PNM
Integrated Resource Plan

2014 – 2033 July 2014

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The information in this document is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, 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 (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

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EXECUTIVE SUMMARY

PNM's 2014-2033 Integrated Resource Plan (IRP) considers PNM's resource mix over the next 20 years. At the beginning of the 20 year period, PNM anticipates significant changes to its generation resource portfolio to implement a Regional Haze Rule compliance plan (Revised State Implementation Plan or Revised SIP) for the San Juan Generating Station (San Juan or SJGS). After implementing the Revised SIP, the most cost effective mix of resources to serve PNM's growing customer energy needs is a mixture of renewable energy and natural gas resources.

In 2013, PNM, the State of New Mexico and the U.S. Environmental Protection Agency (EPA) agreed to pursue a Regional Haze Rule compliance plan to reduce visibility-impairing emissions from SJGS in order to comply with the Clean Air Act. The Revised SIP requires shutting down two of the four units at SJGS at the end of 2017. Subject to New Mexico Public Regulation Commission (Commission or NMPRC) approval in Case No. 13-00390-UT, beginning in 2016 and continuing through early 2018, PNM will make significant changes to its generation resource portfolio to implement the Revised SIP. Replacing retired SJGS capacity with a mixture of new solar, existing nuclear, and new natural gas peaking capacity is the most cost effective resource plan. In addition to cost savings, this plan results in an improvement in visibility, a reduction in greenhouse gas emissions, and other significant environmental benefits.

PNM filed for abandonment of its capacity in SJGS Units 2 and 3 on December 20, 2013 in NMPRC Case No. 13-00390-UT. The most cost effective combination of resources to replace that capacity is:

- Install 40 megawatts (MW) of new single axis tracking solar photovoltaic (solar PV) capacity. PNM needs additional Renewable Energy Certificates (RECs) to meet the New Mexico Renewable Portfolio Standard (RPS) in 2016. The additional solar PV capacity will provide the required RECs and also is an element of the most cost-effective portfolio identified in the IRP. The dual functions served by this resource make it an optimal near-term choice to replace part of the retired San Juan capacity. PNM filed for approval of this resource on June 2, 2014 in NMPRC Case No. 14-00158-UT.
- Receive Commission approval to make PNM's 134 MW ownership in Unit 3 of the Palo Verde Nuclear Generating Station (Palo Verde) as a jurisdictional resource to serve PNM's retail customers prior to 2018. This resource is a component of the most cost-effective replacement portfolio and its addition to PNM's jurisdictional portfolio decreases carbon dioxide (CO_2) emission rates from PNM's resource portfolio. PNM filed for approval to make this plant a jurisdictional resource on December 20, 2013, in Case No. 13-00390-UT.
- Install additional gas peaking capacity prior to the 2018 summer peak as part of the most cost-effective replacement portfolio identified in the IRP process. Additional gas peaking capacity is necessary for system reliability and to

increase system flexibility. PNM will issue a request for proposals (RFP) for this resource within the next nine months to ensure that the resource will be on-line before summer 2018.

This mixture of capacity additions to replace the retired resources at SJGS is cost-effective, whether PNM acquires 132 MW of additional capacity in SJGS Unit 4 or some lesser amount. The amount of capacity that PNM will own in SJGS will be determined through the ongoing ownership restructuring process at SJGS, subject to NMPRC approval in Case No. 13-00390-UT.

Under all of the scenarios examined in the IRP, the resource additions after 2018 that are most cost effective are a mixture of renewable resources and natural gas capacity. The timing, type and quantity of these additions are dependent upon customer demand for energy, greenhouse gas regulations, and future prices of natural gas and renewable resources.

With the proposed addition of Palo Verde Unit 3 capacity and additional capacity in SJGS Unit 4, no additional baseload generation is included in the most cost-effective portfolio. Implementation of the Revised SIP with the most cost-effective portfolio will result in a rebalancing of PNM's mix of baseload, intermediate and peaking resources. The 20-year IRP analysis does not demonstrate a need to begin development of any additional baseload generation.

Four Year Action Plan

Considering these findings, PNM's Four Year Action Plan is:

- **Energy Efficiency:** Develop additional energy efficiency resources to achieve the Efficient Use of Energy Act (EUEA) requirements.
- **Regional Haze Compliance:** Implement the Revised SIP at SJGS by
    - Filing for abandonment of SJGS Unit 2 and 3 Capacity (complete),
    - Filing for approval to build an additional 40 MW of solar PV capacity (complete),
    - Filing for a certificate of public convenience and necessity (CCN) for the 134 MW Palo Verde Unit 3 resource (complete),
    - Filing for a CCN for additional capacity at SJGS Unit 4 (complete),
    - Conducting an RFP and, based on the results of that RFP, filing for approval of additional gas peaking capacity,
- **Greenhouse Gas Reduction:** Work with the State of New Mexico to develop a plan for statewide compliance with EPA's proposed rules under the Clean Air Act Section 111(d) to reduce greenhouse gas emissions in the State and to set standards for new and modified power plants as needed.
- **Transmission Import Capability:** Continue to evaluate long-term transmission requirements and opportunities to improve transmission import capability into Northern New Mexico.

- **Emerging Resources:** Continue to monitor and evaluate emerging technologies, particularly battery storage, for application in the future.

THE MOST COST-EFFECTIVE RESOURCE PORTFOLIO

The Most Cost-Effective Portfolio is the portfolio of existing and new resources that meets electric system demand, provides acceptable system reliability and operational flexibility, and meets applicable legal and regulatory requirements, at the lowest reasonable cost to customers.

To identify the Most Cost-Effective Portfolio for the period 2014 through 2033, PNM examined several thousand potential resource portfolios using four different projections of customer demand and three projections of future natural gas and carbon prices. PNM then tested the results of this analysis under alternative assumptions for the price of wind generation, the contribution of solar capacity to peak hour demand, varying levels of energy efficiency, drought conditions and carbon emission costs.

The Most Cost-Effective Portfolio based on this analysis is summarized in Figure E-1 below.

FIGURE E-1: SUMMARY OF MOST COST-EFFECTIVE PORTFOLIO

Existing Actual Peak: 2008 MW	2018 Peak: 2,048 MW	2033 Peak: 2,890 MW
• San Juan 783 MW • Palo Verde 268 MW • Four Corners 200 MW • Gas 932 MW • Solar 44 MW • Wind 200 MW	• SJGS 443 - 497 MW • Palo Verde 402 MW • Four Corners 200 MW • Gas 1,149 MW • Solar 107 MW • Wind 305 MW	• SJGS 443 - 497 MW • Palo Verde 402 MW • Four Corners 200 MW • Gas 1,676 -1,761 MW • Solar 327 MW • Wind 402 MW

PUBLIC INPUT

The preparation of this IRP Report began in July 2013 with IRP kick-off meetings in Alamogordo, Silver City, Albuquerque and Santa Fe and concluded with a presentation of the findings in this Report on June 26, 2014. During the year, PNM presented the results of its portfolio analyses through a series of public meetings with the goal of providing transparency into the analysis process and identifying process improvements through discussion at the meetings. This process coincided with PNM's SJGS abandonment filing and the preparation of its 2015 Renewable Energy Procurement Plan. The Public Advisory process resulted in the following significant contributions to PNM's planning process:

- An examination of the contribution of solar capacity to meeting customer demand. This caused PNM to refine its solar PV modeling technique, which resulted in an increase in the quantity of solar PV resources in the Most Cost Effective Portfolio over what it otherwise would have been.
- Development of a wind sensitivity analysis demonstrating that the cost of wind energy is the primary factor affecting the amount of wind that can cost-effectively be added to PNM's portfolio.
- Discussion during the Public Advisory sessions that shaped the agenda for subsequent meetings through the process.
- Similar to the 2011-2030 IRP process, interest in the use of water for electric generation is high, so PNM presented data on water use and updated its sensitivity analysis that examines the impact of drought conditions.

CONCLUSION

PNM prepared the 2014-2033 Integrated Resource Plan in compliance with 17.7.3 New Mexico Administrative Code (NMAC) Integrated Resource Plan for Electric Utilities." This IRP confirms that PNM's plan for implementing the Revised SIP by replacing the retired capacity at SJGS with a combination of solar, nuclear and natural gas peaking capacity as proposed in Case No. 13-00390-UT is the most cost-effective means of compliance with EPA's Regional Haze Rule at SJGS and that future portfolio additions after 2018 will be renewable energy and natural gas peaking resources.

1 2014-2033 INTEGRATED RESOURCE PLANNING PROCESS

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

The IRP Rule requires that New Mexico electric public utilities must file an IRP that contains the following information (17.7.3.9B NMAC):

1. A description of existing electric supply-side and demand-side resources,
2. A current load forecast,
3. A load and resources table,
4. Identification of resource options,
5. A description of resource and fuel diversity,
6. Identification of critical facilities susceptible to supply-source or other failures,
7. A determination of the most cost effective resource portfolio and alternative portfolios,
8. A description of the public advisory process,
9. An action plan, and
10. Other information that the utility finds may aid the commission in reviewing the utility's planning processes.

The rule requires New Mexico electric public utilities to file an IRP every three years.

INTEGRATED RESOURCE PLANNING PROCESS

The IRP identifies the most cost-effective resource portfolio that meets the projected electric demands of PNM's jurisdictional electric customers over the next twenty years and describes a four year Action Plan that is consistent with the most-cost effective portfolio.

The IRP planning process, on a macro-level, identifies resources that reliably meet system operational requirements including delivery to customers consistent with applicable regulatory requirements. For planning purposes, PNM uses 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 allows PNM to create a portfolio that has the ability to respond to projections of future events to ensure the availability of adequate resources to meet demand and maintain service reliability. PNM updates its IRP every three years or sooner, if material changes in assumptions would lead to a different course of action.

Approach

PNM designed a multi-dimensional process for its IRP analyses to determine the most cost-effective resource portfolio for the twenty-year period from 2014 through 2033. The process included reviewing existing resources, forecasting future energy needs, examining future resource options, and designing scenarios to evaluate various portfolios to meet requirements. The PNM Integrated Resource Planning group worked with the IRP Public Advisory participants to evaluate cost, proposed environmental policy impacts, and reliability factors while determining the most cost-effective resource portfolio.

Public Participation

In keeping with the IRP Rule, PNM invited the public to participate in the planning process. Goals of the process included increased understanding of the resource options available and the inherent trade-offs between the cost, environmental concerns, and resource reliability. These factors were considered when analyzing different customer load and natural gas cost assumptions.

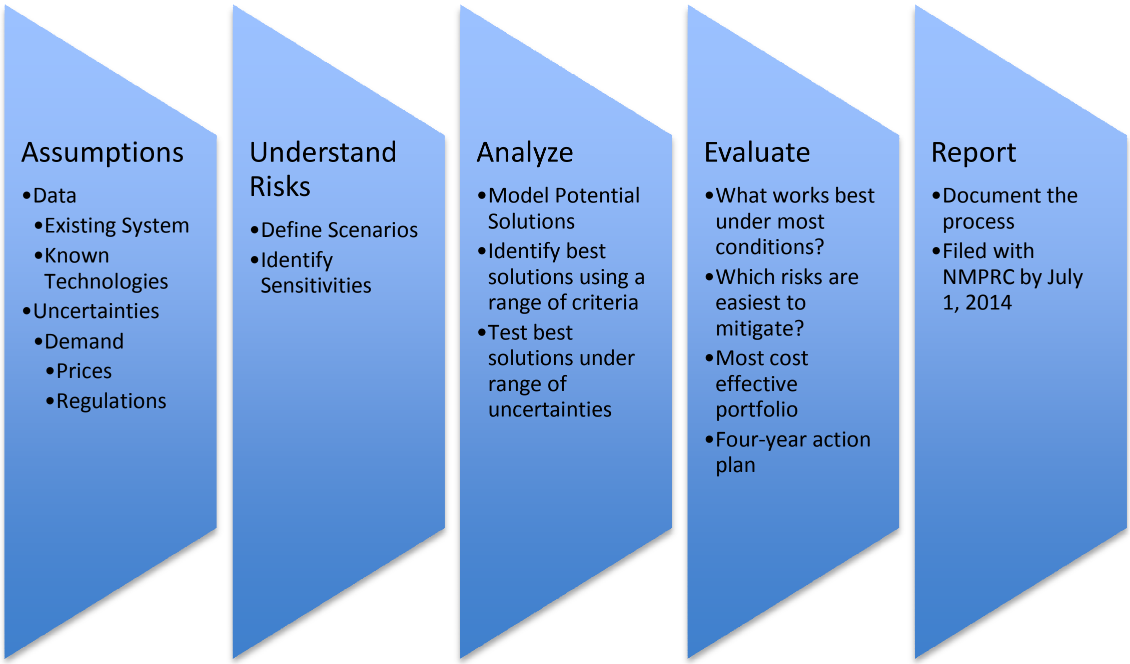
Determining the Most Cost-Effective Resource Portfolio

PNM identified the most cost-effective resource portfolio by considering a variety of factors including regulatory and environmental requirements, environmental impact(s) and system reliability. PNM evaluated each factor for potential financial and non-financial risk. The four-year Action Plan for the period from 2014 through 2018 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.

The IRP Process

The IRP planning process, conducted every three years, is a year-long process that uses historical and projected data, public input, sophisticated software modeling, and technical, financial and regulatory knowledge to determine the most cost-effective portfolio of resources that meets customer needs over the next twenty years. Figure 1-A summarizes the IRP process:

FIGURE 1-A: SUMMARY OF MOST COST-EFFECTIVE PORTFOLIO



ASSUMPTIONS

The process begins with collecting data.

- This includes data on existing system supply- and demand-side resources and known technologies, existing customer loads, and current prices for fuel and new resources, and applicable regulations.
- In addition, forecasts must be created for customer energy requirements (i.e., load in MWh and demand in MW) taking into account both existing and projections of future customers. Fuel prices must be projected for the next twenty years including natural gas, fuel oil, coal and nuclear fuel. IRP planning must also consider the types of generation and demand-side technologies and resources that may be available in the future and their capital and operating costs, as well as assessing issues related to siting new resources and facilities, water availability and transmission resources.

UNDERSTAND RISKS

Given the inherent uncertainty of forecasts and possible 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 analyses, the IRP process examines multiple versions of the future. Each scenario is a different picture of the future that, taken all together, explores alternative customer load growth trends over time, possible future fuel pricing trends, and the capability of differing types of resources to provide energy services to customers under alternative versions of the future.

Analyze

Using economic probabilistic dispatch modeling software, a least-cost resource portfolio can be determined for each of these scenarios. These are then analyzed and evaluated to understand the impacts over the study period. The future is unlikely to look exactly like any one of the scenarios created; 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:

- 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 do they rank compared to other portfolios; and
- Environmental impacts of those portfolios in terms of air quality and water usage.

Throughout the IRP process, public participation is important, since key assumptions to scenario analyses can be improved based on contributions from PNM's customers.

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 another two years (i.e., during 2016-2017), the IRP planning process will be conducted again and a new most cost-effective portfolio may be identified to address conditions and forecasts as they will exist at that time.

2 EXISTING ENERGY SUPPLY AND TRANSMISSION RESOURCES

This section describes PNM's existing supply-side and transmission resources, including PNM-owned generation, purchased generation, and the transmission system currently used by PNM to serve customers. The information in this Section, *Existing System Resources,* responds to the requirements of the IRP Rule Section 17.7.3.9 (C).

SUPPLY RESOURCES

PNM's supply portfolio consists of diverse generating resources that are owned by PNM or that generate power purchased by PNM through a Power Purchase Agreement (PPA). Supply resources are constructed or contracted to serve customer loads, to replace expiring contracts or retiring facilities and to meet public policy requirements, such as the Renewable Portfolio Standard (RPS). Cost and performance data for PNM's existing resources can be found in Appendix A.

An overview of PNM's existing and pending generation resources is presented in Table 2-A. A detailed discussion of each of these resources is presented on the following pages.

Table 2-A: 2014 Overview of Existing and Pending Supply Resources

Resource Name	MW	Fuel	PNM Owned or PPA[1]
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	185	Natural Gas	Owned
Reeves Generating Station	154	Natural Gas	Owned
Valencia Energy Facility	145	Natural Gas	PPA
Delta-Person Generating Station	138	Natural Gas or Oil	PPA
Red Mesa Wind Energy Center	102	Wind	PPA – starts Jan. 1, 2015
Lordsburg Generating Station	80	Natural Gas	Owned
PNM-Owned Solar (multiple sites on distribution system)	44	Solar	Owned
La Luz Energy Center	40	Natural Gas	Owned—starts in 2016
Dale Burgett Geothermal	10	Geothermal	PPA

[1] PPA = Power Purchase Agreement

EXISTING RENEWABLE RESOURCES

PNM's renewable resources include three types of facilities: wind, solar and geothermal.

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 substation located on the Blackwater-BA 345 kilovolt (kV) line (BB 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. (NextEra), under a 25-year power purchase agreement (PPA) that expires in 2028.

The amount of annual wind energy generation from the NMWEC is difficult to predict since it varies with wind activity. Historical data (see Table 2-B) shows that production can range from 490 GWh to 579 GWh per year. PNM forecasts that this facility will generate approximately 525 GWh per year, recognizing that this amount will vary from year to year.

Table 2-B: NMWEC Historical Production

	Actual Generation MWh	Capacity Factor %
2003	212,759	25.3
2004	513,587	28.7
2005	513,068	28.7
2006	528,429	29.6
2007	500,560	28.0
2008	577,508	32.2
2009	533,289	29.8
2010	552,241	30.9
2011	579,900	32.5
2012	545,321	30.5
2013	490,539	27.9

PNM-Owned Solar Resources

PNM currently has 44 MW of solar PV generating facilities in service. The solar PV resources consist of fixed tilt, thin-film panels located near various communities in PNM's service area: Albuquerque, Los Lunas, Las Vegas, Deming, Alamogordo, Otero 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 the New Mexico Wind Energy Center (NMWEC) to supply customers participating in the Sky Blue program.

An additional 23 MW of solar facilities was approved by the NMPRC in December 2013 as part of PNM's 2014 Renewable Energy Portfolio Procurement Plan. Three facilities are under construction in the PNM service territory and will be in service by the end of 2014. These facilities will include single-axis tracking mechanisms that allow the solar panels to follow the sun throughout the day, thereby increasing the amount of electricity generated.

Details of PNM's solar facilities are provided in Table 2-C, below.

Table 2-C: PNM's Solar PV Facilities

Resource Name	In-Service	Nameplate Capacity (MW)	Peak Contribution Capacity (MW)
In-Service			
Albuquerque Solar Energy Center	4/2011	2	1.1
Prosperity Energy Storage Project	9/2011	0.5	0.5
Los Lunas Solar Energy Center	6/2011	5	2.8
Deming Solar Energy Center	8/2011	5	2.8
Las Vegas Solar Energy Center	12/2011	5	2.8
Alamogordo Solar	10/2011	5	2.8
Subtotal		**22.5**	**12.8**
Manzano Solar Energy Center (eastern Valencia County)	10/2013	8	4.4
Los Lunas Solar Energy Center	10/2013	2	1.1
Deming Solar Energy Center	11/2013	4	2.2
Otero Solar Energy Center	11/2013	7.5	4.1
Subtotal		**21.5**	**11.8**
Pending			
Sandoval County	12/2014	8	4.4
Meadowlake	12/2014	9	5.0
Cibola County	12/2014	6	3.3
Subtotal		**23**	**12.7**
Total, In-Service and Pending		**67**	**37.3**

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

PNM-Owned 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 successfully operated since September 2011. It is one of the most successful demonstration projects of battery storage and PV energy in the nation, has been the subject of extensive research, and has 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, a resource 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, and plans for the facility to increase its production up to the 10 MW. 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 exposed to air.

Approved Renewable Resources

Red Mesa Energy Facility

Red Mesa Energy Facility is an existing wind energy facility located about 50 miles west of Albuquerque in Cibola County with 102 MW of generation capacity. Owned by NextEraEnergy, Inc., (NextEra), the facility interconnects to PNM's transmission system on the West Mesa 115 kilovolt (kV) line (KM Line) at the Red Mesa station. In December 2013, the NMPRC approved PNM's plan to enter into a 20-year PPA for the purchase of the generation by this facility beginning on January 1, 2015.

Existing Thermal Resources

PNM's existing thermal generating resources consist of two coal-fueled resources (San Juan Generating Station and Four Corners Power Plant), Palo Verde Nuclear Generating Station, and six natural gas-fueled generating stations. PNM assesses natural gas requirements for its natural gas-fired generating plants on a monthly basis, taking into consideration the anticipated load, weather and other events, like outages in the generating fleet, and makes purchases of gas for the upcoming month which can be supplemented with spot purchase as may be necessary during the month.

San Juan Generating Station

The San Juan Generating Station (SJGS) or (San Juan) is a coal-fired plant that consists of four units. PNM has an overall ownership share of 783 MW. SJGS is located in Waterflow, New Mexico near Farmington. The SJGS units were constructed as follows: Unit 1 in 1976, Unit 2 in 1973, Unit 3 in 1979 and Unit 4 in 1982.

PNM is the majority owner of the plant as well as the plant operator. Table 2-D shows the ownership by generating unit. PNM's ownership share of Unit 3 represents its largest single resource (248 MW). SJGS is PNM's primary source of base-load generation, and PNM relies upon network transmission service rights to bring SJGS energy into the northern New Mexico system.

Table 2-D: SJGS Ownership by Unit

	Current Net MW's				
Participant	Unit 1	Unit 2	Unit 3	Unit 4	Total
PNM	170.0	170.0	248.0	195.0	783.0
Tucson Electric Power	170.0	170.0	-	-	340.0
M-S-R	-	-	-	146.0	146.0
City of Farmington	-	-	-	43.0	43.0
Tri-State	-	-	40.7	-	40.7
Los Alamos County	-	-	-	36.5	35.5
SCPPA	-	-	207.3	-	207.3
Anaheim	-	-	-	50.9	50.9
UAMPS	-	-	-	35.6	35.6
Total	340.0	340.0	496.0	507.0	1,683.0

The coal needed to fuel SJGS is purchased from an adjacent underground coal mine owned by the San Juan Coal Company (SJCC), a subsidiary of BHP Billiton. PNM oversees the administration of the coal contract, and is currently negotiating with SJCC to extend the fuel supply past 2017, as well as investigating other potential fuel supply sources.

In August 2011, the U.S. Environmental Protection Agency (EPA) approved a Federal Implementation Plan (FIP) under its Regional Haze Rule that requires installation of selective catalytic reduction technology ("SCR") with stringent nitrogen oxide ("NOx") emission limits on all four generating units at SJGS by September 21, 2016. In early 2013, PNM, as the operating agent for SJGS, the New Mexico Environment Department (NMED) and EPA agreed to a non-binding term sheet under which the FIP would be replaced by the less costly Revised SIP upon EPA's approval of the Revised SIP after a public process. The Revised SIP would result in the retirement of SJGS Units 2 and 3 by the end of 2017 and the installation of selective non-catalytic reduction technology ("SNCR") on SJGS Units 1 and 4 by the later of January 31, 2016 or 15 months after EPA approval of a Revised SIP. The Revised SIP was approved by the EIB in September 2013 and was submitted to EPA for its approval on October 18, 2013. EPA deemed the Revised SIP application complete on December 17, 2013 and then submitted it to the public for comment. Final EPA action on the Revised SIP is expected by the end of September 2014.

In a December 20, 2013, filing with the NMPRC (Case No. 13-00390-UT), which was supplemented on February 5, 2014 and May 22, 2014, PNM requested certain approvals necessary to effectuate the Revised SIP, as follows:

- Permission to retire SJGS Units 2 and 3 by December 31, 2017 and to recover over 20 years the undepreciated investment in those units as of that date, currently estimated to be approximately $205 million net of the amount of additional SJGS Unit 4 capacity proposed as a replacement resource;
- A CCN to include PNM's ownership share of PVNGS Unit 3, amounting to 134 MW, as a resource to serve New Mexico retail customers at a value of $2,500 per kW, effective January 1, 2018;
- An order allowing cost recovery for the installation on SJGS Units 1 and 4 of SNCR technology and balanced draft equipment to comply with the Revised SIP and the National Ambient Air Quality Standards ("NAAQS") requirements, not to exceed a total cost of $82 million; and
- A CCN for between 78 and 132 MW of additional capacity in SJGS Unit 4, resulting in a net reduction in PNM's share of SJGS generating capacity of not more than 340 MW.

This case is on-going as of the filing of this IRP.

Four Corners Power Plant

The Four Corners Power Plant (Four Corners) in Fruitland, New Mexico consists of two coal-fired units (Units 4 and 5) that are operated by Arizona Public Service (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.

The coal supply for Four Corners has been supplied by the adjacent surface mine through a contract with BHP Navajo Coal Company. Effective December 30, 2013; Navajo Mine Coal Company, LLC (NMCC) acquired ownership of the surface mine. On the same date, the Four Corners owners entered into a coal supply agreement with NMCC which is expected to provide sufficient fuel supply for the life of the units. The Four Corners owners have previously been granted an extension of the land lease from the Navajo Nation. PNM assumes that the Four Corners Power Plant is an available resource that will serve to meet loads through the 2033 timeframe. Currently, PNM relies upon network transmission service rights to bring the energy from the plant into the northern New Mexico system to deliver to New Mexico loads.

Palo Verde Nuclear Generating Station

Palo Verde Nuclear Generating Station (PVNGS) is a 3–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. A list of the PVNGS participants, as well as leased/owned amounts of capacity that PNM controls is provided in Table 2-E.

Table 2-E: Ownership by Unit of PVNGS

Palo Verde Nuclear Generating Station	Unit 1 MWs	Unit 2 MWs	Unit 3 MW	Percent
Utility Owners				
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%
PNM Capacity Rights				
Leased Capacity	104	74		44.3%
Owned Capacity	30	60		55.7%
Total PNM	134	134	134	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 90 MW of that lease-financed capacity. Currently, PNM owns 30 MW in Unit 1 and 60 MW in Unit 2; the remaining 104 MW in Unit 1 and 74 MW in Unit 2 continue to be leased by PNM. The remaining leases for PVNGS Unit 1 and Unit 2 originally had terms expiring in 2015-2016. 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 leases and for a 10 MW lease in Unit 2. 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.

PNM informed the lessors of Unit 2 that PNM would exercise the option to purchase the 64 MW when the lease expires on January 12, 2016. Under the leases, the fair market value purchase price for those leased assets would be determined either by negotiations or through the appraisal process as provided for in the leases. PNM and the lessors agreed to determine the fair market value through the negotiation process and an agreement has been reached for PNM to purchase those leases.

PVNGS Transmission: PNM relies on network transmission rights that have been secured for delivery of energy from PVNGS to serve retail loads in New Mexico. For planning purposes, 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.

PVNGS Unit 3: As part of Case No. 13-00390-UT, PNM requested a CCN to include PNM's 134 MW of PVNGS Unit 3 as a supply resource to serve New Mexico retail customers. The CCN requests a value for ratemaking purposes of $2,500 per kW. PNM has also requested recovery of the costs associated with funding the PVNGS Unit 3 decommissioning trust on a pro rata basis. This application is currently pending before the NMPRC. If approved, this capacity would be available to meet jurisdictional customer demand into 2047. PNM currently has transmission rights that would enable this additional base load power to be brought to New Mexico.

AFTON GENERATING STATION

The Afton Generating Station (Afton) is a 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 (HRSG) and a steam turbine. The plant can be operated either in a simple cycle mode using a combustion turbine (CT) or as a combined cycle generating facility. Energy generated at Afton 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 aeroderivative 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 centers. 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 frames 7FA gas turbines each connected to a HRSG steam generator. PNM owns one-third, or 185 MW, of Luna. Tucson Electric and Freeport-McMoRan each also own one-third interests. In 2008, the NMPRC granted a CCN to make PNM's share of Luna a jurisdictional resource. Unlike Afton, Luna can only operate in combined cycle mode. Luna is able to deliver to southern New Mexico loads directly or, via contracted transmission rights, to PNM's northern load centers. 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 (Reeves) 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 (STG). 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 Reeves 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 controls systems to increase reliability and prolong the life of these units. PNM is addressing the aging of this facility through on-going maintenance programs, and has factored in required maintenance to reach the end of the planning period in 2033.

Delta-Person Generating Station

The Delta-Person Generating Station ("Delta-Person") is a natural gas-fired generating plant with a capacity of approximately 132 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, from whom PNM purchases the entire output of the plant under a PPA. The closing of the purchase transaction was still pending at the time of filing of this IRP Report. Upon closure of the transaction, the plant will be renamed the Rio Bravo Generating Station.

Due to Delta-Person'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. Under plant ownership, PNM anticipates it will be able to improve the facility's generation capacity and obtain a better heat rate than has been available under the PPA; however, the performance tests to confirm this expectation have not yet been conducted.

Delta-Person is a dual-fuel facility. It operates on natural gas supply delivered through the New Mexico Gas Company (NMGC), but when required the plant can operate on fuel oil stored on-site and supplied under a delivery service agreement. PNM anticipates that the Delta-Person facility will be available to meet customer load throughout the planning period.

Valencia Energy Facility

The Valencia Energy Facility (Valencia) is located south of the 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 145 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.

Approved Thermal Resources

La Luz Energy Center

On June 18, 2014, PNM was granted a CCN to construct own and operate the La Luz Energy Center (La Luz) which will be located in Valencia County directly west of PNM's Belen Substation. Comprised of one GE LM6000, La Luz will have the ability to deliver 40 MW of capacity into the northern New Mexico load center. It will be equipped with a Selective Catalytic Reduction (SCR) catalyst and carbon oxidation reduction system. Natural gas supply for La Luz will be delivered through Transwestern's interstate pipeline. The plant is also close to the El Paso Natural Gas Company's interstate pipeline. The plant will be constructed on a schedule to be in-service by the summer of 2016.

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 2-F provides this information for PNM-Owned supply side resources.

Table 2-F: PNM-Owned Rate-Based Supply-Side Resources

Generating Resource	In-Service Date	Retire-ment Date	Location	Unit Capacity (MW)	PNM Capacity (MW)	Owner-ship Share %	Fuel Type	Duty Cycle	Comments
CCN Granted/ Resources In Service									
Palo Verde Unit 1	1986	2045	Wintersburg, AZ	1,314	134	10.20%	Nuclear	Base	30 MW owned 104MW leased
Palo Verde Unit 2	1986	2046		1,314	134	10.20%	Nuclear	Base	60 MW owned 74 MW leased
San Juan Unit 1	1976	After 2033	Waterflow, NM	340	170	50%	Coal	Base	--
San Juan Unit 2	1973			340	170	50%	Coal	Base	--
San Juan Unit 3	1979			497	248	50%	Coal	Base	209 MW PNM Operating Share
San Juan Unit 4	1982	After 2033		507	195	38.5%	Coal	Base	234 MW PNM Operating Share
Four Corners Unit 4	1969	After 2033	Fruitland, NM	770	100	13%	Coal	Base	--
Four Corners Unit 5	1970	After 2033		770	100	13%	Coal	Base	--
Afton CC	2007	After 2033	La Mesa, NM	230	230	100%	Natural Gas	Inter-mediate	--
Luna CC	2006	After 2033	Deming, NM	558	185	33%	Natural Gas	Inter-mediate	Approved rate base in 2008
Lordsburg Unit 1	2002	After 2033	Lordsburg, NM	40	40	100%	Natural Gas	Peaking	Provides 40 MW fast-start
Lordsburg Unit 2	2002	After 2033		40	40				Provides 40 MW fast-start
Reeves Unit 1	1960	After 2030	Albuquerque, NM	44	44	100%	Natural Gas	Peaking	53 years old
Reeves Unit 2	1959			44	44				54 years old
Reeves Unit 3	1962			66	66				51 years old
Solar PV	Various	2041-2044	Various	44	44	100%	Solar	Inter-mittant	--
Approved Resources									
La Luz	2016	2046	Valencia County, NM	40	40	100%	Natural Gas	Peaking	Approved 6/18/14
Solar PV	2015	2045	Various	23	23	100%	Solar	Variable	2014 REPP
Total					2,007				

Table 2-G describes the resources used by PNM to meet jurisdiction retail load under PPAs.

Table 2-G: PNM Contracted Supply-Side Resources

PNM Purchases	Contract Term	Contract Capacity (MW)	Reserve Margin Contribution (MW)	Fuel Type	Duty Cycle
Resources In Service					
Delta-Person Generating Station	Contract through June 2020	138	138	Natural Gas/Oil	Peaking
NM Wind Energy Center	Contract through July 2028	200	10	Wind	Intermittent
Valencia Energy Facility	Contract through May 2028	145	145	Natural Gas	Peaking
Dale Burgett Geothermal	Contract through January 3034	10	6	Geo-thermal	Base Load
Resources Approved but Pending Contract Operations					
Red Mesa Wind Energy Facilily	January 1, 2015 – December 31, 2035	102	5	Wind	Intermittent
Total		595	304		

The capacity listed in Tables 2-F and 2-G 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 reserve margin capacity must be used. 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 due to events such as the expiration of leases and PPAs. PNM's resource plan takes into account such developments and assumes that the resource availability will either be extended or replaced with a more cost-effective resource through a Request for Proposal (RFP) process.

Changes in the Existing Portfolio from the 2011 IRP

Since the 2011 IRP was filed in July 2011, 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.

- **San Juan Generating Station:** In the 2011 IRP, it was anticipated that turbine rotor replacements would result in an increase of the plant's generation capacity to 810 MW. The replacements did not result in increased capacity, so the available capacity for PNM has been adjusted from 810 MW to 783 MW.

- **Las Vegas Generating Station:** Pursuant to the NMPRC's approval in Case No. 10-00264-UT, the 18 MW Las Vegas CT was decommissioned and abandoned. It is no longer available to serve load.

- **Valencia Energy Facility:** In 2012, plant improvements increased the generation capacity from 145 MW to 150 MW during the summer. However, under the PPA, PNM has assurance for peak generation capacity up to 145 MW only. Therefore, PNM only assumes 145 MW capacities on peak for this resource.

- **Delta-Person Generating Station:** After PNM has acquired this plant, PNM will perform tests to determine the actual generation capacity and a heat rate. In the 2011 IRP, PNM reported the contract heat rate and capacity; the generation capacity used in the 2014 IRP reflects PNM's current anticipation as to the results of those tests.

Customer-Sited Distributed Generation

Customers on PNM's system or third-parties contracting with the customer are eligible to construct solar systems at their place of residence or business and participate in PNM's net-metering program and sell the RECs generated by the solar system to PNM, which uses the RECs for RPS compliance. The interconnection of these facilities to PNM's system, the administration of the net metering 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's tariffs that have been reviewed and approved by the NMPRC.

Customer-Sited Solar

Customer-sited solar photovoltaic (PV) installations are a small but fast-growing resource on PNM's system. Customers who choose to install a qualified photovoltaic or solar thermal electric system on their homes or businesses (or that are installed and owned by third-parties) are eligible for PNM programs that allow customers to net-meter and to sell to PNM the RECs associated with the energy. While these customer-sited systems decrease net system demands, PNM still must provide back-up service to interconnected customers.

Customer installations continue to grow both in number and in the size of systems that are being installed. This is due to federal and state tax incentives, the current downward trend in the cost of photovoltaic systems, net-metering and REC payment incentives offered by PNM. Table 2-H shows the number of customers participating in the Customer Solar Programs, the installed capacity, annual RECs and the peak hour generation.

Although these installations are the responsibility of the system owners, PNM assumes that these installations will be maintained, since customers receive net metering and REC payments. For IRP purposes, PNM assumes that the DG installations will continue to operate to offset system load for the entire planning period.

TABLE 2-H: Customer-Sited Renewable DG

Year	Cumulative Number of Participants	Cumulative KW_{AC} Installed	Annual RECs MWh	Peak Hour Generation KW_{AC} (55% of capacity)	% 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%

The PNM rates and tariffs that govern customer-sited renewable development are:

- **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, since 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.

Reserve Margin

Portfolio reliability is a paramount criterion for a public utility. PNM must have resources available to follow customer load as it varies from moment to moment and to be available in the event of the loss of another source of energy, either a generator or a key transmission line. For this purpose, PNM's portfolio analysis includes a planning reserve margin and determines loss-of-load-hours over the 20-year planning horizon as a measure of the effectiveness of any given resource portfolio. A planning reserve margin is necessary to compensate for potential imprecision in the peak demand forecast, such as variations due to weather, and the possibility of a resource contingency (e.g., an outage or failure). The planning reserve margin is calculated as the amount of installed jurisdictional peak resource capacity in excess of projected jurisdictional demand as a percentage of total demand, as shown in Figure 2-I.

Figure 2-I: Planning Reserve Margin Formula

$$\textbf{Planning Reserve Margin } \% = \frac{(MW_{\text{capacity}} - MW_{\text{demand}})}{(MW_{\text{demand}})} x100$$

Since the generation capability of a resource can vary between summer and winter due to temperatures or in the case of renewable resources can be intermittent due to wind or solar resource availability, the IRP analysis uses the net dependable summer capacity coincident with PNM's system peak load in calculating reserve margin. This results in less than the full nameplate output from some resources.

Over the years, PNM has entered into two key Stipulated Agreements affecting reserve margin planning that have been approved by the NMPRC. These are the Case 3137 Stipulation in 2002 which established a planning reserve margin of 15% and the Stipulated Agreement in Case No. 08-00305-UT in 2008 which reduced the planning reserve margin to the greater of 13% or 250 MW. These stipulations are discussed in the Appendix.

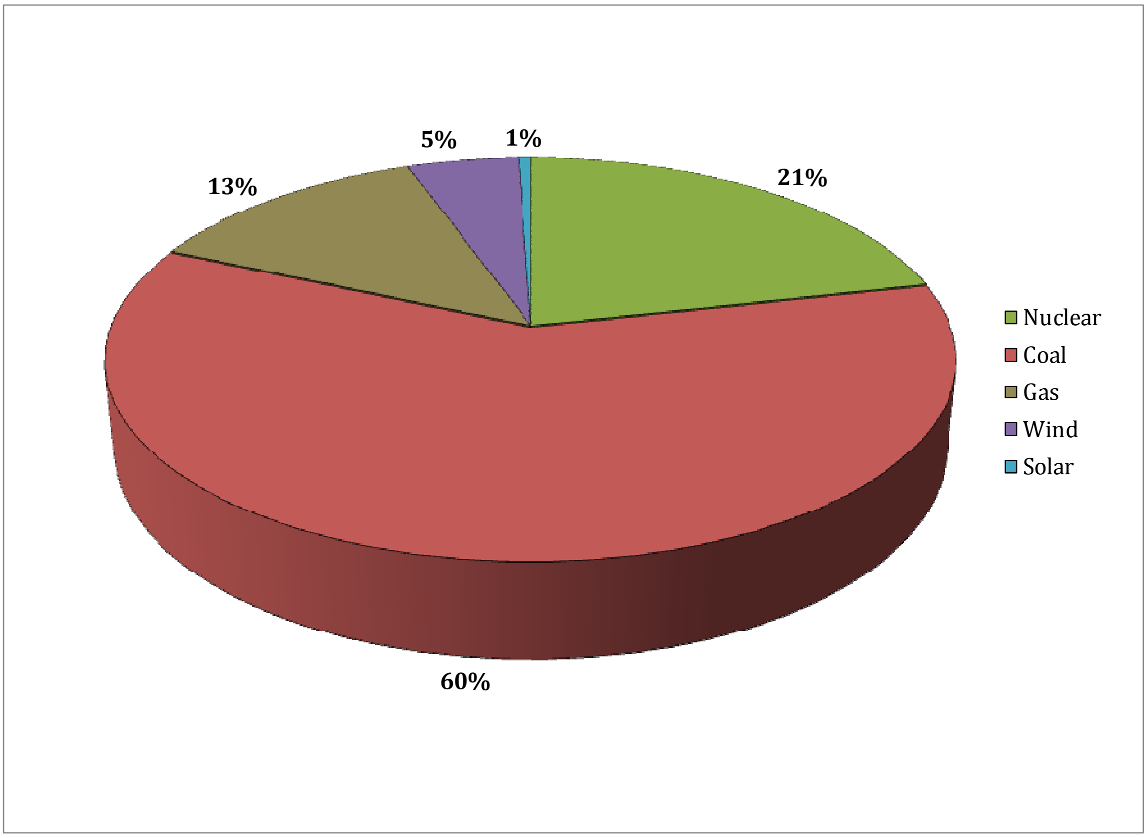
Environmental Impacts of Existing Supply-Side Resources

The various supply-side resources in PNM's existing portfolio have varying impacts on the environment. In response to IRP Rule, Section 17.7.9.C (12), this portion of the report provides information on the percentage of kilowatt-hours generated by fuel, the emission rates of criteria pollutants as well as carbon dioxide and mercury to the extent feasible, and the water consumption rate for each resource.

