industrial customers with peak loads of 150 kW or greater per month. PNM contracted with EnerNOC to manage this program through 2017. This program targets electric loads that can be reduced during periods of peak system demand. EnerNOC installs demand-controlling equipment that runs during the summer peak period of June through September, and this resource can be dispatched within 10 minutes as a peak-shaving resource for up to 100 hours each year.

Energy Efficiency and Demand Response Savings to Date

In accordance with the energy efficiency Rule and the EUEA, PNM filed the first annual PNM energy efficiency and load management program report with the NMPRC on April 1, 2009, and has filed subsequent reports on or about April 1 every year thereafter. The reports include detailed measurement and verification findings as determined by the NMPRC selected independent evaluator, quantified customer adoption rates and energy savings for both energy efficiency programs and demand response programs.

Annual energy savings from PNM energy efficiency and demand response programs is calculated to have reached 82 gigawatthours (GWh) for 2016. Figure 12 shows the annual energy savings and program costs since 2008 for the total portfolio of programs.

Figure 12. Annual Savings from Energy Efficiency and Demand Response



PNM determines the peak demand savings from the approximately 40,000 Power Saver program participants by use of a statistical sampling method that derives a kW savings factor per installed unit. Hourly meter data is also available for the approximately 110 Peak Saver program participants to determine the demand savings available to PNM. Table 16 shows the verified capacity reductions from the demand response programs for the years 2008 through 2016.

Table 16. Verified Capacity Reductions for 2008 through 2016

Year	DR Capacity (MW)
2008	47
2009	53
2010	67
2011	57
2012	57
2013	62
2014	61
2015	59
2016	57

PNM exceeded the 2014 cumulative goal of 411 GWh (5% of PNM's 2005 retail sales) by achieving cumulative savings of 421 GWh, and is on track to exceed the 2020 cumulative goal of 658 GWh (8% of 2005 retail sales). Year-to-year results vary based on date of implementation, customer participation, verified savings, and marketing efforts. Table 17 summarizes the results from 2008 through 2016 for PNM's overall demand-side programs on a combined basis. Through 2016, the programs have achieved 583 GWh of cumulative energy savings and 97 MW of cumulative demand savings, not including the capacity savings from the demand response programs shown separately in Table 16 above.

Table 17. PNM DSM Program Combined Results (2008-2013)

Year	Annual Energy Savings (GWH)	Cumulative Energy Savings (GWH)	Cumulative Demand Savings (MW)
2008	35	35	8
2009	40	75	14
2010	59	134	24
2011	58	192	33
2012	79	271	47
2013	76	346	59
2014	75	421	71
2015	79	501	83
2016	83	583	96

Demand-Influencing Rates and Tariffs

PNM designs rates, tariffs, and demand response and energy efficiency programs to offer customers economic incentives to either shift energy use to off-peak periods, thereby increasing the system load factor, or to reduce system demand and energy through demand-side management. Improving the system load factor results in improved utility asset use and lowers overall system costs. PNM promotes 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.

The IRP implicitly considers the ongoing impact of rates on PNM's resource needs through the load forecast, which, being based on customer usage patterns, captures the effects of these rates on usage. PNM modeled growth in participation in the Power Saver and Peak Saver programs in the same way as for the existing and projected energy efficiency resources.

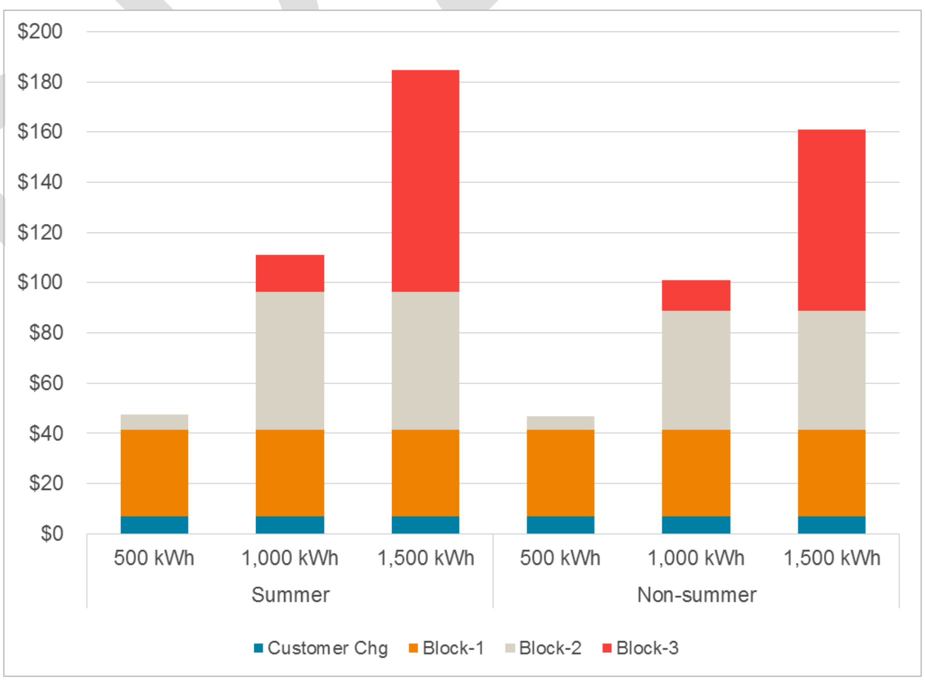
According to New Mexico state statute, "rate" and "rate riders" refer to every rate, tariff, charge, or other compensation for utility service rendered or to be rendered by a utility, as well as any rules, regulations, and requirements related to the rate or rate rider. PNM incorporates load management and load-shifting concepts into several rates and tariffs, and this information is provided as part of the response to IRP Rule Section 17.7.3.9 (F) (3). These include the following:

- Inverted Block Residential Rate Design
- Seasonal Rate Design for all PNM tariffs
- Time of Use Rates
- Demand Rates for Commercial and Industrial Tariffs
- Incremental Interruptible Power Rate
- Voluntary Demand Response Programs

Inverted Block Residential Rate Design

Rates per unit of energy increase for residential customers as usage increases (Rate 1A). This is designed to discourage higher usage by increasing the customer's bill as consumption increases. Figure 13 shows an example of increasing energy block rates for usage.

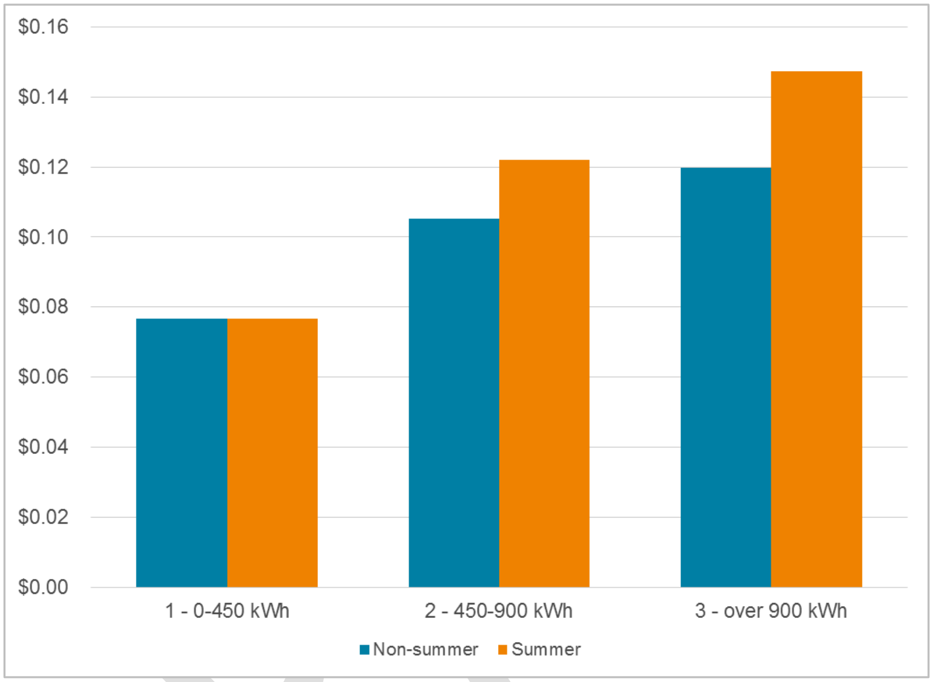
Figure 13. Increasing Energy Block Rates



Seasonal Rate Design

Summer rates are higher than winter rates for most customer classes. This seasonal rate design encourages customers to moderate usage during the summer months when demand on the system is greatest and utility generation costs are highest. By discouraging usage during the peak season, seasonal rates help to delay the need for new resources. Figure 14 also illustrates this rate design.

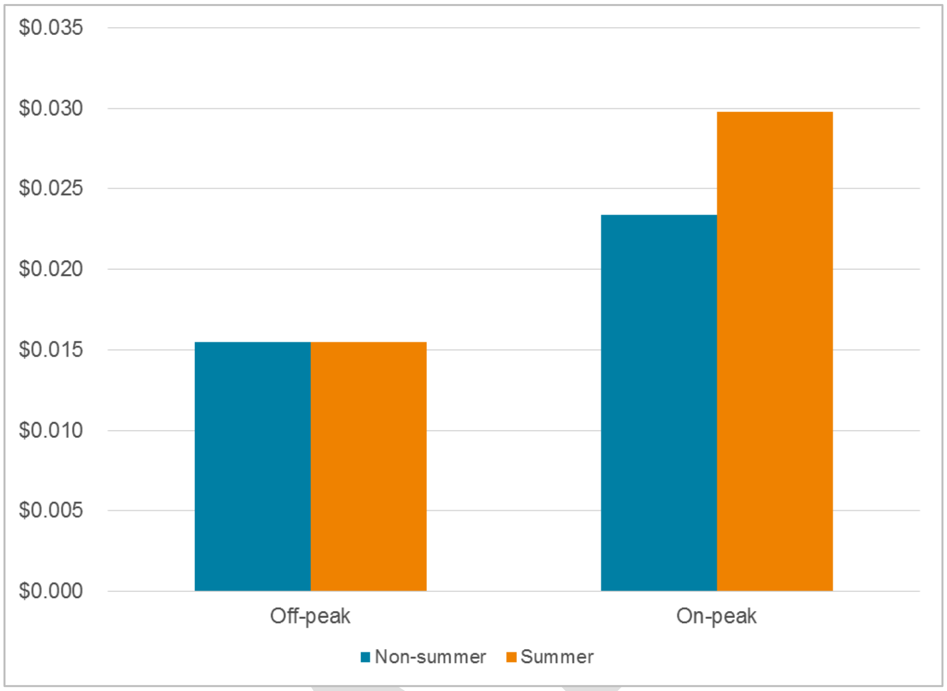
Figure 14. Seasonal Rates



Time-of-Use Rates

PNM offers time-of-use (TOU) rates for Residential (1B), Small Power (2B), General Power (3B & 3C), Large Power (4B), Large Mining (5B), Irrigation (10B), Water Sewage Pumping (11B), Universities (15B), Large Manufacturing (30B), Station Power Service (33B), Large Power Service (35B), and Special Service Rate—Renewable Energy Resources (36B) customer classes. These rates encourage customers to avoid usage during the time when the cost to serve is highest (on-peak) and allow for greater efficiencies in generation resource utilization. TOU rates are required for all larger customers (greater than 50 KW). The remaining customers can choose TOU rates to lower their cost by shifting usage to off-peak periods. Figure 15 shows how PNM’s rates differ between on- and off-peak during summer and non-summer periods.

Figure 15. TOU Rates



Demand Rates

Demand rates charge for on-peak usage during a specific time window. A customer who uses a high rate of power for short periods places "demands" on 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.

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. A customer may bypass an interruption request and will forgo the monthly tariff discount afforded to them, but if the customer fails to interrupt more than two times during any calendar year, the customer will be permanently removed from the rider.

Voluntary Demand Response Programs

Under the energy efficiency rider, residential and business customers (under PNM's Power Saver program) and business customers with a demand greater than 150 kW (under PNM's Peak Saver program) can volunteer to have portions of their load curtailed upon 10-minute notice from June through September, for up to 100 hours per year. This load shifting helps PNM manage peak summer loads.

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

Table 18 lists PNM's existing and operating generation resources. A detailed discussion of each of these resources follows.

Table 18. PNM's Existing and Pending Generation Resources

Resource Name	MW	Fuel	PNM-Owned or PPA1
San Juan Generating Station	783	Coal	Owned
Palo Verde Generating Station	268	Uranium	Owned/Leased
Afton Generating Station	230	Natural Gas	Owned
Four Corners Power Plant	200	Coal	Owned
New Mexico Wind Energy Center	200	Wind	PPA
Luna Energy Facility	189	Natural Gas	Owned
Reeves Generating Station	154	Natural Gas	Owned
Valencia Energy Facility	150	Natural Gas	PPA
Rio Bravo Generating Station	138	Natural Gas or Oil	PPA
Red Mesa Wind Energy Center	102	Wind	PPA
Lordsburg Generating Station	80	Natural Gas	Owned
PNM-Owned Solar (multiple sites on distribution system)	107	Solar	Owned
La Luz Energy Center	40	Natural Gas	Owned
Dale Burgett Geothermal	4	Geothermal	PPA

Existing Renewable Resources

PNM's renewable resources include three types of facilities: wind, solar, and geothermal, which are all described below.

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., under a 25-year PPA that expires in 2028.

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.

The amount of annual wind energy generation is difficult to predict for NMWEC and Red Mesa because it varies with wind activity. Historical data (Table 19) show that production at NMWEC can range from 405 GWh to 579 GWh per year. PNM forecasts that NMWEC will generate approximately 525 GWh per year and that Red Mesa Wind will generate approximately 208 GWH per year.

Table 19. Historical Wind Production Generation and Capacity from 2003–2016

Year	NMWEC		Red Mesa		Total	
	MWhs	Capacity Factor	MWhs	Capacity Factor	MWhs	Capac Factor
2003	211,931	N/A	0		211,931	N/A
2004	514,414	29.3%	0		514,414	29.3%
2005	513,019	29.3%	0		513,019	29.3%
2006	528,567	30.2%	0		528,567	30.2%
2007	500,420	28.6%	0		500,420	28.6%
2008	577,506	32.9%	0		577,506	32.9%
2009	533,289	30.4%	0		533,289	30.4%
2010	552,242	31.5%	0		552,242	31.5%
2011	579,900	33.1%	0		579,900	33.1%
2012	546,321	31.1%	0		546,321	31.1%
2013	493,949	28.2%	0		493,949	28.2%
2014	489,442	27.9%	0		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%

PNM-Owned Universal Solar Resources

PNM currently has 107 MW of universal solar PV-generating facilities in service. The solar PV resources consist of a mix of fixed-tilt and single-axis tracking arrays located 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.

PNM dedicates 1.5 MW of these solar facilities to PNM’s Sky Blue program. The solar-generated energy is blended with generation from NMWEC to supply customers participating in the Sky Blue program. Table 20 lists PNM’s existing owned resources.

Table 20. PNM-Owned Universal Solar Resources

Resource Name	In-Service	Nameplate Capacity (MW)
Fixed Tilt Resources		
Prosperity Battery/Solar	2011	0.5
Reeves Station	2011	2.0
Los Lunas	2011, 2013	7.0
Las Vegas	2011	5.0
Deming	2011, 2013	9.0
Alamogordo	2011	5.0
Manzano (Valencia)	2013	8.0
Otero County	2013	7.5
Single Axis Tracking Resources		
Sandoval (Rio Rancho)	2014	6.1
Meadowlake (Valencia)	2014	9.1
Cibola County	2014	7.6
South Valley (Albuquerque)	2015	10.0
Rio Communities (Valencia)	2015	10.0
Santolina (W. Bernalillo)	2015	10.5
Santa Fe County	2015	9.5

In addition to the solar facilities described above, PNM owns two small PV systems installed before 2007: a 25-kW installation located in Algodones, New Mexico, and a 5-kW installation at PNM's Aztec office facilities located in Albuquerque.

PNM-Owned Universal PV/Battery Demonstration Project

As part of the Department of Energy's Smart Grid Storage Demonstration program, PNM was selected as one of 16 participants nationwide to demonstrate the integration of renewable energy and energy storage. The Prosperity Energy Storage project was the first to come online and has been successfully operated since September 2011. It is one of the most successful demonstration projects of battery storage and PV energy in the nation, and has been the subject of extensive research and facilitated development of smart grid concepts in cooperation with the University of New Mexico, Northern New Mexico College, Ecoult/East Penn Manufacturing, and Sandia National Labs. Located in Albuquerque near Mesa del Sol, this 500-kW PV and 1-MWh-rated battery facility has continually demonstrated the ability to simultaneously smooth the intermittency of the PV output, while shifting PV output to peak periods.

The project is also one of the most highly instrumented PV and storage systems in commercial operation and is gathering one-second-interval data from more than 200 locations on the panels. These data are coupled with a sophisticated back-office control system as well as computer models of the utility grid to continually refine controls and create an optimized dispatchable renewable resource—one that could have an on-peak capacity contribution of 100%. Functionality has been added to allow for reliability-based peak shaving and wholesale market arbitrage.

Dale Burgett Geothermal Facility

The Dale Burgett Geothermal Facility (also 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 to increase its production up to the 10-MW level. 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.

Existing Thermal Resources

PNM's existing thermal-generating resources consist of two coal-fueled resources (SJGS and FCPP), PVNGS, and seven natural gas-fueled generating stations. PNM assesses natural gas requirements for its natural gas-fired generating plants monthly, 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.

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. At the end of 2017, Units 2 and 3 will be retired.

PNM is the plant majority owner and is the plant operator. Table 21 shows the ownership by generating unit following the retirement of the two units. PNM's ownership share of Unit 4 represents the largest single resource (497 MW) in PNM's balancing area. SJGS is PNM's largest source of base-load generation and is delivered to PNM loads over several PNM-owned transmission lines in northern New Mexico.

Table 21.SJGS Ownership by Unit

2018 San Juan Generating Station Ownership	Unit 1 MW	Unit 4 MW	Total	Percentage
Utility Owner				
PNM	170	327	497	58.7%
Tucson Electric Power	170	0	170	20.1%
City of Farmington	0	43	43	5.1%
Los Alamos County	0	37	37	4.3%
UAMPS	0	36	36	4.2%
PNM Merchant	0	65	65	7.7%
Total	**340**	**507**	**847**	**100.0%**

The coal needed to fuel SJGS is purchased from an adjacent underground coal mine owned by the Westmoreland Coal Company. PNM oversees the administration of the coal contract, which runs through June 30, 2022.

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). 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. Table 22 shows the ownership by generating unit at the FCPP.

Table 22. FCPP Ownership

2017 FCPP Ownership	Unit 4 MW	Unit 5 MW	Total	Percentage
Utility Owner				
Arizona Public Service	485	485	970	63%
Four Corners Acquisition	54	54	108	7%
PNM	100	100	200	13%
Salt River Project	77	77	154	10%
Tucson Electric Power	54	54	108	7%
Total	**770**	**770**	**1,540**	**100%**

The coal supply for FCPP is the adjacent surface mine owned by Navajo Mine Coal Company, LLC.

PNM relies upon the transmission system to deliver the power from the FCPP into the northern New Mexico system to deliver to New Mexico loads.

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. On April 21, 2011, the Nuclear Regulatory Commission approved an application to extend the operating licenses of all units at the PVNGS for an additional 20 years. Unit 1 was extended to 2045, Unit 2 through 2046, and Unit 3 through 2047. Table 23 lists the PVNGS participants, and leased and owned amounts of capacity that PNM controls.

Table 23. PVNGS Ownership by Unit

PVNGS Station	Unit 1 MW	Unit 2 MW	Unit 3 MW	Percentage
Utility Owner				
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%
SCPPA (SoCal Public Power)	77	78	77	5.9%
LADWP (Los Angeles)	75	75	75	5.7%
PNM	134	134	134	10.2%
Total	**1,311**	**1,315**	**1,311**	**100.0%**

PVNGS Units 1 and 2: PNM has capacity rights to 134 MW from each of the three units (i.e., 10.2% of each unit). In 1985 and 1986, PNM undertook sale/leaseback financing of its Unit 1 and Unit 2 holdings. These units were placed in-service during 1986. During the intervening years, PNM has bought back 154 MW of that lease-financed capacity. Currently, PNM owns 30 MW in Unit 1 and 124 MW in Unit 2; PNM continues to lease the remaining 104 MW in Unit 1 and 10 MW in Unit 2. The remaining leases for PVNGS Unit 1 and Unit 2 originally had terms expiring in 2015 and 2016. PNM had options to extend the leases or to purchase the leased interest in those units. PNM has exercised those extension options for the Unit 1 and Unit 2 leased capacity. The extended Unit 1 leases have an expiration date of January 15, 2023. The extended Unit 2 lease has an expiration date of January 15, 2024. At the expiration of these extended leases, PNM will again have the option to purchase leased assets at fair market value upon the expiration of the extended lease.

PVNGS Unit 3: PNM owns the full 134-MW share of PVNGS Unit 3, with no lease provisions. In Case 13-00390-UT, the NMPRC granted PNM a Certificate of Convenience and Necessity (CCN) to provide that resource as a supply resource to serve New Mexico retail customers. Beginning in 2018, this capacity will be available to meet jurisdictional customer demand into 2047.

PVNGS Transmission: PNM relies on jointly owned transmission facilities and contracted transmission rights that have been secured for delivery of energy from PVNGS to serve retail loads in New Mexico. The transmission rights to bring PVNGS generation to New Mexico, as well as the long-term fuel contracts, are expected to extend throughout the planning period. 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.

Afton Generating Station

The Afton Generating Station is a 230-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.

Lordsburg Generating Station

Lordsburg Generating Station (Lordsburg) is a natural gas-fired peaking facility located near Lordsburg, New Mexico. Lordsburg has two GE LM6000 aero-derivative units that can deliver a total of 80 MW of fast-start peaking capacity. PNM needs the fast-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 receives a natural gas supply via the El Paso Natural Gas southern main line.

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 189 MW, of Luna. Tucson Electric and Samchully each also own one-third interests in Luna. In 2008, the NMPRC 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 Paseo del Norte and Jefferson intersection in the city of Albuquerque. The 154-MW facility is a natural gas steam electric plant comprised of three units. Unit 1 became operational in 1958 and has a 44-MW steam turbine generator. Unit 2 became operational in 1958 and has a capacity of 44 MW and Unit 3 became operational in 1962 and has a 66-MW capacity. 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 to reach the end of the planning period.

Rio Bravo Generating Station

Rio Bravo Generating Station (Rio Bravo; formerly known as Delta-Person) is a natural gas-fired generating plant with a capacity of approximately 138 MW 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 NMPRC 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 a critical 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 throughout the planning period.

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 150 MW 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 or extend the contract as the expiration date nears. Valencia receives its natural gas fuel supply through a four-mile-long pipeline interconnection to Transwestern's interstate pipeline.

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. Comprised of one GE LM6000, La Luz can deliver 40 MW of capacity into the northern New Mexico load center. It is equipped with selective catalytic reduction and carbon oxidation air emission control systems. 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.

Operational Information for Existing Supply 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 24 and Table 25 provide this information for PNM-owned and contracted supply-side resources.

Table 24. PNM-Owned or Leased Supply-Side Resources

Generating Resource	In-Service Date	Retirement Date	Location	Unit Capacity (MW)	PNM Capacity (MW)	Ownership Share Percentage	Fuel Type	Duty Cycle
Palo Verde Unit 1	1986	2045	Wintersburg, AZ	1,314	134	10.2%	Nuclear	Base
Palo Verde Unit 2	1986	2046		1314	134	10.2%	Nuclear	Base
Palo Verde Unit 3	1988	2046		1314	134	10.2%	Nuclear	Base
San Juan Unit 1	1976	After 2036	Waterflow, NM	340	170	50%	Coal	Base
San Juan Unit 2	1973	2017		340	170	50%	Coal	Base
San Juan Unit 3	1979	2017		497	248	50%	Coal	Base
San Juan Unit 4	1982	After 2036		507	195	38.5%	Coal	Base
Four Corners Unit 4	1969	After 2036	Fruitland, NM	770	100	13%	Coal	Base
Four Corners Unit 5	1970	After 2036		770	100	13%	Coal	Base
Afton CC	2007	After 2036	La Mesa, NM	230	230	100%	Natural Gas	Intermediate
Luna CC	2006	After 2036	Deming, NM	567	189	33%	Natural Gas	Intermediate
Rio Bravo	2000	After 2036	Albuquerque, NM	138	138	33%	Natural Gas	Peaking
Lordsburg Unit 1	2002	After 2036	Lordsburg, NM	40	40	100%	Natural Gas	Peaking
Lordsburg Unit 2	2002	After 2036		40	40			
La Luz	2015	2045	Belen, NM	40	40	100%	Natural Gas	Peaking
Reeves Unit 1	1960	After 2036	Albuquerque, NM	44	44	100%	Natural Gas	Peaking
Reeves Unit 2	1959			44	44			
Reeves Unit 3	1962			66	66			
Solar Photovoltaic	Various	2041–2044	Various	107	107	100%	Solar	Intermittent
Total					**2,323**			

Table 25. PNM Owned Renewable Resources

PNM-Owned Renewable Resource	In-Service Date	PPA Expiration	Location	Facility Capacity (MW)	PNM Capacity (MW)	Purchase Share	Fuel Type	Duty Cycle	Comments
Valencia Energy Facility	2008	2028	Belen, NM	158	150	100%	Natural Gas	Peaking	--
NM Wind Energy Center	2003	2028	House, NM	204	204	100%	Natural Gas	Intermittent	
Red Mesa Wind	2010	2046	Cibola County, NM	102	102	100%	Natural Gas	Intermittent	PPA began 2015
Burgett Geothermal	2014	2039	Animas, NM	4	4	100%	Geothermal	Base	
Total					**468**				

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 resources, the capacity values depend on the amount of capacity they provide at peak, and so the peak contribution capacity values are used for reserve margin planning. For example, the NMWEC wind resource contributes 5% of its installed capacity during summer peak, and fixed-tilt solar resources contribute 55% of their installed capacity during peak.

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 availability will either be extended or replaced with a more cost-effective resource through an RFP and competitive bid process.

Changes in the Existing Portfolio from the 2014 IRP

Since the 2014 IRP was filed in July 2014, PNM's existing generation fleet has experienced several changes to the generating plants and the capacity values published in that report. These are summarized below by generation plant:

- Addition of La Luz: In 2016, the La Luz Energy Center came online and is providing quick-start generation capacity in the Albuquerque load center. This unit provides contingency reserves, either non-spinning when it is not generating or the potential for spinning when it is generating.
- SJGS: At the end of 2017, SJGs Units 2 and 3 will be retired from service. This will reduce PNM's capacity from its largest baseload generator by 286 MW and reduce the number of spinning shafts that provide regulating reserves by two.
- Rio Bravo Generating Station: PNM purchased the Rio Bravo plant (formerly known as Delta, or Delta-Person). This facility has and continues to provide 138 MW of peaking capacity.
- Beginning in 2018, PNM's interest in PVNGS Unit #3 (134 MW) will become part of PNM's capacity under NMPRC jurisdiction. Currently that capacity is excluded from PNM's rate base and the power and energy are not available for NM customers.
- PNM has added 63 MW of universal solar capacity. These facilities are installed at seven sites in PNM's service territory and utilize single-axis tracking solar technology.

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, lines between the cities began to be 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 by way of a 230-kV line to Four Corners built in 1962, concurrent with APS 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 the larger coal-fired generating units at FCPP and SJGS were brought online. This shifted large base-load 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 low-cost coal and nuclear fuel mix 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. Economics drive the maximum use of energy brought in from the more efficient and larger remote generators.

The last PNM backbone transmission line was completed in 1984 when PNM constructed the Eastern Interconnection Project, a 216-mile, 345-kV line from the Placitas area north of Albuquerque located at BA 345-kV Switching Station to Clovis, New Mexico, interconnecting PNM with Southwestern Public Service (SPS) in the eastern grid 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.

The “backbone” of the system consists of the 345 kV lines and 230 kV line built in the 60’s and 70’s that emanate from the Four Corners area in northwest New Mexico and run to the Southeast and South. Power flow on these lines is typically from north to south due to the location of base load generation resources in the Four Corners area and in Arizona.

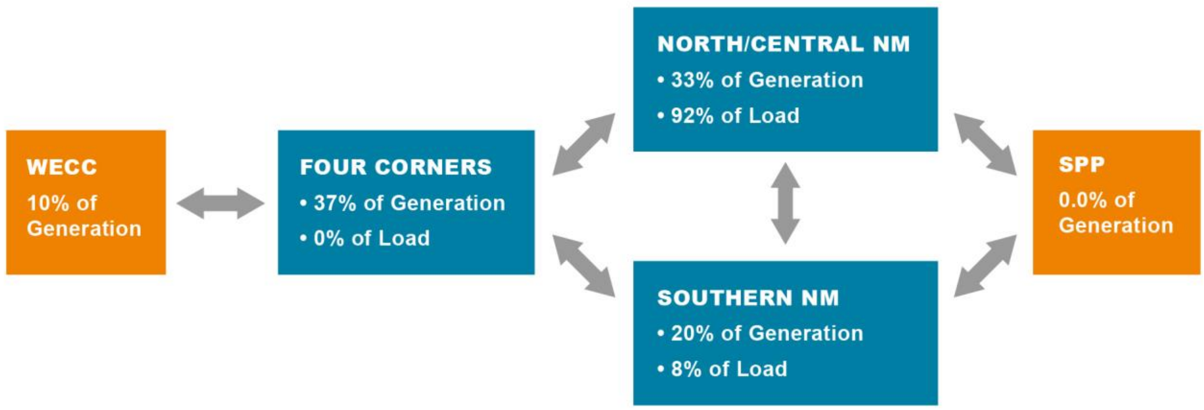
In southern New Mexico, PNM is a joint owner in two 345 kV lines that run from eastern Arizona to the Southeast and East towards El Paso, Texas. PNM also has 25 MW of wheeling rights in a 345 kV line owned by El Paso Electric that runs from Albuquerque to Las Cruces, NM. Historically, power has flowed in an easterly and southerly direction on these 345 kV lines. However, with the significant addition of new generation resources in southern New Mexico over the past several years, flow patterns have changed and power flows can be very light into southern New Mexico when the generation in the south is on-line and running.

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.

Existing Transmission Capabilities

PNM’s loads and generation locations are illustrated in the block diagram in Figure 16. The majority of the PNM load (92%) is located in north and central New Mexico, while 47% of PNM’s resources are located at the Four Corners transmission hub, or beyond, and transmitted, or wheeled, to load centers in north and central New Mexico. Although physical connections exist between PNM and the Southwest Power Pool (SPP) to the east, no firm resources are currently being imported from the SPP grid to serve PNM load.

Figure 16. High-Level PNM Transmission System Diagram

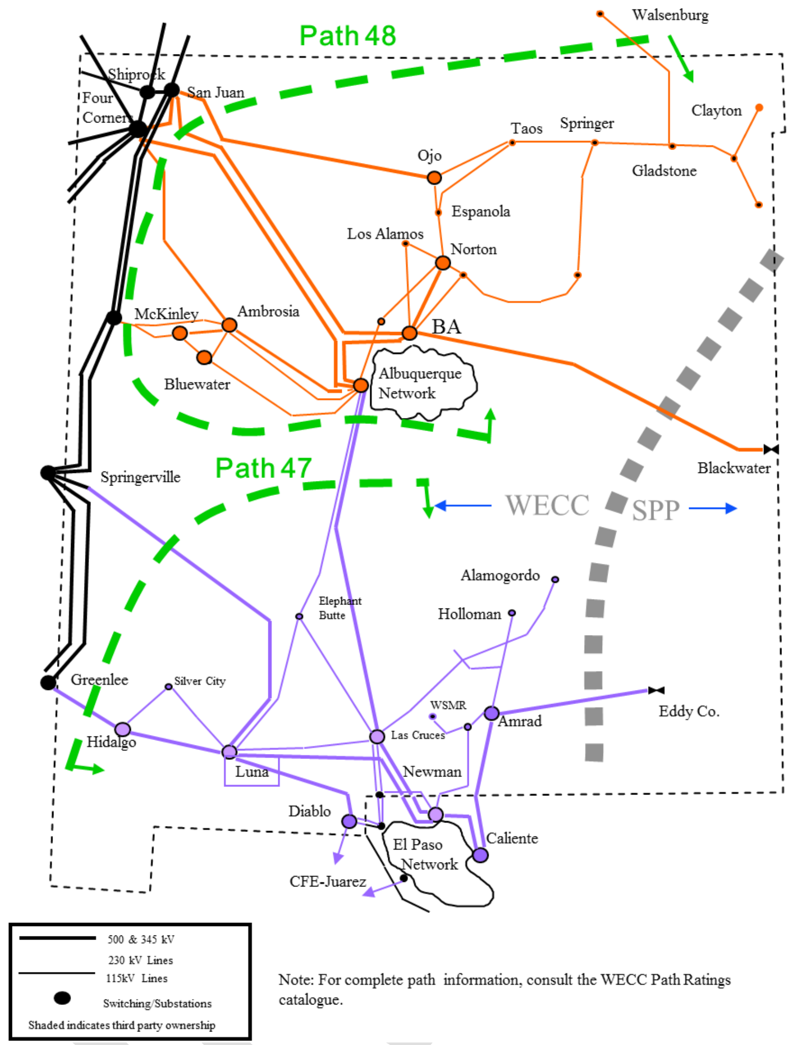


The major transmission lines owned by PNM were primarily developed to deliver remote resources from the Four Corners area of New Mexico to retail and wholesale customers near the load centers in northern and southern New Mexico. Appendix E includes a list of PNM's transmission facilities.

PNM monitors key transmission paths 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.

In New Mexico, there are two key transmission paths (called Path 47 and Path 48) that are defined in the planning and operation of the transmission system. Path 48 describes transmission lines in the northern part of the state, shown as orange lines, and Path 47 describes transmission in the southern part of the state, shown as purple lines, as illustrated in Figure 17. Black and grey-colored lines represent transmission that is external to that of Path 47 or Path 48. Assets within each path comprise a combination of PNM and non-PNM-owned lines or stations. Any transaction that takes place on the PNM system with neighboring systems is bound by the operation of these paths.

Figure 17. Map of WECC Transmission Path 47 and Path 48



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.

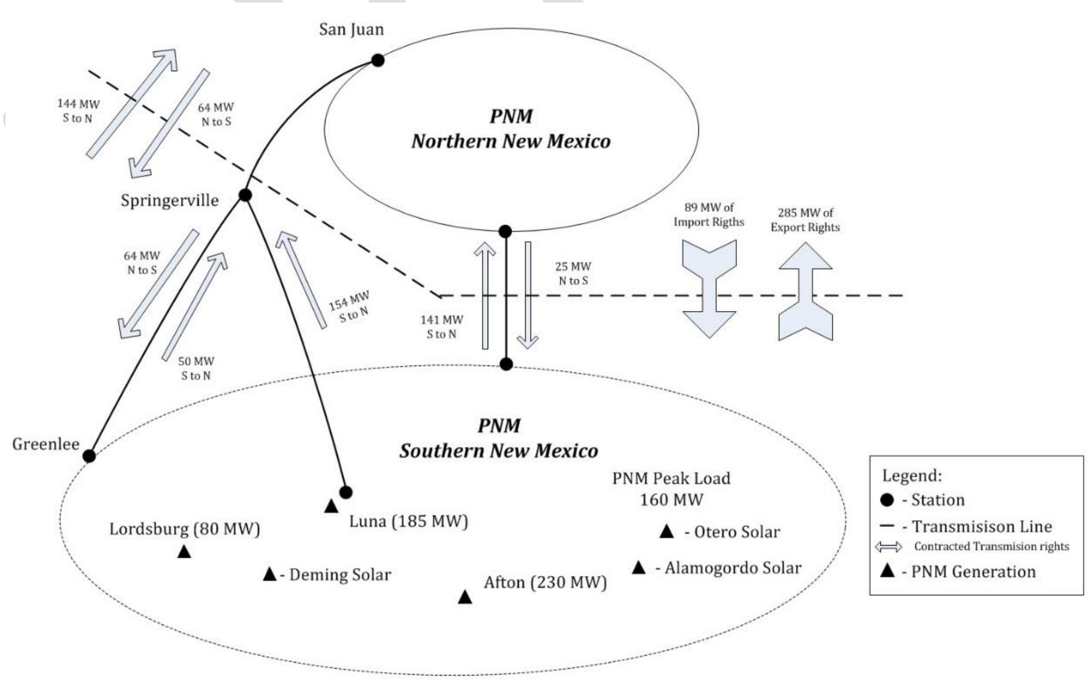
PNM's capacity in Path 47 and Path 48 is fully committed. Transferring existing firm resources and any new resources sited that require transmission along these paths will need to include a transmission system expansion. Resources located on the load side within Path 47 or Path 48 typically help or enhance the operation of these paths by providing a local resource to reduce constraints on these paths. When load increases and Path 48 approaches its import limit, these additional resources can be dispatched to support the system from within a path.

Siting, permitting, cost, and construction timelines for new transmission line projects will continue to be a challenge. The use of load-side generation will continue to play a role in supporting the system and alleviating transmission constraints barring any future barriers to this type of operating practice.

Southern New Mexico Transmission System

PNM's southern New Mexico system, which includes PNM's ownership share in Path 47, delivers power to a combination of jurisdictional service territories which include Deming, Silver City, Lordsburg, Alamogordo, and Ruidoso. The southern New Mexico system also contains three solar facilities and three natural gas fired generation facilities at Afton, Luna, and Lordsburg that PNM integrates into its resource portfolio to effectively dispatch and serve load while minimizing overall utility costs. In addition to PNM's ownership share in Path 47, PNM purchases wheeling 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 area and purchases wheeling from EPE and TEP to move a portion of southern New Mexico generation to northern New Mexico. Figure 18 illustrates the relationship between PNM's southern New Mexico and northern New Mexico import/export rights on the transmission system. These power delivery rights exist over a combination of PNM, Tri-State, and EPE assets. Arrows in Figure 18 indicate the direction of transmission rights between PNM's northern and southern systems that can be utilized to integrate southern New Mexico resources into the entire PNM system. In addition to PNM's ownership share in Path 47, PNM purchases wheeling 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 area and purchases wheeling from EPE and TEP to move a portion of southern New Mexico generation to northern New Mexico.

Figure 18. Southern New Mexico Transmission System



Afton, Luna, and Lordsburg generation resources provide a total of 495 MW of capacity. Because they are located inside the Path 47 transmission boundary, these resources can adequately serve loads in southern New Mexico, with the ability to deliver power to northern New Mexico via 285 MW of transmission rights 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 currently possesses rights to approximately 89 MW of transmission resources for delivering power from northern New Mexico to southern New Mexico across the Path 47 transmission boundary.

Wheeling Agreements

PNM purchases transmission services to serve PNM's retail customer load and wholesale customer requirements from APS, Tri-State, EPE, and TEP. These services are described below.

Transmission Services Purchased by PNM from APS

PNM has two transmission service agreements with APS for delivery of PNM's PVNGS energy to New Mexico. The first purchase is a non-OATT bilateral contract for a 130-MW path and the second is an additional 10 MW of transmission service under APS' OATT for service from the Phoenix to Four Corners. In addition, PNM has secured 135 MW of transmission service from APS to bring Palo Verde Unit 3 to Four Corners starting January 1, 2018 as a PNM jurisdictional resource.

Transmission Services Purchased by PNM from Tri-State

PNM purchases network service from Tri-State under Tri-State's comparability OATT for PNM's retail load in the Town of Clayton, in northeastern New Mexico. PNM has interconnections with Tri-State at Ojo Station north of Santa Fe and at Storrie Lake, north of Las Vegas, New Mexico. PNM delivers power and energy to Tri-State at these interconnections for service to Clayton on Tri-State's system. The Clayton load is approximately 3.5 MW.

Transmission Services Purchased by PNM from EPE

PNM purchases firm point-to-point transmission service under EPE's OATT as follows:

- PNM has 295 MW of transmission rights to deliver resources located in southwestern New Mexico to northern New Mexico.
- PNM has 25 MW of transmission rights to deliver resources located in northern New Mexico to southwestern New Mexico.

Transmission Services Purchased from PNM by TEP

PNM purchases 14 MW of firm point-to-point transmission service under TEP's OATT from SJGS to Greenlee to support system deliveries in southern New Mexico.

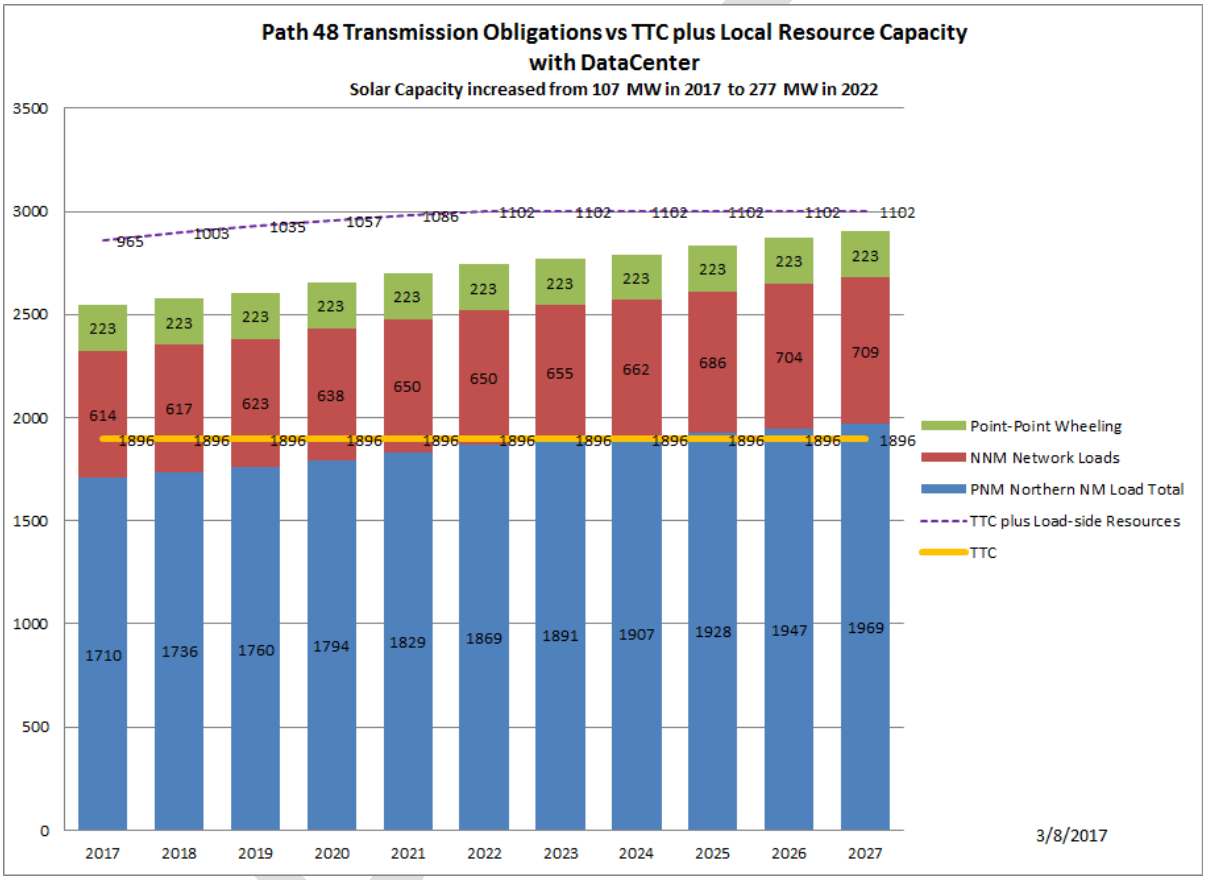
Transmission Service Exchange Agreements between PNM and WAPA

PNM has a transmission service exchange with WAPA for delivery of PNM's PVNGS generation output to New Mexico. WAPA provides PNM 134 MW of transmission service from Phoenix to

Four Corners. In exchange, PNM receives some revenue and provides 247 MW of transmission service from Four Corners to various points of delivery on PNM's transmission system for WAPA.

The amount of load that can be served by imported power over the northern New Mexico transmission system is equal to the Total Transfer Capability of 1896 MW, as shown in Figure 19. The total amount of load that can be served (Load Serving Capability) in northern New Mexico is the sum of imported power and northern New Mexico generated power. The Load Serving Capability is indicated by the purple line in Figure 19. Figure 19 illustrates that, sufficient transmission capacity is expected through 2027.

Figure 19: Transmission Import Limits Relative to Existing Northern NM Generation



Currently, there are ample generation resources in southern New Mexico to serve PNM's southern New Mexico system loads. In addition, PNM currently possesses rights to approximately 89 MW of transmission resources for delivering power from northern New Mexico to southern New Mexico across the Path 47 transmission boundary.

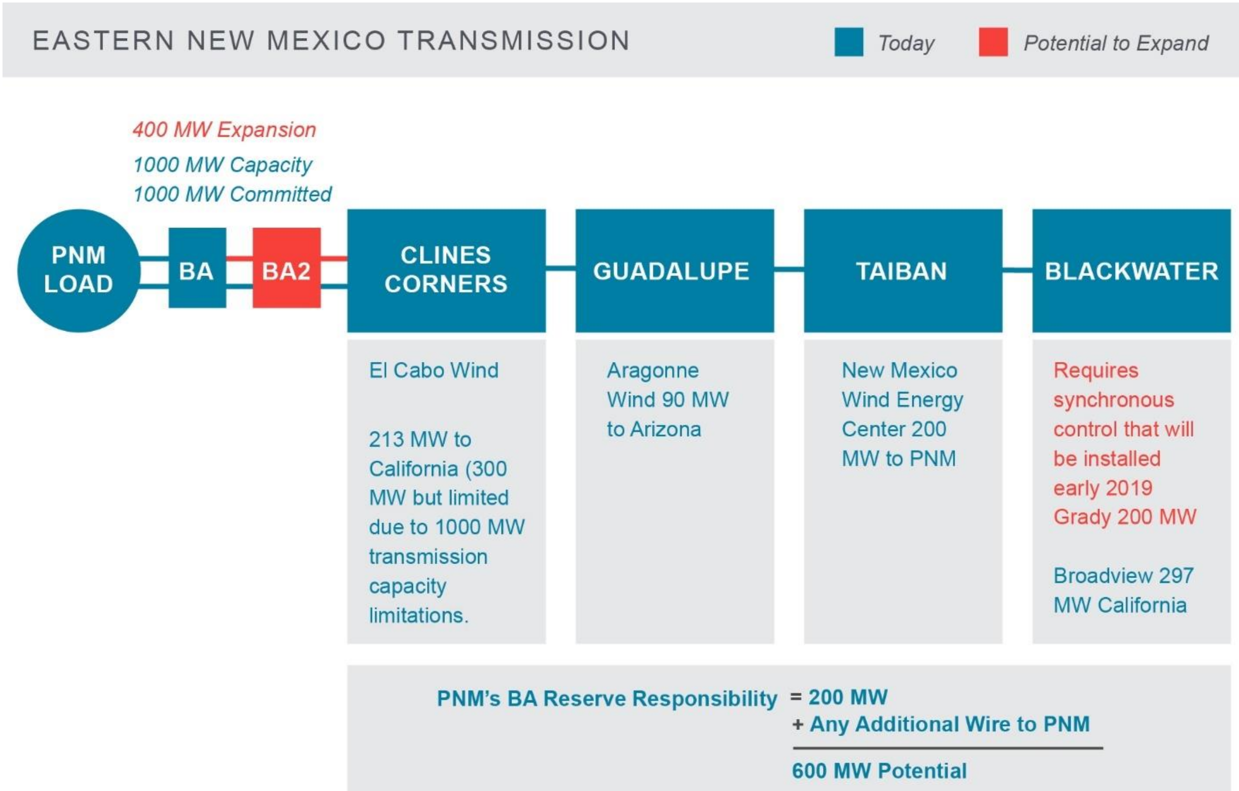
PNM currently has 345 MW of transmission rights to deliver resources located in southern New Mexico for delivery to PNM loads in northern New Mexico. To integrate additional southern New Mexico resources to serve northern loads will require PNM to secure additional transmission rights from the south to the north (San Juan).

Resources sited near the loads are generally not restricted by transfer capability, but can still require transmission improvements to address local network overload or voltage problems because increased flows result from the new resources. Improvements are specific to each interconnection location and should be individually reviewed. Existing resources along with existing large generation interconnection agreements commitments in the Los Lunas and Belen area of Valencia County will utilize all remaining transmission capacity to move power out of the area. Beyond these identified levels, PNM's studies show that additional resources will create transmission congestion unless transmission capacity between Valencia County and Albuquerque is expanded.

Eastern New Mexico Transmission System

In New Mexico, wind resources are concentrated in the eastern portion of the state. Several wind energy centers have already been developed in this area, including the New Mexico Wind Energy Center (200 MW) and Aragonne Mesa (90 MW). Both of these projects 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). Three additional New Mexico wind farm projects have entered into power purchase agreements with customers in California and have acquired or are in the process of acquiring transmission service from PNM. Pattern Energy Group, Inc. has developed the Broadview wind farm (297 MW) that interconnects to PNM's Blackwater station near the Texas border and plans to develop a second wind farm called Grady (200 MW) that will interconnect to their transmission line that is interconnected PNM's Blackwater station. Avangrid is developing the El Cabo wind farm (298 MW) that will interconnect to PNM's EIP line near Clines Corners in June 2017.

Figure 20. Eastern Interconnect Project

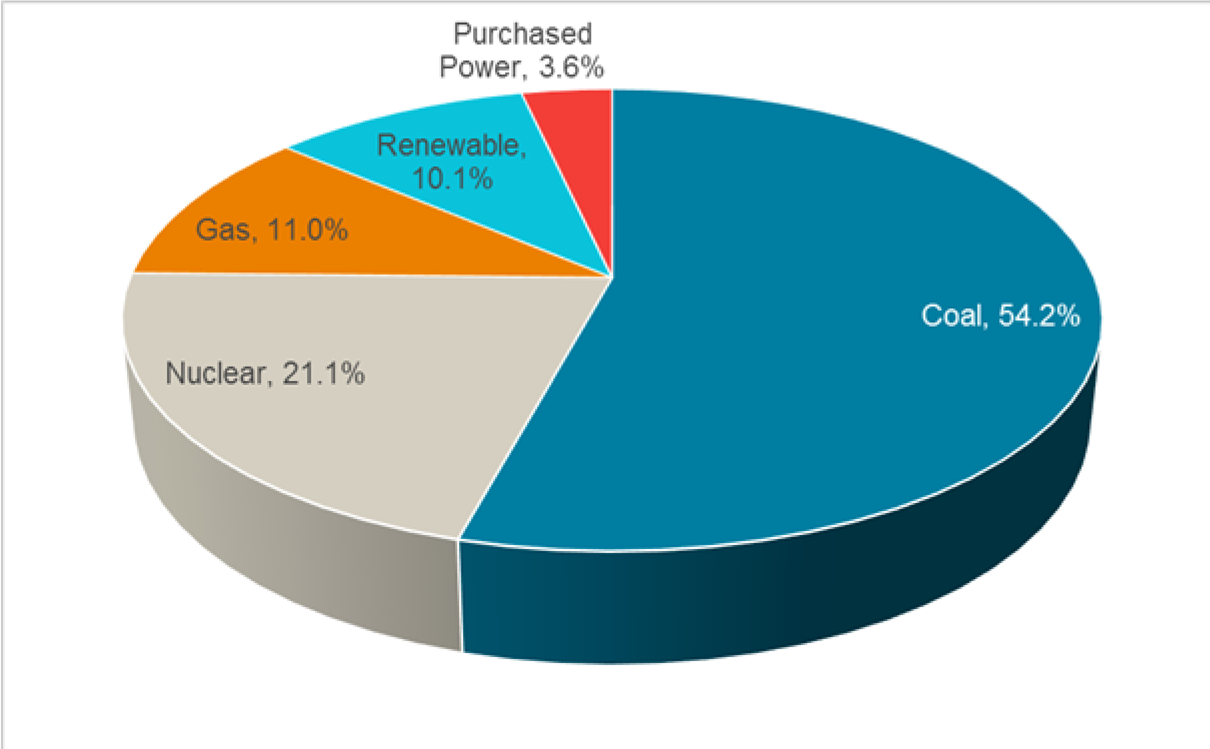


The addition of these wind farms, along with the existing wind farms, will result in 1000 MW of requested transmission service on the EIP line. As a result, PNM will be installing a voltage support device, a Static VAR Compensator ("SVC"), to the EIP line scheduled to be in-service in March 2018 to accommodate these projects' transmission service needs. In addition, a synchronous condenser (i.e., essentially a generator without the turbine to provide synchronous current compensation) will be required at Blackwater station to offer the remaining of transmission service to the Grady windfarm.

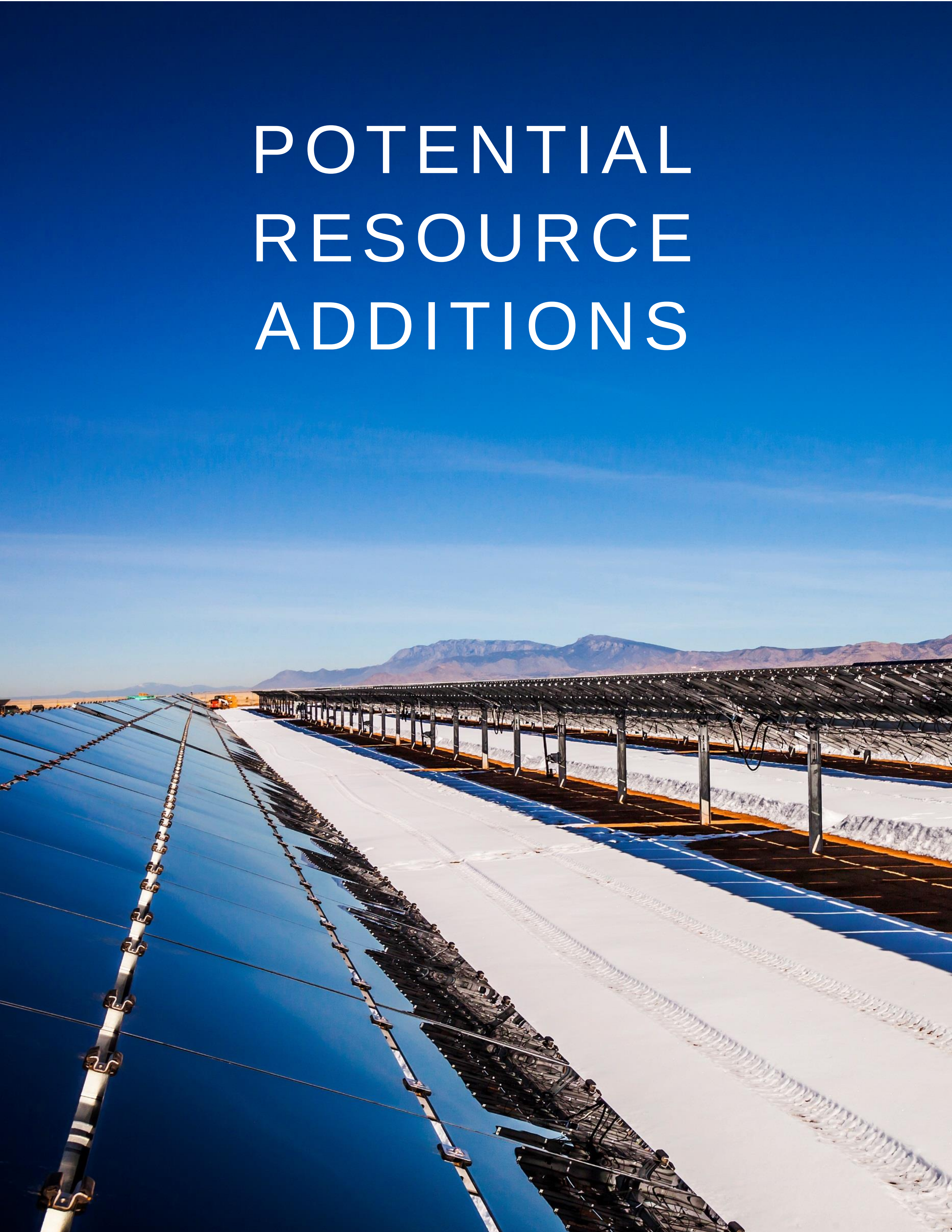
Current Fuel Mix

As shown in Figure 21, PNM currently produces the majority of its energy from coal resources (54.2%), following by nuclear (21.1%), gas (11%), and renewable energy (10.1%).