Fuel Mix for Generation

Figure 2-J illustrates the percentage of the kilowatt hours generated during 2013 by the type of fuel used. Coal and nuclear fuels, since they are base load resources, supply the majority of the energy. Natural gas generation represents a significant share of PNM's generation capacity. Natural gas still provides a relatively small percentage of PNM's generation mix – but an essential part of the mix since it provides load following and peak capacity.

Figure 2-J: PNM's 2013 Fuel Mix Shown as Percentage of Kilowatt Hours Generated



Source: 2013 Federal Energy Regulatory Commission (Form 1)

EMISSIONS FROM PNM-OWNED AND CONTRACTED RESOURCES

Environmental performance for each of the generating plants during 2012 is provided in Tables 2-K(1) and K(2), on the following page. These data were used in the modeling phase of the IRP process for the entire planning period.

Table 2-K(1): Nitrogen Oxides, Carbon Monoxide, and Sulfur Dioxide Emissions of PNM Owned and Contracted Resources

Facility/Unit	Net Generation MWh	NO_X lbs/kWh	CO lbs/kWh	SO_2 lbs/kWh
Afton Generating Station	699,762	0.0001293	0.0002189	0.0000047
Delta-Person Generating Station	22,413	0.0046390	0.0013371	0.0000523
Four Corners Power Plant	1,018,912	0.0052742	0.0003132	0.0017058
Lordsburg Generating Station	4,460	0.0013003	0.0010108	0.0000073
Luna Energy Facility	376,304	0.0001843	0.0004079	0.0000085
New Mexico Wind Energy Center	490,539	0	0	0
Palo Verde Generating Station	3,205,547	0	0	0
PNM-Owned Solar	56,329	0	0	0
Reeves Generating Station	93,360	0.0028879	0.0001151	93,360
San Juan Generating Station	4,967,064	0.0029991	0.0026781	4,967,064
Valencia Energy Facility	81,732	0.0004086	0.0003147	81,732

Table 2-K(2): Particulate Matter, Carbon Dioxide, and Mercury Emissions of PNM Owned and Contracted Resources

Facility/Unit	Net Generation MWh	PM lbs/kWh	CO_2 lbs/kWh	Mercury lbs/kWh
Afton Generating Station	699,762	0.0000628	0.96184	0.0000000
Delta-Person Generating Station	22,413	0.0001137	1.099	0.0000000
Four Corners Power Plant	1,018,912	0.0001656	2.05259	118 lbs per billion kWh
Lordsburg Generating Station	4,460	0.0000812	1.51543	0.0000000
Luna Energy Facility	376,304	0.0000420	0.97207	0.0000000
New Mexico Wind Energy Center	490,539	0	0	0.0000000
Palo Verde Generating Station	3,205,547	0	0	0.0000000
PNM-Owned Solar	56,329	0	0	0.0000000
Reeves Generating Station	93,360	0.0000975	1.56927	0.0000000
San Juan Generating Station	4,967,064	0.0000570	2.31213	1.5 lbs per billion kWh
Valencia Energy Facility	81,732	0.0004199	1.45903	0.0000000

WATER SUPPLY FOR GENERATION FACILITIES

New Mexico's arid climate and periodic drought conditions raise questions about the extent of water use for various purposes, including for power generation. The IRP Rule at 17.7.3.9.C(12)(c) requires that the IRP Report on water use at existing generating plants.

WATER USE AT EXISTING GENERATING PLANTS

PNM is committed to conserving water resources. Less than 2% of the water withdrawals in New Mexico are used in the generation of electricity, and water cost is a very small component of PNM's total generating costs. PNM's generation facilities vary in their water consumption.

Table 2-L shows the water usage per MWh of PNM owned and contracted facilities based on total gallons of water consumed divided by total MWh generated during 2011 through 2013**.** The newer gas turbines like Delta-Person and Valencia are much less water intensive than the 1950s-era Reeves steam-turbine technology. It should also be noted that PVNGS uses reclaimed city water for cooling, so its fresh water intensity is about 23 gallons per MWh compared to its total water intensity of 768 gallons per MWh. Figure 2-M shows the average fresh water and wastewater use for PNM's current fleet.

Table 2-L: 2011-2013 Average Water Usage of PNM Owned and Contracted Resources

Facility	2011 – 2013 Average Water Usage gal/MWh
Afton Generating Station	104
Delta-Person Generating Station	37
Four Corners Power Plant	577
Lordsburg Generating Station	461
Luna Energy Facility	209
New Mexico Wind Energy Center	0
Palo Verde Generating Station	23
PNM-Owned Solar	0
Reeves Generating Station	957
San Juan Generating Station	594
Valencia Energy Facility	22

Table 2-M: Water Intensity for Existing Generation (Gal/MWh)

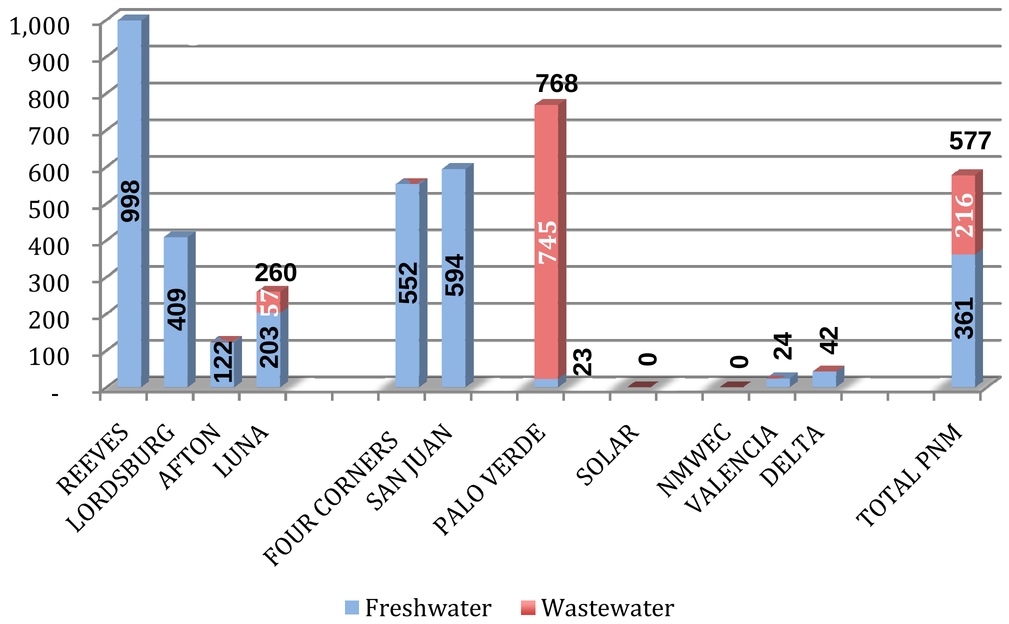
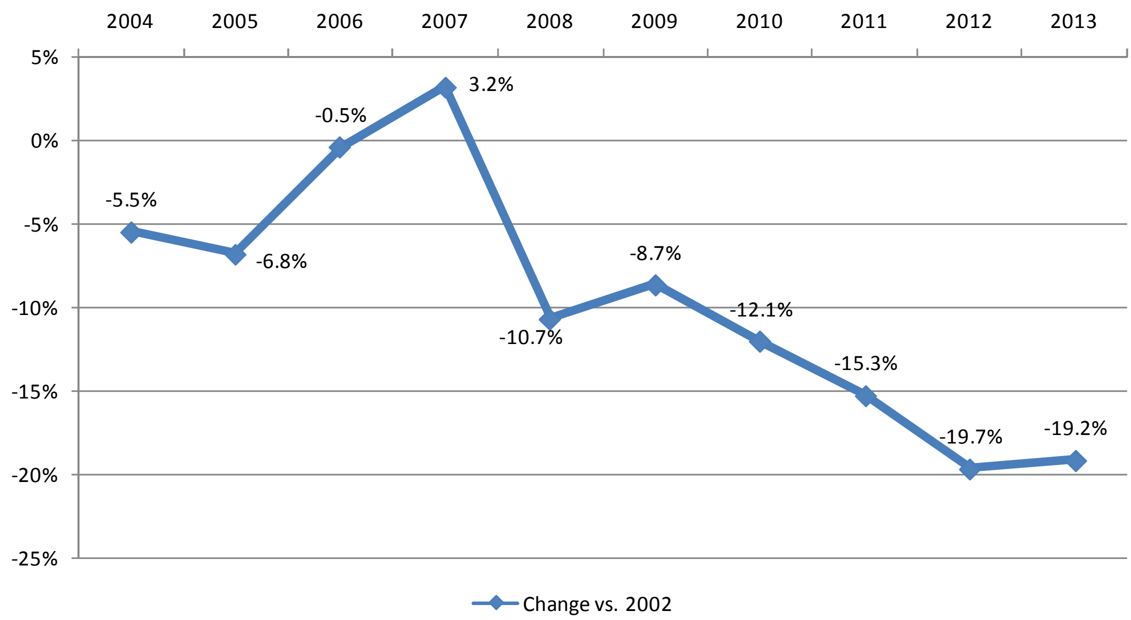


Figure 2-N illustrates the gallons consumed per MWh, also known as water intensity, by PNM's current generation plants.

Figure 2-N: PNM's Generating Portfolio Water Intensity – Change Since 2002



Water usage at PNM's generating facilities vary from year to year due to many different factors such as weather, capacity factor, load factor, leaks, water quality variations, and the availability or ability to use gray water. Nevertheless, water use on a total portfolio basis has been generally declining since 2002, as shown in Figure 2-N, above. For example, the average water intensity of PNM's generating portfolio in 2013 was 19% lower than the intensity during 2002.

Water Security at Existing Plants

Providing for a reliable, sustainable water supply is essential to the successful operation of PNM's generation fleet and is the focus of its Water Resources group. Using a variety of strategies, including water conservation, water rights acquisitions, shortage sharing agreements, and modern technologies, PNM mitigates the risk that a lack of water could impact the availability of its generation fleet for power production.

PNM has secured groundwater rights in connection with the plants at Reeves, Delta-Person, Afton, Luna, Lordsburg and the pending La Luz plant. Groundwater is much less susceptible to annual variations in water availability than is surface water. Reclaimed city waste water is used at Luna and PVNGS. Hybrid Cooling (combination of wet and dry) is utilized at Afton to reduce water consumption. These approaches serve to minimize the fresh water used at those plants.

Severe drought in the Four Corners region, similar to the 2002 drought, could affect the availability of the SJGS and Four Corners plants because they use surface water for cooling. Consequently, PNM has undertaken steps to mitigate this potential by entering into agreements for sharing the impacts of water shortages with tribes and other water users in the San Juan Basin (shortage sharing agreements). Further, in case of a water shortage, PNM has agreements for supplemental water supplies with the Jicarilla Apache Nation and BHP-Billiton for use at SJGS. In April 2010, APS signed a 40-year agreement on behalf of the PVNGS participants with five cities to provide cooling water for power production at PVNGS.

Back-up Fuel Capabilities and Options

This information responds to sections 17.7.3.9B(5) and (6) of the IRP Rule which requires that PNM provide a description of the resource and fuel diversity and identify critical facilities susceptible to supply-source or other failures.

Back-Up Fuel Supply

Generation facilities require fuel and are, therefore, susceptible to interruptions in fuel supply. PNM mitigates the risks of fuel interruption by diversifying the location of its generation plants, the types of fuels that they depend upon, and the sources of fuel for the generating plants. Back-up fuel supply capabilities and options vary by the type of generation plant and the nature of the back-up supply options available at the location of the generating facility, as described in Table 2-O.

Table 2-O: Back-Up Fuel Capabilities

Generating Plant	Back-Up Capability
Four Corners and San Juan	These coal fueled plants maintain coal pile inventories that can be drawn on during periods that coal is not being delivered by their supplier from the nearby coal mines.
Palo Verde Nuclear Generating Station	Palo Verde maintains a 1.5 to 2 cycle refueling strategic inventory. This inventory is held to mitigate potential market or other fuel cycle interruptions. Fuel enrichment is ordered and delivery is scheduled in advance of fuel rod replacement. In the event of non-delivery of contracted enriched uranium, the primary option would be procurement from the market on stockpiled enriched uranium. There is currently one enrichment facility in the U.S., located in Eunice, New Mexico. Fabrication of the fuel rods is ordered and delivery is scheduled just prior to the scheduled reactor fuel rod replacement. Options are limited in the event of non-delivery of the purchased fuel assemblies.
Reeves and Delta-Person	These facilities are served via NMGC and are dependent upon gas transportation and delivery by NMGC. For natural gas supply, NMGC is connected to interstate pipelines at both the northern and southern end of the system serving PNM's NNM load center; therefore, PNM has options to purchase gas supply from multiple suppliers and producing locations to supply these plants. Additionally, the Delta-Person plant is a dual-fueled facility and can burn No. 2 diesel fuel that is stored on-site and that can be re-supplied by a local fuel oil distributor.
Valencia PPA and La Luz	Valencia is and La Luz will be served via the Transwestern pipeline system and PNM can access gas supplies for this plant from multiple suppliers located in the Permian or San Juan Basins.
Afton CC, Luna CC and Lordsburg	These plants are served from the El Paso Natural Gas Pipeline and PNM can access natural gas supply for these plants from multiple suppliers located in the Permian or San Juan basins.
Renewable Energy Facilities	Generation from these facilities is dependent upon the availability of the applicable renewable resource. In the event they are not producing energy, customer load is supplied from the above referenced fossil and nuclear fueled resources and/or with power purchased in the wholesale power market.

PNM Transmission System

For purposes of the IRP Report, transmission facilities are those of 115 kV and above. Reliability of energy supply to customers depends upon the transmission system since most generation facilities are located distant from customer load centers. PNM's transmission system plays a key role in ensuring the reliable delivery of PNM's resources. A detailed discussion of the transmission and distribution systems is beyond the scope of this document. A more in-depth report, including diagrams of the lines, stations and terminal facilities, can be obtained by downloading PNM's most recent Federal Electric Regulatory Commission (FERC) Form 715 filing from the Federal Energy Regulatory Commission ("FERC") website at www.ferc.gov. This information responds to Section 17.7.9.C (11) of the IRP Rule.

Regulatory Background

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 U.S. 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. The start of the Order 1000 planning process is expected to be in 2015.

Transmission System Background

Transmission System Development

The New Mexico 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 back-up 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 Four Corners Power Plant.

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 Four Corners Power Plant and SJGS were brought on-line. This shifted large base load generation from local to remote resources away from load centers, due partly to environmental, economic, water, and fuel availability considerations, while 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, 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.

In the late 1990s, PNM purchased several transmission assets from Tri-State Generation and Transmission (Tri-State). Purchase of these assets allowed PNM to upgrade key portions of its system, further enhancing the import capability of the northern New Mexico system. PNM has made numerous modifications to the existing system in the past 18 years to maximize its use. However, PNM has reached the point where few, if any, opportunities remain to extract additional capability from the existing northern New Mexico system.

Transmission System Configuration

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. Also, generation resources in southern New Mexico can be delivered from the southern New Mexico system to customers in the northern New Mexico system. As customer usage on PNM's transmission system continues to increase, flows from the southern to the northern New Mexico systems will continue unless new resources are located close to the PNM load centers in northern New Mexico.

Although the northern New Mexico system serves the majority of the overall PNM load, the southern New Mexico system is capable of serving PNM load in southern load centers from the Afton, Luna, and Lordsburg generating plants. Resources from the northern New Mexico system can also be used to serve PNM southern loads via imports on existing transmission rights. The southern New Mexico system is also capable of exporting power into the northern New Mexico system.

Transmission System Customers

In addition to PNM wholesale and retail customers, PNM is obligated to ensure delivery capability to all transmission customers (NITS, point-to-point and pre-OATT contract customers) across PNM's system. Approximately 40% to 45% of the PNM system is used to provide transmission service for others.

Network Integration Transmission Service Customers

Network customers include: Tri-State, Los Alamos County (LAC), Navajo Tribal Utility Authority (NTUA), Western Area Power Administration (WAPA) for Kirtland Air Force Base, City of Gallup, Jicarilla Apache Nation, Navopache Electric Cooperative (NEC), and PNM-Wholesale Power Marketing (WPM) (for PNM retail and City of Aztec).

Point-to-Point Transmission Service Customers

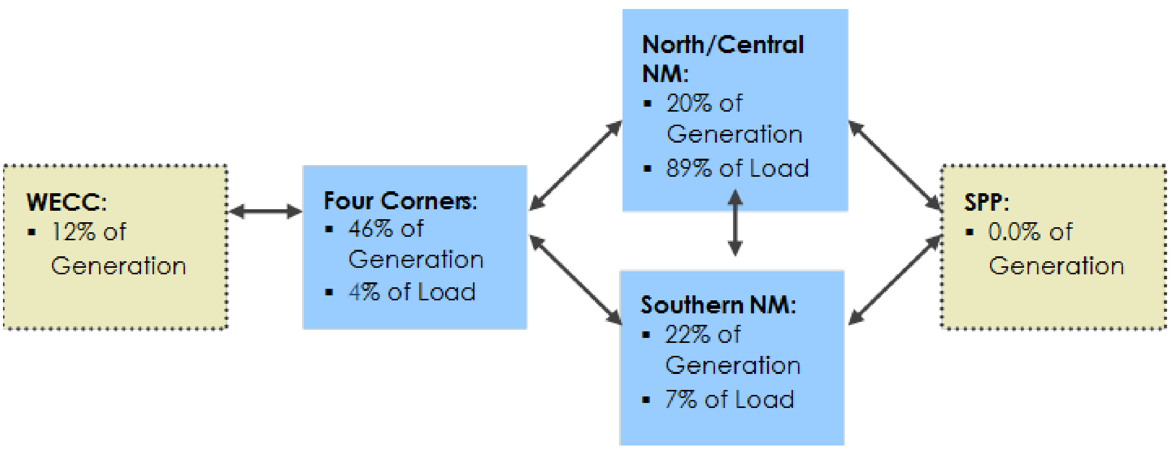
Point-to-point customers include: El Paso Electric Company (EPE), High Lonesome Mesa, Argonne Mesa, NextEra, WAPA, and WPM.

Existing Transmission Capabilities

At a high level, the PNM system can be described by the block diagram in Figure 2-P, which shows the relative generation and load diversity of the PNM system. This diagram illustrates where load and resources (L&R) are located and where loads are served. It illustrates that the majority of the PNM load (89%) is located in North/Central New Mexico. Similarly, more than 50% of PNM's resources are located at Four Corners or beyond and transmitted, or wheeled, to load centers in North/Central New Mexico. Although physical connections exist between PNM and the Southwest Power Pool (SPP) to the east, no supply side resources are currently being imported from the SPP grid to serve PNM load due to the lack of identified available firm economic resources with firm delivery capability to the PNM interconnection point with SPP.

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. A list of Transmission facilities are included in Appendix B.

Figure 2-P: Overview of Existing System Representation During Peak Load



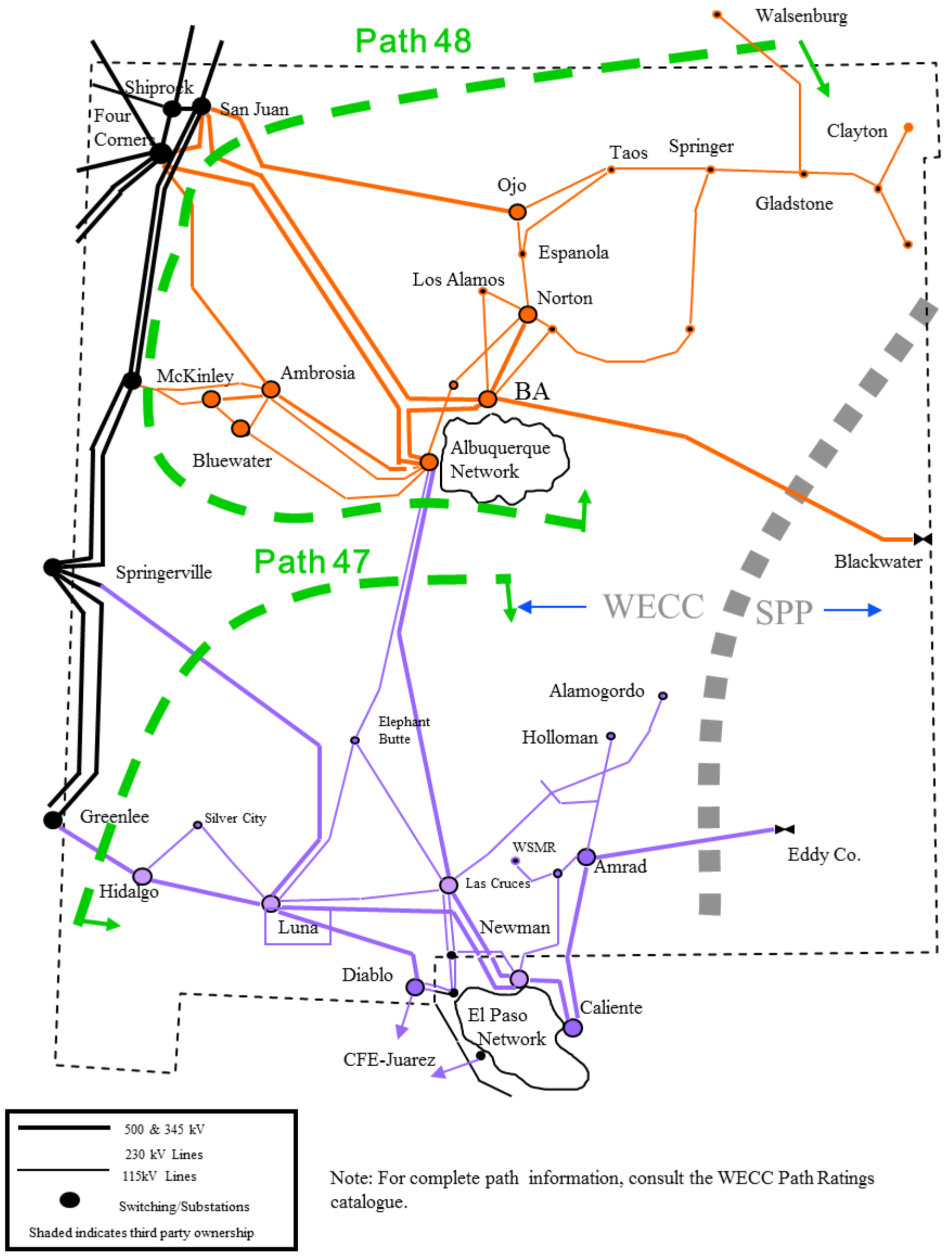
PNM monitors key transmission paths to insure the transmission system is operated in a safe and reliable way. Path limits are established that identified maximum flow levels for safe and reliable operation such that the loss of a major element (e.g., line, transformer, and tie point) can occur without affecting the quality of service delivered by the transmission system. In most cases, customers never know when an element is out of service because the system is operated in a manner that minimizes the effects on customers.

In New Mexico, there are two key paths that define the planning and operation of the transmission system. Path 48 controls the operation of the northern part of the state, and Path 47 controls the operation of the southern part of the state as illustrated in Figure 2-Q. Orange lines represent transmission lines in Path 48. Purple lines represent transmission lines in Path 47. 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 and/or stations. Any transaction that takes place on the PNM system with neighboring systems is bound by the operation of these paths.

PNM's capacity in Path 47 and Path 48 is fully committed to existing firm resources and expansion of the transmission system must be factored into the siting of additional remote resources. Resources located on the load side within Path 47 or Path 48 usually help or enhance the operation of these paths by providing a local resource at the load center. When the 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.

Figure 2-Q: WECC Path 47 and 48



Note: For complete path information, consult the WECC Path Ratings catalogue.

Northern New Mexico Transmission System

The northern New Mexico transmission system includes the WECC rated Path 48. This system delivers power to serve PNM's customer loads in northern New Mexico including the Albuquerque, Santa Fe, and Las Vegas areas, as well as load areas in Valencia County south of the city of Albuquerque. As previously mentioned, 89% of

PNM's total load is within the northern New Mexico transmission system (Path 48) boundary. The northern New Mexico transmission system also delivers power to the load of other utilities located in northern New Mexico that take transmission service from PNM. The total forecast load in northern New Mexico is illustrated in Figure 2-R (shown by bars) and consists of PNM's forecast northern New Mexico load and PNM network transmission customer forecast loads (Transmission Service).

The amount of load which can be served by imported power over the northern New Mexico transmission system is equal to the Total Transfer Capability (blue line in Figure 2-S). The total amount of load that can be served (Load Serving Capability) in northern New Mexico is the sum of the amount of power that can be imported on the transmission system plus the amount of power that can be generated from load-side generation. The Load Serving Capability is indicated by the purple line in Figure 2-S. Starting in 2020, Figure 2-S illustrates that the forecast load (PNM Loads plus Transmission Service) will exceed the Load Serving Capability which indicates a need for either additional load-side generating resources to insure that the transmission system will not be operated above its limits or enhancements to transmission capacity that could allow additional power to be imported.

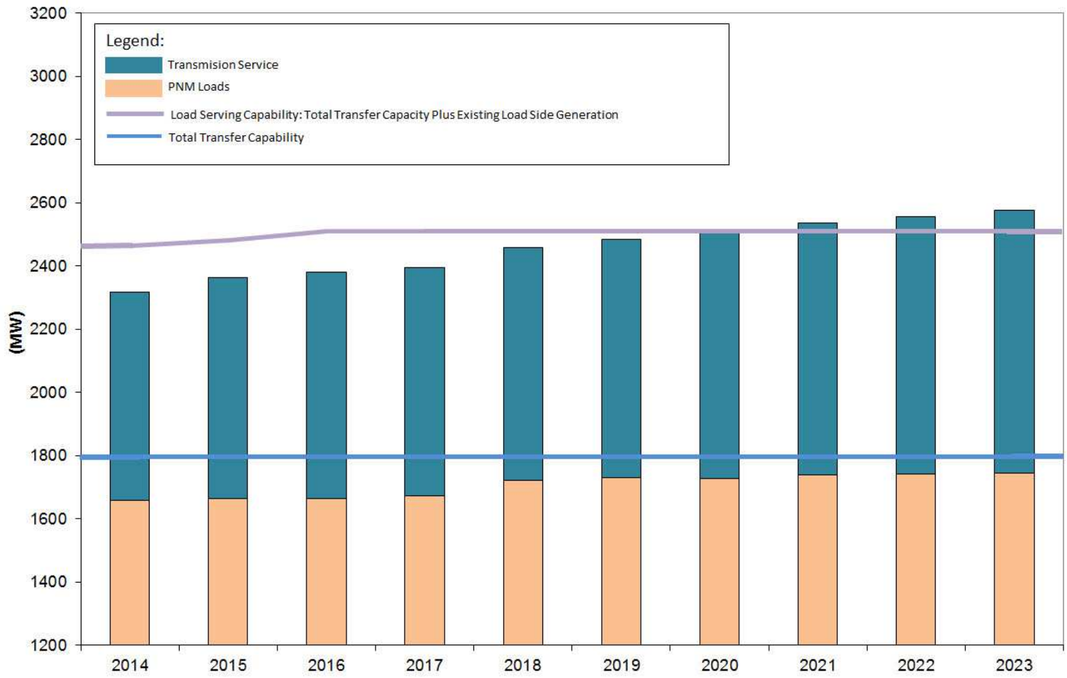
To fully utilize the capacity on Path 48, active voltage support in the Albuquerque area is required. This voltage support is currently provided by dispatching Albuquerque area "load-side" gas-fired generation out of economic dispatch order, which results in an increase of PNM's overall generation cost.

PNM will be installing a Static Var Compensator (SVC)[1] by the fall 2015 in southwest Sandoval County where PNM's "backbone" 345 kV lines converge from the Four Corners area. The location of the SVC will provide flexible voltage support that will enable the full utilization of existing transmission assets. The SVC will be capable of supplying approximately 80% of the voltage support capability currently provided by Albuquerque area load-side generation.

Projections of the transmission requirement for serving the combined PNM northern New Mexico load and transmission customer obligations illustrate a need to expand the existing transmission or generation system in 2020. This constraint problem could be solved a number of ways. Possible solutions include new resources inside the Path 48 boundary, transmission system additions, or reinforcements that increase transfer capabilities on Path 48, or through additional demand-side management options that decrease loads inside the Path 48 boundary.

[1]SVC is a piece of equipment comprised of reactors and capacitors with sophisticated controls that have the ability to quickly and dynamically provide efficient voltage support.

Figure 2-R: Transmission Import Limits Relative to Existing Northern NM Generation



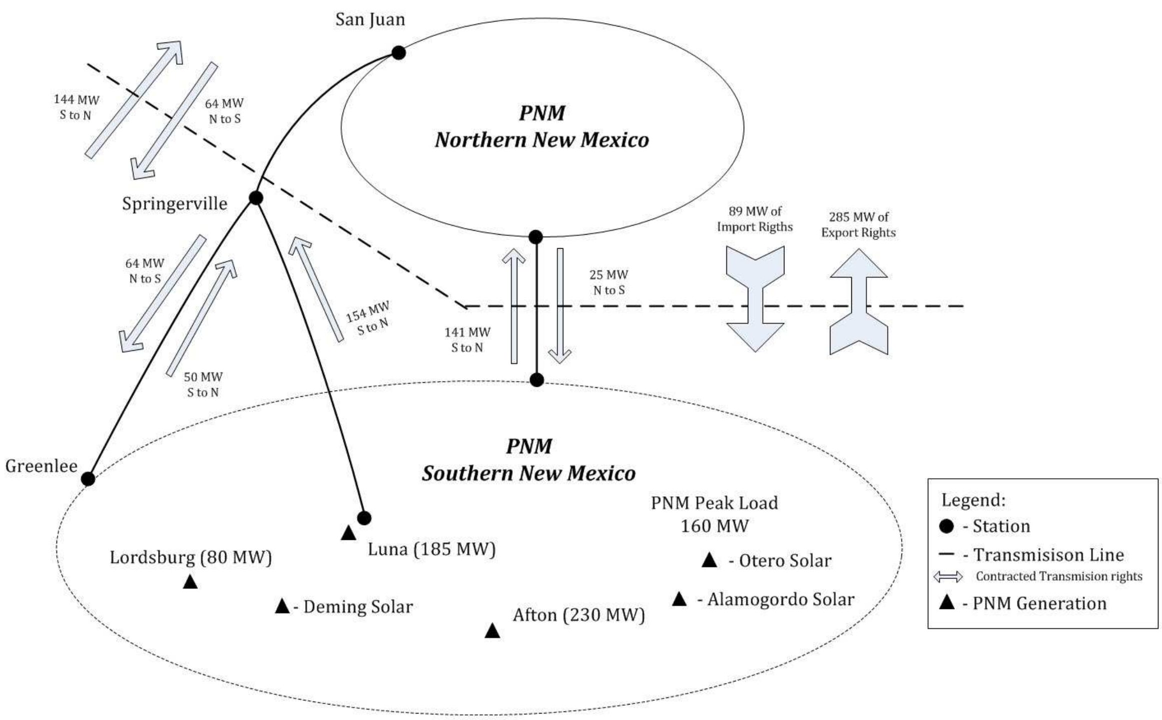
Southern New Mexico Transmission System

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.

Figure 2-S 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 2-S indicate the direction of transmission rights between PNM's northern and southern systems which can be utilized to integrate southern New Mexico resources into the entire PNM system.

Afton, Luna, and Lordsburg generation resources provide a total of 495 MW of capacity. Since 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.

Figure 2-S: Southern New Mexico Transmission System



Currently, there are ample generation resources in southern New Mexico to serve all PNM load 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.

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 will require PNM to secure additional transmission rights from the south to north (San Juan).

OTHER TRANSMISSION SYSTEM LIMITATIONS

Resources sited near the loads are generally not viewed as restricted by transfer capability but can still require transmission improvements to address local network overload or voltage problems that can occur due to increased flows that result from the new resources. The required improvements tend to be specific to each interconnection location and should be reviewed on a case by case basis. The load-side locations near Los Lunas and Belen in Valencia County have been selected for solar generation additions and a limited amount of future gas generation additions. Studies, however, are showing that additional resources beyond what is already planned will create transmission congestion and be at risk of being curtailed unless additional transmission investments are made to increase the capacity between Valencia County and Albuquerque. The timing of system reinforcements will depend on the need to operate both renewable additions and gas generation simultaneously.

As noted earlier, PNM has a single transmission line to the Albuquerque area from eastern New Mexico with a DC converter station allowing for limited transfers between the PNM system and the eastern grid system. Eastern New Mexico continues to be a focus for renewable energy developers. PNM has and is currently processing transmission service requests from the area under the FERC open access requirements with delivery at Four Corners in northeastern New Mexico. Total requests to move power west out of eastern New Mexico greatly exceed the capacity of PNM's eastern transmission line. PNM is performing studies to determine the necessary facility additions to accommodate the transmission service request(s). The requests are queued and studied serially as prescribed by the OATT. Whether this process leads to construction of network upgrades to allow for additional transmission service depends ultimately on the customer's decision to sign a service agreement after the appropriate costs and terms have been defined by the study processes.

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 transmission service obligations and do not specifically address constraints associated with specific resource locations.

- **Jicarilla 345 kV Switching Station** – provides an interconnection to a new Network Transmission Customer in northern New Mexico (in-service May 2014).
- **Alamogordo 115 kV Capacitors** – provides voltage support needed for existing peak load conditions and future load growth in the Alamogordo area (in-service June 2014).
- **Replace Ojo 345/115 kV Transformer** – mitigate potential failure (planned for Summer2014).
- **Yah-Ta-Hey Transformer Addition** – mitigates overloads and improves voltage performance in western New Mexico (planned for 2015).
- **Rio Puerco 345 kV Switchyard Expansion** – loops-in existing 345 kV lines from the San Juan and Four Corners generating stations to mitigate overloads of 115 kV lines and bulk power transformers serving the Albuquerque metropolitan area(planned for Fall 2015).
- **Rio Puerco Static Var Compensator (SVC)** – provides voltage support that will enable the full utilization of existing transmission assets (planned for Fall2015).

- **Rio Puerco-Progress 115 kV Line** – this line will connect Rio Puerco 115 kV station to Progress 115 kV substation to mitigate 115 kV overloads (planned for Fall 2015).
- **Richmond Switching Station** – new switching station in Albuquerque which allows for reconfiguration of the existing 115 kV lines to mitigate 115 kV overloads (planned for 2015).

Transmission Reliability Compliance

PNM plans and operates its transmission system to provide reliable service to its customers and all entities that use its system in accordance with NERC/WECC Operating and Planning Standards. Reliability comprises two measures: adequacy and security. Adequacy addresses the basic ability of the system to transmit power as it is needed. Security addresses the ability of the system to withstand a sudden disturbance or contingency while continuing to provide service.

PNM serves as the NERC certified Balancing Authority (BA) for a large portion of the WECC area of New Mexico and must meet NERC reliability performance standards. Certified operators continuously monitor and use manual and automated means to maintain balance by adjusting imports/exports and maneuvering generation. As the local BA, PNM constantly communicates with neighboring BAs and the WECC Reliability Coordinator.

Variable demand and generation impacts PNM's ability to provide regulation and frequency response services within PNM's BA and adds to the complexity of scheduling the transmission system to insure it meets NERC performance requirements. These impacts will likely need to be addressed in the future IRP process. Details on the integration of variable energy resources (VER) can be located in Appendix B.

Wheeling Agreements

PNM Reliability purchases transmission services to serve native load and wholesale customer requirements from APS, Tri-State, EPE, and Tucson Electric Power (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 Palo Verde generation 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.

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, New Mexico 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 listed below.

- 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 by PNM from TEP

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

Transmission Service Exchange Agreements between PNM and WAPA

In addition, PNM has a transmission service exchange with WAPA for delivery of PNM's Palo Verde generation to New Mexico. WAPA provides PNM 134 MW of transmission service from the 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.

Conclusion- Existing Supply and Transmission Resources

Existing supply resources on PNM's system include a mix of PNM-Owned generation facilities, generators owned by other parties selling their power to PNM, and customer-sited, distributed generation systems. Fuels used by these facilities are diverse and include coal, uranium, natural-gas, solar, wind and geothermal sources. Fuel delivery to the natural gas plants involves one or more of three different gas pipeline systems from two major supply basins. Power plant emissions are monitored and measures are being taken to reduce emissions in the future, including the retirement of coal-fired generation capacity. Measures are also being taken to reduce fresh water intensity and plans have been developed for drought conditions. Transmission system constraints exist, however, and PNM's long-term resource planning must take such constraints into account when planning new resources to meet growing and changing customer loads. Transmission system operations must also take into account the requirements for other, non-PNM transmission customers. Renewables provide a growing resource in PNM's portfolio that lowers overall system emissions and water usage but presents integration challenges that the generation and transmission systems must accommodate.

3. EXISTING DEMAND-SIDE RESOURCES

As defined by the IRP Rule, demand-side resources consist of two types: Energy Efficiency (EE) and Demand Response (DR). PNM's existing resource portfolio includes cost-effective energy efficiency and demand response programs approved by the NMPRC pursuant to the Efficient Use of Energy Act (EUEA). Section 3 describes PNM's existing demand-side energy efficiency and load management resources. This information generally responds to the requirements of the IRP Rule Section 17.7.3.9(C)(9). Customer-owned distributed generation is addressed in the supply side resource section.

ENERGY EFFICIENCY PROGRAMS

PNM's EE programs currently consist of a variety of incentives to encourage customers to install energy-efficient options, which include: (1) instant rebates for the purchase of compact fluorescent light bulbs, (2) rebates for recycling older refrigerators, (3) residential incentives for efficient lighting, appliances and cooling equipment, (4) rebates to small and large commercial customers for lighting, heating, ventilating, air conditioning (HVAC) and other energy efficiency improvements tailored to the customers' business, and (5) incentives that specifically target lower-income customers. Once approved by the NMPRC, EE programs remain in effect until modified or canceled by the NMPRC.

The NMPRC determined these programs were cost-effective using the total resource cost (TRC) ratio, which is a ratio of program benefits to program costs. The EUEA, the state law that governs utility-funded demand-side management programs, was amended in 2013 to replace the TRC test with the Utility Cost Test (UCT), which compares the utility's avoided cost benefits with program expenditures such as rebates and administrative costs. Future programs will be evaluated using the UCT.

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 or delayed cost of capacity additions.

Amendments to the EUEA in 2013 also require utilities to invest 3% of retail sales revenues in energy efficiency and demand response programs. This provides consistency in the level of spending that can be expected over time.

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

Demand Response Programs

Existing demand-side resources include two voluntary DR programs originally approved by the NMPRC in Case No. 07-00053-UT and reauthorized in Case No. 12-00317-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 DR program contractors through a competitive bid process.

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. The program is governed by a 10-year professional services contract that was effective January 31, 2007 and expires September 30, 2017. Comverge installs a device on customers' refrigerated air conditioners that is used to remotely control when the units cycle. During peak periods, PNM can reduce peak demand by remotely cycling the air conditioners, which reduces the collective electricity demand from the A/C units. The program runs during the summer peak period of June through September, and this resource can be dispatched within ten 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 until 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 ten minutes as a peak-shaving resource for up to 100 hours each year.

Energy Efficiency and Demand Response Results

The peak demand savings from the Power Saver program is determined by use of a statistical sampling method that derives a kW savings factor per installed unit. The Peak Saver program provides actual meter data to determine the demand savings available to PNM. Measurement and verification of the DR programs is filed every year on April 1, in accordance with the EE Rule and the EUEA. Table 3-A, below, shows the verified capacity reductions for the years 2008 through 2013.

Table 3-A: Demand Response Program

EE and DR Results	2008	2009	2010	2011	2012	2013
PNM Power Saver (<150 kW)						
Peak demand reduction MW	27.4	36.4	39.5	37.4	38.6	43.2
Participants	16,686	23,126	32,177	37,246	37,397	39,046
PNM Peak Saver (>150 kW)						
Peak demand reduction MW	20.0	17.0	27.5	19.5	18.8	19.1
Participants	45	63	70	70	90	111
Total DR						
DR program capacity MW	47.4	53.4	67.0	56.9	57.4	62.4
2011 IRP Forecast program capacity MW	n/a			75.0	80.0	86.0
Difference	n/a			-18.1	-22.6	-23.6

* The capacity is calculated at the customer meter and therefore does not include transmission losses.

Table 3-A also demonstrates the difference between actual, verified performance and projected performance as forecast in the 2011 IRP. The actual demand reduction, which was not as high as the projected reduction, is attributable to both Power Saver and Peak Saver. In 2011, some customers began dropping out of the Power Saver program, and there was increased participation of smaller A/C units.

In accordance with the EE Rule and the EUEA, PNM filed the first annual PNM EE Program Report with the NMPRC on April 1, 2009, and has filed subsequent reports on April 1 every year thereafter. The reports include detailed measurement and verification findings that quantify customer adoption rates and energy savings, for both energy efficiency programs and demand response programs.

Table 3-B, below, summarizes the results from 2008 through 2013 for PNM's overall Demand-Side programs on a combined basis. Through 2013, the programs have achieved 346 GWh of savings

Table 3-B: Energy Efficiency and Demand Response Program Results

EE and DR Results	2008	2009	2010	2011	2012	2013
Portfolio TRC Ratio	2.71	1.56	2.2	1.78	2.85	
Total annual savings at the customer meter (GWh)	35.2	39.9	58.8	57.6	79.3	75.6
Peak demand reduction (MW)	7.5	6.3	9.9	9.7	13.6	11.9
DR program capacity (MW)	47.0	53.4	67.0	56.9	57.4	62.4
Total program expenses ($M)	$8.0	$12.1	$16.6	$16.6	$17.3	$18.1
Average cost per MWh (EE programs only)	$ 17.6	$16.9	$18.0	$17.4	$14.1	$15.0

PNM is on target to meet or exceed the 2014 cumulative goal of 411 GWh (5% of PNM's 2005 retail sales), and 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. A summary of the overall results by individual program are shown in Table 3-C by MWh.

Table 3-C: Energy Efficiency Program Results through December 2013

Program Annual Energy Savings (MWH)	2008	2009	2010	2011	2012	2013
RESIDENTIAL LIGHTING	24,142	15,663	20,583	18,682	31,222	26,339
REFRIGERATOR RECYCLING	5,745	4,614	7,312	5,741	6,372	7,072
ENERGY STAR HOMES	158	839	831	391	275	163
LI CFLS AND REFRIGERATORS	-	312	1,245	867	1,030	364
EASY SAVINGS	-	3,377	2,390	2,401	2,164	1,616
CFL EXCHANGE	1,942	877	342	-	-	-
COMMUNITY CFL				13	242	110
ENERGY SAVER KIT	130	-	-	-	-	-
ENERGY SMART FOR RENTERS				-	103	-
ADVANCED EVAP. COOLING	17	1	-	-	-	-
COMMERCIAL LIGHTING	2,043	6,594	-	-	-	-
COMMERCIAL COMPREHENSIVE	-	6,707	26,104	28,204	36,564	38,022
COMMERCIAL SELF DIRECT	1,034	243	-	253	168	151
DEMAND RESPONSE	-	665	-	1,046	1,181	1,726
TOTALS	35,211	39,892	58,808	57,598	79,321	75,562

A summary of the results by individual program are shown in Table 3-D by the savings in the kW level of customer demand.

Additional details for each year's program results are available in PNM's annual EE and measurement and verification reports at www.pnm.com/regulatory.

Table 3-D: Energy Efficiency Program Results through December 2013

Program Annual Demand Savings (kW)	2008	2009	2010	2011	2012	2013
RESIDENTIAL LIGHTING	5,533	1,836	2,783	2,378	3,816	3,219
REFRIGERATOR RECYCLING	939	798	1,179	981	1,090	1,209
ENERGY STAR HOMES	93	494	596	280	197	117
LICFLS AND REFRIGERATORS	-	39	145	101	116	59
EASY SAVINGS	-	295	220	221	199	151
CFL EXCHANGE	445	101	39	-	-	-
COMMUNITY CFL				2	28	13
ENERGY SAVER KIT	22	-	-	-	-	-
ENERGY SMART FOR RENTERS				-	12	-
ADVANCED EVAP. COOLING	14	1	-	-	-	-
COMMERCIAL LIGHTING	322	1,136	-	-	-	-
COMMERCIAL COMPREHENSIVE	-	1,478	4,902	5,655	8,141	7,048
COMMERCIAL SELF DIRECT	129	125	-	121	22	17
DEMAND RESPONSE	47,365	53,410	67,032	56,900	57,413	62,382
TOTALS	54,862	59,714	76,896	66,639	71,034	75,213

DEMAND-INFLUENCING RATES AND TARIFFS

PNM designs rates, tariffs and DR and EE 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 EE programs and energy use incentives through bill inserts, direct mail advertising, radio, television, and 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. Growth in participation in the Power Saver and Peak Saver programs was modeled in the same way as for the existing and projected EE resources.

According to 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

Rates per unit of energy increase for residential customers as usage increases (Rate 1A). This is designed to discourage higher usage by increasing cost. Figure 3-E below shows an example of increasing energy block rates for usage.

Seasonal Residential Rate Design

Summer rates are higher than winter rates for most customer classes. This rate encourages customers to avoid 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 3-E also illustrates this rate design.

Time-of-Use Rates

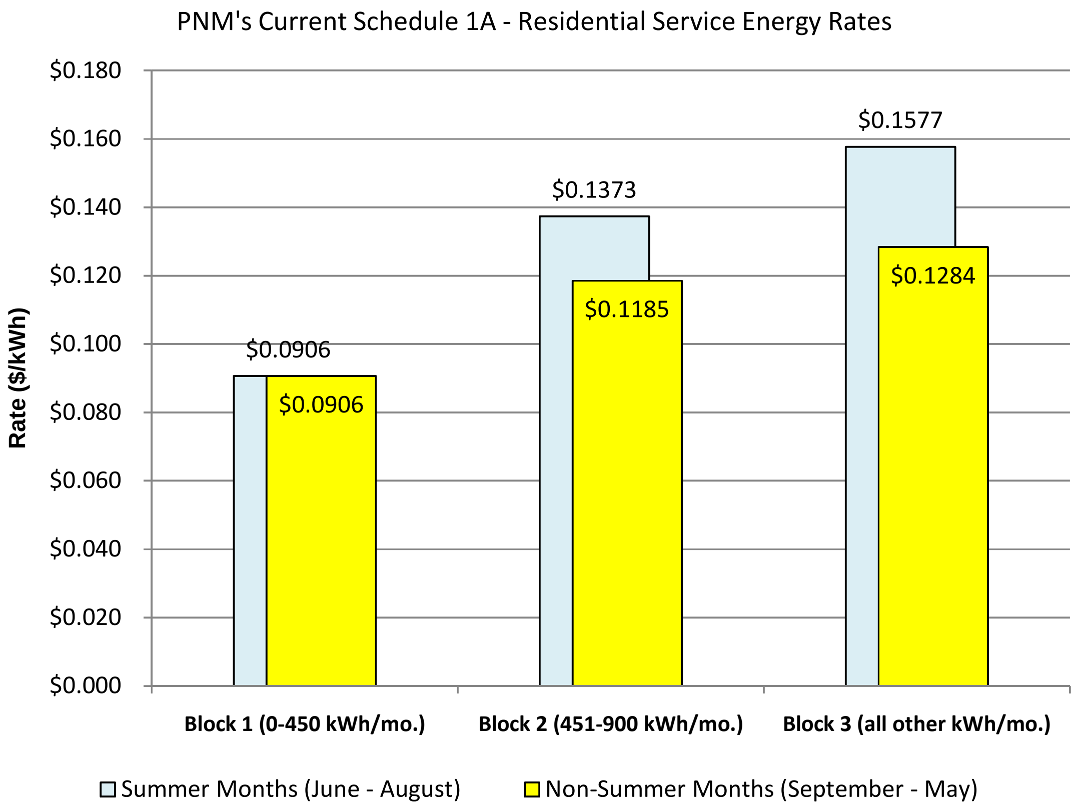
PNM offers Time-Of-Use (TOU) rates for Residential (1B), Small Power (2B), General Power (3B & 3C), Large Power (4B), Large Mining (5B), Irrigation (10B), Water Sewage Pumping (11B), Universities, (15B), and Large Manufacturing (30B) customer classes. These rates encourage customers to avoid usage during the time when the cost to serve is highest 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.

Incremental Interruptible Power Rate

Five General Power and three Large Power customers have contracts for service under PNM's Rate Rider 8. In the event of a PNM system emergency, these customers can be called upon to interrupt their incremental on-peak billed demand with thirty minutes notice during the on-peak period of 8:00 a.m. until 8:00 p.m., Monday through Friday.

Interruptions can extend 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.

Figure 3-E: Example of Inclining Block Energy Rates



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 150kW (under PNM's Peak Saver program) can volunteer to have portions of their load curtailed on ten-minute notice from June through September for up to 100 hours per year. This load shifting helps PNM manage peak summer loads.

Conclusion- Existing Demand-Side Resources

Demand-side resources have proven to be cost-effective resources in lowering the overall level of customer demand and load and in managing summer customer demand peaks. PNM is on the path to meet its 2014 cumulative goal of 411 GWh. Additional, new demand side programs will be necessary to achieve the 2020 cumulative goal of 658 GWh. Recent amendments to the EUEA increase the level of funding and establish a new measure for determining cost effectiveness. PNM's four year action plan will need to reflect these new requirements.

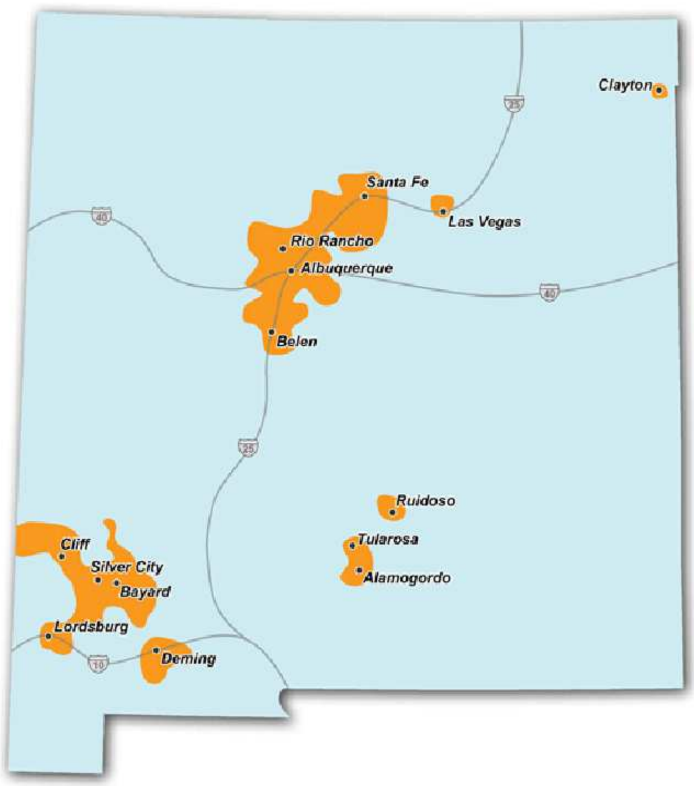
4. SYSTEM LOAD FORECAST: METHODOLOGY AND ASSUMPTIONS

CURRENT LOAD FORECAST

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

PNM faces growing peak demand. In the long-term PNM must serve future system loads, maintain system reserve margins and incorporate progressively higher levels of EE and renewable energy for compliance with applicable regulations. 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. Additional data on the load forecast is included in Appendix C.

Figure 4-A: PNM's Electric Service Territory Map



For this IRP, PNM developed three load forecast scenarios, called low, mid and high, based on current assumptions at the time the forecasts were developed. The low load forecast and a high load forecast incorporated various aspects of forecast uncertainty, such as the level of economic growth, pace of gains in efficiencies, and declining load factors compared to the mid forecast. Late in the process, PNM revised its current load forecast assumptions to account for the loss of a wholesale customer (City of Gallup) and to account for the declining trend in system load factor that was made apparent by reconciling historic demand forecasts to the 2013 system peak demand. This fourth load forecast scenario is the current forecast for the purposes of this IRP.

Each set of input assumptions is used to create a retail energy sales forecast and peak demand forecast. The load forecast scenarios discussed in the following sections encompass both a peak demand forecast and the energy sales forecast on which that peak demand is based.

Methodology Overview

The system load forecast includes energy, customers, and peak demand and comprises three parts: retail loads, existing firm wholesale customers, and distribution and transmission losses. Although the results of PNM's retail forecast are reported by FERC customer class, the forecast is actually prepared at the PNM rate class level.

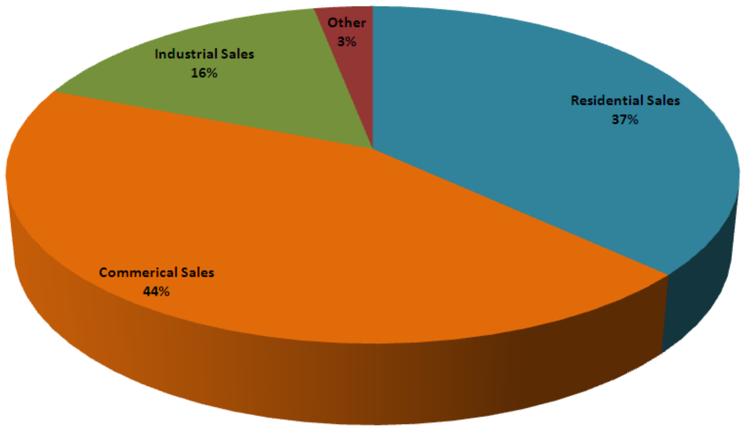
Until recently, PNM relied primarily upon statistically-based time series modeling to prepare its retail load forecasts. This approach incorporates actual growth in customer loads over time, known customer specific growth and near-term impacts of economic activity in PNM's service area. In recent years, and specifically surrounding the economic recession, industry forecasters have seen changes in the relationships between traditional macroeconomic indicators and retail sales growth. To address this concern, in 2013 PNM developed an end use sales forecasting approach. This bottom up approach is important as it can examine the implications of technological advancement and efficiency standards by specific end use in the long term sales model. The current sales forecast model focuses on a two-pronged approach where short term economic trends captured by the statistical regression models are merged with long term changes in usage captured by the detailed end-use level data available in the end use approach.

Sales by Customer Class and FERC Class

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

In 2013, residential sales accounted for 39% of total retail sales, commercial sales accounted for 46% and industrial sales were 12%. The remaining three FERC classes (other public authorities, street lighting, and interdepartmental, usually summarized as "Other") represented only about 3% of retail sales as shown in Figure 4-B.

Figure 4-B: Total Retail Sales by FERC Classes - 2013



Residential Forecast Methodology

The residential energy sales forecast is based on forecasts of growth in the number of customers combined with forecasts of per-customer usage. The forecast of energy sales equals the forecast of the number of customers multiplied by the forecast usage per customer.

Separate forecasts are prepared for each of PNM's two residential rate schedules based on statistical analyses of historical growth in numbers of customers and usage per customer, combined with exogenously forecasted (generally by external sources) macroeconomic variables.

Growth in the number of customers over time is based on the population forecasts from the Bureau of Business and Economic Research (BBER) at the University of New Mexico which were used to determine growth rates for residential customers. BBER's population forecast is prepared at the county level. PNM matches its service territory with the appropriate counties for population growth. Using county data allows PNM's forecast to capture changes in customer mix, as well as the rural to urban migration experienced within the state in recent decades, that would not be captured using a state level population forecast.

The use per customer calculations capture (1) seasonal differences within a year, (2) responses to weather, and (3) changes in usage patterns over time that result from life-style changes, price and detailed end use data. The use-per-customer forecast assumes normal weather derived from a 10-year average of heating and cooling degree-days, which for purposes of this forecast, covers the years 2003 to 2012.

Commercial Forecast Methodology

The FERC commercial class contains several PNM rate classes. The Small Power and General Power classes were forecast the same way as the two residential rate classes: in the aggregate combining separate forecasts of numbers of customers and per customer usage. PNM uses employment estimates from BBER as an input in the commercial customer forecast equation to help capture economic conditions.

Larger customers within the commercial class were forecast differently. PNM's largest commercial customers, including approximately 30 Large Power customers (Rate 4B) and all Universities (Rate 15B), were forecast on an individual basis. Routine contact with these customers provides updates on their growth expectations and identifies new large customers that are anticipated to begin taking service in the forecast period.

Industrial Forecast Methodology

Like the commercial FERC class, the industrial class may take service under several PNM rate classes. PNM serves about 250 industrial customers, the largest 40 constituting the vast majority of energy sales to industrial customers. The largest industrial customers receive service under three rates (Rate Schedules 4B, 5B, and 30B). The forecasts for these customers were based on information obtained directly from the customers in the same manner as the forecasts for Large Power customers in the commercial class. PNM, through its quarterly update process, continually evaluates the forecasts for large customers.

Forecasts for the remaining industrial customers, those served under either Small Power or General Power rate schedules, were prepared in the same way as the forecasts for their counterparts in the commercial class, by aggregating all customers within a rate class and performing statistical time-series analyses

Other Customer Classes Forecast Methodology

The Other Public Authorities class within the "Other retail" category (the largest component), has changed in recent years along with expansion of water pumping loads related to the San Juan-Chama Drinking Water Project in Albuquerque and Buckman Diversion Project in Santa Fe. PNM continues to work with these customers to project future changes in demand.

PNM prepared separate load forecasts for firm wholesale customers using statistical analyses of historical growth in energy sales, which captured seasonal differences within a year, relationship to weather, and changes in usage patterns over time.

Transmission and Distribution Line Loss Estimate s Methodology

Estimates of energy and demand losses for the transmission system were prepared by PNM's Transmission Development and Contracts Department. Energy and demand loss estimates for the distribution system were based on studies prepared by PNM's Distribution Planning Department.

LOAD FORECAST SCENARIOS

Average 20-year growth rates for the low, mid and high load forecast sensitivities developed for this IRP are summarized in Table 4-C. Note that all forecast scenarios presented here predict slowed growth compared to the baseline presented in the *2011 IRP*. This expectation is due, in large part, to the slow economic recovery in recent years, as well as increasing energy efficiency and conservation within PNM's service territory. 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 EE programs. Note that while some EE gains are inherent in the historical data, for the IRP process, incremental gains in EE programs have been treated as a separate component. Changes in use per customer, including these programs, are likely negative, depending upon the saturation sensitivity chosen for PNM's EE program.

Table 4-C: Load Forecast Growth Rates Without Incremental Energy Efficiency

	Current	Low	Mid	High
Population Growth	1.3%	1.0%	1.3%	1.5%
Residential Sector				
Residential Customers	1.3%	0.4%	0.4%	0.4%
Residential Use Per Customer	0.4%	-0.4%	0.3%	1.0%
Residential Energy Sales	1.7%	-0.1%	0.7%	1.4%
Commercial /Industrial Sectors				
Commercial & Industrial Energy Sales	1.0%	0.8%	0.9%	1.2%
Total PNM Energy Sales				
Retail Energy Sales	1.2%	0.05%	0.8%	1.2%
Peak Demand				
System Peak Demand	1.3%	0.1%	0.4%	0.9%

CURRENT LOAD FORECAST

The current load forecast captures updates to the original IRP forecast scenarios driven by additional load analysis and continuation of weak regional economic conditions.

In the near term, energy sales are depressed as large PNM customers continue to scale back operations. New analysis on residential use per customer, specifically the finalization of an end use modeling project conducted late in 2013, is also integrated into this run. The impact is continued decline in residential use per customer, especially in the near and mid-term forecast years (through known 2016 and 2020 standards changes).

In the long run, the output of this model run is higher sales growth than the IRP mid projection. This is primarily due to a more positive outlook for long term residential customer growth. The average annual growth rate of residential customers is 1.5% over the 20 year time frame versus 0.5% in the near term. This is more representative of tempered (but not dramatically reduced) historical customer growth rates which in the two decades pre-recession averaged 2.5%.

A new approach to peak demand forecasting was taken in this scenario model run. The output of this is a demand forecast that increases more quickly than the mid forecast. This will be described in more detail in the load factor section below.

Low Load Forecast

The low load forecast represents a combination of a lingering recession followed by slower economic growth for the out years. The low load forecast was partially driven by the "Recovery Stalls" scenario presented in the July 2013 quarterly FOR-UNM economic forecast by UNM's BBER. This analysis was presented with a 20% probability and predicts less underlying strength in the national economy and increased vulnerability to cuts in federal discretionary spending and global economic crises. The impact of this scenario to PNM's forecast is primarily in the commercial sector, where lingering high unemployment as the "new norm" will slow commercial customer growth.

The low load forecast also assumes lower growth in use per customer for both residential and commercial customers. This can be attributed to larger than expected efficiency gains and/or increased response to price increases. Finally, the industrial energy load and sales forecast is altered by assuming a load loss equivalent to the loss of a large-power customer every 18 months with a load of about 3 MW.

Mid Load Forecast

PNM developed the mid load forecast in December, 2013, using normalized weather and BBER's base scenario for projected economic conditions. The base scenario of the economic forecast predicts a continuation of the economic recovery, with employment growth rates of 1.7% by 2014. As with the pessimistic economic scenario described in the low load forecast, the base also accounts for the "new norm" in unemployment being significantly higher than New Mexico unemployment rates in recent decades.

PNM's base load forecast assumes moderate residential and commercial customer increases, driven by population growth of about 1.2%, as the New Mexico economy moves past the recent recession. However, it does not climb to some of the higher growth rates seen in the 1990's for the service area. Use per customer flattens out due to price response and energy efficiency.

High Load Forecast

The high load forecast represents strong, sustained economic and population growth in the service territory. Assumptions for this scenario were broadly based upon BBER's optimistic scenario "The Recovery Reignites." To correspond with migration to the service area, likely influenced by job growth and strong economic conditions, unemployment rates were also lowered. Consistent with increased job opportunities, this forecast also includes increases in industrial energy sales equivalent to a new large-power customer with a load of about 3 MW every 18 months beginning in 2015. This scenario also includes a slight uptick in use per customer (before the impact of EE programs) which corresponds to increased appliance saturation and penetration of refrigerated air conditioning that is popular in new housing units.

Historical Comparison of Load Forecasts

PNM's demand forecasts prepared in 2011 through 2013 tended to over-forecast system peak demands on a weather-normalized basis. A key factor in this has been declining sales growth in the aftermath of the recent economic recession. Extreme weather is also important, PNM uses a ten-year weather normal versus a 30-year normal for its weather normalization to better capture recent warming trends, but extreme weather conditions are often difficult to predict.

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.

PNM has seen a continuation of the deteriorating load factor reported in the 2008 IRP for both the total system and the retail portion of PNM's load. Actual and weather normalized system load factors in recent year are presented in Table 4-D.

The system load factor has fallen below 60% in several instances in recent years, a significant decrease from averages of around 63% seen in the early 2000s. Deterioration of load factor is difficult to predict for the forecast period. While recent history would infer continuing deterioration, PNM's demand response programs "shave" peak demand, while 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.

Table 4-D: PNM System Load Factor Summary

	Actual	Weather Normalized Actual
2006	63.6%	63.4%
2007	62.7%	62.6%
2008	63.0%	60.3%
2009	60.8%	61.0%
2010	58.7%	59.8%
2011	60.1%	60.5%
2012	59.3%	60.0%
2013	56.6%	57.3%

PNM used recent history to predict the load factor without overlaying a trend (either upward or downward). The same load factor is used in each of the three original forecast scenarios (i.e., low, mid and high). The current forecast recognizes the likelihood of long-term deterioration of PNM's system load factor absent development of further initiatives to improve it as shown in Figure 4-E. This approach applies 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 continues to grow at a rate slightly higher than energy sales.

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 while PNM is a summer-peaking utility, the winter peak is generally 75-85% 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 prior winter peak. Figure 4-F on the following page provides a comparison of the peak demand and forecast sensitivities.

Figure 4-E: Comparison of PNM's Energy Forecast Sensitivities

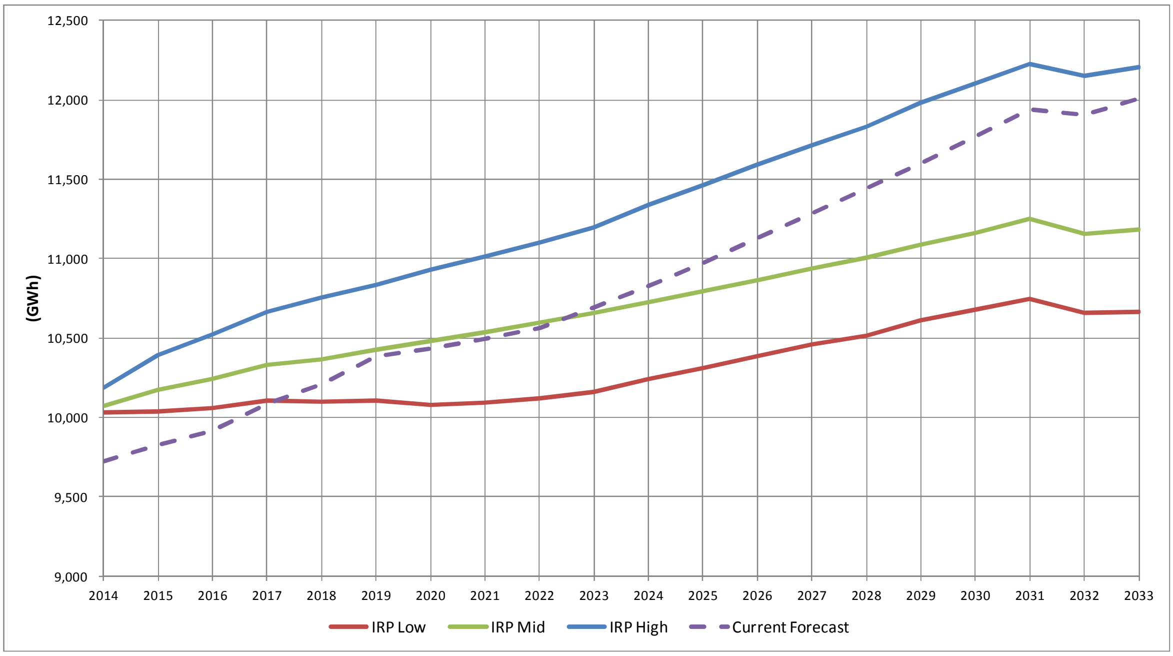
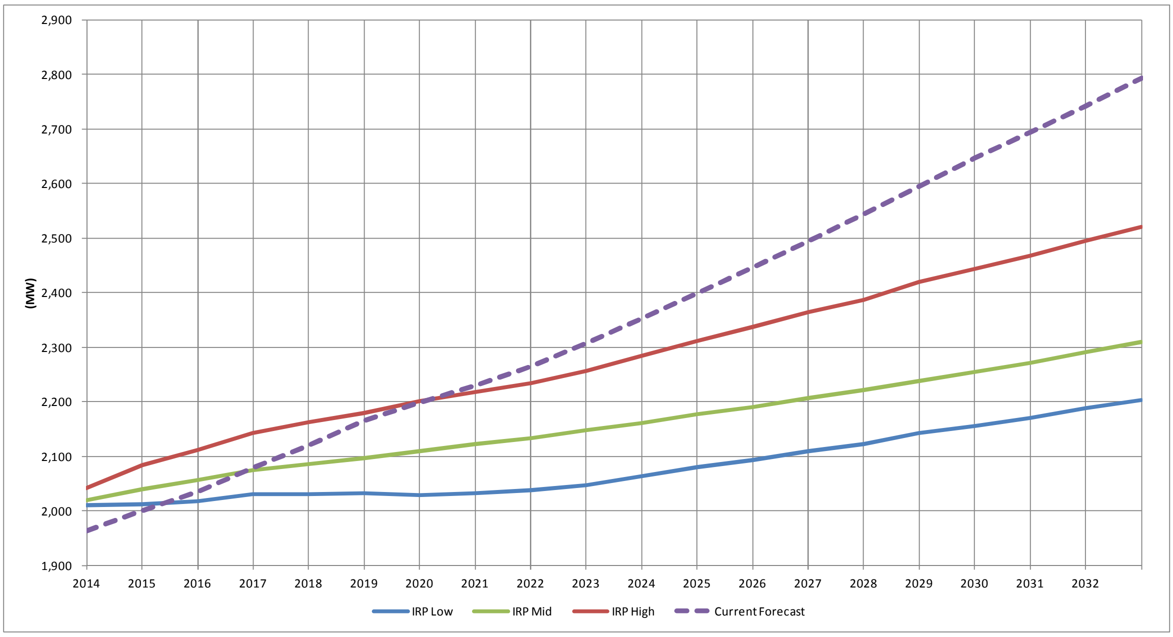


Figure 4-F: Comparison of PNM Forecast Peak Demand for Electricity



Historical Load Forecasts

Historical load forecasts compared to actual load are shown in Tables 4-G and 4-H. The columns represent forecast cycle and the rows represent the year forecasted. For example, row 2013, column 2011 represents 2013's demand as forecasted in 2011.

Table 4-G: PNM System Peak Demand Comparison (Weather-Normalized)

Forecasted Peak Demand MW	2009	2010	2011	2012	2013	Actual	Weather Normalized Actual
2009	1,870					1,866	1,857
2010	1,899	1,893				1,973	1,938
2011	1,929	1,893	1,950			1,938	1,924
2012	1,951	1,903	1,959	1,967		1,948	1,925
2013	1,979	1,904	1,995	1,980	1,978	2,008	1,977

Table 4-H: PNM System Energy Comparison (Weather-Normalized)

Forecasted Energy Sales GWh	2009	2010	2011	2012	2013	Actual	Weather Normalized Actual
2009	9,762					9,937	9,985
2010	9,921	9,351				10,150	10,064
2011	10,065	9,360	10,200			10,204	10,113
2012	10,233	9,488	10,295	10,209		10,145	10,063
2013	10,362	9,548	10,401	10,226	10,129	9,952	9,895

Load Forecast Conclusion

PNM's customer energy consumption has been declining over the past couple of years on a 10-year weather normalized basis. For this IRP, PNM developed a new demand and sales forecast, incorporating retail and wholesale customers' growth, consumption patterns and line losses. A July 2013 economic forecast, prepared by the BBER at the University of New Mexico was used for this forecast. First, a base case forecast was prepared (called the mid forecast) and then a low and high forecast was developed which adjusted the mid forecast for potential customer and/or technology impacts. The low and high forecasts were used to test the sensitivity of portfolios based on the mid-forecast to risks of loss of load if the future load forecast were to vary significantly from the mid-forecast levels.

5. FUTURE RESOURCE OPTIONS

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 them may already be known, but not yet commercially available or cost effective; some may not yet be known. However, development of a 20-year most cost-effective portfolio cannot be based on speculation of uncertain technology improvements, but rather must take into account what is available and known at the present time. In three years, when the IRP process is again undertaken, the most cost-effective portfolio can be reevaluated taking into account resource options, technologies and costs available at that time. For purposes of this IRP, available resource options for planning the 20-year most cost effective portfolio depend upon technologies and costs at the present time. The following discussion addresses these resource options and resources that currently appear to be on the horizon, but not yet commercially cost-effective. This section of the IRP Report addresses the requirements of Section 17.7.3.9F of the IRP Rule.

SUPPLY RESOURCE OPTIONS

The IRP considers all feasible resources including current and developing new resource options. A discussion of each potential resource option, its feasibility of being implemented during the planning horizon, and fuel assessment are presented in this section. Fifteen different generation resources are identified as available to be included in a portfolio over the next 20 years and were allowed to be selected in the portfolio analysis. 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. Cost and performance data for new supply side resource options can be found in Appendix D.

250 MW NEW COMBINED CYCLE GAS GENERATION

For this option PNM assumes a 1x1 combined cycle gas turbine, which provides a relatively high efficiency rating. The 250 MW size represents a typical manufactured capacity for this type of configuration using high efficiency turbines. The 250 MW combined cycle gas turbine (CCGT) is modeled assuming a $1,545/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 reduce water usage and associated costs, PNM assumed this CCGT will utilize hybrid or dry cooling technology. This additional cost is included in the installed capital pricing above. PNM used the EPRI Technical Assessment Guide (TAG) database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level.

204 MW NEW COMBINED CYCLE GAS GENERATION

PNM models a 1x1 combined cycle gas turbine option, which also provides a relatively high efficiency rating and does not exceed PNM's current largest generation unit at this size. The 204 MW size represents a typical manufactured capacity. The 204 MW CCGT is modeled assuming a $1,780/kW installed capital cost and about a 7,100 Btu/kWh heat rate. Installing a larger unit may decrease the capacity cost and heat rate, but would increase costs for reliability reserves on PNM's system. Unlike gas turbines, combined cycle plants require large amounts of water to condense the steam cycle. To reduce water usage and associated costs, PNM assumed this CCGT will utilize hybrid or dry cooling technology. This additional cost is included in the installed capital pricing above. 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. This resource was assumed to be sited so as not to require any major transmission upgrades by siting it near PNM's largest load center, the Albuquerque/Santa Fe area.

177 & 143 MW New Gas Turbine

The 177 MW and 143 MW gas turbines (GT) are modeled as heavy frame units. The 177 MW option is modeled with 9,790 Btu/kWh heat rate and $979/kW installed capital cost, and the 143 MW option is modeled with 10,142 Btu/kWh heat rate and $1,006/kW installed capital cost. 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. The 177 MW and 143 MW sizes represents typical manufactured capacity. This technology can help PNM maintain system voltage, regulation and meet spinning reserve requirements. These resources are expected to require relatively little acreage and minimal amounts of water. Thus, these resources were assumed to be sited so as not to require any major transmission line or upgrades and allowing PNM to site within WECC Path 48 in north central New Mexico.

Additionally, PNM assumed that two more options where these could only be sited at or near SGJS and utilize the available transmission from the San Juan Plant to PNM load centers in north central New Mexico (see the description of PNM's transmission system in Section 3). PNM also assumed a $10 million cost to build a new gas pipeline from an interstate pipeline to the San Juan plant.

93 MW New Reciprocating Engines

The 93 MW of reciprocating gas engines is based upon operating ten smaller sized reciprocating engines at a heat rate of 8,900 Btu/kWh heat rate and $1,521/kW installed capital cost. Reciprocating engines can operate over the full ranges and offer maximum load following flexibility. PNM used the EPRI TAG database as the source of the unit characteristics. This resource was assumed to be sited so as not to require any major transmission upgrades and allow PNM to site it within WECC Path 48 in north central New Mexico.

85 MW New Gas Turbine

The 85 MW GT is based upon a typical manufactured size of aero-derivative hybrid gas turbine with a 9,150 Btu/kWh heat rate and $1,679/kW installed capital cost. Similar to the 177 MW CT shown above, this unit can provide quick start capability (full operating load in 10 minutes) with a proven track record. 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 to represent typical siting conditions around New Mexico. This resource was assumed to be sited so as not to require any major transmission upgrades and allow PNM to site it within WECC Path 48 in north central New Mexico.

40 MW New Gas Aeroderivative Turbine

The 40 MW option is based upon one 40 MW aero-derivative turbine at a 9,800 Btu/kWh heat rate and $1,644/kW installed capital cost. 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. Similar to the 85 MW GT discussed above, this unit can provide quick start capability (full operating load in 10 minutes) to help maintain system reliability. This resource was assumed to bypass any major transmission upgrades and allow PNM to site it within WECC Path 48 in north central New Mexico.

100 MW Wind Resource

New Mexico offers abundant and excellent wind resources. This option is assumed to be a new 100 MW wind facility, located in NM and would be procured through a third party entity under a long term power purchase agreement at the rate of 44.41 $/MWh levelized over a thirty year life. Based on previous RFPs, PNM used an average of costs to provide a proxy for this resource. This option assumes minimal interconnection costs and does not assume any transmission upgrade costs as this depends heavily on the location of a new wind facility and access to the PNM transmission system. The wind resource is located on the eastern side of New Mexico and any required transmission upgrades would need to be evaluated on a case by case basis.

20 MW Increment Solar PV Resource

This option based upon a new 20 MW, single axis tracking solar PV facility, located in NM with a $1,981/kW installed capital cost based upon expected costs from developers. PNM used two different cost options to take into account the current federal investment tax credit being reduced from 30% to 10% beginning in 2017. As the penetration of solar increases on PNM's system it will begin to affect the system peak hour during the summer. PNM applies a declining contribution to reserve margin with each successive resource addition made. This option assumes very minimal interconnection costs and does not include transmission upgrade costs as this resource is expected to be located on PNM distribution facilities.

50 MW Solar Trough

This option based upon a 50 MW parabolic trough technology of which PNM would participate in as part of larger project (>100 MW) to take advantage of larger economies of scale. This proxy alternative would be located in NM with a $4,178/kW installed capital cost without storage and $7,291/kW with three hour storage based upon EPRI TAG estimates. PNM assumes that 100% of these solar facilities' rated capacity will be available on peak to meet reserve margin requirements. This option assumes very minimal interconnection costs and does not include transmission upgrade costs.

10 MW Geothermal Resource

Using information gather from the past few RFPs that PNM has issued, PNM believes that some potential still exists for new geothermal resources. Based on previous RFPs, PNM used an average of costs to provide a proxy for this resource from a third party developer at an expected PPA rate of $131.49/MWh levelized over a thirty year life. The primary factor driving siting of geothermal facilities is the location of a viable geothermal resource. This option assumes minimal interconnection costs due to recent experience with the Dale Burgett Geothermal facility. Therefore, geothermal alternatives would need to be evaluated on a case by case basis.

134 MW Existing Nuclear Generation (Palo Verde Unit 3)

PNM has rights to 134 MW of Palo Verde Nuclear Generating Station from Unit 3 which is not currently in ratebase. PNM has assumed that PV Unit 3 could be transferred at a cost of 2,500 $/kW beginning in 2018, consistent with Case No. 13-00390-UT. The current operating license expires in 2047. PNM has assumed that transmission rights can be secured and held to be able to deliver generation to the Four Corners hub. From there, with the retirement of San Juan Generating Station Units 2 & 3, there will enough transmission service available to move this generation to load.

200 MW New Coal Generation

A 200 MW of coal generation facility is based upon participation in a coal plant of a larger size. PNM used the EPRI TAG database as the source of the new unit characteristics complete with environmental controls such as selective catalytic reduction and carbon capture. Based on EPRI TAG estimates, PNM assumes a cost of $5,195/kW. Since carbon capture and sequestration (CCS) is not commercially available, PNM assumes the earliest coal combined with CCS could be an available resource is 2020. This resource was assumed to be sited so as to not require any major transmission upgrades and allow PNM to site it within WECC Path 48 in north central New Mexico.

200 MW New Nuclear Generation

A 200 MW of nuclear generation facility is based upon participation in a plant of a larger size. PNM used the EPRI TAG database as the source of the new unit characteristics to provide a proxy for the new nuclear costs currently undergoing the licensing process for other utilities. Based on EPRI TAG estimates, PNM assumes a cost of $6,102/kW. Although those licensing processes are currently for plants sited on the eastern side of the US, PNM used this to simulate the cost to build nearer to load. This resource was assumed to bypass any major transmission upgrades and allow PNM to site it within WECC Path 48 in north central New Mexico.