Figure 21. 2016 PNM Proportions of Energy Produced by Each Fuel Type



POTENTIAL RESOURCE ADDITIONS



Potential Resource Additions

The IRP Rule says that, if approved, an IRP provides *prima facie* evidence as to the type of resources PNM requests to add to its portfolio in the future. PNM has developed a list of commercially available resources and emerging technologies expected to be commercially available in the near future for analysis. Selection of any of the representative resources in the MCEP is an indication of the correct type of resource for the future portfolio under the pricing and operation assumptions assumed in the analysis. Following the IRP, PNM will conduct a resource acquisition solicitation to determine the best resource within the type identified.

Over the 20-year planning horizon used in this IRP, it is likely that new resource technologies will be developed affecting both supply-side and demand-side resource options. Some of these technologies may already be known, but not yet commercially available or cost-effective; some may not yet be known. However, development of a 20-year MCEP cannot be based on speculation of uncertain technology improvements, but rather must account for what is available and presently known. In three years, when the IRP process is again undertaken, resource options, technologies, and costs for the MCEP will be re-evaluated and considered at that time. For purposes of this IRP, available resource options for planning the 20-year MCEP depend upon technologies and costs assumed today.

Future Energy Efficiency Resources

PNM modeled the impact of energy efficiency throughout the planning period. The projected energy and demand savings are based on the following assumptions:

- Current programs, as well as new programs, continue to be approved by the NMPRC.
- Successful identification and implementation of new programs required to meet the EUEA net savings requirements of 8% of 2005 retail sales by 2020 (658 GWh). The projected impact results in savings that meet or exceed the EUEA minimum target savings in 2020.
- PNM will invest 3% of applicable retail revenues annually on energy efficiency and load management programs, as specified in the EUEA.
- Assumptions regarding the maturation of energy-efficient technologies, specifically, the cost of procuring future savings, will increase at an average annual rate of 4.0%.
- Recognizing that the actual escalation rate of the cost of energy efficiency per kWh saved may vary from the projected rate of 4.0%, PNM included two sensitivity cases that assume higher and lower escalation rates over time of 6.0% and 2.0%, respectively.

Future Demand Response Resources

PNM engaged in a strategic planning effort beginning in 2016 for its demand response programs, including assessment of potential enhancements and growth and administering a Request for Proposals (RFP) process. The RFP process resulted in selection of vendors to enhance the existing Peak Saver and Power Saver programs and manage implementation in 2018-2022.

The Peak Saver program targets non-essential peak electric loads and is available to 50 kW or greater commercial and industrial customers. Participating customers receive an incentive based on their level of load reduction at the end of each control season. Over the next five years, the Peak Saver program will retain all of the same program elements that are currently available to customers with the addition of better energy usage and monitoring options for participants. As possible, many participant sites will be automated to improve load monitoring and control and to provide easy access to energy usage data. The automation will allow for integrating a large number of smaller loads to make DR attractive to small and medium size customers which will allow for participation growth.

The PNM Power Saver program targets residential customers and small commercial customers not served under the Peak Saver program. This program cycles non-critical loads, such as refrigerated air conditioning units, on and off during summer peak hours in exchange for a modest incentive paid at the end of each control season. Over the next five years, PNM expects to growth the program by offering a Wi-Fi thermostat option to customers who have previously dropped out as well as new participants. Customers with existing thermostats will also be allowed to participate under the bring-your-own-thermostat (BYOT) option. Wi-Fi enables a more enhanced customer experience by interactively engaging the customer via any internet connected device (such as a mobile phone or computer). Participants can have a thermostat provided and installed at no charge or enroll in the program using their own qualifying thermostat. In either case, control events initiate through interacting with the thermostats through the participants' home Wi-Fi networks. The thermostat option will provide the additional benefits of potential energy savings through using verifiable set-back strategies and providing a higher level of customer satisfaction.

Supply Resource Options

The IRP considers all feasible resources, including current and developing new resource options. This section includes a discussion of each potential resource option, its feasibility of being implemented during the planning horizon, and fuel assessment. PNM has identified and included several generation resource types in the analysis for possible inclusion in the 20-year portfolio plan. Costs for each resource included all associated fuel and operating expenses for existing resources and revenue requirements for new resource alternatives. A discussion of the resource alternatives, along with a narrative describing each resource, is provided below. Appendix D contains cost and performance data for new supply-side resource options.

Renewable Portfolio Standard Resource Additions

The Renewable Portfolio Standard (RPS) for investor-owned electric utilities in New Mexico steps up from 15% to 20% in 2020. PNM already meets the 15% current standard, but will require additional renewable resources to meet the 20% standard. Based on the information presented in PNM's June 2017 Renewable Energy Procurement Plan (REPP), PNM estimates a need for an additional 263,000 MWh per year of RECs. PNM could supply these certificates by purchasing the RECs, buying renewable power, or constructing resources needed to meet both the 5% increase in total energy required and the associated diversity requirements. Based on the bids received in PNM's most recent renewable energy request for proposals, PNM is proposing in its 2017 REPP that the additional RECs to meet 2020 RPS requirements can be supplied through an additional 50 MW of wind capacity by 2019 and an additional 50 MW of universal solar capacity by 2020. All portfolios evaluated for this IRP assume these additional resources for RPS compliance are met through the 50-MW each of new wind and solar at prices and capabilities as described in the resource sections below.

Data Center Resource Additions

As discussed in the "Customers, Load Forecast" section, the load forecast assumes the recently announced data center will expand through 2023. The data center is committed to matching its energy demand with renewable energy production. As the facility expands, PNM expects to add additional renewable energy resources with a mix of wind and solar resources to match the data center's energy use. The incremental list is shown in Table 26.

Table 26. Incremental Wind and Solar to Meet Data Center Loads

Year	Solar PV (MW)	Wind (MW)
2018	30	50
2019	40	0
2020	30	50
2021	30	50
2022	40	30
2023	20	0

At the time this report was written, the only identified renewable energy resource expansion associated with the data center customer was 30 MW of single-axis tracking photovoltaic (PV) solar. Actual resource additions will vary from this list as the data center expands and to account for practical limits like transmission system availability for the wind resources.

Energy Storage Technology

Energy storage is a technology that stores energy for later use. Types of energy storage technologies include battery, mechanical storage such as a fly wheel, or thermal storage such as ice storage.

Storage Technology	Expected Life	Description	Comments
Compressed Air	15-20 Years	Uses off-peak energy to compress air for storage; suitable geologic space required for large scale	Requires geology with good containment (salt caverns, underground mines, etc.); mature technology
Flywheel	20+ Years	Mechanical devices that spin, storing rotational energy that is released when needed	High power density, relatively low energy capacity (short powerful discharge)
Pumped Hydro	20+ Years	Water lifted off-peak to a reservoir above a conventional hydro power plant	Limited available sites; proven technology
Other	varies	Includes ice and other thermal storage	

Battery Lead-Acid	5-15 Years	The most common battery; a mature technology, available since the 19th century	Proven workhorse, but in utility application has low depth of discharge, poor operation in partial charge and short lifespan;
Battery Lithium-Ion	5-15 Years	By far, now the most common battery type for utility scale storage; also used extensively in electronics	Electric vehicle and utility applications
Battery Sodium	5-15 Years	Classified as high-temperature; generally maintained at temperature of 300°C or more	High cost with suport system requirements (high temperature)
Battery Zinc	5-15 Years	Zinc batteries have a number of potential advantages, but are not in widespread commercial deployment	Currently unproven at commercial cost level requirements
Flow Battery	15-20 Years	Rechargeable and akin to fuel cells; two chemical solutions allow current to pass thru a separating membrane	Scalable, some concerns with balance of system costs; high potential for future advances

Batteries appear to have best potential for widespread application and provide services such as peaking capacity, time shifting of generation to match load or supply levels, frequency regulation, distribution service quality, transmission support, ramping support, and operating and contingency reserves. The choice of battery type, size and design will affect the ability to provide these various services and the cost. Design factors include battery capacity, total energy storage, rate of recharge, efficiency of energy returned versus charging energy, expected life, degradation of performance (over time, cycles, etc.) and system regulation capability.

Recent public policy actions have been taken to improve the cost-effectiveness of battery (or other) storage technology. The California Public Utilities Commission established a target of installing 1,325 MW of storage capability on the grid by 2020. This mandate may allow some cost savings to emerge as a result of learnings from large scale deployment. Core research funding is also ongoing in industry and academia. Currently, significant tax incentives are available for battery investment that is coupled with renewable energy resources. In light of these measures, PNM expects that battery storage can/may become commercially available and cost effective within the plan horizon.

PNM included two versions of battery storage in the capacity expansion modeling: a 2-MW, two-hour storage battery and a 40-MW, four-hour battery. The capital cost of the 2-hour battery is assumed to be $1,892/kW and the capital cost for the 4-hour battery is assumed to be $2,925/kW. These prices are based on recent battery acquisitions in neighboring service territories and are verified using the EPRI cost database. The reliability analysis will explore the quantity of energy storage required to have a beneficial impact on system reliability, and PNM will estimate the range of costs that can be avoided for provision of spinning reserves if a battery is installed in the system. The capacity provided by a battery is assumed to be capable of meeting the need for traditional quick-start generation capacity that would be provided by an equivalent amount of gas-fired capacity.

Table 27 summarizes several storage technologies. Not only can PNM use energy storage to meet system peak load, it can potentially use it as operating reserves. PNM can also use energy storage to modify load (e.g., by charging the storage system during typically low-load periods such as during the night). Various energy storage technologies are in different phases of development, many are in the demonstration phase.

Table 27. Storage Technologies

Storage Technology	Expected Life	Description	Comments
Compressed Air	15-20 Years	Uses off-peak energy to compress air for storage; suitable geologic space required for large scale	Requires geology with good containment (salt caverns, underground mines, etc.); mature technology
Flywheel	20+ Years	Mechanical devices that spin, storing rotational energy that is released when needed	High power density, relatively low energy capacity (short powerful discharge)
Pumped Hydro	20+ Years	Water lifted off-peak to a reservoir above a conventional hydro power plant	Limited available sites; proven technology
Other	varies	Includes ice and other thermal storage	
Battery Lead-Acid	5-15 Years	The most common battery; a mature technology, available since the 19th century	Proven workhorse, but in utility application has low depth of discharge, poor operation in partial charge and short lifespan;
Battery Lithium-Ion	5-15 Years	By far, now the most common battery type for utility scale storage; also used extensively in electronics	Electric vehicle and utility applications
Battery Sodium	5-15 Years	Classified as high-temperature; generally maintained at temperature of 300^{o}C or more	High cost with suport system requirements (high temperature)
Battery Zinc	5-15 Years	Zinc batteries have a number of potential advantages, but are not in widespread commercial deployment	Currently unproven at commercial cost level requirements
Flow Battery	15-20 Years	Rechargeable and akin to fuel cells; two chemical solutions allow current to pass thru a separating membrane	Scalable, some concerns with balance of system costs; high potential for future advances

Batteries appear to have best potential for widespread application and provide services such as peaking capacity, time shifting of generation to match load or supply levels, frequency regulation, distribution service quality, transmission support, ramping support, and operating and contingency reserves. The choice of battery type, size and design will affect the ability to provide these various services and the cost. Design factors include battery capacity, total energy storage, rate of recharge, efficiency of energy returned versus charging energy, expected life, degradation of performance (over time, cycles, etc.) and system regulation capability.

Recent public policy actions have been taken to improve the cost-effectiveness of battery (or other) storage technology. The California Public Utilities Commission established a target of installing 1,325 MW of storage capability on the grid by 2020. This mandate may allow some cost savings to emerge as a result of learnings from large scale deployment. Core research funding is also ongoing in industry and academia. Currently, significant tax incentives are available for battery investment that is coupled with renewable energy resources. In light of these measures, PNM expects that battery storage can/may become commercially available and cost effective within the plan horizon.

PNM included two versions of battery storage in the capacity expansion modeling: a 2-MW, two-hour storage battery and a 40-MW, four-hour battery. The capital cost of the 2-hour battery is assumed to be $1,892/kW and the capital cost for the 4-hour battery is assumed to be $2,925/kW. These prices are based on recent battery acquisitions in neighboring service territories and are verified using the EPRI cost database. The reliability analysis will explore the quantity of energy storage required to have a beneficial impact on system reliability, and PNM will estimate the range of costs that can be avoided for provision of spinning reserves if a battery is installed in the system. The capacity provided by a battery is assumed to be capable of meeting the need for traditional quick-start generation capacity that would be provided by an equivalent amount of gas-fired capacity.

Universal Solar PV

PNM has included several universal solar photovoltaic (PV) resource additions—all assume single-axis tracking technology. The additions are assumed at three different sizes: 10 MW, 50 MW, and 100 MW. Pricing options shown in the table in Appendix K reflect the revenue requirements calculated from bids received by PNM in a public request for proposals for renewable energy resources issued in 2016. The cost data assumed for the resources also assume solar resources built before 2020 receive the current 30% federal investment tax credit. Beginning in 2020, solar resources are assumed to receive a 10% federal investment tax credit. Because solar pricing has been changing rapidly, and the cost is dependent upon unknown, future tax credits, PNM performed a sensitivity analysis (See Analysis Results Section, Solar Sensitivity) to determine the impact of a wider range of solar pricing on portfolio recommendations.

PNM also assumed appropriate transmission interconnection costs and transmission upgrade costs for each of the three potential sizes. Finally, the smaller resources are assumed to be interconnected to PNM's distribution system; larger resources require interconnection at the transmission voltage level.

As solar energy production increases on PNM's system, the need for resources to meet peak load after accounting for solar energy's contribution moves to later hours in the day. PNM applied a declining contribution to the reserve margin with each successive solar resource addition.

When PNM evaluates the ability of incremental solar capacity to help meet system peak load, it considers the extent to which previously installed solar will shift the net peak hour. This analysis is described in the Analysis Results Section, Solar Sensitivitiy

Beyond this decline in the peak contribution from incremental solar, The California Independent System Operator (CAISO or California ISO) has identified other challenges for the electric grid. CAISO depicted this situation in a now-famous graph that has become known as the duck curve due to its resemblance to the profile of a duck (Figure 22).

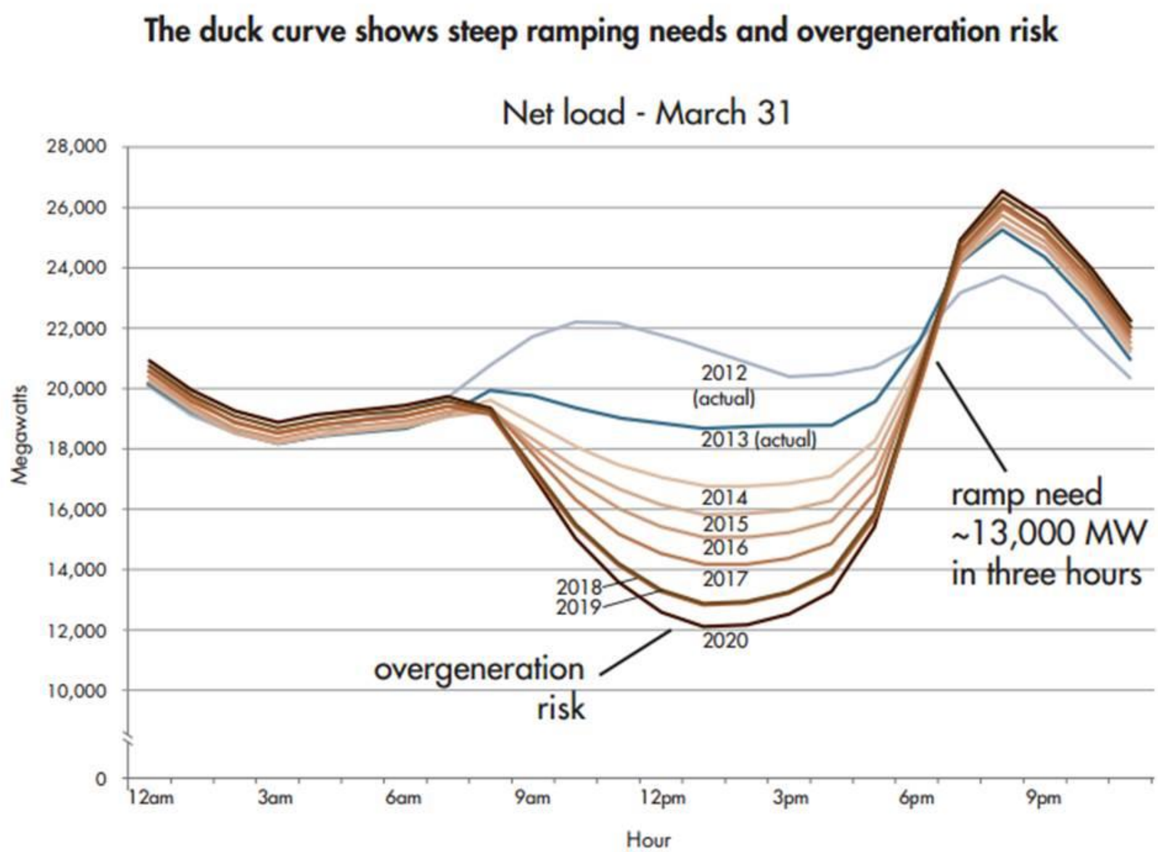
> "With a changing resource mix that includes an increasing amount of variable energy resources, the California ISO will face steep ramps and will need to meet increasing or decreasing electricity demand quickly. We will need resources with fast ramping and fast start capabilities as well as the ability to start multiple times during an operating day. The California ISO also expects an increased risk of overgeneration, when resources are supplying more electricity than is needed to satisfy real-time electricity requirements. This condition creates negative market prices that may create shortfalls in expected market revenues for certain resources. In addition, there is a risk of decreased frequency response capability when fewer resources are operating and available to automatically adjust electricity production to maintain grid reliability.
>
> "…the reduction in generation capacity that can adjust its production of energy in response to under or over-frequency occurrences raises grid reliability concerns. The California ISO must maintain resources with sufficient capabilities on its system at all times to effect real-time control performance. In order for ISO to comply with FERC's recently approved Frequency Response and Frequency Bias Setting standard (BAL-003-1), the ISO will have to operate in a manner such that resources on governor control must forego operating at their maximum capability and reserve available headroom at all times in order to provide frequency response following a disturbance. Low net load conditions create more challenges to meet this requirement because it requires the commitment of additional resources at a time when too much generation is already on the system."[5]

PNM has analyzed these issues, and the analysis is discussed in the Analysis Results, Reliability Analysis section. At the current level of solar capacity on its system, PNM continues to receive peak capacity benefit from incremental solar and does not yet experience the severe operating challenges of the duck curve situation. However, the regional grid is moving to higher penetration levels and to the extent PNM becomes more linked to the grid, adding NM solar will face those challenges.

[5] FERC Docket No. AD14-9-000, comments of Brad Bouillon, CAISO

Utilities in the southwest are particularly affected by this as solar energy is physically most productive in areas of southern latitude and clear skies. Solar also best matches load in utility systems which have their peak load in summer daytime hours.

Figure 22. California "Duck Curve"



Solar Thermal with Storage

PNM has not received any recent bids for solar thermal resources to provide input assumptions for a new resource. Rather, PNM relied on data from a solar thermal tower installation to characterize this potential new resource, along with a 12-hour energy storage system. The revenue requirements in the portfolio analysis are calculated based on a 100-MW solar thermal tower with 12 hours of energy storage, a 45% capacity factor (which is higher than typical solar PV because of the storage component), and an all-in energy price of $185 per MWh.

Wind

Wind resources were characterized in generic 50- to 100-MW increments with a 40% capacity factor based on bids received by PNM in a 2016 public request for proposals for renewable energy resources. PNM conducted a sensitivity analysis around wind price, capacity factor, and total capacity that can be integrated into the portfolio. Wind price and availability are also impacted by transmission availability. If transmission system capacity is insufficient to transfer energy to loads, costs must reflect the need for additional transmission.

Geothermal

PNM based assumptions for a new generic 15-MW geothermal energy generator with an 85% capacity factor in the new resource option database. This facility is sized and priced based on bids received by PNM in a 2016 public request for proposals for renewable energy resources.

Small Aeroderivative

A 40-MW aero-derivative option was considered with a 9,800-Btu/kWh heat rate and $1,150/kW installed capital cost. This unit can provide quick-start capability (full operating load in 10 minutes) to provide contingency reserves. PNM assumed this resource would not require any major transmission upgrades because it would be sited within WECC Path 48 in north central New Mexico.

Large Aeroderivative

PNM considered a typical 85-MW-sized gas turbine with a 9,800-Btu/kWh heat rate and $1,065/kW installed capital cost. This unit can provide quick-start capability for contingency reserves (full operating load in 10 minutes). PNM used the Electric Power Research Institute's (EPRI's) Technical Assessment Guide (TAG) database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level to represent typical siting conditions around New Mexico. PNM assumed this unit would be sited within WECC Path 48 in north central New Mexico and not require transmission upgrades.

Heavy Frame Combustion Turbine

PNM included an option for heavy frame 187-MW gas turbines with a 9,600-Btu/kWh heat rate and $753/kW installed capital cost. This technology can help PNM maintain system voltage and regulation and meet spinning reserve requirements. It is expected that these resources will require relatively little acreage and minimal amounts of water. PNM assumed this resource can be sited at SJGS and not require transmission upgrades because of the retirements of SJGS Units 2 and 3 by the end of 2017.

PNM also assumed that one of these units could be sited at or near SJGS and utilize available transmission from the SJGS to PNM load centers in north central New Mexico (see the "Existing Transmission System" section). It was also assumed the cost to build a new gas pipeline from an interstate pipeline to the SJGS plant would be included in the price estimates for the gas transportation agreement with this option.

1x1 New Combined Cycle Gas Generation

For this option, PNM assumed a 1 x 1 combined cycle gas turbine of a typical 289-MW manufactured size and $1,023/kW installed capital cost and approximately a 6,950-Btu/kWh heat rate. Unlike gas turbines, combined cycle plants require large amounts of water to condense the steam cycle. To minimize water usage and associated costs, PNM assumed this combined cycle gas turbine will utilize hybrid or dry cooling technology, which is included in the capital costs. PNM used the EPRI TAG database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level.

Rio Bravo Expansion to 1 x 1 Combined Cycle

There are two existing heavy frame combustion turbines in PNM's resource portfolio that may be retrofit with a heat recovery steam generator and steam turbine to create a new 1 x 1 natural gas combined cycle generator. PNM characterized a conversion of the Rio Bravo facility to model this resource. Expanding Rio Bravo would increase the capacity of this unit from 138 MW on peak to 210 MW (for a total 72 MW increase), while improving the heat rate from 11,071 to 7,200. Converting a combustion turbine to combined cycle would also likely eliminate its quick-start capability. Because combined cycle expansion works on heat recovery from the existing combustion turbine, no additional gas supply is needed. In addition to expected costs to upgrade the unit, PNM assumed a $5 million transmission system upgrade would be required. Because the cost and feasibility of this upgrade is currently unknown, PNM conducted sensitivity analysis around the capital cost requirements.

250 MW Existing Combined Cycle

PNM characterized a resource option to purchase a 250-MW share of a 550-MW existing combined cycle plant. This assumption is based on a similar transaction in Arizona. The capability of this unit is based on a 2 x 1 combined cycle generator with a heat rate of 7,000 and a capital cost of $700/kW, including costs for transmission. This characterization is for modeling purposes because PNM is unware of any partial purchases of a 550-MW natural gas combined cycle unit.

Reciprocating Engines

PNM included reciprocating engines of up to 41 MW in one installation, with a heat rate of 8,800 Btu/kWh and $1,218/kW installed capital cost. Reciprocating engines can operate over the full range of the unit size, offering quick-start generation and maximum load-following flexibility. The EPRI TAG database was used as the source of the unit characteristics. PNM assumed this resource would be sited within WECC Path 48 in north central New Mexico and not require transmission upgrades.

Potential Projects to Improve Transmission Capability

Under-Construction Transmission Facilities

PNM's transmission construction plans are derived from its annual transmission planning process. The projects listed below are currently under construction or have been completed recently. These projects are intended to provide additional transmission capability or voltage support to increase or maximize utilization of existing transmission facilities. The projects are primarily addressing capacity constraints associated with load growth and existing transmission service obligations and do not specifically address constraints associated with new, specific resource locations, as listed here:

- **Blackwater Switching Station Expansion** – The Blackwater Station was expanded in association with the interconnection of Western Interconnect. LLC transmission line for the Broadview wind farm (in-service January 2017).

- **Clines Corner Switching Station** – new switching station in association with the interconnection of the El Cabo wind farm to the EIP line (in-service expected date April 2017)
- **Richmond Switching Station** – new switching station in Albuquerque which allows for reconfiguration of the existing 115 kV lines to mitigate 115 kV overloads (in-service expected date May 2017).
- **Yah-Ta-Hey Transformer Addition** – mitigates overloads and improves voltage performance in western New Mexico (in-service expected date Fall 2017).
- **Guadalupe Static Var Compensator (SVC)** – provides voltage support that will enable the full utilization of the B-A to Blackwater transmission line for point to point transmission service (in-service expected date March 2018).
- **Cabezon Switching Station** – new switching station in Sandoval County in association with the interconnection of Tri-State new 345/115-kV Torreon substation to the Cabezon Station on PNM's San Juan-to-Rio Puerco 345-kV transmission line (in-service expected date April 2018).

Potential New Transmission Projects

PNM characterized potential new transmission projects associated with new generation, or for possible energy purchases for analysis in this IRP. The next few sections describe these resources.

New Generation in Southern New Mexico

PNM considered an 80 MW new generation resource to be developed in southern New Mexico. Associated with this potential resource is the need for additional third-party firm point-to-point transmission service from Tucson Electric Power (TEP) to be able to transmit the power to PNM’s central and northern load centers. Based on TEP’s current FERC-accepted transmission tariff rates, the expected transmission cost for 80 MW plant, including ancillary services, are approximately $2.6 million per year. Additionally, the expected interconnection costs for the 80 MW Plant connecting to the 345 kV transmission system in southern New Mexico is $12 million, assuming a new three breaker 345 kV station connected to a PNM transmission line.

New Generation Near Belen, New Mexico

PNM also considered a new 80 MW plant sited near Belen, New Mexico. The existing transmission system from the Belen area to Albuquerque is at or near its maximum transfer capability due to existing and planned resources in this area. To accommodate a second La Luz unit, a high capacity transformer would replace the Tome 115/46 kV transformer and the line termination switches on the Person-Tome 115 kV line would need to be replaced. One of the two units of the 80 MW plant could be interconnected using the existing La Luz Energy Center facility site interconnection point; leaving only the need to interconnect 40 MW of new generation at Belen. The 40 MW incremental generation will require the following transmission upgrades.

- Convert the Person-Belen 46 kV line to operate at 115 kV, including: the 46kV rated equipment at Louden Hills and Bosque Farms distribution stations; expand the Person and Tome 115 kV stations;
- Re-conductor the Person-Prosper 115 kV line to higher rating; and
- Re-conductor the Prosper- KAFB 115 kV line to higher rating.

The cost of these transmission upgrades would be approximately $20.3 million, with an expected interconnect cost to connect to the Belen 115 kV switching station, of $1 million.

New Generation at SJGS Station

A new 80 MW generating plant at the San Juan switching station requires an expansion of the switching station to add a new bay position and all interconnection equipment. In addition, a west bus sectionalizing 345 kV circuit breaker will need to be installed to split the bus to accommodate the long outage construction time for the new bay position. The expected cost of these transmission upgrades is $4.6 million

Potential New Transmission Projects

PNM characterized potential new transmission projects associated with new generation, or for possible energy purchases for analysis in this IRP. The next few sections describe these resources. To build transmission, one must have a very long-term view. Transmission is a classic victim of “not in my back yard” sentiments and transmission is particularly challenging to site given the amount of public and Native American lands in New Mexico.

Merchant Transmission in New Mexico

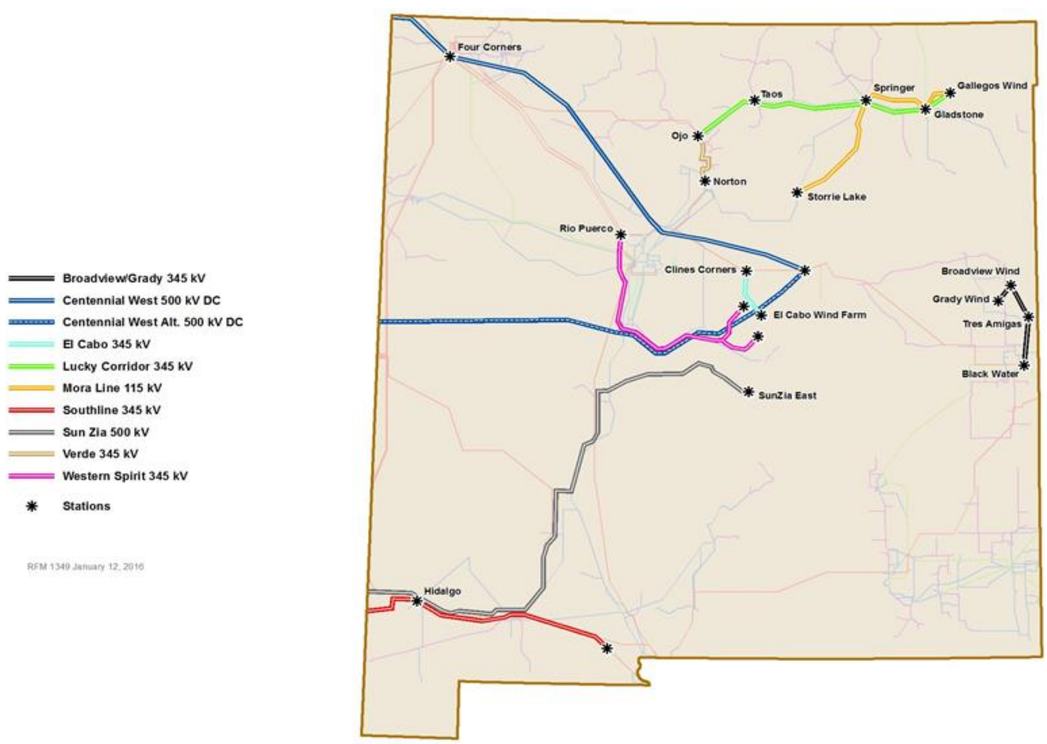
Transmission development, particularly high voltage transmission, is the focus of a number of policy initiatives at the federal and regional. Significant transmission is needed throughout the country if the highest quality renewable energy potential is to be developed and transported and also to support the basic reliability needs of the nation. To meet this need, FERC has developed rules and incentives to enable merchant transmission; and, as a result there are a number of merchant transmission project proposed in New Mexico as shown in the map below. Some of these merchant projects could take 10 or more years to complete and several of these are projected to cost $1 billion or more.

PNM is required, per FERC policy, to provide transmission interconnection service on a non-discriminatory basis to any eligible customer that submits the requisite application and information. Once a valid application for transmission interconnection is submitted, the procedures provide for a study process that determines the most appropriate facilities necessary to interconnect the proposed transmission project to the transmission grid. The study process also determines the impacts to the transmission grid caused by the proposed interconnection and any transmission system reinforcements needed to remedy such impacts, if required.

PNM has completed technical studies and executed a Standard Transmission Construction and Interconnection Agreement in July 2012, which incorporates the requirements for interconnection of the Tres Amigas 345 kV line (Western Interconnect) to PNM’s Blackwater station. The Tres Amigas interconnection to PNM's Blackwater Station was completed in January 2017 to inject power from the Broadview windfarm. The El Cabo 345 kV transmission line interconnection is being developed by Avangrid for their El Cabo wind farm (298 MW) that will interconnect to PNM's EIP line near Clines Corners by April 2017 as part of a large generation interconnection agreement.

PNM is in process of completing the technical studies for the Mora 115 kV line, Western Spirt 345 kV line and Verde 345 kV line transmission interconnection projects. Figure 23 shows the proposed location of each of these lines.

Figure 23. Potential New Merchant Transmission



The Mora 115 kV line is proposed by Lucky Corridor, LLC and will interconnect with PNM's and Tri-State Generation and Transmission Cooperative's 115 kV systems in northern New Mexico. The project would serve to connect approximately 160 MW of renewable resources in north eastern New Mexico. The project would potentially support delivery of additional renewable resources to the Four Corners area or load in north eastern New Mexico.

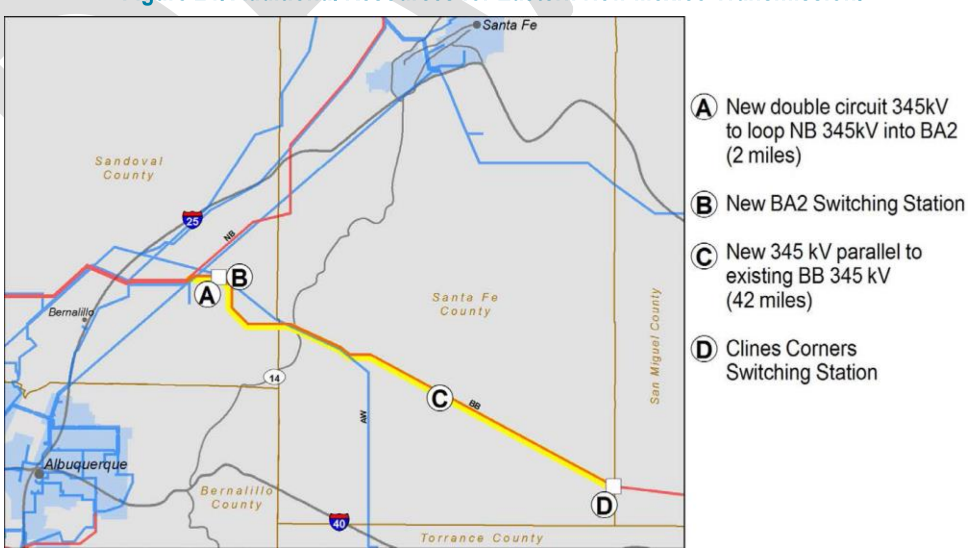
Development of the Western Spirit project is being pursued by Clean Line Energy Partners. The project consists of an approximately 140 mile 345 kV line that could deliver up to 1000 MW of renewable energy resources from east central New Mexico to PNM's Rio Puerco switching station. The project would enhance the ability to deliver additional renewable resources to loads in northern New Mexico or for export to the Four Corners area and out-of-state markets.

The Verde transmission line, proposed by Hunt Power, connects the Ojo 345 kV switching station to the Norton 345 kV switching station through an approximately 30 mile 345 kV line. The project would increase the ability to import power into Northern New Mexico from the Four Corners area by completing a third full 345 kV path into the Albuquerque metropolitan area. Along with other system improvements, the Verde project would be expected to accommodate the import of between 400 to 650 MW of additional resources located at San Juan, Four Corners or in Arizona. The project also has the potential to support exports of wind generation to the Four Corners area from eastern New Mexico if additional delivery capability into the existing transmission system around Albuquerque is developed.

Eastern New Mexico Transmission

The New Mexico wind resources are concentrated in the eastern portion of the state. The existing and development of wind farms in the area will result in 1000 MW of transmission service obligations on the EIP line. Any additional transmission service commitments will require that additional transmission line(s) and station(s) be developed. There is presently a desire for additional firm transmission capacity from eastern New Mexico to accommodate renewable energy development by wind merchant developers. Additional transmission capacity above 1000 MW can be achieved by building a parallel transmission line, 345 kV circuit, between the Clines Corners 345 kV station and a new 345 kV station east of the existing BA station (looping in the existing BB line and the BA-Norton line). Building these facilities will result in additional 300 to 400 MW of firm capacity from the Clines Corners area. Figure 24 illustrates the additional resources considered.

Figure 24. Additional Resources for Eastern New Mexico Transmission.

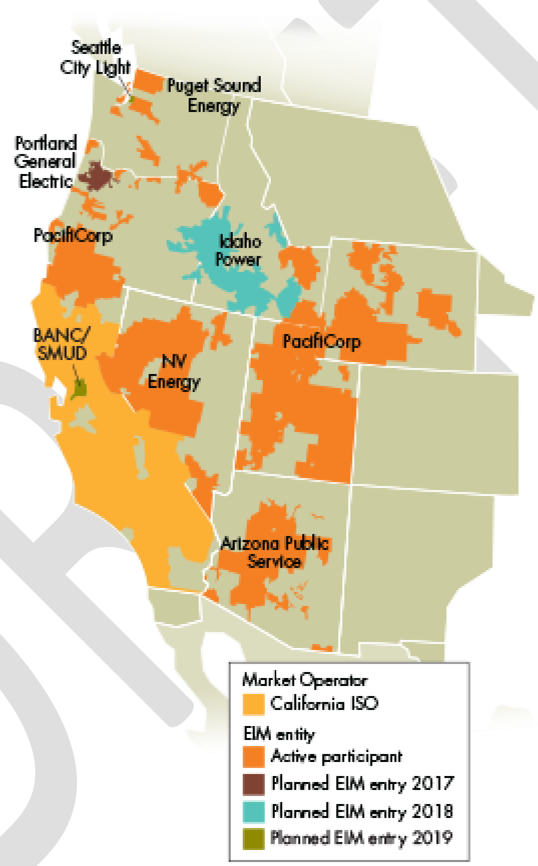


Potential New Electric Market Interactions

CAISO Energy Imbalance Market

CAISO launched the western Energy Imbalance Market ("EIM") on Nov. 1, 2014 with its first utility participant, Oregon-based PacifiCorp. EIM was later joined by Las Vegas-based NV Energy on Dec. 1, 2015, Puget Sound Energy of Bellevue, Washington, and Arizona Public Service of Phoenix, Arizona, on Oct. 1, 2016. This voluntary market service is available to other utilities in the West. Portland General Electric and Idaho Power each announced they will be EIM participants. Figure 25 illustrates the utilities currently in and committed to join the EIM.

Figure 25. EIM Participants



The EIM aggregates the variability of electricity generation and load for multiple balancing authority areas and utility territories and performs a 5-minute security constrained economic dispatch. In addition, an EIM facilitates greater integration of renewable resources through the aggregation of flexible resources from neighboring states, capturing the associated diversity benefits from the expanded geographic footprint and the expanded potential use for those resources.

The EIM market rules require each BA area to maintain enough generation capacity to meet load, ramping and reserve requirements and prohibits leaning on the market for capacity. EIM allows the BA to use lower-cost third-party generation when sufficient real-time transmission is available to replace higher-cost generation resources.

Table 28 shows the startup and ongoing cost for PacifiCorp, Nevada Energy, Arizona Public Service, and Puget Sound Energy. The utilities that have joined the EIM so far have had a favorable outcome with respect to payback time of the initial investment. Nevada Energy and Arizona Public Service currently have staff of 10 and 14 FTEs, respectively to administer EIM (e.g. real-time desk, resource scheduling, outage tracking, energy accounting).

Table 28. EIM Startup and Ongoing Costs and Projected Benefits

Utility	Start	Estimated Customers	Estimated Generation Capacity (MW)	Startup Costs	Ongoing Costs	Gross Benefit Estimate (Company Only)
PacifiCorp	1/1/2014	1,700,000	10,600	$3M - $6M	$2M - $5M	$21M - $129M 2017 in 2012$
Nevada Energy	1/1/2015	1,200,000	6,100	$11M	$2.6M	$9M - $18M 2017 in 2013$ and $15M - $29M 2022 in 2013$
Arizona Public Service	10/1/2016	1,200,000	9,000	$13M- $19M revised to $23.5M	$4M	$7M-$18M 2020 in 2014$
Puget Sound Energy	10/1/2016	1,100,000	3,000	$14.2M	$3.5M	$18.3M-$20.1M 2020 in 2014$
PacifiCorp	1/1/2014	1,700,000	10,600	$3M - $6M	$2M - $5M	$21M - $129M 2017 in 2012$
Nevada Energy	1/1/2015	1,200,000	6,100	$11M	$2.6M	$9M - $18M 2017 in 2013$ and $15M - $29M 2022 in 2013$
Arizona Public Service	10/1/2016	1,200,000	9,000	$13M- $19M revised to $23.5M	$4M	$7M-$18M 2020 in 2014$
Puget Sound Energy	10/1/2016	1,100,000	3,000	$14.2M	$3.5M	$18.3M-$20.1M 2020 in 2014$

PNM plans to contract with a consulting firm to perform a study to evaluate the costs and benefits of PNM participating in the EIM. The study will evaluate EIM benefits to PNM based on a set of study scenarios, including loads, resources, and potential transmission constraints for access to markets for real-time transactions.

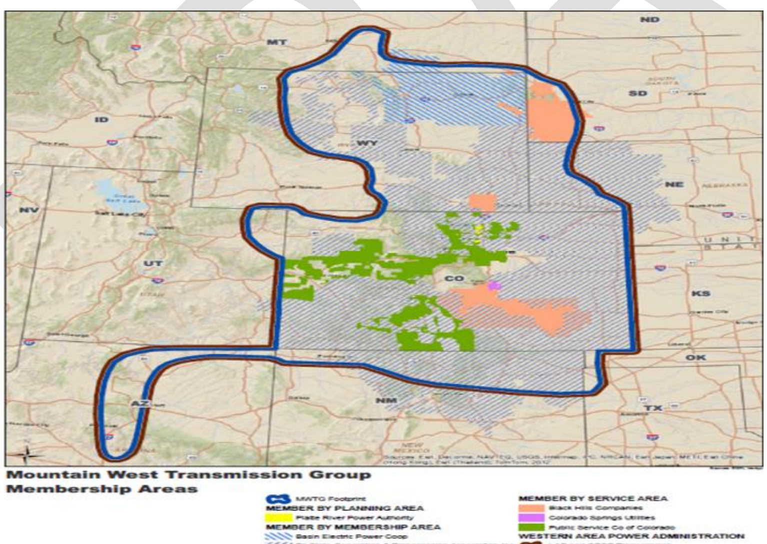
Mountain West Transmission Group

An effort to create an organized electricity market is taking shape in the inland West even as CAISO continues to build the case for expanding its operations into the wider region. A number of other Colorado utilities have become more involved in the development of the Mountain West Transmission Group ("MWTG"). The MWTG is analyzing the possibility of developing a single transmission tariff and provider throughout Colorado and the WAPA system in Arizona. All the parties in the following list would potentially be a network customer of MWTG.

- Public Service Company of Colorado (PSCo)
- Western Area Power Administration (WAPA)
- Tri-State
- Basin Electric
- Black Hills Corp
- Platte River Power Authority
- Colorado Springs Utilities

As shown in Figure 26, the group's footprint covers most of Colorado and Wyoming, along with smaller areas of Arizona, Montana, New Mexico and Utah.

Figure 26. Footprint of Proposed Mountain West Transmission Group



The MWTG issued a request for information (RFI) from Reginal Transmission Organizations (RTOs) to CAISO, SPP, Mid-Continent Independent System Operator (MISO), PJM Interconnection (PJM) to provide tariff administration services and market operator services. MWTG is also performing a market study to assess organized market benefits.

Potential New Electric Market Interactions

PNM regularly conducts wholesale power transactions to help balance electric supply and demand and to help keep fuel costs low. The transactions are between PNM and other utilities and market participants in the WECC, and serve to increase the overall efficiency and cost-effectiveness of the entire electric grid. For example, PNM may purchase energy to meet a shortfall in total available generation for the next hour at a lower cost than starting one of its own gas-fired peaking units. Or, if PNM has extra capacity for the next hour and other market participants are offering to purchase at prices that are higher than the incremental costs of generating the additional energy, PNM will sell its excess. The lower-cost purchased energy and the revenues from sales are credited to PNM's customers via the fuel clause.

Power is frequently traded at locations that multiple entities have transmission and generation such as the Palo Verde or Four Corners hub. Power for future delivery can be bought or sold in multiple time frames, but can generally be categorized as "month(s)-ahead," "day(s)-ahead," and "hour(s)-ahead." Intra-hour transactions are typically not available to PNM, so PNM must utilize its own generation to regulate for unpredicted changes in renewable generation or load within the hour. Month-ahead and day-ahead transactions are generally traded in a quantity of power for certain blocks of hours called "on-peak" and "off-peak."

PNM's opportunities to buy and sell power have declined over the past few years because of various reasons such as the baseline unit retirement in the region, entry into the California EIM by certain entities, more stringent electricity and gas scheduling requirements, FERC rules requiring designation and un-designation of resources, scheduling and tagging constraints, and transmission availability/costs from trading hubs that have more participants. The decline in available market liquidity requires PNM to rely on its own resources to balance supply and demand more often in the future than in the past.

Evolving Regional Power Markets

The California Independent System Operator (CAISO) has developed an Energy Imbalance Market (EIM) to help California solve some of the issues caused by the increasing amounts of variable energy resources. CAISO's Energy Management System (EMS) receives real-time operational data from participants and produces dispatch simulations to optimize near-term future electricity supplies to meet demands over the EIM footprint while accounting for transmission and other system limitations. Dispatch instructions are sent to the BAs for participating resources and the BAs are expected to dispatch their generation to comply with the instructions from CAISO or otherwise face penalties.

Participation in the EIM is open to BAs in the WECC meeting specific requirements. To participate, PNM would be required to upgrade certain meters and other hardware to comply with data accuracy and reporting requirements in addition to upgrading its software to be able to manage the additional complexity of operating in an EIM environment. Additional accounting and operations personnel would likely be needed as well. In return, PNM could save energy costs by sharing in the higher operational efficiency of the EIM and reducing regulating requirements for its own variable energy resources. PNM plans to study the costs and benefits of joining the EIM in the future.

The Mountain West Transmission Group is currently evaluating different options for its members that include forming their own Regional Transmission Organization (RTO). Although PNM is not a member of Mountain West, other nearby utilities are and, therefore, availability and/or costs of power at the Four Corners hub could be impacted.

ANALYSIS TECHNIQUES

ANALYSIS TECHNIQUES

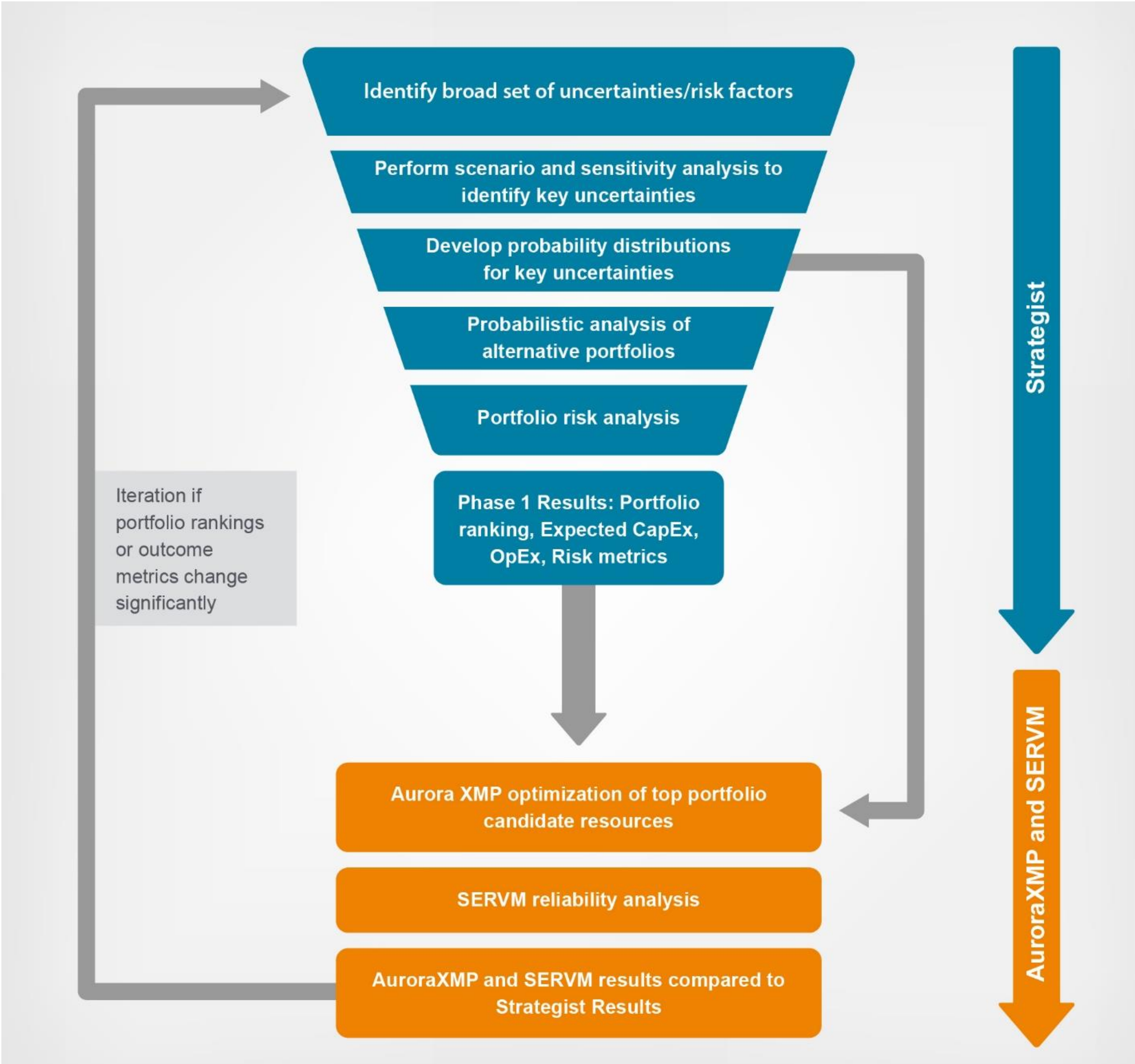
The analytical goals of the IRP are to develop an MCEP and a four-year action plan to pursue the MCEP, along with the other beneficial strategies identified. The IRP Rule defines MCEP as “those supply-side resources and demand-side resources that minimize the net present value of revenue requirements proposed by the utility to meet electric system demand during the planning period consistent with reliability and risk considerations.”

In addition, the MCEP must comply with all legal and regulatory requirements including energy efficiency and demand response program requirements, the RPS and renewable resource diversity requirements, Reasonable Cost Threshold impacts, environmental regulations, transmission system operational requirements, and industry system reliability and operating reserve requirements.

Consistent with IRP best practices, PNM uses several analysis techniques to understand opportunities and risks associated with future uncertainty. The approach combines scenario, sensitivity, and probabilistic analyses to estimate expected portfolio performance and costs, and the associated risks. Scenarios are a set of assumptions defining an overall outlook of the forecast period. In the sensitivity analysis, PNM examines changes to the values of one or more of the assumption input factors within a scenario. For the probability assessment, PNM looks at the impact of simultaneous variation in select input factor values.

This work requires evaluating hundreds of thousands of combinations of demand and supply options in simulations of the complex electric supply grid. Figure 27 describes the process PNM followed to analyze potential resource plans.

Figure 27. Analysis Process

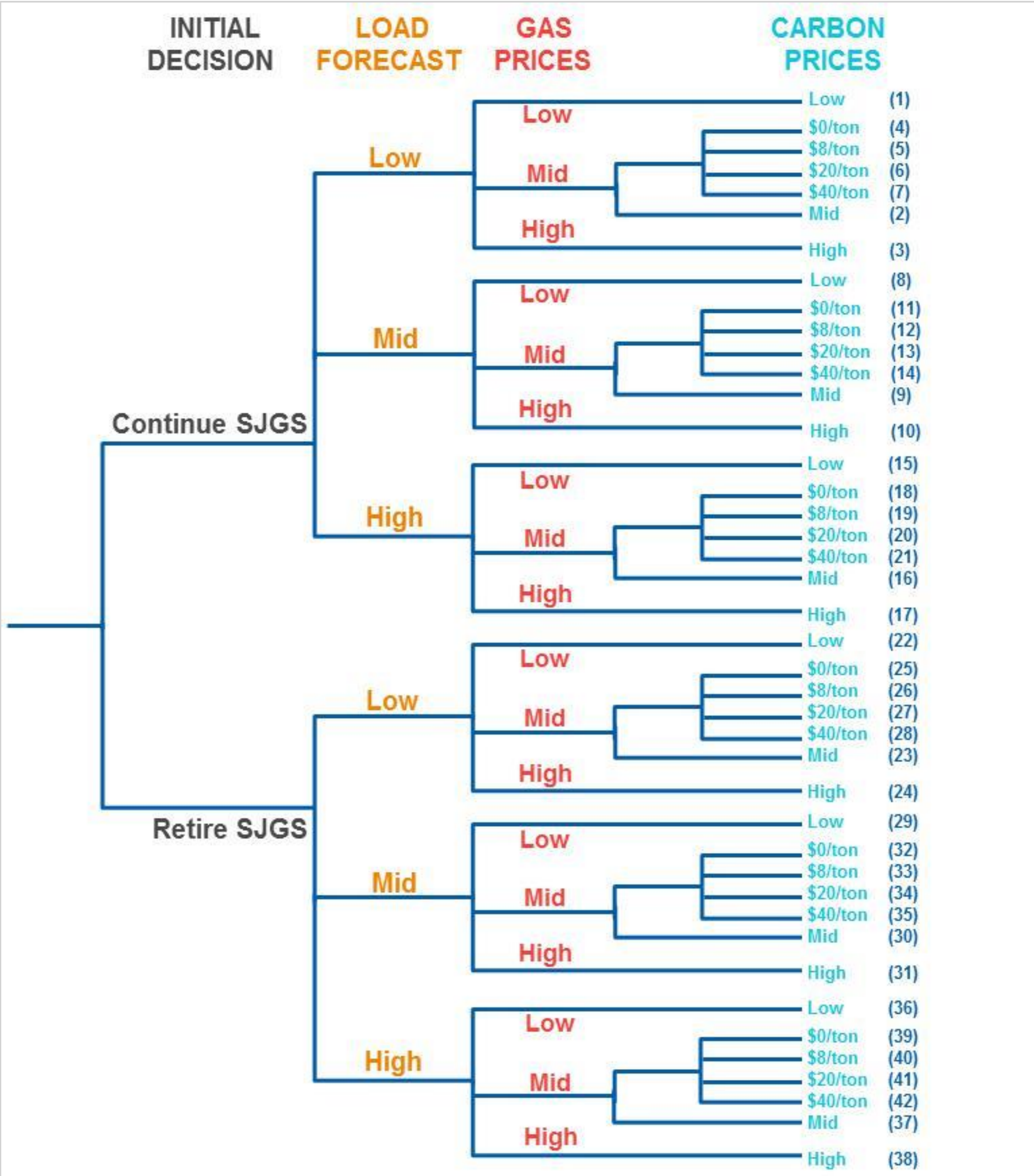


Scenarios

A scenario is an assumed series of events that could affect the selection of the best supply and demand options that PNM should pursue for the MCEP. PNM agreed to develop MCEPs for two primary scenarios in this IRP: a scenario that assumes SJGS will continue operations after 2022, and a scenario that assumes SJGS will not operate after 2022 (soon after SJGS's current coal supply agreement expires). In addition to these SJGS scenarios, PNM defined other scenarios to fully understand the opportunities and risks associated with either SJGS future.