250 MW Existing Combined Cycle Generation

A 250 MW of market based combined cycle generation facility was based on recent plant purchase transactions in Arizona. It may be possible to purchase a portion of a larger existing plant at prices publicized by recent purchasers (approximately $700/kW). In order for this to be a viable alternative as a replacement option in 2018, PNM expects that it will have to obtain transmission services for a period of two years before commencement of any power delivery in 2018 to the Four Corners hub. This cost has been included in the costs for this alternative. Since the Arizona market appears to have opportunities to purchase from merchant facilities, the performance of this alternative is based on summertime conditions in Phoenix. Final costs, performance, location and viability would depend upon the results of an RFP process.

78 or 132 MW Existing Coal Generation at San Juan Unit 4

As part of the current ownership mix, PNM has the ability to increment capacity at San Juan Unit 4. PNM included a 78 and 132 MW incremental addition as a resource alternative.

Key Operating and Financial Modeling Assumptions

Table 5-A provides the key data on the operating and financial assumptions used in modeling the above described resource options used in analyzing alternative portfolio options for this IRP Report.

Table 5-A: Modeling Assumptions

Financial Assumptions		Detail	Duration	
Planning Period		2014-2033		
Cost of Capital (After-tax)		8.18%		
Inflation		2.5%	per year	
Escalation on O&M		2.5%	per year	
Escalation on Fuel (natural gas)		Varies	Pace Global pricing assumptions	
Escalation on Fuel (coal/nuclear)		Varies	nuclear - 2.5% per year after 2020	
Property Tax Rate		2.45%		
Property Tax Rate		4.66%	solar technologies only	
Federal Incentives				
	Solar (ITC)	30% (prior 2017)		
	Solar (ITC)	10% (post 2017)		
State Incentives				
	Solar(AEC)	10%		
	Solar(PTC)	Varies	10 years, caps at 200 GWh	
Depreciation for New Resource Options		**Book Life**	**Book Method**	**Tax Method**
Nuclear		40 yrs	Straight Line	15 Yrs MACRS
Coal		40 yrs	Straight Line	20 Yrs MACRS
Combined Cycle		40 yrs	Straight Line	20 Yrs MACRS
Combustion Turbine		40 yrs	Straight Line	15 Yrs MACRS
Solar		40 yrs	Straight Line	5 Yrs MACRS
Other Modeling Assumptions		**Amount**	**Source/Reference/Notes**	
Annual Reserve Margin Target		14%	Higher than 13% Resource Stipulation to account for uncertainty in DR Programs, Wind, Solar and DG contribution at peak	
Carbon Emission Cost Adder (CO2)		Varies	Beginning in 2020, Pace Global pricing assumptions	
Capacity factor for Wind alternative		39%	Based on results from RFPs issued	
Capacity factor for existing PV resources		26.7%	Based on NREL data	
Capacity factor for new PV resources		32%	Based on PNM RFP bids	
Capacity factor for new solar thermal resource:		28%/100%	Based on NREL data (without storage)/with storage	
Contribution to Peak (% of Nameplate)				
Wind		5%	Based on historical data of existing wind facilities	
Solar PV Technologies (fixed tilt)		55%	Based on Historical Performance	
Solar PV Technologies (single axis tracking)		varies	begins at 76% then declines thereafter; based on NREL & RFP data	

EMERGING TECHNOLOGIES

Emerging energy supply technologies discussed during the IRP process included: solar cell technology, smart inverters, small modular nuclear power and energy storage. However, except for solar PV and solar thermal, at the present time PNM does not have adequate information on these technologies to include them in the portfolio analysis. For these emerging technologies, PNM presented an overview of each technology, identifying the technology's function, benefits and potential impact on load shape and load management, and cost-effectiveness if successfully commercialized. A brief overview for each technology is presented in the following paragraphs.

SOLAR TECHNOLOGY

New Mexico has abundant solar potential to generate electricity. There are two types of solar power technology: solar cell that directly converts sunlight into electrical energy, and solar thermal in which solar energy is used to heat a transfer medium such as oil based fluid that is subsequently used to heat steam to power a generator. Both types of solar power mechanisms have technologies on the cusp of commercialization that may become cost effective within a few years.

SOLAR PHOTOVOLTAIC

Generally, solar PV cell technology is maturing and the cost for solar cell manufacturing has decreased significantly from just several years ago, as PNM has determined based on the bids received during the past few years in response to RFPs for renewable resources. High Tech PV solar cells are approaching the theoretical physical limit of being able to convert solar energy into electricity, which is about 50%. However, the current price for High Tech PV technology is not yet competitive with current commercially available solar cell technology.

Another solar cell technology is “thin film”, which would be applied to roof tops, for example. Thin film is showing big improvements in the past couple years in terms of conversion capability, which would be expected to reduce production costs and improve the economic attractiveness to the retail market. One significant advantage of solar cell technology is that it is very easily scalable, from a small sized facility on a residential roof-top to a large utility scale facility of 20 MW to 50 MW, or greater depending upon the availability of land to site the facility upon.

SOLAR THERMAL – POWER TOWER

Solar towers use a large number of mirrors to reflect solar energy to a tower in which an intermediate medium, such as molten sulfur, is heated. The medium is then used to flash water into steam which is used to turn a generator. Solar tower technology requires a significant land area, has a relatively high water requirement for cooling and has a conversion efficiency of 8 to 22%. Although this is the lowest cost utility-scale solar thermal technology, key issues confronting this technology are the further reduction in costs to achieve commercial competitiveness and scale-up to improve generation capacity, which would require additional acreage for solar mirror installations.

SOLAR THERMAL – PARABOLIC TROUGH

Parabolic Trough technology uses a row of mirrors to heat a medium flowing through a pipe in front of the mirrors, such as molten salt, that is then used to flash water into steam for turning a generator. As with a power tower facility, this is a utility-scale technology that requires a large land area for siting. Although this is the most mature of the solar thermal technologies, it only has a conversion efficiency of about 13.5%, has a high water use requirement for cooling, and faces significant issues in reducing cost and in preventing freeze of the molten salt when not circulating due to cold weather or night time conditions.

SOLAR THERMAL – DISH ENGINE

Solar thermal dish engine technology uses concentrated solar power to heat a fluid that drives a piston engine to generate electricity. There has been some early, but limited, deployment of this technology, including in New Mexico. Although dish engine technology has the highest efficiency among the solar thermal technologies, in the range of 16% to 30%, the technology faces significant challenges concerning maintenance costs, operating sustainability and performance variability.

Other Technologies

Smart Inverters

Inverters convert the direct current energy generated by a solar cell to AC energy flowing on to the utility's electric system. As customer-sited distributed generation facilities grow in number across a utility's system, the intermittency or variability of their generation can cause voltage fluctuations across a utility's system that have the potential to cause flickering in a neighborhood or even a loss of power. For example, a cloud passing over a neighborhood with a high concentration of solar rooftop systems could cause a significant drop of generation in the neighborhood and create a sudden drain on the distribution system serving that area that could disrupt service. To prevent this condition and to protect its electrical system and service to customers, most utilities require automatic shut-down of an inverter under certain circumstances of power fluctuations.

Smart inverters are not a supply resource, per se. However, they are specifically designed to help deal with intermittent generation and to help those resources stay connected during voltage disturbances to the utility's system, thereby increasing the deliverability of customer-sited generation to the system during a disturbance and throughout a day. Additionally, as the technology is advancing, it is becoming more diverse in its capabilities such as facilitating bi-directional communications between the device and the utility. At present, smart inverters are anticipated to add about $150 to a customer's solar PV system installation costs. It is anticipated that smart inverters could become commercially available on a widespread basis within 3 to 5 years. Recently, public utilities in California provided recommendations for a pilot project to be started that would require smart inverter installation on new solar PV systems with a goal of making it mandatory to include smart inverters on new installations by late 2015.

Small Modular Nuclear Reactors

A small modular nuclear reactor (SMR) is defined as a reactor that generates 300 MW or less. SMR is currently in the technical feasibility design phase and is envisioned as a generation resource that could help reduce fossil fuel base generation. Target costs for this technology are around $80 per MWh in a time frame that is in the mid-2020s or later.

Energy Storage Technology

Energy storage is a technology that stores energy in some form to be used at a later time. This can be in the form of chemical storage, such as a battery, mechanical storage such as a fly wheel, or thermal storage such as ice storage. Several storage technologies are summarized below in Table 5-B. Energy storage not only can be used to meet system peak load, but potentially could be available as an operating reserve mechanism and for system regulation. Energy storage also could be used to modify load, for example, by "charging" the storage system during normally low-load periods, such as during the night. Differing energy storage technologies are in different phases of development, but are generally in or near the demonstration phase. In 2013, the California Public Utilities Commission established a target of having 1,325 MW of storage capability on the grid within 10 years.

Table 5-B: Storage Technologies and Associated Costs.

Storage Type	Power/Energy Application	Specific Applications	Relative Cost	Relative Size
Pumped Hydro	Energy (hours/days)	Shifting/smoothing Wind/Solar (current)	Low	Very Large
Compressed Air	Energy (hours)	Shifting Wind (proposed)	Low	Large
Flow Batteries (Vanadium Redox, Zinc Bromine)	Energy (some Power ability)	Smoothing/Shifting Wind/Solar (demonstration phase) Deferring system expansion (proposal)	High (until proven – forecasted to be low)	Medium
Metal Air Batteries	Energy	Shifting Wind/ Solar (proposed)	High (until proven – forecasted to be low)	Medium
Sodium Sulfur Batteries	Energy (some Power ability)	Smoothing Wind/Solar (demonstration phase) Deferring system expansion (current)	High	Medium - Large
Lithium Ion Batteries	Power (minutes)	Smoothing Solar (demonstration phase)	Medium – High (potential for cost erosion from associated Auto build)	Small - Medium
Lead Acid Batteries	Power (some energy ability)	Shifting and Smoothing Solar (demonstration phase) Deferring system expansion (proposal)	Low	Small - Medium
Flywheels	Power (seconds – minutes)	Regulation on ISO (current)	Medium	Medium - Large
Nickel Cadmium Batteries	Power	System deferral (proposed)	Medium	Small - Medium
Ultra Capacitors	Power (sub seconds to seconds)	Smoothing/ regulation (proposed)	High	Small - Medium

Storage Type	Power/Energy Application	Specific Applications	Relative Cost	Relative Size
Thermal Energy	Energy	Cooling shift to off peak (current)	Low	Small

Microgrids

PNM and the Public Advisory Group also reviewed the potential for microgrids as a load management resource. A microgrid is a system consisting of distributed resources serving one or more customers that can work together, as an island connected or detached from the utility grid. This could be as small as a single building or as large as an entire neighborhood. The growth of customer-sited solar distributed generation, smart inverters, and other potential resources such as local energy storage capability has increased the interest in and potential for microgrid development in the future. Microgrid technology would have the ability to modify the load profile of a utility, given that customers would be able to rely upon their own energy resources. Given that microgrid development depends upon an integration of current and still developing electric system supply, load management and information technologies, a timeline for the implementation of microgrids is estimated to be 8 to 12 years out. The cost of establishing a microgrid is high; a demonstration project would likely cost between $71 to $100 million. Current research and development efforts concerning microgrids are targeting reduction in costs and savings in technology installation costs. For purposes of this IRP Report, PNM did not include microgrid technology as a resource option given the present day uncertainty regarding its costs, benefits, and timing.

Water for Future Resources

Depending on the type of generation needs in the future, water can play a critical role in the feasibility, cost and site selection for those generation facilities. Solar PV and wind consume no water, and simple-cycle gas turbines use minimal water. Steam-turbine plants (such as combined-cycle gas, coal and nuclear) use the most water primarily because of the need to cool the working fluid (steam) that turns the turbines. If the future resource mix calls for generation that requires significant amounts of cooling, the planning process would include an evaluation of the availability and cost of the following cooling resources (in approximate ascending order of initial cost and operating cost impacts):

1. Raw groundwater
2. Raw surface water
3. Private or municipal potable water
4. Reclaimed municipal wastewater
5. Impaired water (such as brackish, produced water from oil and gas exploration, industrial wastewater, etc.)
6. Hybrid cooling (air cooling with water cooling)
7. Air cooling

In the context of developing future generation, water availability and cost can be key factors, but having these alternative cooling resources means that water rarely has the potential to shape the location or cost of a facility like other factors such as transmission availability, fuel supply, elevation, and land availability.

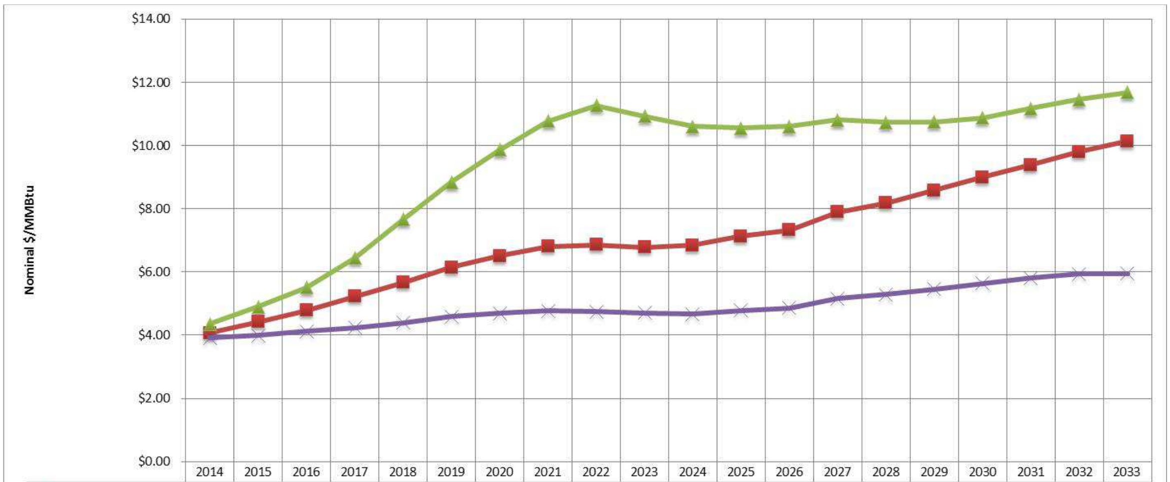
FUEL SUPPLY COST PROJECTIONS

PNM contracted with a nationally known energy consulting service, PACE Global, to provide a coordinated set of price curves for natural gas fuel and CO_2 that was used by PNM throughout the IRP Process. This enabled the analysis of resource alternatives to be conducted using different price trajectory curves that were premised on the same set of scenario assumptions. Furthermore, the portfolio analyses were conducted using three coordinated alternative visions of the future as developed by PACE Global. The detailed data and analyses underlying these scenarios are presented in Appendix E of this IRP Report. PNM reviewed these scenarios and the assumptions behind them with the Public Advisory Group. There alternative scenarios are:

- Reference: Economic and pricing conditions remain similar to what they are currently.
- Low Gas/Low Carbon: Policies focus is on promoting gas production with a later implementation of greenhouse gas emission regulations compared to the other two scenarios.
- High Gas/High Carbon: Policies result in restricted gas production with an earlier, more aggressive carbon regulation compared to the other two scenarios.

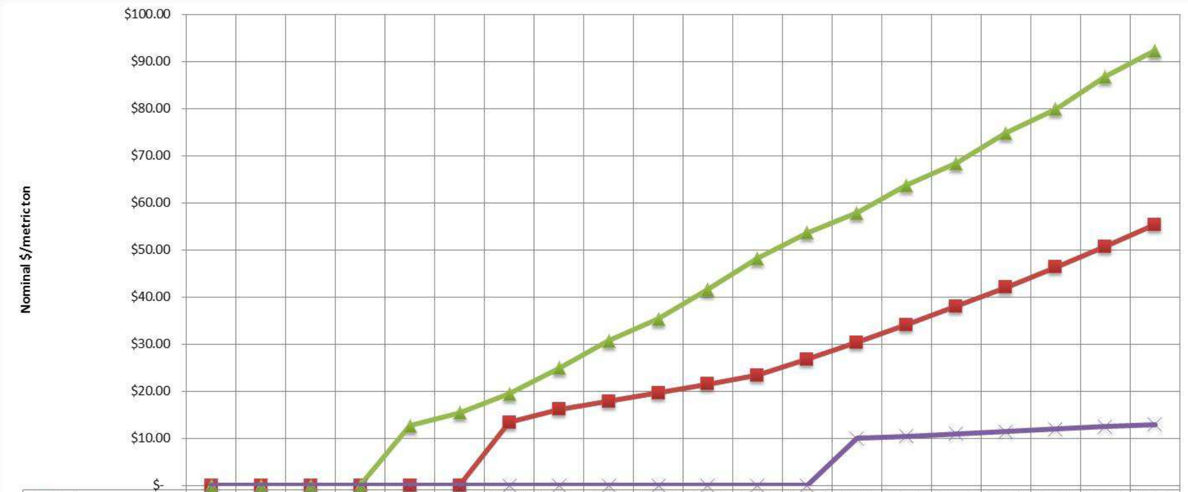
These scenarios are shown in Figure 5-C for natural gas and Figure 5-D for CO_2 pricing. Refer to Appendix E for fuel pricing at SJGS, Four Corners and Palo Verde.

FIGURE 5-C: PACE NATURAL GAS PRICE CURVES



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Reference	$4.08	$4.42	$4.78	$5.22	$5.67	$6.14	$6.51	$6.81	$6.86	$6.79	$6.84	$7.13	$7.32	$7.90	$8.19	$8.58	$9.00	$9.39	$9.80	$10.14
High Gas/High Carbon	$4.36	$4.91	$5.51	$6.44	$7.66	$8.85	$9.87	$10.78	$11.27	$10.94	$10.61	$10.56	$10.61	$10.82	$10.73	$10.75	$10.88	$11.17	$11.46	$11.68
Low Gas/Low Carbon	$3.91	$3.99	$4.12	$4.24	$4.39	$4.59	$4.70	$4.77	$4.75	$4.70	$4.67	$4.78	$4.86	$5.16	$5.28	$5.45	$5.64	$5.80	$5.93	$5.94

FIGURE 5-D – PACE CO2 PRICE CURVES



Reference	$-	$-	$-	$-	$-	$-	$13.40	$16.24	$17.92	$19.68	$21.52	$23.43	$26.85	$30.41	$34.14	$38.04	$42.11	$46.36	$50.80	$55.43
High Gas/High Carbon	$-	$-	$-	$-	$12.76	$15.45	$19.49	$24.98	$30.72	$35.43	$41.69	$48.25	$53.69	$57.93	$63.83	$68.47	$74.86	$79.93	$86.85	$92.38
Low Gas/Low Carbon	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$10.00	$10.50	$11.00	$11.50	$12.00	$12.50	$13.00

TRANSMISSION FOR NEW RESOURCES

All new potential resources should include costs that reflect transmission improvements required to connect the resources to PNM's system, and transmission service costs required to deliver the power. Since the major assumption for this IRP is that any new resources would be sited within the NNM load pocket; the need for transmission improvements would be limited to station integration costs and require little, if any, newly built transmission facilities. For this IRP, PNM assumed that new transmission would not be built to new resources in remote locations.

DEMAND-SIDE RESOURCES FOR THE FUTURE

Future demand-side resource options are represented by energy efficiency forecasts, DR programs, and demand reductions through rate design. While renewable DG programs are considered demand-side resources, the IRP presents the customer-owned renewable DG program within the discussion of renewable resource options in Section 2 of this report. Amendments to the EUEA in 2013 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 the term of the 2014 IRP. The level of savings achieved becomes a function of the effectiveness of each program and rate of increase in cost to procure incremental savings. PNM also assumed a continuation of the general structure of the current demand-influencing rates and tariffs discussed in Section 3 of this IRP Report.

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:

1. Current programs, as well as new programs, continue to be approved by the NMPRC.
2. Successful identification and implementation of new programs required to meet the EUEA net savings requirements of 5% of 2005 retail sales by 2014 (411 GWh) and 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 2014 and 2020.
3. PNM invests three percent of applicable retail revenues annually on energy efficiency and load management programs, as specified in the EUEA.
4. Assumptions regarding the maturation of energy efficient technologies; specifically, the cost of procuring future savings will increase at an average annual rate of 3.0%.
5. Recognizing that the actual escalation rate of the cost of energy efficiency per kWh saved may vary from the projected rate of 3.0%, two sensitivity cases are included assuming higher and lower escalation rates over time of 4.0% and 2.0%, respectively.

FUTURE DEMAND RESPONSE RESOURCES

Approved demand-side programs include DR programs for residential, commercial, and industrial customers. PNM believes that these are aggressive programs that may not be capable of expanding beyond their estimated impacts of between 60 MW and 69 MW of customer demand reduction. For this reason, PNM is not initially modeling new DR programs as a future resource option. PNM will continue to seek more DR opportunities should the existing programs exceed projections (see DR program results in Section 3) and customer growth continues. In addition, PNM will also consider other customer programs that result in shifting customer demand to off-peak periods. For example, offering incentives to customers to install thermal energy storage systems could permanently move cooling loads to off-peak times. New programs such as thermal energy storage would be subject to analysis of cost effectiveness and the potential customer market for the technology.

6. THE MOST COST-EFFECTIVE PORTFOLIO

The IRP Rule defines "most cost effective resource portfolio" 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 Most Cost-Effective Portfolio must comply with all legal and regulatory requirements. Applicable legal and regulatory requirements, which have been described above or in the appendices to this IRP Report, include the Revised SIP, 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. Essentially, the Most Cost-Effective Portfolio meets electric system demand, provides acceptable system reliability and operational flexibility, meets applicable legal and regulatory requirements, and minimizes financial cost to customers.

To identify the Most Cost-Effective Portfolio for the period 2014 through 2033, PNM examined thousands of potential resource portfolios taking into account multiple scenarios and sensitivity studies of differing resources, economic conditions, carbon prices, and customer demands. Alternative scenarios for economics and fuel pricing were developed as well as for customer demand levels in order to test the sensitivity of resource portfolio to alternative assumptions and conditions. A number of these were presented to the Public Advisory Group during several meetings. The remainder of this section describes the analytical methodology used, highlights the resource preferences that appeared across multiple resource portfolio scenarios, presents the Most Cost-Effective Portfolio, and then describes the impact of different sets of policies, regulatory requirements, and resource constraints.

ANALYSIS METHODOLOGY

The IRP planning and analysis process requires consideration of studies, forecasts, and regulatory predictions together with historical data, existing resource availability, current regulation, and the costs associated with alternative portfolio solutions. Resource analysis considers both the short and long term cost impact to the customer, while reliably delivering the expected services and meeting other regulatory and operational requirements. To perform its analysis for determining the most-cost effective portfolio, PNM used a resource planning modeling software called Strategist®, which is widely used in the electric industry for long-range resource planning and portfolio analyses. The program conducts a rigorous evaluation of up to 5,000 unique resource portfolios and selects and ranks them based on various user-specified criteria. Strategist® identifies the net present value (NPV) over the planning period of each portfolio that meets user-specified input requirements. Examples of such criteria include:

- **Customer Demand,** including projections of peak demand, energy consumption, and customer load factors over the 20-year period.

- **Reserve Margin,** which is a measure of the capability of the portfolio to compensate for the loss of its largest energy resource or higher than expected customer loads. PNM's current planning reserve margin is the greater of 13% of peak load or 250 MW.
- **Resource Constraints**, which are set to avoid the selection of multiple large generation resource additions within a single year in order to manage capital investment requirements.

Strategist® output provides a listing of resource additions over the planning horizon to meet load requirements and other user-specified requirements. The output includes:

- **Net Present Value**, which measures the NPV of the costs that would be incurred over the period from utilizing the resources in the portfolio, including capital investment and O&M costs.
- **Loss of Load Hours**, which is a probability calculation of the number of hours over the 20-year planning period during which customers would experience an outage.
- **CO_2 Emissions**, which measures the amount of CO_2 emissions that would result from the portfolio over the planning period which represents a cost risk to the portfolio from potential future carbon emission regulations.

Based on the outputs and performance of various portfolios, PNM selected least-cost portfolios for further analysis. PNM conducted a Monte Carlo assessment on these portfolios to examine the impact of future conditions could vary from the assumptions initially used for the Strategist® analyses. The Monte Carlo analysis uses randomly selected values from probability distributions for each variable to determine how random variation subject to probabilistic occurrence (stochastic outcomes) affects the cost of the portfolio being modeled. Specifically, the Monte Carlo analysis examined the effect on the portfolio cost when customer load, CO_2 costs, natural gas prices and the wholesale market price of electricity could be different than forecasts using 900 sets of input variables, i.e. 900 "draws", from a probability distribution customized for each of these key risk factors.

Most Cost-Effective Portfolio

The Most Cost-Effective Portfolio additions resulting from the analyses described above are shown in Figure 6-A, below. Two portfolios are shown because of the current uncertainty in PNM's potential future ownership share in San Juan Unit 4. The two likely scenarios are that PNM will own either an additional 78 MW or an additional 132 MW in SJGS Unit 4 beginning in 2018 compared to PNM's current capacity in that unit. The portfolios are based on an analysis assuming the current demand forecast, the reference gas and carbon price forecasts as developed by PACE Global, and a mid-CO_2 cost projection.

FIGURE 6-A: MOST COST-EFFECTIVE PORTFOLIO ADDITIONS

Scenario Description	Revised SIP with PV3 78 MW Scenario	Revised SIP with PV3 132 MW Scenario
Load Forecast	Current	Current
Gas Pricing	PACE Reference Case	PACE Reference Case
CO2	PACE Reference Case ($11 in 2020)	PACE Reference Case ($11 in 2020)
San Juan Investment Recovery	$16,401,523	$16,401,523
SJ Retirements/Unit 4 Addition	Units 2 & 3 (Dec 2017) + 78 MW to SJ4	Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014		
2015	Red Mesa (102 MW)	Red Mesa (102 MW)
	2015 Solar (23 MW)	2015 Solar (23 MW)
2016	Aeroderivative (40 MW)	Aeroderivative (40 MW)
	Solar PV Tier 1 (40 MW)	Solar PV Tier 1 (40 MW)
2017	San Juan BART	San Juan BART
2018	Large GT (177 MW)	Large GT (177 MW)
	Palo Verde 3 (134 MW)	Palo Verde 3 (134 MW)
2019	Solar PV Tier 2 (60 MW)	
2020	Solar PV Tier 2 (20 MW)	Solar PV Tier 2 (20 MW)
	Solar PV Tier 3 (20 MW)	
2021	Solar PV Tier 3 (60 MW)	Solar PV Tier 2 (60 MW)
2022	Solar PV Tier 3 (60 MW)	Solar PV Tier 3 (40 MW)
2023	Large GT (177 MW)	Solar PV Tier 3 (60 MW)
		Wind (100 MW)
2024		Large GT (177 MW)
2025		
2026	Large GT (177 MW)	
	Wind (100 MW)	
2027		2nd Aeroderivative (40 MW)
2028		Large GT (177 MW)
2029		
2030	Reciprocating Engines (93 MW)	
2031	2nd Aeroderivative (40 MW)	Aeroderivative (40 MW)
		Solar PV Tier 3 (40 MW)
2032	Aeroderivative (40 MW)	Reciprocating Engines (93 MW)
2033	Small GT (85 MW)	

Note: PV Tier information on Table 6-W

The resources added in 2015 and La Luz in 2016 are approved by the NMPRC. All of the other resources shown on the portfolios were selected through the IRP analysis process.

PORTFOLIO SCENARIO ANALYSES

PNM examined two SJGS Unit 4 ownership scenarios under the four load forecasts and three price sensitivities. In addition to this combination of scenarios and sensitivities, PNM examined additional sensitivities related to energy efficiency, wind, solar, drought conditions and the carbon prices required by the NMPRC for use in IRP analysis. The following conclusions are reached by examining the results of this analysis:

- Load and load factor are the largest contributors to changes in the resource portfolio additions.

- Natural gas prices and expected costs associated with carbon emissions affect the timing of renewable resources additions.
- There is currently no need for additional baseload resources after 2018

Under all load and pricing conditions, the near term additions remain a mixture of solar, Palo Verde Unit 3 and gas peaking capacity. The load forecast can impact the size of the gas peaking capacity. The renewable resources added to the portfolio in the future may require additional resources to maintain operating reserve margins.

Scenario/Sensitivity Analysis

PNM examined the impact of the load forecast on future resource additions against the impact of future price projections on future resource additions. The load forecast drives the timing and type of new resource additions throughout the study period to a greater extent than assumed prices of natural gas and carbon emissions. The following scenarios and sensitivities illustrated in Figure 6-B were considered for portfolios with an assumed 78 MW capacity addition in SJGS Unit 4 and an assumed 132 MW capacity addition in SJGS Unit 4.

FIGURE 6-B: LOAD AND PRICING SCENARIO/SENSITIVITIES

	Pricing Scenarios		
Load Forecast	**Reference**	**High gas/High carbon**	**Low gas/low carbon**
Current	X	X	X
IRP High	X	X	X
IRP Mid	X	X	X
IRP High	X	X	X

Sensitivity to Load

The load forecast drives the timing and type of new resource additions. For this reason it is important to see the effects on the portfolios under different load variations. As discussed in Section 4, PNM developed four load forecasts for use in this IRP. The portfolios necessary to illustrate the conclusions are provided here. All of the portfolios generated for this analysis are provided in the Appendix F of this report.

Sensitivity to Load – 78 MW

Figure 6-C shows the resulting portfolios under the four load forecasts if PNM's current ownership share in SJGS Unit 4 increases by 78 MW. Resource selection across all four portfolios is similar. In the near term, 40 MW of solar PV and the 134 MW Palo Verde Unit 3 resource additions are selected in all cases as replacements for SJGS capacity to be retired under the Revised SIP. The size of the gas peaker planned for 2018 varies depending upon the load forecast, ranging from 177 MW in size for the current and high load forecasts to 143 MW in the mid load forecast case to nothing selected the low load

forecast case. After 2018, solar resources are added in the quantities needed to maintain reserve margins. After adding solar, additional gas peaking and wind resources are added in all cases.

FIGURE 6-C: LOAD COMPARISONS FOR 78 MW CASE

LOAD COMPARISON - 78 MW								
Scenario Description	Reserve Margin		Reserve Margin		Reserve Margin		Reserve Margin	
Load Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
Gas Pricing		PACE Reference Case		PACE Reference Case		PACE Reference Case		PACE Reference Case
CO2		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)
Energy Efficiency Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
PV DG Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
Renewable Procurements		2014 REPP		2014 REPP		2014 REPP		2014 REPP
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan O&M Harvest Savings		Units 2 & 3		Units 2 & 3		Units 2 & 3		Units 2 & 3
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	18.0%		13.4%		14.7%		15.2%	
2015	17.8%	Red Mesa (102 MW)	13.0%	Red Mesa (102 MW)	15.5%	Red Mesa (102 MW)	17.1%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	15.5%	Aeroderivative (40 MW)	18.8%	Aeroderivative (40 MW)	21.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	14.6%	San Juan BART	18.4%	San Juan BART	21.1%	San Juan BART
2018	14.6%	Large GT (177 MW)	14.7%	Large GT (177 MW)	15.2%	Large GT (143 MW)	14.1%	Palo Verde 3 (134 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Solar PV Tier 2 (80 MW)
				Solar PV Tier 2 (60 MW)				
2019	14.4%	Solar PV Tier 2 (60 MW)	14.1%		14.8%		14.4%	
2020	14.2%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (20 MW)	14.7%		15.2%	
		Solar PV Tier 3 (20 MW)						
2021	14.2%	Solar PV Tier 3 (60 MW)	14.0%	Solar PV Tier 3 (20 MW)	14.5%	Wind (100 MW)	15.2%	
2022	14.3%	Solar PV Tier 3 (60 MW)	14.1%	Solar PV Tier 3 (20 MW)	14.3%		15.4%	
2023	20.4%	Large GT (177 MW)	14.3%	Solar PV Tier 3 (40 MW)	14.5%	Solar PV Tier 2 (20 MW)	15.2%	
2024	18.2%		14.1%	Solar PV Tier 3 (40 MW)	14.1%		14.5%	
2025	15.9%		20.9%	Large GT (177 MW)	14.1%	Solar PV Tier 2 (20 MW)	14.0%	Wind (100 MW)
2026	21.3%	Large GT (177 MW)	19.8%	Wind (100 MW)	14.1%	Solar PV Tier 2 (20 MW)	14.4%	Solar PV Tier 3 (40 MW)
		Wind (100 MW)						
2027	18.8%		18.4%		14.5%	Solar PV Tier 2 (20 MW)	14.0%	Solar PV Tier 3 (20 MW)
						Solar PV Tier 3 (20 MW)		
2028	16.4%		17.2%		14.3%	Solar PV Tier 3 (20 MW)	14.5%	Solar PV Tier 3 (40 MW)
2029	14.1%		15.5%		14.4%	Solar PV Tier 3 (40 MW)	14.4%	Solar PV Tier 3 (40 MW)
2030	15.3%	Reciprocating Engines (93 MW)	14.2%		14.5%	Solar PV Tier 3 (40 MW)	15.5%	2nd Aeroderivative (40 MW)
2031	14.8%	2nd Aeroderivative (40 MW)	17.3%	Reciprocating Engines (93 MW)	15.8%	2nd Aeroderivative (40 MW)	14.6%	
				Solar PV Tier 3 (20 MW)		Solar PV Tier 3 (20 MW)		
2032	14.2%	Aeroderivative (40 MW)	15.5%		14.2%		14.9%	Aeroderivative (40 MW)
2033	15.0%	Small GT (85 MW)	14.3%		15.1%	Aeroderivative (40 MW)	14.1%	
PRESENT VALUE PORTFOLIO COST	**$6,848,233,021**		**$6,655,342,435**		**$6,567,026,200**		**$6,245,453,116**	
20-Year Loss of Load (Hours)	**28.39**		**47.63**		**64.68**		**93.25**	
20-Year CO2 (Metric Tons)	**101,289,756**		**100,064,035**		**101,692,115**		**95,834,605**	

SENSITIVITY TO LOAD – 132 MW

Figure 6-D shows the resulting portfolios under the four load forecasts if PNM's current ownership share in SJGS Unit 4 increases by 132 MW. Resource selection across all four portfolios is similar not just to each other but to the resources selected in the 78 MW case. In the near term, 40 MW of solar PV and the 134 MW Palo Verde Unit 3 resource additions are selected in all cases as replacements for SJGS capacity to be retired under the Revised SIP. The size of the gas peaker planned for 2018 varies depending upon the load forecast, ranging from 177 MW in size for the current and high load forecasts to nothing selected in the mid and low load forecast cases. After 2018, solar resources are added in the quantities needed to maintain reserve margins. The 132 MW portfolios differ from the 78 MW portfolios more after 2018 because the additional capacity at SJGS means less need in the early years for resources to maintain reserve margin.

FIGURE 6-D: LOAD COMPARISONS FOR 132 MW CASE

LOAD COMPARISON - 132 MW								
Scenario Description	Reserve Margin		Reserve Margin		Reserve Margin		Reserve Margin	
Load Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
Gas Pricing		PACE Reference Case		PACE Reference Case		PACE Reference Case		PACE Reference Case
CO2		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)
Energy Efficiency Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
PV DG Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
Renewable Procurements		2014 REPP		2014 REPP		2014 REPP		2014 REPP
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan O&M Harvest Savings		Units 2 & 3		Units 2 & 3		Units 2 & 3		Units 2 & 3
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	18.0%		13.4%		14.7%		15.2%	
2015	17.8%	Red Mesa (102 MW)	13.0%	Red Mesa (102 MW)	15.5%	Red Mesa (102 MW)	17.1%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	15.5%	Aeroderivative (40 MW)	18.8%	Aeroderivative (40 MW)	21.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	14.6%	San Juan BART	18.4%	San Juan BART	21.1%	San Juan BART
2018	17.2%	Large GT (177 MW)	15.1%	Large GT (177 MW)	14.3%	Palo Verde 3 (134 MW)	14.6%	Palo Verde 3 (134 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Solar PV Tier 2 (80 MW)		Solar PV Tier 2 (20 MW)
						Solar PV Tier 3 (20 MW)		
2019	14.8%		14.5%		14.5%	Solar PV Tier 3 (20 MW)	14.8%	
2020	14.1%	Solar PV Tier 2 (20 MW)	14.6%	Solar PV Tier 2 (20 MW)	14.3%		15.7%	
2021	14.7%	Solar PV Tier 2 (60 MW)	14.2%	Wind (100 MW)	14.4%	Solar PV Tier 3 (20 MW)	15.7%	
2022	14.2%	Solar PV Tier 3 (40 MW)	14.4%	Solar PV Tier 2 (20 MW)	14.2%		15.9%	
2023	14.0%	Solar PV Tier 3 (60 MW)	14.2%	Solar PV Tier 2 (20 MW)	14.3%	Solar PV Tier 3 (20 MW)	15.6%	
		Wind (100 MW)						
2024	19.9%	Large GT (177 MW)	14.2%	Solar PV Tier 2 (20 MW)	14.4%	Solar PV Tier 3 (20 MW)	15.0%	
				Solar PV Tier 3 (20 MW)				
2025	17.5%		14.0%	Solar PV Tier 3 (40 MW)	14.3%	Solar PV Tier 3 (20 MW)	14.2%	
2026	15.1%		14.2%	Solar PV Tier 3 (60 MW)	14.1%	Solar PV Tier 3 (20 MW)	14.2%	Solar PV Tier 2 (20 MW)
2027	14.4%	2nd Aeroderivative (40 MW)	14.7%	2nd Aeroderivative (40 MW)	15.4%	2nd Aeroderivative (40 MW)	14.3%	Solar PV Tier 2 (20 MW)
						Wind (100 MW)		Wind (100 MW)
2028	19.4%	Large GT (177 MW)	14.0%	Solar PV Tier 3 (20 MW)	14.6%		14.4%	Solar PV Tier 2 (20 MW)
2029	16.9%		20.1%	Large GT (177 MW)	15.6%	Aeroderivative (40 MW)	14.3%	Solar PV Tier 3 (40 MW)
2030	14.5%		18.7%		14.6%		14.5%	Solar PV Tier 3 (40 MW)
2031	14.8%	Aeroderivative (40 MW)	17.4%		17.2%	Small GT (85 MW)	14.1%	Solar PV Tier 3 (20 MW)
		Solar PV Tier 3 (40 MW)						
2032	16.3%	Reciprocating Engines (93 MW)	15.6%		15.6%		14.5%	2nd Aeroderivative (40 MW)
2033	14.0%		14.3%		14.7%		14.7%	Solar PV Tier 3 (40 MW)
PRESENT VALUE PORTFOLIO COST	**$6,852,061,359**		**$6,660,633,231**		**$6,549,065,930**		**$6,271,415,605**	
20-Year Loss of Load (Hours)	**32.15**		**52.44**		**127.93**		**112.85**	
20-Year CO2 (Metric Tons)	**103,932,981**		**101,877,265**		**101,660,462**		**100,243,825**	

LOAD COMPARISON SUMMARY

The following observations can be made from analyzing across the four load forecasts and the 78 and 132 ownership cases for SJGS Unit 4:

- The near term portfolio additions for Palo Verde Unit 3 and 40 MW solar are unaffected by changes in the load forecast;
- The 2018 gas peaker size depends upon the load forecast but is 177 MW in the current load forecast case for either SJGS Unit 4 ownership assumption;
- Higher demand results in solar resource additions occurring a year or two sooner compared to lower demand cases;
- Higher energy sales accelerates the timing of wind resource additions;
- Higher demand results in earlier and larger conventional resources being added; and
- No baseload resources are indicated throughout the study period other than the need to replace SJGS Units 2 and 3 capacity with Palo Verde Unit 3 and additional capacity in SJGS Unit 4.

SENSITIVITY TO PRICE

The cost of fuel and the future cost associated with carbon emissions have an impact on the additional resources chosen over the next twenty years. The load forecast analysis shows that under all the load scenarios, the result is a mix of natural gas and renewable resources after capacity retired at SJGS is replaced. For this IRP, PNM hired PACE to develop three sets of price curves for use in the analysis. Similar to load, price impacts are examined for 78 MW and 132 MW cases of additional capacity at SJGS Unit 4. The use of the current load forecast is provided here to illustrate the conclusions. All of the portfolios generated for this analysis are provided in Appendix F.