Historically, the assumption with the largest impact on resource portfolio development is the forecasted load. Electric load grows in unpredictable ways and is tied to economic growth in the service territory and changes in electricity use per customer. Additionally, assumptions about future natural gas prices can vary widely and, thus, are used to define scenarios. The historical price volatility and natural gas' prominent role in setting electric prices by fueling the marginal resource that ramps up or down with varying loads at each hour of the day, cause natural gas price assumptions to be an important driver of resource plan decisions. Best practices also dictate that future costs associated with carbon emissions must be considered. Since fossil fuel generation is a significant contributor to the electric supply mix, and anticipated, uncertain future regulation of carbon emissions associated with electricity generation is expected to impact costs, future assumptions for carbon costs are considered in the scenarios. PNM has developed 21 scenarios for each of the two primary scenarios around SJGS, for a total of 42 scenarios analyzed in this IRP. These scenarios are identified and numbered sequentially in Figure 28.

Figure 28. IRP Scenarios



SJGS Scenario Assumptions

Constructing the two primary scenarios required building assumptions around the cost and operation of SJGS before and after 2022. Table 29 summarizes the assumptions used for each of the two primary scenarios. As noted in Figure 28, scenarios where SJGS continues numbered 1-21 while SJGS retirement scenarios are numbered 22-42.

Table 29. SJGS Scenario Assumptions

Assumption	SJGS Continues	SJGS Retires in 2022
Co-owners	PNM and the other owners will maintain existing ownership shares in Units 1 and 4	The existing operation agreements will define cost allocations for mine reclamation and plant decommissioning
Coal Supply	Existing reserves provide sufficient coal for a new supply agreement through at least 2036	PNM will continue to operate through the 2022 summer peak by managing coal inventory obtained through the current supply contract that terminates on June 30, 2022
Coal Price	Future coal-cost sensitivity developed by assumed costs to operate the existing underground mine	Projection of price from the existing coal supply agreement, assuming inventory management to run thorough 2022 summer peak
Ongoing Maintenance	Maintenance cycles and costs are projected based on current budgets for both units	In anticipation of shutdown in 2022, plant management reduces maintenance costs beginning in 2018
Asset Recovery	Plant balances will depreciate through 2053	A regulatory asset for unrecovered costs, including return on and return of rate base, will be created and collected over a 20-year period beginning upon retirement

These assumptions were used to create the projected annual costs for operation, maintenance, and fuel cost for the plant under both scenarios.

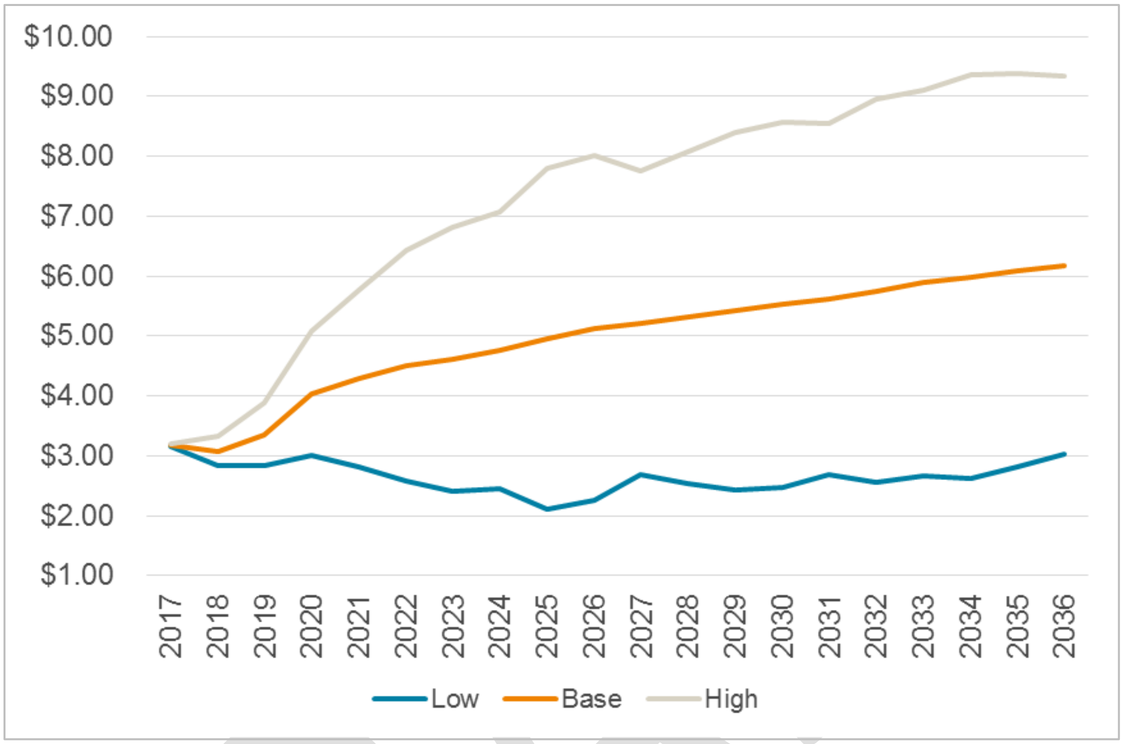
Load Forecast Scenario Assumptions

The load forecast section of this report provides a detailed explanation of the development of assumptions for three load scenarios for this IRP. As shown in Figure 28, low load forecasts are Scenarios 1-7 and 22-29; mid load scenarios are numbered 8-15 and 30-37, and high load scenarios are numbered 16-21 and 38-42.

Natural Gas and CO2 Scenario Assumptions

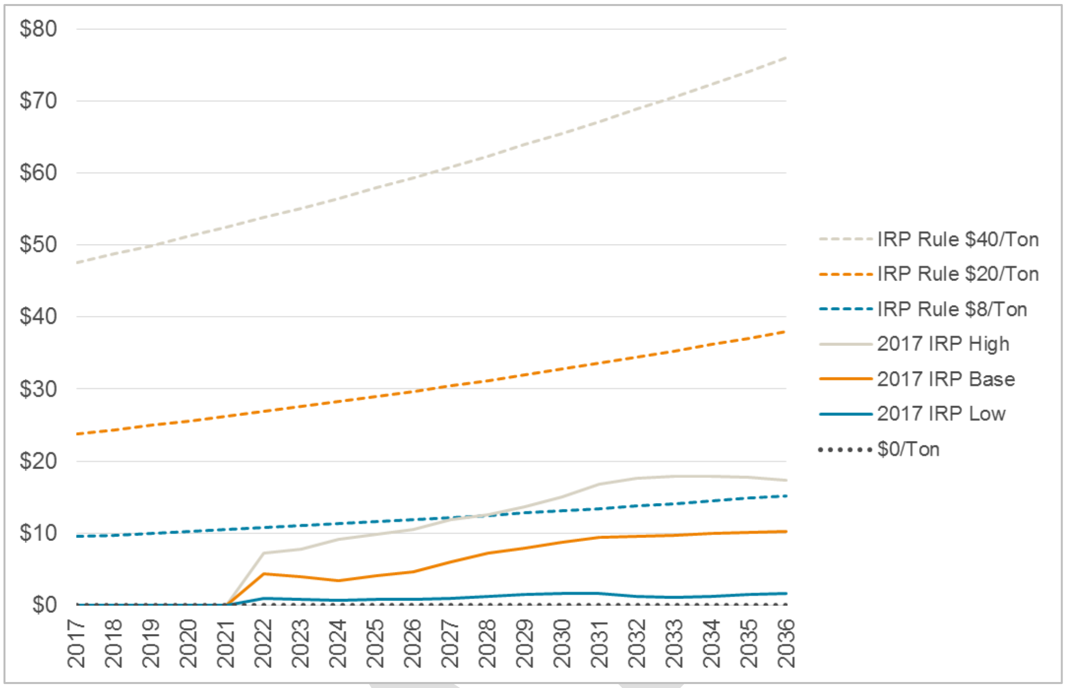
PNM contracted with a nationally known energy consulting service, PACE Global (PACE), to provide a coordinated set of price curves for natural gas fuel and CO_2 emissions for the scenario definitions. PACE created the scenario prices in August 2016 using global natural gas supply and demand, electric supply, and carbon pricing models it had developed to advise previous clients. PACE provided a baseline scenario that assumed a business-as-usual perspective in the short term, followed by an assumption that most states would comply with the stayed Clean Power Plan using a mass-based emission standard and interstate trading of allowances. The baseline also assumed that gas and electricity supply and demand would balance over the long term, in line with existing trends. High- and low-gas and carbon scenarios were created using statistical techniques to estimate future CO_2 and gas price ranges. Appendix I provides details of this work. Figure 29 shows natural gas prices in the three scenarios. As shown in Figure 28, low gas price scenarios are numbered 1,8,15,22,29,and 36; mid gas price scenarios are numbered 2-6, 9-13, 16-20, 23-27, 30-34, and 37-41; and high gas price scenarios are numbered 7,14,21, 28, 35, and 42.

Figure 29. New Mexico Natural Gas Price ($/mmbtu) Sensitivities



In addition to the above scenarios, PNM built scenarios using CO_2 price assumptions that were used in its previous IRPs. The final order in NMPRC Case No. 06-00448-UT requires regulated utilities to provide portfolio cost estimates using CO_2 emission prices of $8 (Scenarios 3,10, 17, 24, 31, and 38), $20 (Scenarios 4, 11, 18, 25, 32, and 39), and $40 (Scenarios 4, 11, 18, 25, 32, and 39) per metric ton (starting price in 2010 dollars, escalating at 2.5% per annum). Also, in response to public advisory comments in previous IRPs, and in recognition of the current uncertainty surrounding future carbon emission regulation, PNM created scenarios (2, 9, 16, 23, 30, and 37) that assumed no additional costs would be associated with CO_2 emissions before 2036. Figure 30 illustrates the seven CO_2 prices PNM used for scenario definitions in this IRP.

Figure 30. CO_2 Price Scenarios



Sensitivity Analysis

Resource options or other assumptions can affect the cost and reliability expectation for portfolios within each scenario. PNM tested the impact of the each of the individual assumptions described in the following sections on the mid-load, mid-gas price, and mid-carbon scenarios for both SJGS scenarios unless otherwise noted.

Four Corners Power Plant (FCPP) 2031 Retirement

Currently, the FCPP has a coal supply agreement that will provide fuel through 2031 and a site lease that runs through 2041. The base scenarios assume the plant would operate through the end of the existing site lease and assumed that the fuel supply agreement would be extended beyond 2031, past the end of the 2036 planning period. To test the impact of a retirement at FCPP at the end of the fuel supply agreement, PNM analyzed the plan with and without a retirement at FCPP. PNM is currently depreciating Four Corners through 2041, so a 2031 retirement analysis includes the assumption that PNM will recover the return on and return of any undepreciated asset value, beginning at plant retirement.

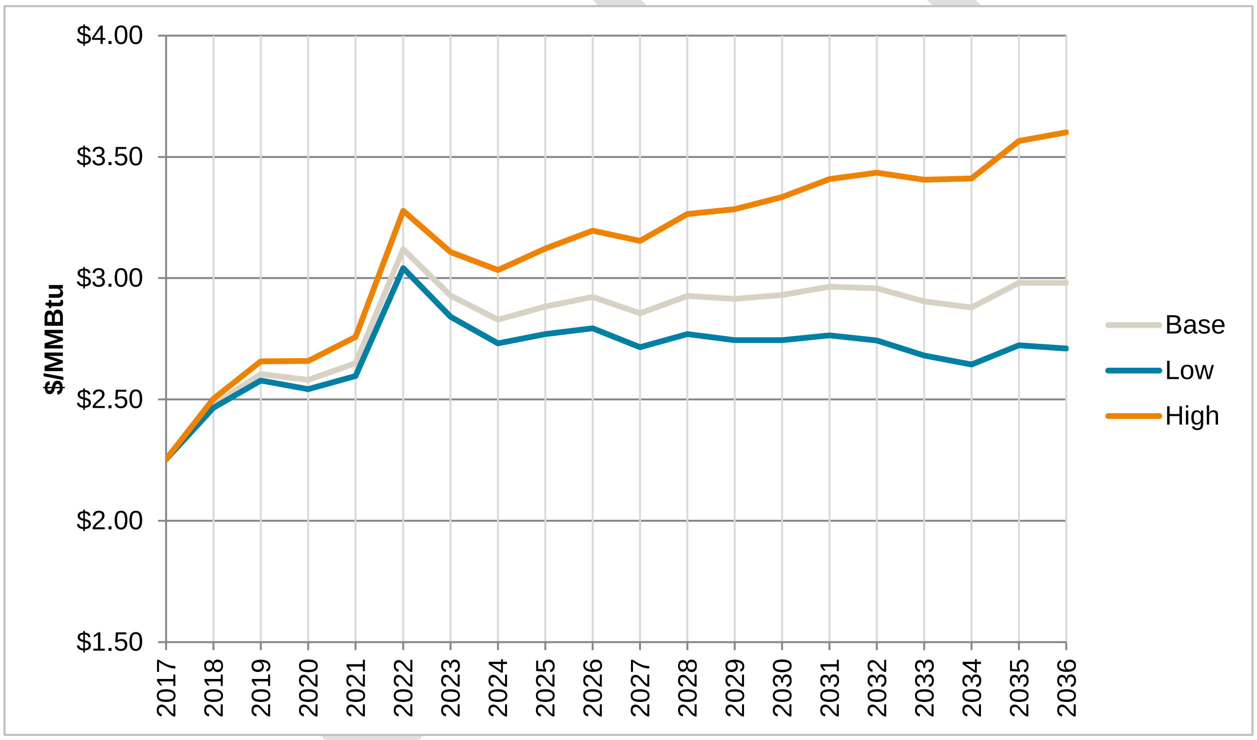
PVNGS-Leased Capacity

PNM conducted sensitivity analysis around whether or not the PVNGS-leased capacity of 104 MW currently projected to expire in 2023 and 10 MW currently projected to expire in 2024 is renewed for future years. PNM also examined the reliability impact, the cost variability impacts, and the carbon emission impact of retaining the currently leased capacity. PNM has been investing in leasehold improvements since the plant was built. Whether or not PVNGS-leased capacity is renewed, the costs for PNM to fully recover the costs and return on investment associated with leasehold improvements are included in the plan costs. The cost to secure the leased capacity for long-term use is unknown. If PNM does not use the energy and capacity from the PVNGS leases, the impacts on the portfolios for each scenario also include risks of increased CO_2 emissions, additional natural gas price risk, and the need to pursue resource options to replace the capacity. These risks are discussed in more detail in the Monte Carlo analysis section of this report.

SJGS Coal Prices

PNM estimated coal costs for SJGS for each of the two primary scenarios. Plant management will not determine final coal pricing for 2023 and beyond until July 2018. PNM performed sensitivity analysis using the range of potential coal costs for SJGS to assess the impact of coal prices on the two SJGS scenarios. Coal prices also affect the Retire SJGS scenario due to the impacts of the remaining coal inventory. Figure 31 illustrates the range used for SJGS coal costs.

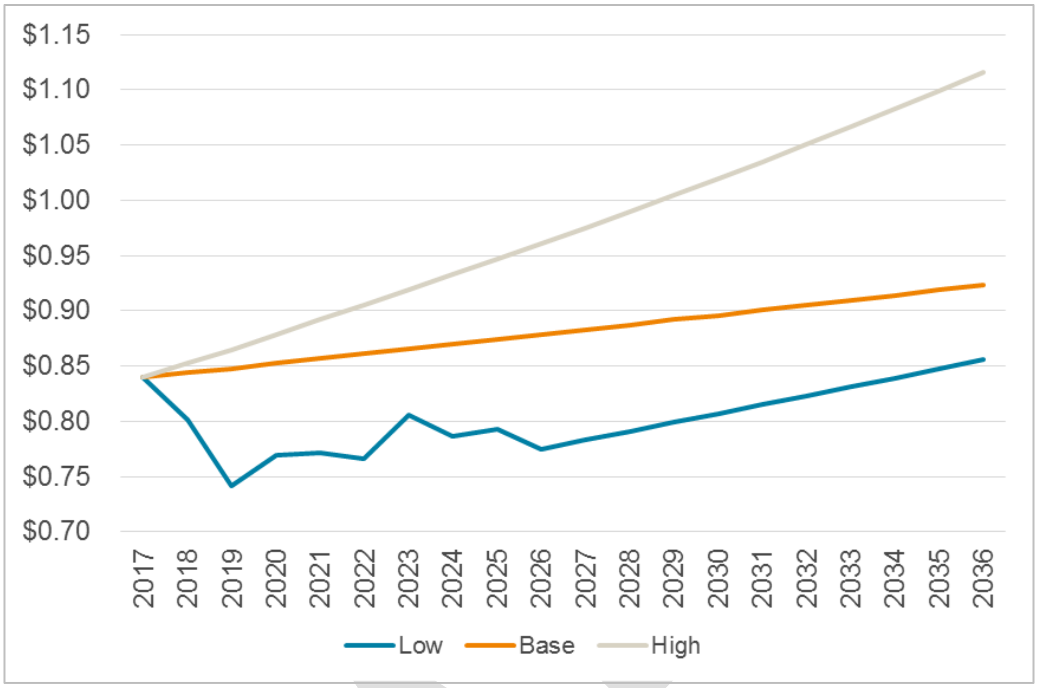
Figure 31. SJGS Coal Price ($/mmbtu) Sensitivities



PVNGS O&M and Fuel Price Range

PVNGS is a significant supply resource in PNM's portfolio. PNM tested the impact of retaining the existing leased capacity on its resource portfolio. In the mid-load scenarios, PNM tested the impact of a range of operations and maintenance costs and nuclear fuel prices as shown in Figure 32.

Figure 32. PVNGS Nuclear Fuel Price ($/mmbtu) Sensitivities (Revising the Graph)



Impact of Energy Efficiency and Demand Response Programs

PNM assumes it will fully spend up to the limit of 3% of revenues on energy efficiency and demand management programs in future years, as required by the EUEA. Sensitivity analysis was conducted to assess the impacts of continuing to implement demand and energy savings associated with the 3% spending level. To perform the sensitivity, PNM removed the incremental demand and energy savings that will be created by future programs to identify the future benefits in terms of overall cost savings and deferring the need to build new generation capacity. Figure 33 and Figure 34 illustrate the incremental and cumulative demand and energy expected from PNM's energy efficiency programs.

Figure 33. Incremental Cumulative Energy Efficiency Forecast – Demand (MW)

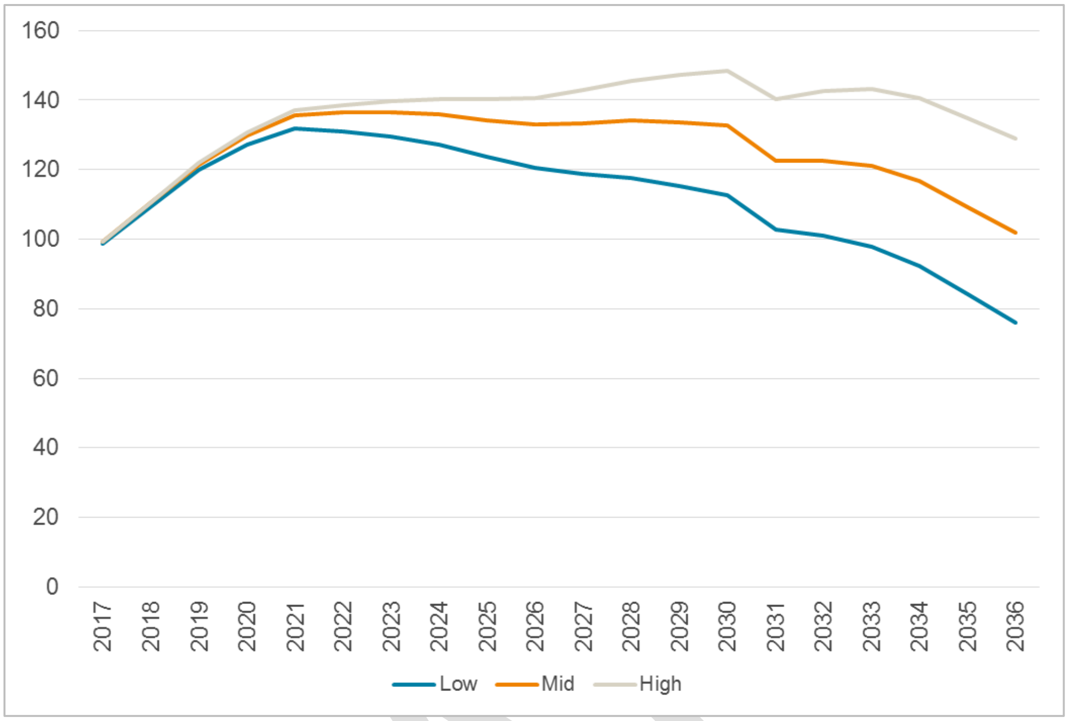
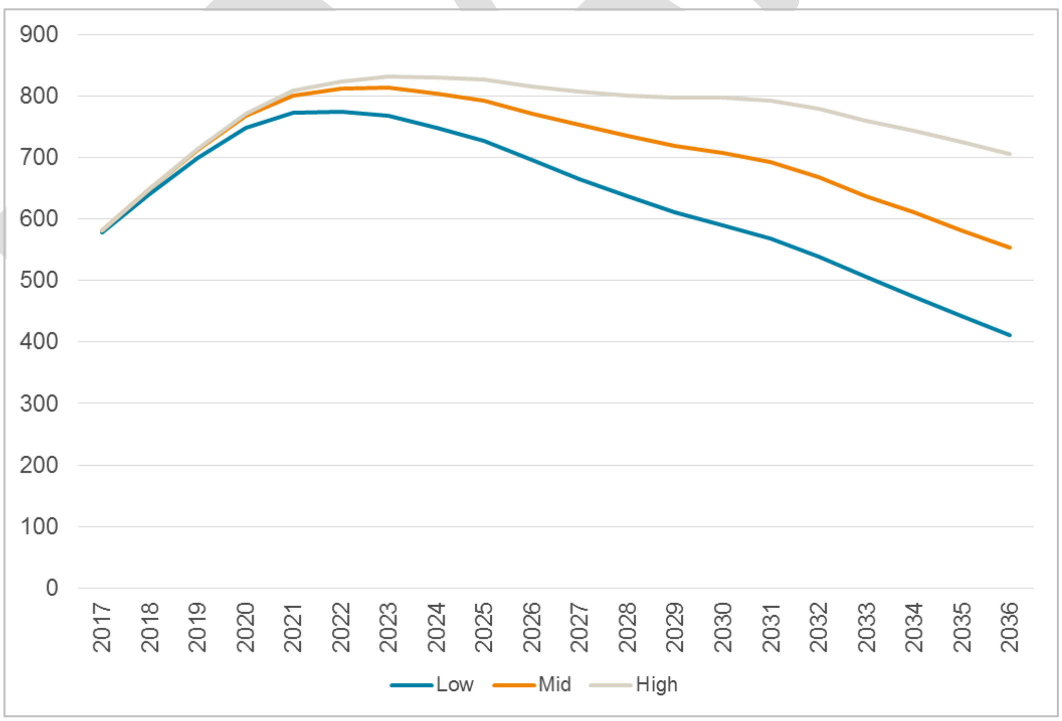


Figure 34. Incremental Cumulative Energy Efficiency Forecast – Energy (GWh)



Natural Gas Type, Size and Price

In the supply option resource database, sizes and prices for a range of natural gas combined cycle plants and reciprocating engine installations were assumed. As of today, PNM does not know what combined cycle options or reciprocating engine options may be provided by the bidders in the request for proposals that will be issued after this IRP. To better characterize the risks and opportunities associated with additional natural gas capacity with lower heat rates than provided by combustion turbines in PNM's resource portfolio, PNM tested a range of purchase prices for natural gas capacity.

Solar Sensitivity

Solar resources were identified as significant resource additions in PNM's 2014 IRP. Going forward, and particularly in the SJGS retirement scenarios, PNM expects a significant expansion of solar resources. Future solar costs are dependent upon tax credits and equipment pricing. Also, to date PNM has successfully pursued a strategy of adding universal solar in roughly 10 MW increments and interconnected these resources at distribution level, saving money by avoiding interconnection at the transmission level. As the inventory of sites where solar can be interconnected to the distribution system is filled, PNM may need to pursue solar facilities in larger increments, requiring interconnection at the transmission level and higher costs. Finally, the value of solar to the resource portfolio is a function of the solar availability relative to expected load at the time of solar availability. PNM examined the portfolio costs in a sensitivity analysis to see if additional capacity is needed to meet net loads late in the day or after sundown. Like the wind sensitivity presented in the 2014 IRP, PNM conducted a robust solar sensitivity to understand how future solar additions affect the least-cost portfolios.

Wind Sensitivity

Similar to solar resources, wind costs are dependent upon tax credits and equipment pricing. Wind resources are also sensitive to location (for available wind), and the portfolio impact is affected by the location diversity. PNM conducted a wind resource sensitivity to characterize the risks and opportunities associated with adding wind resources to:

- Evaluate a range of pricing for new wind resources
- Evaluate a range of capacity factors for new wind resources
- Evaluate a range of facility sizes for new wind resources
- Ascertain the value of building new transmission resources to access wind supplies that are geographically diverse compared to PNM's existing wind resources

Renewable Energy Integration Costs

Adding variable types of energy resources (such as wind and solar) requires system flexibility to respond when supply changes quickly or unexpectedly. This takes the form of more frequent starts or ramps at the natural gas generators or operating the natural gas generators at less than full output that is usually associated with higher-heat rates. The least-cost portfolio construction analysis is conducted based on average output characteristics of the resource portfolio. Integration costs are included in the analysis based on study work performed by Astrape Consulting for the Renewable Integration Study (RIS). In this IRP, PNM used the RIS results to estimate a proxy for integration costs of \$1.73/MWh (2018) for solar and from \$4.00/MWh (2018) for wind. PNM applied these costs to any new solar or wind resource that the model added to the resource plant to see if there were any changes to the MCEP when these costs were added.

Energy Storage Costs

Utility installation of energy storage resources has become more common. As utilization of these resources increases, the expectation is that costs will decrease as standardization and capabilities improve. Energy storage modeling assumptions were created from public information. To test the impact of a lower future cost on resource portfolios, PNM assumed a declining cost curve based on the historical solar resource price declining rate.

Small Modular Nuclear Reactors

Small modular nuclear reactors (SMR) are potential future resources that can offer a new source of carbon-free power, should they become commercially available. The benefits are similar to retaining the PVNGS-leased capacity. There are a few efforts underway to develop this resource, but the precise date of its availability and the future cost is unknown. PNM included an SMR as potential future resource options and tested the sensitivity to price in the scenarios that show significant additions of new energy supplies in the future.

High-Load Forecast Data Center Assumption

As described in the load forecast section, PNM used a range of assumptions for the existing data center in its three load forecast scenarios. To test the impact of adding another data center that is supplied by additional renewable resources which are earmarked to that customer, as often occurs with these types of customers, PNM performed a sensitivity in the high load scenarios of doubling the renewable energy assumed for the existing data center.

Monte Carlo Analysis

The IRP Rule calls for utilities to consider risk and uncertainty of resource options. PNM conducted scenario and sensitivity analysis to provide a framework for assessing cost impacts of different future assumptions. Real-world system conditions will vary from assumptions and variations of multiple assumptions may occur simultaneously. PNM considered this likelihood using stochastic financial risk analysis (stochastic analysis or risk analysis) to simultaneously vary multiple modeling assumptions and quantify the impact on the total cost of potential resource portfolios. Consistent with IRP best practices, PNM used a specific stochastic financial risk analysis technique known as Monte Carlo to estimate the range of financial risk associated with each portfolio with varying assumptions.

The Monte Carlo simulation uses randomly selected values from variable probability distributions to determine how random variation subject to probabilistic occurrence (stochastic outcomes) affects the cost of the portfolio being modeled. PNM conducted the Monte Carlo analysis using the following steps:

- **Step 1:** Identify the variables that should be included in the Monte Carlo analysis. This was accomplished by inspecting the tornado diagrams resulting from sensitivity analyses to identify those having significant impacts on the portfolio costs.
- **Step 2:** Determine the potential range of values for input variables (including load forecast, natural gas fuel prices, market prices for electricity, and CO_2 costs). Then define a probability distribution for each variable (i.e., the likelihood that each value in the range may occur).
- **Step 3:** Determine the correlation among input variables, if any (i.e., the change in one variable directly related to a change in another variable).
- **Step 4:** Generate a set of random input conditions, one value from each of the defined variables probability distribution reflecting any correlation among the variables, for each year of the study period.
- **Step 5:** Calculate the resource portfolio's total system cost for each selected set of randomly generated variable values using both the Strategist and AuroraXMP models to optimize dispatch of the selected portfolio of resources and then by running the model over 900 draws.
- **Step 6:** Aggregate the results of the random draws from Step 4 and calculate the average net present value (NPV) cost of all the simulations along with the cost of scenario at the 95th percentile of the 900 simulations (representing a 5% likelihood that actual costs are greater than this value).

Reliability Analysis

In addition to the financial risks, PNM evaluated portfolio combinations under various resource scenarios for performance against the reliability metrics of planning reserve margin and loss of load probability. Within the loss of load probability analysis, PNM evaluated whether the risk of loss of load was due to an overall capacity shortage or the need for quick response resources or operating reserves. PNM used this analysis to ensure the portfolio reliably meets demand.

MCEP Evaluation Process

To identify the MCEP for the period 2017 through 2036, PNM examined hundreds of thousands of potential resource portfolios that accounted for multiple scenarios and sensitivity studies of differing resources, economic conditions, carbon prices, and customer demands. Scenarios combining alternative futures for loads, natural gas prices and possible carbon taxes were considered to test the sensitivity of resource portfolio to alternative assumptions and conditions. PNM presented significant results from these studies to the Public Advisory Group during several meetings.

The first step to determine MCEPs is to estimate a least-cost portfolio for each scenario. Differences in the input assumptions between scenarios can result in a different system resource portfolio mix. For example, a high-gas price scenario will result in a recommended portfolio that has less reliance on gas-fired plants than the portfolio recommended for a low gas price scenario. Sensitivity analysis shows how robust the portfolio choices are within reasonable ranges of input assumptions. Monte Carlo analysis highlights the financial risk associated with a portfolio in an uncertain future. PNM compared the Monte Carlo results of the two portfolios under a range of energy demand, gas prices and carbon prices to identify risk mitigation strategies and confirm the importance of individual resource types within the MCEP.

Computational Resources

Several computational resources are required to work through the process of creating least-cost portfolios for each scenario, test sensitivities, and calculate Monte Carlo results and loss of load probabilities. This section describes the resources PNM used for this work.

Supplemental Models and Data Assembly Tools

PNM used a variety of sources to create input values for each of the models described below. These included PNM's budgeting system, revenue requirements models, load forecasting models and other data systems. These range from Excel spreadsheets to complex database analysis programming systems. Each of the two SJGS scenarios required input assumptions for the costs to operate and maintain existing resources and the costs to acquire, operate, and maintain any new resource option. For resource retirement scenarios and sensitivities, this also requires calculating future asset values and value recovery costs in the spreadsheets.

Strategist Model

PNM licenses a commonly used capacity expansion model called Strategist from ABB to estimate least-cost resource portfolios. Strategist is a comprehensive, long-range resource planning tool for electric utilities. PNM used this tool for least-cost portfolio estimations for all scenarios, sensitivities, and Monte Carlo calculations.

The Strategist model utilizes a proprietary, dynamic programming algorithm to conduct a rigorous evaluation of up to 5,000 unique resource portfolios and selects and ranks the resource portfolios based on various user-specified criteria. It can model a wide range of resource alternatives such as energy efficiency and demand side alternatives, storage technologies, renewable and thermal generating units, various types of power purchase and sales agreements, and the electric market. The model identifies the least-cost resource portfolio based on NPV of total utility costs while meeting loads within reliability requirements, emissions mandates, construction limitations, and RPS and energy efficiency requirements.

Input data include fuel price projections; new resource construction costs; demand and energy forecasts and load shapes; energy efficiency projections; resource performance characteristics such as dispatchability, transmission capacity attributes, resource retirements, planned outages; and other relevant inputs. The model optimizes portfolio selection by calculating capital requirements, fuel costs, and O&M costs using economic dispatch to meet demand and energy requirements for each of the thousands of portfolio options and ranking each by the NPV of total utility cost. The model considers the existing resource portfolio and new resource options when determining the MCEP for a given scenario. PNM hosted a detailed presentation from ABB on how Strategist works and its capabilities at the November 10, 2016, Public Advisory meeting.

AuroraXMP

PNM licenses AuroraXMP from EPIS. AuroraXMP is a widely used economic dispatch model that evaluates portfolio economic dispatch on an hourly basis. This is an improvement over the typical week approach used for economic dispatch within Strategist. PNM used AuroraXMP to verify the fuel-mix implications illustrated in the Strategist results, particularly natural gas dispatch within key scenarios or sensitivities and to perform a portion of the reliability analysis. The reliability analysis suggests several strategies to maintain reliability, namely holding back generation for regulating reserves or curtailing dispatch from must run resources. PNM used AuroraXMP to evaluate different regulating reserve strategies to determine the optimal mix of natural gas resources in the MCEP and to help identify sources of value for energy storage resources.

SERVM

Under a consulting agreement with Astrapé Consulting, PNM used the SERVM model to calculate effective load carrying capabilities and loss of load probability metrics for the reliability 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 more capability to perform reliability risk assessments than Strategist, AuroraXMP, or other traditional capacity expansion models. 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.

ANALYSIS RESULTS

ANALYSIS RESULTS

As described earlier, PNM evaluated two primary scenarios in this IRP: an assumed continuation of SJGS in PNM's supply portfolio (Continue SJGS) through the planning period and an assumed shutdown of the plant after the summer peak in 2022 (Retire SJGS). The two scenarios create very different needs for future resources. Figure 35 and Figure 36 illustrate the future needs required to meet demand at 4:00 p.m. on a hot summer day, which represents PNM's historic system peak hour. If SJGS continues in operation, there is much less need for new resources compared to the retirement scenario.

Figure 35. SJGS Continues Scenario

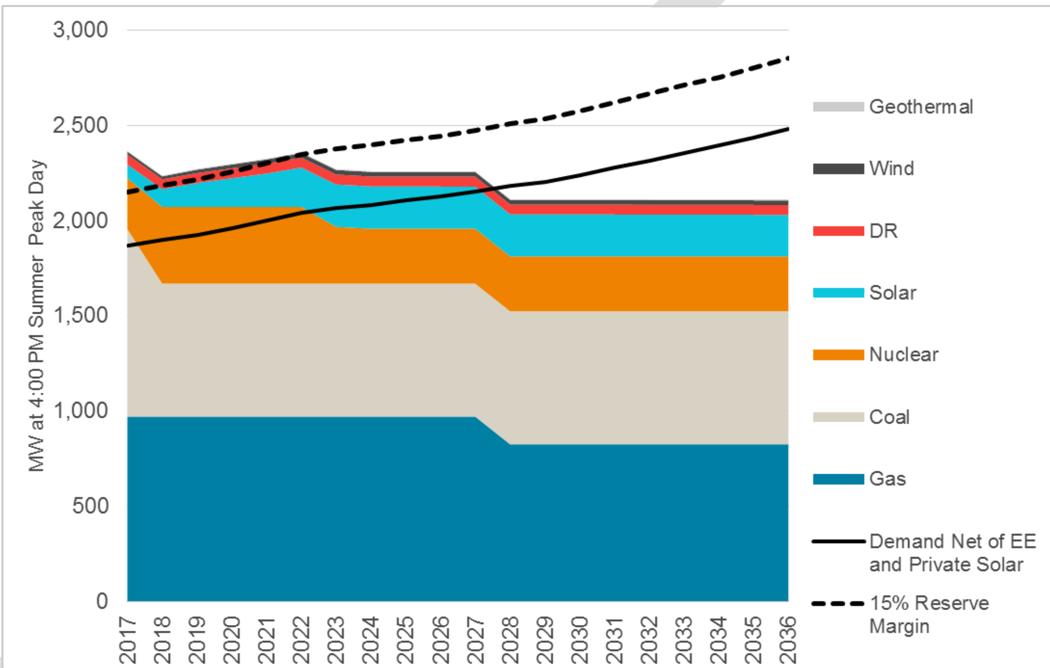
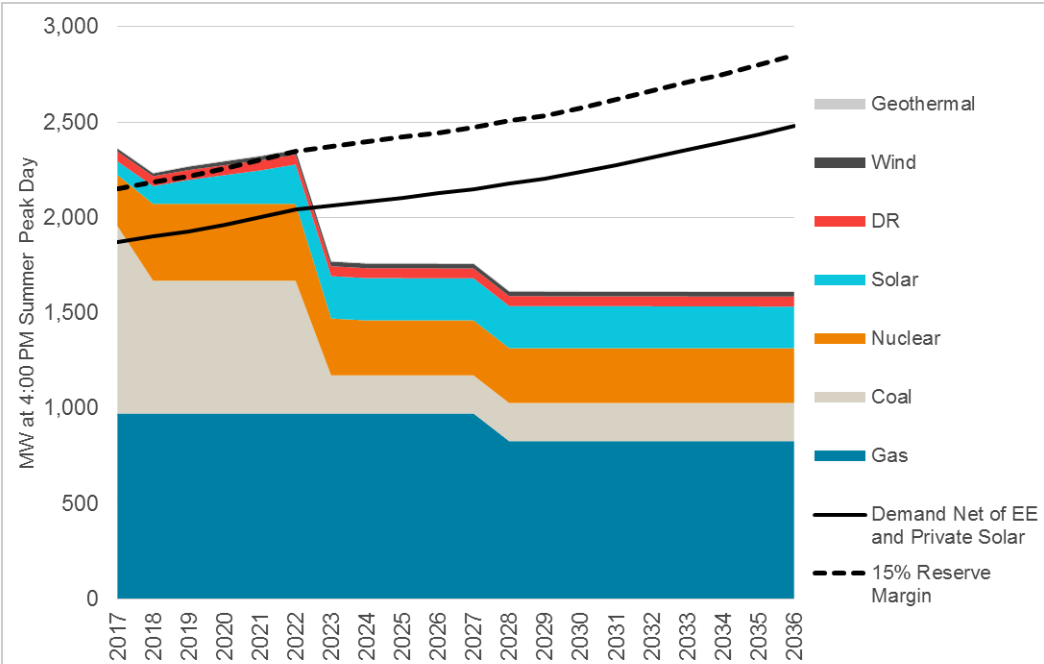


Figure 36. SJGS Retires Scenario



In addition to looking at the historic peak hour, the demands on PNM's system are changing. With the addition of significant universal and private solar resources available to meet the 4:00 p.m. load, the drop in availability may be larger than the drop in loads by 8:00 p.m. on a hot summer day. In the past, PNM met system reliability needs and ensured sufficient summer peaking capacity was available. As supply and demand relationships change with existing generation retirement, energy efficiency, and private solar resource growth along with new universal solar and wind generators, PNM needs to ensure sufficient capacity is available at every hour of the year.

PNM examined these changing needs through its scenario and sensitivity analysis, economic dispatch modeling, and Monte Carlo risk analysis within the two primary scenarios. Because the needs within these two scenarios are so different, this IRP presents the analysis results for both scenarios separately.

Continue SJGS Scenario

The SJGS Continues scenario assumes the station's two units operating post 2017 will continue to operate after 2022 and through the end of the planning period.

New resource additions in the continuation scenario are driven by replacement of expiring PVNGS leases, the Valencia and New Mexico Wind Energy Center PPAs, and maintaining planning reserve margins while supplying load growth. PNM compared the type of resources added against reliability measurements to ensure requirements for planning reserves, regulating reserves, and contingency reserves were all met before constructing the MCEP for this scenario.

Least-Cost Portfolios

PNM used the Strategist model and the database of existing and potential resource options to build least-cost portfolios using 21 scenarios of load, gas, and carbon pricing for the Continue SJGS Scenario (Scenarios 1-21). Appendix N shows the least-cost portfolio meeting reliability requirements for each of the 21 scenarios, which informed the decision for the final MCEP.

In all cases, PNM assumed it will achieve compliance with the 2020 RPS by using a 50/50 mix of wind and solar resources and that data center customers will add renewable energy resources to the portfolio to meet environmental goals. The portfolios built for the scenarios and sensitivities provided in Appendix L show these resources labeled as “PNM 2020 RPS” compliance or “Data Center1” resources, which are added from 2018 through 2023. The same RPS compliance and data center resources are assumed in every scenario or sensitivity.

Load Scenarios

Resource additions in the mid-load scenarios of the SJGS Continues portfolios are needed to respond to capacity reductions from the 114 MW of PVNGS-leased capacity retiring in 2023 through 2024, and the end of the Valencia and New Mexico Wind Energy center PPAs in 2028. This retired capacity gets replaced in the mid-load scenarios with the cheapest source of capacity in the resource option database, which is a heavy frame gas combustion turbine. Later in the planning period, reserve margins are maintained with a combination of gas peaking and renewable energy resources.

The relationship between resource retirements and replacements is also consistent in the low- and high-load scenarios. In the low-load scenario, reserve margins remain higher through the PVNGS lease expirations and the mix of gas peaking and renewable energy resources begins after the end of the Valencia PPA. Because the load-growth rate in the low-load scenario is much less than the mid-scenario, the incremental gas capacity resource and renewable resource additions are smaller than in the mid-load scenarios. In the high-load scenarios, gas peaking capacity gets added in the least-cost portfolios before the PVNGS lease expirations, and reserve margins are maintained with a combination of heavy frame gas peaking and renewable energy resources through the planning period.

Gas and Carbon Price Scenarios

The gas and carbon price assumptions have the impact of changing the mix of renewable and gas peaking resources added to maintain reserve margins in the three load scenarios. Higher gas and carbon price assumptions favor more carbon free energy resources, including renewable energy and retention of the PVNGS leases. In low-price scenarios for gas and carbon, gas peaking capacity is favored over the carbon-free resources.

SJGS Retires Scenario

The SJGS Retires scenario is characterized by the assumption that the two units of the SJGS station that will continue operating after 2017 will cease operation after the summer peak load period in 2022.

Retiring SJGS capacity after the 2022 summer peak creates a significant need for replacement resources. Replacement resources are a mix of renewable energy, gas peaking, and retention of the PVNGS leased capacity. PNM compared the type of resources added against reliability measurements to ensure requirements for planning reserves, regulating reserves, and contingency reserves were all met. Appendix M shows the least-cost portfolio meeting reliability requirements for each of the 21 scenarios (Scenarios 22-42, which informed the decision for the final MCEP.

Least-Cost Portfolios

PNM built the least-cost portfolios for the Retire SJGS scenarios using the same gas price, load, and carbon price scenarios as described above in the SJGS Continues scenarios. The coal cost forecast used was created using the existing coal supply agreement.

Load Scenarios

Retiring SJGS capacity after the 2022 summer peak creates a significant need for replacement resources starting in 2023. SJGS is replaced by a combination of renewable energy, gas peaking, and retention of the expired PVNGS leases. The mix of these resources is affected by the load forecast assumptions. In the mid-load scenario with mid-price gas and carbon assumptions (Scenario 30) , planning reserve margins are low through 2026, and in the period of 2023 through 2026, the replacement options for SJGS capacity include hundreds of MW of solar resources, heavy frame gas peaking capacity, and retention of the PVNGS leases. The high-load scenarios add natural gas-combined cycle capacity to the potential replacement mix in 2023 and renewable energy resource options are added before 2022. In the low-load scenarios (Scenarios 22-28), replacements are limited to natural gas peaking capacity in the mid carbon and gas price scenario.

Gas and Carbon Price Scenarios

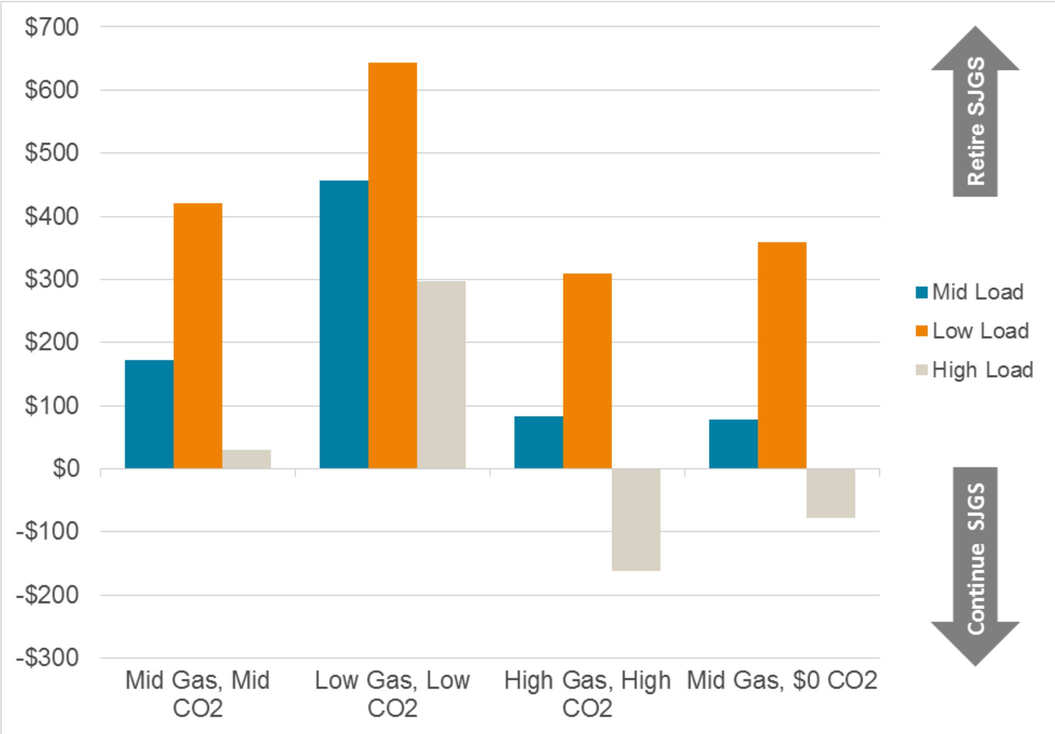
The gas and carbon price assumptions have the impact of changing the mix of renewable and gas resources added to replace SJGS capacity in all three load scenarios. Higher gas and carbon price assumptions favor more carbon-free energy resources, including more renewable energy and retention of the PVNGS leases. In low-price scenarios for gas and carbon (Scenarios 22, 29, and 36) natural gas combined cycle capacity replace carbon-free resources (i.e. renewable energy and PVNGS leased capacity).

Comparison of Retire SJGS Scenario to Continue SJGS Scenario

A comparison of the net present value of costs for the two SJGS scenarios shows that under most of the combinations of load, natural gas and carbon prices examined, there is a long term cost savings for PNM's customers if PNM exits SJGS in 2022. The magnitude of the savings is dependent upon the load, natural gas and carbon prices, but the conclusion that retiring SJGS will provide cost savings is based upon the value of moving from the fixed cost energy supplied by SJGS to a variable cost portfolio of renewable energy and traditional resources that better matches the future load forecast.

Figure 37 shows the difference between the net present values of continuing and retiring SJGS. A positive value occurs when it is less expensive, over the twenty-year planning period analysis, to retire SJGS in 2022 than to continue operations through the planning period. The four groups of bars are four combinations of natural gas and carbon prices. The three bars within each group show the result for a given load forecast within each combination of gas and carbon pricing.

Figure 37. Comparison of Retire vs. Continue SJGS



The scenarios that favor continuing SJGS are only select high load scenarios, specifically scenarios with (1) high load and high gas and carbon prices (Scenario 17) and (2) high load, mid gas prices, and no carbon price (Scenario 18). These scenarios were built with the assumption that a second data center will locate within PNM's service territory. PNM has not added additional renewable energy associated with this second data center load – that possibility is one of the sensitivities that is discussed later in the report. This is true even in the high natural gas price scenario.

Carbon prices are based on the combined set of gas and carbon prices provided by PACE for this IRP. The high carbon price from the PACE price curves is lower than the carbon prices provided by the NMPRC for use in electric integrated resource planning. A higher carbon price than reflected in the graph above would increase the differential in net present values in favor of retiring SJGS. PNM also tested the impact of no carbon price over the twenty year planning period. Similar to the scenarios using the PACE price curves, no cost of carbon in the future is not as significant to the results as PNM's current load forecast. Figure 38, Figure 39, and Figure 40 summarize the NPV cost results of all scenarios.

Figure 38. Mid-Load Scenarios NPV Cost Comparison

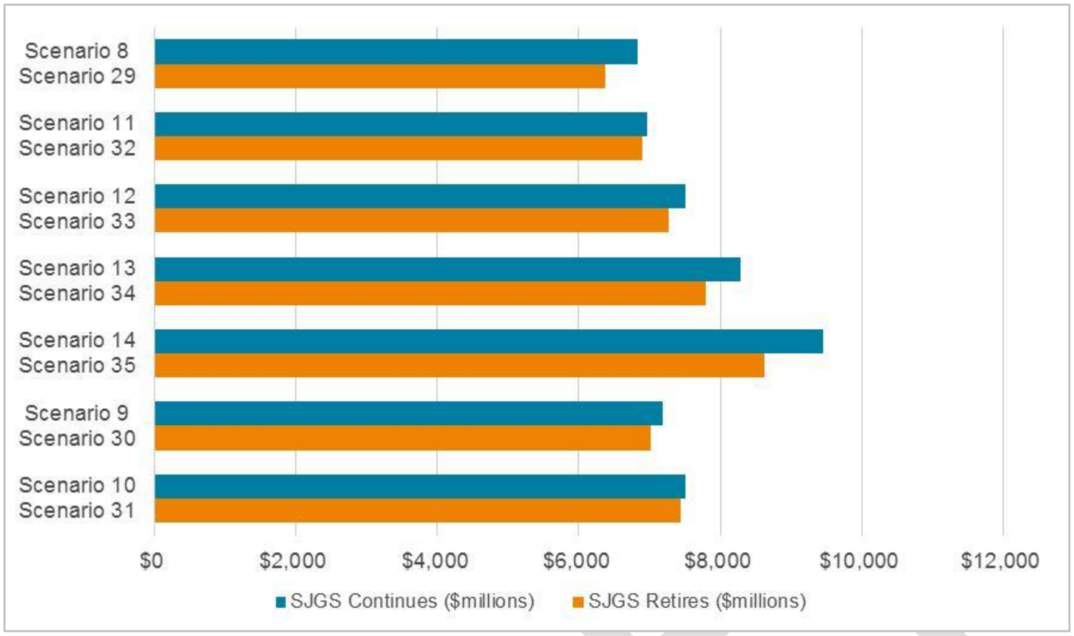


Figure 39. High Load Scenarios NPV Cost Comparison

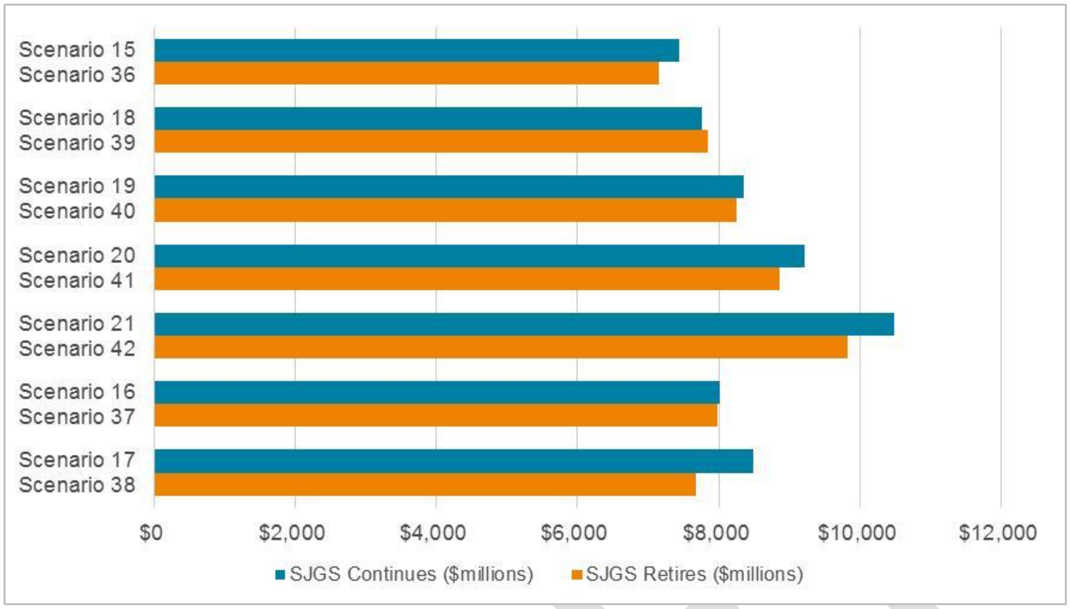
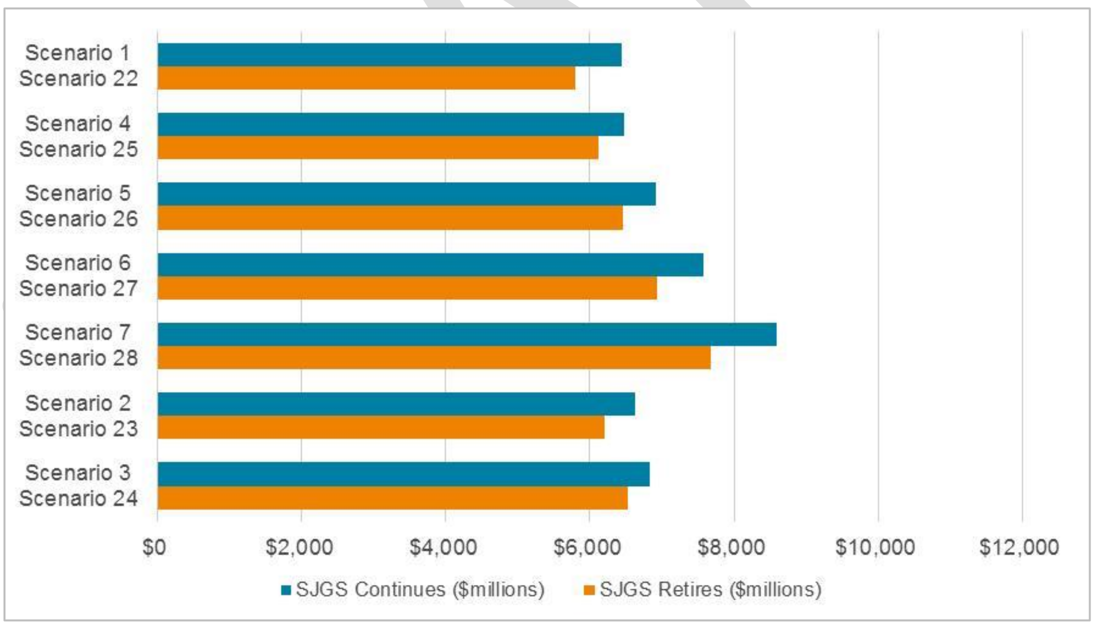


Figure 40. Low Load Scenarios NPV Cost Comparison



Sensitivities Analysis

PNM tested a range of resource assumptions and future cost estimates within the capacity expansion modeling using either sensitivity analysis or Monte Carlo analysis. The resources that were tested and the technique used is based expected portfolio impacts for the types of resources and types of risks associated with each resource. PNM widely considered variable affecting SJGS, FCPP and PVNGS. None of the potential replacement resources for these three baseload resources have the same characteristics, so PNM anticipates baseload replacement will require a mix of different resource types. Several of the sensitivities are designed to test resources to attempt to quantify the best mixture of baseload replacement resources.

The other sensitivities are cost variables that should be considered due to their potential to impact future service costs but do not exhibit the type of variability that is best evaluated with a Monte Carlo analysis. Figure 41 and Figure 42 illustrate the tornado diagrams for the two primary scenarios for each of the sensitivity variables examined. The diagrams illustrate the importance of the load forecast and natural gas costs, which are scenario-defining variables and are also evaluated in the Monte Carlo analysis. Other potentially significant variables like coal and nuclear costs do not vary as much as load and natural gas prices, so PNM considered the risk associated with these variables using sensitivity analysis. The following are short definitions of each of the variables studied:

- Energy Forecast—shows the range of costs using the low, mid, and high energy forecasts described in the “Customers” section of this report.
- PACE Gas/CO2—shows the impact of the range of natural gas and CO2 prices
- Energy Market—shows the range of costs or savings due to the ability to make off-system sales and purchases using a range electric market prices
- 0$ CO2—shows the cost reduction if carbon price is zero versus the mid CO2 price
- High/Low EE—shows the range of costs when using the low, mid, and high energy efficiency forecasts
- No Integration Cost - Shows magnitude of the impact of including integration costs in the cost of new renewable resources in the capacity expansion modeling

Figure 41. SJGS Continues Tornado Diagram

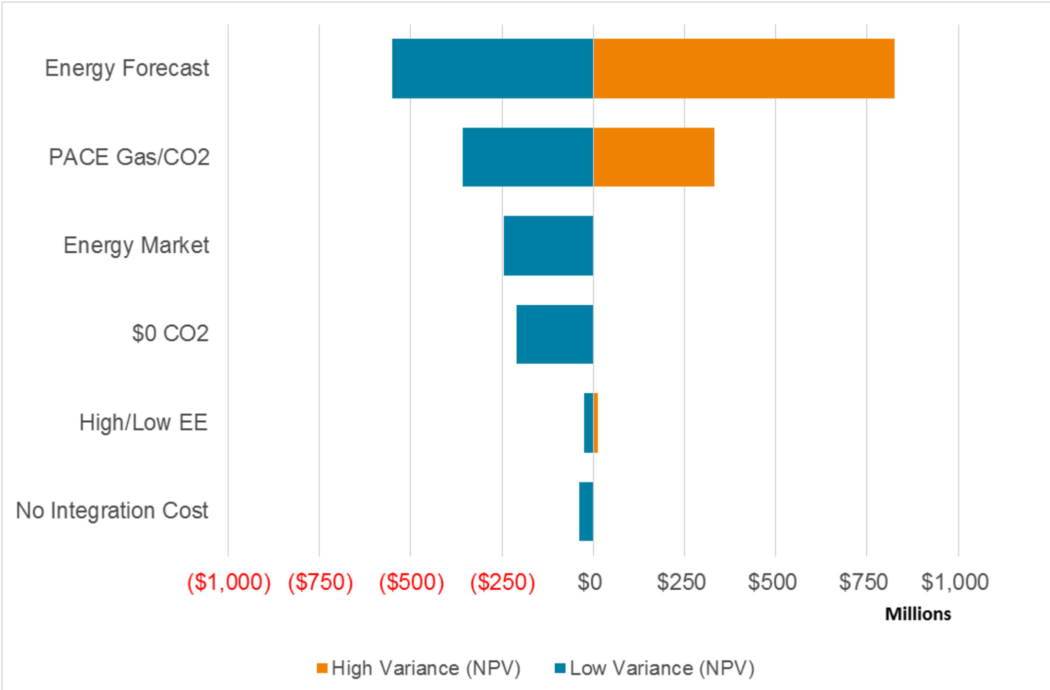
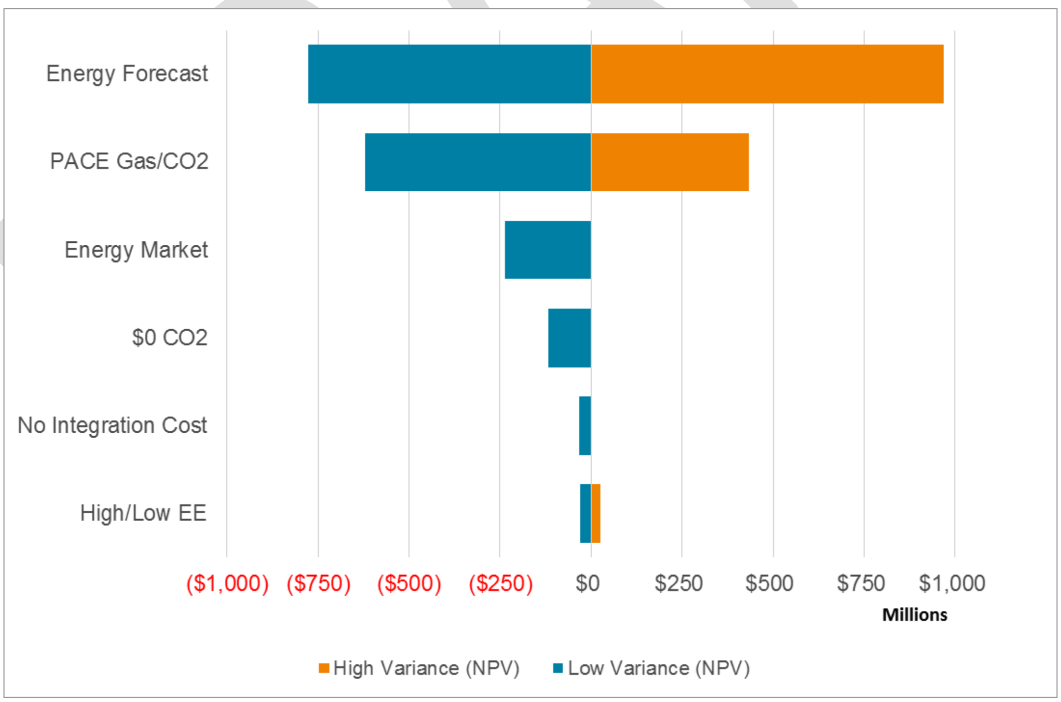


Figure 42. SJGJ Retires Tornado Diagram



FCPP 2031 Retirement

A comparison of the net present values of retiring Four Corners in 2031 also shows the potential for long term cost savings for PNM's customers if PNM retires its Four Corners capacity in 2031.

The Four Corners retirement sensitivity does not impact the SJGS Continues scenario prior to 2031 and does not impact the resource options selected to replace capacity in the SJGS Retires scenarios. Figure 43, Figure 44, and Figure 45 illustrate the NPV cost results of these sensitivities.

Figure 43. FCPP Sensitivity Mid Load Forecast NPV Cost Comparisons

Figure 44. FCPP Sensitivity Low Load Forecast NPV Cost Comparisons

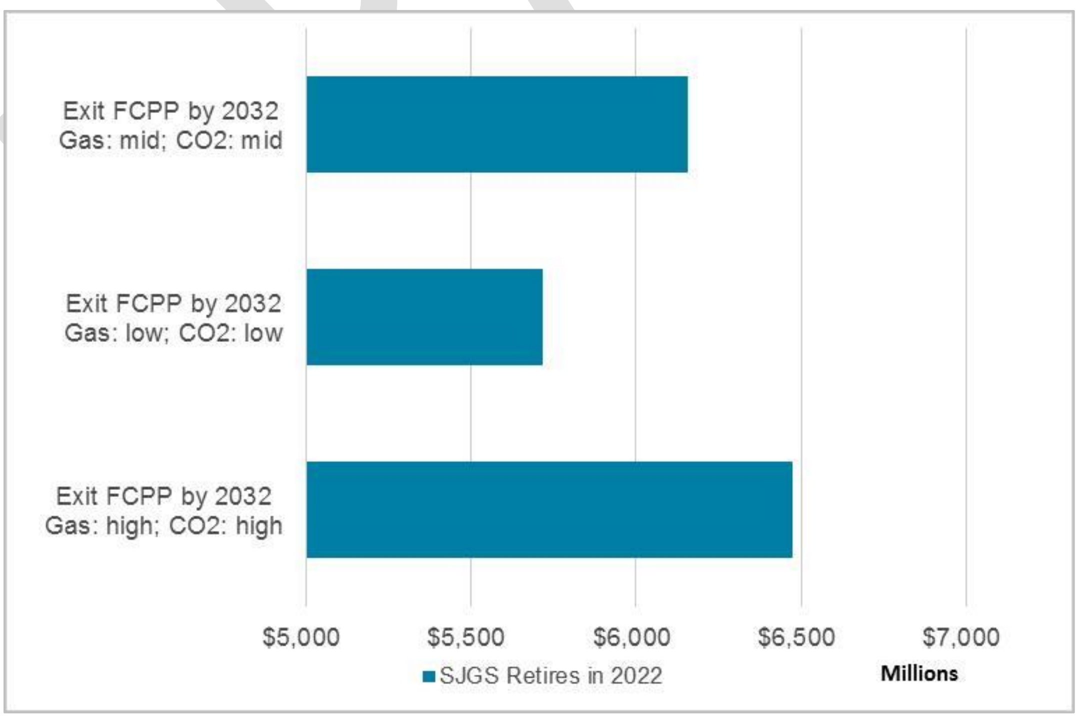
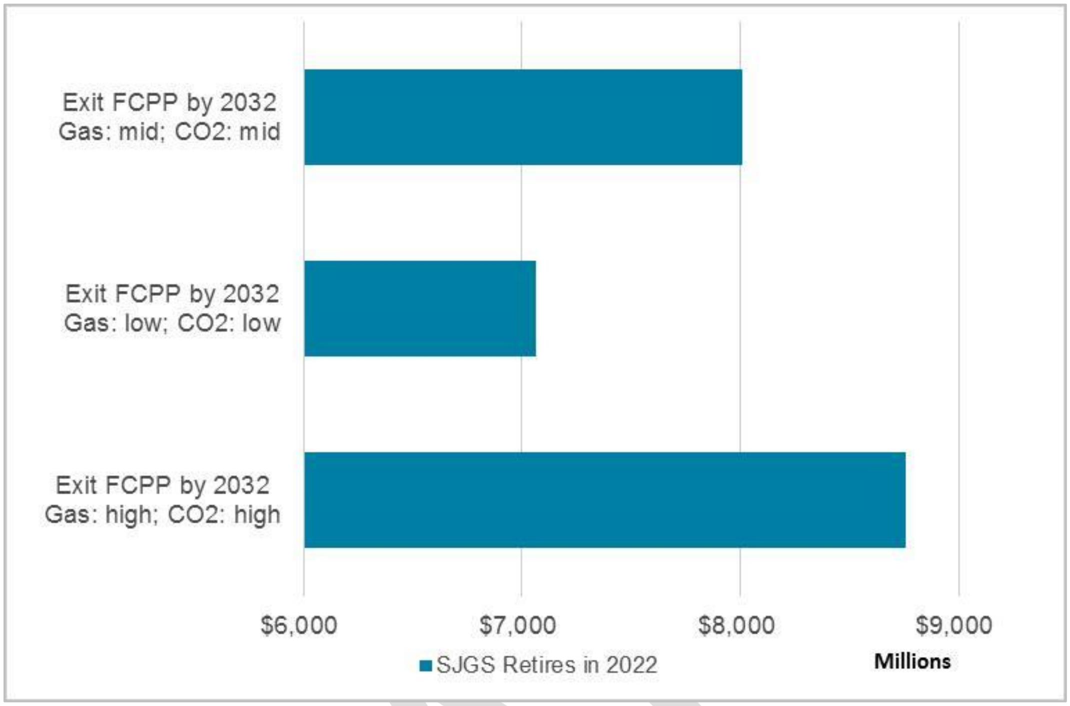


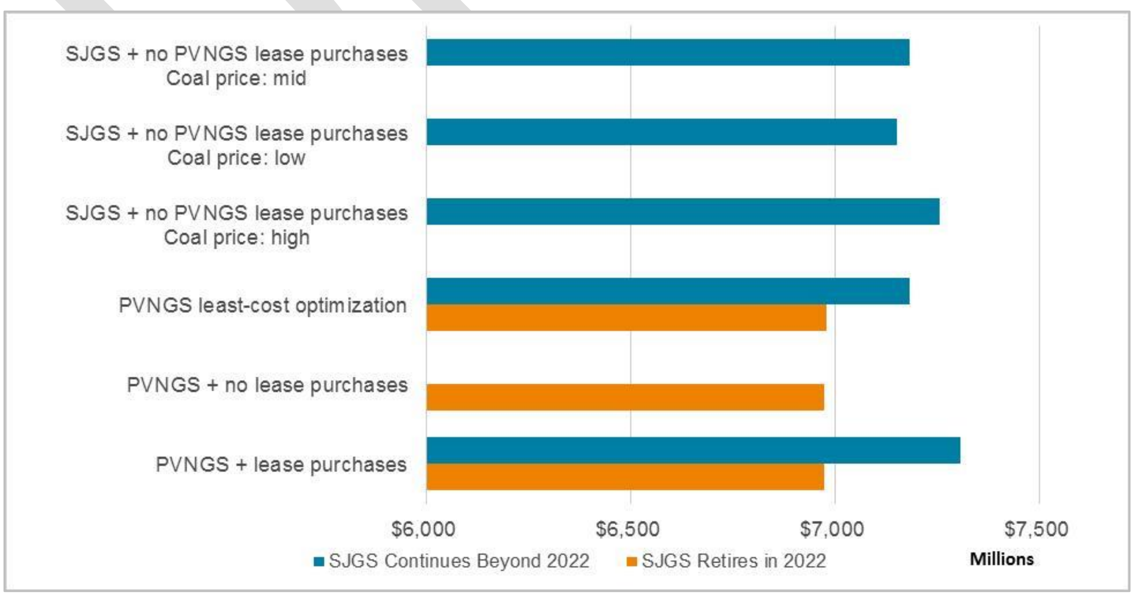
Figure 45. FCPP Sensitivity High Load Forecast NPV Cost Comparison



PVNGS-Leased Capacity

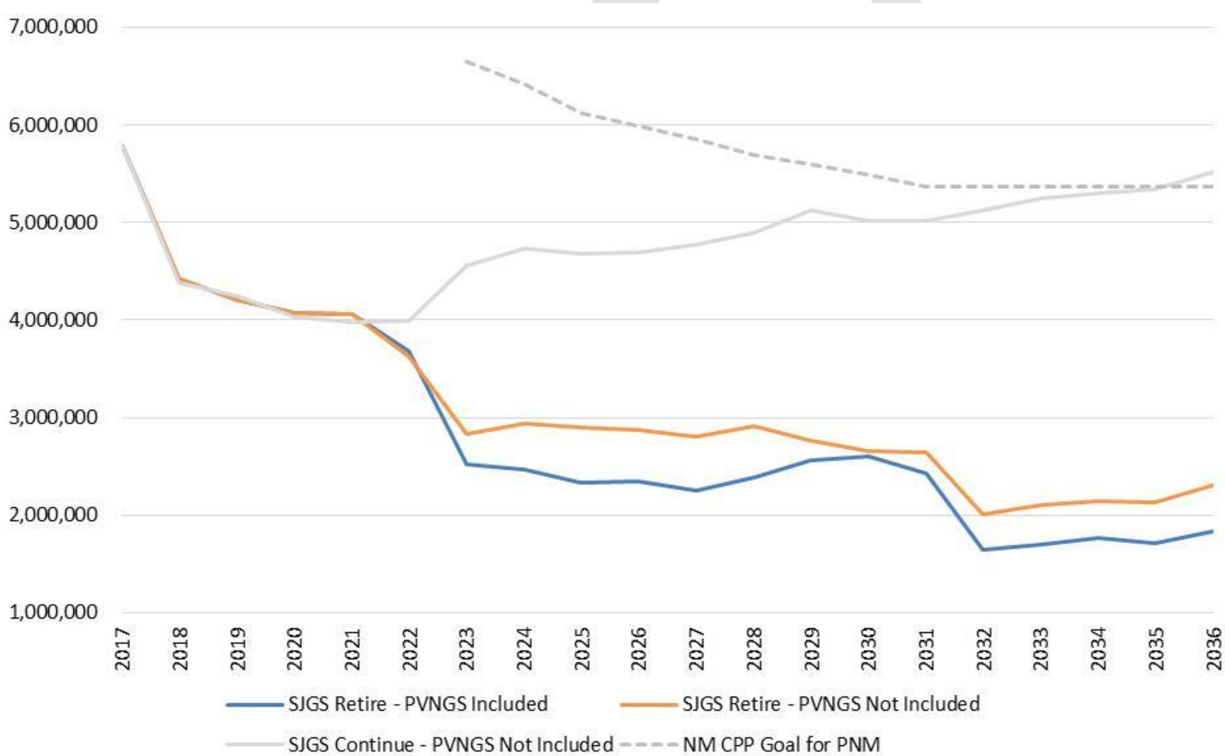
The price and terms at which PNM can retain the PVNGS-leased capacity beyond lease expirations are unknown. The least-cost capacity expansion modeling shows that the PVNGS-leased capacity can be included in the least-cost portfolios for the SJGS shutdown case if PNM can repurchase the leased capacity from the lessors. If SJGS continues, the lease purchases are not included in the least cost capacity expansion modeling. Figure 47 illustrates the NPVs of the capacity expansion modeling.

Figure 46. PVNGS Sensitivities Mid Load Forecast NPV Cost Comparisons



Whether the PVNGS-leased capacity is included in the MCEP has implications for overall portfolio carbon emissions, loss of load probabilities, and the range of economic risk indicated by the Monte Carlo analysis. Without the PVNGS-leased capacity, PNM's supply portfolio will be more dependent on natural gas, so carbon emissions will be higher and the cost to operate the portfolio will be more susceptible to volatile natural gas prices and the potential for carbon regulation requirements. This results in both higher carbon emissions and more cost risk associated with volatile natural gas prices. Figure 47 shows the carbon emission profile if the leased capacity is retained compared to carbon emission if the nuclear energy is removed from the supply portfolio. The MCEP evaluation illustrates these relationships and explains why retaining the PVNGS leases is included in the MCEP for the SJGS retirement case and not included in the MCEP for the SJGS Continues case. Retaining the PVNGS leased capacity also minimizes freshwater use, with lease retention lowering freshwater use by 5.6 billion gallon over the twenty year analysis period.

Figure 47. CO_2 Levels With and Without PVNGS



SJGS Coal Prices

As shown on the tornado diagrams, the SJGS coal prices have a more significant impact in the SJGS Continues scenario than the retirement scenario. PNM tested different coal price curves against the San Juan Continues scenario. These resulting portfolios of the capacity expansion modeling are shown in table x for the mid, high and low coal cost sensitivities using the mid gas and CO2 pricing curves. Under all pricing conditions, the portfolio and resource selection remains unchanged over the entire planning period. Changing the coal cost does affect the fuel mix, but not resource selections. Also, the cost differential between the mid and low range is not significant enough to change the conclusion in the SJGS Continue versus SJGS retire scenario analysis.

Nuclear Fuel Price and O&M Range

This analysis is not complete at the time the draft report is written, the final report will illustrate the relationship between this potential cost variation and total portfolio cost estimates.

Energy Efficiency and Demand Response Program Continuation

Continuing the energy efficiency and demand response programs produces savings both in terms of overall portfolio cost and the need for system investment. Removing the impact of future energy efficiency and demand response programs from the energy and demand forecasts in either the Continue SJGS or Retire SJGS scenarios has the same impact on resource needs. Without the demand savings from the programs, 40 MW of additional gas peaking capacity is needed in 2018 and another 41 MW in 2020. The NPV cost of ceasing program implementation, which saves the annual spending on program implementation, is calculated on the SJGS scenarios using mid load, gas and carbon assumptions. The savings associated with future program implementation is almost double in the Retire SJGS scenario compared to the Continue SJGS scenario.

- Continue SJGS Scenario NPV savings: $72.4 million
- Retire SJGS Scenario NPV savings: $140 million

Natural Gas Type Size and Price

PNM has not completed this sensitivity analysis in time for presentation in the draft report. The database of potential new resources includes a representative selection of a wide range of combustion turbine, reciprocating engines and combined cycle technologies. The capacity expansion modeling is selecting combustion turbines when flexible capacity is most needed. The modeling also selects reciprocating engines when there is a capacity need and a need for more energy than is typically supplied by a combustion turbine. While combined cycle technologies are not appearing in the least cost capacity expansion portfolios, these technologies are among the resources included in the top ten of the lowest cost of the thousands of portfolios generated in each optimization. So, clearly, this merits further study to better understand the conditions that favor one technology over another.

Solar Sensitivity

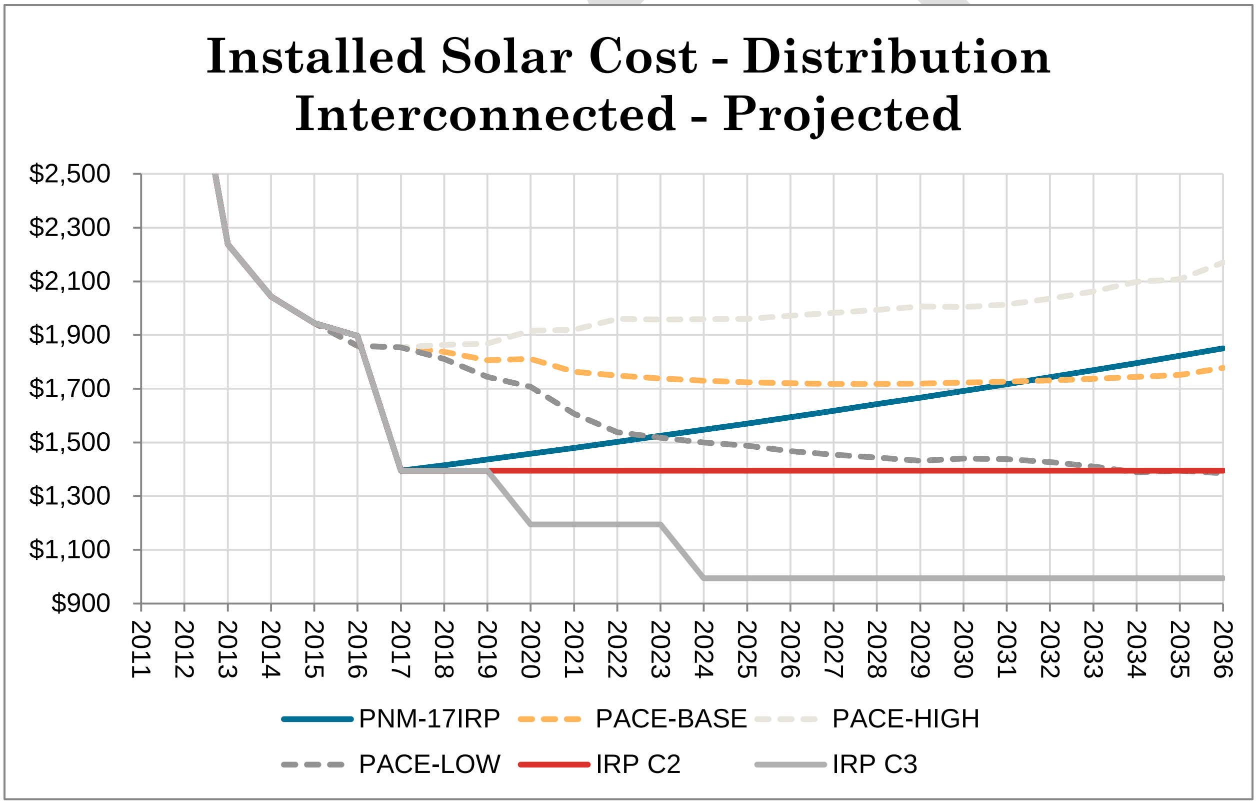
Solar prices have been steadily declining since PNM first began installing utility scale solar in 2011. Recent request for proposals (RFPs) show that prices for photovoltaics continue to decline. Since New Mexico has abundant solar potential it is important for PNM to understand the impact of lower solar prices and role it plays in resource selection since it could greatly impact a portfolio. PNM conducted sensitivity analysis on solar pricing to be able to quantify how the price of solar affects resource selection.

Two very important modeling factors that can affect how solar is selected in Strategist model are the costs and the effective load capacity capability (ELCC). For the costs, PNM reviewed the capital cost to install solar as well as the role of tax subsidies; for the ELCC, PNM reviewed how new solar additions in the future could shift the peak hour. For this solar sensitivity PNM did not analyze the need to add conventional resource additions or include integration costs to mitigate reliability problems that could occur when the renewable penetration level increases (It is discussed in the Reliability Analysis section). This sensitivity focused on the role of solar pricing in moving solar resource additions earlier or changing resource needs in the near term than occurs in the capacity expansion modeling using current cost estimates.

Pricing

PNM's past solar pricing assumptions all come from responses to RFPs. At the beginning of the 2017 planning process PNM relied on PACE forecasting to develop pricing curves as shown in the figure below. However, recent market data from the most current RFP issued in the first quarter of 2017 attracted even lower prices than forecasted. Therefore, to conduct this sensitivity PNM relied on the most recent RFP data to develop the cost curves in comparison to the PACE forecasts as shown in Figure 48.

Figure 48. Solar Cost Assumptions



Since the RFP data only provides point estimates it is important to develop pricing estimates for solar in the future. PNM started with the point estimate and created three price curves. In keeping with current modeling practices and to remain consistent with all other resource alternatives in the database, the starting point was escalated at 1.5% annually. At a minimum, this means that relative to other technologies, solar PV maintains the same cost differential as in year 20 as year 1 (see curve PNM-17IRP in Figure 48). The second price curve was used to estimate a flat pricing curve (see curve IRP C2); however, in comparison to other alternatives this represents a declining cost curve as all other technologies are escalating at 1.5% annually. Finally, a third cost curve was developed to represent significant cost savings should the market prices keep declining (see IRP C3). These three pricing curves set the foundation for the solar sensitivity analysis PNM conducted.

Federal tax incentives for installing solar facilities are greatly impacted during the planning period as shown in Table 30. PNM assumed the 30% investment tax credit even when it expires for any installation occurring after 2020.

Table 30. Solar Investment Tax Credits

Solar inService	Federal Tax Credit
<2020	30%
2020	26%
2021	22%
>2021	10%

Effective Load Carry Capability (ELCC)

The effective load carrying capability (ELCC) of a generator represents the ability of generator to provide power at any time. Dispatchable generators such as gas turbines or combined cycles have high ELCC values because they can be called upon to provide 100% power at any time. Intermittent resources (non-dispatchable) such as solar photovoltaics or wind do not exhibit as high ELCCs since they may not provide maximum power at the same time of PNM's peak. This is especially important since increasing levels of solar penetration can shift the peak hour which could directly impact resource selection in a portfolio. Therefore, it is important to understand and assign ELCC values for all existing and future renewable resources. PNM relies on manufacturer data as well as historical data to set the ELCCs for solar. On PNM's existing system, approximately 65 MW of customer owned PV systems and 107 MW of utility owned solar are installed. Because of the lack of historical data for the customer owned PV systems, PNM relied on NREL data to determine the ELCC for fixed tilt PV systems. This assumption is expected to change once PNM has received enough historical data to reflect a more accurate range. Current installations of Integrated Data Recorders have only been in place for over a year and PNM expects to receive more data before determining if the ELCC proxy used from NREL is accurate enough for continued use. Because of the lack of historical data to create a trend for the purposes of this sensitivity PNM did not deviate from the 56% ELCC.

For utility owned solar (both fixed tilt and tracking); PNM relies on a mixture of historical data and manufacturer bids from a previous RFP to determine the starting point of the ELCC. Similar to the previous IRP, PNM uses the same ELCC for existing installations on PNM's system: 56% for fixed tilt and 76% for tracking. While this is not enough to shift the peak hour today; by 2020 there exists enough solar on PNM's system with the additions for RPS compliance and Facebook resources that any incremental solar can cause the peak hour to shift an hour later. For additional new solar resources, PNM recognizes that large amounts of penetrations become more inclined to shift the peak hour; therefore, using unchanging ELCCs for solar sensitivity modeling is inaccurate.

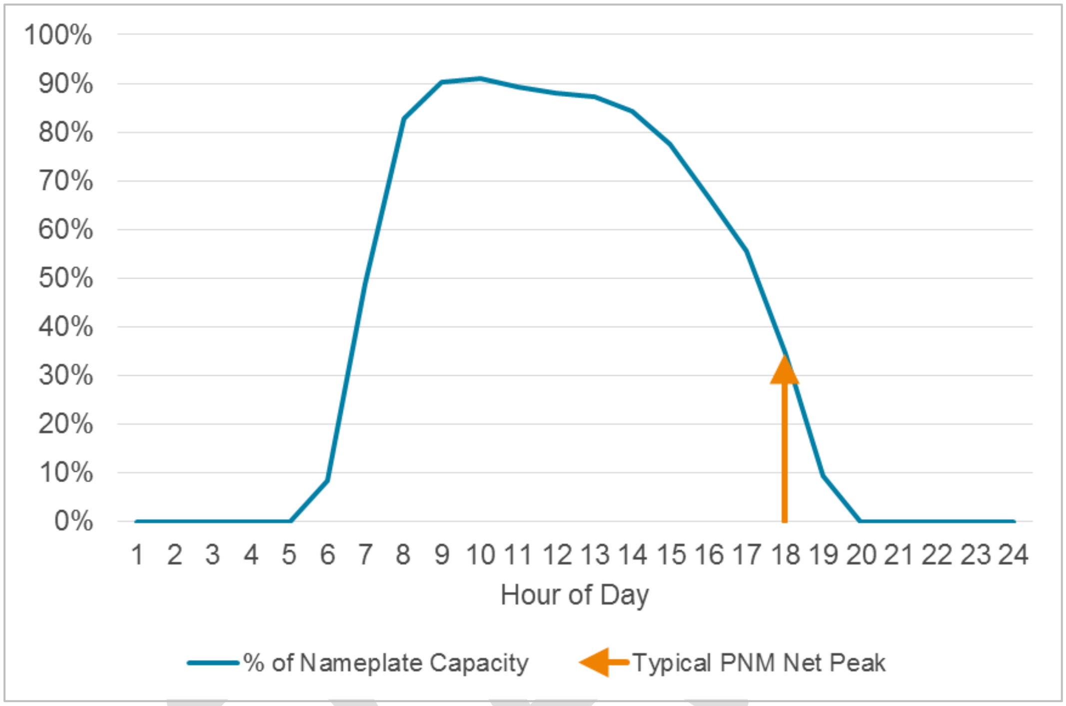
Using the methodology as described in PNM's 2014 IRP, PNM used the load forecast to determine when the peak hour is shifted (Table 31) combined with the solar energy production for the peak month (Figure 49) to determine the ELCCs for each solar tier for new additions. In 2018 the table shows that PNM can add 62 MW of solar before the peak will shift one hour forward and can add an incremental 100 MW can be added before it the peak hour shifts 2 hours forward.

Table 31. 2018 Solar Energy Production Over Peak Hours

Hour	HE MST	HE MDT	2018 PNM Peak	Previous Hour MV Change	Solar PV Peak Contribution	Total Solar PV Needed to Shift Peak	Incremental Solar PV Needed to Shift Peak	Peak	Solar PV Tier
1	1:00 AM	2:00 AM	1,065		0%				
2	2:00 AM	3:00 AM	1,014		0%				
3	3:00 AM	4:00 AM	988		0%				
4	4:00 AM	5:00 AM	973		0%				
5	5:00 AM	6:00 AM	975		0%				
6	6:00 AM	7:00 AM	1,045		8%				
7	7:00 AM	8:00 AM	1,140		49%				
8	8:00 AM	9:00 AM	1,236		83%				
9	9:00 AM	10:00 AM	1,361		90%				
10	10:00 AM	11:00 AM	1,474		91%				
11	11:00 AM	12:00 PM	1,582		89%				
12	12:00 PM	1:00 PM	1,663		88%				
13	1:00 PM	2:00 PM	1,756		87%				
14	2:00 PM	3:00 PM	1,828		84%				
15	3:00 PM	4:00 PM	1,869		78%				
16	**4:00 PM**	**5:00 PM**	**1,900**	**31.1**	**67%**	**62**	**62**	**Peak Hour**	**Tier 1**
17	**5:00 PM**	**6:00 PM**	**1,877**	**-23.1**	**56%**	**161**	**100**	**Peak Hour +1**	**Tier 2**
18	**6:00 PM**	**7:00 PM**	**1,817**	**-59.5**	**35%**	**431**	**270**	**Peak Hour +2**	**Tier 3**
19	7:00 PM	8:00 PM	1,683	-134.3	9%	0	0	Peak Hour +3	No ELCC
20	8:00 PM	9:00 PM	1,641	-42.4	0%	0	0	Peak Hour +4	No ELCC
21	9:00 PM	10:00 PM	1,576		0%				
22	10:00 PM	11:00 PM	1,419		0%				
23	11:00 PM	12:00 AM	1,263		0%				
24	12:00 AM	1:00 AM	1,159		0%				

Shifting the peak hour forward one or two hours can diminish the value of solar in the portfolio as the sun's position on the horizon directly affects the amount of power that can be produced by that facility (Figure 49). A one hour shift drops the ELCC by roughly 10% (hour ending 17) and two hours forward (hour ending 18) by more than 20%.

Figure 49. Solar Energy Production by Hour



Moving to the year 2022, this becomes more dramatic as more solar additions are seen the portfolios to meet RPS compliance and serve the data center load (. See table x. Here the additions in the portfolios indicate that the peak hour has already been shifted one hour forward to 5 pm and any new solar additions would receive a 56% ELCC up to a quantity of 42MW. After that, the solar ELCC would remain at 35% for additions up to 289 MW for incremental solar resource additions. By 2023, the data center resource additions have sufficiency filled tier 1 and therefore any additional solar that would be added to a portfolio is expected to receive a 35% ELCC.

Table 32. 2022 Solar Energy Production Over Peak Hours

Hour	HE MST	HE MDT	2022 PNM Peak	Previous Hr MV Change	Solar PV Peak Contribution	Total Solar PV Needed to Shift Peak	Incremental Solar PV Needed to Shift Peak	Peak
1	1:00 AM	2:00 AM	1,144		0%			
2	2:00 AM	3:00 AM	1,089		0%			
3	3:00 AM	4:00 AM	1,061		0%			
4	4:00 AM	5:00 AM	1,046		0%			
5	5:00 AM	6:00 AM	1,048		0%			
6	6:00 AM	7:00 AM	1,122		8%			
7	7:00 AM	8:00 AM	1,225		49%			
8	8:00 AM	9:00 AM	1,328		83%			
9	9:00 AM	10:00 AM	1,462		90%			
10	10:00 AM	11:00 AM	1,584		91%			
11	11:00 AM	12:00 PM	1,700		89%			
12	12:00 PM	1:00 PM	1,786		88%			
13	1:00 PM	2:00 PM	1,886		87%			
14	2:00 PM	3:00 PM	1,964		84%			
15	3:00 PM	4:00 PM	2,008		78%			
16	4:00 PM	5:00 PM	2,041	33.4	67%	0	0	
17	**5:00 PM**	**6:00 PM**	**2,016**	**-24.9**	**56%**	**42**	**42**	**Peak Hour**
18	**6:00 PM**	**7:00 PM**	**19,552**	**-63.9**	**35%**	**331**	**289**	**Peak Hour +1**
19	7:00 PM	8:00 PM	1,808	-144.3	9%	0	0	Peak Hour +2
20	8:00 PM	9:00 PM	1,762	-45.5	0%	0	0	Peak Hour +3
21	9:00 PM	10:00 PM	1,693		0%			
22	10:00 PM	11:00 PM	1,525		0%			
23	11:00 PM	12:00 AM	1,356		0%			
24	12:00 AM	1:00 AM	1,245		0%			

Results

Using the base case scenarios (SJGS Continues and SJGS Retires) PNM modeled three pricing curves to assess impacts on portfolio additions. Under both base cases (SJGS Continues and SJGS Retires), using the 2017 IRP solar price curve, up to 250 MW of solar is available and the optimal portfolio adds all 250 MW. This indicates that further study is necessary to determine if the portfolio could handle even more solar. PNM similarly modeled the other two cost curves to determine the amount of solar chosen. When the maximum available solar was chosen, PNM modelled the scenarios to allow for more solar resources. The results for this sensitivity are summarized in Table 33.

Table 33. Solar Sensitivity Results

Pricing Curve	Solar Additions (MW)	Solar Additions Allowed (MW)
SJGS Continues		
PNM - 2017 IRP	250	250
Cost Curve 2	250	250
Cost Curve 3	250	400
Cost Curve 4	550	1,100
SJGS Retires		
PNM - 2017 IRP	250	250
Cost Curve 2	250	250
Cost Curve 3	400	550
Cost Curve 4	650	1,100

Under the flat pricing curve, because the Strategist model selected all available solar resource additions in the least cost plan equivalent, the sensitivity was re-run using a greater amount of solar available to find the optimum addition. This is true for both SJGS scenarios. Under the declining pricing curve, PNM allowed more resources to be selected; however, not everything was chosen.

A brief look at the Continue SJGS portfolios under all pricing curves (Table 33) indicates that solar isn't selected until 2029, halfway through the planning period which indicates there isn't a need for entire amount of solar energy even at a cheaper price. Most importantly, near term resource decisions remain unchanged even though the overall costs of the portfolio are less costly than the base. Overall the portfolios show a declining overall net present value because of the solar resource additions added later in the planning period are replacing coal and natural gas fuel sources that are rising relatively higher than the pace of solar pricing.

Under the Retire SJGS for all pricing curves, the solar resource additions are moved up in the portfolio and begin to be added in the 2022/2023 timeframe. This suggests that solar pricing affects the timing when it comes into a portfolio. However, similar to the SJGS Continues case all near term resource decisions remain the same as the NPV of the system costs decline. One difference in the lower pricing curve is that the addition of solar resource in 2023 displaces the need for one gas resource in the 2022 timeframe.

Wind Sensitivity

PNM tested a range of pricing, sizing and capacity factors to determine how these variables affect the timing and quantity of wind resource additions in an optimized portfolio. All sensitivities were performed for both Continue SJGS and Retire SJGS scenarios. Table 34 shows the combinations evaluated. For pricing sensitivity PNM assumed that any new wind could be obtained at flat pricing levels for 20 years and that all costs such as incentive costs, administrative, transmission service or transmission upgrades would also be included. This analysis also assumes sufficient transmission capacity is always available.

Table 34. Wind Sensitivity Results

	SJGS Continues	SJGS Retires
Pricing (2017 $/MWh)		
$46.85	✓ (base case)	X (base case)
$40.00	✓	✓
$30.00	✓	✓
$20.00	✓	✓
Wind Facility Size (MW)		
100 MW	✓ (base case)	✓ (base case)
50 MW	✓	✓
150 MW	✓	✓
200 MW	✓	✓
Wind Capacity Factor (%)		
45%	✓ (base case)	✓ (base case)
25%	✓	✓
50%	✓	✓

Continue SJGS

The wind pricing sensitivity shows that as the price for wind decreases; the wind resources are selected earlier in the planning period (see Table 35). Even though wind is available to be selected in Strategist as early as 2021, in no pricing sensitivity modeling run does it come into the least cost plan in the first year available. These results show that wind costs need to be about half of what PNM's recent bids indicate for early portfolio addition. Even at the low pricing, other near term planning decisions are unaffected by the addition of wind resources.

Table 35. Wind Price Sensitivity Results on Wind Addition Timing in Continue SJGS Scenario

Timeframe	46.85 $/MWh	40.00 $/MWh	30.00 $/MWh	20.00 $/MWh
2035-2036	✓			
2029-2031		✓	✓	
2023-2025				✓

Retire SJGS

The wind pricing sensitivity in the Retire SJGS case shows the same conclusion as the Continue SJGS scenario: as pricing declines wind is selected earlier and traditional resource additions are unaffected. Early wind selection does, however, defer solar resource additions. Solar is selected in 2023 when wind is about $47/MWh. When wind cost falls to $40, then the first solar addition is delayed by one to two years (see Table 36) as well as solar additions that occur later in the planning period. This trend continuously occurs as wind pricing declines, demonstrating that wind pricing will affect the timing of both wind and solar resources in the Retire SJGS scenario.

Timing when wind is selected in the portfolio at various pricing levels

Table 36. Wind Price Sensitivity Results of Wind Addition Timing in Retire SJGS Scenario

Timeframe	46.85 $/MWh	40.00 $/MWh	30.00 $/MWh	20.00 $/MWh
2022				✓
2023			✓	
2025/2029		✓		
2031-2032	✓			

Wind Facility Size

Portfolio selection is not particularly sensitive to wind facility size (see Table 37). Different sizes either delay or accelerate by one year at the most under the retirement scenarios. For the continuation case, wind additions larger than 100 MW can accelerate resource selection by 3 years.

Timing when wind is selected in the portfolio at various sizes

Table 37. Sensitivity Results of Wind Facility Size Variation

	SJGS Continues	SJGS Retires
100 MW (base case)	2035/2036	2031/2032
50 MW	2035/2036	2030/2031
150 MW	2032/2036	2031/2032
200 MW	2032/2036	2032

Wind Capacity Factor

For all the sensitivity modeling runs, the wind capacity factor had no effect on near term decisions. Wind is selected as an economic resource late in the planning period. These results show that wind could be selected earlier in some cases (see Table 38) there is no clear trend as it depends largely on the upfront resources that are added to meet the load requirements.

Table 38. Sensitivity Results of Wind Capacity Factor Variation

Capacity Factor	Continue SJGS	Retire SJGS
45% (base case)	2035/2036	2031/2032
25%	2033	2027
55%	2032/2036	2032

Of the three variables, pricing had the largest impact. Since wind economics is dependent upon how well the resource produces at a location; the pricing can be largely affected by economies of scale.

Renewable Energy Integration Costs

Renewable integration costs play a role in when renewable resources are added to a portfolio. Under the SJGS continuation case no major changes to portfolio occur until after 2028. After 2028, the addition of integration costs for solar result in delaying solar resource additions by one to two years in the later years of the planning period. Including wind integration costs in the capacity expansion modeling eliminates wind additions in the outer years. Because no near-term resource additions are affected, the overall impact of adding renewable integration costs to the SJGS continuation case is considered minor.

For the SJGS retirement case, solar integration costs have the impact in reducing the size of or delaying renewable energy additions. However, in the later years of the planning period 2033, any deferred solar is included back in portfolio. Overall, similar to the SJGS continuation case, renewable integration costs for wind are considered of minor impact since it occurs very late over the twenty years and only delays selection by one year. Integration costs for solar additions though directly impact the amount of capacity that is added in the near term to replace SJGS retired capacity therefore is considered the important. As noted elsewhere in this report, PNM will be re-evaluating the quantity and timing of solar additions in the MCEP after the conclusion of this IRP.

Small Modular Nuclear Reactors

Small modular nuclear reactors are potential future resources that offer a new source of carbon-free power. PNM has not completed this sensitivity analysis in time to present in the draft report. This will be added in the final report.

High-Load Forecast Data Center Assumption

Assuming an increase in renewable energy supplied by a second data center in the high-load forecast affects resource options and the NPV of cost calculations in the least-cost portfolios.

In comparing the Continue SJGS with the Retire SJGS scenarios, the continue option fares best with a high load forecast assumption. The high load forecast assumed an addition of a second large customer like the new data center customer. The optimized portfolios used for the scenario comparisons did not assume a new large customer would also bring renewable energy similar to the existing data center customer. To test the impact of adding renewable energy along with the new large customer in the high load scenario, PNM created an additional portfolio for the high load case under the SJGS Continue scenario and for the SJGS Retire scenario by adding more renewable energy for that new large customer's loads. This sensitivity was completed using the mid gas and CO2 price forecasts. .For the Continue SJGS scenario, the additional renewable energy for a new large customer increases the portfolio costs relative to the portfolio without additional renewable energy for a new large customer by $126 M. In contrast, the additional renewable energy associated with a new large customer lowers portfolio cost in the high load scenario in the Retire SJGS case by $129 M. Including renewable energy in the high load case that is associated with a new large customer further indicates that the most cost effective approach is the Retire SJGS scenario.

Monte Carlo

The IRP Rule calls for utilities to consider risk and uncertainty in their analysis of resource options. The IRP scenario and sensitivity analysis provide a framework for assessing cost impacts of different future assumptions. PNM used a Monte Carlo simulation analysis to estimate the range of financial risk associated with specific portfolios in a given scenario. To develop ranges and probability inputs for each of the variables, PNM assessed the range of outcomes for different variables reviewed through scenario and sensitivity analyses.

The following graphs illustrate that moving to a more flexible system by retiring SJGS also results in more cost flexibility. The average NPV results show similar relationships between Continue SJGS and Retire SJGS as observed in the NPVs from the least cost capacity expansion modeling. The 5% risk tail measures are higher in the Retire SJGS scenarios. This reflects a higher reliance on variable cost resources in those scenarios. A higher cost variability means that costs could be higher on the high end or lower on the low end than would be expected from a portfolio with lower cost variability.

Figure 50. Average NPV Results for Mid Load Scenarios and Key Sensitivities

Figure 51. NPV Risk (5% Tail) for Mid Load Scenarios and Key Sensitivities

Figure 52. Average NPV Results for High Load Scenarios and Key Sensitivities

Figure 53. NPV Risk (5% Tail) for High Load Scenarios and Key Sensitivities

Figure 54. Average NPV Results for Low Load Scenarios

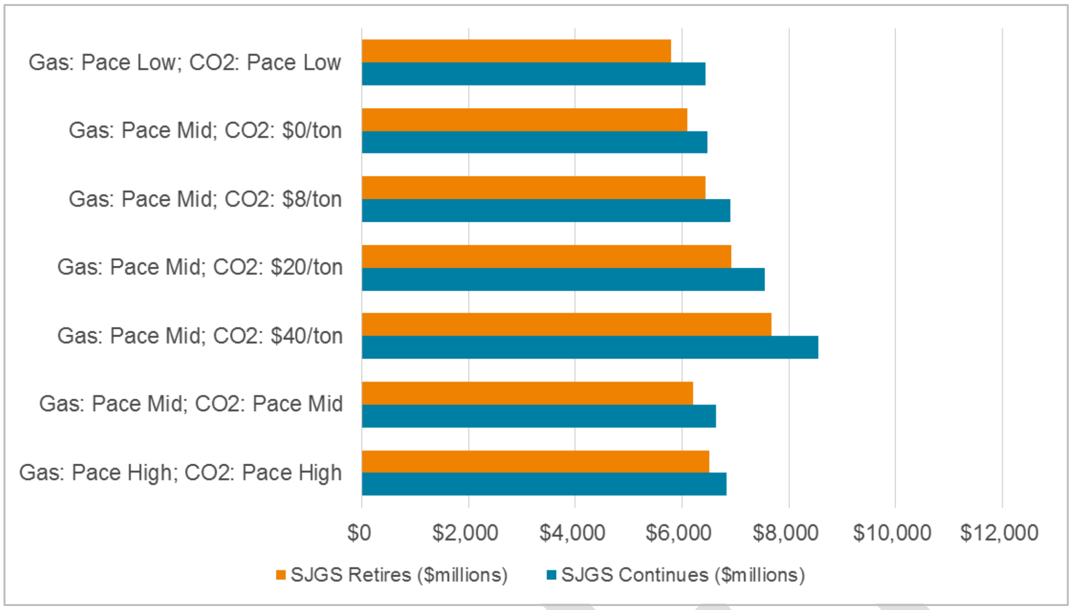
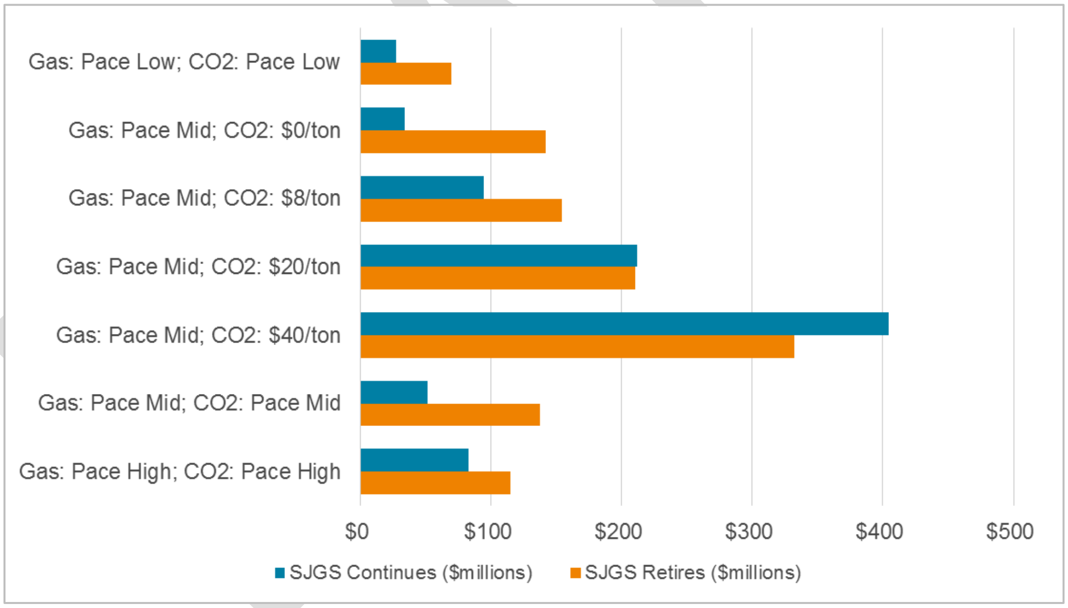


Figure 55. NPV Risk (5% Tail) for High Load Scenarios



Reliability Analysis

To analyze the dynamic nature of PNM's system, PNM contracted Astrape Consulting to analyze reliability and flexibility of the PNM system across a number of scenarios. Specifically, Astrape analyzed impacts of increasing renewable energy penetration on PNM's reliability metrics and costs; and to develop rules of thumb regarding additional flexible generation or additional operating reserves needed to maintain adequate reliability. Astrape uses a chronological, production cost and reliability software called Strategic Energy and Risk

Valuation Model (SERVM) to capture the intra-hour volatility of an operating grid within a BA. The SERVM software can perform over 11,000 yearly simulations at 5 minute intervals to approximate the needs of a system over the entire year. Models such as Strategist are not designed to capture the dynamic nature of resources such as wind as it can vary significantly within minutes. Strategist utilizes a simplistic dispatch algorithm and therefore cannot be use to understand PNM's operational needs.

Baseline Reliability Metrics

PNM benchmarked the current portfolio to set a baseline for comparison. Working off the original Renewable Integration Study performed by Astrape in 2018, the baseline was set at calendar year 2021 to simulate any additional renewable needs after PNM has meet the RPS requirements by 2020. Major changes to PNM's portfolio begin to occur in 2022 when SJGS could retire from the portfolio. PNM simulated 2024 to understand impacts when losing a major baseload resource coupled with significant amounts of added renewables. The metrics and costs for both years for PNM's portfolio are shown in Table 39 on the following page.

These metrics show that PNM's mid-load forecast $LOLE_{flex}$ in 2021 remains within the range for adequate reliability assuming the 1 day in 20 standard ($LOLE_{flex}$ of 0.2) with small amounts of renewable curtailments occurring. However, under the high load forecast, curtailments increase and PNM would begin to see over 4 times the events for $LOLE_{flex}$. For this case, the amount of flex events are significant enough to cause concern and require PNM to procure flexible resources to mitigate the rise in events. The metrics are shown in Table 40 on the following page.

Table 39. Mid Load Scenario: Reliability Impacts for Mid Load with Added Renewables in 2021

2021 Load Forecast	Renewable Penetration	Load Following Target	Curtailment		$LOLE_{cap}$*	$LOLE_{flex}$**	Costs
2017 IRP		% of Load	% of Renewable	MWh	Events per Year		$
Mid Load	17.0%	7.0%	1.9%	45,019	0.18	0.07	$373,273,478
High Load	20.4%	7.0%	2.2%	66,447	0.23	0.31	$422,161,778

* $LOLE_{cap}$ – loss of load expectation due to not having adequate capacity

** $LOLE_{flex}$ – loss of load expectation due to inflexible resources

Table 40. Mid Load Scenario: Reliability Impacts of Baseload Unit Loss Coupled with Added Renewable in 2024

2024 Load Forecast	Renewable Penetration	Load Following Target	Curtailment		$LOLE_{cap}$*	$LOLE_{flex}$**	Costs
2017 IRP	% of Load		% of Renewable	MWh	Events per Year		$
Mid Load	21.1%	7.0%	1.9%	33,747	0.19	0.11	$519,618,635
High Load	29.4%	7.0%	2.9%	140,185	0.05	1.20	$618,459,283

* $LOLE_{cap}$ – loss of load expectation due to not having adequate capacity

** $LOLE_{flex}$ – loss of load expectation due to inflexible resources

In a 2024 mid-load scenario with added renewables replacing baseline, analysis shows the 1 in 20 standard is held but “flex events” rise, indicating that renewable penetration levels are outpacing the fleet’s ability to load follow. Under a similar high load case, flex events are significantly high and unacceptable without some mitigation; curtailments rise to over 4 times the acceptable amount in order to maintain system operating reserves. To understand the proportion, a single 10 MW photovoltaic facility with tracking generates approximately 29,000 MWhs. Roughly 20 MW of solar PV facilities would need to be curtailed to meet reliability standards for the entire year and conventional generation would have to be operated at cost of approximately $146,000 over the year 2021. In the high load case, that number moves from 20 MW of curtailment to almost 100 MW.

Summary

Because PNM’s renewable additions in the future are not fully quantified and can change on a yearly basis, Astrape developed guidelines for likely impacts on reliability. Incrementing by adding a mix of solar resources and wind, the results are shown in the below graph. Change in LOLE or curtailments needed associated with renewable penetrations are shown in Figure 56 and Figure 57. The flexibility of the PNM’s system becomes more quickly constrained when renewable penetrations begin to rise above 20% as shown by the steep slope in the curve, indicating that unless PNM adds flexible conventional resources that PNM would have to curtail renewable resources to maintain operating reserves at its minimum level of 7%. To add more renewables to PNM’s system, the law of diminishing return applies. The graph shows that under a 40% RPS, PNM would have to curtail roughly 48% percent of marginal renewable energy additions once PNM has reached the 40% target. For every additional renewable resource added to PNM’s portfolio, curtailments also rise. Curtailments will be a least cost operating procedure under this scenario.