The portfolios have less sensitivity to price than to load. As the portfolio comparisons in Figure 6-E and 6-F illustrate, the higher the gas and carbon emission prices, the sooner wind resources are added to the portfolios. This is best illustrated by the timing of the first addition of a wind resource in each portfolio. Wind is selected as soon as 2018 in the high gas, high carbon runs and as late as 2029 in the low gas, low carbon runs. This trend is the same for both the 78 and 132 MW case. Additional information on the selection of wind in the portfolios is provided in the wind sensitivity section.

FIGURE 6-E: PRICE COMPARISONS FOR 78 MW CASE

PRICE COMPARISON - 78 MW						
Scenario Description	Reserve Margin		Reserve Margin		Reserve Margin	
Load Forecast		Current		Current		Current
Gas Pricing		PACE Reference Case		PACE High Gas/High Carbon		PACE Low Gas/Low Carbon Case
CO2		PACE Reference Case ($11 in 2020)		PACE Hi Gas/Hi Carbon Case ($11 in 2018)		PACE Low Gas/Low Carbon Case ($10 in 2027)
Energy Efficiency Forecast		Current		Current		Current
PV DG Forecast		Current		Current		Current
Renewable Procurements		2014 REPP		2014 REPP		2014 REPP
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan O&M Harvest Savings		Units 2 & 3		Units 2 & 3		Units 2 & 3
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	18.0%		18.0%		18.0%	
2015	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	17.8%	San Juan BART	17.8%	San Juan BART
2018	14.6%	Large GT (177 MW)	14.8%	Large GT (177 MW)	14.6%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
				Wind (100 MW)		
2019	14.4%	Solar PV Tier 2 (60 MW)	14.7%	Solar PV Tier 2 (60 MW)	14.4%	Solar PV Tier 2 (60 MW)
2020	14.2%	Solar PV Tier 2 (20 MW)	14.4%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (20 MW)
		Solar PV Tier 3 (20 MW)		Solar PV Tier 3 (20 MW)		Solar PV Tier 3 (20 MW)
2021	14.2%	Solar PV Tier 3 (60 MW)	15.5%	Solar PV Tier 3 (100 MW)	14.2%	Solar PV Tier 3 (60 MW)
2022	14.3%	Solar PV Tier 3 (60 MW)	14.5%	Solar PV Tier 3 (20 MW)	20.9%	Large GT (177 MW)
2023	20.4%	Large GT (177 MW)	20.6%	Large GT (177 MW)	18.9%	
2024	18.2%		18.5%		16.8%	
2025	15.9%		16.1%		14.4%	
2026	21.3%	Large GT (177 MW)	21.3%	Large GT (177 MW)	19.7%	Large GT (177 MW)
		Wind (100 MW)				
2027	18.8%		18.8%		17.2%	
2028	16.4%		16.4%		14.8%	
2029	14.1%		14.1%		14.1%	Solar PV Tier 3 (60 MW)
						Wind (100 MW)
2030	15.3%	Reciprocating Engines (93 MW)	15.3%	Reciprocating Engines (93 MW)	15.3%	Reciprocating Engines (93 MW)
2031	14.8%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)
2032	14.2%	Aeroderivative (40 MW)	14.2%	Aeroderivative (40 MW)	14.2%	Aeroderivative (40 MW)
2033	15.0%	Small GT (85 MW)	15.0%	Small GT (85 MW)	15.0%	Small GT (85 MW)
PRESENT VALUE PORTFOLIO COST	**$6,848,233,021**		**$7,664,015,969**		**$6,238,315,880**	
20-Year Loss of Load (Hours)	**28.39**		**24.41**		**27.92**	
20-Year CO2 (Metric Tons)	**101,289,756**		**99,247,138**		**102,933,175**	

FIGURE 6-F: PRICE COMPARISONS FOR 132 MW CASE

PRICE COMPARISON - 132 MW						
Scenario Description	Reserve Margin		Reserve Margin		Reserve Margin	
Load Forecast		Current		Current		Current
Gas Pricing		PACE Reference Case		PACE High Gas/High Carbon		PACE Low Gas/Low Carbon Case
CO2		PACE Reference Case ($11 in 2020)		PACE Hi Gas/Hi Carbon Case ($11 in 2018)		PACE Lo Gas/Lo Carbon Case ($10 in 2027)
Energy Efficiency Forecast		Current		Current		Current
PV DG Forecast		Current		Current		Current
Renewable Procurements		2014 REPP		2014 REPP		2014 REPP
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan O&M Harvest Savings		Units 2 & 3		Units 2 & 3		Units 2 & 3
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	18.0%		18.0%		18.0%	
2015	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	17.8%	San Juan BART	17.8%	San Juan BART
2018	17.2%	Large GT (177 MW)	15.8%	Large GT (143 MW)	17.2%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
				Wind (100 MW)		
2019	14.8%		14.2%	Solar PV Tier 2 (20 MW)	14.8%	
2020	14.1%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (40 MW)	14.1%	Solar PV Tier 2 (20 MW)
2021	14.7%	Solar PV Tier 2 (60 MW)	15.4%	Solar PV Tier 2 (20 MW)	14.7%	Solar PV Tier 2 (60 MW)
				Solar PV Tier 3 (80 MW)		
2022	14.2%	Solar PV Tier 3 (40 MW)	14.4%	Solar PV Tier 3 (20 MW)	14.2%	Solar PV Tier 3 (40 MW)
2023	14.0%	Solar PV Tier 3 (60 MW)	20.5%	Large GT (177 MW)	20.3%	Large GT (177 MW)
		Wind (100 MW)				
2024	19.9%	Large GT (177 MW)	18.4%		18.2%	
2025	17.5%		17.0%	Solar PV Tier 3 (40 MW)	15.8%	
2026	15.1%		14.6%		14.4%	Solar PV Tier 3 (40 MW)
2027	14.4%	2nd Aeroderivative (40 MW)	19.7%	Large GT (177 MW)	19.5%	Large GT (177 MW)
2028	19.4%	Large GT (177 MW)	17.2%		17.1%	
2029	16.9%		14.9%		14.7%	
2030	14.5%		14.0%	2nd Aeroderivative (40 MW)	14.1%	2nd Aeroderivative (40 MW)
						Wind (100 MW)
2031	14.8%	Aeroderivative (40 MW)	15.5%	Reciprocating Engines (93 MW)	15.6%	Reciprocating Engines (93 MW)
		Solar PV Tier 3 (40 MW)				
2032	16.3%	Reciprocating Engines (93 MW)	15.0%	Aeroderivative (40 MW)	14.3%	Solar PV Tier 3 (40 MW)
2033	14.0%		15.7%	Small GT (85 MW)	14.0%	Aeroderivative (40 MW)
						Solar PV Tier 3 (20 MW)
PRESENT VALUE PORTFOLIO COST	**$6,852,061,359**		**$7,670,910,744**		**$6,223,888,831**	
20-Year Loss of Load (Hours)	**32.15**		**28.82**		**32.81**	
20-Year CO2 (Metric Tons)	**103,932,981**		**101,648,873**		**106,463,398**	

Solar continues to be selected to maintain reserve margin. In the high gas and high carbon case for the 132 MW case, solar is added sooner, which lowers the size of the gas peaking plant in 2018 from 177 MW to 143.

The pricing sensitivity yields the following observations:

- The near term additions of Palo Verde Unit 3, 40 MW solar addition and a gas turbine remain unchanged in least cost portfolios;
- Wind and solar resources are accelerated in the near term under high pricing case;
- Pricing does not affect the near term portfolios for reference and low gas/low carbon case;
- Solar additions are followed up with a conventional resource - usually a gas peaker; and,
- Other than the need to replace SJGS Units 2 and 3 capacity with Palo Verde Unit 3 and additional capacity in SJGS Unit 4, no baseload resources are indicated throughout the study period.

ENERGY EFFICIENCY SENSITIVITY

PNM analyzed two energy efficiency sensitivities off the current load forecast. The projections for the base assumption and the two sensitivities presented below in Figure 6-G are based on the energy savings that PNM estimates will be saved over time through implementation of energy efficiency programs. The range of savings was determined by varying the amount of savings achieved per dollar spent. PNM first determines gross savings which are the total savings from all participants in the PNM programs. For purposes of reporting savings to the NMPRC that qualify for achieving the goals identified in the EUEA, utilities must reduce the gross savings to account for the impact of free-rider participants. A free-rider is a participant in the program that would have implemented the energy efficiency measure even without the utility incentives. The savings from these participants are subtracted from gross savings and the resulting net savings are reported annually to the NMPRC. Figure 6-G shows the incremental annual net savings from 2008 through 2033. The savings through 2013 represent actual results based on savings reported to the NMPRC. The two sensitivity cases are shown as dashed lines.

Figure 6-G: Historical and Projected Annual Energy Efficiency Savings

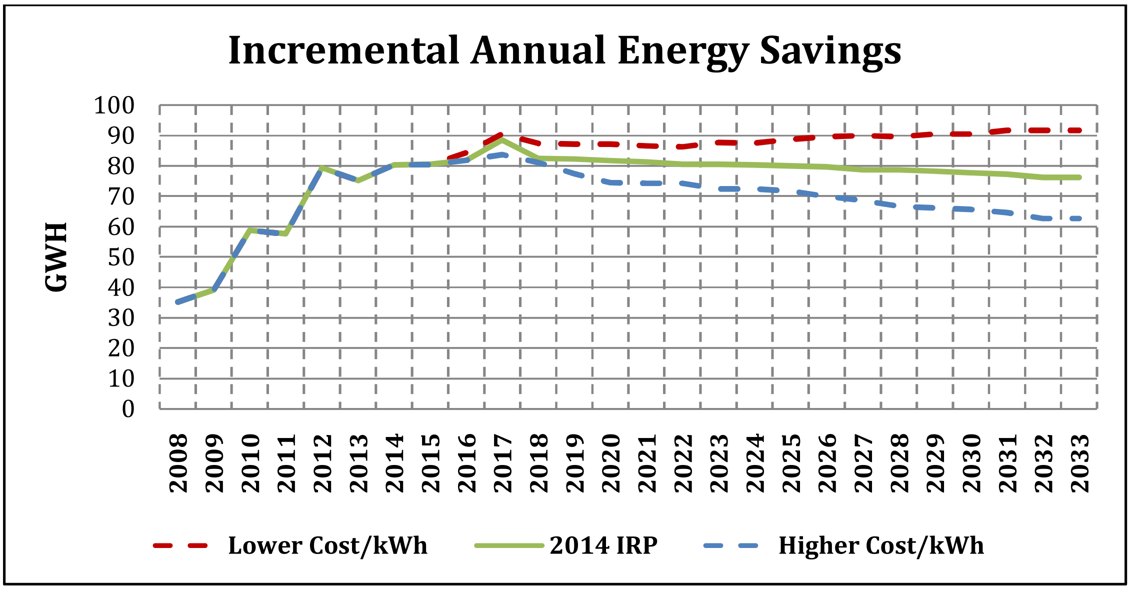
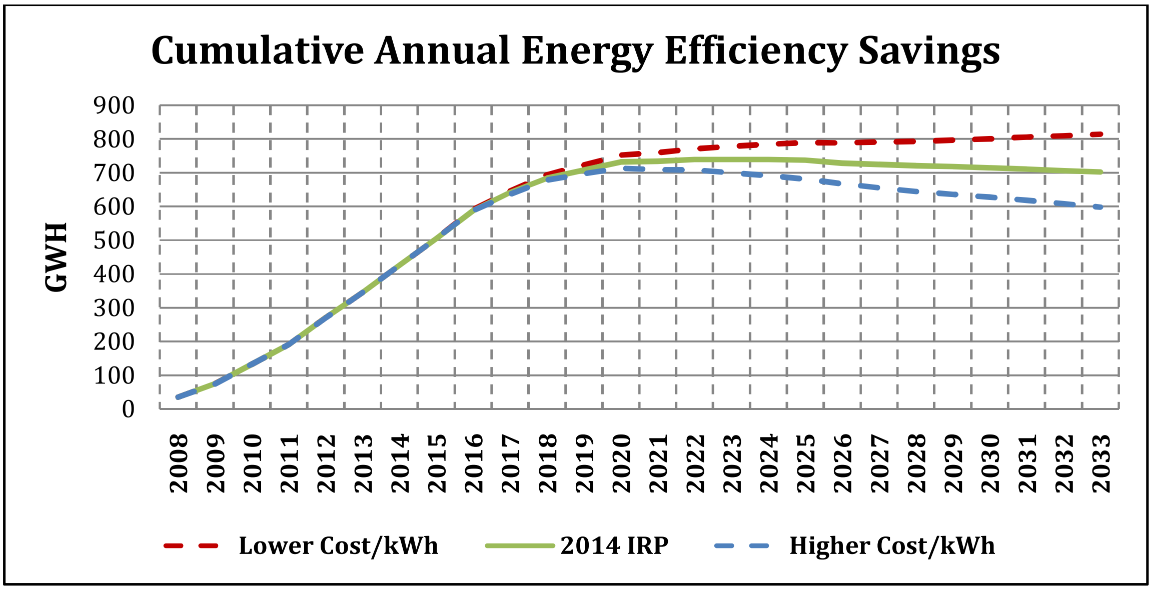


Figure 6-H shows the cumulative net savings as a result of energy efficiency program deployment beginning in 2008 and continuing through the planning period. The annual savings achieved in EE programs in any particular year, due to new customer participants, will continue to save energy throughout the effective useful life of each program. Therefore, the impact is cumulative as shown in Figure 6-H. The savings through 2013 represent actual results based on savings reported to the NMPRC. The two sensitivity cases are shown as dashed lines.

Figure 6-H: Historical and Projected Cumulative Savings



Across both EE sensitivities the least cost portfolio is very similar until 2026. Small differences are found in the magnitude and timing of solar additions in the 2019-2020 timeframe but for the most part these are similar portfolios, as shown on Figure 6-I. The magnitude of this solar addition is different under the EE Low and EE high sensitivities. If the impact of EE is lower than predicted, more solar is added. Since the energy efficiency sensitivities have no effect on the near term portfolio additions and minor changes in the mid-term additions, it can be concluded that sensitivity to the savings achieved by energy efficiency does not impact the supply side resource additions to the portfolio.

Figure 6-I: 78 MW EE Forecast Portfolio Comparisons

PORTFOLIO COMPARISON - MID LOAD, MID GAS, MID CARBON						
Scenario Description	Reserve Margin	**Revised SIP with PV3 78 MW to SJ4**	Reserve Margin	**Revised SIP with PV3 78 MW to SJ4 + EE Low**	Reserve Margin	**Revised SIP with PV3 78 MW to SJ4 + EE High**
Load Forecast		Current Forecast		Current Forecast		Current Forecast
Gas Pricing		PACE Reference Case		PACE Reference Case		PACE Reference Case
CO2		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	18.0%		18.1%		18.1%	
2015	17.8%	Red Mesa (102 MW)	17.9%	Red Mesa (102 MW)	17.9%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	20.1%	Aeroderivative (40 MW)	20.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	18.2%	San Juan BART	18.3%	San Juan BART
2018	14.6%	Large GT (177 MW)	14.9%	Large GT (177 MW)	15.0%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
2019	14.4%	Solar PV Tier 2 (60 MW)	14.0%	**Solar PV Tier 2 (40 MW)**	14.3%	**Solar PV Tier 2 (40 MW)**
2020	14.2%	Solar PV Tier 2 (20 MW)	14.2%	**Solar PV Tier 2 (40 MW)**	14.5%	**Solar PV Tier 2 (40 MW)**
		Solar PV Tier 3 (20 MW)				
2021	14.2%	Solar PV Tier 3 (60 MW)	14.4%	Solar PV Tier 3 (60 MW)	14.3%	**Solar PV Tier 3 (40 MW)**
				Wind (100 MW)		**Wind (100 MW)**
2022	14.3%	Solar PV Tier 3 (60 MW)	14.0%	**Solar PV Tier 3 (40 MW)**	14.1%	**Solar PV Tier 3 (40 MW)**
2023	20.4%	Large GT (177 MW)	20.2%	Large GT (177 MW)	20.4%	Large GT (177 MW)
2024	18.2%		17.9%		18.2%	
2025	15.9%		15.8%		16.2%	
2026	21.3%	Large GT (177 MW)	14.1%	**Solar PV Tier 3 (40 MW)**	14.2%	**Solar PV Tier 3 (20 MW)**
		Wind (100 MW)				
2027	18.8%		19.2%	**Large GT (177 MW)**	19.4%	**Large GT (177 MW)**
2028	16.4%		16.8%		17.0%	
2029	14.1%		14.4%		14.7%	
2030	15.3%	Reciprocating Engines (93 MW)	15.5%	Reciprocating Engines (93 MW)	14.3%	**2nd Aeroderivative (40 MW)**
						Solar PV Tier 3 (20 MW)
2031	14.8%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)	14.1%	Aeroderivative (40 MW)
						Solar PV Tier 3 (20 MW)
2032	14.2%	Aeroderivative (40 MW)	15.3%	**Small GT (85 MW)**	15.3%	**Reciprocating Engines (93 MW)**
2033	15.0%	Small GT (85 MW)	14.6%	**Aeroderivative (40 MW)**	16.0%	Small GT (85 MW)
PRESENT VALUE PORTFOLIO COST		**$6,848,233,021**		**$6,855,984,733**		**$6,802,493,410**
20-Year CO2 (Metric Tons)		**101,289,756**		**101,108,278**		**100,494,186**

Notes:
1. All portfolios assume net retirement of 340 MW at San Juan Generating Station
2. Text in **BLUE** signifies resource is selected sooner as compared to the same scenario description in the MidLoadMidGas/Carbon portfolio
3. Text in **RED** signifies resource is selected later as compared to the same scenario description in the MidLoadMidGas/Carbon portfolio
4. Text in **GREEN** signifies resource is different from what is selected in the MidLoadMidGas/Carbon portfolio

The modeling for the 132 MW scenario is provided in Figure 6-J. Across the low EE sensitivity the least cost portfolio is very similar until 2027. Small differences are found in the magnitude and timing of solar addition in the 2021 but for the most part these are similar portfolios. After 2031, the energy efficiency profile begins to delay a peaking resource but because it is towards the tail end of the planning period it is considered only minimally. More importantly, is that if the projection of EE is lower than predicted it would not affect the portfolio by adding more resources.

Under the high EE case, the earliest change occurs in the mid-term in 2021. Solar resources are added every other year in larger sizes rather than added in smaller increments by year. A look at the reserve margins show that these additions are used as low cost capacity additions and staggered bi-annually so that the timing of these additions can be considered flexible. As expected, with the higher EE conventional resources are pushed out in the later years.

A comparison of the costs of across these portfolios shows the low EE sensitivity is the most costly even though the portfolios are relatively the same. The cost of the portfolio rises as a direct result of the increased generation to meet the lower energy contribution from the forecast. In a similar vein, high EE is seen as the least costly because resource additions are delayed and the existing sources can be backed down to meet the lower need.

Overall, it can be concluded:

- The range of potential energy efficiency savings does not affect the near term additions of Palo Verde 3, the 40 MW solar addition or the larger scale gas turbine identified as replacement options for retired capacity at SJGS,
- Higher savings per dollar spent on energy efficiency will affect the timing of solar additions, and
- Lower savings per dollar spent on energy efficiency does not impact supply side resource additions in the most cost-effective portfolio.

Figure 6-J: 132 MW EE Forecast Portfolio Comparisons

PORTFOLIO COMPARISON - MID LOAD, MID GAS, MID CARBON						
Scenario Description	Reserve Margin	**Revised SIP with PV3 132 MW to SJ4**	Reserve Margin	**Revised SIP with PV3 132 MW to SJ4 + EE Low**	Reserve Margin	**Revised SIP with PV3 132 MW to SJ4 + EE High**
Load Forecast		Current Forecast		Current Forecast		Current Forecast
Gas Pricing		PACE Reference Case		PACE Reference Case		PACE Reference Case
CO2		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	18.0%		18.1%		18.1%	
2015	17.8%	Red Mesa (102 MW)	17.9%	Red Mesa (102 MW)	17.9%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	20.1%	Aeroderivative (40 MW)	20.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	18.2%	San Juan BART	18.3%	San Juan BART
2018	17.2%	Large GT (177 MW)	17.5%	Large GT (177 MW)		Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)	17.7%	Palo Verde 3 (134 MW)
2019	14.8%		15.2%			
2020	14.1%	Solar PV Tier 2 (20 MW)	14.6%	Solar PV Tier 2 (20 MW)	15.4%	
2021	14.7%	Solar PV Tier 2 (60 MW)	14.4%	**Solar PV Tier 2 (40 MW)**	14.2%	**Solar PV Tier 2 (40 MW)**
2022	14.2%	Solar PV Tier 3 (40 MW)	14.2%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (40 MW)
				Solar PV Tier 3 (20 MW)	14.3%	
2023	14.0%	Solar PV Tier 3 (60 MW)	14.1%	Solar PV Tier 3 (60 MW)	14.0%	Solar PV Tier 3 (60 MW)
		Wind (100 MW)		Wind (100 MW)	14.2%	
2024	19.9%	Large GT (177 MW)	19.8%	Large GT (177 MW)		Solar PV Tier 3 (80 MW)
						Wind (100 MW)
2025	17.5%		17.7%		14.0%	**2nd Aeroderivative (40 MW)**
2026	15.1%		15.0%		19.2%	**Large GT (177 MW)**
2027	14.4%	2nd Aeroderivative (40 MW)	14.1%	**Solar PV Tier 3 (60 MW)**	16.8%	
2028	19.4%	Large GT (177 MW)	19.0%	Large GT (177 MW)	14.5%	
2029	16.9%		16.6%		19.4%	**Large GT (177 MW)**
2030	14.5%		14.0%		16.9%	
2031	14.8%	Aeroderivative (40 MW)	15.3%	**Reciprocating Engines (93 MW)**	14.7%	
		Solar PV Tier 3 (40 MW)				
2032	16.3%	Reciprocating Engines (93 MW)	14.3%	**2nd Aeroderivative (40 MW)**	15.8%	Reciprocating Engines (93 MW)
2033	14.0%		15.1%	**Small GT (85 MW)**	15.0%	**Aeroderivative (40 MW)**
PRESENT VALUE PORTFOLIO COST		**$6,852,061,359**		**$6,857,828,377**		**$6,805,874,228**
20-Year CO2 (Metric Tons)		**103,932,981**		**104,390,462**		**103,163,243**

Drought Sensitivity

PNM modeled water curtailments at SJGS to simulate the effects of drought during 2015-2017. As illustrated in Figure 6-K; there is no difference in the portfolio before and after the simulated drought takes effect under the 78 MW case. The reduced generation did not change the near term portfolio, cause a change in the type of resources that were already existing as replacement power sources or add any new resources to the portfolio. The unchanged portfolio, however, means that a change in the dispatch occurred and existing, more costly generation is used to replace the lost baseload generation. Additionally since the portfolio remained alike, the increase in the loss of load hours tells us that any unserved energy would be met using emergency energy purchased from the wholesale market at higher costs. Those two actions then translate to higher overall portfolio costs as seen the in $69 million difference in portfolios.

Figure 6-K: 78 MW Drought Sensitivity Portfolio Comparison

PORTFOLIO COMPARISON - MID LOAD, MID GAS, MID CARBON				
Scenario Description	Reserve Margin	**Revised SIP with PV3 78 MW to SJ4**	Reserve Margin	**Revised SIP with PV3 78 MW to SJ4 + Drought Sensitivity**
Load Forecast		Current Forecast		Current Forecast
Gas Pricing		PACE Reference Case		PACE Reference Case
CO2		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)
San Juan Investment Recovery		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	18.0%		18.0%	
2015	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	17.8%	San Juan BART
2018	14.6%	Large GT (177 MW)	14.6%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
2019	14.4%	Solar PV Tier 2 (60 MW)	14.4%	Solar PV Tier 2 (60 MW)
2020	14.2%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (20 MW)
		Solar PV Tier 3 (20 MW)		Solar PV Tier 3 (20 MW)
2021	14.2%	Solar PV Tier 3 (60 MW)	14.2%	Solar PV Tier 3 (60 MW)
2022	14.3%	Solar PV Tier 3 (60 MW)	14.3%	Solar PV Tier 3 (60 MW)
2023	20.4%	Large GT (177 MW)	20.4%	Large GT (177 MW)
2024	18.2%		18.2%	
2025	15.9%		15.9%	
2026	21.3%	Large GT (177 MW)	21.3%	Large GT (177 MW)
		Wind (100 MW)		Wind (100 MW)
2027	18.8%		18.8%	
2028	16.4%		16.4%	
2029	14.1%		14.1%	
2030	15.3%	Reciprocating Engines (93 MW)	15.3%	Reciprocating Engines (93 MW)
2031	14.8%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)
2032	14.2%	Aeroderivative (40 MW)	14.2%	Aeroderivative (40 MW)
2033	15.0%	Small GT (85 MW)	15.0%	Small GT (85 MW)
PRESENT VALUE PORTFOLIO COST		**$6,848,233,021**		**$6,917,332,357**
20-Year Loss of Load (Hours)		**28.39**		**94.34**
20-Year CO2 (Metric Tons)		**101,289,756**		**101,108,278**

Under the 132 MW case, this same trend occurs as shown in Figure 6-L. The portfolios are exactly the same and the loss of load hours is over three times greater than the portfolio without the drought. The delta between the two portfolio costs and the emissions saved are greater here ($71 million) due to greater sourcing of existing coal generation. A larger amount of lower costing energy would need to be replaced with more costly sources thereby increasing the overall portfolio costs.

For both these cases, a drought sensitivity shows no effect on the near term portfolio additions of Palo Verde Unit 3, 40 MW of solar and large gas turbine. Nor does it show any changes to future portfolio additions.

Figure 6-L: 78 MW Drought Sensitivity Portfolio Comparison

PORTFOLIO COMPARISON - MID LOAD, MID GAS, MID CARBON				
Scenario Description	**Reserve Margin**	**Revised SIP with PV3 132 MW to SJ4**	**Reserve Margin**	**Revised SIP with PV3 132 MW to SJ4 + Drought Sensitivity**
Load Forecast		Current Forecast		Current Forecast
Gas Pricing		PACE Reference Case		PACE Reference Case
CO2		PACE Reference Case ($11 in 2020)		PACE Reference Case ($11 in 2020)
San Juan Investment Recovery		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	18.0%		18.0%	
2015	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	17.8%	San Juan BART
2018	17.2%	Large GT (177 MW)	17.2%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
2019	14.8%		14.8%	
2020	14.1%	Solar PV Tier 2 (20 MW)	14.1%	Solar PV Tier 2 (20 MW)
2021	14.7%	Solar PV Tier 2 (60 MW)	14.7%	Solar PV Tier 2 (60 MW)
2022	14.2%	Solar PV Tier 3 (40 MW)	14.2%	Solar PV Tier 3 (40 MW)
2023	14.0%	Solar PV Tier 3 (60 MW)	14.0%	Solar PV Tier 3 (60 MW)
		Wind (100 MW)		Wind (100 MW)
2024	19.9%	Large GT (177 MW)	19.9%	Large GT (177 MW)
2025	17.5%		17.5%	
2026	15.1%		15.1%	
2027	14.4%	2nd Aeroderivative (40 MW)	14.4%	2nd Aeroderivative (40 MW)
2028	19.4%	Large GT (177 MW)	19.4%	Large GT (177 MW)
2029	16.9%		16.9%	
2030	14.5%		14.5%	
2031	14.8%	Aeroderivative (40 MW)	14.8%	Aeroderivative (40 MW)
		Solar PV Tier 3 (40 MW)		Solar PV Tier 3 (40 MW)
2032	16.3%	Reciprocating Engines (93 MW)	16.3%	Reciprocating Engines (93 MW)
2033	14.0%		14.0%	
PRESENT VALUE PORTFOLIO COST		**$6,852,061,359**		**$6,923,389,733**
20-Year Loss of Load (Hours)		**32.15**		**102.51**
20-Year CO2 (Metric Tons)		**103,932,981**		**102,490,633**

Wind Sensitivity

During the 2014 IRP planning process, PNM became aware of proposed power purchases of wind energy by another New Mexico electric utility at energy costs much lower than PNM had seen or received in its previous renewable RFP's. In addition, the IRP public advisory group expressed their concerns regarding the initial pricing PNM was using in its portfolio analysis assumptions. For both these reasons, PNM analyzed the various characteristics of a wind power purchase contract and impact of including a wind resource in PNM's most cost-effective portfolio. This wind sensitivity analysis was designed to determine the main driver that would result in wind energy being added to PNM's portfolio of resources in a cost-effective manner. The goals of the wind sensitivity analysis were to;

1. Evaluate a range of PPA pricing for new wind resources
2. Evaluate a range of capacity factors for new wind resources
3. Evaluate a range of facility sizes for new wind resources

The wind sensitivity analysis was conducted utilizing the Strategist® modeling tool. The identical data for the existing system of resources, IRP mid load forecast and IRP new alternative resources were used for each sensitivity. For each set of sensitivities modeled, the measure of the impact was determined by the year in which a wind resource was chosen in the least cost portfolio. The following figures graphically show how each sensitivity affects when a wind facility is chosen.

To conduct the analysis PNM needed to define what ranges of pricing, capacity factors and facility sizes to use. The pricing used from PNM's 2012 renewable RFP was set as the price ceiling, with subsequent pricing sensitivities reducing the first year starting price by $5.00 per MWh. PNM used approximate pricing from the second lowest cost wind facility project that was bid into the 2012 renewable RFP. The lowest cost wind facility project, Red Mesa Wind Energy Facility, was selected as part of PNM's 2014 Renewable Energy Procurement Plan and was approved by the NMPRC in Case No. 13-00183-UT. As shown in Table 6-M below, the pricing ceiling begins at $45.00 per MWh in the first year and sensitivities were analyzed down to $20.00 per MWh. Each first year price was escalated at a 2% and a 3% per annum price inflator to reflect typical PPA cost streams. A 20-year levelized cost of energy was also calculated for cost comparison of the various sensitivities.

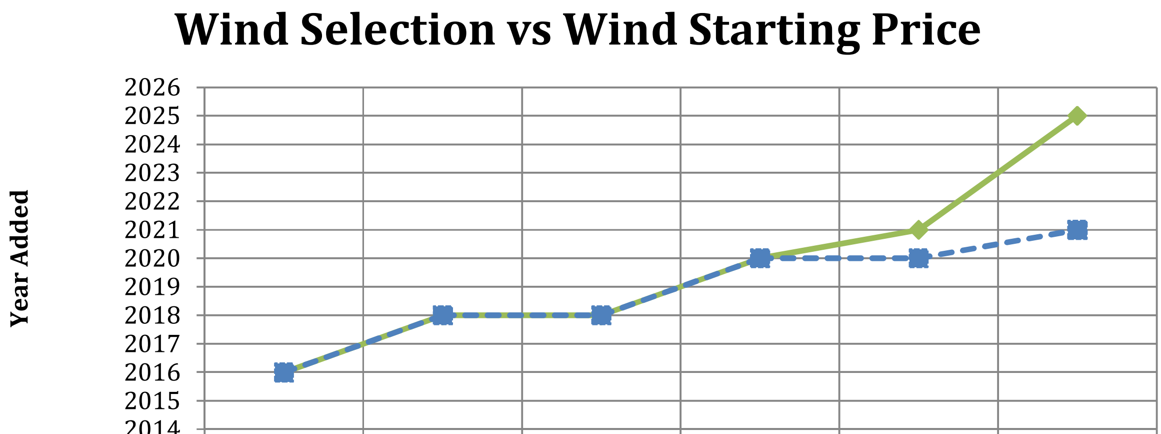
Table 6-M: Wind Price Assumptions

PPA costs escalating at 2% per annum		PPA costs escalating at 3% per annum	
First Year PPA Price ($/MWh)	20-year Levelized Price ($/MWh)	First Year PPA Price ($/MWh)	20-year Levelized Price ($/MWh)
$20.00	$23.10	$20.00	$24.91
$25.00	$28.88	$25.00	$31.14
$30.00	$34.65	$30.00	$37.37
$35.00	$40.43	$35.00	$43.60
$40.00	$46.20	$40.00	$49.82
$45.00	$51.98	$45.00	$56.05

As shown in Figure 6-N, the starting price is reflected on the horizontal axis and the year the wind facility is added to the least cost portfolio is shown on the vertical axis. The results show that as the price of energy decreases, the 100 MW wind facility is added earlier to the portfolio and as the price increases it is added later to the portfolio. The annual escalator of the pricing also impacts the timing of wind acquisitions. With a 3% annual PPA cost escalator, the 100 MW wind facility is added later for the $40 per

MWh and $45 per MWh starting price as compared to the 2% escalator. In essence, the higher escalator results in a higher cost of energy over the 20-year planning period. A starting price of $30 per MWh or lower moves the 100 MW wind facility into the four year action plan period; however, PNM has not received an RFP bid with pricing this low, or an equivalent pricing, for construction of a project.

Figure 6-N: Wind Price Impact



	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00
3.0% Esc	2016	2018	2018	2020	2021	2025
2.0% Esc	2016	2018	2018	2020	2020	2021

Since the annual wind energy production can vary greatly depending on its location, PNM examined the effect of varying the amount of annual energy produced by a facility at a fixed size. For this analysis, the wind facility size was set at 100 MW and the capacity factor was adjusted from 36% to up to 51%. The capacity factor range used in this sensitivity analysis was based upon bids PNM has received in its 2011 and 2012 renewable RFP's. In comparison, PNM's existing wind farm contract, NMWEC has averaged approximately a 30% annual capacity factor over the past 10 years. However, newer vintage wind turbines are equipped with more efficient turbine blades and control equipment that in turn can contribute to higher energy output per turbine than older models.

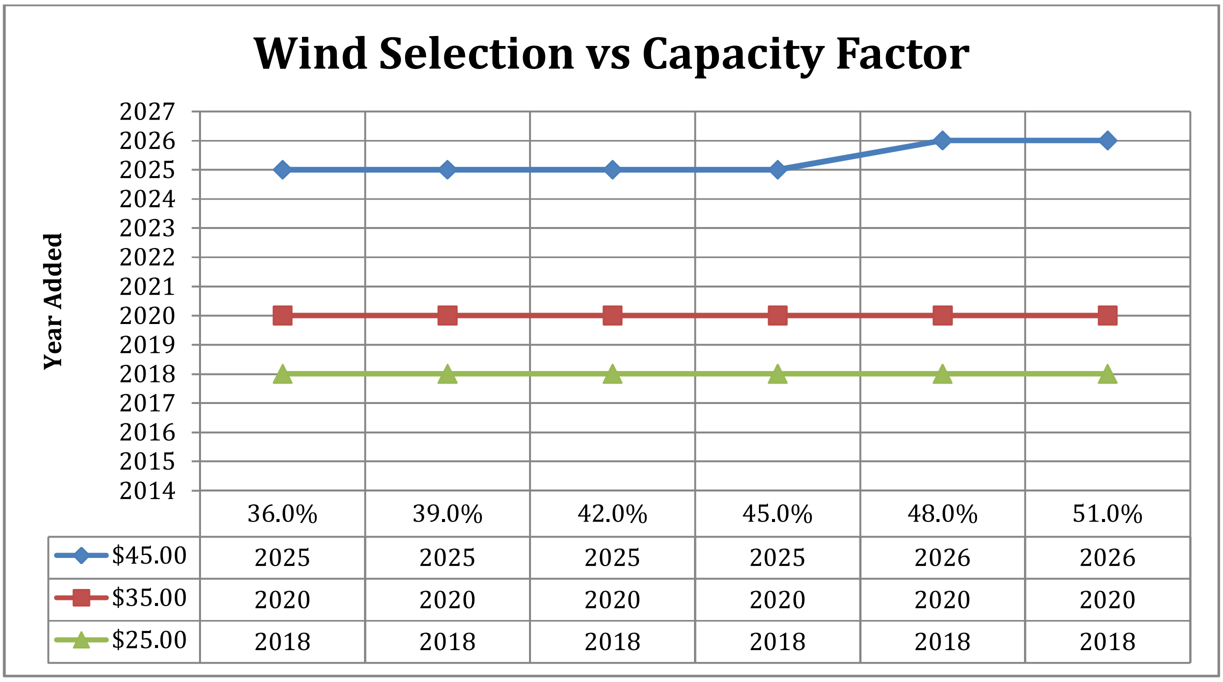
In conjunction with different first year pricing, PNM composed the sensitivities shown in Table 6-O to determine the impacts of varying wind capacity factors.

Table 6-O: Wind First Year Price Assumptions for Sensitivity Analyses

$45 per MWh First Year PPA Price	$35 per MWh First Year PPA Price	$25 per MWh First Year PPA Price
Annual Capacity Factor ($/MWh)	Annual Capacity Factor ($/MWh)	Annual Capacity Factor ($/MWh)
36%	36%	36%
39%	39%	39%
42%	42%	42%
45%	45%	45%
48%	48%	48%
51%	51%	51%

As shown in Figure 6-P, the annual capacity factor is reflected on the horizontal axis and the year a wind facility is included in the least cost portfolio is shown on the vertical axis. The results show that, in general, annual capacity factor for a 100 MW facility does not impact the timing of wind in the resource portfolio. For the $45 per MWh starting price sensitivity, the capacity factors of 48% and 51% shift out the wind in the portfolio by one year. This is due to the increased cost to purchase the entire energy output from the wind facility over the 20-year study period. Figure 6-P also shows that the most important variable affecting selection of wind in the portfolio is the starting price of the PPA.

Figure 6-P: Wind Capacity Factor Impact



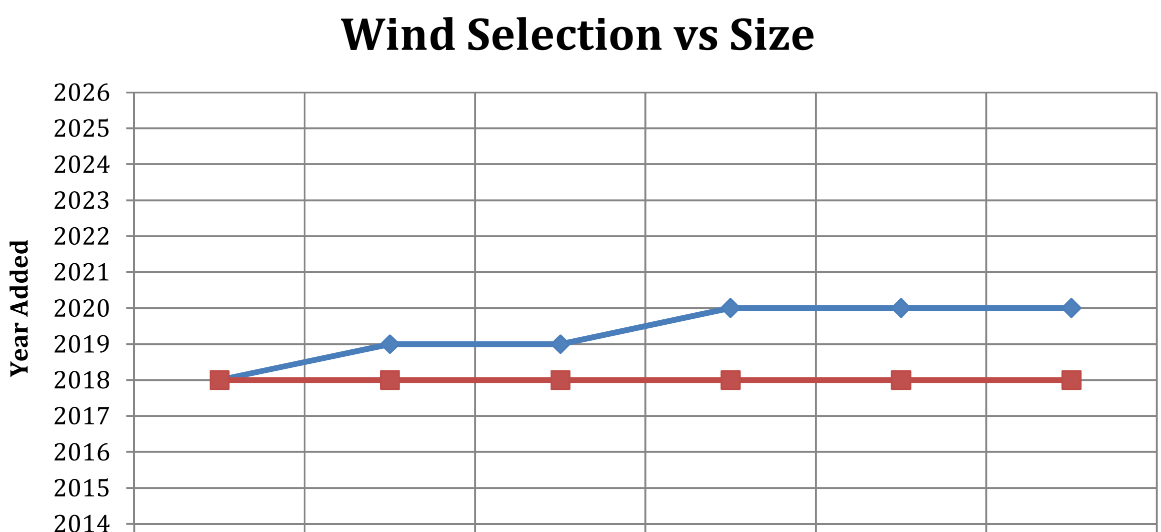
The sizing of a wind facility is the other variable PNM analyzed in the wind sensitivity analysis. Wind facility maximum capacity sizing was adjusted between 100 MW and 350 MW in 50 MW increments. Two pricing levels were evaluated at each of the facility sizes at a 36% capacity factor assumption. The options used in the analysis are shown below in Table 6-Q.