Figure 56. LOLE With Increasing Renewable Penetration

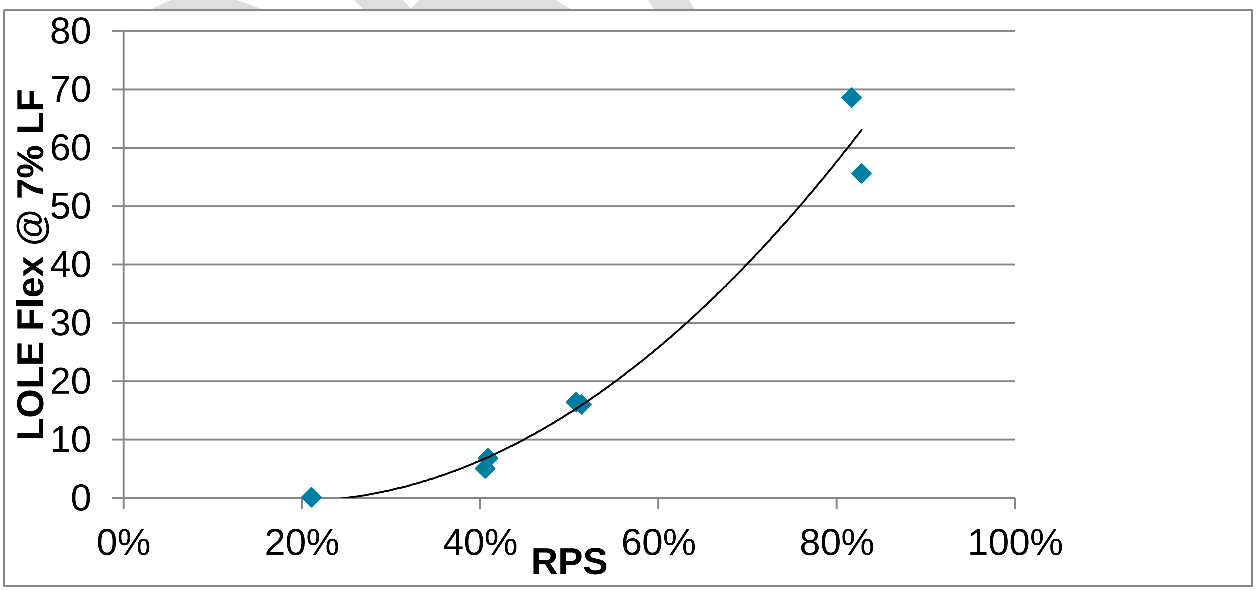
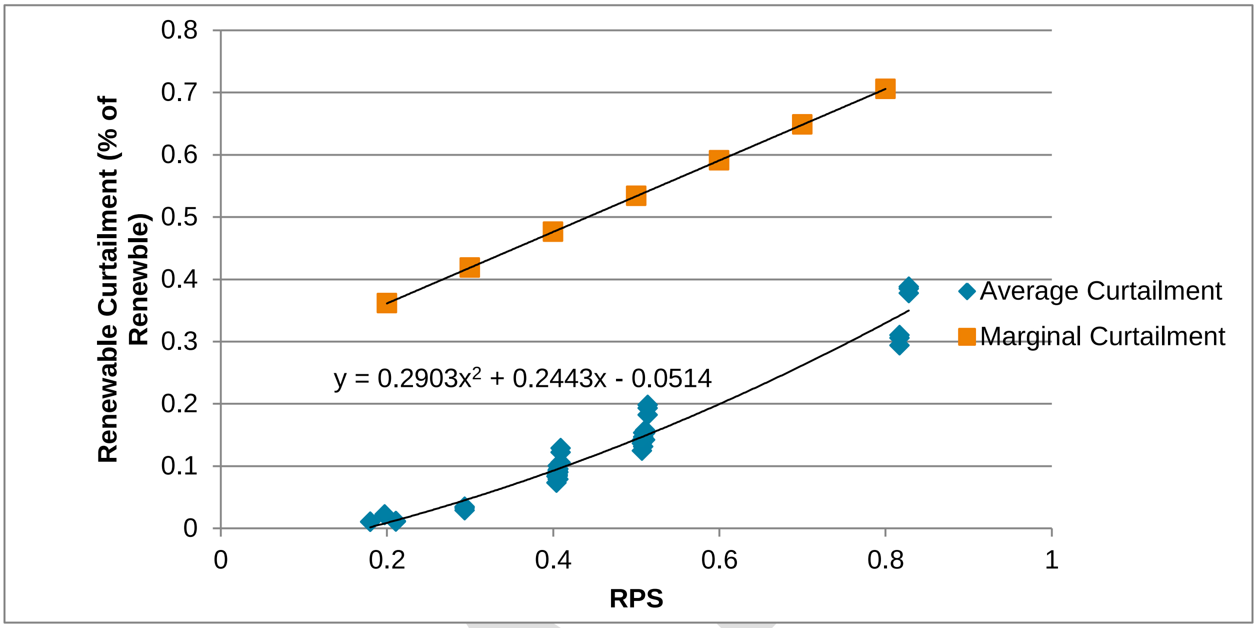


Figure 57. Renewable Curtailment Associated with Increasing Penetration



Average Curtailment represents % of entire renewable fleet curtailed at each RPS level

Marginal Curtailment represents the % of the next additional renewable MW that would be curtailed at each RPS level

The study results show that from a reserve margin perspective, the .2 LOLE standard is met with a 17.5% reserve margin. The modeled portfolios reliable when renewable curtailments are allowed. However, as renewable penetration increases closer to 40%, curtailment also increases substantially and the need for higher amounts of load following would be required in order to maintain system reliability. Results are summarized in Table 41.

Table 41. Renewable Penetration and Load Following

RPS	Required Load Following
20%	7% of Load
30%	13% of Load
40%	>15% of Load
50%	>15% of Load + Significant Additional Flexible Resources
80%	>15% of Load + Significant Additional Flexible Resources

Most Cost-Effective Portfolio

To identify the MCEP for the period 2017 through 2036, PNM examined hundreds of thousands of potential resource portfolios, accounting for multiple scenarios and sensitivity studies of differing resources, economic conditions, carbon prices, and customer demands. PNM developed alternative scenarios for economics, fuel pricing, and customer demand levels to test the sensitivity of resource portfolio to alternative assumptions and conditions. PNM presented these analyses to the Public Advisory Group during several meetings.

PNM determined the MCEPs by assessing a least-cost portfolio for each scenario. Differences in the input assumptions between scenarios resulted in a different system resource portfolio mix. For example, high gas price scenarios resulted in portfolios with less reliance on gas-fired plants than portfolios recommended for low gas price scenarios. Sensitivity analysis shows how robust the portfolio choices are within reasonable ranges of input assumptions. Monte Carlo analysis highlights the financial risk associated with a portfolio in an uncertain future. PNM used the Monte Carlo results to compare the two SJGS scenario portfolios under a range of gas prices and other input variables within the same analysis. This work helped identify risk mitigation strategies and confirm the importance of individual resource types within the MCEP.

Portfolios

Table 42 shows the loads and resources plan for the first 10 years of the MCEP. A 20 year plan is included in Appendix O.

Table 42. MCEP Loads and Resource Plan

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Forecasted System Peak Demand	1,830	1,839	1,843	1,867	1,891	1,911	1,916	1,923	1,937	1,948
Forecasted Incremental Energy Efficiency	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)
Forecasted Incremental Customer Sited PV	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)
Net System Peak Demand (MW)	**1,871**	**1,900**	**1,926**	**1,961**	**1,999**	**2,033**	**2,053**	**2,071**	**2,093**	**2,114**
Four Corners	200	200	200	200	200	200	200	200	200	200
San Juan	783	497	497	497	497	497	-	-	-	-
Total Coal Resources (MW)	**983**	**697**	**697**	**697**	**697**	**697**	**200**	**200**	**200**	**200**
Palo Verde Unit 1 & Unit 2	268	268	268	268	268	268	268	268	268	268
Palo Verde Unit 3	-	134	134	134	134	134	134	134	134	134
Total Nuclear Resources (MW)	**268**	**402**	**402**	**402**	**402**	**402**	**402**	**402**	**402**	**402**
Reeves	154	154	154	154	154	154	154	154	154	154
Afton	230	230	230	230	230	230	230	230	230	230

Lordsburg	80	80	80	80	80	80	80	80	80	80
Luna	189	189	189	189	189	189	189	189	189	189
Rio Bravo	138	138	138	138	138	138	138	138	138	138
Valencia	150	150	150	150	150	150	150	150	150	150
La Luz	40	40	40	40	40	40	40	40	40	40
Reciprocating Engines	-	-	-	-	-	-	41	41	41	41
Large Gas Turbine	-	-	-	-	-	-	187	187	187	187
Large Gas Turbine	-	-	-	-	-	-	187	187	187	187
Reciprocating Engines	-	-	-	-	-	41	41	41	41	41
Total Natural Gas Resources (MW)	**981**	**981**	**981**	**981**	**981**	**1,022**	**1,437**	**1,437**	**1,437**	**1,437**
Total Demand Response Programs (MW, Net of losses)	**45**	**47**	**48**	**49**	**51**	**53**	**54**	**56**	**57**	**59**
Wind Purchase (NMWEC)	10	10	10	10	10	10	10	10	10	10
Wind Purchase (Red Mesa)	5	5	5	5	5	5	5	5	5	5
Prosperity Battery Demo	1	1	1	1	1	1	1	1	1	1
Utility Scale Solar PV (22 MW - 2012 REPP)	12	12	12	12	12	12	11	11	11	11
Utility Scale Solar PV (20 MW - 2013 REPP)	11	11	11	11	11	11	11	10	10	10
Utility Scale Solar PV (23 MW - 2014 REPP)	16	15	15	15	15	15	15	15	15	15
Utility Scale Solar PV (40 MW - 2015 REPP)	30	30	30	30	29	29	29	29	28	28
PNM Sky Blue - 1.5 MW Solar	1	1	1	1	1	1	1	1	1	1
Dale Burgett Geothermal Plant	2	2	5	5	5	5	5	5	5	5

Data Center 1 Solar PV - 20 MW	-	-	-	-	-	-	11	11	11	11
Data Center 1 Solar PV - 40 MW	-	-	-	-	-	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	-	-	-	23	23	23	23	23	23
Data Center 1 Solar PV - 30 MW	-	-	-	23	23	23	23	23	23	23
Data Center 1 Solar PV - 40 MW	-	-	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	23	23	23	23	23	23	23	23	23
Data Center 1 Wind - 30 MW	-	-	-	-	-	1	2	2	2	2
Data Center 1 Wind - 50 MW	-	-	-	-	2	3	3	3	3	3
Data Center 1 Wind - 50 MW	-	-	-	3	3	3	3	3	3	3
Data Center 1 Wind - 50 MW	-	-	3	3	3	3	3	3	3	3
Solar PV for 2020 RPS	-	-	-	17	17	17	17	17	17	17
Wind for 2020 RPS	-	-	-	-	-	-	-	-	-	-
50 MW Solar PV	-	-	-	-	-	-	-	-	-	17
100 MW Solar PV	-	-	-	-	-	-	-	-	35	35
50 MW Solar PV	-	-	-	-	-	-	-	17	17	17
Total Renewable Resources (MW)	**87**	**109**	**144**	**186**	**211**	**242**	**253**	**270**	**305**	**321**
Total System Resources (MW)	**2,364**	**2,236**	**2,272**	**2,316**	**2,342**	**2,416**	**2,346**	**2,365**	**2,401**	**2,419**
Reserve Margin (MW)	**493**	**336**	**346**	**354**	**342**	**383**	**294**	**294**	**308**	**305**
Reserve Margin (%)	**26.4%**	**17.7%**	**18.0%**	**18.1%**	**17.1%**	**18.8%**	**14.3%**	**14.2%**	**14.7%**	**14.4%**

1. PNM assumes a capacity credit for renewable resources based on type of technology and contribution at the peak hour.
2. Demand response resources grossed up for transmission losses.
3. PNM assumes a 100% capacity credit for Prosperity Battery Demo.
4. Capacity credit for geothermal resource is based upon developer estimates.

Transmission

The existing transmission system adequately meets the needs of current loads and resources. PNM considered projected changes to loads and resources for the future and identified two items that merit further study to address. These studies are included in the four-year action plan:

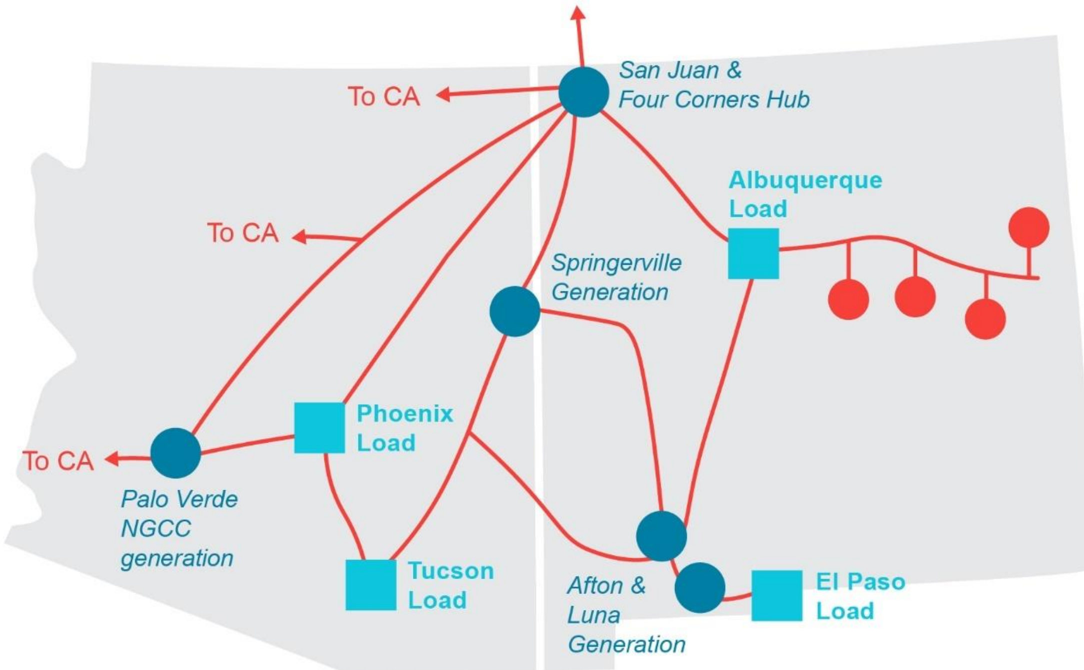
- Siting requirements for SJGS and FCPP replacement resources
- Additional transmission from eastern New Mexico is needed to support future wind energy supply to PNM's customers

Siting Requirements for SJGS and FCPP Replacement Resources

The effect of additional generating unit shut downs in the Four Corners area on operation of the transmission grid has not been studied beyond existing shutdowns of FCPP Units 1, 2 and 3 and SJGS Units 2 and 3. There would be a potential need to replace voltage control from the generating units with additional devices that can increase or reduce shunt reactive compensation in the area. It is likely that most control can be accomplished through use of new and existing switched shunt reactors or capacitors but significant frequent variation in loadings could also drive consideration of dynamic control like an Static Var Compensator (SVC). The existing transmission out of the Four Corner's area was optimized for transferring power to load centers in Arizona, California and New Mexico. Without the generation at the existing locations, it is likely that overall transfer capability of the system will be reduced below the historic transfer levels. Depending on the location and direction of future transfers on the existing transmission paths, there may be a need to modify or add series compensation or add flow control devices like a phase-shifting transformer to re-optimize the overall transfer capability of the system. Additional studies are needed to better define the voltage control requirements and limitations on transfer capability as a result of additional generating unit shutdowns in the area.

This IRP considered retiring SJGS in 2022 and the potential retirement of FCPP in 2031. PNM will need to replace the voltage support service provided by SJGS with other generation. Figure 58 shows how both the SJGS and FCPP sit between the Albuquerque/El Paso and Phoenix/Tucson load centers. If both plants are retired, reliable transmission system operations may require some form of voltage support at the Four Corners Hub. Additionally, new generation could benefit from the existing transmission facilities if it were located at SJGS. The overall PNM system will also benefit from a plant sited at the same location because of voltage support provided from that location. PNM will further study transmission system operational requirements associated with SJGS and FCPP retirements as part of the four-year action plan..

Figure 58. Transmission Network Map



Transmission Needed for Wind Resource Expansion

Because of weather conditions that result in consistent wind availability, New Mexico's best siting opportunity for wind resources is in eastern New Mexico. The existing transmission system includes a radial line from the BA switching station east of Albuquerque to the Blackwater HVDC converter station near Clovis, New Mexico. Pattern Energy Group, Inc. has developed the Broadview wind farm (297 MW) that interconnects to PNM's Blackwater station near the Texas border and plans to develop a second wind farm called Grady (200 MW) that will interconnect to their transmission line that is interconnected PNM's Blackwater station . Avangrid is developing the El Cabo wind farm (298 MW) that will interconnect to PNM's line near Clines Corners in June 2017.

The addition of these wind farms, along with the existing wind farms, will result in 1000 MW of requested transmission service on the EIP line. As a result, PNM will be installing a voltage support device, a Static VAR Compensator (SVC), to the EIP line scheduled to be in-service in March 2018 to accommodate these projects' transmission service needs. In addition, a synchronous condenser (i.e., essentially a generator without the turbine to provide synchronous current compensation) will be required at Blackwater station to offer the remaining of transmission service to the Grady windfarm.

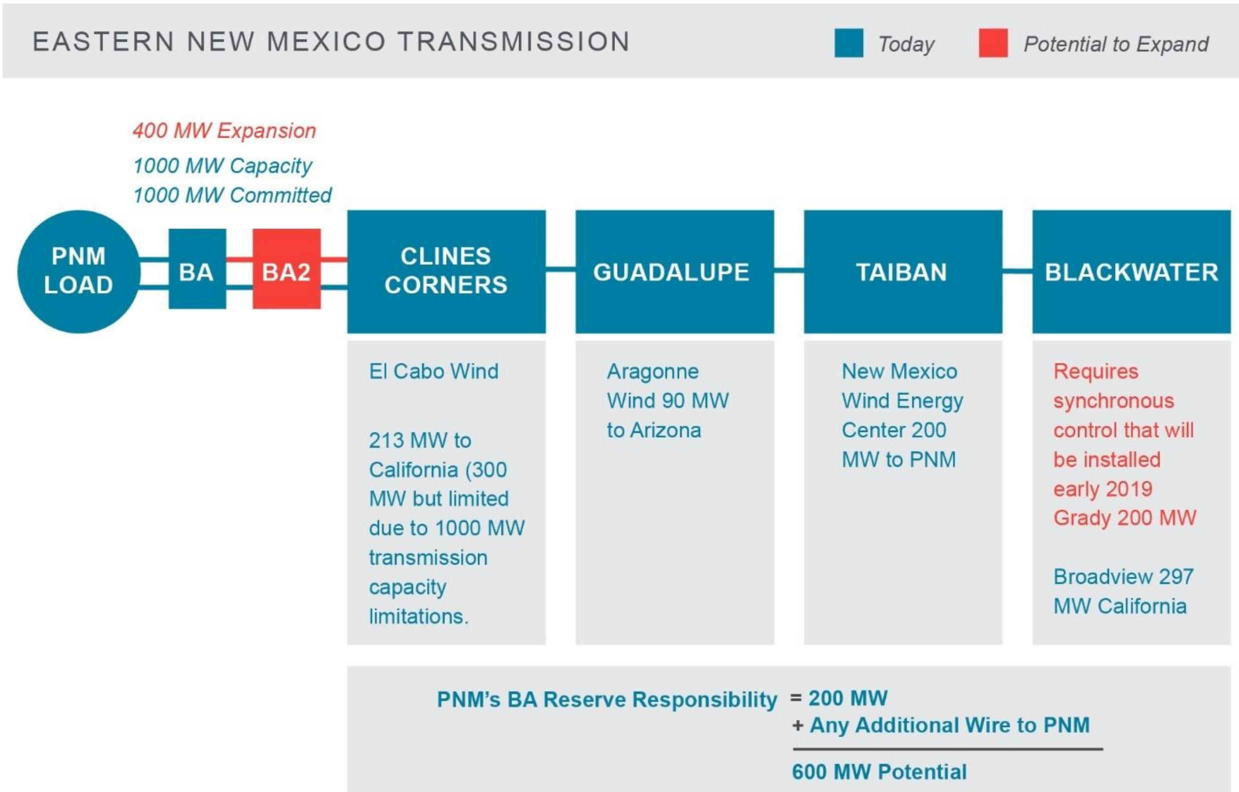
Table 43. Blackwater to Albuquerque Transmission Loads

Name	Size (MW)	Receiving Balancing Area
New Mexico Wind Energy Center	200	PNM
Broadview/Grady	497	California Independent System Operator
Aragonne Mesa	90	Arizona Public Service
El Cabo	213	California Independent System Operator
Total	**1,000**	

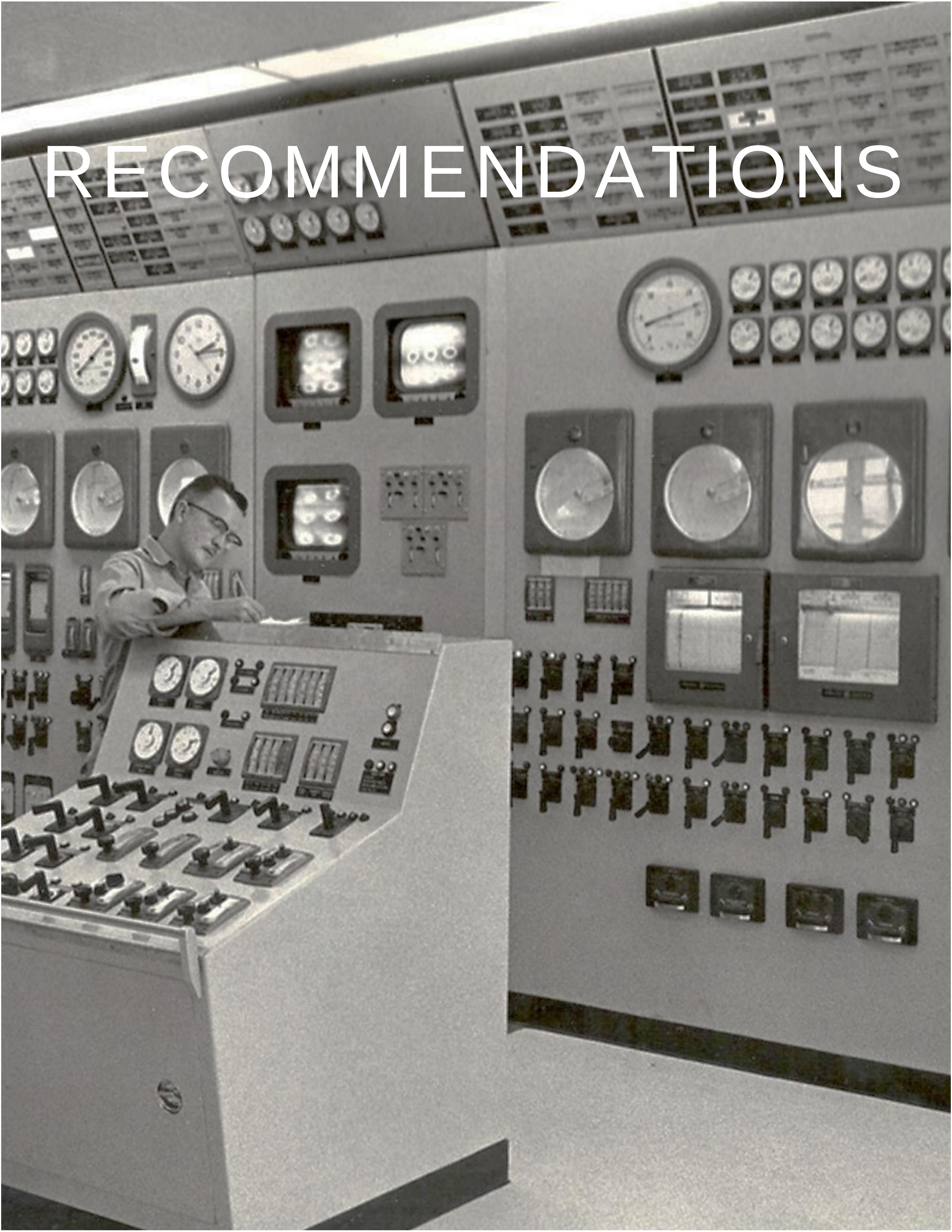
PNM characterized a potential transmission system resource of a 400-MW expansion of the eastern New Mexico transmission line to transmit an additional 400 MW of wind generation to PNM's customers as described in the Eastern New Mexico Transmission section above. A 400-MW expansion could provide sufficient wind generation to meet both PNM's RPS requirements and the currently projected data center requirement. The MCEP assumes the 400-MW expansion along with additional wind resources to ensure future RPS compliance along with renewable energy to supply to the projected new data center.

Adding 400 MW of wind capacity to the eastern New Mexico transmission line affects PNM's reliability metrics because the largest single hazard would be 400 MW. Figure 59 is an illustration of the loads and resources connected to the Blackwater to Albuquerque line, with and without the expansion. If the new transmission line trips out of service, delivery of the power supplied on this line will be curtailed. Each balancing area must account for this possibility when assessing the need for planning reserves; PNM's current largest single hazard is SJGS Unit 4. Through the benefit of a hazard-sharing agreement, this hazard is about 350 MW. If SJGS Unit 4 is retired, PNM's largest single hazard will fall to the Afton plant at 230 MW. Under an expanded transmission capacity and associated new wind generation, the largest single hazard would increase to 400 MW. The four-year action plan includes a feasibility study to identify the best option for PNM's customers.

Figure 59. Eastern New Mexico Transmission



RECOMMENDATIONS



RECOMMENDATIONS

This section provides a description of the MCEP and alternative plans to meet PNM's customer requirements from 2018 through 2036.

Most Cost-Effective Portfolio

The analysis for this IRP supports the following resource additions and retirements in the MCEP:

Before 2022

- Continue meeting the EUEA targets for implementation of PNM's energy efficiency and load management programs.
- Add renewable resources by 2020 for continued compliance with the Renewable Portfolio Standard.

In 2022

- Pursue retirement of PNM's remaining capacity at SJGS in 2022 after the expiration of the existing coal supply agreement.
- Retain the currently leased capacity at PVNGS.
- Replace the retired SJGS with a mix of renewable energy resources, quick-start natural gas peaking capacity, and potentially energy storage.

After 2022

- Build a new transmission line to access wind energy from eastern New Mexico.
- Maintain system reserves as load grows with renewable energy and gas peaking or energy storage additions.
- Plan to replace the RECs and energy from the New Mexico Wind Energy Center PPA that expires in 2028.
- Plan to replace the capacity provided by Valencia when the Valencia PPA expires in 2028.
- Pursue abandonment of PNM's capacity at the FCPP at the expiration of the current fuel supply agreement in 2031 and plan, in future IRPs, to replace the energy and capacity provided by the FCPP.

This portfolio provides the best balance of cost and reliability and results in a significant reduction in the environmental impact of providing energy to PNM's customers. PNM would have no more coal generation in its resource portfolio by 2031, and PNM will increase its renewable energy supply of total load to 32.6% in 2025. Figure 60 and Figure 61 show the proportions of energy served by different fuel sources in 2017 and 2025.

Figure 60. 2017 MCEP Energy Shares

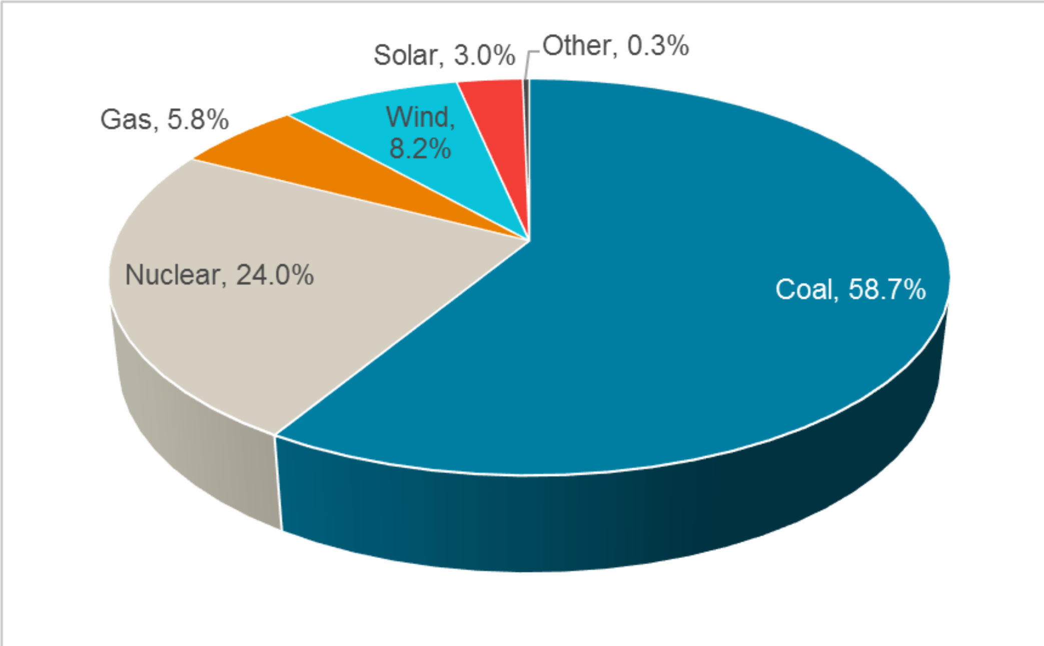
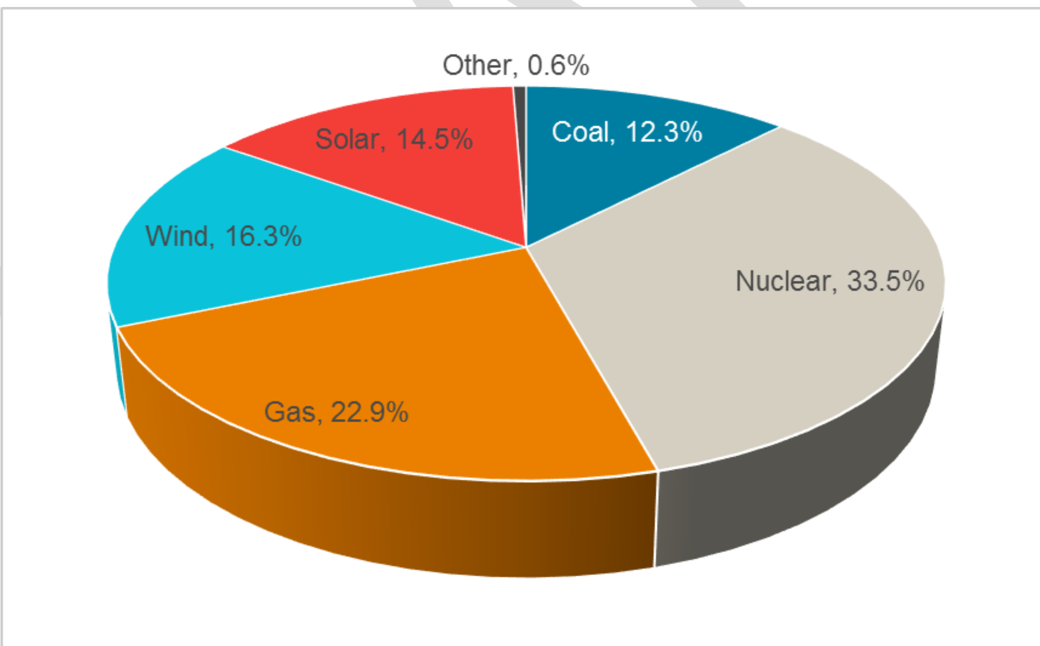


Figure 61. 2025 MCEP Energy Shares



This portfolio is the most cost-effective because it maintains a reasonable reliability expectation while achieving the following:

- Lowest projected customer cost
- Lowest carbon emission profile
- Elimination of coal generation in 2031

The MCEP achieves the lowest projected customer cost because it reduces fixed costs and operations of PNM's existing baseload resources while increasing flexibility to produce energy that better matches projected customers' future energy use. The lower carbon emission profile reduces environmental impacts while protecting against cost risk associated with known or reasonably anticipated air-emission environmental regulations. The MCEP also reduces risks of additional costs to customers from coal generation, the largest source of cost risk from known or reasonably anticipated or potential future air, water, and waste environmental regulations. A load and resource table that illustrates the type of resources and resource additions and retirements by year is provided in Appendix N

Alternate Portfolios

In addition to the MCEP, the following alternate portfolios also provide service with a reasonable reliability expectation. Based on current resource cost assumptions, these portfolios will likely result in a more expensive service cost or carry higher risk from volatile natural gas prices and potential environmental regulations.

Continue Coal Baseload

The least-cost portfolio that continues SJGS through the planning period includes the following resource additions and retirements:

Before 2022

- Continue meeting the EUEA targets for implementation of PNM's energy efficiency and load management programs.
- Add renewable resources by 2020 for continued compliance with the Renewable Portfolio Standard.

2022 and Beyond

- Build a new transmission line to access wind energy from eastern New Mexico.
- Maintain system reserves as load grows with renewable energy and gas peaking or energy storage additions.
- Plan to replace the RECs and energy from the New Mexico Wind Energy Center PPA that expires in 2028.
- Plan to replace the capacity provided by Valencia when the Valencia PPA expires in 2028.
- Pursue abandonment of PNM's capacity at the FCPP at the expiration of the current fuel supply agreement in 2031 and plan in future IRPs to replace the energy and capacity provided by the FCPP.

The MCEP is preferred over this portfolio because maintaining the fixed costs and high-capacity factors associated with coal baseload does not provide flexible operations to match future projected customer use. As PNM and PNM's customers add more renewable energy, there will be less need for traditional generation year over year. The MCEP addresses this by reducing traditional baseload generation while increasing flexible generation operation to take advantage of the low renewable energy costs when available. Continuing SJGS also subjects PNM customers to risks of higher costs associated with possible future environmental regulations given the continued reliance on coal-fired generation.

Higher than 50% Renewable Energy Use

PNM examined increasing renewable energy use to levels beyond 50% of energy supplied. This portfolio was created by doubling the renewable energy additions in the MCEP, and results in 50% renewable energy supply by 2032. In addition to the portfolio additions and retirements reflected by the MCEP, increasing renewable energy supply beyond 50% must be supported by the following to maintain reasonable reliability expectations:

- Procure a similar quantity of gas peaking resources as in the MCEP.
- Portfolio costs are slightly higher than the MCEP in the capacity expansion analysis, which does not include the significant increase in load following and system flexibility described in the reliability analysis
- Renewable energy curtailments will become a common, low cost reliability management option.

These observations are driven by the need to maintain reliability at reasonable levels considering currently available storage technology. As technology changes, PNM will revisit this portfolio in future IRPs to reassess whether renewable energy use in excess of 50% of energy supplied is cost-effective. This alternate portfolio shows how a 50% renewable energy portfolio can be feasible, and emphasizes the need for flexibility in the MCEP.

Abandon PVNGS-Leased Capacity

In the portfolio analysis, PNM treated the existing leased capacity at PVNGS as a resource available for purchase upon lease expiration. The IRP analysis found that retaining the leased capacity is favorable because of its high reliability, no air emissions, and the hedge it provides against volatile natural gas prices. If assumptions change and PNM does not retain the leased capacity, the following changes to the MCEP would occur:

- Procure a low heat rate natural gas combined cycle generation facility to replace PVNGS energy
- A 9% increase in CO2 emissions over the planning period
- A 30% increase in the cost risk range calculated in the Monte Carlo analysis because of natural gas cost volatility
- Paying ongoing financial obligations associated with this resource

Retaining the PVNGS-leased capacity does not preclude pursuit of a portfolio with renewable energy resource supplying over 50% of energy. However, the same technology improvement required to efficiently operate the "Higher than 50% Renewable Use" portfolio would also be needed if PNM abandons the PVNGS-leased capacity.

Four-Year Action Plan

The four-year plan detailed in Table 44 provides actions PNM will take to implement the MCEP, which include monitoring technologies that could enable a cost-effective Higher than 50% Renewable Use portfolio.

Table 44. MCEP Four-Year Action Plan

Task	Action	Timing
Energy efficiency and load management	File plans to continue energy efficiency and load management programs in accordance with NMPRC Rules.	File a plan at least every three years (most recent application was in May 2017).
	Complete DSM potential study to assess availability of cost-effective energy efficiency and load management beyond EUEA requirements.	2017
2020 RPS compliance	Procure resources to maintain compliance with RPS when standard increases from 15% to 20% in 2020.	2017 RFP, request resources in 2018 Renewable Procurement Plan filing
Explore options for system supply and reliability	Assess costs and benefits of joining the California EIM.	Begin study in 2017, future action depends on study results
	Assess cost to maintain Reeves Generating Station and develop plan to maintain voltage support at Reeves long term	Study cost to maintain Reeves in 2017, assess reliability requirements and long term investment strategy in context of need for SJGS replacement capacity
	Participate in regional transmission planning groups	Ongoing
Pursue abandonment of SJGS in 2022	RFP for Energy Storage	2017 to test MECP replacement mix, refresh bids before 2021
	All Source Renewable RFP	2017 for 2020 RPS, refresh bids prior to 2021
	Procure PVNGS Leased Capacity	2017 for inclusion in SJGS Abandonment filing
	Request SJGS abandonment consistent with IRP MCEP	2018 filing
	Power Flow Study to determine SJGS replacement resource siting requirements	2018 CCN applications for SJGS replacement resources
	RFP for Flexible Gas Capacity	2019 to support CCN applications for 2022 in-service date
New transmission capacity for wind from eastern New Mexico	Assess potential for development or participation in transmission system expansion.	Begin process in 2017

APPENDICES

APPENDICES

The following appendices provide details of the inputs and analyses presented in the previous sections.

Appendix A contains detailed annual demand and energy forecasts for each of the low, mid, and high forecast scenarios, along with graphs showing the typical weekly load profiles for winter, spring, summer, and fall.

Appendix B provides full names of the acronyms used throughout this document.

Appendix C contains a glossary of IRP terminology used throughout the document.

Appendix D contains a detailed description of the balancing area reliability requirements.

Appendix E contains a list of PNM's existing transmission facilities

Appendix F describes an analysis of how PNM's variable energy resources are integrated

Appendix G describes rules and regulations that are considered in the IRP analysis.

Appendix I provides details of CO2 and gas price forecasts.

Appendix J provides cost and performance data for PNM's existing generating resources.

Appendix K provides detailed cost and performance data for new supply-side resource options

Appendix L contains the least cost portfolios for each of the 21 SJGS Continues scenarios.

Appendix M contains the least cost portfolios for each of the 21 SJGS Retires scenarios.

Appendix N Load and Resources Table..

Appendix A: Load Forecast Details

Figure 62. 2017 IRP Mid–Low–High Demand Forecasts (one of two)

2017 IRP (MID - LOW - HIGH) DEMAND FORECASTS																				
MID DEMAND (MW)	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*
2017 IRP	*Jun-17*	*Jun-18*	*Jun-19*	*Jun-20*	*Jun-21*	*Jun-22*	*Jun-23*	*Jun-24*	*Jun-25*	*Jun-26*	*Jun-27*	*Jun-28*	*Jun-29*	*Jun-30*	*Jun-31*	*Jun-32*	*Jun-33*	*Jun-34*	*Jun-35*	*Jun-36*
PNM Forecasted Load Total	1,911	1,961	2,009	2,056	2,108	2,163	2,201	2,230	2,260	2,291	2,323	2,356	2,390	2,424	2,460	2,496	2,534	2,572	2,610	2,650
EE (incremental)	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)	(136)	(138)	(146)	(147)	(142)	(138)	(135)	(134)	(129)	(122)
PV-DG (incremental)	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(47)	(48)
Net System Total	1,871	1,900	1,926	1,961	1,999	2,041	2,064	2,082	2,105	2,125	2,150	2,180	2,204	2,236	2,276	2,315	2,354	2,392	2,435	2,480
LOW DEMAND (MW)	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*
2017 IRP	*Jun-17*	*Jun-18*	*Jun-19*	*Jun-20*	*Jun-21*	*Jun-22*	*Jun-23*	*Jun-24*	*Jun-25*	*Jun-26*	*Jun-27*	*Jun-28*	*Jun-29*	*Jun-30*	*Jun-31*	*Jun-32*	*Jun-33*	*Jun-34*	*Jun-35*	*Jun-36*
PNM Forecasted Load Total	1,906	1,896	1,904	1,929	1,953	1,963	1,976	1,991	2,008	2,027	2,046	2,067	2,089	2,112	2,135	2,159	2,184	2,209	2,235	2,261
EE (incremental)	(23)	(36)	(51)	(63)	(77)	(91)	(105)	(116)	(124)	(135)	(143)	(147)	(157)	(161)	(157)	(154)	(153)	(154)	(151)	(145)
PV-DG (incremental)	(18)	(31)	(42)	(44)	(44)	(45)	(46)	(47)	(48)	(49)	(51)	(52)	(53)	(54)	(55)	(57)	(58)	(59)	(60)	(62)
Net System Total	1,865	1,830	1,810	1,822	1,832	1,827	1,825	1,828	1,835	1,842	1,852	1,869	1,879	1,897	1,923	1,948	1,973	1,996	2,024	2,055
HIGH DEMAND (MW)	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*
2017 IRP	*Jun-17*	*Jun-18*	*Jun-19*	*Jun-20*	*Jun-21*	*Jun-22*	*Jun-23*	*Jun-24*	*Jun-25*	*Jun-26*	*Jun-27*	*Jun-28*	*Jun-29*	*Jun-30*	*Jun-31*	*Jun-32*	*Jun-33*	*Jun-34*	*Jun-35*	*Jun-36*
PNM Forecasted Load Total	1,915	2,003	2,078	2,175	2,269	2,361	2,439	2,509	2,561	2,602	2,645	2,688	2,732	2,778	2,824	2,872	2,921	2,971	3,023	3,076
EE (incremental)	(23)	(35)	(50)	(61)	(73)	(85)	(97)	(105)	(111)	(118)	(123)	(123)	(129)	(128)	(122)	(118)	(114)	(112)	(107)	(100)
PV-DG (incremental)	(18)	(19)	(21)	(19)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(26)	(27)	(28)	(29)	(31)	(32)	(33)	(34)
Net System Total	1,875	1,948	2,007	2,095	2,176	2,257	2,321	2,382	2,427	2,461	2,497	2,540	2,577	2,622	2,673	2,725	2,776	2,828	2,884	2,943

Figure 63. 2017 IRP Mid-Low-High Demand Forecasts (two of two)

2017 IRP (MID - LOW - HIGH) ENERGY FORECASTS

MID ENERGY (GWH) 2017 IRP	*Forecast 2017*	*Forecast 2018*	*Forecast 2019*	*Forecast 2020*	*Forecast 2021*	*Forecast 2022*	*Forecast 2023*	*Forecast 2024*	*Forecast 2025*	*Forecast 2026*	*Forecast 2027*	*Forecast 2028*	*Forecast 2029*	*Forecast 2030*	*Forecast 2031*	*Forecast 2032*	*Forecast 2033*	*Forecast 2034*	*Forecast 2035*	*Forecast 2036*
PNM Forecasted Load Total	9,040	9,195	9,544	9,862	10,170	10,475	10,650	10,729	10,802	10,902	10,956	11,037	11,111	11,190	11,269	11,351	11,428	11,507	11,588	11,671
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE (incremental)	(197)	(284)	(401)	(511)	(610)	(695)	(756)	(815)	(872)	(928)	(969)	(988)	(1,001)	(1,006)	(1,000)	(984)	(959)	(932)	(906)	(881)
PV-DG (incremental)	(47)	(83)	(118)	(150)	(151)	(153)	(156)	(159)	(161)	(164)	(167)	(170)	(173)	(176)	(179)	(182)	(185)	(188)	(191)	(194)
Net System Total	8,796	8,828	9,025	9,201	9,410	9,627	9,737	9,755	9,769	9,809	9,820	9,879	9,938	10,009	10,091	10,186	10,284	10,388	10,490	10,597

LOW ENERGY (GWH) 2017 IRP	*Forecast 2017*	*Forecast 2018*	*Forecast 2019*	*Forecast 2020*	*Forecast 2021*	*Forecast 2022*	*Forecast 2023*	*Forecast 2024*	*Forecast 2025*	*Forecast 2026*	*Forecast 2027*	*Forecast 2028*	*Forecast 2029*	*Forecast 2030*	*Forecast 2031*	*Forecast 2032*	*Forecast 2033*	*Forecast 2034*	*Forecast 2035*	*Forecast 2036*
PNM Forecasted Load Total	8,998	8,980	9,105	9,328	9,465	9,460	9,461	9,454	9,445	9,436	9,428	9,421	9,411	9,402	9,394	9,387	9,376	9,368	9,359	9,352
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE (incremental)	(197)	(284)	(402)	(514)	(617)	(706)	(773)	(839)	(905)	(971)	(1,022)	(1,053)	(1,079)	(1,096)	(1,103)	(1,100)	(1,087)	(1,072)	(1,057)	(1,042)
PV-DG (incremental)	(47)	(102)	(156)	(207)	(208)	(210)	(213)	(216)	(219)	(221)	(224)	(227)	(230)	(233)	(236)	(239)	(242)	(245)	(248)	(251)
Net System Total	8,754	8,594	8,547	8,607	8,640	8,544	8,474	8,399	8,322	8,244	8,182	8,141	8,102	8,073	8,055	8,048	8,047	8,051	8,054	8,059

HIGH ENERGY (GWH) 2017 IRP	*Forecast 2017*	*Forecast 2018*	*Forecast 2019*	*Forecast 2020*	*Forecast 2021*	*Forecast 2022*	*Forecast 2023*	*Forecast 2024*	*Forecast 2025*	*Forecast 2026*	*Forecast 2027*	*Forecast 2028*	*Forecast 2029*	*Forecast 2030*	*Forecast 2031*	*Forecast 2032*	*Forecast 2033*	*Forecast 2034*	*Forecast 2035*	*Forecast 2036*
PNM Forecasted Load Total	9,088	9,284	9,670	10,130	10,749	11,339	11,792	12,149	12,368	12,522	12,625	12,783	12,892	13,033	13,171	13,318	13,461	13,614	13,764	13,924
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EE (incremental)	(195)	(278)	(389)	(493)	(584)	(660)	(711)	(760)	(805)	(850)	(878)	(885)	(888)	(882)	(867)	(846)	(817)	(786)	(756)	(726)
PV-DG (incremental)	(47)	(64)	(79)	(93)	(93)	(96)	(99)	(101)	(104)	(107)	(110)	(112)	(115)	(118)	(121)	(124)	(127)	(130)	(134)	(137)
Net System Total	8,847	8,942	9,201	9,544	10,071	10,583	10,982	11,288	11,459	11,564	11,637	11,786	11,889	12,033	12,182	12,348	12,517	12,698	12,875	13,061

Figure 64 through Figure 67 show a typical week load profile on PNM's system in January, April, July, and October to illustrate the variability of load on the system caused by the season of the year as well as the differences in load variability during the day and week during those months. Dotted lines illustrate the impact of wind and solar resources on PNM's load patterns.

Figure 64. January Load Profile: Typical Week

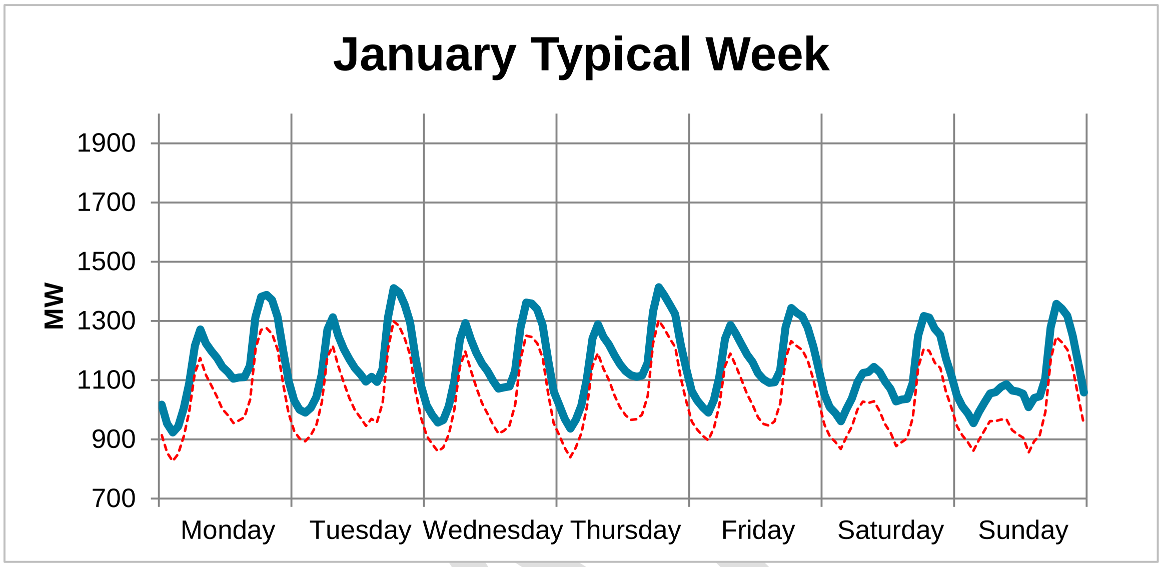


Figure 65. April Load Profile: Typical Week

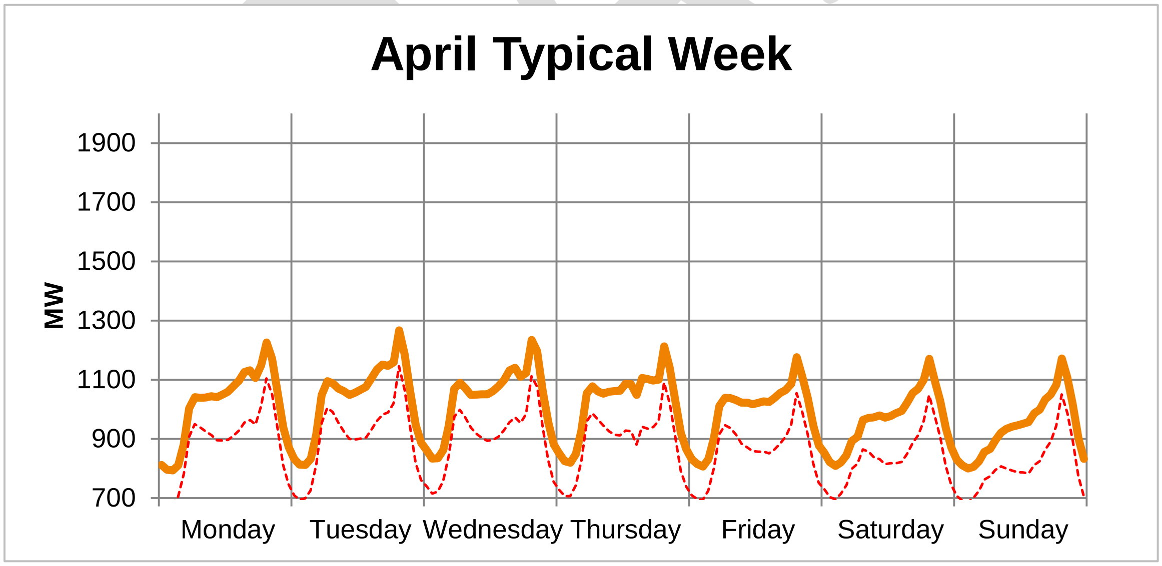


Figure 66. July Load Profile: Typical Week

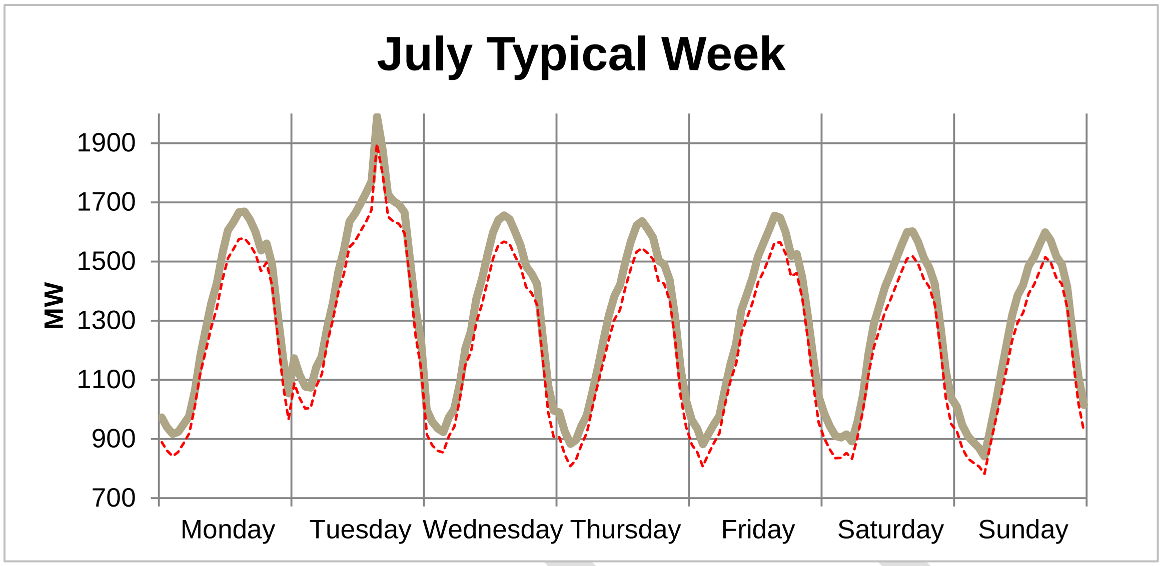
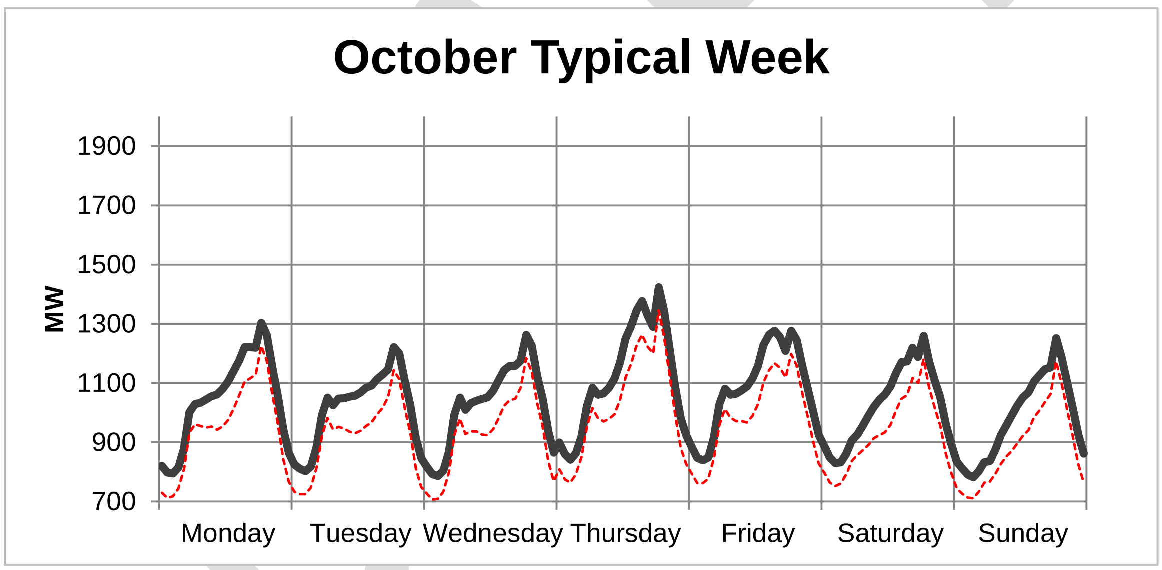


Figure 67. October Load Profile: Typical Week



Appendix B: Acronym List

APS: Arizona Public Service Company

Btu: British thermal unit

BA: Balancing Authority

CAA: Clean Air Act

CCN: Certificate of Convenience and Necessity

CO_2: Carbon dioxide

COP: Conferences of the Parties

DCS: Disturbance Control Standard

DG: Distributed Generation

DSM: Demand-Side Management

EGU: Electric Generating Unit

EPA: Environmental Protection Agency

EPRI: Electric Power Research Institute

EUEA: Efficient Use of Energy Act 62-17 NMSA

FCPP: Four Corners Power Plant

FERC: Federal Energy Regulatory Commission

GE: General Electric Company

GHG: Greenhouse Gas

GWh: Gigawatt-hour

IRP: Integrated Resource Plan

kW: Kilowatt, also shown as kW; a measure of capacity equal to 1,000 watts

kWh: Kilowatt-hour, a measure or energy produced or consumed

lbs: Pounds

MCEP: Most cost-effective portfolio

MW: Megawatt

MWh: Megawatt-hour

NDCs: Nationally Determined Contributions

NERC: North American Electric Reliability Council

NMAC: New Mexico Administrative Code

NMPRC: New Mexico Public Regulation Commission

NMWEC: New Mexico Wind Energy Center

NSPS: New Source Performance Standards

OATT: Open Access Transmission Tariff

Peak RC: WECC reliability coordinator

PPA: Power Purchase Agreement

PV: Photovoltaic

PVNGS: Palo Verde Nuclear Generating Station located near Phoenix, Arizona

REC: Renewable Energy Certificate

RFP: Request for Proposals

RGS: Reeves Generating Station

RPS: Renewable Portfolio Standard

SJGS: San Juan Generating Station located near Farmington, New Mexico

SPP: Southwest Power Pool

SRSG: Southwest Reserve Sharing Group

TAG: Technical Assessment Guide (by EPRI)

TEP: Tucson Electric Power Company

TOU: Time of Use

UNFCCC: United Nations Framework Convention on Climate Change

WECC: Western Electricity Coordinating Council

Appendix C: Glossary of IRP Terminology

95th percentile: A value on a scale of 100 that indicates the percent of a distribution that is equal to or below 95% of the distribution (also referred to as *upper-tail*)

ACE Diversity Interchange: Power system control areas within three major (and essentially separate) areas of North America are interconnected electrically, thus enjoying vastly improved reliability and economy of operation compared to operating in isolation. Each must continually balance load, interchange, and generation to minimize adverse influence on neighboring control areas and interconnection frequency. This requires investment in control systems and the sacrifice of some fuel conversion efficiencies to achieve the objective of complying with minimum control performance standards set by the North American Electric Reliability Council (NERC). Control also increases wear and tear on machinery in the pursuit of these goals. Area control area (ACE) and area diversity interchange (ADI) offer a means of reducing this control burden without undue investment or sacrifice by any participant in a group. (Source: IEEE, http: //ieeexplore.ieee.org/Xplore/login.jsp?url=/iel1/59/8797/00387953.pdf?arnumber=387953)

Aeroderivative: A type of gas turbine for electrical power generation

Availability factor: The ratio of the time a generating facility is available to produce energy at its rated capacity, to the total amount of time in the period being measured, as defined by the IRP Rule

Avoided costs: The incremental cost to a utility for capacity and/or energy that could be avoided if another incremental resource addition such as energy efficiency were added that deferred or eliminated the need for the original addition

Base load: A resource that is most economically used by running at a capacity factor of 65% or greater on an annual basis. *See also* capacity factor.