Table 6-Q: Wind Size Assumptions

$30 per MWh First Year PPA Price	$25 per MWh First Year PPA Price
Wind Facility Size (MW)	Wind Facility Size (MW)
100	100
150	150
200	200
250	250
300	300
350	350

As shown in Figure 6-R, the wind facility size is reflected on the horizontal axis and the year a wind facility is added to the least cost portfolio is shown on the vertical axis. The analysis shows too that, if the starting price for wind is $25 per MWh, the timing of wind in the portfolio is unchanged through the range of sizes analyzed, and the wind is added early in the 20-year planning period. Also, if the starting price for wind is $30 per MWh, the timing of wind in the portfolio changes as the wind facility sizing increases. As wind facility size increases, the price to purchase the energy stays the same, however the volume of energy increases and so does the annual cost of purchasing the entire wind facility output. In general, the wind facility sizing range evaluated was fairly large and the resulting time shift of economically adding the facility to the portfolio only changed modestly. As with the capacity factor sensitivities, pricing plays the larger role affecting when wind is selected in the portfolio.

Figure 6-R: Wind Size Impact



	100	150	200	250	300	350
$30	2018	2019	2019	2020	2020	2020
$25	2018	2018	2018	2018	2018	2018

After evaluating the three parts of the wind sensitivity analysis, the results show that energy pricing for the wind facility has the greatest influence on when wind is added to the least cost portfolio. Annual capacity factor and wind facility size had smaller effects, but not enough to overcome the pricing of wind energy. PNM will continue to track and monitor market trends for wind energy pricing.

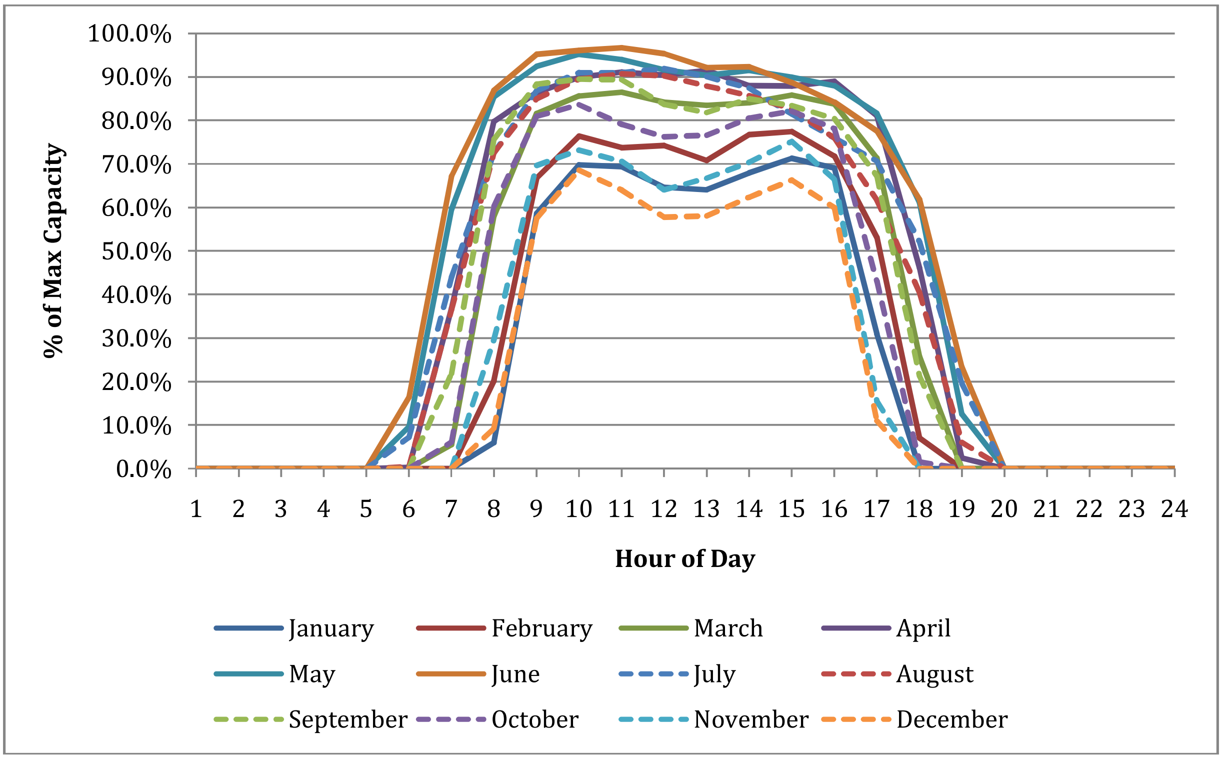
Solar Resource Modeling Evaluation

During the 2014 IRP planning process, PNM and the IRP Public Advisory group discussed how peak contribution provided by solar PV decreases as the penetration of solar PV in the portfolio increases. This can directly affect the amount of solar PV being economically added to the PNM system. As an improvement in the modeling, PNM pursued better methods for solar PV modeling in this IRP.

The two most important aspects that needed to be addressed were (1) how to define the solar PV resource that would be used in the Strategist® modeling and (2) determine the contribution to peak of each increment of new solar PV on PNM's system.

To define the solar PV resource, PNM utilized data received in its November 2013 Renewable RFP bids for use in the Strategist® modeling tool. Since Strategist® uses typical week data as input, PNM averaged the typical week energy production curves from the top two bidders/projects. The top two bidders provided the best overall pricing and supporting data related to their projects which was based on a combination of demonstrated performance and forecasting experience. The typical day energy production curve for the 12 months of a typical year are shown below in Figure 6-S. The production profiles reflect polycrystalline solar panels mounted on single axis trackers that would be located in central New Mexico. This configuration is based on the top tier solar PV projects bid into the 2013 Renewable RFP.

Figure 6-S: Solar Typical Day Energy Production



The energy production curve from July was used to define the effect of solar PV contribution on PNM's system peak. July is the month when PNM is most likely to see its annual system peak demand and the hour that corresponds with the peak is normally 4pm or hour 16. The production curve is shown below in Figure 6-T. As shown in Figure 6-T, the solar PV peak contribution at the peak hour is approximately 76%.

Figure 6-T: July Typical Day Energy Production

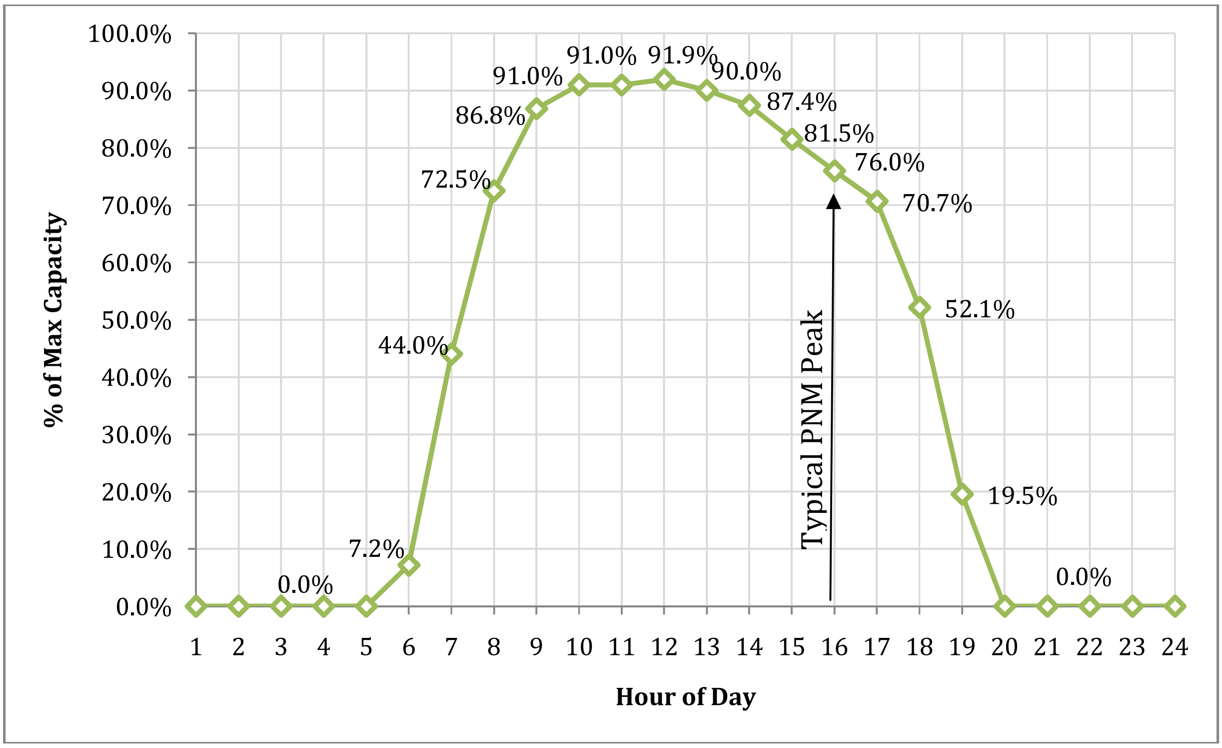
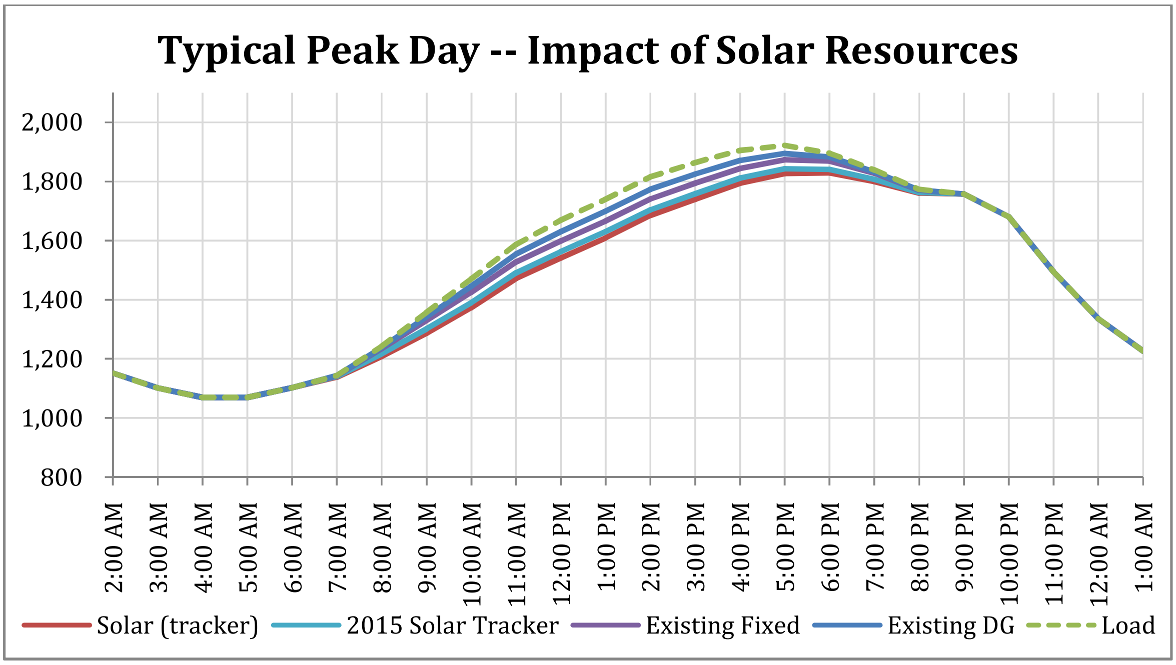


Figure 6-T shows the values of a system peak day profile for the PNM system. PNM took the average of 2011, 2012 and 2013 system demand profiles for peak days in those years. The previous hour MW change column shows the difference, in MW, of change in demand from the previous hour. The peak contribution column shows how the solar PV peak contribution correlates with the peak demands.

Solar generation is dispatched automatically as generated, in normal system and solar facility operations. This energy displaces energy that would need to be generated from other non-solar generators, such as PNM's gas plants. PNM's assessment of the impact of solar generation found that as more solar generation is added to the system, it effectively moves the peak generation required from gas plants further into the late-afternoon. This trend can be seen in Figure 6-U.

Figure 6-U: Typical Peak Day Net Demand After Solar Generation Dispatch



The dotted line at the top is total customer demand prior to any solar dispatch. As solar resources are added, the demand curve drops and begins to trend towards a level amount of demand between 5:00 and 6:00 p.m. With additional PNM solar facilities being constructed in 2014 and proposed for 2016, the peak demand period from the perspective of requiring additional resources will be shifting from 5:00 pm to 6:00 pm. This will reduce the capacity value for subsequent solar facilities from 76% to about 71%, as shown below in Table 6-V. Although the capacity value will be decreasing, solar throughout the day will continue to provide a hedge against future carbon prices; this hedge would not be affected by the shifting of the peak demand period.

Table 6-V: Solar Hourly Data

MST	MDT	2011-2013 Avg MW	Prev Hour MW Change	Solar PV Peak Contribution	Notes
1:00 AM	2:00 AM	1,152		0.0%	
2:00 AM	3:00 AM	1,102	(50.00)	0.0%	
3:00 AM	4:00 AM	1,070	(32.00)	0.0%	
4:00 AM	5:00 AM	1,070	0.00	0.0%	
5:00 AM	6:00 AM	1,103	33.00	0.0%	
6:00 AM	7:00 AM	1,144	41.00	7.2%	
7:00 AM	8:00 AM	1,243	99.00	44.0%	
8:00 AM	9:00 AM	1,357	114.00	72.5%	
9:00 AM	10:00 AM	1,470	113.00	86.8%	
10:00 AM	11:00 AM	1,587	117.00	91.0%	
11:00 AM	12:00 PM	1,669	82.00	91.0%	
12:00 PM	1:00 PM	1,740	71.00	91.9%	
1:00 PM	2:00 PM	1,815	75.00	90.0%	
2:00 PM	3:00 PM	1,864	49.00	87.4%	
3:00 PM	4:00 PM	1,905	41.00	81.5%	
4:00 PM	5:00 PM	1,922	17.00	76.0%	peak hour
5:00 PM	6:00 PM	1,895	(27.00)	70.7%	peak hour + 1
6:00 PM	7:00 PM	1,838	(57.00)	52.1%	peak hour + 2
7:00 PM	8:00 PM	1,773	(65.00)	19.5%	peak hour + 3
8:00 PM	9:00 PM	1,757	(16.00)	0.0%	peak hour + 4
9:00 PM	10:00 PM	1,681	(76.00)	0.0%	
10:00 PM	11:00 PM	1,495	(186.00)	0.0%	
11:00 PM	12:00 AM	1,336	(159.00)	0.0%	
12:00 AM	1:00 AM	1,227	(109.00)	0.0%	

Table 6-W shows the peak hour at 4 pm with a system peak demand of 1922 MW. The following hour, peak hour + 1, system peak demand is 27 MW lower. Therefore, it is expected that up to 27 MW of new capacity can be added to the system at the same contribution factor before it changes the peak hour. This does not mean that 27 MW would be the size for a new solar PV facility that keeps the peak hour the same. Since solar PV peak contribution at 4 pm is 76% of the solar PV facility maximum capacity, 35.5 MW would be the name plate capacity size of solar PV that would equate to the 27 MW. A solar PV facility larger than 35.5 MW added to PNM's system would result in PNM's peak hour shifting to peak hour +1. This would be repeated for the next hour, and so on.

To integrate this methodology into the Strategist modeling, discrete solar PV facility sizes needed to be identified. Since the majority of PNM's past solar PV installations were in increments of approximately 20 MW, PNM chose to use that same size for the modeling of future solar PV alternatives. A tabulation of incremental solar PV contributions is shown in Figure 6-W. Groupings of solar PV facilities are formed when the sum of contribution at peak surpasses the value necessary to move the peak hour to the next hour through peak hour + 4. The groupings are referred to as Tier 1, Tier 2, Tier 3 and Tier 4 solar PV facilities. Each tier correlates to the contribution at peak that each solar facility in that grouping will provide to PNM's system when incrementally added. The peak contributions are based on the data shown in Table 6-W.

Table 6-W: Solar Tier Data

Resource Alternatives	MW	Solar PV Contribution at Peak (%)	Incremental Solar PV (MW)	Grouping
Solar PV Build 1	20.0	76.0%	15.2	Tier 1
Solar PV Build 2	20.0	76.0%	30.4	
Solar PV Build 3	20.0	70.7%	14.1	Tier 2
Solar PV Build 4	20.0	70.7%	28.3	
Solar PV Build 5	20.0	70.7%	42.4	
Solar PV Build 6	20.0	70.7%	56.5	
Solar PV Build 7	20.0	52.1%	10.4	Tier 3
Solar PV Build 8	20.0	52.1%	20.9	
Solar PV Build 9	20.0	52.1%	31.3	
Solar PV Build 10	20.0	52.1%	41.7	
Solar PV Build 11	20.0	52.1%	52.1	
Solar PV Build 12	20.0	52.1%	62.6	
Solar PV Build 13	20.0	52.1%	73.0	
Solar PV Build 14	20.0	19.5%	3.9	Tier 4
Solar PV Build 15	20.0	19.5%	7.8	
Solar PV Build 16	20.0	19.5%	11.7	
Solar PV Build 17	20.0	19.5%	15.6	

Table 6-X summarizes the previous table in terms of the maximum capacity of solar PV installations that are modeled in each tier and the maximum MW at peak that would be provided from each tier grouping. The figure shows the contribution to peak of each tier of new solar PV that corresponds to the system peak hour after all existing solar resources are accounted for. The increments of solar provided in Table 6-X were used in the updated Strategist® modeling for the IRP portfolio analysis.

Table 6-X: Solar Peak Data

Solar Installation	Solar PV Install Incremental Capacity Limit	Contribution at Peak	MW At Peak
	(MW)	(%)	(MW)
Solar PV Tier 1	40.0	76%	30.4
Solar PV Tier 2	80.0	71%	56.5
Solar PV Tier 3	140.0	52%	73.0
Solar PV Tier 4	80.0	20%	15.6

With the solar PV assumptions identified, the modeling technique used in Strategist® needed to be evaluated. Prior to the updated solar PV modeling, PNM had been modeling solar PV additions in 20 MW increments and using an iterative process to scale up to the least cost solar resource addition. For example, with the 40 MW addition identified for construction next year, PNM initially ran the Strategist® optimization with a 20 MW solar PV resource increment available. When a 20 MW solar PV resource was selected in the least cost portfolio, PNM re-optimized with an incremental 20 MW addition available. This process was repeated to confirm that 40 MW was the correct size for the least cost portfolio versus a 20 MW or 60 MW addition in 2015. In order to properly model this, PNM began using a modeling technique, within Strategist®, to associate each 20 MW incremental solar PV capacity addition with its associated on-peak capacity contribution and to scale up in size automatically. This technique is a refinement and improvement of past modeling in two ways; (1) automation of scaling of solar PV resource additions and (2) accurate accounting of solar PV contribution as penetration increases.

In conclusion, updating the solar PV modeling methodology has made a significant improvement to PNM's planning process and provided a greater understanding of how solar PV resources can be economically incorporated into PNM's future portfolio of resources. PNM will continue to use this methodology in the future and may refine it to improve the accuracy of results from the Strategist® modeling.

CO_2 Prices

PNM performed a sensitivity based on the standardized carbon emission costs in the final order in NMPRC Case 06-00448-UT. The resulting portfolios can be found in Appendix F. Per the order, these costs $8, $20, and $40 per metric ton (starting price in 2010 dollars escalating at 2.5% per annum) were added to the dispatch cost of each existing and new resource beginning in 2014. Based on these results; the following trends occur here that are similar to the trends identified in the price sensitivities based on the carbon and natural gas prices provided by PACE:

- 40 MW Solar and gas turbine peaker remains as near term options,
- Wind resources are accelerated in the portfolio as the carbon price increases, and
- Solar resources are accelerated in both timing and magnitude as the carbon price increases.

Risk Impacts

The IRP Rule calls for utilities to consider risk and uncertainty in its analysis of resource options. The IRP scenario modeling analysis provides the overall framework for assessing cost impacts of different conditions. For example, scenarios are determined by the outlook for future fuel prices (high or low), the growth rate of the utility's customer demand and the regional haze compliance assumptions for SJGS. In addition to scenario modeling, risk assessment also looks at the variation of key input factors within those scenarios. As an example, natural gas prices will vary daily, seasonally and yearly within each of the low, middle or high gas price scenarios.

Real-world system conditions will vary from assumptions used for scenario analysis, and multiple variations from those assumptions may occur simultaneously. Stochastic financial risk analysis (Stochastic Analysis or Risk Analysis) provides a rigorous analysis by simultaneously varying multiple modeling assumptions and quantifying the impact to the total cost of potential resource portfolios. The IRP evaluation used stochastic financial risk analysis. Understanding the variability of input factors and the effect on costs is an important part of determining the most cost effective portfolio that will perform well regardless of changes in future system conditions.

Scenario analysis determines the impact of discrete changes in the input variables, such as load growth or fuel prices. Stochastic financial risk analysis differs from scenario analysis in that it tests the uncertainty regarding the various conditions, including correlated changes in system variables over a continuous range of expected variables. That is, it looks at what happens when several input variables change from their expected values simultaneously. Sometimes they all change in one direction, sometimes in different directions, and sometimes one changes while another does not. Stochastic analysis can provide insight to determine conditions that are favorable or unfavorable for certain resource choices or combination of choices by identifying portfolio financial risks.

A least cost portfolio is determined 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. Stochastic analysis can be used to compare the two portfolios under a range of gas prices and also varies other input variables within the same analysis. The important summary outputs collected from the stochastic analysis are the expected cost-to-customers of each portfolio and the risk that the cost could be much higher than that expected level. The expected cost is measured by the mean (average) NPV cost while the risk is measured by the 95th percentile cost.

Optimally, the best portfolio will have the lowest average cost as well as the lowest 95th percentile (upper tail) financial risk. However, often the utility is faced with a choice or trade-off of lower risk vs. lower cost.

Monte Carlo Analysis

There are many methods to perform financial risk assessment; one is the Monte Carlo method. 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. The Monte Carlo analysis used for PNM’s IRP consists of the following steps:

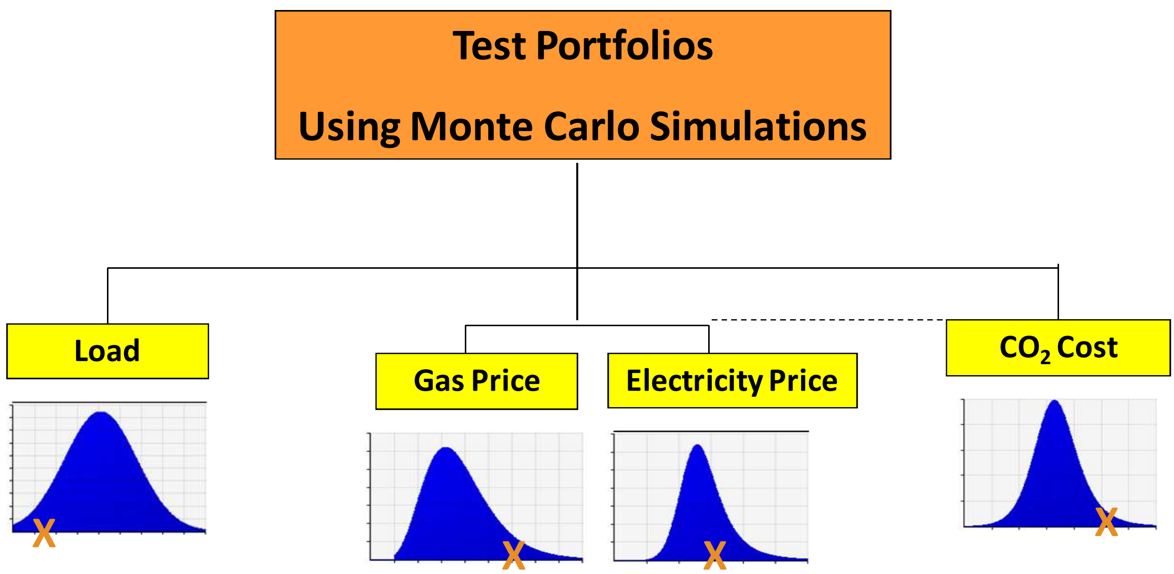
- *Step 1:* Determine the potential range of values for input variables (including load forecast, natural gas fuel prices, market prices for electricity, and CO_2 costs). Then define a probability distribution for each variable; i.e. the likelihood that each value in the range may occur.

- *Step 2:* Determine the correlation among input variables if any, i.e. the change in one variable directly related to a change in another variable.
- *Step 3:* 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 4:* Calculate the resource portfolio's total system cost for each selected set of randomly generated variable values using modeling software to optimize dispatch of the selected portfolio of resources and then by running the model over 900 draws.
- *Step 5:* Aggregate the results of the random draws from Step 4 and calculate the average cost and cost variability (mean NPV and 95th percentile risk).

Steps four and five then repeat for each portfolio, using the same randomly generated conditions. This analysis subjects each portfolio to the same probable conditions including market sales or purchases that can lower portfolio costs through economic dispatch of units.

Figure 6-Y illustrates Steps 1 and 2 to determine the probability distributions for each of four variables. As discussed below there are correlations between the values of each of these variables (electricity prices tend to be high when gas prices are also high). Each one of the 900 draws includes a value for each of the four variables. Those values (shown as an X in Figure 6-Y) are drawn to reflect Step 3. Each draw is then used in the Strategist® model as in Step 4 and 5 to calculate the portfolio cost.

Figure 6-Y: Monte Carlo Draw Illustration



Monte Carlo analysis is suitable for complex models because of the computational power of modern computers and software for statistical estimation and calculation. PNM's IRP stochastic analysis applied 900 sets of input variables (900 "draws") to the Strategist® model. The least cost portfolios from the scenarios discussed in the scenario analysis were subjected to evaluation under Monte Carlo analysis. The objective of the simulations is to assess how the various portfolios respond to the variety of possible future conditions.

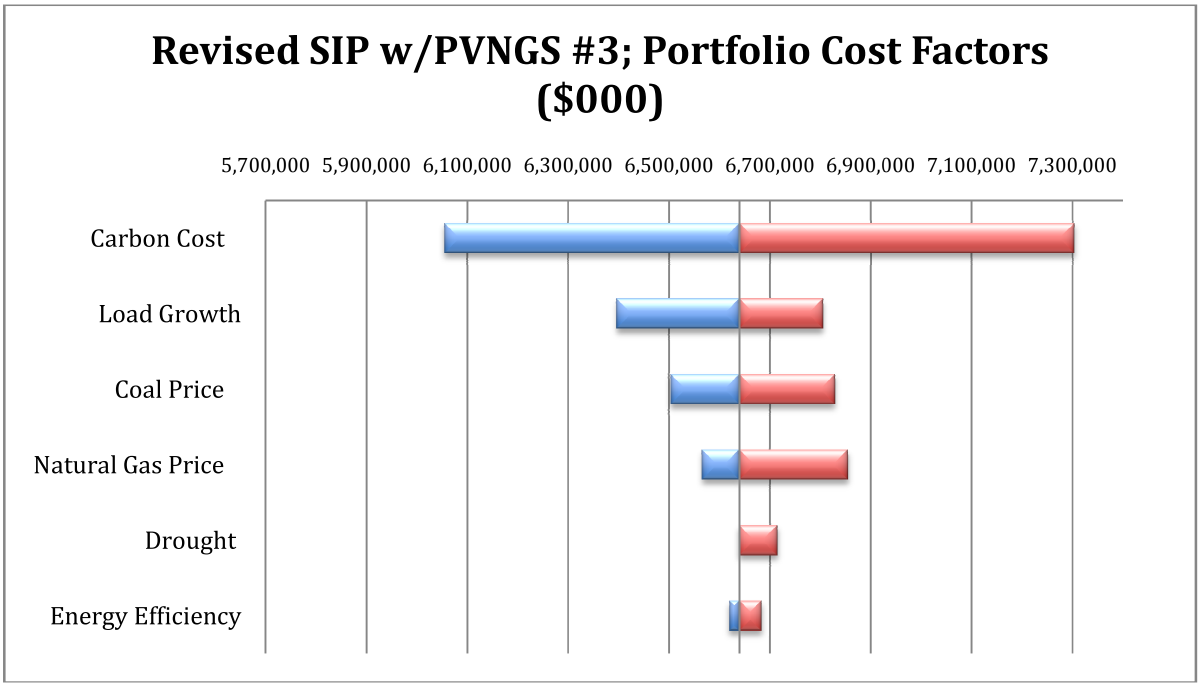
MONTE CARLO INPUT VARIABLES

The variables chosen for the Monte Carlo simulations were selected based on both importance to system costs and variability. Variables that do not have a large impact on cost or that are relatively stable and predictable in their values were not examined. The variables discussed below were varied in the Monte Carlo simulations.

- Load forecast risk
- CO_2 cost risk
- Natural gas price risk
- Wholesale market electricity price risk

These four variables were included in the risk analysis because they met the criteria of having a potentially substantial impact on the results and have considerable volatility in their values. Figure 6-Z illustrates the range of impact on expected system costs calculated by varying the assumption for each factor from its low cost value up to its high cost value. Blue bars (bars on the left side of the graph) represent savings versus the reference case assumptions and red bars (bars on the right side of the graph)indicate higher costs.

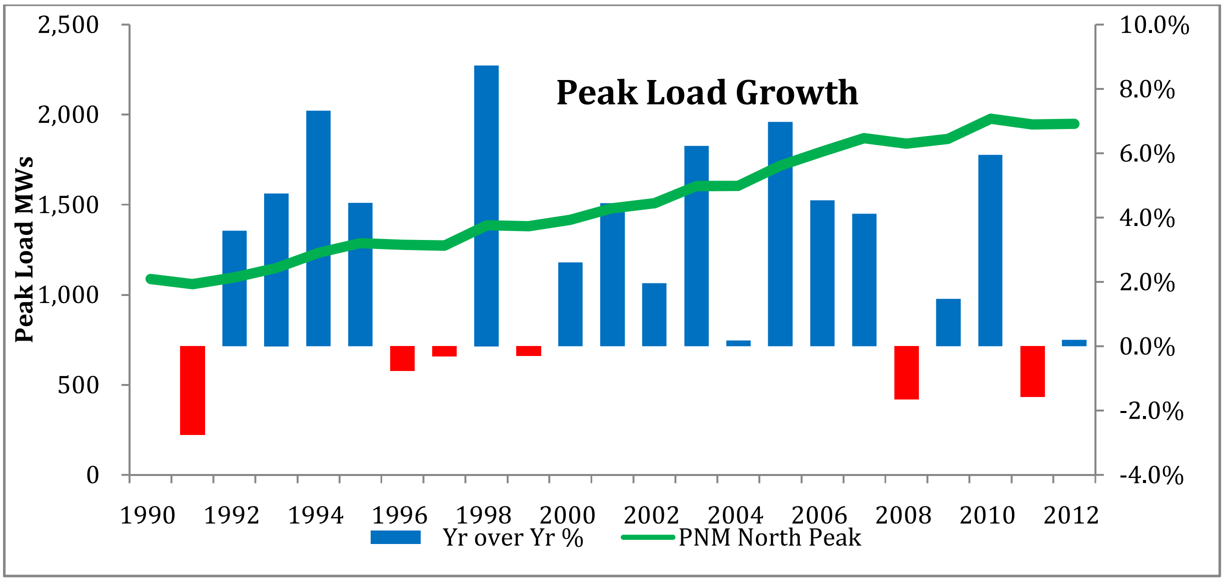
Figure 6-Z: Relative Impacts of Cost Factors



Load Forecast Risk

The customer load forecast is one of the primary drivers of resource selection. There is considerable uncertainty and variability in forecasting load growth. PNM examined four different load forecasts in the scenario analysis (current, high, mid and low) as shown in Figure 6-AA. The four forecasts reflect the uncertainty over the long-term trends in load growth. There is also variability in load from year to year that will be present regardless of which long-term trend may emerge. This variability is largely determined by weather, although other short-term factors like economic conditions will have some effect. Since 1990, PNM's peak load has grown at an average rate around 2.7%, yet load growth has varied between -3% and +9%.

Figure 6-AA: Comparison of Actual Annual Peak Growth Demand



A robust portfolio will have the flexibility to keep costs low under conditions above or below expected load without violating reliability criteria. In addition, over time, the portfolio must adapt to variation in the long-term growth trend. The stochastic simulations test the portfolios under these varying conditions. The 900 draw simulations vary year-over-year load growth values from the mid-load forecast value each year.

Natural Gas Price Risk

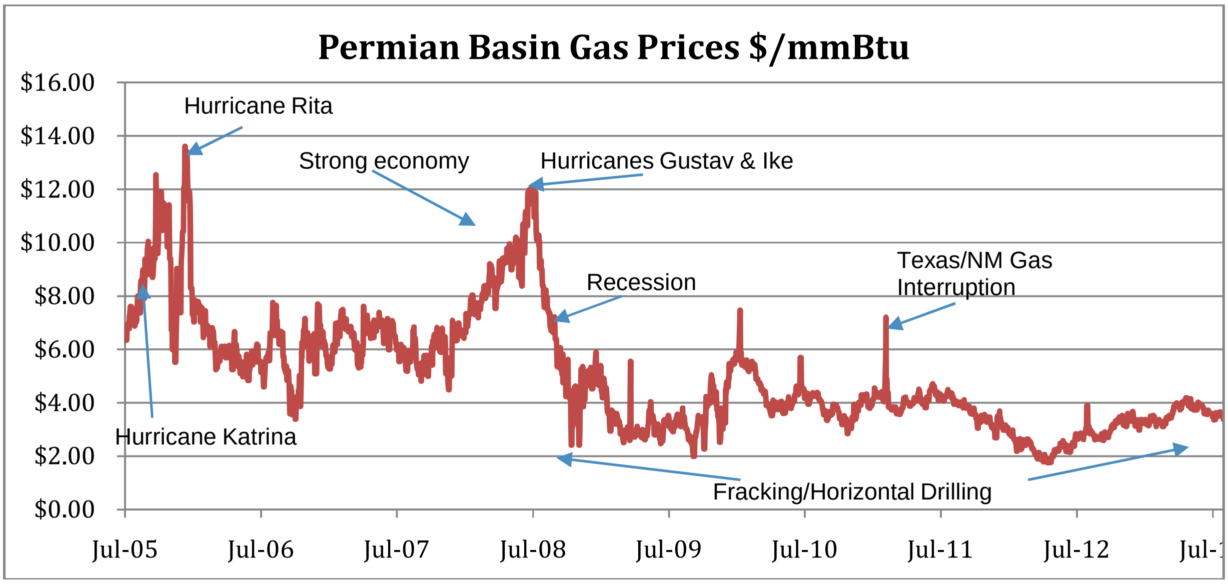
Fuel costs represent a large portion of total generation operating costs. In 2013, fuel costs were just under 60% of PNM's production costs at the Company's generating plants[2]. Natural gas prices are considered among the most volatile of commodity prices (as are wholesale electricity prices that generally trend with natural gas prices). Also, the amount of gas-fired generation is increasing nationally relative to both coal and nuclear generation. In addition, gas-fired generation is being utilized more heavily to balance variations in generation and demand. Because of the importance of gas prices and the volatility of those prices, gas prices are included among the variables examined in the stochastic risk analysis. This captures the impacts of the volatility in gas-fired resource requirements, along with the variability of renewable resource output.

PNM used historic gas price volatility to estimate the variation to be used in the Monte Carlo simulation draws. A data period from July 2005 to July 2013 was studied, as shown in Figure 6-AB. This period was chosen as it included a number of events that significantly impacted gas prices. In 2005, hurricanes Katrina and Rita caused major supply disruptions. The period also covered a time of strong economic growth and energy demand, followed by a severe recession and drop in demand. Other weather-

[2] Fuel costs were 59.2% of production expenses. This does not include figures from generation resources under PPAs (Delta, Valencia, NMWEC).

related events impacted prices, including a severe cold snap in February 2011 that affected New Mexico and Texas gas and electricity supplies. Also, gas supplies increased significantly during this time with the development of drilling technologies that allow greater production from shale gas deposits. As a result, variation in prices was quite high during the period.

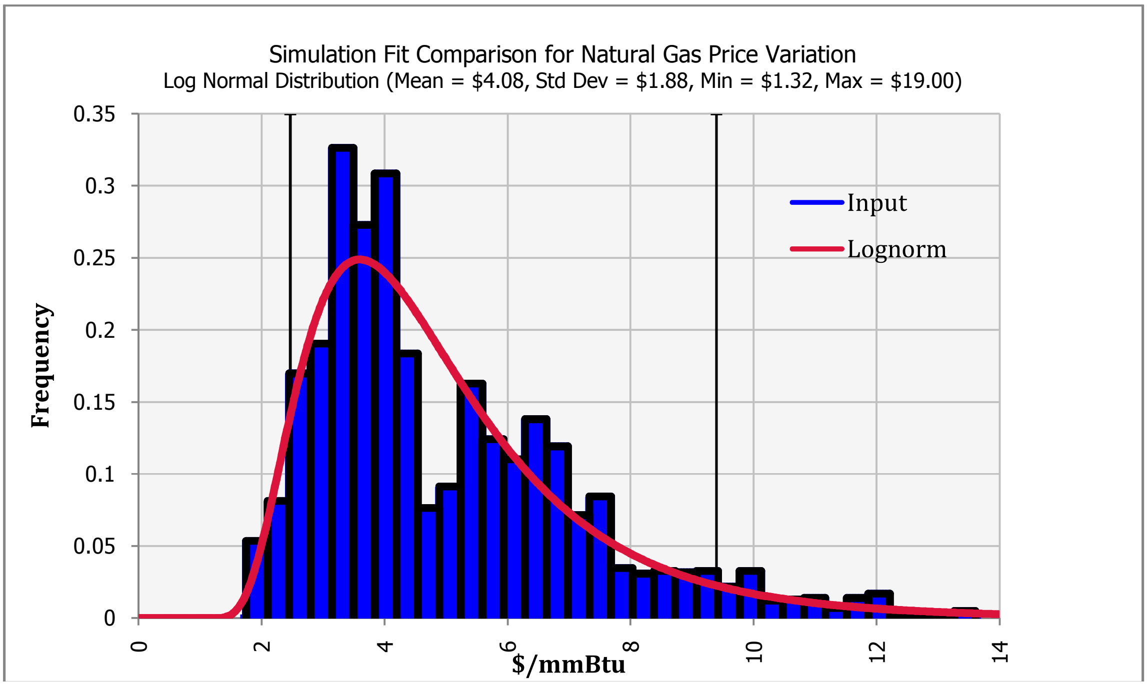
Figure 6-AB: Historical Gas Prices



Daily gas prices over this period averaged $4.98/MMBtu. Prices ranged from a low of $1.75 to a high of $13.62/MMBtu. The data is for natural gas delivered to the El Paso Natural Gas Company pipeline system in the Permian Basin of Southeast NM and West Texas.

Natural gas has a very liquid futures market, in which buyers and sellers can contract for sales at future dates. Prices for forward date transactions are quoted real-time. These price quotes for trade dates extend several years into the future. The reference case gas price forecast was based on the futures market price quotes for the near-term, with future escalation determined by the various scenario assumptions over the 20-year study period. For the Monte Carlo simulations, volatility based on the historic data was applied to each scenario's gas price forecast. Gas prices for 2014 in the 900 draws ranged from $1.32/MMBtu to $19.00/MMBtu. The risk simulations take into account the probability (albeit slight) that these extreme values could emerge. Figure 6-AC shows the probability distribution of gas prices.

Figure 6-AC: Probability Distribution of Gas Prices

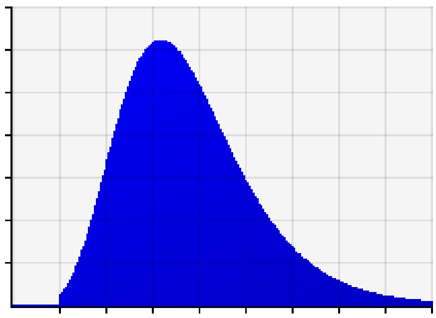


CO_2 Cost Risk

A wide range of carbon assumptions was examined in the IRP scenario analyses. The carbon cost assumption varied from $0 per metric ton to over $50 per metric ton of CO_2 in scenarios designed to look specifically at greenhouse gas (GHG) cost impacts. Carbon costs have a large cost impact under the scenarios using the various Pace assumptions and have great uncertainty regarding their volatility.