Biomass resource: As defined by the IRP Rule, a recognized renewable resource type that uses renewable fuels such as agriculture or animal waste, small diameter timber, salt cedar and other phreatophyte or woody vegetation removed from river basins or watersheds, landfill gas and anaerobically digested waste biomass. *See also* renewable energy

Biomass Study: PNM Biomass Assessment: Status Report

Cap and trade: A regulatory body sets a cap on emissions of a designated pollutant, and sells permits equivalent to a firm's emissions. Firms that need to increase their emission permits must buy them from those who require fewer permits.

Capacity factor: Actual energy generated over a certain time period divided by theoretical ability to generate electricity over that same time period. Capacity factor is most often referenced as an annual calculation.

Capacity uprate: The maximum power level at which a nuclear power plant may operate

Carbon dioxide: Carbon dioxide (CO_2) is an important greenhouse gas because it is thought to contribute to global warming. Although it is not currently a regulated pollutant, it is the subject of pending federal legislation seeking to make it a regulated pollutant. That legislation would seek to reduce its CO_2 production by penalizing power plants for their emission into the atmosphere. An NMPRC Order in Case No. 06-00448-UT requires that electric utilities use the following standardized prices for carbon emissions in their IRP filing: $8, $20, and $40 per metric ton for their low, medium, and high price sensitivities, respectively.

Centralized solar: Thermal solar facility that concentrates sunlight to collect heat and uses that heat to create steam that then drives a steam turbine to create electric generation (also referred to as *concentrating solar*)

Climate change: A significant change in measures of climate, including temperature, precipitation, or wind, that lasts for an extended period of time, resulting from natural factors or human activities that change the atmosphere's composition and the land surface

Combined cycle gas turbine: For electric generation, *combined cycle* refers to a gas turbine that generates electricity and heat in the exhaust used to make steam, which then drives a steam turbine to generate additional electricity.

Constrained transmission: A transmission system that can no longer accommodate additional capacity to meet demand is constrained.

Conventional resources: Coal, nuclear, and natural gas resources that have historically been the most commonly used to supply electricity (also referred to as *traditional resources*)

Crediting: A billing mechanism that credits distribution generation system owners for electricity they add to the grid. When a home or business is net-metered, electricity generated is credited against what electricity is consumed when the home or business electricity use exceeds the system's output. Customers are only billed for their "net" energy use.

Demand response: A resource comprising programs that compensate electricity users in exchange for the ability to interrupt or reduce their electric consumption when system demand is particularly high and/or system reliability is at risk.

Demand: Usage at a point in time, measured in MW or kW

Demand-side resources: As defined by the IRP Rule, energy efficiency, and load management, as those terms are defined in the Efficient Use of Energy Act

Dispatchability: The ability of a generating unit to increase or decrease generation, or to be brought online or shut down at the request of a utility's system operator

Distributed generation: Electric generation that is sited at a customer's premises, providing energy to the customer load at that site and/or providing electric energy for use by multiple customers in contiguous distribution substation areas. In this report, it refers to PNM customer-sited, renewable, distributed generation program for solar photovoltaic systems less than 10 kilowatts in size.

Duty cycle: Generating facility design that determines how a facility is operated. Duty Cycle classifications are baseload, intermediate, or peaking.

EE Rule: Energy Efficiency Rule (17.7.2 New Mexico Administrative Code)

Emergency energy: Energy purchases to meet unserved load

Energy efficiency: Measures, including energy conservation measures or programs that target consumer behavior, equipment, or devices to result in a decrease in consumption of electricity without reducing

the amount or quality of energy services, as defined by the IRP Rule

Energy: Usage over a period of time, measured in GWh, MWh, or kWh

Equivalent availability: Typically referred to as *Equivalent Availability Factor* (*EAF*), the proportion of hours in a given time period that a resource is available to generate at full capacity

Financial risk: Expected cost to the customer and the variability and uncertainty of future cost outcomes.

Fixed cost: Costs that are independent of output. *Contrast* variable costs.

Forced outage rate: Percentage of time a unit is not operational when it is expected to be in service

Geothermal Study: Geothermal Resource Development Needs in New Mexico

Geothermal: Electric generation fueled by heat from geologic formations, which qualifies as a renewable resource under 17.9.572 NMAC

Heat rate: The ratio of energy inputs used by a generating facility expressed in BTUs (British Thermal Units) to the energy output of that facility expressed in kilowatt-hours, as defined by the IRP Rule

Intermediate: A resource that is most economically run at capacity factors between 20% and 65% of the time on an annual basis. *See also* capacity factor.

Itron Potential Study: Public Service New Mexico Electric Energy Efficiency Potential Study, dated September 20, 2006

IRP Rule: Integrated Resource Plan for Electric Utilities, NMPRC Rule 17.7.3 New Mexico Administrative Code (17.7.3 NMAC).

Jurisdictional load: Case 3137 Stipulation identifies jurisdictional load as New Mexico retail load and wholesale firm requirement customers contracted prior to September 2, 2002.

Load duration curve: Illustration of the relationship between generating capacity requirements and capacity utilization. The load duration curve helps determine which type of resource best matches system load requirements.

Load and Resources: A load and resources table shows annual balance between load and the resources to meet the load, and includes the reserve margin calculation

Load factor: Peak demand divided by average demand

Load forecasting: The prediction of the demand for electricity over the planning period for the utility, as defined by the IRP Rule

Load management: Measures or programs that target equipment or devices to decrease peak electricity demand or shift demand from peak to off-peak periods, as defined by the IRP Rule

Load-following resource: This resource has a response rate that can meet normal fluctuations in load.

Loss of load probability: Percent of time load is not served

Marginal cost: The highest system resource cost for the hour

Mean: The expected value of a random variable (of a probability distribution), which is also called the *population mean*

Monte Carlo: Risk analysis technique utilizing multiple iterations calculated using random draws for sensitivity variables from a defined distribution for the variables

Most cost-effective resource portfolio: Those supply-side resources and demand-side resources that minimize the net present value of revenue requirements proposed by the utility to meet electric system demand during the planning period consistent with reliability and risk considerations, as defined by the IRP Rule

Nameplate capacity: The rated output of an electrical generator; it can also refer to the rated capacity of a power plant.

Net present value: The difference between the present values of cash inflows and the present value of cash outflows

Network transmission service: The transmission of capacity and energy from network generating resources to PNM's load.

Non-spinning reserves: The extra generating capacity that is not currently connected to the system, but can become available after a short delay

Particulate matter: A complex mix of extremely small particles and liquid droplets, including acids, organic chemicals, metals, and soil and dust, creating particle pollution

Peak demand: Occurs when demand for energy is at its greatest

Peak shaving: A strategy used to reduce electricity use during times of peak demand, typically employed through demand-response programs

Peaking: A resource that is most economically run at a capacity factor of less than 20%. See also *capacity factor*

Photovoltaic solar: Solar generation that uses photovoltaic panels to convert sunlight directly to energy

Planning period: The future period for which a utility develops its IRP. For purposes of this rule, the planning period is 20 years, from 2014–2033.

Plug-in hybrids: Hybrid automobiles whose batteries are recharged by plugging into an electric socket

Point-to-point transmission service: Delivery of power from one location to another, without branching to other locations

Portfolio: A combination of resource additions/assets over the planning period that meet the reserve margin criteria

Probability distribution: Describes the likelihood of a random parameter over a range of possible values

Public utility: As defined by the IRP Rule, public utility or utility has the same meaning as in the Public Utility

Act, except that it does not include a distribution cooperative utility, as defined in the Efficient Use of Energy Act

Qualifying facilities: FERC established a new class of generating facilities that would receive special rate and regulatory treatment to support implementation of the Public Utility Regulatory Policies Act of 1978. Generating facilities fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities.

Rankine cycle: A heat engine with a vapor power cycle commonly found in power plants

Rate rider: According to State Statute 62-3-3-H, "Rate" means every rate, tariff, charge, or other compensation for utility service rendered or to be rendered by a utility and every rule, regulation, practice, act, requirement, or privilege in any way relating to such rate, tariff, charge, or other compensation and any schedule or tariff or part of a schedule or tariff thereof.

Reasonable Cost Threshold: is a customer protection mechanism that limits the customer bill impact resulting from renewable energy procurements by utilities. It is the cost level established by the Commission above which a public utility shall not be required to add renewable energy to its electric energy supply portfolio pursuant to the renewable portfolio standard.

Regional Entity: According to NERC, "NERC works with eight regional entities to improve the reliability of the bulk power system. The members of the regional entities come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico."

Regional haze: According to the EPA, regional haze is visibility impairment that is produced by activity that emits fine particles and their precursors over a geographic area.

Reliability: The ability of the electric system to supply the demand and energy requirements of the customers when needed and to withstand sudden disturbances

Renewable energy: As defined by the IRP Rule, electrical energy generated by means of a low or zero emissions generation technology with substantial long-term production potential and generated by use of renewable energy resources that may include solar, wind, hydropower, geothermal, fuel cells that are not fossil fueled, and biomass resources. See *biomass resource*

Renewable resources: Generation resources that are based on a renewable fuel supply

Retail sales: The sale of energy to end users

Risk plot: The process of transposing a distribution histogram by measuring the mean and the 95th percentile and plotting the mean on the x-axis and the 95th percentile on the y-axis

Scenario: A combination of sensitivity values used to generate portfolios

Sensitivity: A variable that has a significant impact on risk evaluation

Solar: Electric generation fueled directly by sunlight

Solar hybrid: A thermal solar facility with the ability to supplement heat from the sun with heat derived by

burning natural gas

Spinning reserves: Backup energy production capacity that can be available to a transmission system within 10 minutes and can operate continuously for at least two hours after being brought online

Spot prices: The price quoted for immediate settlement (payment) of a commodity

Stochastic analysis: Stochastic financial risk analysis

Strategist®: The resource portfolio modeling software that PNM uses for resource plan optimization. Strategist® is a registered trademark of Ventyx.

Total system costs: Total sum of annual costs for meeting the system's energy requirements with all resources

Upper tail: A value on a scale of 100 that indicates the percentage of a distribution that is equal to or below 95% of the distribution (also referred to as *95th percentile*)

Tri-State: Tri-State Generation and Transmission cooperative

Valencia: Valencia Generation Facility located near Belen, New Mexico

Variable costs: Costs that change with unit output. *Contrast* fixed costs

Water intensity: A measure of the water resource needed to generate over a defined period

Wheeling: Transportation of electric power over transmission lines

Wind: Electric generation fueled by wind turbines

Appendix D: Detailed Explanation of Primary MCEP Standards

This appendix provides a detailed explanation of the three primary MCEP standards for PNM's BA discussed in the Planning Considerations Section under Operating Reserves.

BAL-002-1

BAL-002-1 is the Disturbance Control Performance Standard which sets requirements to restore supply and demand balance in the event of a system disturbance. It defines the allowable recovery period and the requirement to establish new reserves following a disturbance. To ensure compliance, PNM must maintain contingency reserves, which are resources under PNM's control that can be activated to respond to Disturbance Control Standard (DCS) events within the required time periods. An example of a typical DCS event would be the loss of a BA's single largest hazard. If PNM does not comply with these standards, not only can monetary penalties be assessed, but PNM is also exposed to a load-shed directive from WECC's Peak Regional Coordinator (RC), who monitors system reliability across WECC. System recovery is required to occur within 15 minutes and reserves must be restored within 60 minutes.

Within the 15-minute DCS recovery period, the first five minutes is when the BA conducts the following activities:

- Call and activate non-spinning reserves, which must be available within 10 minutes.
- Verify that PNM is receiving assistance from its reserve sharing group
- Activate any hazard share agreements

The remaining 10 minutes of the DCS reserve recovery period allow for spinning and non-spinning units to ramp up to their 10-minute delivery capability. At the end of the 15-minute recovery period, PNM's area control error must return to zero or to the pre-contingency value or bring supply into balance with the load.

Theoretically, PNM could meet these requirements through power purchases or sales; because of time and other constraints, PNM cannot practically depend upon market purchases to comply with the 15-minute DCS recovery requirement. These constraints include the following:

- Uncertainty as to whether counter-parties will be willing to reduce their reserve margins intra-hour
- The time required to contact potential counterparties to determine the availability and/or deliverability of an intra-hour market power transaction
- The time required to negotiate an energy purchase once the availability and deliverability of the power is confirmed.
- The complexity of determining deliverability, which requires consideration of the following:
    - Identification of transmission constraints from the point of receipt to the point of delivery (e.g., at Palo Verde, Four Corners, or San Juan)

- Intra-hour scheduling and tagging constraints. For the BA's to agree to an intra-hour interchange transaction, the electronic e-tag that is submitted has to be deemed an emergency for the receiving balance authority. WECC allows a 60-minute period for an emergency tag submittal for transfer of energy between balancing authorities; however, the process to implement such a transaction requires additional inter-company communications for verification, which can further delay the recovery.
- Time of year and day; during high load periods such as third quarter (July, August, and September) and the peak hours of the day, counterparties may not have excess energy to sell or generation units available to bring online
- Weather and loads in the WECC; when PNM is experiencing peak loads because of extreme temperatures, surrounding balance authorities are likely to be experiencing the same conditions and system stresses

In addition to the practical issues with relying upon market purchases and sales for system reliability that exist today, an observed recent loss of market liquidity and depth must factor into PNM's plans for a reliable resource portfolio. Market depth refers to the number of counterparties that are actively buying and selling in the day-ahead and hour-ahead markets. Market liquidity refers to the same concept but, in addition, also refers to the amount of power that counterparties are willing to transact (i.e., sell or purchase).

Market liquidity and depth have declined over time. The following factors have contributed to the loss of market liquidity and depth:

- Retirement of base load units throughout the western United States
- Market power concerns by some market entities
- Entry into the California Energy Imbalance Market by some entities
- More stringent gas scheduling requirements on interstate gas pipelines
- More stringent electricity scheduling rules
- FERC rules requiring designation/un-designation of resources
- Scheduling and tagging constraints across the scheduling hour
- Smaller differences between system incremental costs caused by newer gas units being on the margin
- Time of year and day (as discussed above)
- Weather and loads in the WECC (as discussed above)
- Ability for a natural gas generator to acquire intra-day gas supply and transportation
- Transmission availability to schedule the purchased power to PNM's load
- Scarcity of gas storage

There is much less market depth and liquidity in the real-time and day-ahead markets at the Four Corners and San Juan trading hubs than in the past, and the market situation is unlikely to improve because of planned generation retirements in the Four Corners region.

There are fewer willing counterparties today; in most cases, when a counterparty is willing to enter into a transaction, the amount of energy offered is significantly less than in the past.

For these reasons, PNM does not plan on intra-hour market purchases and is not a viable resource option for complying with the requirements for DCS reserve recovery or other reliability requirements.

BAL-002-WECC-2

As PNM adds more variable energy supplies to the system, PNM must consider the need to provide the requisite regulating reserves (i.e., ancillary services and flexibility) to maintain reliability as generation from the new resources ramps up and down. Increased intermittent generation on PNM's system has increased the fluctuations of generation output on the system. This also increases the need for quick-response solutions.

Contingency reserves are comprised of spinning and non-spinning reserves; spinning reserves must constitute at least 50% of the required amount of contingency reserves. Spinning reserves are the portion of reserves that the utility can call upon to immediately respond to a system disturbance. Spinning reserves include the following:

- PNM-controlled generation or storage resources that are online and synchronized to the BA's system so they can be accessed immediately to provide power to the system
- Market-based products (spin capacity) that are available to be called upon within the required recovery period (e.g., a generator located in another electric utility's system)

Market-based products for spin capacity are agreements with other entities for capacity and/or energy that can be called upon to assist PNM in responding to, and recovering from, a DCS event, re-establishing contingency reserves, and replacing lost generation to meet PNM's load service obligations. Market solutions mitigate, to the extent that they are available, the need for PNM to invest in new generation to comply with NERC and WECC standards. Use of these products requires PNM to maintain sufficient transmission capacity to utilize the agreements within the timeframes needed. Two market solutions for management of and recovery from DCS events include the following:

- **Southwest Reserve Sharing Group (SRSG) participation:** PNM is a participant in SRSG and benefits from sharing contingent reserves, thereby reducing NERC and WECC compliance costs
- **Hazard share agreement:** PNM is currently pursuing a 100-MW hazard share agreement with Tri-State that will improve PNM's ability to meet DCS recovery and contingency reserve restoration requirements at little or no cost. A hazard share agreement is between two generator owners that agree to share the risks of a generator loss by providing immediate assistance to each other in the event of the loss of the named resource.

SRSG is comprised of 15 southwestern utilities and registered under NERC. SRSG administers NERC compliance requirements for certain reliability standards including BAL-002, the DCS for utilities in the WECC region. This standard establishes the criteria and reporting requirements to ensure that an area BA, such as PNM, restores the electricity supply and demand balance within prescribed time limits following a reportable system disturbance. SRSG participants share contingency reserves to maximize generator dispatch efficiency, reduce the costs of compliance with the DCS, and enhance electric reliability. The SRSG geographical area covers Arizona, New Mexico, southern Nevada, parts of southern California including the Imperial Valley, and El Paso, Texas.

Similar to planning reserves, an adequate level of regulating reserves can be determined by considering loss of load probability (LOLP). The BAL-002-WECC-2 Standard establishes the minimum LOLP level, and PNM must remain in compliance with the minimum standards. Load and generation can vary quickly throughout the day, so PNM maintains a margin over the minimum standard to ensure continuous compliance. The minimum margin that PNM should carry is affected by the frequency and magnitude of sudden changes in the supply and demand balance. PNM has studied the relationship between the cost to carry regulating reserves and the probability of not having enough regulating reserves to respond to events that cause load or generation to suddenly change. Findings of this study follow:

- The need for flexible capacity is driven by short-duration fluctuations in the supply demand balance (e.g., if a cloud floats over a PV solar generator, the change in generation is instant, but the associated change in demand from reduced household cooling needs will take longer to occur)
- Because loss of generation events typically are of short notice and duration, spinning reserves are more valuable as a supply of regulating reserves than non-spinning reserves

Non-spinning reserves are resources that are not online and synchronized to the balance authority's system, but that are available to respond to system disturbances within a 10-minute period. There are many types of non-spinning reserves, including the following:

- Offline generation capable of ramping up and synchronizing to the grid within 10 minutes. PNM's 10-minute available generating units include the two Lordsburg LM6000 units, the La Luz LM6000 unit, and the Rio Bravo Frame-7 unit on fuel oil.
- Shared contingency reserves, which PNM can access as a participant in the SRSG. Participants in SRSG share contingency reserves to maximize generator dispatch efficiency. SRSG assistance is provided for 60 minutes after the system disturbance. Shared reserves decrease the costs of compliance with the DCS standards and contribute to electric reliability in the Western Interconnection.
- Interruptible (Non-Firm) Interchange Transactions under which PNM's sales to a counterparty can be recalled within 10 minutes to provide contingency reserves.
- Hazard sharing agreements with one or more external balancing authorities or with other generators within another balancing authority's area.
- Demand response management actions to remove load from the system within the disturbance recovery period. An example of this mechanism would be the demand response contracts that PNM has with Comverge and Enernoc. These contracts run June through September, with varying amounts of capacity available on weekdays

between the hours of 1:00 p.m. and 8:00 p.m. for Comverge and 8:00 a.m. and 8:00 p.m. for Enernoc.

- Generator-based power purchase agreement (PPA) or market purchases that can be delivered within the DCS recovery period.

PNM can use spinning reserves that exceed the spinning reserve requirement to meet the non-spinning contingency reserve requirement.

Standard energy purchases do not directly provide ancillary services such as spin, non-spin and frequency response. If available, market purchases can provide PNM the ability to ramp-down its generation or take it offline to create contingency reserves. But, given the future uncertainty of availability, market purchases are not a reliable means of meeting the contingency reserves requirement.

Under the BAL-002-WECC-2 standard, once reserves are activated to recover from a DCS event, those reserves must be restored within 60 minutes. Noncompliance with the standard can result in a directive by the Peak RC to shed load. Restoring reserves allows PNM to accomplish a timely recovery from another DCS event should one occur.

BAL-003-1

NERC Standard BAL-003-1 is the Frequency Response Requirement. PNM, in its role as a BA, is required to have sufficient frequency response capability to maintain interconnection frequency within predefined boundaries by arresting frequency deviations and supporting frequency until the system’s frequency is restored to its scheduled value.

Appendix E: Transmission Facilities

Table 45, Table 46, and Table 47 provide lists of PNM's existing transmission facilities.

Table 45. Existing Transmission Switching Stations

Name	Voltage Levels	Operator if Jointly Owned
Artesia	345	EPE
Alamogordo	115	PNM
Algodones	115	
Ambrosia	230, 115	
Amrad	345, 115	EPE
BA	345, 115	
Belen	115	
Bisti	230	
Blackwater	345	
Britton	115	
Corrales Bluffs	115	
Clines Corners	345	
El Cerro	115	
Embudo	115	
Four Corners	500, 345, 230	APS
Gallegos	230, 115	
Greenlee	345	TEP
Guadalupe	345	
Hidalgo	345	EPE (345), PNM (115)
Irving	115	
Kirtland	115	
Kyrene	500	SRP
Los Morros	115	
Lordsburg	115	
Luna	345, 115	EPE (345), PNM (115)
McKinley	345	TEP
MD1	115	
Mimbres	115	
Misson	115	
North	115	
Norton	115	
Ojo	345, 115	
Picacho	115	EPE
Pachman	115	
Palo Verde	500	SRP
Person	115	
Pillar	230	
Prager	115	
Red Mesa	115	
Reeves	115	
Rio Puerco	345, 115	
San Juan	345, 230	
Sandia	345, 115	
Scenic	115	
Shiprock	345	WAPA
Snow Vista	115	
Springerville	345	TEP
Taiban Mesa	345	
Tome	115	
Turquoise	115	
Valencia	115	
Veranda	115	
West Mesa	345, 230, 115	
West Wing	500	SRP
Yah-Ta-Hey	115	
Zia	115	

Table 46. Existing Transmission Lines

Line Code	Voltage	From-To Switching Station Names or Substation Name if Tap Line
AA	115	Arriba Tap (VS Line)
AB	115	Reeves-BA (East Circuit)
AC	115	Alamogordo - Carrizo (TSGT)
AF	230	Pillar-Four Corners
AH	115	Alamogordo - Holloman (EPE)
AL	115	Pachman - Algodones
ANZ	115	Norton-Zia
ANZ	115	Algodones to 3-way switch
AR	115	Alamogordo - Amrad
AT	115	Person-El Cerro
AV	115	Avila Tap (RB Line)
AW	115	Algodones - Britton
AY	115	Ambrosia -Yah-Ta-Hey
BA	115	Bel Air Tap (HW Line)
BB	345	BA - Guadalupe
BI	230	Ambrosia -Bisti
BJ	345	Rio Puerco - West Mesa
BP	230	Bisti - Pillar
BW	115	Bluewater (TSGT) - West Mesa
CB	115	BA - Pachman
CE	115	Pachman - Scenic
CG	115	PN-HW Lines (Albuquerque Tie)
CM	115	Church Rock Tap (AY Line)
CN	115	Cornell Tap
CQ	115	Coal Tap
CS	115	Corrales Bluffs - Sara 1 & 2
CT	115	Corrales Bluffs - Sara 3 & 4 Substation
CY	115	Pachman - Corrales Bluff
DL	115	Mimbres - Picacho
DM	115	Mimbres - Deming 1 and 2 (TSGT Line)
EB	115	Embudo - Sandia
EG	115	East Gallup Tap (AY Line)
EJ	115	Embudo - Juan Tabo Sub
ER	115	Embudo -Reeves
ES	115	El Dorado Tap (SL Line)
ET	115	Eastridge Tap (SE Line)
FC	345	San Juan - Four Corners
FW	345	Four Corners - West Mesa
GC	230	Gallegos - Pillar
HG	115	Hollywood - Gavilan
HO	115	Hernandez (TSGT) - Ojo
HR	115	Hidalgo - Turquoise
HW	115	EB-SP Line (Albuquerque Tie)
IC	115	Irving - Corrales Bluffs
IR	115	Irving - Reeves
JA	115	Jarrales Tap
KA	115	Kirtland - USAF
KB	115	Kirtland - Sandia Lab (KAFB)
KC	115	Marquez Tap (KM Line)
KD	115	Kirtland - Sandia Labs Area 5 (SNL)
KM	115	West Mesa - Red Mesa
KS	115	Kirtland - Sandia
LB	115	Lordsburg - Hidalgo
LK	115	Luna - Kenecott Tap
LL	345	Luna Station - Luna Energy Facility
LO	115	Lost Horizon Tap
LS	115	San Lucas Tap (KM Line)
LT	115	Leyendecker Tap (TL Line)
LU	115	Lenkurt Tap (EB Line)
LW	115	Lawrence Tap (SE Line)
MA	115	Red Mesa - Ambrosia
MB	115	Ambrosia -Bluewater (TSGT)
MH	115	MD1 - Ivanhoe Sub (Phelps Dodge)
MI	115	Miguel Lujan Tap (NS Line)

TTable 46. Existing Transmission Lines (Continued)

Line Code	Voltage	From-To Switching Station Names or Substation Name if Tap Line
ML	115	Mimbres - Luna
MN	115	North-Mission
MP	115	Montano Tap (NP Line)
MR	115	MD1 - Turquoise
MT	115	Menual Tap (EB Line)
MW	115	Mimbres - Hermanas - Hondale
NB	345	Norton - BA
NH	115	Norton - Hernandez (TSGT)
NL	115	Norton - ETA (DOE)
NO	115	Noe Tap (Gallup) (EG Line)
NR	115	Reeves - Mission
NS	115	Norton - Zia
NW	115	West Mesa - Reeves
OJ	345	San Juan - Ojo
PA	115	Studio Tap (PS Line)
PL	115	Lomas Tap (PN Line)
PM	115	Person - West Mesa
PN	115	North - Prager
PR	115	Pachman - Progress Sub
PS	115	Person - Kirtland
PV	115	Rio Puerco - Veranda
PW	115	Person-Snow Vista
RB	115	Reeves - BA (West Circuit)
RE	115	Reeves - Embudo
RL	115	BA - STA (STA Owned by LANL)
RN	115	Reeves - North
RR	115	Veranda - Corrales Bluff
RS	115	BA - Zia
SE	115	Sandia - Embudo
SG	115	Signetics Tap (AB Line)
SK	115	West Mesa-Scenic
SL	115	Zia - Valencia
SP	115	Sandia - Person
SR	345	San Juan - Shiprock
ST	115	San Pedro - I-40 (Albuquerque Tie)
TB	345	Taiban Mesa - Blackwater
TC	115	Tome-El Cerro
TG	345	Taiban Mesa - Guadalupe
TJ	115	Tome - Belen
TL	115	North - Lyendecker (EB Line)
TR	115	Truman Tap (SP Line)
TV	115	Tome - Valencia Energy Facility (Blackhills)
TW	115	Britton-Willard (TSGT)
TY	115	Turquoise - Tyrone Sub (Phelps Dodge)
UT	115	University Tap (HW Line)
VS	115	Valencia - Storrie Lake (TSGT)
WA	230	West Mesa - Ambrosia
WB	115	Belen-Los Morros
WC	115	Wesmeco Tap (SP Line)
WD	115	West Mesa-Los Morros
WG	115	West Gallup Tap (AY Line)
WJ	115	West Mesa-Snow Vista
WL	115	Willard (TSGT) - Belen
WN	345	Rio Puerco - BA
WP	115	West Mesa - Prager
WR	115	West Mesa - Irving
WS	345	West Mesa - Sandia
WV	115	West Mesa - Volcano
WW	345	San Juan - BA
YN	115	Yah-Ta-Hey - Coalmine (NTUA)
YP	115	Yah-Ta-Hey - Pittsburg Midway Sub
ZF	115	Zia - South Pacheco
ZN	115	Mejia Tap (NZ Line)

Table 47: Existing Joint OwnedTransmission Lines

Line Code	Voltage	From-To Switching Station Names	Operator
	345	Amrad - Artesia	EPE
SJ-MC 1	345	San Juan - McKinley Line 1	TEP
SJ-MC 2	345	San Juan - McKinley Line 2	TEP
	345	McKinley - Springerville Line 1	TEP
	345	McKinley - Springerville Line 2	TEP
	345	Springerville - Greenlee	TEP
GH	345	Greenlee - Hidalgo	EPE
HL	345	Hidalgo - Luna	EPE
	500	Palo Verde - Westwing Line 1	SRP
	500	Palo Verde - Westwing Line 2	SRP
	500	Hassayampa - Jojoba - Kyrene	SRP

Appendix F: Integration of Variable Energy Resources

In general, resource planning studies identify the most economical resource mix to meet a time-varying load profile. However, the addition of renewables to the transmission grid adds challenges in regulating the electric system to balance resources with load because the output of most renewable resources can vary greatly over short periods of time. Traditional dispatchable thermal generation is challenged by growing requirements to accommodate large amounts of variable energy resources (VER).

In 2003, PNM interconnected its first significant VER (the 204 MW New Mexico Wind Energy Center) and quickly saw a jump in regulation requirements for system operations, particularly related to the regulation for moment-to-moment power fluctuations. This was compounded by the degradation of the instantaneous response capabilities of PNM's coal plants caused by increasing use of regional coal plants to serve as regulating resources as wind generation increased. Utilities have moved to limit coal plant use as regulating resources in order to maintain operating efficiency and to preserve future response capability.

Given the present situation and level of existing resources available for regulation and imbalance service, PNM is very near the limit of its ability to integrate additional VERs based upon the need to conform to NERC control performance standards.

PNM has limited regulating resources to provide the required regulation and frequency response service for additional VER capacity located within PNM's BA. By using dynamic scheduling, PNM substantially transfers the obligation for operating additional generation to regulate the VER when it is physically located within another BA. As of today, PNM has implemented dynamic scheduling for three wind farms rated at a total of 292 MW. However, the challenge remains regarding providing regulation for VERs for PNM's system and within the BA.

The integration of additional VER presents a lengthy set of challenges for the industry. The FERC, through its rulemaking process, is also looking for solutions. FERC has a VER rulemaking underway that proposes new forecasting, intra-hour scheduling requirements, and ancillary pricing mechanisms.

Regional Initiatives

In addition to the use of dynamic scheduling to reduce its regulating burden, PNM has participated in several regional initiatives to address this issue. The following list provides the existing and proposed methods and initiatives for sharing a BA's regulating burden that PNM is exploring jointly with its regional utility neighbors.

Dynamic Scheduling

NM uses dynamic scheduling to reduce energy imbalances for PNM BA interconnected VERs selling output to an entity located within another BA. As a result, the utility in the receiving BA provides the regulation, load-following, imbalance, and other ancillary service requirements. As such, VER integration costs are shifted to the renewable energy consumers. Once established, dynamic scheduling effectively creates a larger footprint for sharing the regulation burden of intermittent resources. Dynamic scheduling also avoids:

- Use of and wear-and-tear on the VER's host BA's existing limited regulation generating resources
- The need for a host BA to construct or purchase additional flexible response generating resources to provide regulation for third-party users as additional VERs are eventually interconnected in that BA

WECC Reliability Based Controls

WECC initiated the Reliability Based Control (RBC) Field Trial on March 2010 to maintain frequency and manage the Area Control Error (ACE). ACE is the difference between scheduled and actual electric generation while accounting for frequency bias within a control area. PNM joined the WECC RBC Field Trial in June 2011. The integration of VER can cause an increase in the frequency variation which may then contribute to ACE. Since the 1990s, Automatic Generation Control (AGC) systems have regulated ACE within limits prescribed by the Control Performance Standard (CPS) 2, mandated by NERC. The RBC is a proposed replacement for CPS2 that relaxes the limits on a BA's ACE when ACE is in a direction that helps the interconnection recover from a frequency variation, thereby reducing the impact of variable generation on control performance while also reducing wear and tear on regulating generators. To date, the RBC Field Trial has not had a significant adverse effect on interconnection frequency or transmission grid congestion.

Dynamic Scheduling System

Dynamic Scheduling System (DSS) is a joint initiative between Columbia Grid, Northern Tier Transmission Group, and WestConnect. DSS facilitates the dynamic transfer of energy through a common communication protocol infrastructure to allow quick setup of dynamic schedules, which currently can take months to implement. Instead of the months now required to implement current dynamic schedules, DSS will accomplish the same feat within minutes. Consistent with existing practices, bilateral transactions will still be established contractually between the buyer and seller irrespective of the DSS, but the terms of the agreement would be communicated via approved dynamic e-Tags using existing processes and practices. DSS provides participants access to one another's generation and resources, giving merchant and reliability entities a standard method to easily and quickly exchange commodities between balancing areas.

Regional Transmission Planning and Coordination Groups

Numerous organizations are involved in planning coordination of the western grid. Planning processes involve open dialog and opportunity for all stakeholders to have input into the development of PNM's transmission plans. In addition to the planning meetings that PNM sponsors twice per year, PNM also participates in the WECC Planning Coordination Committee, WECC Transmission Expansion Planning Policy Committee (TEPPC), 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 the customers and company stockholders. 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 non-discriminatory 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) and the Transmission Planning Policy Expansion Committee (TEPPC). PNM has membership in several of the PCC subcommittees and workgroups that focus in varying degrees on transmission planning and coordination activities.

Planning Coordination Committee

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.

Transmission Expansion Planning Policy Committee

TEPPC's three main functions include: (1) overseeing database management (for economic modeling), (2) providing policy and management of the planning process, and (3) guiding the analyses and modeling for Western Interconnection economic transmission expansion planning. These functions complement, but do not replace, the responsibilities of WECC members and stakeholders to develop and implement specific expansion projects.

Membership in TEPPC is based on balanced representation designed to reflect the geographic and stakeholder breadth of WECC. TEPPC will include transmission providers, policymakers, governmental representatives, and others with expertise in planning, building new economic transmission, evaluating the economics of transmission or resource plans, or managing public planning processes. PNM participates in the TEPPC stakeholder meetings and is a member of the TEPPC Technical Advisory Subcommittee (TAS), which conducts the study work needed to support the TEPPC charter. TAS has work groups that support the models, data, and study assumptions being used in the TEPPC study program. At times, PNM participates in these work groups.

Other Coordination Groups

PNM has membership in several additional committees or coordination groups that more specifically focus on the southwest and New Mexico. These groups developed independently of WECC, but now have processes coordinated with WECC's committees. These include processes and policies resulting from legislation and FERC requirements seeking an open stakeholder process for planning and coordination on a regional basis. The main committees are listed below.

WestConnect

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 is comprised of 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.

Southwest Variable Energy Resource Initiative (SVERI)

SVERI is a coalition of utilities in the desert southwest that was formed in the fall of 2012. The SVERI participants include Arizona Public Service Company, El Paso Electric, Imperial Irrigation District, Public Service Company of New Mexico, the Salt River Project, Tucson Electric Power, and the Desert Southwest region of the Western Area Power Administration.

SVERI's mission is to evaluate likely penetration, locations, and operating characteristics of VERs within the Southwest subregion over the next 20 years. It explores tools that may facilitate VER integration and provide benefits to customers.

SVERI launched a dedicated website that provides near real-time data for renewable energy resources from across the desert Southwest and the net effect they have on load and other resources. The website is available to the public and can be accessed at http://sveri.uaren.org.

Appendix G: Rules and Regulations

Transmission System

Over the last 18 years, U.S. electric transmission service has undergone major regulatory changes in the way transmission services are offered and provided and how transmission system planning is conducted.

FERC Order No. 888

The largest change stems from the 1996 implementation of the FERC Order No. 888. This order requires that a jurisdictional transmission provider, such as PNM, provide open access for transmission capacity to all eligible customers via an Open Access Transmission Tariff (OATT or Tariff). Eligible customers (e.g., Tri-State Generation and Transmission on behalf of its cooperative members, and Los Alamos County) under the Tariff can contract for Network Integration Transmission Service (NITS) to integrate their designated network resources and designated network loads on the PNM transmission system in a manner comparable to how PNM serves its own retail and wholesale customers.

The order obligates PNM to plan its transmission system to meet not only its own retail customer needs, but also its delivery obligations to NITS and long-term, firm point-to-point transmission service customers. Tariff customers can also choose to contract for firm point-to-point transmission service on a long-term basis with rollover rights that are essentially perpetual.

Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPACT) legislated the implementation on a nationwide basis of mandatory transmission grid reliability rules for all owners, operators, and users of the systems. Under the EPACT, FERC was given authority to develop, monitor, and enforce all aspects of transmission grid reliability. FERC delegated to the North American Electric Reliability Corporation (NERC) the role of the national Electric Reliability Organization (ERO). The Western Electric Coordinating Council (WECC) has been delegated the role of the Regional Entity within North American Electric Reliability Corporation (NERC) that will monitor and enforce the mandatory reliability standards in the Western United States. Failing to comply with the ERO standards subjects a utility to sanctions and civil penalties of up to $1 million per day for each incident for the most substantive failures to follow FERC's grid reliability rules.

FERC Order No. 890

Issued in February 2007, after broader powers were delegated to FERC and NERC under the EPACT, this order clarified and strengthened these obligations initially established by Order No. 888 and required regional coordination by transmission companies of transmission system planning.

FERC Order No. 1000

FERC Order 1000, issued July, 21, 2011, expands the responsibilities for regional coordination in transmission system planning. Public utility transmission providers participate in a regional transmission planning process that evaluates transmission alternatives at the regional level in order to resolve the region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes. These processes must incorporate transmission needs driven by public policy requirements and result in a regional transmission plan. PNM participation in Order 1000 is through is participation in WestConnect, which started in 2015.

System Reliability Standards

PNM regards system reliability as an overarching consideration for selecting the most cost-effective resource portfolio. The following paragraphs review the system reliability standards required of PNM. As previously discussed, PNM's planning reserve margin target is set by NMPRC at the greater of 13% or 250 MW. In addition, PNM's planning reserve must consider operating requirements, loss of the largest load-side resource, including transmission, and forecast uncertainty due to normal forecast fluctuations and extreme weather. The combination of these factors is an approximate minimum reserve of 250 MW.

WECC and NERC Criteria

As a member of Western Electricity Coordinating Council (WECC) and North American Electric Reliability Council (NERC), PNM complies with reliability criteria to ensure that its electric systems are safely and reliably operated.

PNM must comply with NERC operating standards, which, in part, might dictate the use of certain resources to meet the requirements. These include Control Performance Standards[6] (CPS), which measure a control area operator's ability to control system frequency and balance its load and generation at all times. They also include Disturbance Control Standards[7], which measure the control area's ability to respond to generator or load loss.

PNM must also comply with NERC standards that relate to transmission planning and operations. These include Transmission Planning Standards[8] (TPL), which measure the sufficiency of the transmission system to meet present and future needs. TPL standards state that, "The interconnected power system shall be operated at all times so that general system instability, uncontrolled separation, cascading outages or voltage collapse will not occur as a result of any single contingency or multiple contingencies of sufficiently high likelihood."

Power Supply Assessment (PSA)

NERC requires WECC to annually evaluate future resource adequacy of the western region based upon annual resource plans submitted by member utilities. The PSA is a regional and subregional determination of resource adequacy, rather than an individual utility evaluation

---

6 See BAL-001-0_1a.pdf

7 See BAL-002-1.pdf and BAL-002-WECC-1.pdf

8 See TPL-001-0.1 through TPL-004-0 standards

of resource adequacy. The purpose, as stated in the Reliability Assessment Guide book[9], is "to project whether enough physical resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths." PNM, balancing area coordinator (BAC) in New Mexico, participates in the PSA study process and collects historical and future load and resource information from load-serving entities (LSEs) within New Mexico. This assessment is important because, if the PSA were to identify a resource adequacy issue in the region or subregion where PNM operates, PNM would be obligated to participate in finding a solution to the resource deficiency.

Reserve Sharing Agreements

In addition to meeting planning criteria, PNM also ensures that its resource portfolio meets operating conditions. From time to time, the operation of PNM's system may warrant additional generation or the use of certain types of reserves to maintain adequate stability.

PNM recognizes the economic and reliability benefits of participating in the Southwest Reserve Sharing Group (SRSG) for operating reserves. The operating reserve margin is measured in real time to maintain proper system frequency and balancing of loads to resources in the southwestern United States.

Southwestern U.S. utilities specify their load requirements and their resource availability on an hourly basis to SRSG. The SRSG administration examines the risk or the likelihood of a system disturbance to determine the collective reserves it needs to hold. SRSG then notifies each utility of the operational reserves they should hold, in addition to the resources each utility uses to serve its customers. Total SRSG operating reserves can be split between spinning reserves (coming from units that are operating at less than their full output) and non-spinning reserves (resources that are not operating, but can be brought online within 10 minutes). PNM's participation in SRSG is critical to minimizing the expense of PNM's reliability obligations. If PNM had to provide all of the necessary reserves itself, the requirement would equal its single largest operating unit, which is the utility's largest risk.

PNM's SRSG allocation is partly determined by the size of the units that are included in PNM's operating portfolio. Currently, PNM's single largest potential risk is SJGS Unit 4 (240 megawatts), if it is operating, or Afton (230 megawatts), if Afton is operating and SJGS Unit 4 is not. Looking forward, and for purposes of this IRP, PNM must determine how new resource additions might change the level of reserves required for SRSG purposes or otherwise result in additional costs to meet reliability standards. Generally, PNM's planning criterion is to limit the size of new generation to that of the current largest unit.

Other System Reliability Standards

Although states have played the primary role in setting reserve margin requirements, federal agencies (Federal Energy Regulatory Commission [FERC] and NERC) have taken on increased responsibility. Numerous states (including Maryland, New Jersey, Pennsylvania,

---

[9] See Reliability Assessment Guidebook v1.2

Ohio, Indiana, Wyoming, Delaware, and the District of Columbia, in addition to portions of Michigan, Wisconsin, Illinois, Kentucky, Tennessee, and Virginia) have received approval from FERC to utilize one-day-in-10-years resource planning criteria. Implementation of this criterion would result in planning for sufficient resources so that no more than 48 loss-of-load hours would be experienced in a 20-year planning period. This is a more stringent criterion than PNM’s existing reserve planning criteria, but could be a consideration for future planning.

Appendix I: Details of CO_2 and Gas Price Forecasts

This information was presented at PNM's September 22, 2017 IRP meeting. The document is available on PNM's website, the location is:

https://www.pnm.com/documents/396023/3306887/Pace_price+slides+16_0922.pdf/601dc30d-e49b-4d63-9a55-8ff82d1c26df

Appendix J: Cost and Performance Data for PNM's Existing Generating Resources

Resource Performance Data - Existing Resources

		San Juan Unit 1	San Juan Unit 2	San Juan Unit 3	San Juan Unit 4	Four Corners Unit 4	Four Corners Unit 5	Palo Verde Unit 1 Owned	Palo Verde Unit 2 Owned	Palo Verde Unit 3	Luna	Afton
Facility Output	MW	170	170	248	195*	100	100	124	30	134	185	230
Peak Contribution	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Estimated Heatrate @ max output	Btu/kWh	10,786	10,786	10,475	10,669	10,114	10,114	10,300	10,300	10,300	7,098	7,029
Expected Capacity Factor	%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%
Forced Outage Rate	%	10.5%-14.5%	10.5%-14.5%	10.5%-14.5%	10.5%-14.5%	12%	12%	2%	2%	2%	3%	3%
Emission Rates												
CO_2 Rate	lbs/MWh	2,150	2,103	2,166	2,173	1,929	2,041	-	-	-	917	902
CO Rate	lbs/MWh	3.65	4.29	2.49	1.20	0.28	0.28	-	-	-	0.13	0.15
SO_2 Rate	lbs/MWh	0.65	0.54	0.79	0.73	1.16	1.71	-	-	-	0.00	0.00
NO_x Rate	lbs/MWh	2.81	2.75	2.71	2.81	5.00	5.10	-	-	-	0.10	0.15
Hg Rate	lbs/GWh	0.002	0.002	0.002	0.002	0.009	0.008	0.000	0.000	0.000	Do Not Monitor	Do Not Monitor
PM_{10} Rate	lbs/MWh	0.033	0.033	0.031	0.053	0.069	0.117	0.000	0.000	0.000	0.027	0.062
Water Usage	gal/MWh	647	647	647	647	496	496	18	18	18	202	85
Construction Time	months											
Expected Retirement Date	Year	Scenario	Year End 2017	Year End 2017	Scenario	Scenario	Scenario	2045	2046	2047	2042	2042
Facility Life	Years	Scenario	2	2	Scenario	Scenario	Scenario	28	29	30	30	30

Resource Cost & Financial Data - Existing Resources

		San Juan Unit 1	San Juan Unit 2	San Juan Unit 3	San Juan Unit 4	Four Corners Unit 4	Four Corners Unit 5	Palo Verde Unit 1	Palo Verde Unit 2	Palo Verde Unit 3	Luna	Afton
Facility Output	MW	170	170	248	195*	100	100	134	134	134	185	230
Utility Owned												
Preliminary Rev Requirements - Cap. Exp. (NPV)	k$	See Summary Table for Capital Expenditures by Plant										
Cost of Capital	%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
Reference Year Dollars	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017
Fixed O&M	$/kWyr											
Base O&M - 5 yr ave		See Summary Table for O&M Expenses by Plant										
Transmission												
Fuel Handling/Gas Reservation												
Property Taxes												
Total												
Variable O&M												
Base O&M		included FOM	included FOM	included FOM	included FOM	included FOM	included FOM	included FOM	included FOM	included FOM	included FOM	included in FOM
Integration Costs												
Total Variable O&M costs	$/mwh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PPA												
Energy Price												
Base Energy Price												
Transmission Service												
Integration Costs												
Total Energy Price	$/mwh											
Reference Year Dollars												
Annual Escalation	%											

** Facility output will increase to 327 MW beginning in 2018*

Data on this table represents planning assumptions as of 4/8/2017.

represents a scenario will be performed

Resource Performance Data - Existing Resources														
		Lordsburg Unit 1	Lordsburg Unit 2	La Luz	Reeves Unit 1	Reeves Unit 2	Reeves Unit 3	Rio Bravo	Solar Fixed Tilt	Solar Tracking	Valencia	NM Wind Energy Center	Red Mesa Wind	Dale Burgett
Facility Output	MW	40	40	40	44	44	66	138	40	67	150	200	102	8
Peak Contribution/Estimated ELCC	%	100%	100%	100%	100%	100%	100%	100%	55%	71%	100%	5%	5%	56%
Estimated Heatrate @ max output	Btu/kWh	9,596	9,576	9,485	12,039	12,039	12,039	10,284			10,177			
Expected Capacity Factor	%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-28%	0-33%	0-100%	0-100%	0-100%	0-100%
Forced Outage Rate	%	3%	3%	3%	3%	3%	3%	3%			3%			
Emission Rates														
CO_2 Rate	lbs/MWh	1,369	1,304		1,461	1,435	1,401	1,398	-	-	1,339	-	-	-
CO Rate	lbs/MWh	0.72	0.50	0.09	0.04	0.01	0.79	0.02	-	-	0.14	-	-	-
SO_2 Rate	lbs/MWh	0.01	0.01	0.13	0.01	0.01	0.01	0.01	-	-	0.01	-	-	-
NO_x Rate	lbs/MWh	1.20	1.19	0.01	2.84	3.10	2.77	0.50	-	-	0.39	-	-	-
Hg Rage	lbs/MWh	Do Not Monitor	Do Not Monitor	Do Not Monitor	Do Not Monitor	Do Not Monitor	Do Not Monitor	Do Not Monitor	-	-	Do Not Monitor	-	-	-
PM_{10} Rate	lbs/MWh	0.141	0.134	0.084	0.091	0.089	0.087	0.026	-	-	0.187	-	-	-
Water Usage	gal/MWh	100	100	100	619	619	619	10	-	-	10	-	-	-
Construction Time	months													
Expected Retirement Date	Year	After 2036	After 2036	After 2036	After 2036	After 2036	After 2036	After 2036	After 2036	After 2036				
Contract Expiration	Year										May 2028	July 2028	Dec 2035	Jan 2034
Facility Life	Years	40	40	40	Sensitivity	Sensitivity	Sensitivity	40	25	25				

Resource Cost & Financial Data - Existing Resources

		Lordsburg Unit 1	Lordsburg Unit 2	La Luz	Reeves Unit 1	Reeves Unit 2	Reeves Unit 3	Rio Bravo	Solar	Solar	Valencia	NM Wind Energy Center	Red Mesa Wind	Dale Burgett
Facility Output	MW	40	40	40	44	44	66	138	40	67	150	200	102	8
Utility Owned														
Preliminary Rev Requirements - Cap. Exp. (NPV)	k$	See Summary Table for Capital Expenditures by Plant												
Cost of Capital	%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%						
Reference Year Dollars	2016	2017	2017	2017	2017	2017	2017	2017	2017	2017				
5 Yr Fixed O&M	$/kWyr													
Base O&M											$ -	$ -	$ -	$ -
Transmission											$ -	$ -	$ -	$ -
Gas Reservation											$ -	$ -	$ -	$ -
Property Taxes											$ -	$ -	$ -	$ -
Total											$ -	$ -	$ -	$ -
Variable O&M														
Base O&M		included FOM	included FOM	included FOM	included FOM	included FOM	included FOM	included FOM	included FOM	included FOM	$ -	$ -	$ -	$ -
Integration Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Variable O&M costs	$/mwh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PPA														
Demand	$/kWmo										$8.15			
Fixed O&M	$/kWmo										$1.79			
Gas Reservation Fee	$/kWmo										$1.03			
Total											$10.97	$ -	$ -	$ -
Variable/Energy Price (non fuel)														
Base Energy Price											$ -	$ 27.25	$ 68.25	
Transmission Service											$ -	$ -	$ -	
Variable O&M											$ 6.72	$ -	$ -	
Integration Costs											$ -	$ -	$ -	
Total Energy Price	$/mwh										$ 6.72	$ 27.25	$ 68.25	
Reference Year Dollars											2017	2017	2017	2017
Annual Escalation	%											Fixed	2.0%	

Data on this table represents planning assumptions as of 4/8/2017.

Appendix K: Cost and Performance Data for New Supply-Side Resource Options

New Resource Alternatives Performance Data - Conventional Resources

		Small Aeroderivative	Large Aeroderivative	Mid Gas Turbine	Large Gas Turbine	Reciprocating Engines	Combined Cycle New Build	Rio Bravo Expansion	Combined Cycle Existing	Palo Verde Unit 1 Ownership	Palo Verde Unit 2 Ownership	Battery 2 hr Storage	Battery 4 hr Storage
Expected Facility Output	MW	40	85	140	187	41	289	210	250	104	10	2	40
(@ 4000 ft, 90 F)													
Estimated ELCC	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Tier 2 - 80 MW													
Tier 3 - 120 MW													
Tier 4 - >80 MW													
Estimated Heatrate @ max output	Btu/kWh	9,800	9,800	10,400	9,600	8,800	6,999	7,200	7,000	10,300	10,300	Charging tech	Charging tech
Expected Capacity Factor	%	5-15%	5-15%	5-25%	5-25%	5-65%	25-65%	25-65%	25-65%	0-100%	0-100%	0-15%	0-15%
Forced Outage Rate	%	3%	3%	3%	3%	3%	5%	5%	5%	2%	2%	2.0%	2.0%
Emission Rates													
CO_2 Rate	lbs/MWh	1,140	1,115	1,300	1,300	980	845	845	845	-	-	-	-
CO Rate	lbs/MWh	0.0892	0.2800	0.1800	0.1800	0.2600	0.1200	0.1200	0.1200	-	-	-	-
SO_2 Rate	lbs/MWh	0.1313	-	-	-	-	-	-	-	-	-	-	-
NO_x Rate	lbs/MWh	0.0098	0.1100	0.3900	0.3900	3.6500	0.0800	0.0800	0.0800	-	-	-	-
Hg Rage	lbs/MWh	-	-	-	-	-	-	-	-	0.000	0.000	-	-
PM_{10} Rate	lbs/MWh	0.0838	-	-	-	-	1.0000	1.0000	1.0000	0.000	0.000	-	-
Water Usage	gal/MWh	100	150	50	50	150	150	150	600	18	18	-	-
Construction Time	months	9	12	12	12	12	24	24	24			24	24
First Year Available	Year	2020	2020	2020	2020	2020	2021	2022	2021	2024	2023	2021	2021
Facility Life	Years	40	40	40	40	40	40	40	40	29	29	30	30

New Resource Alternatives Cost & Financial Data - Conventional Resources

		Small Aeroderivative	Large Aeroderivative	Mid Gas Turbine	Large Gas Turbine	Reciprocating Engines	Combined Cycle New Build	Rio Bravo Expansion	Combined Cycle Existing	Palo Verde Unit 1 Ownership	Palo Verde Unit 2 Ownership	Battery 2 hr Storage	Battery 4 hr Storage
Expected Facility Output	MW	40	85	140	187	41	289	210	250	104	10	2	40
(@ 4000 ft, 90 F)													
Investment Tax Credit - Federal	%	-	-	-	-	-	-	-	-	-	-	-	-
Production Tax Credit - Federal		No	No	No	No	No	No	No	No	No	No	No	No
Production Tax Credit - State		No	No	No	No	No	No	No	No	No	No	No	No
Proxy Property Tax	%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	1.3%	1.3%	1.3%	2.7%	2.7%
Utility Ownership													
Capital Cost													
Construction Cost		$ 38,000	$ 78,000	$ 116,000	$ 126,000	$ 43,500	$ 258,000	$ 145,200	$ -	$ -	$ -	$ 3,700	$ 114,400
Transmission Upgrades/Interconnection		$ 3,000	$ 5,000	$ 5,000	$ 5,000	$ 2,500	$ 10,000	$ 5,000	$ -	$ -	$ -	$ -	$ -
AFUDC		$ 1,512	$ 3,043	$ 4,395	$ 4,729	$ 1,678	$ 17,553	$ 10,267	$ -	$ -	$ -	$ 84	$ 2,583
Owners Costs		$ 3,500	$ 4,500	$ 5,400	$ 5,000	$ 2,250	$ 10,200	$ 7,500	$ -	$ -	$ -	$ -	$ -
Total Capital Costs	k$	$ 46,012	$ 90,543	$ 130,795	$ 140,729	$ 49,928	$ 295,753	$ 167,967	$ 175,000	$ 260,000	$ 25,000	$ 3,784	$ 116,983
Total Capital Costs	$/kW	$ 1,150	$ 1,065	$ 934	$ 753	$ 1,218	$ 1,023	$ 800	$ 700	$ 2,500	$ 2,500	$ 1,892	$ 2,925
Revenue Requirements (Capital Only)	k$	$ 55,761	$ 109,492	$ 161,188	$ 174,395	$ 30,551	$ 396,160	$ 222,764	$ 248,280			$ 4,680	$ 144,707
Cost of Capital	%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
Reference Year Dollars		2017	2017	2017	2017	2017	2017	2017	2017	2024	2023	2017	2017
Fixed O&M	$/kWyr												
Base O&M		$ 17.4	$ 16.0	$ 6.25	$ 4.9	$ 4.90	$ 20.0	$ 22.2	$ 22.0			$ 28.0	$ 39.0
Gas Reservation		$ 26.0	$ 26.0	$ 26.0	$ 26.0	$ 26.0	$ 26.0	$ 18.1	$ 26.0			$ -	$ -
Transmission Service		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 40.8			$ -	$ -
Property Taxes		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ -
Total		$ 43.4	$ 42.0	$ 32.3	$ 30.9	$ 30.9	$ 46.0	$ 40.3	$ 88.8			$ 28.0	$ 39.0
Variable O&M													
Base O&M		$ 5.26	$ 4.64	$ 4.00	$ 2.56	$ 2.21	$ 2.57	$ 2.75	$ 2.55	$ -	$ -	Charging Tech	Charging Tech
Integration Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Variable O&M costs	$/mwh	$ 5.26	$ 4.64	$ 4.00	$ 2.56	$ 2.21	$ 2.57	$ 2.75	$ 2.55	$ -	$ -	$ -	$ -
PPA													
Energy Price													
Base Energy Price													
Transmission Upgrades/ /Interconnection													
Integration Costs													
Total Energy Price	$/mwh												
Reference Year Dollars													
Annual Escalation	%												

Data on this table represents planning assumptions as of 4/8/2017.

represents a scenario will be performed

New Resource Alternatives Performance Data - Renewable Resources

		Solar Photovoltaic Tracking	Solar Photovoltaic Tracking	Solar Photovoltaic Tracking	Solar Power Tower 10 hr storage	Solar Photovoltaic for RPS	Wind for RPS	Wind	Geothermal
Nameplate Facility Output	MW	10	50	99	100	50		100	15
Estimated ELCC	%					71%	0%	5%	100%
Tier 2 - 80 MW	%	71%	71%	71%	100%				
Tier 3 - 140 MW	%	52%	52%	52%	100%				
Tier 4 - >80 MW	%	20%	20%	20%	100%				
Estimated Heatrate @ max output	Btu/kWh								
Expected Capacity Factor	%	33%	33%	33%	45%	33%	49%	40%	85%
Forced Outage Rate	%	0%	0%	0%	0%	0%	0%	0%	0%
Emission Rates									
CO_2 Rate	lbs/MWh	-	-	-	-	-	-	-	-
SO_2 Rate	lbs/MWh	-	-	-	-	-	-	-	-
NO_x Rate	lbs/MWh	-	-	-	-	-	-	-	-
Hg Rage	lbs/MWh	-	-	-	-	-	-	-	-
PM_{10} Rate	lbs/MWh	-	-	-	-	-	-	-	-
Water Usage	gal/MWh	-	-	-	600	-	-	-	100
Construction Time	months	9	15	15	24	15	12	24	24
First Year Available	Year	2018	2019	2019	2020	2020	2019	2021	2021
Facility Life	Years	30	30	30	30	30	25	25	30

New Resource Alternatives Cost & Financial Data - Renewable Resources

		Solar Photovoltaic Tracking	Solar Photovoltaic Tracking	Solar Photovoltaic Tracking	Solar Power Tower 10 hr storage	Solar Photovoltaic Tracking	Wind	Wind	Geothermal
Nameplate Facility Output	MW	10	50	99	100	50		100	15
Investment Tax Credit - Federal*	%	Yes	Yes	Yes	Yes	Yes	-	-	10%
Production Tax Credit - Federal							Yes	Yes	Yes
Production Tax Credit - State		No	No	No	No	No	No	No	No
Proxy Property Tax	%	2.6%	2.6%	2.6%					
Utility Ownership									
		ITC= 30%	*ITC= 30%*	*ITC= 30%*					
Capital Cost									
Construction Cost		$ 11,650	$ 57,033	$ 114,067					
Transmission Costs		$ 950	$ 3,500	$ 7,000					
AFUDC		$ 241	$ 1,137	$ 2,275					
Owners Costs		$ 1,100	$ 4,000	$ 8,000					
Total Capital Costs	k$	$ 13,941	$ 65,670	$ 131,342					
Total Capital Costs	$/kW	$ 1,394	$ 1,327	$ 1,327					
Revenue Requirements (Capital Only)	k$	$ 16,423	$78,252	$156,505					
Cost of Capital	%	7.7%	7.7%	7.7%					
Reference Year Dollars	Yr	2017	2017	2017					
Fixed O&M	$/kWyr								
Base O&M		$ 17.0	$ 17.0	$ 17.0					
Property Taxes		$ -	$ -	$ -					
Total		$ 17.0	$ 17.0	$ 17.0					
Variable O&M									
Base O&M		$ -	$ -	$ -					
Integration Costs		$ 1.70	$ 1.70	$ 1.70					
Total Variable O&M costs	$/mwh	$ 1.70	$ 1.70	$ 1.70					
PPA									
Energy Price									
Base Energy Price	$/mwh				$ 185.00	$ 39.10	$24.71	$ 34.75	$ 65.30
Transmission Upgrades/	$/mwh				$ -	included	included	$ 7.00	$ 17.91
Interconnection	$/mwh					included	included	included	included
PPA Administration	$/mwh					$ 1.40	$ 1.33	$ 1.04	$ 1.79
Integration Costs	$/mwh				$ -	$ 1.78	$ 4.06	$ 4.06	$ -
Total Energy Price	$/mwh				$ 185.00	$ 42.28	$30.10	$ 46.85	$ 85.00
Reference Year Dollars		2016	2016	2016	2016	2020	2019	2019	2021
Annual Escalation	%				none	see renewable costs sheet	see renewable costs sheet	see renewable costs sheet	see renewable costs sheet

Data on this table represents planning assumptions as of 4/8/2017.

represents a scenario will be performed

New Resource Alternatives Performance Data - Renewable Resource Costs

		Solar Power Tower 10 hr storage	Solar Photovoltaic for RPS	Wind For RPS	Wind	Geothermal	Data Center1 Solar PV	Data Center1 Wind
Nameplate Facility Output	MW	100	50		100	15	Varies	Varies
Annual Energy Cost								
$/MWh	2017	$ 185.00					$ 47.50	$ 46.10
$/MWh	2018	$ 185.00					$ 47.50	$ 46.10
$/MWh	2019	$ 185.00		$ 30.10	$ 46.85		$ 47.50	$ 46.10
$/MWh	2020	$ 185.00	$ 42.28	$ 30.68	$ 46.93		$ 47.50	$ 46.10
$/MWh	2021	$ 185.00	$ 42.33	$ 31.26	$ 47.01	$ 85.00	$ 47.50	$ 46.10
$/MWh	2022	$ 185.00	$ 42.38	$ 31.86	$ 47.09	$ 85.00	$ 47.50	$ 46.10
$/MWh	2023	$ 185.00	$ 42.43	$ 32.47	$ 47.17	$ 85.00	$ 47.50	$ 46.10
$/MWh	2024	$ 185.00	$ 42.48	$ 33.09	$ 47.25	$ 85.00	$ 47.50	$ 46.10
$/MWh	2025	$ 185.00	$ 42.53	$ 33.72	$ 47.33	$ 85.00	$ 47.50	$ 46.10
$/MWh	2026	$ 185.00	$ 42.58	$ 34.37	$ 47.41	$ 85.00	$ 47.50	$ 46.10
$/MWh	2027	$ 185.00	$ 42.63	$ 35.03	$ 47.50	$ 85.00	$ 47.50	$ 46.10
$/MWh	2028	$ 185.00	$ 42.68	$ 35.70	$ 47.58	$ 85.00	$ 47.50	$ 46.10
$/MWh	2029	$ 185.00	$ 42.74	$ 36.38	$ 47.67	$ 85.00	$ 47.50	$ 46.10
$/MWh	2030	$ 185.00	$ 42.79	$ 37.08	$ 47.76	$ 85.00	$ 47.50	$ 46.10
$/MWh	2031	$ 185.00	$ 42.85	$ 37.79	$ 47.85	$ 85.00	$ 47.50	$ 46.10
$/MWh	2032	$ 185.00	$ 42.90	$ 38.51	$ 47.94	$ 85.00	$ 47.50	$ 46.10
$/MWh	2033	$ 185.00	$ 42.96	$ 39.25	$ 48.03	$ 85.00	$ 47.50	$ 46.10
$/MWh	2034	$ 185.00	$ 43.02	$ 40.00	$ 48.13	$ 85.00	$ 47.50	$ 46.10
$/MWh	2035	$ 185.00	$ 43.08	$ 40.77	$ 48.22	$ 85.00	$ 47.50	$ 46.10
$/MWh	2036	$ 185.00	$ 43.14	$ 41.55	$ 48.32	$ 85.00	$ 47.50	$ 46.10

Data on this table represents planning assumptions as of 4/8/2017.

Appendix L: Least Cost Portfolios for Each of 21 SJGS Continues Scenarios

Scenario 1

2017 IRP SJGS Continues Beyond 2022 LOAD = LOW, GAS = LOW, CO2 = LOW						*17IRP_01_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,742,955	1,303	1,665	**$6,441,805,859**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,168,548	975	1,448	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**33.67**
2019	Data Center1 Solar2 (40 MW)	25.49	2,805,739	900	1,277	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,509,501	827	1,116	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,376,391	785	1,041	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	2,263,127	754	967	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**77,443,111**
2023	Data Center1 Solar6 (20 MW)	25.14	2,547,394	842	986	
	Palo Verde Investment Recovery					**20-Year CO2 Cost (NPV)**
2024		24.45	2,605,121	871	1,003	**$22,893,442**
2025		23.98	2,519,249	847	978	
2026		23.58	2,448,208	846	971	***20-Year PNM CO2 (lbs/MWh)***
2027		22.96	2,508,306	857	992	**907**
2028	Reciprocating Engines (41 MW)	16.03	2,598,920	883	1,041	

2017 IRP *SJGS Continues Beyond 2022* *LOAD = LOW, GAS = LOW, CO2 = LOW*							*17IRP_01_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**		**Optimized Portfolio (NPV)**
2029		14.83	2,653,001	916	1,108		*20-Year PNM NM CO2 (lbs/MWh)*
2030	Reciprocating Engines (41 MW)	15.89	2,652,304	932	1,116		**1,129**
2031		14.30	2,684,239	923	1,127		
2032	Aeroderivative (40 MW)	14.86	2,666,175	925	1,122		20-Year Freshwater (Bn of Gal)
2033	Aeroderivative (40 MW)	15.43	2,712,186	938	1,134		**44.038**
2034	Aeroderivative (40 MW)	15.87	2,706,068	939	1,142		
2035		14.23	2,696,321	931	1,140		*Outside Adjustment 1*
2036	Solar PV Large (50 MW)	14.78	2,685,307	969	1,199		**$0**
	Solar PV Large (100 MW)						
							Outside Adjustment 2
							$0
							Outside Model Adjustment 3
							$0
							Outside Model Adjustment 4
							$0
							Total Optimized NPV + Adjustments
							$6,441,805,859
							Average Risk NPV + Adjustments
							$6,438,276,385

Scenario 2

2017 IRP SJGS Continues Beyond 2022 LOAD = LOW, GAS = MID, CO2 = MID						*17IRP_02_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,742,955	1,303	1,665	**$6,631,605,656**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,165,175	976	1,449	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**33.97**
2019	Data Center1 Solar2 (40 MW)	25.49	2,797,815	902	1,278	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,497,807	830	1,117	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,366,993	788	1,042	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	2,259,286	758	969	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**77,932,523**
2023	Data Center1 Solar6 (20 MW)	25.14	2,558,763	851	996	
	Palo Verde Investment Recovery					**20-Year CO2 Cost (NPV)**
2024		24.45	2,603,684	877	1,008	**$140,183,280**
2025		23.98	2,559,104	863	1,000	
2026		23.58	2,451,391	853	978	***20-Year PNM CO2 (lbs/MWh)***
2027		22.96	2,498,324	860	993	**913**
2028	Reciprocating Engines (41 MW)	16.03	2,587,971	887	1,042	
2029		14.83	2,666,653	928	1,122	***20-Year PNM NM CO2 (lbs/MWh)***
2030	Reciprocating Engines (41 MW)	15.89	2,660,145	941	1,127	**1,135**
2031		14.30	2,672,026	928	1,129	

2017 IRP *SJGS Continues Beyond 2022* *LOAD = LOW, GAS = MID, CO2 = MID*						*17IRP_02_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2032	Aeroderivative (40 MW)	14.86	2,662,123	932	1,128	**20-Year Freshwater (Bn of Gal)**
2033	Aeroderivative (40 MW)	15.43	2,713,992	946	1,142	**44.374**
2034	Aeroderivative (40 MW)	15.87	2,703,921	946	1,149	
2035		14.23	2,688,745	936	1,145	***Outside Adjustment 1***
2036	Solar PV Large (50 MW)	14.78	2,676,630	973	1,202	**$0**
	Solar PV Large (100 MW)					
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,631,605,656
						Average Risk NPV + Adjustments
						$6,631,281,173

Scenario 3

2017 IRP SJGS Continues Beyond 2022 LOAD = LOW, GAS = HIGH, CO2 = HIGH						17IRP_03_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,742,894	1,303	1,665	**$6,826,907,594**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,161,095	977	1,450	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**34.93**
2019	Data Center1 Solar2 (40 MW)	25.49	2,792,615	904	1,279	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,495,054	831	1,117	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,363,484	789	1,042	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	2,257,094	759	969	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**77,813,062**
2023	Data Center1 Solar6 (20 MW)	25.14	2,554,611	852	996	
	Palo Verde Investment Recovery					**20-Year CO2 Cost (NPV)**
2024		24.45	2,600,044	878	1,008	**$264,960,665**
2025		23.98	2,554,927	864	1,000	
2026		23.58	2,447,807	854	978	***20-Year PNM CO2 (lbs/MWh)***
2027		22.96	2,495,161	861	993	**913**
2028	Reciprocating Engines (41 MW)	16.03	2,583,585	888	1,043	
2029		14.83	2,661,258	929	1,123	***20-Year PNM NM CO2 (lbs/MWh)***
2030	Reciprocating Engines (41 MW)	15.89	2,653,974	943	1,128	**1,134**
2031		14.30	2,667,665	929	1,130	

2017 IRP SJGS Continues Beyond 2022 LOAD = LOW, GAS = HIGH, CO2 = HIGH						17IRP_03_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO_2 Tons[1]**	**PNM CPP CO_2 lbs/MWh[1]**	**PNM NM CPP CO_2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2032	Aeroderivative (40 MW)	14.86	2,658,621	933	1,129	20-Year Freshwater (Bn of Gal)
2033	Solar PV Large (50 MW)	14.28	2,637,293	938	1,131	**44.318**
2034	Aeroderivative (40 MW)	14.73	2,635,622	940	1,140	
2035	Aeroderivative (40 MW)	15.08	2,617,362	930	1,135	*Outside Adjustment 1*
2036	Solar PV Large (100 MW)	14.78	2,672,002	975	1,203	**$0**
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,826,907,594
						Average Risk NPV + Adjustments
						$6,828,856,958

Scenario 4

2017 IRP *SJGS Continues Beyond 2022* *LOAD = LOW, GAS = MID, CO2 = $0*						*17IRP_04_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,742,955	1,303	1,665	**$6,471,616,625**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,165,175	976	1,449	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**33.78**
2019	Data Center1 Solar2 (40 MW)	25.49	2,797,815	902	1,278	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,497,807	830	1,117	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,366,993	788	1,042	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	2,259,149	758	969	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**77,946,981**
2023	Data Center1 Solar6 (20 MW)	25.14	2,558,138	851	996	
	Palo Verde Investment Recovery					**20-Year CO2 Cost (NPV)**
2024		24.45	2,603,334	877	1,008	**$0**
2025		23.98	2,558,695	863	999	
2026		23.58	2,451,392	853	978	***20-Year PNM CO2 (lbs/MWh)***
2027		22.96	2,498,081	861	993	**913**
2028	Reciprocating Engines (41 MW)	16.03	2,587,671	887	1,042	
2029		14.83	2,665,889	928	1,122	***20-Year PNM NM CO2 (lbs/MWh)***
2030	Reciprocating Engines (41 MW)	15.89	2,659,186	941	1,127	**1,135**
2031		14.30	2,671,303	928	1,129	

2017 IRP SJGS Continues Beyond 2022 LOAD = LOW, GAS = MID, CO2 = $0						17IRP_04_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2032	Aeroderivative (40 MW)	14.86	2,661,684	932	1,128	**20-Year Freshwater (Bn of Gal)**
2033	Aeroderivative (40 MW)	15.43	2,713,239	946	1,142	**44.383**
2034	Aeroderivative (40 MW)	15.87	2,703,480	946	1,149	
2035		14.23	2,687,378	937	1,145	***Outside Adjustment 1***
2036	Solar PV Large (50 MW)	14.78	2,675,152	974	1,203	**$0**
	Solar PV Large (100 MW)					
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,471,616,625
						Average Risk NPV + Adjustments
						$6,472,100,402

Scenario 5

2017 IRP SJGS Continues Beyond 2022 LOAD = LOW, GAS = MID, CO2 = $8 NMPRC						17IRP_05_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,713,203	1,293	1,650	**$6,913,895,281**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,116,299	962	1,423	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**34.29**
2019	Data Center1 Solar2 (40 MW)	25.49	2,785,050	895	1,268	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,502,933	829	1,116	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,369,913	787	1,042	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	2,261,138	757	969	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**77,765,876**
2023	Data Center1 Solar6 (20 MW)	25.14	2,560,145	851	996	
	Palo Verde Investment Recovery					**20-Year CO2 Cost (NPV)**
2024		24.45	2,604,280	876	1,008	**$394,761,858**
2025		23.98	2,560,066	862	999	
2026		23.58	2,452,277	853	978	***20-Year PNM CO2 (lbs/MWh)***
2027		22.96	2,499,278	860	993	**911**
2028	Reciprocating Engines (41 MW)	16.03	2,588,773	887	1,042	
2029		14.83	2,667,773	927	1,122	***20-Year PNM NM CO2 (lbs/MWh)***
2030	Reciprocating Engines (41 MW)	15.89	2,661,110	941	1,127	**1,132**
2031		14.30	2,673,273	928	1,129	

2017 IRP ***SJGS Continues Beyond 2022*** ***LOAD = LOW, GAS = MID, CO2 = $8 NMPRC***						***17IRP_05_01***
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2032	Aeroderivative (40 MW)	14.86	2,663,424	932	1,128	**20-Year Freshwater (Bn of Gal)**
2033	Aeroderivative (40 MW)	15.43	2,714,994	946	1,142	**44.254**
2034	Aeroderivative (40 MW)	15.87	2,705,067	946	1,149	
2035		14.23	2,689,545	936	1,145	***Outside Adjustment 1***
2036	Solar PV Large (50 MW)	14.78	2,676,687	973	1,202	**$0**
	Solar PV Large (100 MW)					
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,913,895,281
						Average Risk NPV + Adjustments
						$6,909,216,984

Scenario 6

2017 IRP SJGS Continues Beyond 2022 LOAD = LOW, GAS = MID, CO2 = $20 NMPRC						*17IRP_06_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,469,588	1,236	1,563	**$7,567,878,406**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	2,872,543	905	1,310	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**34.72**
2019	Data Center1 Solar2 (40 MW)	25.49	2,609,518	854	1,187	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,400,280	802	1,067	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,285,575	765	1,002	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	2,211,769	744	945	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**75,668,101**
2023	Data Center1 Solar6 (20 MW)	25.14	2,494,656	831	967	
	Palo Verde Investment Recovery					**20-Year CO2 Cost (NPV)**
2024		24.45	2,548,709	859	983	**$958,511,617**
2025		23.98	2,522,787	850	981	
2026		23.58	2,432,187	844	967	***20-Year PNM CO2 (lbs/MWh)***
2027		22.96	2,470,285	850	978	**887**
2028	Reciprocating Engines (41 MW)	16.03	2,565,688	877	1,029	
2029		14.83	2,623,740	912	1,099	***20-Year PNM NM CO2 (lbs/MWh)***
2030	Reciprocating Engines (41 MW)	15.89	2,622,088	927	1,106	**1,092**
2031		14.30	2,640,124	915	1,111	

2017 IRP SJGS Continues Beyond 2022 LOAD = LOW, GAS = MID, CO2 = $20 NMPRC						*17IRP_06_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons**[1]	**PNM CPP CO2 lbs/MWh**[1]	**PNM NM CPP CO2 lbs/MWh**[1]	**Optimized Portfolio (NPV)**
2032	Aeroderivative (40 MW)	14.86	2,636,120	921	1,112	**20-Year Freshwater (Bn of Gal)**
2033	Solar PV Large (50 MW)	14.28	2,600,722	923	1,109	**42.732**
2034	Aeroderivative (40 MW)	14.73	2,615,159	927	1,124	
2035	Aeroderivative (40 MW)	15.08	2,588,997	915	1,115	***Outside Adjustment 1***
2036	Solar PV Large (50 MW)	14.18	2,474,339	895	1,059	**$0**
	Wind (100 MW)					
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,567,878,406
						Average Risk NPV + Adjustments
						$7,544,223,125

Scenario 7

2017 IRP SJGS Continues Beyond 2022 LOAD = LOW, GAS = MID, CO2 = $40 NMPRC						17IRP_07_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,001,999	1,130	1,399	**$8,597,297,531**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	2,505,304	820	1,143	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**28.36**
2019	Data Center1 Solar2 (40 MW)	25.49	2,297,501	783	1,045	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,127,581	740	945	**$8,557,666,663**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,041,893	710	894	**$404,457,714**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	2,007,005	698	857	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**68,967,024**
2023	Data Center1 Solar6 (20 MW)	25.14	2,217,387	766	858	
	Palo Verde Investment Recovery					**20-Year CO2 Cost (NPV)**
2024		24.45	2,272,794	794	875	**$1,751,950,821**
2025		23.98	2,281,884	792	886	
2026		23.58	2,221,944	793	882	***20-Year PNM CO2 (lbs/MWh)***
2027		22.96	2,236,879	793	885	**802**
2028	Wind (100 MW)	14.11	2,181,688	769	843	
2029	Reciprocating Engines (41 MW)	15.09	2,204,758	796	896	***20-Year PNM NM CO2 (lbs/MWh)***
2030	Reciprocating Engines (41 MW)	16.16	2,178,925	804	893	**941**
2031		14.56	2,204,631	794	899	

2017 IRP *SJGS Continues Beyond 2022* *LOAD = LOW, GAS = MID, CO2 = $40 NMPRC*						*17IRP_07_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2032	Aeroderivative (40 MW)	15.11	2,229,927	805	909	**20-Year Freshwater (Bn of Gal)**
2033	Aeroderivative (40 MW)	15.68	2,214,958	805	902	**37.762**
2034		14.12	2,239,356	812	917	
2035	Aeroderivative (40 MW)	14.47	2,208,925	799	909	***Outside Adjustment 1***
2036	Solar PV Large (100 MW)	14.18	2,232,283	834	954	**$0**
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$8,597,297,531
						Average Risk NPV + Adjustments
						$8,557,666,663

Scenario 8

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = LOW, CO2 = LOW						*17IRP_08_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons**[1]	**PNM CPP CO2 lbs/MWh**[1]	**PNM NM CPP CO2 lbs/MWh**[1]	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,774,759	1,304	1,665	**$6,826,179,984**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,332,329	990	1,453	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**32.31**
2019	Data Center1 Solar2 (40 MW)	17.96	3,100,938	927	1,298	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,837,805	858	1,148	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,803,606	829	1,094	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.34	2,774,307	805	1,030	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**97,098,564**
2023	Data Center1 Solar6 (20 MW)	19.66	3,348,627	917	1,080	
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$30,132,882**
2024		18.20	3,503,256	955	1,108	
2025		17.00	3,396,656	926	1,077	***20-Year PNM CO2 (lbs/MWh)***
2026		15.91	3,418,810	937	1,087	**987**
2027		14.66	3,606,374	962	1,123	
2028	Large GT (187 MW)	14.76	3,680,714	978	1,153	***20-Year PNM NM CO2 (lbs/MWh)***
2029	Reciprocating Engines (41 MW)	14.85	3,881,891	1,014	1,209	**1,210**
2030	Reciprocating Engines (41 MW)	15.03	3,965,245	1,031	1,217	

2017 IRP *SJGS Continues Beyond 2022* *LOAD = MID, GAS = LOW, CO2 = LOW*						*17IRP_08_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2031	Aeroderivative (40 MW)	14.76	4,055,943	1,030	1,232	**20-Year Freshwater (Bn of Gal)**
2032	Aeroderivative (40 MW)	14.53	4,094,572	1,035	1,233	**53.624**
2033	Large GT (187 MW)	20.55	4,235,983	1,050	1,241	
2034		18.45	4,246,728	1,048	1,244	***Outside Adjustment 1***
2035		16.35	4,358,537	1,050	1,249	**$0**
2036		14.01	4,601,294	1,093	1,297	
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,826,179,984
						Average Risk NPV + Adjustments
						$6,817,811,322

Scenario 9

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = MID, CO2 = MID						*17IRP_09_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons**[1]	**PNM CPP CO2 lbs/MWh**[1]	**PNM NM CPP CO2 lbs/MWh**[1]	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,774,759	1,304	1,665	**$7,183,530,438**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,328,914	990	1,454	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**35.81**
2019	Data Center1 Solar2 (40 MW)	17.96	3,091,564	930	1,300	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,823,350	862	1,150	**$7,180,045,668**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,789,661	833	1,096	**$90,683,487**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.34	2,772,501	810	1,035	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**96,437,615**
2023	Data Center1 Solar6 (20 MW)	19.66	3,377,002	934	1,099	
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$182,723,518**
2024		18.20	3,499,924	965	1,117	
2025		17.00	3,473,633	953	1,111	***20-Year PNM CO2 (lbs/MWh)***
2026		15.91	3,438,125	952	1,103	**992**
2027		14.66	3,584,733	969	1,126	
2028	Large GT (187 MW)	14.76	3,661,653	986	1,157	***20-Year PNM NM CO2 (lbs/MWh)***
2029	Reciprocating Engines (41 MW)	14.85	3,889,704	1,029	1,224	**1,214**
2030	Solar PV Large (100 MW)	14.75	3,753,647	1,031	1,218	

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = MID, CO2 = MID						17IRP_09_01
Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons[1]	PNM CPP CO2 lbs/MWh[1]	PNM NM CPP CO2 lbs/MWh[1]	Optimized Portfolio (NPV)
2031	Reciprocating Engines (41 MW)	14.52	3,816,075	1,024	1,224	20-Year Freshwater (Bn of Gal)
2032	Aeroderivative (40 MW)	14.30	3,873,606	1,033	1,231	**53.520**
2033	Large GT (187 MW)	20.33	4,009,617	1,048	1,240	
2034		18.22	4,033,860	1,050	1,247	*Outside Adjustment 1*
2035		16.13	4,118,850	1,047	1,246	**$0**
2036	Solar PV Large (50 MW)	14.50	4,257,908	1,087	1,293	
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,183,530,438
						Average Risk NPV + Adjustments
						$7,180,045,668

Scenario 10

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = HIGH, CO2 = HIGH						17IRP_10_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,774,696	1,304	1,665	**$7,514,167,031**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,324,776	992	1,455	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**30.96**
2019	Data Center1 Solar2 (40 MW)	17.96	3,085,118	931	1,301	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,820,251	863	1,150	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,784,487	834	1,096	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.34	2,768,847	811	1,035	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**93,144,292**
2023	Data Center1 Solar6 (20 MW)	19.66	3,369,353	936	1,099	
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$330,246,549**
2024		18.20	3,492,474	967	1,117	
2025		17.00	3,465,325	955	1,112	***20-Year PNM CO2 (lbs/MWh)***
2026		15.91	3,429,947	954	1,104	**952**
2027		14.66	3,576,994	971	1,127	
2028	Large GT (187 MW)	14.76	3,654,864	989	1,159	***20-Year PNM NM CO2 (lbs/MWh)***
2029	Solar PV Large (50 MW)	14.00	3,512,940	967	1,128	**1,146**
	Wind (100 MW)					

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = HIGH, CO2 = HIGH						17IRP_10_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO_2 Tons[1]**	**PNM CPP CO_2 lbs/MWh[1]**	**PNM NM CPP CO_2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2030	Reciprocating Engines (41 MW)	14.42	3,315,808	924	1,044	**20-Year Freshwater (Bn of Gal)**
	Wind (100 MW)					**51.955**
2031	Reciprocating Engines (41 MW)	14.20	3,382,291	917	1,050	
2032	Large GT (187 MW)	20.33	3,435,912	925	1,057	***Outside Adjustment 1***
2033		18.32	3,577,093	944	1,075	**$0**
2034		16.25	3,601,361	946	1,081	
2035		14.19	3,677,664	945	1,085	***Outside Adjustment 2***
2036	Aeroderivative (40 MW)	14.20	3,837,116	988	1,136	**$0**
	Solar PV Large (50 MW)					
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,514,167,031
						Average Risk NPV + Adjustments
						$7,513,199,496

Scenario 11

2017 IRP *SJGS Continues Beyond 2022* *LOAD = MID, GAS = MID, CO2 = $0*						*17IRP_11_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,774,759	1,304	1,665	**$6,972,674,891**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,328,914	990	1,454	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**35.65**
2019	Data Center1 Solar2 (40 MW)	17.96	3,091,564	930	1,300	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,823,350	862	1,150	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,789,661	833	1,096	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.34	2,771,747	810	1,035	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**98,155,383**
2023	Data Center1 Solar6 (20 MW)	19.66	3,375,559	934	1,099	
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$0**
2024		18.20	3,498,301	965	1,117	
2025		17.00	3,472,619	953	1,111	***20-Year PNM CO2 (lbs/MWh)***
2026		15.91	3,437,428	952	1,103	**998**
2027		14.66	3,583,299	969	1,126	
2028	Large GT (187 MW)	14.76	3,661,258	987	1,158	***20-Year PNM NM CO2 (lbs/MWh)***
2029	Reciprocating Engines (41 MW)	14.85	3,887,853	1,030	1,225	**1,220**
2030	Reciprocating Engines (41 MW)	15.03	3,963,136	1,047	1,232	
2031	Aeroderivative (40 MW)	14.76	4,031,767	1,041	1,239	**20-Year Freshwater (Bn of Gal)**

2017 IRP *SJGS Continues Beyond 2022* *LOAD = MID, GAS = MID, CO2 = $0*						*17IRP_11_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2032	Aeroderivative (40 MW)	14.53	4,089,979	1,050	1,246	**54.352**
2033	Large GT (187 MW)	20.55	4,219,424	1,062	1,251	
2034		18.45	4,248,528	1,064	1,260	*Outside Adjustment 1*
2035		16.35	4,339,899	1,063	1,259	**$0**
2036		14.01	4,562,529	1,104	1,303	
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,972,674,891
						Average Risk NPV + Adjustments
						$6,970,141,052

Scenario 12

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = MID, CO2 = $8 NMPRC						*17IRP_12_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,744,311	1,294	1,650	**$7,505,862,609**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,278,714	976	1,428	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**37.45**
2019	Data Center1 Solar2 (40 MW)	17.96	3,072,796	921	1,287	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,829,084	860	1,149	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,793,509	832	1,095	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.34	2,774,115	810	1,035	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**94,979,978**
2023	Data Center1 Solar6 (20 MW)	19.66	3,379,654	933	1,098	
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$469,240,361**
2024		18.20	3,502,243	964	1,116	
2025		17.00	3,475,870	953	1,111	***20-Year PNM CO2 (lbs/MWh)***
2026		15.91	3,440,318	951	1,103	**984**
2027		14.66	3,586,927	968	1,126	
2028	Large GT (187 MW)	14.76	3,663,838	986	1,157	***20-Year PNM NM CO2 (lbs/MWh)***
2029	Solar PV Large (100 MW)	14.56	3,687,598	1,015	1,211	**1,205**
2030	Reciprocating Engines (41 MW)	14.75	3,755,367	1,031	1,218	

2017 IRP *SJGS Continues Beyond 2022* *LOAD = MID, GAS = MID, CO2 = $8 NMPRC*						*17IRP_12_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2031	Reciprocating Engines (41 MW)	14.52	3,818,242	1,023	1,223	**20-Year Freshwater (Bn of Gal)**
2032	Solar PV Large (100 MW)	14.07	3,683,395	1,018	1,215	**52.737**
2033	Large GT (187 MW)	20.10	3,805,246	1,033	1,224	
2034		18.00	3,838,779	1,035	1,233	***Outside Adjustment 1***
2035		15.91	3,904,221	1,031	1,230	**$0**
2036	Solar PV Distribution (50 MW)	14.29	4,049,615	1,057	1,251	
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,505,862,609
						Average Risk NPV + Adjustments
						$7,497,132,302

Scenario 13

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = MID, CO2 = $20 NMPRC						17IRP_13_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,498,301	1,237	1,563	**$8,278,471,781**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,019,112	917	1,314	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**30.87**
2019	Data Center1 Solar2 (40 MW)	17.96	2,878,624	878	1,204	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,710,945	831	1,097	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,688,288	806	1,050	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.34	2,697,261	791	1,003	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**90,467,073**
2023	Data Center1 Solar6 (20 MW)	19.66	3,263,270	903	1,055	
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$1,121,692,241**
2024		18.20	3,414,345	940	1,083	
2025		17.00	3,399,336	932	1,082	***20-Year PNM CO2 (lbs/MWh)***
2026		15.91	3,386,412	935	1,081	**925**
2027		14.66	3,534,843	952	1,105	
2028	Large GT (187 MW)	14.76	3,625,976	972	1,140	***20-Year PNM NM CO2 (lbs/MWh)***
2029	Solar PV Large (50 MW)	14.00	3,467,190	946	1,103	**1,110**
	Wind (100 MW)					

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = MID, CO2 = $20 NMPRC						*17IRP_13_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2030	Reciprocating Engines (41 MW)	14.19	3,545,643	965	1,115	**20-Year Freshwater (Bn of Gal)**
2031	Reciprocating Engines (41 MW)	14.20	3,345,441	899	1,031	**49.952**
	Wind (100 MW)					
2032	Large GT (187 MW)	20.33	3,400,283	909	1,038	***Outside Adjustment 1***
2033		18.32	3,533,586	926	1,054	**$0**
2034		16.25	3,567,649	929	1,062	
2035		14.19	3,629,631	925	1,061	***Outside Adjustment 2***
2036	Solar PV Large (50 MW)	14.69	3,530,091	934	1,066	**$0**
	Solar PV Distribution (50 MW)					
	Solar PV Large (100 MW)					***Outside Model Adjustment 3***
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$8,278,471,781
						Average Risk NPV + Adjustments
						$8,244,136,553

Scenario 14

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = MID, CO2 = $40 NMPRC						*17IRP_14_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,026,094	1,130	1,399	**$9,445,201,625**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	2,635,741	830	1,147	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**34.39**
2019	Data Center1 Solar2 (40 MW)	17.96	2,517,172	799	1,053	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,394,663	763	968	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,390,521	742	933	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.34	2,443,905	737	907	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**75,139,016**
2023	Data Center1 Solar6 (20 MW)	15.64	2,458,606	724	776	
	Palo Verde Investment Recovery					**20-Year CO2 Cost (NPV)**
	PVNGS U1 Lease Purchase (104 MW)					**$1,894,115,762**
2024		14.21	2,526,653	744	782	
2025	Solar PV Large (100 MW)	14.70	2,486,924	743	793	***20-Year PNM CO2 (lbs/MWh)***
2026	Aeroderivative (40 MW)	15.51	2,499,265	753	800	**768**
2027		14.27	2,520,243	746	793	
2028	Large GT (187 MW)	14.38	2,666,679	779	844	***20-Year PNM NM CO2 (lbs/MWh)***
2029	Aeroderivative (40 MW)	14.65	2,621,448	767	828	**860**

2017 IRP SJGS Continues Beyond 2022 LOAD = MID, GAS = MID, CO2 = $40 NMPRC						*17IRP_14_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
	Wind (100 MW)					
2030	Solar PV Large (50 MW)	14.00	2,392,763	720	740	**20-Year Freshwater (Bn of Gal)**
	Wind (100 MW)					**40.618**
2031	Large GT (187 MW)	20.20	2,477,179	721	760	
2032		18.16	2,561,125	738	778	***Outside Adjustment 1***
2033		16.18	2,571,287	734	767	**$0**
2034		14.14	2,647,835	748	790	
2035	Reciprocating Engines (41 MW)	14.51	2,647,941	742	791	***Outside Adjustment 2***
	Solar PV Large (50 MW)					**$0**
2036	Reciprocating Engines (41 MW)	14.57	2,726,219	756	796	
	Solar PV Distribution (50 MW)					***Outside Model Adjustment 3***
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$9,445,201,625
						Average Risk NPV + Adjustments
						$9,397,057,758

Scenario 15

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = LOW, CO2 = LOW						*17IRP_15_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,813,199	1,306	1,665	**$7,445,245,766**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,380,511	989	1,441	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**24.72**
2019	Data Center1 Solar2 (40 MW)	14.06	3,093,719	909	1,251	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					
2020	Data Center1 Solar3 (30 MW)	14.14	2,907,456	855	1,129	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	3,084,372	846	1,102	**112,467,872**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	3,273,720	846	1,073	**$36,086,456**
	Data Center1 Wind4 (30 MW)					
2023	Data Center1 Solar6 (20 MW)	17.73	3,974,114	945	1,096	***20-Year PNM CO2 (lbs/MWh)***
	Large GT (187 MW)					**1,007**
	Palo Verde Investment Recovery					
2024		14.37	4,309,960	987	1,127	***20-Year PNM NM CO2 (lbs/MWh)***
2025	Large GT (187 MW)	19.98	4,299,237	966	1,104	**1,198**
2026		18.39	4,364,323	976	1,113	

2017 IRP *SJGS Continues Beyond 2022* *LOAD = HIGH, GAS = LOW, CO2 = LOW*						*17IRP_15_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2027		16.70	4,579,410	999	1,140	**20-Year Freshwater (Bn of Gal)**
2028	Large GT (187 MW)	16.20	4,690,923	1,013	1,164	**59.277**
2029		14.10	4,916,952	1,040	1,201	
2030	Large GT (187 MW)	19.28	5,019,092	1,052	1,202	***Outside Adjustment 1***
2031		16.96	5,151,150	1,052	1,214	**$0**
2032		14.75	5,246,515	1,060	1,219	
2033	Aeroderivative (40 MW)	14.04	5,395,035	1,067	1,217	***Outside Adjustment 2***
2034	Aeroderivative (40 MW)	14.67	5,453,144	1,064	1,218	**$0**
	Reciprocating Engines (41 MW)					
2035	Aeroderivative (40 MW)	14.40	5,479,430	1,060	1,214	***Outside Model Adjustment 3***
	Solar PV Large (50 MW)					**$0**
2036	Rio Bravo CC Expansion (210 MW)	14.38	5,614,215	1,069	1,215	
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,445,245,766
						Average Risk NPV + Adjustments
						$7,433,279,574

Scenario 16

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = MID						17IRP_16_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,813,199	1,306	1,665	**$8,008,169,969**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,376,584	990	1,442	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**22.21**
2019	Data Center1 Solar2 (40 MW)	14.06	3,083,905	912	1,253	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					
2020	Data Center1 Solar3 (30 MW)	14.14	2,891,930	858	1,130	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	3,067,502	850	1,103	**109,416,256**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	3,269,190	854	1,080	**$213,649,668**
	Data Center1 Wind4 (30 MW)					
2023	Data Center1 Solar6 (20 MW)	17.73	4,002,583	962	1,114	***20-Year PNM CO2 (lbs/MWh)***
	Large GT (187 MW)					**983**
	Palo Verde Investment Recovery					
2024		14.37	4,295,925	998	1,134	***20-Year PNM NM CO2 (lbs/MWh)***
2025	Large GT (187 MW)	19.98	4,376,703	994	1,136	**1,156**
2026		18.39	4,386,047	995	1,130	

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = MID						17IRP_16_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2027		16.70	4,546,676	1,006	1,143	**20-Year Freshwater (Bn of Gal)**
2028	Large GT (187 MW)	16.20	4,668,094	1,022	1,169	**58.703**
2029	Wind (100 MW)	14.29	4,661,548	1,009	1,149	
2030	Reciprocating Engines (41 MW)	14.09	4,513,811	977	1,089	***Outside Adjustment 1***
	Wind (100 MW)					**$0**
2031	Large GT (187 MW)	18.87	4,629,873	976	1,099	
2032		16.62	4,734,556	986	1,108	***Outside Adjustment 2***
2033		14.44	4,884,544	995	1,110	**$0**
2034	Aeroderivative (40 MW)	14.22	4,868,652	995	1,116	
	Solar PV Large (50 MW)					***Outside Model Adjustment 3***
2035	Aeroderivative (40 MW)	14.56	4,788,084	983	1,105	**$0**
	Solar PV Large (100 MW)					
2036	Rio Bravo CC Expansion (210 MW)	14.54	4,973,006	1,004	1,122	***Outside Model Adjustment 4***
						$0
						Total Optimized NPV + Adjustments
						$8,008,169,969
						Average Risk NPV + Adjustments
						$8,003,236,337

Scenario 17

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = HIGH, CO2 = HIGH						*17IRP_17_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,813,134	1,306	1,665	**$8,483,213,625**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,372,483	991	1,443	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**20.82**
2019	Data Center1 Solar2 (40 MW)	14.06	3,078,704	913	1,253	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					
2020	Data Center1 Solar3 (30 MW)	14.14	2,888,141	859	1,131	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	3,060,226	852	1,104	**99,578,508**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	3,263,652	855	1,081	**$357,699,570**
	Data Center1 Wind4 (30 MW)					
2023	Data Center1 Solar6 (20 MW)	14.16	3,475,215	860	959	***20-Year PNM CO2 (lbs/MWh)***
	Palo Verde Investment Recovery					**898**
	PVNGS U1 Lease Purchase (104 MW)					
2024	Large GT (187 MW)	18.73	3,698,974	886	970	***20-Year PNM NM CO2 (lbs/MWh)***
2025		16.56	3,834,605	895	990	**1,028**

2017 IRP *SJGS Continues Beyond 2022* *LOAD = HIGH, GAS = HIGH, CO2 = HIGH*							*17IRP_17_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**		**Optimized Portfolio (NPV)**
2026	Wind (100 MW)	15.22	3,603,046	851	919		
2027	Solar PV Large (50 MW)	14.27	3,606,484	844	912		**20-Year Freshwater (Bn of Gal)**
2028	Large GT (187 MW)	14.01	3,560,366	827	888		**54.694**
	Wind (100 MW)						
2029	Large GT (187 MW)	19.19	3,803,497	869	948		***Outside Adjustment 1***
2030		17.16	3,838,790	872	939		**$0**
2031		14.88	4,004,504	880	964		
2032	Reciprocating Engines (41 MW)	14.21	4,122,281	894	977		***Outside Adjustment 2***
2033	Aeroderivative (40 MW)	14.76	4,026,985	882	956		**$0**
	Solar PV Large (100 MW)						
2034	Large GT (187 MW)	19.12	4,151,110	897	978		***Outside Model Adjustment 3***
2035		16.78	4,290,774	901	988		**$0**
2036		14.26	4,507,777	931	1,016		
							Outside Model Adjustment 4
							$0
							Total Optimized NPV + Adjustments
							$8,483,213,625
							Average Risk NPV + Adjustments
							$8,481,838,959

Scenario 18

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = $0						*17IRP_18_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,813,199	1,306	1,665	**$7,762,764,281**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,376,584	990	1,442	Portfolio LOLH (Hours)
	Data Center1 Wind1 (50 MW)					**24.99**
2019	Data Center1 Solar2 (40 MW)	14.06	3,083,905	912	1,253	
	Solar PV Distribution (50 MW)					Risk Porfolio Average (NPV)
	Wind for RPS (50 MW)					
2020	Data Center1 Solar3 (30 MW)	14.14	2,891,930	858	1,130	
	Data Center1 Wind2 (50 MW)					Risk Portfolio Tail (NPV)
	Reciprocating Engines (41 MW)					
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					20-Year CO2 (Tons)
2021	Data Center1 Solar4 (30 MW)	19.67	3,067,502	850	1,103	112,296,603
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					20-Year CO2 Cost (NPV)
2022	Data Center1 Solar5 (40 MW)	16.87	3,268,359	854	1,080	$0
	Data Center1 Wind4 (30 MW)					
2023	Data Center1 Solar6 (20 MW)	17.73	4,000,223	963	1,114	*20-Year PNM CO2 (lbs/MWh)*
	Large GT (187 MW)					**1,009**
	Palo Verde Investment Recovery					
2024		14.37	4,293,432	999	1,135	*20-Year PNM NM CO2 (lbs/MWh)*
2025	Large GT (187 MW)	19.98	4,374,434	994	1,136	1,194
2026		18.39	4,384,503	995	1,130	

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = $0						*17IRP_18_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2027		16.70	4,543,902	1,007	1,143	**20-Year Freshwater (Bn of Gal)**
2028	Large GT (187 MW)	16.20	4,667,045	1,023	1,170	**59.665**
2029		14.10	4,900,458	1,054	1,211	
2030	Large GT (187 MW)	19.28	4,992,283	1,065	1,211	***Outside Adjustment 1***
2031		16.96	5,125,202	1,064	1,222	**$0**
2032		14.75	5,237,357	1,074	1,231	
2033	Reciprocating Engines (41 MW)	14.26	5,115,057	1,036	1,166	***Outside Adjustment 2***
	Wind (100 MW)					**$0**
2034	Aeroderivative (40 MW)	14.04	5,112,087	1,038	1,175	
	Solar PV Large (50 MW)					***Outside Model Adjustment 3***
2035	Aeroderivative (40 MW)	14.39	5,031,785	1,027	1,165	**$0**
	Solar PV Large (100 MW)					
2036	Rio Bravo CC Expansion (210 MW)	14.37	5,181,100	1,043	1,173	***Outside Model Adjustment 4***
						$0
						Total Optimized NPV + Adjustments
						$7,762,764,281
						Average Risk NPV + Adjustments
						$7,757,741,268

Scenario 19

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = $8 NMPRC						*17IRP_19_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,782,092	1,296	1,650	**$8,359,545,813**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,326,678	976	1,416	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**22.20**
2019	Data Center1 Solar2 (40 MW)	14.06	3,067,464	904	1,241	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					
2020	Data Center1 Solar3 (30 MW)	14.14	2,898,999	857	1,130	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	3,072,606	849	1,103	**109,195,491**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	3,273,197	853	1,080	**$529,732,898**
	Data Center1 Wind4 (30 MW)					
2023	Data Center1 Solar6 (20 MW)	17.73	4,005,327	962	1,114	***20-Year PNM CO2 (lbs/MWh)***
	Large GT (187 MW)					**981**
	Palo Verde Investment Recovery					
2024		14.37	4,299,041	997	1,134	***20-Year PNM NM CO2 (lbs/MWh)***
2025	Large GT (187 MW)	19.98	4,379,359	993	1,136	**1,154**
2026		18.39	4,389,491	994	1,130	

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = $8 NMPRC						17IRP_19_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO_2 Tons[1]**	**PNM CPP CO_2 lbs/MWh[1]**	**PNM NM CPP CO_2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2027		16.70	4,549,693	1,006	1,143	**20-Year Freshwater (Bn of Gal)**
2028	Large GT (187 MW)	16.20	4,671,204	1,022	1,169	**58.553**
2029	Wind (100 MW)	14.29	4,664,786	1,009	1,149	
2030	Reciprocating Engines (41 MW)	14.09	4,516,131	977	1,089	***Outside Adjustment 1***
	Wind (100 MW)					**$0**
2031	Large GT (187 MW)	18.87	4,632,393	975	1,099	
2032		16.62	4,737,650	986	1,108	***Outside Adjustment 2***
2033		14.44	4,888,019	994	1,110	**$0**
2034	Aeroderivative (40 MW)	14.22	4,869,692	995	1,115	
	Solar PV Large (50 MW)					***Outside Model Adjustment 3***
2035	Aeroderivative (40 MW)	14.56	4,788,419	982	1,105	**$0**
	Solar PV Large (100 MW)					
2036	Rio Bravo CC Expansion (210 MW)	14.54	4,973,712	1,004	1,122	***Outside Model Adjustment 4***
						$0
						Total Optimized NPV + Adjustments
						$8,359,545,813
						Average Risk NPV + Adjustments
						$8,348,984,007

Scenario 20

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = $20 NMPRC						*17IRP_20_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,533,514	1,239	1,562	**$9,221,303,250**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,086,212	921	1,313	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**21.72**
2019	Data Center1 Solar2 (40 MW)	14.06	2,890,196	864	1,167	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					
2020	Data Center1 Solar3 (30 MW)	14.14	2,770,605	825	1,075	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	2,946,063	820	1,053	**103,053,510**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	3,164,943	827	1,040	**$1,251,056,091**
	Data Center1 Wind4 (30 MW)					
2023	Data Center1 Solar6 (20 MW)	17.73	3,881,488	932	1,074	***20-Year PNM CO2 (lbs/MWh)***
	Large GT (187 MW)					**940**
	Palo Verde Investment Recovery					
2024		14.37	4,223,926	978	1,109	***20-Year PNM NM CO2 (lbs/MWh)***
2025	Reciprocating Engines (41 MW)	14.17	4,028,213	923	1,037	**1,099**
	Wind (100 MW)					

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = $20 NMPRC						*17IRP_20_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2026	Solar PV Large (100 MW)	14.07	3,865,435	915	1,023	**20-Year Freshwater (Bn of Gal)**
2027	Aeroderivative (40 MW)	14.04	4,049,620	932	1,046	**55.152**
2028	Large GT (187 MW)	14.27	4,095,734	945	1,068	
	Solar PV Large (50 MW)					***Outside Adjustment 1***
2029	Large GT (187 MW)	19.64	4,057,074	930	1,046	**$0**
	Wind (100 MW)					
2030		17.60	4,171,043	947	1,056	***Outside Adjustment 2***
2031		15.32	4,273,502	943	1,063	**$0**
2032	Aeroderivative (40 MW)	14.61	4,377,200	954	1,072	
2033	Large GT (187 MW)	19.19	4,556,007	969	1,084	***Outside Model Adjustment 3***
2034		16.86	4,620,563	971	1,089	**$0**
2035		14.56	4,737,904	969	1,090	
2036	Rio Bravo CC Expansion (210 MW)	14.54	4,944,483	993	1,110	***Outside Model Adjustment 4***
						$0
						Total Optimized NPV + Adjustments
						$9,221,303,250
						Average Risk NPV + Adjustments
						$9,184,140,991

Scenario 21

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = $40 NMPRC						*17IRP_21_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,056,181	1,131	1,398	**$10,485,561,813**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	2,693,741	833	1,146	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**20.86**
2019	Data Center1 Solar2 (40 MW)	14.06	2,526,984	786	1,021	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					
2020	Data Center1 Solar3 (30 MW)	14.14	2,436,688	754	945	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	2,606,395	750	930	**88,151,322**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	2,816,368	759	923	**$2,155,039,731**
	Data Center1 Wind4 (30 MW)					
2023	Data Center1 Solar6 (20 MW)	14.37	2,797,644	718	758	***20-Year PNM CO2 (lbs/MWh)***
	Palo Verde Investment Recovery					**799**
	PVNGS U1 Lease Purchase (104 MW)					
	Wind (100 MW)					***20-Year PNM NM CO2 (lbs/MWh)***
2024	Large GT (187 MW)	18.94	3,043,933	752	785	**888**