There is very limited experience with pricing in carbon allowance markets and none that are likely to match what U.S. carbon costs will be under pending regulations. Probability distribution therefore could not be reliably estimated by historic data. Instead, it was assumed that the price volatility would follow a log normal distribution, similar to natural gas pricing. The price values cannot be negative and tend to have a long right tail (meaning there is a small probability of a very high cost outcome). The stochastic analysis then applied this distribution to each of the carbon price forecasts in the various scenarios and examined the resulting portfolios.

Figure 6-AE: Probability Distribution of CO_2 Prices

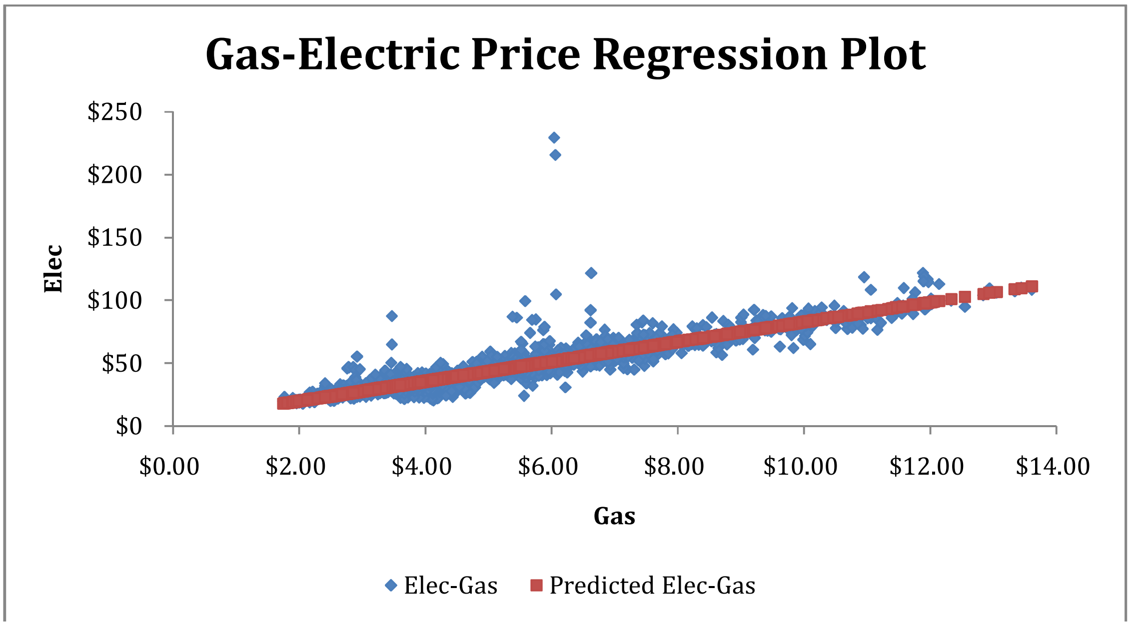


WHOLESALE ELECTRIC PRICE RISK

For the stochastic analysis, the Strategist® model was extended to include wholesale electric market transactions to reflect the actual operation of the PNM resource portfolio. The dispatch of the portfolio is allowed to interact with the regional marketplace, where market sales or purchases can lower portfolio costs through economical usage of regional units. For example, at peak load times, PNM may need to run less-efficient units to meet the load. If wholesale power is available at a lower cost than the cost of generating at those units, PNM will purchase power rather than dispatch those units. Similarly, when PNM has spare capacity during off-peak hours, it may be able to sell power at a price that covers generating costs and thereby provide a credit to customer cost. Costs and benefits of market sales are directly passed through to customers and are subject to the review of the NMPRC.

Figure 6-AF shows a statistical estimation of the relationship between natural gas and electricity prices. Daily prices for wholesale electricity (at the Palo Verde market hub) were compared with daily natural gas prices (El Paso Permian index). The figure illustrates a linear regression estimation that indicates a strong relationship between gas costs and power prices.

Figure 6-AF: Gas and Electricity Price Relationship



In the future, CO_2 costs attached to electric generation will affect electric prices. The amount of CO_2 per MWh will depend on the efficiency or heat rate of the plant setting the market price. There has not yet been a history of CO_2 market prices that can be correlated to electricity prices. For the stochastic analysis, PNM assumed that the market price of electricity will track the cost of CO_2 at a ratio of approximately $0.40/MWh for each $1/metric ton of CO_2 cost. This reflects an assumption of 117 pounds (lbs) of CO_2 per MMBtu of gas, and that a natural gas combined cycle plant operating with a heat rate of 7,500 Btu/kWh is, on the margin, setting the price for electricity.

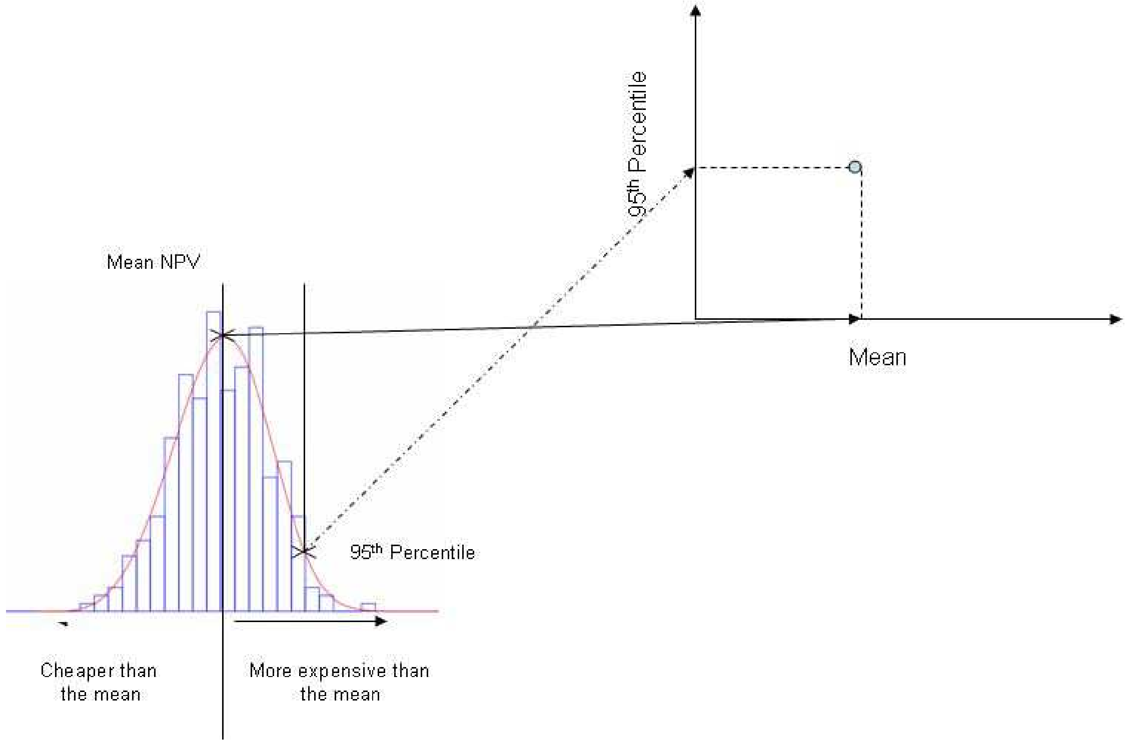
For the Monte Carlo draws, the price of electricity varies with the price of gas and the price of CO_2 and also includes additional uncorrelated variability. This additional variation is included in the Strategist® model in hourly price curves for dispatch modeling. As a consequence of the volatility in gas and carbon price draws, electricity prices vary sharply also. For more details, see Appendix E.

Simulation Results

The Strategist® model calculated the NPV of the total system cost for each of the scenario portfolios for each of the 900 simulation draws. The simulation results for each scenario portfolio produce a measure of cost and a measure of risk. The cost of that portfolio is the mean value of the 900 total system costs calculations. This is the expected NPV of costs to customers. The statistic selected to measure risk is the value representing the 95th percentile of the 900 system cost results. That is, there is a 5%

likelihood that the actual costs of this portfolio will be greater than this value[3]. The combination of cost and risk indicated by these measures can be shown graphically as in Figure 6-AG.

Figure 6-AG: Plotting Portfolio Risk and Cost Measures



Generally our results look like a familiar bell curve as in Figure 6-AH. A riskier portfolio will produce a flatter and more spread-out distribution curve representing greater variation in the likely results. A flatter curve indicates a higher probability that the actual result will differ from the average or expected amount.

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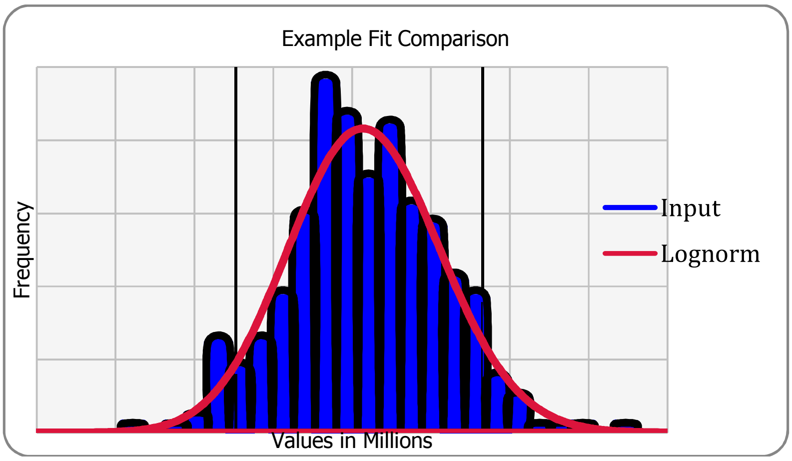
[3] The use of a 5% probability tail is a common measure of the dispersion of values in a probability distribution. For example, "tail" refers to the high values at the end of the familiar bell-shaped distribution curve showing that only 5% of outcomes can be expected to have a value above that level. Other frequently used measures include a 2 ½% tail or 1% tail. Samples indicate these measures were consistent with the 5% test results used in the simulations.

Figure 6-AH: Example 900 Draw Simulations

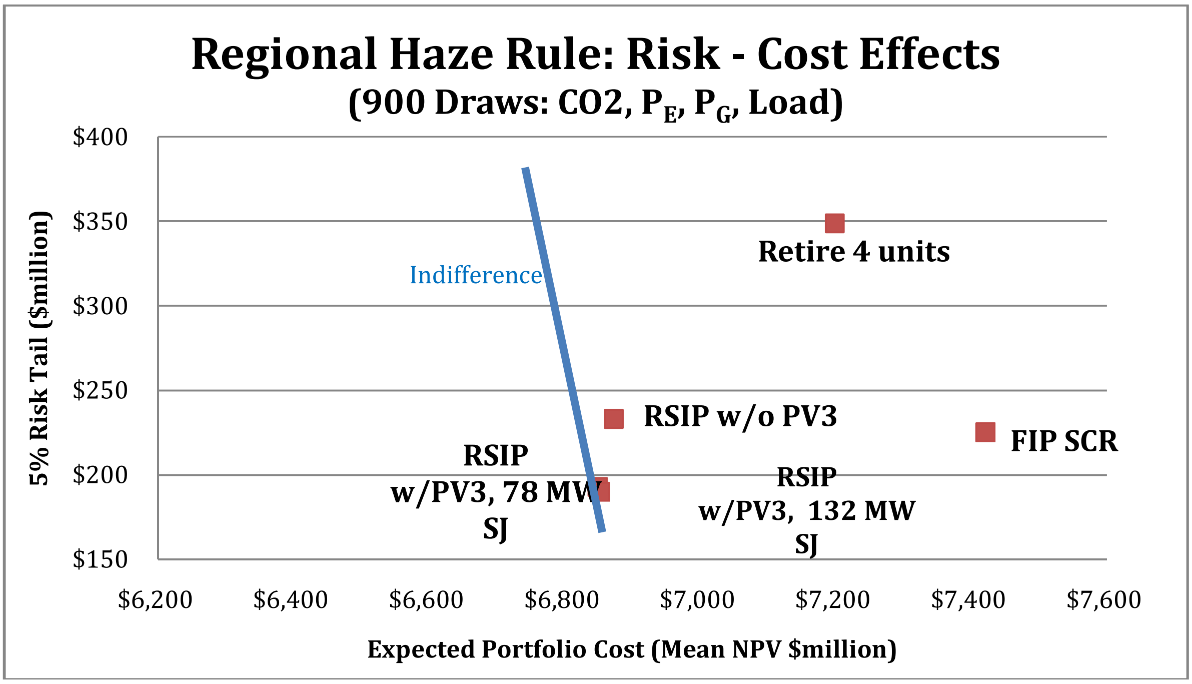


The mean value and 95th percentile results are reported for all scenario portfolios.

REGIONAL HAZE RULE SCENARIO SIMULATIONS COMPARISON

A number of scenarios looked at potential resolutions to the EPA's Regional Haze Rule findings, which are being considered by the NMPRC in Case No. 13-00390-UT. Figure 6-AI plots the risk and cost results of the least cost portfolios from those scenarios.

Figure 6-AI: Risk-Cost Trade-Off



The horizontal axis measures the mean value of the Monte Carlo analysis. The vertical axis plots the difference between the mean cost and the 95th percentile cost. The optimal result for a portfolio is low cost and low risk, plotted closest to the lower left corner of the graph. To review the scenarios:

- FIP SCR – this scenario has SCR technology installed on all four units at SJGS (Federal Implementation Plan)
- Retire 4 Units – this scenario would retire all four units at SJGS
- Revised SIP w/o PV3 – the Revised State Implementation Plan would retire two units at SJGS and install less-expensive SNCR on the remaining two units
- Revised SIP w/PV3, 78 MW SJ – this is the Revised SIP with 134 MW of PVNGS Unit 3 used as partial replacement for the retired coal capacity and 78 MW of additional capacity in SJGS Unit 4
- Revised SIP w/PV3, 132 MW SJ – this version 134 MW of Palo Verde Unit 3 and 132 MW of additional coal capacity in San Juan Unit 4.

The plots show that the "Retire 4 Units" portfolio has the highest risk and the "FIP SCR" has the highest total cost. The two Revised SIP portfolios that include PV3 show the lowest cost and risk combinations. In this case, the results show that the two Revised SIP portfolios with PV3 are more cost-effective than the other three portfolios.

Observations From Risk Simulations

Results from the stochastic risk analysis can be summarized:

- Differences in risk among the portfolios tend to be small relative to differences in mean cost.
- Differences in the portfolios based on the three general responses to the EPA Haze Rule (Revised SIP 2-unit Shutdown, FIP-SCR, 4-unit Shutdown) are more significant than the differences in selection of future capacity additions.
- Gas price volatility has the biggest impact on risk in a scenario of 4-unit retirement.
- The portfolios tend to be dominated by PNM's existing plants. New resources represent a relatively small amount of capacity and energy compared with plants already in place.
- Base load coal and nuclear plants continue to provide a large portion of generation.
- Renewables have less risk exposure to carbon and gas price increases, but more exposure to load volatility due to higher installation cost.
- Gas resources have less exposure to load variability and electricity prices and tend to be lower cost than renewables. They have less exposure to load growth variation. They are of course, sensitive to gas price volatility and to carbon prices, although to a lesser extent than coal resources.
- Risk is generally lower with portfolios that have a diverse mix of coal, nuclear, gas and renewables.

7. LOAD AND RESOURCES TABLE

COMPARISON OF LOADS AND RESOURCES

The Load and Resources Table (L&R Table) presents a comparison over the next 10 years of customer peak demand in MW to the demand-side, energy efficiency and generation resources currently existing or pending to meet that demand. The L&R Table also identifies the resulting planning reserve margin and shows when new resources will be required to maintain the reserve margin and reliably serve customer loads. Section 17.7.3.9E of the IRP Rule requires that the IRP present an updated L&R Table. Due to the existing uncertainty associated with PNM's future capacity in SJGS Unit 4, PNM is presenting an L&R table for each of the two SJGS Unit 4 capacity ownership scenarios.

Tables 7-A and 7-B present PNM's current forecast of PNM retail and jurisdictional wholesale customer demand and identifies currently existing jurisdictional resources available to meet that demand, and pending resources. Theses L&R Tables show that existing resources decline over time, primarily due to the expiration of contracts for purchased power or leases for generation capacity, while projected customer demand is expected to increase.

NET SYSTEM PEAK DEMAND

In the L&R Tables, the forecasted Net System Peak Demand on Line 4 is the 2014 Current Forecasted System Peak Demand on Line 5 reduced by Forecasted Incremental Customer-Sited PV and Forecasted Incremental Energy Efficiency, shown on Lines 6 and 7.

FORECAST PEAK DEMAND

The peak demand forecast presented in the L&R Tables is the current load forecast presented in Section 4 of this report. Customer peak demand grows by about 0.7% per year over the next 10 years, but at a slightly higher average rate of 0.8% per year through 2018. Part of the customer load, however, is served with customer-sited solar generation and energy efficiency resources, which are shown as decrements to the forecasted peak demand. The Net System Peak demand represents the actual peak demand that PNM must plan for.

Tables 7-A: Load and Resources Table (Revised SIP 78 MW SJGS Unit 4)

PUBLIC SERVICE COMPANY OF NEW MEXICO

Revised SIP 78 MW SJGS Unit 4 Scenario Load and Resource Projections for Summer Peak

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	Retail Demand + Losses	1,772	1,807	1,840	1,882	1,920	1,964	1,994	2,026	2,059	2,099
(2)	Navopache (without losses)	62	62	62	62	63	63	63	63	63	64
(3)	Aztec (without losses)	7	7	7	7	7	7	8	7	7	7
(4)	TNMP Retail - PNM South (with dist losses, without trans losses)	122	124	126	128	130	133	134	134	135	137
(5)	2014 Current Forecasted System Peak Demands*	1,963	2,000	2,035	2,080	2,119	2,166	2,198	2,230	2,265	2,308
(6)	Forecasted Incremental Customer Sited PV	(15)	(18)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
(7)	Forecasted Incremental Energy Efficiency	(21)	(29)	(36)	(43)	(50)	(55)	(60)	(64)	(69)	(75)
(8)	**Net System Peak Demand (MW)**	**1,927**	**1,952**	**1,979**	**2,015**	**2,048**	**2,090**	**2,117**	**2,145**	**2,174**	**2,211**
(9)	Four Corners	200	200	200	200	200	200	200	200	200	200
(10)	San Juan (340 MW retirement)	783	783	783	783	443	443	443	443	443	443
(11)	**Total Coal Resources (MW)**	983	983	983	983	643	643	643	643	643	643
(12)	Palo Verde Unit 1 and Unit 2	268	268	268	268	268	268	268	268	268	268
(13)	Palo Verde Unit 3					134	134	134	134	134	134
(14)	**Total Nuclear Resources (MW)**	268	268	268	268	402	402	402	402	402	402
(15)	Reeves	154	154	154	154	154	154	154	154	154	154
(16)	Afton	230	230	230	230	230	230	230	230	230	230
(17)	Luna	185	185	185	185	185	185	185	185	185	185
(18)	Lordsburg	80	80	80	80	80	80	80	80	80	80
(19)	Valencia (PPA)	145	145	145	145	145	145	145	145	145	145
(20)	Delta-Person	138	138	138	138	138	138	138	138	138	138
(21)	La Luz			40	40	40	40	40	40	40	40
(22)	SJGS Replacement Resource: Gas Peaking Resource					177	177	177	177	177	177
(23)	2023 Gas Peaking Resource										177
(23)	**Total Natural Gas Resources (MW)**	932	932	972	972	1,149	1,149	1,149	1,149	1,149	1,326
(24)	Total Demand Response Programs (MW, net of losses)*	48	50	50	52	52	52	52	52	52	52
(25)	Wind Purchases (NMWEC & Red Mesa)	10	15	15	15	15	15	15	15	15	15
(26)	Utility Scale Solar PV (42 MW by 2013 + 23 MW in 2015)	23	40	40	40	40	39	39	39	39	39
(27)	Utility Scale Prosperity Battery Demo (net of losses)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
(28)	PNM Sky Blue - 1.5 MW Solar	1	1	1	1	1	1	1	1	1	1
(29)	2015 Renewable Plan Resource -8 MW Geothermal	6	6	6	6	6	6	6	6	6	6
(30)	SJGS Replacement Resource: Utility Scale Solar PV (40 MW)			30	30	30	30	30	30	29	29
(31)	2019 Utility Scale Solar PV (60 MW)						42	42	42	42	42
(32)	2020 Utility Scale Solar PV (40 MW)							25	24	24	24
(33)	2021 Utility Scale Solar PV (60 MW)								31	31	31
(34)	2022 Utility Scale Solar PV (60 MW)									31	31
(35)	**Total Renewable Resources (MW)**	40	62	92	92	92	134	158	188	219	218
(36)	**Total System Resources (MW)**	**2,271**	**2,295**	**2,365**	**2,367**	**2,338**	**2,380**	**2,404**	**2,434**	**2,465**	**2,641**
(37)	**Reserve Margin (MW)**	**344**	**342**	**386**	**352**	**290**	**290**	**287**	**289**	**291**	**430**
(38)	**Reserve Margin (%)**	**17.8%**	**17.5%**	**19.5%**	**17.4%**	**14.2%**	**13.9%**	**13.5%**	**13.5%**	**13.4%**	**19.4%**

Notes:

* Assumes existing demand response contracts will be replaced with a similar resource at the end of the contract's term.
* PNM assumes a capacity credit for renewable resources based on type of technology and contribution at the peak hour
* Demand Response & Solar Resources grossed up for Transmission losses
* PNM assumes a 100% capacity credit for Prosperity Battery Demo
* Capacity credit for geothermal resource is based upon developer estimates
* Future resources are currently being selected through RFP's for renewables, natural gas, and load management, consistent with the action plan in PNM's 2011 IRP, filed July 18, 2011. PNM continually evaluates its need for resources as circumstances change.

Figure 7-B: Load and Resources Table (Revised SIP 132 MW SJGS Unit 4)

PUBLIC SERVICE COMPANY OF NEW MEXICO

Revised SIP 132 MW SJGS Unit 4 Scenario Load and Resource Projections for Summer Peak

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	Retail Demand + Losses	1,772	1,807	1,840	1,882	1,920	1,964	1,994	2,026	2,059	2,099
(2)	Navopache (without losses)	62	62	62	62	63	63	63	63	63	64
(3)	Aztec (without losses)	7	7	7	7	7	7	8	7	7	7
(4)	TNMP Retail - PNM South (with dist losses, without trans losses)	122	124	126	128	130	133	134	134	135	137
(5)	2014 Revised Forecasted System Peak Demands*	1,963	2,000	2,035	2,080	2,119	2,166	2,198	2,230	2,265	2,308
(6)	Forecasted Incremental Customer Sited PV	(15)	(18)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
(7)	Forecasted Incremental Energy Efficiency	(21)	(29)	(36)	(43)	(50)	(55)	(60)	(64)	(69)	(75)
(8)	**Net System Peak Demand (MW)**	**1,927**	**1,952**	**1,979**	**2,015**	**2,048**	**2,090**	**2,117**	**2,145**	**2,174**	**2,211**
(9)	Four Corners	200	200	200	200	200	200	200	200	200	200
(10)	San Juan (286 MW retirement)	783	783	783	783	497	497	497	497	497	497
(11)	**Total Coal Resources (MW)**	983	983	983	983	697	697	697	697	697	697
(12)	Palo Verde Unit 1 and Unit 2	268	268	268	268	268	268	268	268	268	268
(13)	Palo Verde Unit 3					134	134	134	134	134	134
(14)	**Total Nuclear Resources (MW)**	268	268	268	268	402	402	402	402	402	402
(15)	Reeves	154	154	154	154	154	154	154	154	154	154
(16)	Afton	230	230	230	230	230	230	230	230	230	230
(17)	Luna	185	185	185	185	185	185	185	185	185	185
(18)	Lordsburg	80	80	80	80	80	80	80	80	80	80
(19)	Valencia (PPA)	145	145	145	145	145	145	145	145	145	145
(20)	Delta-Person	138	138	138	138	138	138	138	138	138	138
(21)	La Luz			40	40	40	40	40	40	40	40
(22)	SJGS Replacement Resource: Gas Peaking Resource					177	177	177	177	177	177
(23)	**Total Natural Gas Resources (MW)**	932	932	972	972	1,149	1,149	1,149	1,149	1,149	1,149
(24)	Total Demand Response Programs (MW, net of losses)*	48	50	50	52	52	52	52	52	52	52
(25)	Wind Purchases (NMWEC & Red Mesa)	10	15	15	15	15	15	15	15	15	15
(26)	Utility Scale Solar PV (42 MW by 2013 + 23 MW in 2015)	23	40	40	40	40	39	39	39	39	39
(27)	Utility Scale Prosperity Battery Demo (net of losses)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
(28)	PNM Sky Blue - 1.5 MW Solar	1	1	1	1	1	1	1	1	1	1
(29)	2015 Renewable Plan Resource -8 MW Geothermal	6	6	6	6	6	6	6	6	6	6
(30)	SJGS Replacement Resource: Utility Scale Solar PV (40 MW)			30	30	30	30	30	30	29	29
(31)	2020 Utility Scale Solar PV (20 MW)							14	14	14	14
(32)	2021 Utility Scale Solar PV (60 MW)								42	42	42
(33)	2022 Utility Scale Solar PV (40 MW)									21	21
(34)	2023 Utility Scale Solar PV (60 MW)										31
(35)	2023 Utility Scale Wind (100 MW)										5
(36)	**Total Renewable Resources (MW)**	40	62	92	92	92	91	105	147	167	203
(37)	**Total System Resources (MW)**	**2,271**	**2,295**	**2,365**	**2,367**	**2,392**	**2,391**	**2,405**	**2,447**	**2,467**	**2,503**
(38)	**Reserve Margin (MW)**	**344**	**342**	**386**	**352**	**344**	**301**	**288**	**302**	**293**	**292**
(39)	**Reserve Margin (%)**	**17.8%**	**17.5%**	**19.5%**	**17.4%**	**16.8%**	**14.4%**	**13.6%**	**14.1%**	**13.5%**	**13.2%**

Notes:

* Assumes existing demand response contracts will be replaced with a similar resource at the end of the contract's term.
* PNM assumes a capacity credit for renewable resources based on type of technology and contribution at the peak hour
* Demand Response & Solar Resources grossed up for Transmission losses
* PNM assumes a 100% capacity credit for Prosperity Battery Demo
* Capacity credit for geothermal resource is based upon developer estimates
* Future resources are currently being selected through RFP's for renewables, natural gas, and load management, consistent with the action plan in PNM's 2011 IRP, filed July 18, 2011. PNM continually evaluates its need for resources as circumstances change.

Customer-Sited PV Forecast

The L&R Tables includes the projection of customer-sited generation from solar PV systems as a decrement to projected peak demand. This is because the customer demand that PNM must serve is net of the demand being met by the customer-sited generation. The solar PV forecast shown in Tables 7-A and 7-B is developed using information on historical customer interconnections and the size of the facilities being connected.

Energy Efficiency Forecast

The L&R Table also shows that customer demand is being reduced by customer-sited energy efficiency programs. In contrast, the demand response resource is shown as a firm PNM resource, since it is PNM that determines when to dispatch that resource, under the program guidelines as approved by the NMPRC. The L&R Table shows the level of demand response reaching 52 MW by 2017 and continuing at that level thereafter. This reflects an assumption that even though the current contracts with Comverge and EnerNOC will expire in 2017, that the programs will be continued or replaced by more cost-effective programs.

Accounting for EE programs is increasingly important to the forecasting process as the program effects grow. The L&R Tables show the incremental gains in energy efficiency demand savings over 2011 in the twenty year IRP load forecast. As these programs mature, the actual energy savings becomes embedded into historical sales data and is, therefore, embedded in the underlying load forecast.

Thermal Resources

The L&R Table shows currently existing resources over the next 10 years. It also includes the La Luz Plant, which is a proposed 40 MW gas-fired facility that the NMPRC recently approved. Total PVNGS capacity reflects PNM's plans to extend the leases or purchase leased capacity at fair value upon final expiration of the leases. The natural gas-fired thermal plants are also projected to be in-service throughout the 20-year planning period. All thermal generating plants are projected to be available to meet peak demand at their full planned capacity.

Renewable Energy Resources

The L&R Table shows energy resources that are currently existing and approved or renewable energy resources and their contribution to PNM's generation during the peak load hour. Based on historic data, wind resources are projected to contribute 5% of their capacity to meeting peak load. Depending on use of tracking systems and battery storage, PNM-owned solar generation ranges from 55% to 100% of capacity at the peak load hour. The Dale Burgett Geothermal facility is projected to be operating at a peak of 6 MW, which is the summer-derated value expected when the facility reaches 10 MW of net capacity.

8. DESCRIPTION OF THE PUBLIC ADVISORY PROCESS

PNM began preparing for the Public Advisory process in the spring of 2013 by placing newspaper advertisements and sending notifications in customer bills to create public awareness. On July 17, 2013, PNM began the process by notifying the NMPRC in accordance with the IRP Rule. The Public Advisory process was designed to provide transparency to PNM's resource planning by affording the opportunity for community meetings and inviting public participation. Through a series of meetings, representatives of the general public and various interest groups, along with PNM employees, actively engaged in the planning process by providing comments, sharing concerns, and proposing alternative scenarios, assumptions, and methodologies for consideration in this IRP.

PUBLIC ADVISORY MEETINGS

The purpose of the public advisory meetings was to provide an open and transparent process to inform and educate members regarding resource planning, as well as collect member comments, which could be incorporated into this IRP. At the meetings, PNM presented and discussed all of the data and analytic techniques used in this IRP and PNM provided hard-copy handouts of related reports and analyses to all meeting participants. PNM encouraged an open discussion of the topics and related issues. Table 8-A lists the IRP Public Advisory meetings, including dates, and topics discussed.

Table 8-A: Topics of IRP Public Advisory Meetings

Date	Topics
Jul. 2013	In a series of four public meetings, in Alamogordo, Silver City, Albuquerque and Santa Fe, PNM presented a broad overview of the IRP process, NMPRC expectations, regulatory requirements, utility bill factors and rate design.
Sept. 17, 2013	An introduction to the processes for IRP planning and portfolio analyses, collection of key assumptions portfolio risk assessments, and the regulatory and portfolio resource planning issues presented by regional haze compliance requirements at the San Juan Generating Plant.
Sept. 20, 2013	IRP goals and regulatory requirements. Overview of the preliminary mid-high-low demand sensitivity forecasts and the Pace Global forecasts. Overview of existing demand-side resources and energy efficiency regulatory requirements and PNM programs. Including O&M costs, emissions and water usage. An introduction to the transmission system.
Sept. 26, 2013	Detailed discussion of the methodology and processes to be undertaken in the portfolio analyses and Monte Carlo risk assessments used in identifying the Most Cost Effective Portfolio to be included in the 2014-

Date	Topics
	2033 IRP Report.
Nov. 15, 2013	Discussion of net system peak demand; fuel price forecasts; more detail on power plant water use intensity; PNM's solar/batter storage project; wind resource sensitivity; and a detailed discussion of PNM's transmission system.
Jan. 9, 2014	Overview of the analysis progress to date and remaining analyses to be conducted regarding portfolio modeling and risk analysis; presentation of the regional haze compliance scenarios and a comparison of the portfolio similarities and differences in costs and emission profiles.
Jan. 27, 2014	Review and discussion of advanced energy technologies; review and discussion of the mid-high-low demand sensitivity forecasts and underlying assumptions.
Feb. 7, 2014	Review of IRP goals, detailed discussion of the portfolio analyses undertaken and portfolio comparisons.
Feb. 18, 2014	Additional detail on portfolio modeling results and comparisons; sensitivities to CO2 pricing; energy efficiency impact sensitivities; portfolio sensitivities to drought conditions.
Mar. 11, 2014	Impact of solar penetration on net demand; impact of wind in meeting load; customer-sited distributed generation update, results of risk analyses of natural gas prices, load growth, emissions and electric market prices.
Jun. 26, 2014	Public advisory wrap-up.

Public Advisory Process Impact on the IRP Planning Process

The Public Advisory process resulted in significant contributions to PNM's planning process. Substantial feedback was provided, including prioritization recommendations regarding what areas had been covered adequately and which required more analysis.

Areas of Emphasis – Environmental Assumptions

As in past IRPs, the impact of environmental regulations has a major impact on resource selection for integrated planning. These include the EPA's Regional Haze Rule and the proposed Revised SIP for SJGS, potential greenhouse gas emission regulations, and other emissions from fossil fuel plants. Siting of resource facilities and transmission is affected by environmental regulation also.

A wide range of carbon assumptions was examined in the IRP scenario analyses. Carbon costs have a large cost impact under the various Pace Global macro-assumption scenarios and have great uncertainty regarding their volatility. The cost impact also varies sharply by the type of resource – from nearly zero with solar/wind to potentially very significant for gas and coal generation. As a consequence of the large impact and the uncertainty of GHG regulation, carbon cost scenarios became one key assumption for the IRP modeling.

Other environmental regulations were of interest and were considered in the analysis. This included the impacts on natural gas costs from potential regulation of hydraulic fracturing for natural gas drilling. Changes in natural gas costs can impact the choice of gas-fired generation versus other resources.

Areas of Emphasis – Energy Efficiency and Water Conservation

The public advisory participants indicated that conservation of natural resources is an important goal. Energy efficiency programs can reduce the consumption of valuable resources such as fuel and water. The demand side management programs and how they affect load and resource planning were discussed at length in the meetings and in this report. This combination of demand and supply is the "integrated" part of IRP.

There was a strong consensus among the members that water conservation required special consideration. Several sensitivity analyses regarding the availability of water were performed. Also, water usage is tracked and reported in the modeling work. While acknowledging that water cost is a small part of total cost and that the Company has ample water rights for generation needs, PNM agreed with the working group that water is a scarce and important resource in New Mexico. Conservation of water and advance preparation for the possibility of water supply interruptions therefore became a point of emphasis in the IRP.

Areas of Emphasis – Other Technologies

The public advisory participants wanted to explore potential new technologies as well as other conventional generation types that were not emerging from the modeling as cost-effective portfolios. Building additional nuclear plants showed to be too expensive for selection, but new small modular nuclear reactor technology may have promise for future application. Renewable resources other than wind or solar were discussed; specifically geothermal and bio-mass.

Advanced technologies hold promise to serve as demand-side resources or to make supply resources more efficient. Technology advances may also result in increased demands on utilities. For example, electric vehicles may shift demand for gasoline into increased demand for electricity for battery charging.

Smart-grid applications can help on both the demand and supply sides of the equation. Smart appliances can reduce load or shift usage to off-peak times. Smart meters can improve pricing signals to customers and allow more efficient dispatch of generation. The increasing use of technology is leading to more efficient wholesale market organization. Coordination among utilities can enhance dispatch efficiency, offsetting increasing transmission congestion and costs of aging infrastructure. Storage technology improvements may help with peak trimming and also mitigate some challenges that renewables pose due to their intermittent generation characteristics. Battery, thermal and other storage advances will be monitored.

Other questions from participants addressed the role of distributed generation. Issues regarding reliability, maintenance costs and regulation of generation were also addressed.

SPECIFIC PROCESS IMPROVEMENTS FROM PUBLIC ADVISORY PROCESS

The Public Advisory process resulted in the following significant contributions to PNM's planning process:

- An examination of the contribution of solar capacity to meeting customer demand resulted in PNM refining its solar PV modeling technique. This resulted in an increase in the quantity of solar PV resources in the Most Cost Effective Portfolio over what it otherwise would have been.
- Development of a wind sensitivity analysis demonstrating that resource cost is the determinative factor in the decision to add wind resources to PNM's portfolio.
- Discussion during the Public Advisory sessions shaped the agenda for each meeting through the process.
- Interest in the use of water for electric generation was high so PNM presented data on water use and updated its sensitivity analysis that examines the impact of drought conditions.

9. ACTION PLAN FOR 2014-2018

The IRP Rule at Section 17.7.3.9I requires that PNM include in the IRP Report an action plan for the four-year period following the filing of the IRP. Additionally, PNM is required to include a status report of the specific actions that were presented in the action plan in the 2011 IRP Report.

ACTION PLAN

PNM's four-year action plan identifies actions to be taken during 2014-2018 to implement the resource acquisitions identified in this 20-year IRP. This includes actions that must be taken during the 2014-2018 period to address resource additions occurring after 2018. PNM's current action plan is shown in Table 9-A.

Table 9-A: 2014-2018 Action Plan

RESOURCE STRATEGY	ACTION	TIMING AND STATUS
SAN JUAN UNITS 2 AND 3 RETIREMENT AND BASELOAD REPLACEMENT RESOURCES		
Retire San Juan Units 2 and 3 by end of 2017.	1. Pursue currently filed abandonment application at the NMPRC.	Filing made in December 2013.NMPRC decision by end of 2014 or early 2015
Acquire replacement base load capacity in San Juan Unit 4	1. Pursue currently filed application for a CCN for 78 MW at the NMPRC	Filing made in December 2013.NMPRC decision by end of 2014 or early 2015
Obtain NMPRC authorization to use PVNGS Unit 3 as a new base load jurisdictional resource	1. Pursue currently filed application for a CCN at the NMPRC	Filing made in December 2013.NMPRC decision by end of 2014 or early 2015
RENEWABLE ENERGY SUPPLY RESOURCES		
Develop Renewable Resources to Use for SJGS Replacement Resources	1. Seek NMPRC approval for 40 MW of new solar renewable resources to be constructed for RPS and diversity compliance and to replace generating capacity for the retired SJGS capacity. Once approved, construct in time to be in-service by 2016.	Filing at NMPRC made on June 1, 2014. There is a six-month review process. The construction schedule will be addressed in the contract.
Develop New Renewable Resources for RPS Compliance	1. Periodically issue RFPs to evaluate renewable resource availability and price.	Updates to be made when called for by changes in customer load or in renewable markets or by regulatory developments affecting.

RESOURCE STRATEGY	ACTION	TIMING AND STATUS
	2. Annually file Renewable Energy Plans for NMPRC approval.	PNM filed a renewable energy procurement plan on June 1, 2014 and will annually file additional plans every June 1.
NATURAL GAS GENERATION RESOURCES		
Develop New Natural Gas-Fired Resources to Meet System Requirements in 2015-2017	1. Conduct preliminary site selection study for all natural gas resource types.	Site scoping is underway.
	2. Issue an RFP for natural gas resources to determine optimal technology, location, and ownership structure.	Preparations for issuing an RFP have commenced. The RFP is anticipated to be issued no later than the third quarter of 2014.
	3. File for CCN approval from NMPRC for identified optimal gas resource(s)	Initial planning for a CCN application has begun. A filing in 1st quarter 2015 is anticipated. The CCN regulatory review process can take up to 15 months.
MONITOR, EVALUATE, AND NEGOTIATE EXISTING RESOURCE CONTRACTS		
Preserve Generation Resources at PVNGS Units 1 and 2.	1. For leases expiring in 2016, negotiate purchase at market value.	PNM will purchase 64 MW of PVNGS that are currently being leased. The remaining leased capacity has lease terms to 2023 or 2024.
	2. File applications at NMPRC to acquire the expiring leased capacity upon execution of contracts.	
Extend SJGS fuel supply beyond the current coal supply contract.	1. Negotiate coal contract extension with San Juan Coal Company.	Discussions with San Juan Coal Company have been initiated.
	2. Investigate options for alternative coal supplies for SJGS.	Examination of the potential for alternative coal supplies is underway.
DEMAND AND LOAD MANAGEMENT RESOURCES		
Develop Energy Efficiency Potential	1. File Energy Efficiency Plan in the fall of 2014 taking into account recent amendments to the EUEA with input from the energy efficiency public advisory process.	PNM is assessing the implications of the recent EUEA amendments and has begun the EE public advisory process.