2017 IRP SJGS Continues Beyond 2022 LOAD = HIGH, GAS = MID, CO2 = $40 NMPRC						17IRP_21_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2025		16.77	3,189,286	763	810	
2026	Solar PV Large (50 MW)	15.93	3,166,172	769	812	20-Year Freshwater (Bn of Gal)
2027		14.27	3,245,110	768	813	**46.157**
2028	Large GT (187 MW)	14.01	3,222,276	757	796	
	Wind (100 MW)					*Outside Adjustment 1*
2029	Reciprocating Engines (41 MW)	14.87	3,279,372	779	832	**$0**
	Solar PV Large (100 MW)					
2030	Aeroderivative (40 MW)	14.44	3,325,961	786	829	*Outside Adjustment 2*
2031	Large GT (187 MW)	19.21	3,459,636	790	849	**$0**
2032		16.95	3,578,093	806	864	
2033		14.76	3,670,201	809	863	*Outside Model Adjustment 3*
2034	Large GT (187 MW)	19.12	3,782,799	823	883	**$0**
2035		16.78	3,926,217	828	895	
2036		14.26	4,140,011	858	924	*Outside Model Adjustment 4*
						$0
						Total Optimized NPV + Adjustments
						$10,485,561,813
						Average Risk NPV + Adjustments
						$10,422,750,605

Appendix M: Least Cost Portfolios for Each of 21 SJGS Retires Scenarios

Scenario 22

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = LOW, CO2 = LOW						*17IRP_22_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,742,955	1,303	1,665	**$5,798,100,516**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,209,340	982	1,459	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**10.88**
2019	Data Center1 Solar2 (40 MW)	25.49	2,764,815	893	1,265	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,560,191	835	1,129	**$5,790,750,813**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,469,907	799	1,065	**$69,750,287**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	1,909,663	687	837	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**56,859,414**
2023	Data Center1 Solar6 (20 MW)	18.40	1,110,447	534	454	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$14,677,153**
2024		17.72	1,126,926	554	459	
2025		17.27	1,071,394	536	445	***20-Year PNM CO2 (lbs/MWh)***
2026		16.90	1,017,270	537	432	**679**
2027		16.32	1,042,823	536	439	

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = LOW, CO2 = LOW							17IRP_22_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**		**Optimized Portfolio (NPV)**
2028	Large GT (187 MW)	17.26	1,069,577	553	463		*20-Year PNM NM CO2 (lbs/MWh)*
2029		16.05	1,205,240	588	527		**722**
2030		14.94	1,206,555	601	529		
2031	Reciprocating Engines (41 MW)	15.49	1,184,363	580	521		20-Year Freshwater (Bn of Gal)
2032	Reciprocating Engines (41 MW)	16.09	1,145,288	580	509		**27.288**
2033		14.62	1,192,578	588	521		
2034	Aeroderivative (40 MW)	15.07	1,171,672	589	521		*Outside Adjustment 1*
2035	Solar PV Large (50 MW)	14.29	1,134,009	577	515		**$0**
2036	Aeroderivative (40 MW)	14.26	1,238,971	617	562		
							Outside Adjustment 2
							$0
							Outside Model Adjustment 3
							$0
							Outside Model Adjustment 4
							$0
							Total Optimized NPV + Adjustments
							$5,798,100,516
							Average Risk NPV + Adjustments
							$5,790,750,813

Scenario 23

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = MID, CO2 = MID						*17IRP_23_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,742,955	1,303	1,665	**$6,210,925,266**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,205,966	983	1,460	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**9.46**
2019	Data Center1 Solar2 (40 MW)	25.49	2,756,771	895	1,266	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,548,701	838	1,131	**$6,204,291,391**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,460,128	802	1,066	**$137,636,292**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	1,896,178	693	840	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**55,699,327**
2023	Data Center1 Solar6 (20 MW)	18.40	1,062,696	547	444	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$85,061,023**
2024		17.72	1,079,778	567	449	
2025		17.27	1,019,931	551	433	***20-Year PNM CO2 (lbs/MWh)***
2026		16.90	962,639	552	419	**668**
2027		16.32	996,917	549	429	
2028	Large GT (187 MW)	17.26	1,022,689	567	453	***20-Year PNM NM CO2 (lbs/MWh)***
2029	Wind (100 MW)	16.32	976,393	554	434	**681**
2030		15.21	976,450	565	435	

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = MID, CO2 = MID						17IRP_23_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2031	Solar PV Large (50 MW)	14.52	911,349	543	419	20-Year Freshwater (Bn of Gal)
2032	Reciprocating Engines (41 MW)	15.13	871,641	543	405	**27.316**
2033	Solar PV Large (50 MW)	14.55	864,565	544	405	
2034	Reciprocating Engines (41 MW)	15.05	844,485	545	402	*Outside Adjustment 1*
2035	Solar PV Distribution (50 MW)	14.28	819,985	522	382	**$0**
2036	Aeroderivative (40 MW)	14.25	913,213	558	426	
						Outside Adjustment 2
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,210,925,266
						Average Risk NPV + Adjustments
						$6,204,291,391

Scenario 24

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = HIGH, CO2 = HIGH						17IRP_24_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,742,894	1,303	1,665	**$6,517,884,000**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,201,895	984	1,461	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**7.53**
2019	Data Center1 Solar2 (40 MW)	25.49	2,751,452	897	1,267	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,546,200	839	1,131	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,457,319	803	1,066	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	1,889,452	695	839	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**48,937,695**
2023	Data Center1 Solar6 (20 MW)	14.12	571,175	421	230	
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$129,000,734**
	PVNGS U1 Lease Purchase (104 MW)					
	Wind (100 MW)					***20-Year PNM CO2 (lbs/MWh)***
2024	Reciprocating Engines (41 MW)	15.70	541,442	425	215	**574**
2025		15.26	525,103	421	214	
2026		14.90	499,164	426	207	***20-Year PNM NM CO2 (lbs/MWh)***
2027		14.32	481,656	409	197	**513**

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = HIGH, CO2 = HIGH						*17IRP_24_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2028	Large GT (187 MW)	15.28	536,520	435	226	
2029	Wind (100 MW)	14.35	503,583	426	214	**20-Year Freshwater (Bn of Gal)**
2030	Solar PV Large (50 MW)	14.17	442,095	420	189	**25.789**
2031	Reciprocating Engines (41 MW)	14.73	454,719	410	196	
2032	Solar PV Large (50 MW)	14.12	423,495	414	186	***Outside Adjustment 1***
2033	Aeroderivative (40 MW)	14.70	417,645	408	180	**$0**
2034	Solar PV Distribution (50 MW)	14.02	405,782	408	175	
2035	Aeroderivative (40 MW)	14.38	427,785	403	184	***Outside Adjustment 2***
2036	Aeroderivative (40 MW)	14.35	462,704	424	200	**$0**
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,517,884,000
						Average Risk NPV + Adjustments
						$6,518,484,705

Scenario 25

2017 IRP *SJGS Retires in 2022* *LOAD = LOW, GAS = MID, CO2 = $0*						*17IRP_25_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons**[1]	**PNM CPP CO2 lbs/MWh**[1]	**PNM NM CPP CO2 lbs/MWh**[1]	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,742,955	1,303	1,665	**$6,112,395,516**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,205,966	983	1,460	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**11.41**
2019	Data Center1 Solar2 (40 MW)	25.49	2,756,771	895	1,266	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,548,701	838	1,131	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,460,128	802	1,066	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	1,896,042	693	840	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**57,073,344**
2023	Data Center1 Solar6 (20 MW)	18.40	1,057,808	549	443	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$0**
2024		17.72	1,073,868	568	448	
2025		17.27	1,014,247	552	432	***20-Year PNM CO2 (lbs/MWh)***
2026		16.90	960,945	552	419	**685**
2027		16.32	991,893	551	427	
2028	Large GT (187 MW)	17.26	1,018,580	569	452	***20-Year PNM NM CO2 (lbs/MWh)***
2029		16.05	1,152,256	605	518	**710**
2030		14.94	1,154,714	617	520	

2017 IRP *SJGS Retires in 2022* *LOAD = LOW, GAS = MID, CO2 = $0*						*17IRP_25_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2031	Solar PV Large (50 MW)	14.26	1,078,372	594	503	**20-Year Freshwater (Bn of Gal)**
2032	Reciprocating Engines (41 MW)	14.87	1,034,790	593	488	**27.678**
2033	Solar PV Large (50 MW)	14.29	1,027,211	595	489	
2034	Reciprocating Engines (41 MW)	14.80	995,801	595	484	***Outside Adjustment 1***
2035	Solar PV Distribution (50 MW)	14.04	969,014	571	461	**$0**
2036	Aeroderivative (40 MW)	14.25	906,723	561	425	
	Wind (100 MW)					***Outside Adjustment 2***
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,112,395,516
						Average Risk NPV + Adjustments
						$6,105,155,745

Scenario 26

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = MID, CO2 = $8 NMPRC						*17IRP_26_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,713,203	1,293	1,650	**$6,452,189,141**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	3,156,052	969	1,434	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**8.75**
2019	Data Center1 Solar2 (40 MW)	25.49	2,739,210	887	1,253	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,553,826	836	1,130	
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,463,046	801	1,066	
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	1,900,770	692	840	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**54,617,898**
2023	Data Center1 Solar6 (20 MW)	18.40	1,067,923	546	445	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$300,678,172**
2024		17.72	1,083,868	565	450	
2025		17.27	1,024,214	549	434	***20-Year PNM CO2 (lbs/MWh)***
2026		16.90	969,070	550	421	**653**
2027		16.32	1,000,738	548	429	
2028	Large GT (187 MW)	17.26	1,026,372	566	453	***20-Year PNM NM CO2 (lbs/MWh)***
2029	Wind (100 MW)	16.32	980,723	552	435	**658**
2030		15.21	979,791	564	436	

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = MID, CO2 = $8 NMPRC						*17IRP_26_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2031	Solar PV Large (50 MW)	14.52	915,347	542	420	**20-Year Freshwater (Bn of Gal)**
2032	Solar PV Large (50 MW)	14.17	692,653	492	321	**26.910**
	Wind (100 MW)					
2033	Reciprocating Engines (41 MW)	14.80	719,951	497	329	***Outside Adjustment 1***
2034	Solar PV Distribution (50 MW)	14.12	677,741	487	309	**$0**
2035	Reciprocating Engines (41 MW)	14.53	684,302	477	311	
2036	Aeroderivative (40 MW)	14.49	766,526	512	350	***Outside Adjustment 2***
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,452,189,141
						Average Risk NPV + Adjustments
						$6,442,439,315

Scenario 27

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = MID, CO2 = $20 NMPRC						17IRP_27_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,469,588	1,236	1,563	**$6,938,158,313**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	2,932,603	916	1,331	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**7.98**
2019	Data Center1 Solar2 (40 MW)	25.49	2,554,810	844	1,168	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,456,341	811	1,083	**$6,921,615,279**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,386,919	781	1,030	**$210,312,927**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	1,877,240	681	825	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**51,778,171**
2023	Data Center1 Solar6 (20 MW)	18.67	913,963	494	374	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$712,750,862**
	Wind (100 MW)					
2024		17.99	925,680	513	377	***20-Year PNM CO2 (lbs/MWh)***
2025		17.55	874,947	499	364	**618**
2026		17.17	822,865	499	350	
2027		16.59	846,893	496	357	***20-Year PNM NM CO2 (lbs/MWh)***
2028	Large GT (187 MW)	17.53	880,279	515	380	**605**
2029	Wind (100 MW)	16.58	830,436	501	361	

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = MID, CO2 = $20 NMPRC						17IRP_27_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2030		15.47	828,458	512	361	20-Year Freshwater (Bn of Gal)
2031	Solar PV Large (50 MW)	14.78	777,277	490	347	**25.587**
2032	Solar PV Large (50 MW)	14.17	708,958	487	326	
2033	Reciprocating Engines (41 MW)	14.80	736,014	491	334	*Outside Adjustment 1*
2034	Solar PV Distribution (50 MW)	14.12	696,714	481	314	**$0**
2035	Reciprocating Engines (41 MW)	14.53	704,015	471	316	
2036	Aeroderivative (40 MW)	14.49	786,357	506	356	*Outside Adjustment 2*
						$0
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,938,158,313
						Average Risk NPV + Adjustments
						$6,921,615,279

Scenario 28

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = MID, CO2 = $40 NMPRC						*17IRP_28_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.71	4,001,999	1,130	1,399	**$7,683,006,453**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	22.20	2,566,264	832	1,164	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**7.98**
2019	Data Center1 Solar2 (40 MW)	25.49	2,241,033	772	1,024	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.10	2,183,949	750	963	**$7,669,401,366**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	27.81	2,147,900	728	926	**$332,331,371**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	29.93	1,708,445	642	749	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**45,191,019**
2023	Data Center1 Solar6 (20 MW)	14.12	622,626	407	245	
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$1,259,175,790**
	PVNGS U1 Lease Purchase (104 MW)					
	Wind (100 MW)					***20-Year PNM CO2 (lbs/MWh)***
2024	Reciprocating Engines (41 MW)	15.70	590,868	411	230	**530**
2025		15.26	577,297	406	229	
2026		14.90	551,100	411	223	***20-Year PNM NM CO2 (lbs/MWh)***
2027		14.32	528,836	395	211	**461**

2017 IRP SJGS Retires in 2022 LOAD = LOW, GAS = MID, CO2 = $40 NMPRC						*17IRP_28_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2028	Large GT (187 MW)	15.28	585,513	420	241	
2029	Wind (100 MW)	14.35	553,700	410	229	20-Year Freshwater (Bn of Gal)
2030	Solar PV Large (50 MW)	14.17	487,481	406	204	**22.883**
2031	Reciprocating Engines (41 MW)	14.73	498,760	397	210	
2032	Solar PV Large (50 MW)	14.12	466,743	401	201	*Outside Adjustment 1*
2033	Aeroderivative (40 MW)	14.70	460,254	395	195	**$0**
2034	Solar PV Distribution (50 MW)	14.02	448,451	395	189	
2035	Aeroderivative (40 MW)	14.38	470,655	390	199	*Outside Adjustment 2*
2036	Aeroderivative (40 MW)	14.35	506,127	410	214	**$0**
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,683,006,453
						Average Risk NPV + Adjustments
						$7,669,401,366

Scenario 29

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = LOW, CO2 = LOW						17IRP_29_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,774,759	1,304	1,665	**$6,370,336,297**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,372,823	997	1,465	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**19.46**
2019	Data Center1 Solar2 (40 MW)	17.96	3,058,849	920	1,284	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,881,795	866	1,160	**$6,370,324,705**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,883,504	841	1,115	**$114,704,228**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.82	2,386,685	732	898	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**69,993,060**
2023	1x1 NGCC (250 MW)	17.42	1,616,601	572	530	
	Data Center1 Solar6 (20 MW)					**20-Year CO2 Cost (NPV)**
	2 x Large GT (374 MW)					**$19,381,029**
	Palo Verde Investment Recovery					
2024		15.96	1,668,037	591	538	***20-Year PNM CO2 (lbs/MWh)***
2025		14.78	1,665,314	582	538	**716**
2026	Reciprocating Engines (41 MW)	15.65	1,660,995	586	536	
2027		14.39	1,714,471	589	543	***20-Year PNM NM CO2 (lbs/MWh)***
2028	Large GT (187 MW)	14.50	1,782,333	606	569	**771**
2029	Large GT (187 MW)	21.25	1,979,538	638	623	

2017 IRP *SJGS Retires in 2022* *LOAD = MID, GAS = LOW, CO2 = LOW*						*17IRP_29_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2030		19.50	2,027,251	652	629	**20-Year Freshwater (Bn of Gal)**
2031		17.38	2,065,846	643	634	**37.372**
2032		15.37	2,085,335	649	635	
2033	Reciprocating Engines (41 MW)	15.18	2,170,503	656	643	***Outside Adjustment 1***
2034	Aeroderivative (40 MW)	14.83	2,201,065	660	651	**$0**
2035	Aeroderivative (40 MW)	14.43	2,277,234	660	659	
2036	Aeroderivative (40 MW)	14.44	2,364,626	689	688	***Outside Adjustment 2***
	Solar PV Large (50 MW)					**$0**
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,370,336,297
						Average Risk NPV + Adjustments
						$6,370,324,705

Scenario 30

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = MID						17IRP_30_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,774,759	1,304	1,665	**$7,010,625,047**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,369,408	998	1,466	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**16.48**
2019	Data Center1 Solar2 (40 MW)	17.96	3,049,218	922	1,286	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,867,669	869	1,162	**$7,020,104,756**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,869,329	845	1,117	**$163,864,564**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.82	2,375,595	742	904	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**60,196,496**
2023	Data Center1 Solar6 (20 MW)	14.00	1,140,553	501	388	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$93,208,159**
	PVNGS U1 Lease Purchase (104 MW)					
	Reciprocating Engines (41 MW)					***20-Year PNM CO2 (lbs/MWh)***
	Solar PV Large (50 MW)					**628**
	Solar PV Distribution (50 MW)					
2024	Reciprocating Engines (41 MW)	14.56	1,136,080	508	379	***20-Year PNM NM CO2 (lbs/MWh)***
2025	Solar PV Large (50 MW)	14.22	1,099,079	500	375	**610**

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = MID						*17IRP_30_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2026	Aeroderivative (40 MW)	15.04	1,114,909	511	381	
2027	Wind (100 MW)	14.03	967,631	462	320	**20-Year Freshwater (Bn of Gal)**
2028	Large GT (187 MW)	14.14	1,065,572	489	356	**29.043**
2029	Large GT (187 MW)	20.90	1,251,350	526	418	
2030	Wind (100 MW)	19.37	1,079,705	490	352	***Outside Adjustment 1***
2031		17.25	1,144,306	490	370	**$0**
2032		15.25	1,178,894	500	378	
2033	Solar PV Large (100 MW)	14.79	1,120,795	490	361	***Outside Adjustment 2***
2034	Aeroderivative (40 MW)	14.44	1,172,119	503	379	**$0**
2035	Aeroderivative (40 MW)	14.05	1,262,171	507	400	
2036	Rio Bravo CC Expansion (210 MW)	14.67	1,284,193	513	400	***Outside Model Adjustment 3***
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,010,625,047
						Average Risk NPV + Adjustments
						$7,020,104,756

Scenario 31

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = HIGH, CO2 = HIGH						*17IRP_31_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,774,696	1,304	1,665	**$7,431,820,750**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,365,281	999	1,467	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**16.16**
2019	Data Center1 Solar2 (40 MW)	17.96	3,042,550	924	1,287	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,864,948	870	1,162	**$7,449,998,600**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,865,600	846	1,117	**$216,871,867**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.82	2,367,412	744	904	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**58,370,193**
2023	Data Center1 Solar6 (20 MW)	14.24	956,675	473	333	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$166,575,422**
	PVNGS U1 Lease Purchase (104 MW)					
	Reciprocating Engines (41 MW)					***20-Year PNM CO2 (lbs/MWh)***
	Solar PV Large (100 MW)					**613**
	Wind (100 MW)					
2024	PVNGS U2 Lease Purchase (10 MW)	14.13	888,801	469	307	***20-Year PNM NM CO2 (lbs/MWh)***

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = HIGH, CO2 = HIGH						17IRP_31_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
	Solar PV Large (50 MW)					581
2025	Reciprocating Engines (41 MW)	14.93	889,679	466	309	
2026	Solar PV Large (50 MW)	14.67	867,755	471	306	20-Year Freshwater (Bn of Gal)
2027	Solar PV Distribution (50 MW)	14.25	844,703	448	288	**28.636**
2028	Large GT (187 MW)	14.58	798,645	438	270	
	Wind (100 MW)					*Outside Adjustment 1*
2029	Large GT (187 MW)	21.34	947,220	473	324	**$0**
2030		19.58	949,463	477	320	
2031		17.46	1,005,907	474	336	*Outside Adjustment 2*
2032		15.45	1,039,452	486	345	**$0**
2033	Aeroderivative (40 MW)	15.21	1,079,858	487	349	
2034	Aeroderivative (40 MW)	14.86	1,125,323	500	365	*Outside Model Adjustment 3*
2035	Aeroderivative (40 MW)	14.47	1,217,364	504	387	**$0**
2036	Rio Bravo CC Expansion (210 MW)	15.07	1,229,966	511	385	
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,431,820,750
						Average Risk NPV + Adjustments
						$7,449,998,600

Scenario 32

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = $0						*17IRP_32_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,774,759	1,304	1,665	**$6,894,673,875**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,369,408	998	1,466	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**19.35**
2019	Data Center1 Solar2 (40 MW)	17.96	3,049,218	922	1,286	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,867,669	869	1,162	**$6,902,045,928**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,869,329	845	1,117	**$219,528,739**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.82	2,374,866	742	904	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**66,902,371**
2023	1x1 NGCC (250 MW)	17.42	1,556,680	587	522	
	Data Center1 Solar6 (20 MW)					**20-Year CO2 Cost (NPV)**
	2 x Large GT (374 MW)					$0
	Palo Verde Investment Recovery					
2024		15.96	1,604,484	607	530	***20-Year PNM CO2 (lbs/MWh)***
2025		14.78	1,596,215	600	529	**703**
2026	Solar PV Large (50 MW)	14.53	1,530,950	599	519	
2027	Solar PV Large (50 MW)	14.10	1,526,528	594	519	***20-Year PNM NM CO2 (lbs/MWh)***
2028	Large GT (187 MW)	14.21	1,588,938	614	546	**731**
2029	Solar PV Large (100 MW)	14.02	1,647,625	638	587	

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = $0						17IRP_32_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2030	Reciprocating Engines (41 MW)	14.21	1,684,596	649	591	**20-Year Freshwater (Bn of Gal)**
2031	Large GT (187 MW)	20.44	1,720,458	639	596	**35.295**
2032	Wind (100 MW)	18.60	1,560,577	606	534	
2033	Wind (100 MW)	16.81	1,478,137	577	489	***Outside Adjustment 1***
2034		14.76	1,504,200	584	497	**$0**
2035	Reciprocating Engines (41 MW)	14.40	1,570,369	580	507	
2036	Aeroderivative (40 MW)	14.42	1,654,204	600	524	***Outside Adjustment 2***
	Solar PV Distribution (50 MW)					**$0**
						Outside Model Adjustment 3
						$0
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$6,894,673,875
						Average Risk NPV + Adjustments
						$6,902,045,928

Scenario 33

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = $8 NMPRC						17IRP_33_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,744,311	1,294	1,650	**$7,266,460,406**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,317,031	983	1,439	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**16.69**
2019	Data Center1 Solar2 (40 MW)	17.96	3,028,477	913	1,272	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,873,401	868	1,161	**$7,272,730,080**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,873,169	844	1,116	**$186,044,717**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.82	2,380,233	741	904	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**59,372,709**
2023	Data Center1 Solar6 (20 MW)	14.00	1,144,906	500	388	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$322,642,250**
	PVNGS U1 Lease Purchase (104 MW)					
	Reciprocating Engines (41 MW)					***20-Year PNM CO2 (lbs/MWh)***
	Solar PV Large (50 MW)					**621**
	Solar PV Distribution (50 MW)					
2024	Reciprocating Engines (41 MW)	14.56	1,139,922	507	380	***20-Year PNM NM CO2 (lbs/MWh)***
2025	Solar PV Large (50 MW)	14.22	1,103,515	499	376	**603**

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = $8 NMPRC						17IRP_33_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2026	Aeroderivative (40 MW)	15.04	1,120,174	510	382	
2027	Wind (100 MW)	14.03	970,911	461	321	20-Year Freshwater (Bn of Gal)
2028	Large GT (187 MW)	14.14	1,069,741	488	357	**28.721**
2029	Solar PV Large (100 MW)	14.18	993,550	474	339	
	Wind (100 MW)					*Outside Adjustment 1*
2030	Large GT (187 MW)	20.93	994,165	479	333	**$0**
2031		18.78	1,051,994	477	350	
2032		16.75	1,084,539	488	358	*Outside Adjustment 2*
2033		14.79	1,124,091	489	362	**$0**
2034	Aeroderivative (40 MW)	14.44	1,174,096	502	379	
2035	Aeroderivative (40 MW)	14.05	1,262,581	506	399	*Outside Model Adjustment 3*
2036	Rio Bravo CC Expansion (210 MW)	14.67	1,285,062	513	400	**$0**
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,266,460,406
						Average Risk NPV + Adjustments
						$7,272,730,080

Scenario 34

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = $20 NMPRC						17IRP_34_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,498,301	1,237	1,563	**$7,794,089,422**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	3,076,748	928	1,333	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**17.04**
2019	Data Center1 Solar2 (40 MW)	17.96	2,829,767	868	1,187	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,760,979	839	1,111	**$7,794,208,791**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,774,166	820	1,074	**$240,158,768**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.82	2,348,788	728	887	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**57,212,024**
2023	Data Center1 Solar6 (20 MW)	14.24	994,466	463	341	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$774,115,778**
	PVNGS U1 Lease Purchase (104 MW)					
	Reciprocating Engines (41 MW)					***20-Year PNM CO2 (lbs/MWh)***
	Solar PV Large (100 MW)					**601**
	Wind (100 MW)					
2024	Reciprocating Engines (41 MW)	14.79	990,333	471	333	***20-Year PNM NM CO2 (lbs/MWh)***
2025	Solar PV Large (50 MW)	14.45	960,947	464	330	**576**

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = $20 NMPRC						*17IRP_34_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2026	Aeroderivative (40 MW)	15.27	976,940	474	336	
2027		14.02	985,029	465	332	**20-Year Freshwater (Bn of Gal)**
2028	Large GT (187 MW)	14.36	932,762	454	313	**27.526**
	Wind (100 MW)					
2029	Solar PV Large (50 MW)	14.18	1,006,923	470	341	***Outside Adjustment 1***
	Solar PV Distribution (50 MW)					**$0**
2030	Large GT (187 MW)	20.93	1,006,969	475	336	
2031		18.78	1,064,866	473	353	***Outside Adjustment 2***
2032		16.75	1,098,120	484	361	**$0**
2033		14.79	1,135,672	485	364	
2034	Aeroderivative (40 MW)	14.44	1,187,767	498	381	***Outside Model Adjustment 3***
2035	Aeroderivative (40 MW)	14.05	1,274,927	502	401	**$0**
2036	Rio Bravo CC Expansion (210 MW)	14.67	1,305,166	508	403	
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,794,089,422
						Average Risk NPV + Adjustments
						$7,794,208,791

Scenario 35

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = $40 NMPRC						17IRP_35_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.36	4,026,094	1,130	1,399	**$8,626,066,422**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	17.67	2,694,195	841	1,168	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**18.38**
2019	Data Center1 Solar2 (40 MW)	17.96	2,466,163	789	1,034	
	Wind for RPS (50 MW)					**Risk Porfolio Average (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,444,967	771	983	**$8,628,466,462**
	Data Center1 Wind2 (50 MW)					
	Solar PV for RPS (49.5 MW)					**Risk Portfolio Tail (NPV)**
2021	Data Center1 Solar4 (30 MW)	17.11	2,481,660	757	960	**$391,767,165**
	Data Center1 Wind3 (50 MW)					
2022	Data Center1 Solar5 (40 MW)	16.82	2,150,302	684	810	**20-Year CO2 (Tons)**
	Data Center1 Wind4 (30 MW)					**54,598,563**
2023	Data Center1 Solar6 (20 MW)	14.24	1,012,171	459	344	
	2 x Large GT (374 MW)					**20-Year CO2 Cost (NPV)**
	Palo Verde Investment Recovery					**$1,462,120,733**
	PVNGS U1 Lease Purchase (104 MW)					
	Reciprocating Engines (41 MW)					***20-Year PNM CO2 (lbs/MWh)***
	Solar PV Large (100 MW)					**575**
	Wind (100 MW)					
2024	Solar PV Large (100 MW)	14.48	927,542	458	320	***20-Year PNM NM CO2 (lbs/MWh)***
2025	Reciprocating Engines (41 MW)	15.28	936,215	454	324	**541**

2017 IRP SJGS Retires in 2022 LOAD = MID, GAS = MID, CO2 = $40 NMPRC						17IRP_35_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2026		14.20	952,532	464	330	
2027	Aeroderivative (40 MW)	14.83	958,692	455	326	**20-Year Freshwater (Bn of Gal)**
2028	Large GT (187 MW)	15.16	911,175	445	308	**25.482**
	Wind (100 MW)					
2029	Solar PV Distribution (50 MW)	14.18	1,025,343	466	345	***Outside Adjustment 1***
2030	Large GT (187 MW)	20.93	1,024,542	471	339	**$0**
2031		18.78	1,084,003	469	357	
2032		16.75	1,116,301	480	365	***Outside Adjustment 2***
2033		14.79	1,153,696	481	367	**$0**
2034	Aeroderivative (40 MW)	14.44	1,205,842	494	385	
2035	Aeroderivative (40 MW)	14.05	1,293,976	498	405	***Outside Model Adjustment 3***
2036	Rio Bravo CC Expansion (210 MW)	14.67	1,325,555	503	407	**$0**
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$8,626,066,422
						Average Risk NPV + Adjustments
						$8,628,466,462

Scenario 36

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = LOW, CO2 = LOW						*17IRP_36_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,813,199	1,306	1,665	**$7,147,179,172**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,420,740	996	1,453	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**21.85**
2019	Data Center1 Solar2 (40 MW)	14.06	3,053,446	902	1,238	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					**$7,139,431,349**
2020	Data Center1 Solar3 (30 MW)	14.14	2,954,309	862	1,141	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					**$161,129,674**
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	3,169,723	860	1,124	**81,525,179**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	2,852,063	769	939	**$23,785,861**
	Data Center1 Wind4 (30 MW)					
2023	2x1 NGCC (500 MW)	17.86	2,026,985	587	560	***20-Year PNM CO2 (lbs/MWh)***
	Data Center1 Solar6 (20 MW)					**729**
	Large GT (187 MW)					
	Palo Verde Investment Recovery					***20-Year PNM NM CO2 (lbs/MWh)***
2024		14.49	2,202,775	611	578	**780**
2025	Large GT (187 MW)	20.11	2,279,061	609	586	

2017 IRP *SJGS Retires in 2022* *LOAD = HIGH, GAS = LOW, CO2 = LOW*						*17IRP_36_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2026		18.52	2,312,487	616	589	**20-Year Freshwater (Bn of Gal)**
2027		16.82	2,390,491	620	596	**35.425**
2028	Large GT (187 MW)	16.32	2,501,872	636	621	
2029		14.21	2,718,695	664	663	***Outside Adjustment 1***
2030	Large GT (187 MW)	19.40	2,801,165	677	670	**$0**
2031		17.08	2,871,842	671	676	
2032		14.86	2,926,323	678	679	***Outside Adjustment 2***
2033	Aeroderivative (40 MW)	14.15	3,060,936	688	690	**$0**
2034	Small GT (85 MW)	14.91	3,117,656	691	696	
2035	Aeroderivative (40 MW)	14.04	3,230,247	692	703	***Outside Model Adjustment 3***
2036	Aeroderivative (40 MW)	14.33	3,418,413	719	729	**$0**
	Reciprocating Engines (41 MW)					
						Outside Model Adjustment 4
						$0
						Total Optimized NPV + Adjustments
						$7,147,179,172
						Average Risk NPV + Adjustments
						$7,139,431,349

Scenario 37

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = MID, CO2 = MID						17IRP_37_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,813,199	1,306	1,665	**$7,977,958,188**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,416,812	997	1,454	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**15.36**
2019	Data Center1 Solar2 (40 MW)	14.06	3,043,353	904	1,240	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					**$7,971,170,761**
2020	Data Center1 Solar3 (30 MW)	14.14	2,939,114	866	1,143	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					**$261,041,876**
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	3,152,778	864	1,125	**72,550,027**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	2,844,667	780	947	**$122,378,147**
	Data Center1 Wind4 (30 MW)					
2023	1x1 NGCC (250 MW)	14.09	1,585,023	535	455	***20-Year PNM CO2 (lbs/MWh)***
	Data Center1 Solar6 (20 MW)					**664**
	Large GT (187 MW)					
	Palo Verde Investment Recovery					***20-Year PNM NM CO2 (lbs/MWh)***
	PVNGS U1 Lease Purchase (104 MW)					666

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = MID, CO2 = MID						17IRP_37_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
	Reciprocating Engines (41 MW)					
	Solar PV Large (50 MW)					20-Year Freshwater (Bn of Gal)
2024	Large GT (187 MW)	18.66	1,719,071	554	467	**38.575**
2025		16.49	1,819,490	560	486	
2026		14.95	1,867,636	571	495	*Outside Adjustment 1*
2027	Solar PV Large (100 MW)	14.70	1,781,015	554	477	**$0**
2028	Large GT (187 MW)	14.43	1,739,524	546	463	
	Wind (100 MW)					*Outside Adjustment 2*
2029	Aeroderivative (40 MW)	14.10	1,787,070	546	468	**$0**
	Wind (100 MW)					
2030	Large GT (187 MW)	19.28	1,819,551	552	467	*Outside Model Adjustment 3*
2031		16.96	1,922,138	553	485	**$0**
2032		14.75	1,991,199	565	495	
2033	Aeroderivative (40 MW)	14.04	2,078,437	568	500	*Outside Model Adjustment 4*
2034	Large GT (187 MW)	18.42	2,176,417	582	519	**$0**
2035		16.09	2,318,916	588	538	
2036	Aeroderivative (40 MW)	14.94	2,473,009	610	561	*Total Optimized NPV + Adjustments*
						$7,977,958,188
						Average Risk NPV + Adjustments
						$7,971,170,761

Scenario 38

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = HIGH, CO2 = HIGH						17IRP_38_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,813,134	1,306	1,665	**$8,645,016,313**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,412,725	998	1,455	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**15.14**
2019	Data Center1 Solar2 (40 MW)	14.06	3,037,959	906	1,240	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					**$8,639,054,238**
2020	Data Center1 Solar3 (30 MW)	14.14	2,935,705	866	1,143	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					**$368,662,442**
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	3,147,457	865	1,126	**70,693,088**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	2,837,050	782	948	**$221,659,888**
	Data Center1 Wind4 (30 MW)					
2023	1x1 NGCC (250 MW)	14.03	1,286,199	495	383	***20-Year PNM CO2 (lbs/MWh)***
	Data Center1 Solar6 (20 MW)					**650**
	Large GT (187 MW)					
	Palo Verde Investment Recovery					***20-Year PNM NM CO2 (lbs/MWh)***
	PVNGS U1 Lease Purchase (104 MW)					**639**

2017 IRP *SJGS Retires in 2022* *LOAD = HIGH, GAS = HIGH, CO2 = HIGH*						*17IRP_38_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
	Solar PV Large (50 MW)					
	Solar PV Large (100 MW)					**20-Year Freshwater (Bn of Gal)**
	Wind (100 MW)					**37.441**
2024	Large GT (187 MW)	19.03	1,380,556	507	389	
	PVNGS U2 Lease Purchase (10 MW)					***Outside Adjustment 1***
2025		16.85	1,467,996	513	408	**$0**
2026		15.31	1,517,885	526	418	
2027	Reciprocating Engines (41 MW)	15.30	1,553,907	517	417	***Outside Adjustment 2***
2028	Large GT (187 MW)	15.02	1,517,895	510	404	**$0**
	Wind (100 MW)					
2029	Aeroderivative (40 MW)	14.48	1,737,762	544	457	***Outside Model Adjustment 3***
2030	Aeroderivative (40 MW)	14.06	1,770,619	550	456	**$0**
2031	Large GT (187 MW)	18.83	1,873,496	550	474	
2032		16.59	1,944,699	563	485	***Outside Model Adjustment 4***
2033		14.40	2,032,916	566	491	**$0**
2034	Small GT (85 MW)	15.16	2,108,824	577	506	
2035	Aeroderivative (40 MW)	14.29	2,254,756	583	526	***Total Optimized NPV + Adjustments***
2036	Rio Bravo CC Expansion (210 MW)	14.26	2,296,606	589	524	**$8,645,016,313**
						Average Risk NPV + Adjustments
						$8,639,054,238

Scenario 39

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = MID, CO2 = $0						17IRP_39_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,813,199	1,306	1,665	**$7,840,290,063**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,416,812	997	1,454	Portfolio LOLH (Hours)
	Data Center1 Wind1 (50 MW)					**15.36**
2019	Data Center1 Solar2 (40 MW)	14.06	3,043,353	904	1,240	
	Solar PV Distribution (50 MW)					Risk Porfolio Average (NPV)
	Wind for RPS (50 MW)					**$7,833,071,841**
2020	Data Center1 Solar3 (30 MW)	14.14	2,939,114	866	1,143	
	Data Center1 Wind2 (50 MW)					Risk Portfolio Tail (NPV)
	Reciprocating Engines (41 MW)					**$252,322,166**
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					20-Year CO2 (Tons)
2021	Data Center1 Solar4 (30 MW)	19.67	3,152,778	864	1,125	72,719,868
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					20-Year CO2 Cost (NPV)
2022	Data Center1 Solar5 (40 MW)	16.87	2,843,919	781	947	$0
	Data Center1 Wind4 (30 MW)					
2023	1x1 NGCC (250 MW)	14.09	1,578,277	536	454	*20-Year PNM CO2 (lbs/MWh)*
	Data Center1 Solar6 (20 MW)					**666**
	Large GT (187 MW)					
	Palo Verde Investment Recovery					*20-Year PNM NM CO2 (lbs/MWh)*
	PVNGS U1 Lease Purchase (104 MW)					666

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = MID, CO2 = $0						17IRP_39_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
	Reciprocating Engines (41 MW)					
	Solar PV Large (50 MW)					20-Year Freshwater (Bn of Gal)
2024	Large GT (187 MW)	18.66	1,710,952	556	466	**38.597**
2025		16.49	1,811,677	562	485	
2026		14.95	1,864,059	572	494	*Outside Adjustment 1*
2027	Solar PV Large (100 MW)	14.70	1,774,826	556	477	**$0**
2028	Large GT (187 MW)	14.43	1,733,127	548	462	
	Wind (100 MW)					*Outside Adjustment 2*
2029	Aeroderivative (40 MW)	14.10	1,780,962	548	467	**$0**
	Wind (100 MW)					
2030	Large GT (187 MW)	19.28	1,813,699	554	466	*Outside Model Adjustment 3*
2031		16.96	1,915,665	555	484	**$0**
2032		14.75	1,987,592	567	495	
2033	Aeroderivative (40 MW)	14.04	2,075,079	571	501	*Outside Model Adjustment 4*
2034	Large GT (187 MW)	18.42	2,170,972	585	520	**$0**
2035		16.09	2,315,540	591	539	
2036	Aeroderivative (40 MW)	14.94	2,468,866	614	562	*Total Optimized NPV + Adjustments*
						$7,840,290,063
						Average Risk NPV + Adjustments
						$7,833,071,841

Scenario 40

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = MID, CO2 = $8 NMPRC						17IRP_40_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,782,092	1,296	1,650	**$8,255,436,969**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,363,733	982	1,427	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**15.05**
2019	Data Center1 Solar2 (40 MW)	14.06	3,024,218	896	1,227	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					**$8,245,590,955**
2020	Data Center1 Solar3 (30 MW)	14.14	2,946,098	864	1,142	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					**$257,067,454**
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	3,157,783	862	1,125	**70,679,942**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	2,849,530	779	947	**$367,924,890**
	Data Center1 Wind4 (30 MW)					
2023	1x1 NGCC (250 MW)	14.03	1,308,811	489	387	***20-Year PNM CO2 (lbs/MWh)***
	Data Center1 Solar6 (20 MW)					**650**
	Large GT (187 MW)					
	Palo Verde Investment Recovery					***20-Year PNM NM CO2 (lbs/MWh)***
	PVNGS U1 Lease Purchase (104 MW)					**647**

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = MID, CO2 = $8 NMPRC						*17IRP_40_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
	Solar PV Large (50 MW)					
	Solar PV Large (100 MW)					**20-Year Freshwater (Bn of Gal)**
	Wind (100 MW)					**37.558**
2024	Large GT (187 MW)	18.61	1,435,188	508	402	
2025		16.44	1,529,566	515	422	***Outside Adjustment 1***
2026		14.90	1,575,345	526	431	**$0**
2027	Reciprocating Engines (41 MW)	14.90	1,607,357	519	429	
2028	Large GT (187 MW)	14.63	1,572,651	511	416	***Outside Adjustment 2***
	Wind (100 MW)					**$0**
2029	Aeroderivative (40 MW)	14.10	1,791,955	545	469	
2030	Large GT (187 MW)	19.28	1,825,672	551	467	***Outside Model Adjustment 3***
2031		16.96	1,927,927	552	485	**$0**
2032		14.75	1,997,398	563	495	
2033	Aeroderivative (40 MW)	14.04	2,084,788	567	501	***Outside Model Adjustment 4***
2034	Large GT (187 MW)	18.42	2,179,464	581	519	**$0**
2035		16.09	2,321,126	587	538	
2036	Aeroderivative (40 MW)	14.94	2,474,655	610	561	***Total Optimized NPV + Adjustments***
						$8,255,436,969
						Average Risk NPV + Adjustments
						$8,245,590,955

Scenario 41

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = MID, CO2 = $20 NMPRC						17IRP_41_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,533,514	1,239	1,562	**$8,862,271,625**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	3,142,325	932	1,332	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**15.18**
2019	Data Center1 Solar2 (40 MW)	14.06	2,841,029	855	1,151	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					**$8,842,204,983**
2020	Data Center1 Solar3 (30 MW)	14.14	2,821,649	834	1,089	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					**$322,897,189**
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	3,031,829	833	1,076	**69,370,504**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.87	2,786,821	761	921	**$898,155,046**
	Data Center1 Wind4 (30 MW)					
2023	1x1 NGCC (250 MW)	14.03	1,327,308	484	390	***20-Year PNM CO2 (lbs/MWh)***
	Data Center1 Solar6 (20 MW)					**638**
	Large GT (187 MW)					
	Palo Verde Investment Recovery					***20-Year PNM NM CO2 (lbs/MWh)***
	PVNGS U1 Lease Purchase (104 MW)					**634**

2017 IRP *SJGS Retires in 2022* *LOAD = HIGH, GAS = MID, CO2 = $20 NMPRC*						*17IRP_41_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
	Solar PV Large (50 MW)					
	Solar PV Large (100 MW)					**20-Year Freshwater (Bn of Gal)**
	Wind (100 MW)					**36.645**
2024	Large GT (187 MW)	18.61	1,449,309	505	404	
2025		16.44	1,542,990	511	424	***Outside Adjustment 1***
2026		14.90	1,588,596	523	433	**$0**
2027	Reciprocating Engines (41 MW)	14.90	1,618,998	516	430	
2028	Large GT (187 MW)	14.63	1,583,688	509	417	***Outside Adjustment 2***
	Wind (100 MW)					**$0**
2029	Aeroderivative (40 MW)	14.10	1,802,684	542	470	
2030	Large GT (187 MW)	19.28	1,834,638	548	468	***Outside Model Adjustment 3***
2031		16.96	1,938,416	549	486	**$0**
2032		14.75	2,007,521	560	496	
2033	Aeroderivative (40 MW)	14.04	2,093,674	564	502	***Outside Model Adjustment 4***
2034	Large GT (187 MW)	18.42	2,188,860	578	520	**$0**
2035		16.09	2,328,277	584	538	
2036	Aeroderivative (40 MW)	14.94	2,483,653	607	561	***Total Optimized NPV + Adjustments***
						$8,862,271,625
						Average Risk NPV + Adjustments
						$8,842,204,983

Scenario 42

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = MID, CO2 = $40 NMPRC						*17IRP_42_01*
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
2017	FCPP Maint./Outage Capital	26.08	4,056,181	1,131	1,398	**$9,831,214,625**
	San Juan Investment Recovery					
2018	Data Center1 Solar1 (30 MW)	14.74	2,750,714	844	1,166	**Portfolio LOLH (Hours)**
	Data Center1 Wind1 (50 MW)					**15.33**
2019	Data Center1 Solar2 (40 MW)	14.06	2,476,064	776	1,003	
	Solar PV Distribution (50 MW)					**Risk Porfolio Average (NPV)**
	Wind for RPS (50 MW)					**$9,809,411,451**
2020	Data Center1 Solar3 (30 MW)	14.14	2,488,052	763	960	
	Data Center1 Wind2 (50 MW)					**Risk Portfolio Tail (NPV)**
	Reciprocating Engines (41 MW)					**$445,890,766**
	Solar PV Large (50 MW)					
	Solar PV for RPS (49.5 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	19.67	2,695,012	765	955	**65,861,795**
	Data Center1 Wind3 (50 MW)					
	Large GT (187 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	17.09	2,337,040	666	760	**$1,690,475,451**
	Data Center1 Wind4 (30 MW)					
	Wind (100 MW)					***20-Year PNM CO2 (lbs/MWh)***
2023	1x1 NGCC (250 MW)	14.03	1,351,038	479	394	**605**
	Data Center1 Solar6 (20 MW)					
	Large GT (187 MW)					***20-Year PNM NM CO2 (lbs/MWh)***
	Palo Verde Investment Recovery					**593**
	PVNGS U1 Lease Purchase (104					

2017 IRP SJGS Retires in 2022 LOAD = HIGH, GAS = MID, CO2 = $40 NMPRC						17IRP_42_01
Year	**Resource**	**Reserve Margin**	**PNM NM CPP CO2 Tons[1]**	**PNM CPP CO2 lbs/MWh[1]**	**PNM NM CPP CO2 lbs/MWh[1]**	**Optimized Portfolio (NPV)**
	MW)					
	Solar PV Large (50 MW)					20-Year Freshwater (Bn of Gal)
	Solar PV Large (100 MW)					**34.202**
2024	Large GT (187 MW)	19.03	1,442,929	492	399	
	PVNGS U2 Lease Purchase (10 MW)					*Outside Adjustment 1*
2025		16.85	1,531,943	498	417	**$0**
2026		15.31	1,582,086	510	427	
2027	Reciprocating Engines (41 MW)	15.30	1,611,491	503	425	*Outside Adjustment 2*
2028	Large GT (187 MW)	15.02	1,575,297	495	411	**$0**
	Wind (100 MW)					
2029	Aeroderivative (40 MW)	14.48	1,794,570	529	464	*Outside Model Adjustment 3*
2030	Aeroderivative (40 MW)	14.06	1,825,288	535	462	**$0**
2031	Large GT (187 MW)	18.83	1,924,329	536	479	
2032		16.59	1,995,482	548	490	*Outside Model Adjustment 4*
2033		14.40	2,079,577	553	495	**$0**
2034	Small GT (85 MW)	15.16	2,162,159	563	510	
2035	Aeroderivative (40 MW)	14.29	2,303,290	570	529	*Total Optimized NPV + Adjustments*
2036	Rio Bravo CC Expansion (210 MW)	14.26	2,366,258	574	530	**$9,831,214,625**
						Average Risk NPV + Adjustments
						$9,809,411,451

Appendix N. MCEP Loads and Resources Table

Public Service Company of New Mexico

Line No.	Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
(1)	Forecasted System Peak Demand	1,830	1,839	1,843	1,867	1,891	1,911	1,916	1,923	1,937	1,948	1,964	1,991	2,007	2,037	2,081	2,123	2,164	2,201	2,248	2,298
(2)	Forecasted Incremental Energy Efficiency	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)	(136)	(138)	(146)	(147)	(142)	(138)	(135)	(134)	(129)	(122)
(3)	Forecasted Incremental Customer Sited PV	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(47)	(48)
(4)	**Net System Peak Demand (MW)**	1,871	1,900	1,926	1,961	1,999	2,033	2,053	2,071	2,093	2,114	2,138	2,168	2,193	2,225	2,265	2,304	2,343	2,381	2,423	2,468
(5)	Four Corners	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	-	-	-	-	-
(6)	San Juan	783	497	497	497	497	497	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(7)	**Total Coal Resources (MW)**	983	697	697	697	697	697	200	200	200	200	200	200	200	200	200	-	-	-	-	-
(8)	Palo Verde Unit 1 & Unit 2	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268
(9)	Palo Verde Unit 3	-	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
(10)	**Total Nuclear Resources (MW)**	268	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402
(11)	Reeves	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
(12)	Afton	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
(13)	Lordsburg	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
(14)	Luna	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189
(15)	Rio Bravo	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	-	-
(16)	Valencia	150	150	150	150	150	150	150	150	150	150	150	-	-	-	-	-	-	-	-	-
(17)	La Luz	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
(18)	Natural Gas Fired Resource	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
(19)	Natural Gas Fired Resource	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	210	210
(20)	Natural Gas Fired Resource	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	40
(21)	Natural Gas Fired Resource	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	40	40
(22)	Natural Gas Fired Resource	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187
(23)	Natural Gas Fired Resource	-	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187	187	187	187
(24)	Natural Gas Fired Resource	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187
(25)	Natural Gas Fired Resource	-	-	-	-	-	-	41	41	41	41	41	41	41	41	41	41	41	41	41	41
(26)	Natural Gas Fired Resource	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187	187	187	187	187	187
(27)	Natural Gas Fired Resource	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187	187	187	187	187	187
(28)	Natural Gas Fired Resource	-	-	-	-	-	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
(29)	**Total Natural Gas Resources (MW)**	981	981	981	981	981	1,022	1,437	1,437	1,437	1,437	1,437	1,474	1,661	1,661	1,661	1,848	1,888	1,928	2,000	2,040
(30)	**Total Demand Response Programs (MW, Net of losses)**	45	47	48	49	51	53	54	56	57	59	60	60	60	60	60	60	60	60	60	60
(31)	Wind Purchase (NMWEC)	10	10	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-
(32)	Wind Purchase (Red Mesa)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-
(33)	Prosperity Battery Demo	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
(34)	Utility Scale Solar PV (22 MW - 2012 REPP)	12	12	12	12	12	12	11	11	11	11	11	11	11	11	11	11	11	11	11	11
(35)	Utility Scale Solar PV (20 MW - 2013 REPP)	11	11	11	11	11	11	11	10	10	10	10	10	10	10	10	10	10	10	10	10
(36)	Utility Scale Solar PV (23 MW - 2014 REPP)	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	14	14	14	14	14
(37)	Utility Scale Solar PV (40 MW - 2015 REPP)	30	30	30	30	29	29	29	29	28	28	28	28	28	27	27	27	27	27	26	26
(38)	PNM Sky Blue - 1.5 MW Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
(39)	Dale Burgett Geothermal Plant	2	2	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-
(40)	100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5
(41)	100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5
(42)	50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18
(45)	50 MW Solar PV	-	-	-	-	-	-	-	-	-	17	17	17	17	17	17	17	17	17	17	17
(46)	100 MW Solar PV	-	-	-	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35
(47)	50 MW Solar PV	-	-	-	-	-	-	-	17	17	17	17	17	17	17	17	17	17	17	17	17
(48)	Data Center 1 Solar PV - 20 MW	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
(49)	Data Center 1 Solar PV - 40 MW	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
(50)	Data Center 1 Solar PV - 30 MW	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
(51)	Data Center 1 Solar PV - 30 MW	-	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
(52)	Data Center 1 Solar PV - 40 MW	-	-	-	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
(53)	Data Center 1 Solar PV - 30 MW	-	-	-	-	-	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11
(54)	Data Center 1 Wind - 30 MW	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
(55)	Data Center 1 Wind - 50 MW	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
(56)	Data Center 1 Wind - 50 MW	-	-	-	-	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
(57)	Data Center 1 Wind - 50 MW	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
(58)	Solar PV for 2020 RPS	-	-	-	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
(59)	Wind for 2020 RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(60)	**Total Renewable Resources (MW)**	87	109	144	186	211	242	253	270	305	321	339	338	328	327	332	337	336	331	331	326
(61)	**Total System Resources (MW)**	2,364	2,236	2,272	2,316	2,342	2,416	2,346	2,365	2,401	2,419	2,438	2,474	2,651	2,650	2,655	2,647	2,686	2,721	2,793	2,828
(62)	**Reserve Margin (MW)**	493	336	346	354	342	383	294	294	308	305	300	306	458	426	391	343	343	341	370	359
(63)	**Reserve Margin (%)**	26.4%	17.7%	18.0%	18.1%	17.1%	18.8%	14.3%	14.2%	14.7%	14.4%	14.0%	14.1%	20.9%	19.1%	17.2%	14.9%	14.7%	14.3%	15.3%	14.6%

Notes:

1. PNM assumes a capacity credit for renewable resources based on type of technology and contribution at the peak hour.
2. Demand response resources grossed up for transmission losses.
3. PNM assumes a 100% capacity credit for Prosperity Battery Demo
4. Capacity credit for geothermal resource is based upon developer estimates.

PNM: Powering New Mexico Since 1917

About PNM

Founded in 1917 as Albuquerque Gas and Electric Company, PNM is a subsidiary of PNM Resources, a utility holding company based in Albuquerque, NM, and the only New Mexico-headquartered company traded on the New York Stock Exchange (NYSE:PNM). PNM employs more than 1,500 New Mexicans.

Albuquerque Gas and Electric Company Headquarters on 5th and Central in 1938

Reliable, Affordable Electricity for Homes and Businesses

PNM provides electricity to more than 500,000 New Mexicans living in seven pueblos and more than 40 communities, including Albuquerque, Santa Fe, Rio Rancho, Belen, Alamogordo, Las Vegas, Ruidoso, Deming and Silver City.

- Consistently in top quartile performance nationally for reliability.
- Average residential bills in the top 25 percent for affordability in the region based on percent of annual household income.
- Industrial rates ranked in the top 25 percent for affordability for the region.

PNM Good Neighbor Fund

Funded by PNM customers, employees and shareholders, this program provides financial assistance to customers who are experiencing financial challenges and meet certain income and account requirements. Qualified customers may receive payment towards a past-due PNM electric bill. Learn more at ***PNM.com/goodneighbor-fund.***

Investing in the Community

Each year, PNM and the PNM Resources Foundation assist New Mexico communities with more than $3 million of support to nonprofit organizations. Since 1983, the Foundation has invested more than $14 million in local nonprofit organizations to build strong and vibrant communities. Through funding from PNM shareholders, employees, customers and our company, PNM also invests in the communities it serves in three key areas education, economic development and the environment. Learn more at ***PNM.com/community-investments.***

Strong Environmental Stewards

PNM is committed to providing responsible leadership for the preservation of the environment and to continuously improve our operations to reduce environmental impact. For information on key environmental areas, including clean energy, energy conservation, avian protection, waste reduction, water conservation, natural resource protection and other areas. Learn more at ***PNM.com/envir-highlights.***

Energy Efficiency

PNM offers rebates and services to customers to reduce the initial cost of energy efficiency improvements, helping customers to save money and protect the environment. Learn more at ***PNM.com/save.***

PNM Sky Blue®

PNM Sky Blue is a voluntary program that allows customers to purchase wind and solar energy at a premium price to show their commitment to the environment. Customers can purchase 100 kWh "blocks" of electricity or sign up for a set percentage of their usage. Learn more at ***PNM.com/pnm-sky-blue1.***

PNM®