Resource Strategy	Action	Timing and Status
Develop Cost Effective Demand Response Potential	1. Determine best strategy to replace or extend existing demand response programs beyond 2017.	Such a proposal will be included in the next EE program application after the 2014 filing.
Identify and Implement New Programs to Meet EUEA Requirement of 8% of 2005 Retail Sales by 2020 and Annual Spending Equivalent to 3% of Retail Revenues	1. Review potential cost effective programs with public advisory group and, as applicable, propose to NMPRC for approval.	This will be done in the preparation process for each upcoming bi-annual plan filing.
	2. Continue to use results of annual M&V reports to identify program enhancement opportunities or replacement needs	This will be done annually.
	3. Continue to monitor developments at other utilities and assess potential for PNM's service area.	On-going.
Transmission Resources		
Evaluate Long-Term Transmission Requirements	1. Participate in regional transmission development activities consistent with FERC Order 1000.	PNM will continue to participate in regional transmission planning consistent with FERC approved Order 1000 procedures.
	2. Evaluate opportunities to improve transmission import capability into Northern New Mexico.	PNM continues to evaluate opportunities to enhance PNM's transmission system.
New Technology Development		
Evaluate Storage Viability, Benefits& Costs	1. Continue with the evaluation of the Prosperity Solar Energy Battery Project	Testing in collaboration with multiple entities began in 2011 and will be completed in 2014. Additional research opportunities are being investigated that would use the Prosperity Energy Storage facility.
	2. Monitor industry research on broad spectrum of storage technologies.	Ongoing.
Monitor and Assess Deployment of Smart Grid Technology and Remote Metering	1. Monitor deployment by PNM's affiliate in Texas and evaluate lessons learned.	Currently following affiliate's progress in Texas and developing regulatory

Resource Strategy	Action	Timing and Status
	2. Evaluate feasibility of implementing Automated Metering Infrastructure (AMI) in PNM's retail service area	framework at the State level. PNM periodically assesses the feasibility of implementing AMI on its system.
	3. Monitor other industry participants to determine impacts and benefits of emerging grid and metering technologies	Ongoing.
Monitor New Resource Technologies and Enhancements to Existing Technologies	1. Monitor advancements in resource technologies including modular nuclear reactors, carbon capture, gas efficiency improvements, renewable technology and efficiency improvements	Currently participating in industry-wide research forums and working with resource manufacturers and developers.
Monitor Deployment of Electric Vehicles	1. Monitor industry research regarding impacts and penetration of electric vehicles	Monitoring developments in research and commercial growth in the industry and New Mexico is on-going.

Status Report on 2011 IRP Action Plan

The IRP Rule requires that the IRP Report include a status report on the specific actions set forth in the prior IRP Report. The report is provided in Table 9-B. The first two columns list the strategy and action described in the 2011 IRP; the third column presents the status update.

Table 9-B: Status Report on 2011 IRP Action Plan

Implementation Strategy	Action	Status Report
Fully Develop Energy Efficiency Potential	1. Evaluate energy efficiency as part of the process for preparing annual energy efficiency filings for the NMPRC.	PNM is participated in a statewide potential study initiated by the New Mexico Energy, Minerals and Natural Resources Department. PNM will use the study to benchmark the energy efficiency forecast and help identify program applications.
	2. Propose aggressive energy efficiency programs meeting the TRC test.	Most recently, PNM received approval of programs filed October 5, 2013. Additional program filings will be made at least every two years, depending on numerous factors such as actual performance of existing programs and the identified potential for

Implementation Strategy	Action	Status Report
		new program offerings.
Fully Develop Cost Effective Load Management Potential	1. Determine best strategy to extend existing programs beyond 2017.	Preliminary discussions have been initiated with PNM's two existing contractors.
	2. Investigate potential for additional demand response and technologies that can shift peak demand, such as thermal energy storage.	PNM continues efforts to increase customer participation in demand response programs and evaluation of the cost-effectiveness of other programs impacting peak demand.
Develop Cost-Effective Diverse Renewable Resources	1. Periodically issue RFPs to evaluate renewable resource availability and price	PNM issued RFPs for renewable resources in November 2012 and December 2013. Winning bids were included in the following year's renewable energy plans.
	2. Annually file Renewable Energy Plans for NMPRC approval	PNM filed Renewable Energy Portfolio Procurement Plans on July 1, 2012 and 2013 and on June 1, 2014.
Add Natural Gas-Fired Resources to meet system requirements in 2015-2017	1. Conduct preliminary site selection study encompassing all natural gas resource types.	Site scoping continued into 2012.
	2. Issue an RFP for natural gas resources to determine optimal technology, location, and ownership structure.	PNM issued an RFP in October 2011 for new peaking resources.
	3. File for CCN approval from NMPRC for identified optimal gas resource(s)	A CCN Application was filed for the 40 MW La Luz plant in May 2013. The regulatory review process can take up to 15 months.
Evaluate Long-Term Transmission Requirements	1. Monitor and participate in regional transmission development activities	PNM participated in regional transmission planning groups to monitor developments and formulate a regional planning coordination process consistent with FERC Order 1000.
	2. Evaluate increased transmission import capability through PNM's transmission planning stakeholder process.	Opportunities were and continue to be assessed.

Implementation Strategy	Action	Status Report
Evaluate Storage Viability, Benefits, & Costs	1. Test and develop a report on ability of batteries to firm the dispatch of energy generated by PV systems.	The Prosperity solar PV and batter plant went on-line in 2011. Studies continue of the capabilities of the plant to provide system regulation and meet load swings.
	2. Monitor industry research on broad spectrum of storage technologies.	Continuing.
Monitor Deployment of Smart Grid and Remote Metering	1. Monitor deployment by affiliate in Texas and evaluate lessons learned.	On-going.
	2. Monitor other industry participants to determine impacts and benefits of emerging grid and metering technologies	Currently following various pilot projects and utility implementations.
Monitor New Resource Technologies and Enhancements to Existing Technologies	1. Monitor advancements in resource technologies including modular nuclear reactors, carbon capture, gas efficiency improvements, renewable technology and efficiency improvements	Currently participating in industry-wide research forums and working with resource manufacturers and developers.
Monitor Deployment of Electric Vehicles	1. Monitor industry research regarding impacts and penetration of electric vehicles	Monitoring and research is ongoing.
Monitor, Evaluate and Negotiate Existing Resource Contracts	1. Extend SJGS fuel supply beyond 2017	PNM has entered into discussions with San Juan Coal Company and is evaluating the potential for alternative coal supplies.
	2. Secure PVNGS leases	Continuing.

10. Appendices

Appendix A: Existing Generation Performance and O&M Data

Existing Resources											
Resource Name	San Juan GS Unit 1	San Juan GS Unit 2	San Juan GS Unit 3	San Juan GS Unit 4	Palo Verde Unit 1	Palo Verde Unit 2	Four Corners Units 4	Four Corners Units 5	Reeves Unit 1	Reeves Unit 2	Reeves Unit 3
Strategist Name	SANJUAN 1	SANJUAN 2	SANJUAN 3	SANJUAN 4	PVERDE 1	PVERDE 2	FOURCORN 4	FOURCORN 5	REEVES 1	REEVES 2	REEVES 3
Financial Planning Database											
IRP Size, MW	170	170	248	195	134	134	100	100	44	44	66
IRP Reference Year	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014
Construction Escalation, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
O&M Escalation, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Total Plant Cost, $000's											
AFUDC, $000's											
Total Capital+AFUDC, $000's											
Total Capital+AFUDC, $/kW											
Total Capital NPV Strat Input, $000's											
IRP/BART Performance and O&M											
IRP/BART Size, MW	170	170	248	195	134	134	100	100	44	44	66
Year 1st Available	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014
Fixed O&M, $/kW-yr					$ 164.66	$ 138.55	$ 86.64	$ 86.64	$ 32.08	$ 32.08	$ 32.08
Fixed O&M, k$/yr	See SJGS Table				$22,065	$18,566	$8,664	$8,664	$1,412	$1,412	$2,117
Variable O&M, $/MWh	included in FOM										
Variable O&M, k$/yr											
Forced Outage Rate	See SJGS Forced Outage Rate Sheet (Page 5)				2.00%	2.00%	12.00%	12.00%	3.30%	3.30%	3.30%
Average Heat rate, Btu/kWh	10,991	10,991	10,991	10,991	10,300	10,300	9,850	9,850	10,979	10,979	10,979
PPAs											
PPA Alternative - COE ($/MWh)											
IRP Reference Year											
PPA Escalation per year (%)											
Emissions Data											
NOx (lbs/MWh)	0.01601	0.01601	0.01601	0.01601	0.0000	0.0000	0.04943	0.04943	0.00012	0.00012	0.00012
SO2 (lbs/MWh)	0.00461	0.00461	0.00461	0.00461	0.00000	0.00000	0.01599	0.01599	0.00000	0.00000	0.00000
CO2 (lbs/MWh)	2,312	2,312	2,312	2,312	-	-	2,053	2,053	1,569	1,569	1,569
Mercury ($1x10^{-9}$ lbs/kWh)	0.63000	0.63000	0.63000	0.63000	-	-	9.64000	9.64000	Not reported	Not reported	Not reported
Fresh Water Usage (gal/MWh)	594				23		522		998		

Existing Resources											
Resource Name	Afton	Luna	Lordsburg Units 1-2	Delta	Solar	Solar	Solar	Valencia	NMWEC	Red Mesa	Lightning Dock
Strategist Name	AFTNCC	LUNA	LDBG	DELTA	PV-21.5	PV-22.5	S15O	BH-VAL	NMWEC	RMESA	LDGEO
Financial Planning Database											
IRP Size, MW	230	185	80	138	21.5	22.5	23	145	200	102	10
IRP Reference Year	2014	2014	2014	2014	2014	2014	2015	2014	2014	2015	2015
Construction Escalation, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
O&M Escalation, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Total Plant Cost, $000's											
AFUDC, $000's											
Total Capital+AFUDC, $000's											
Total Capital+AFUDC, $/kW											
Total Capital NPV Strat Input, $000's											
IRP/BART Performance and O&M											
IRP/BART Size, MW	230	185	80	138	21.5	22.5	23	145	200	102	10
Year 1st Available	2014	2014	2014	2014	2014	2014	2015	2014	2014	2014	2015
Fixed O&M, $/kW-yr	$ 24.35	$ 28.25	$ 15.28	$ 10.13	$ 24.19	$ 24.04	$ 18.61	$ 32.35			
Fixed O&M, k$/yr	$5,601	$5,226	$1,222	$1,398	$520	$541	$428	$4,690			
Variable O&M, $/MWh											
Variable O&M, k$/yr											
Equivalent Availability	91.20%	93.50%	98.30%								
Forced Outage Rate	3.30%	3.30%	3.30%	3.30%				3.30%			
Average Heat rate, Btu/kWh	7,750	7,450	9,600	10,600				10,600			
PPAs											
PPA Alternative - COE ($/MWh)									27.25	28.62	97.47
IRP Reference Year									2014	2015	2014
PPA Escalation per year (%)									0.0%	4.5%	2.75%
Emissions Data											
CO(lbs/MWh)	0.00013	0.00012	0.00130	0.00464	0.00000	0.00000	0.00000	0.00042	0.0000	0.0000	0.0000
NOx (lbs/MWh)	0.00012	0.00000	0.00002	0.00008	0.00000	0.00000	0.00000	0.00004	0.00000	0.00000	0.00000
Particulate (lbs/MWh)	0.00000	0.00001	0.00001	0.00005	0.00000	0.00000	0.00000	0.00001	0.0000	0.0000	0.0000
SO2 (lbs/MWh)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
CO2 (lbs/MWh)	962	972	1,515	1,099	-	-	-	1,459	-	-	-
Mercury ($1x10^{-9}$ lbs/kWh)	Not reported	Not reported	-	Not reported	-	-	-	Not reported	-	-	-
Fresh Water Usage (gal/MWh)	122	333	409	42	0	0	0	24	0	0	0

	San Juan Generating Station											
	FIP ("4 SCR")				Revised SIP (78 MW Unit 4)				Revised SIP (132 MW Unit 4)			
	Unit 1	Unit 2	Unit 3	Unit 4	Unit 1	Unit 2	Unit 3	Unit 4	Unit 1	Unit 2	Unit 3	Unit 4
Year	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)	Total O&M (k$/yr)
2014	$ 39,248	$ 41,666	$ 49,836	$ 40,143	$ 33,831	$ 36,205	$ 47,969	$ 37,718	$ 33,831	$ 36,205	$ 47,969	$ 37,718
2015	$ 46,011	$ 37,897	$ 63,632	$ 44,038	$ 42,087	$ 35,426	$ 51,680	$ 46,504	$ 42,087	$ 35,426	$ 51,680	$ 46,504
2016	$ 39,021	$ 46,874	$ 60,594	$ 52,095	$ 35,697	$ 35,697	$ 52,075	$ 40,946	$ 35,697	$ 35,697	$ 52,075	$ 40,946
2017	$ 44,676	$ 40,568	$ 58,722	$ 50,450	$ 41,378	$ 36,931	$ 53,876	$ 42,362	$ 41,378	$ 36,931	$ 53,876	$ 42,362
2018	$ 42,790	$ 47,329	$ 67,139	$ 49,561	$ 37,678	$ -	$ -	$ 57,661	$ 39,649	$ -	$ -	$ 67,442
2019	$ 48,342	$ 43,561	$ 63,109	$ 54,645	$ 46,149	$ -	$ -	$ 50,557	$ 48,128	$ -	$ -	$ 59,217
2020	$ 44,454	$ 49,272	$ 69,911	$ 51,442	$ 37,182	$ -	$ -	$ 63,067	$ 39,194	$ -	$ -	$ 74,143
2021	$ 50,328	$ 45,266	$ 65,623	$ 56,820	$ 38,063	$ -	$ -	$ 53,239	$ 40,107	$ -	$ -	$ 62,314
2022	$ 46,248	$ 51,362	$ 72,893	$ 53,474	$ 43,961	$ -	$ -	$ 54,242	$ 46,040	$ -	$ -	$ 63,446
2023	$ 52,565	$ 47,205	$ 68,477	$ 59,278	$ 39,773	$ -	$ -	$ 61,302	$ 41,892	$ -	$ -	$ 71,833
2024	$ 48,273	$ 59,330	$ 81,834	$ 55,769	$ 40,765	$ -	$ -	$ 56,966	$ 42,924	$ -	$ -	$ 66,568
2025	$ 60,784	$ 49,274	$ 71,521	$ 66,349	$ 47,416	$ -	$ -	$ 58,386	$ 49,616	$ -	$ -	$ 68,195
2026	$ 50,382	$ 56,149	$ 79,722	$ 58,161	$ 42,828	$ -	$ -	$ 66,093	$ 45,069	$ -	$ -	$ 77,349
2027	$ 57,344	$ 51,430	$ 74,691	$ 64,403	$ 43,901	$ -	$ -	$ 61,346	$ 46,183	$ -	$ -	$ 71,587
2028	$ 52,579	$ 58,697	$ 83,355	$ 60,654	$ 57,633	$ -	$ -	$ 62,890	$ 59,955	$ -	$ -	$ 73,355
2029	$ 59,938	$ 53,675	$ 77,992	$ 67,248	$ 46,135	$ -	$ -	$ 79,338	$ 48,498	$ -	$ -	$ 92,970
2030	$ 54,868	$ 61,358	$ 87,145	$ 63,252	$ 47,297	$ -	$ -	$ 66,110	$ 49,702	$ -	$ -	$ 77,043
2031	$ 62,648	$ 56,014	$ 81,430	$ 70,219	$ 54,958	$ -	$ -	$ 67,790	$ 57,403	$ -	$ -	$ 78,967
2032	$ 57,252	$ 64,137	$ 91,102	$ 65,960	$ 49,718	$ -	$ -	$ 76,691	$ 52,205	$ -	$ -	$ 89,535
2033	$ 65,479	$ 58,452	$ 85,012	$ 73,322	$ 50,979	$ -	$ -	$ 71,298	$ 53,506	$ -	$ -	$ 82,982

	Energy Efficiency			Distributed Generation		
Year	Demand at Peak (MW)	Annual Energy (GWh)	Annual Cost ($000)	Demand at Peak (MW)	Annual Energy (GWh)	Annual Cost ($000)
2014	(23.94)	(184.05)	$ 18,386	(15.57)	(67.55)	$ 7,857
2015	(33.77)	(252.80)	$ 18,663	(18.57)	(82.07)	$ 8,213
2016	(42.21)	(301.66)	$ 18,595	(20.95)	(92.23)	$ 8,429
2017	(52.44)	(353.14)	$ 20,957	(21.69)	(95.97)	$ 8,579
2018	(60.50)	(397.54)	$ 19,191	(22.40)	(95.97)	$ 8,536
2019	(66.51)	(425.75)	$ 19,378	(22.29)	(95.49)	$ 8,494
2020	(76.32)	(450.06)	$ 19,604	(22.17)	(95.01)	$ 8,451
2021	(80.46)	(490.87)	$ 19,783	(22.07)	(94.54)	$ 8,409
2022	(89.79)	(537.00)	$ 19,963	(21.96)	(94.06)	$ 8,367
2023	(95.05)	(573.56)	$ 20,144	(21.84)	(93.59)	$ 8,325
2024	(100.44)	(593.06)	$ 20,326	(21.74)	(93.12)	$ 8,284
2025	(104.34)	(611.58)	$ 20,510	(21.63)	(92.66)	$ 8,242
2026	(104.36)	(620.83)	$ 20,695	(21.52)	(92.20)	$ 8,201
2027	(105.69)	(624.00)	$ 20,881	(21.41)	(91.73)	$ 8,160
2028	(106.86)	(622.86)	$ 21,068	(21.31)	(91.28)	$ 8,119
2029	(106.90)	(625.04)	$ 21,257	(21.20)	(90.82)	$ 8,079
2030	(104.79)	(615.60)	$ 21,446	(21.09)	(90.37)	$ 8,038
2031	(102.10)	(583.60)	$ 21,638	(20.99)	(89.91)	$ 7,998
2032	(93.18)	(538.29)	$ 21,830	(20.88)	(89.46)	$ 7,958
2033	(93.15)	(512.32)	$ 22,023	(20.77)	(89.02)	$ 7,918

	Forced Outage Rate (%)							
	RSIP Cases				FIP Cases			
Year	SANJUAN 1	SANJUAN 2	SANJUAN 3	SANJUAN 4	SANJUAN 1	SANJUAN 2	SANJUAN 3	SANJUAN 4
2014	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%
2015	13.8%	13.8%	13.8%	13.8%	12.3%	12.3%	12.3%	12.3%
2016	13.3%	13.3%	13.3%	13.3%	11.0%	11.0%	11.0%	11.0%
2017	14.5%	14.5%	14.5%	14.5%	10.8%	10.8%	10.8%	10.8%
2018	11.0%			11.0%	11.3%	11.3%	11.3%	11.3%
2019	11.0%			11.0%	11.0%	11.0%	11.0%	11.0%
2020	11.0%			11.0%	11.0%	11.0%	11.0%	11.0%
2021	12.0%			12.0%	11.3%	11.3%	11.3%	11.3%
2022	10.5%			10.5%	10.8%	10.8%	10.8%	10.8%
2023	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2024	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2025	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2026	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2027	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2028	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2029	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2030	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2031	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2032	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%
2033	10.5%			10.5%	10.5%	10.5%	10.5%	10.5%

APPENDIX B: TRANSMISSION FACILITIES

Table B-1: 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	
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 B-2: 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)

Table B-2: 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 B-3: 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

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, since 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 due to increasing use of regional coal plants to serve as regulating resources as wind generation increased. Utilities have moved to limit their 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 Balancing Area ("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 in regards to 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

PNM uses dynamic scheduling to reduce energy imbalances for VERs that are interconnected in PNM's BA and selling its output to an entity that is physically located within another BA. As a result, the utility in the BA that receives the output from the VER uses its resources to provide the regulation, load-following, imbalance or other ancillary service requirements. Therefore, the cost for the integration of the VERs is shifted to the consumers of the renewable energy. 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 VER host BA's existing limited regulation generating resources, and
- 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.

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. PNM joined the WECC RBC Field Trial in June 2011. The integration of VER can cause an increase in the frequency variation within an interconnected electric system. Frequency variation contributes to a Balancing Area (BA) Area Control Error (ACE) through the frequency bias term in the ACE equation. ACE is a quantity that each BA Automatic Generation Control (AGC) system computes and regulates by ramping generation to match its load. Since the 1990's, AGC systems have regulated ACE within limits prescribed by the CPS2 Control Performance Standard mandated by NERC. 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 set up 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 coordinating the planning of the western grid. Planning processes involve open dialogue 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 each 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 since 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 who have spent extensive time and effort on a project ahead of PNM committing time and money on a new technology or a new method of operating the system.

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, assure 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 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:

a. 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,
b. 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,
c. Evaluate proposed additions or alterations in facilities in relation to established reliability criteria,
d. Identify the types and investigate the impact of delay on the timing and availability of power generation and transmission facilities,
e. Review reports and recommendations prepared by subcommittees and others concerning reliability and adequacy of power supply and forward same with comments and/or recommendations to the Board of Directors in a timely manner, and
f. 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 of TEPPC is based on balanced representation designed to reflect the geographic and stakeholder breadth of WECC. TEPPC will include transmission providers, policy makers, 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. PNM at times 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.

<u>WestConnect</u>

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 normally 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.

<u>Southwest Area Transmission Planning Oversight Committee</u>

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.

<u>Other Transmission Planning Committees</u>

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. While 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, Salt River Project, Tucson Electric Power and the Desert Southwest region of the Western Area Power Administration.

SVERI mission is to evaluate likely penetration, locations and operating characteristics of VERs within the Southwest Sub-region over the next 20 years. It explore 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 C: LOAD FORECAST DATA

Current System Peak Demand (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PNM Retail (PNM North)	1,577	1,608	1,638	1,676	1,710	1,750	1,778	1,807	1,837	1,875	1,914	1,953	1,995	2,035	2,083	2,124	2,169	2,209	2,250	2,294
Distribution Losses	74	76	77	79	80	82	82	83	84	86	87	88	90	92	92	94	96	97	99	101
Transmission Losses	121	123	125	128	130	132	134	135	137	139	141	143	145	149	148	152	154	157	159	162
Subtotal	1,772	1,807	1,840	1,882	1,920	1,964	1,994	2,026	2,059	2,099	2,141	2,184	2,230	2,276	2,323	2,370	2,419	2,463	2,508	2,557
TNMP Retail (PNM South)	122	124	126	128	130	133	134	134	135	137	140	142	144	147	149	152	155	157	160	163
Wholesale																				
Gallup	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Navopache	62	62	62	62	63	63	63	63	63	64	64	64	64	64	65	65	65	65	65	65
Aztec	7	7	7	7	7	7	8	7	7	7	7	8	7	8	8	8	7	8	8	8
Subtotal	69	69	69	69	70	70	71	70	71	71	71	72	72	72	72	72	72	73	73	73
Energy Efficiency Programs (incremental)	(21)	(29)	(36)	(43)	(50)	(55)	(60)	(64)	(69)	(75)	(79)	(80)	(80)	(81)	(81)	(81)	(81)	(81)	(81)	(81)
Distributed Generation (incremental)	(15)	(18)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(20)	(20)	(20)	(20)	(20)	(20)
Net System Total	1,927	1,952	1,979	2,015	2,048	2,090	2,117	2,146	2,175	2,212	2,252	2,297	2,344	2,393	2,442	2,493	2,545	2,593	2,640	2,692

2014 IRP Mid System Peak Demand (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PNM Retail (PNM North)	1,586	1,603	1,614	1,629	1,637	1,647	1,656	1,665	1,675	1,685	1,696	1,707	1,718	1,729	1,741	1,753	1,766	1,779	1,798	1,816
Distribution Losses	77	78	79	80	80	80	81	81	82	82	83	83	84	84	85	86	86	87	87	88
Transmission Losses	126	127	128	129	130	131	131	132	133	134	135	135	136	137	138	139	140	141	142	144
Subtotal	1,792	1,812	1,824	1,841	1,849	1,861	1,871	1,882	1,893	1,904	1,916	1,928	1,941	1,954	1,967	1,981	1,995	2,010	2,031	2,048
TNMP Retail (PNM South)	123	125	126	128	128	129	129	130	131	132	133	135	136	137	139	141	142	143	144	145
Wholesale																				
Gallup	35	35	36	37	38	38	39	39	40	40	40	41	41	43	43	44	44	45	43	43
Navopache	62	62	62	62	63	63	63	63	63	64	64	64	64	64	65	65	65	65	65	65
Aztec	7	7	7	7	7	7	8	7	7	7	7	8	7	8	8	8	7	8	8	8
Subtotal	104	104	106	106	107	108	109	110	110	111	111	113	112	115	115	116	117	118	116	116
Energy Efficiency Programs (incremental)	(22)	(32)	(40)	(49)	(57)	(62)	(72)	(75)	(84)	(91)	(94)	(98)	(98)	(99)	(100)	(100)	(98)	(96)	(87)	(87)
Distributed Generation (incremental)	(15)	(17)	(20)	(20)	(21)	(21)	(21)	(21)	(21)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(19)
Net System Total	1,983	1,991	1,997	2,005	2,007	2,014	2,017	2,025	2,029	2,036	2,046	2,058	2,071	2,087	2,102	2,118	2,136	2,156	2,184	2,203

2014 IRP Low System Peak Demand (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PNM Retail (PNM North)	1,578	1,578	1,581	1,589	1,589	1,589	1,583	1,585	1,589	1,598	1,609	1,620	1,632	1,643	1,655	1,668	1,678	1,688	1,706	1,722
Distribution Losses	77	77	77	78	78	78	77	77	78	78	79	79	80	80	81	81	82	82	83	84
Transmission Losses	125	125	126	126	126	127	126	126	127	128	128	129	130	131	132	133	134	135	136	136
Subtotal	1,783	1,783	1,787	1,796	1,796	1,796	1,790	1,792	1,796	1,806	1,819	1,832	1,844	1,858	1,871	1,885	1,898	1,908	1,927	1,942
TNMP Retail (PNM South)	123	125	126	128	128	129	129	130	131	132	133	135	136	137	139	141	142	143	144	145
Wholesale																				
Gallup	35	35	36	37	38	38	39	39	40	38	40	41	41	43	42	44	44	45	43	43
Navopache	62	62	62	62	63	63	63	63	63	63	64	64	64	64	62	65	65	65	65	65
Aztec	7	7	7	7	7	7	8	7	7	7	7	8	7	8	8	8	7	8	8	8
Subtotal	104	104	106	106	107	108	109	110	110	109	111	113	112	115	111	116	117	118	116	116
Energy Efficiency Programs (incremental)	(22)	(32)	(40)	(49)	(57)	(62)	(72)	(75)	(84)	(91)	(94)	(98)	(98)	(99)	(100)	(100)	(98)	(96)	(87)	(87)
Distributed Generation (incremental)	(15)	(17)	(20)	(20)	(21)	(21)	(21)	(21)	(21)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(19)
Net System Total	1,974	1,963	1,959	1,961	1,954	1,950	1,936	1,936	1,933	1,935	1,949	1,962	1,975	1,990	2,002	2,022	2,038	2,054	2,081	2,097

2014 IRP High System Peak Demand (MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PNM Retail (PNM North)	1,607	1,642	1,665	1,689	1,707	1,720	1,737	1,751	1,765	1,785	1,806	1,827	1,849	1,871	1,892	1,915	1,936	1,955	1,981	2,004
Distribution Losses	78	80	81	82	83	84	85	85	86	87	88	89	90	91	92	93	94	95	96	97
Transmission Losses	127	130	131	133	135	136	137	138	139	141	142	144	146	147	149	151	152	154	155	158
Subtotal	1,815	1,855	1,880	1,908	1,928	1,943	1,962	1,977	1,994	2,016	2,040	2,063	2,088	2,112	2,136	2,162	2,185	2,206	2,235	2,260
TNMP Retail (PNM South)	123	125	126	128	128	129	129	130	131	132	133	135	136	137	139	141	142	143	144	145
Wholesale																				
Gallup	35	35	36	37	38	38	39	39	40	38	40	41	41	43	42	44	44	45	43	43
Navopache	62	62	62	62	63	63	63	63	63	63	64	64	64	64	62	65	65	65	65	65
Aztec	7	7	7	7	7	7	8	7	7	7	7	8	7	8	8	8	7	8	8	8
Subtotal	104	104	106	106	107	108	109	110	110	109	111	113	112	115	111	116	117	118	116	116
Energy Efficiency Programs (incremental)	(22)	(32)	(40)	(49)	(57)	(62)	(72)	(75)	(84)	(91)	(94)	(98)	(98)	(99)	(100)	(100)	(98)	(96)	(87)	(87)
Distributed Generation (incremental)	(15)	(17)	(20)	(20)	(21)	(21)	(21)	(21)	(21)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(19)
Net System Total	2,005	2,034	2,053	2,073	2,086	2,096	2,108	2,121	2,130	2,144	2,170	2,193	2,218	2,245	2,267	2,299	2,326	2,352	2,388	2,414

Current Annual Energy (GWh)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PNM Retail (PNM North)	8,023,463	8,114,831	8,189,436	8,340,818	8,444,967	8,594,750	8,638,572	8,687,209	8,746,528	8,859,612	8,976,324	9,097,978	9,228,367	9,361,660	9,492,342	9,626,345	9,769,829	9,912,427	9,871,713	9,955,272
Distribution Losses	260,634	261,159	261,763	264,926	266,829	270,654	271,061	271,219	271,604	274,182	277,522	281,064	285,184	289,589	294,051	298,555	303,676	309,427	309,482	312,102
Transmission Losses	362,257	363,406	364,643	369,187	372,139	377,549	378,400	378,952	379,815	383,529	388,177	393,090	398,743	404,753	410,827	416,957	423,889	431,589	431,978	435,634
Subtotal	8,646,353	8,739,396	8,815,842	8,974,931	9,083,935	9,242,952	9,288,033	9,337,380	9,397,947	9,517,322	9,642,023	9,772,132	9,912,295	10,056,002	10,197,220	10,341,856	10,497,395	10,653,443	10,613,173	10,703,009
TNMP Retail (PNM South)	593,753	602,693	611,074	624,456	636,148	650,704	654,760	659,196	664,635	675,271	686,402	698,032	710,540	723,279	735,824	748,609	762,350	775,873	778,949	789,350
Wholesale																				
Gallup	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Navopache	444,921	446,415	447,909	449,404	450,898	452,392	453,886	455,380	456,875	458,369	459,863	461,357	462,851	464,346	465,840	467,334	468,828	470,322	471,817	473,325
Aztec	38,151	38,384	38,618	38,853	39,089	39,327	39,565	39,805	40,046	40,288	40,532	40,777	41,023	41,270	41,518	41,768	42,019	42,271	42,524	42,780
Subtotal	483,072	484,799	486,527	488,256	489,987	491,719	493,451	495,186	496,921	498,657	500,395	502,134	503,874	505,615	507,358	509,102	510,847	512,593	514,341	516,105
Energy Efficiency Programs (incremental)	(156,994)	(219,114)	(265,970)	(319,042)	(366,086)	(400,944)	(432,081)	(475,800)	(523,468)	(559,690)	(576,973)	(593,136)	(600,639)	(602,477)	(599,936)	(599,572)	(589,812)	(560,027)	(517,479)	(492,855)
Distributed Generation (incremental)	(65,046)	(79,032)	(88,808)	(92,410)	(92,410)	(91,948)	(91,488)	(91,031)	(90,575)	(90,122)	(89,672)	(89,224)	(88,777)	(88,334)	(87,892)	(87,452)	(87,015)	(86,580)	(86,147)	(85,716)
Net System Total	9,501,138	9,528,742	9,558,665	9,676,191	9,751,574	9,892,483	9,912,676	9,924,931	9,945,460	10,041,438	10,162,175	10,289,938	10,437,292	10,594,086	10,752,574	10,912,543	11,093,764	11,295,302	11,302,836	11,429,892

2014 IRP Mid Annual Energy (GWh)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PNM Retail (PNM North)	8,138,091	8,222,903	8,277,155	8,349,051	8,376,229	8,424,185	8,467,866	8,513,594	8,561,452	8,611,845	8,663,421	8,716,315	8,770,365	8,827,136	8,884,670	8,943,436	9,005,580	9,070,452	8,980,622	8,993,341
Distribution Losses	263,805	263,979	263,897	264,519	263,990	264,664	265,318	265,521	265,629	266,146	267,262	268,454	269,979	271,788	273,760	275,671	278,054	281,242	279,692	280,088
Transmission Losses	366,364	367,102	367,457	368,640	368,382	369,606	370,798	371,435	371,959	372,962	374,685	376,507	378,742	381,334	384,129	386,848	390,169	394,486	392,727	393,283
Subtotal	8,768,260	8,853,985	8,908,509	8,982,210	9,008,602	9,058,455	9,103,982	9,150,550	9,199,040	9,250,954	9,305,368	9,361,276	9,419,086	9,480,258	9,542,560	9,605,955	9,673,803	9,746,180	9,653,041	9,666,712
TNMP Retail (PNM South)	600,753	610,227	617,391	623,644	628,617	633,792	638,708	643,751	649,004	654,324	659,772	665,385	671,119	677,078	683,152	689,295	695,726	702,319	700,331	704,060
Wholesale																				
Gallup	222,455	226,287	230,119	233,951	237,783	241,615	245,447	249,279	253,111	256,943	260,775	264,607	268,439	272,271	276,103	279,935	283,767	287,599	291,431	295,421
Navopache	444,921	446,415	447,909	449,404	450,898	452,392	453,886	455,380	456,875	458,369	459,863	461,357	462,851	464,346	465,840	467,334	468,828	470,322	471,817	473,325
Aztec	38,151	38,384	38,618	38,853	39,089	39,327	39,565	39,805	40,046	40,288	40,532	40,777	41,023	41,270	41,518	41,768	42,019	42,271	42,524	42,780
Subtotal	705,527	711,086	716,646	722,208	727,770	733,334	738,899	744,465	750,032	755,601	761,170	766,741	772,313	777,887	783,461	789,037	794,614	800,192	805,772	811,526
Energy Efficiency Programs (incremental)	(177,224)	(243,425)	(290,477)	(340,052)	(382,803)	(409,961)	(433,376)	(472,673)	(517,091)	(552,300)	(571,078)	(588,905)	(597,810)	(600,864)	(599,768)	(601,863)	(592,774)	(561,967)	(518,335)	(493,331)
Distributed Generation (incremental)	(65,046)	(79,032)	(88,808)	(92,410)	(92,410)	(91,948)	(91,488)	(91,031)	(90,575)	(90,122)	(89,672)	(89,224)	(88,777)	(88,334)	(87,892)	(87,452)	(87,015)	(86,580)	(86,147)	(85,716)
Net System Total	9,832,271	9,852,842	9,863,261	9,895,600	9,889,776	9,923,672	9,956,724	9,975,062	9,990,410	10,018,456	10,065,561	10,115,274	10,175,931	10,246,026	10,321,514	10,394,971	10,484,354	10,600,144	10,554,662	10,603,250

2014 IRP Low Annual Energy (GWh)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PNM Retail (PNM North)	8,095,635	8,092,389	8,103,335	8,141,816	8,128,843	8,125,430	8,091,247	8,099,960	8,114,989	8,145,075	8,212,776	8,269,726	8,324,142	8,382,198	8,423,171	8,501,554	8,555,276	8,602,010	8,679,852	8,761,468
Distribution Losses	262,429	259,789	258,355	257,953	256,193	255,278	253,517	252,621	251,777	251,721	253,360	254,699	256,243	258,088	259,540	262,051	264,151	266,718	270,325	272,867
Transmission Losses	364,453	361,275	359,740	359,490	357,502	356,498	354,306	353,389	352,562	352,747	355,195	357,216	359,473	362,113	364,176	367,735	370,659	374,113	379,574	383,143
Subtotal	8,722,518	8,713,454	8,721,430	8,759,259	8,742,538	8,737,206	8,699,070	8,705,969	8,719,328	8,749,543	8,821,331	8,881,642	8,939,857	9,002,399	9,046,888	9,131,340	9,190,086	9,242,841	9,329,751	9,417,478
TNMP Retail (PNM South)	600,753	610,227	617,391	623,644	628,617	633,792	638,708	643,751	649,004	654,324	659,772	665,385	671,119	677,078	683,152	689,295	695,726	702,319	700,331	704,060
Wholesale																				
Gallup	222,455	226,287	230,119	233,951	237,783	241,615	245,447	249,279	253,111	256,943	260,775	264,607	268,439	272,271	276,103	279,935	283,767	287,599	291,431	295,421
Navopache	444,921	446,415	447,909	449,404	450,898	452,392	453,886	455,380	456,875	458,369	459,863	461,357	462,851	464,346	465,840	467,334	468,828	470,322	471,817	473,325
Aztec	38,151	38,384	38,618	38,853	39,089	39,327	39,565	39,805	40,046	40,288	40,532	40,777	41,023	41,270	41,518	41,768	42,019	42,271	42,524	42,780
Subtotal	705,527	711,086	716,646	722,208	727,770	733,334	738,899	744,465	750,032	755,601	761,170	766,741	772,313	777,887	783,461	789,037	794,614	800,192	805,772	811,526
Energy Efficiency Programs (incremental)	(177,224)	(243,425)	(290,477)	(340,052)	(382,803)	(409,961)	(433,376)	(472,673)	(517,091)	(552,300)	(571,078)	(588,905)	(597,810)	(600,864)	(599,768)	(601,863)	(592,774)	(561,967)	(518,335)	(493,331)
Distributed Generation (incremental)	(65,046)	(79,032)	(88,808)	(92,410)	(92,410)	(91,948)	(91,488)	(91,031)	(90,575)	(90,122)	(89,672)	(89,224)	(88,777)	(88,334)	(87,892)	(87,452)	(87,015)	(86,580)	(86,147)	(85,716)
Net System Total	9,786,528	9,712,310	9,676,182	9,672,649	9,623,713	9,602,423	9,551,813	9,530,481	9,510,697	9,517,045	9,581,524	9,635,640	9,696,702	9,768,166	9,825,842	9,920,356	10,000,637	10,096,805	10,231,372	10,354,016

2014 IRP High Annual Energy (GWh)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PNM Retail (PNM North)	8,242,938	8,421,856	8,537,216	8,660,366	8,739,404	8,803,284	8,888,535	8,955,361	9,027,040	9,113,437	9,234,658	9,338,895	9,448,832	9,555,884	9,646,768	9,779,682	9,881,441	9,977,059	10,067,344	10,162,007
Distribution Losses	267,204	270,366	272,189	274,382	275,436	276,574	278,498	279,299	280,075	281,648	284,885	287,629	290,864	294,226	297,243	301,447	305,097	309,353	313,537	316,485
Transmission Losses	371,084	375,984	379,002	382,386	384,354	386,239	389,219	390,708	392,186	394,685	399,391	403,400	408,042	412,816	417,079	423,020	428,115	433,916	440,250	444,389
Subtotal	8,881,227	9,068,206	9,188,407	9,317,134	9,399,194	9,466,097	9,556,251	9,625,369	9,699,301	9,789,770	9,918,934	10,029,923	10,147,738	10,262,926	10,361,089	10,504,150	10,614,654	10,720,328	10,821,131	10,922,881
TNMP Retail (PNM South)	600,753	610,227	617,391	623,644	628,617	633,792	638,708	643,751	649,004	654,324	659,772	665,385	671,119	677,078	683,152	689,295	695,726	702,319	700,331	704,060
Wholesale																				
Gallup	222,455	226,287	230,119	233,951	237,783	241,615	245,447	249,279	253,111	256,943	260,775	264,607	268,439	272,271	276,103	279,935	283,767	287,599	291,431	295,421
Navopache	444,921	446,415	447,909	449,404	450,898	452,392	453,886	455,380	456,875	458,369	459,863	461,357	462,851	464,346	465,840	467,334	468,828	470,322	471,817	473,325
Aztec	38,151	38,384	38,618	38,853	39,089	39,327	39,565	39,805	40,046	40,288	40,532	40,777	41,023	41,270	41,518	41,768	42,019	42,271	42,524	42,780
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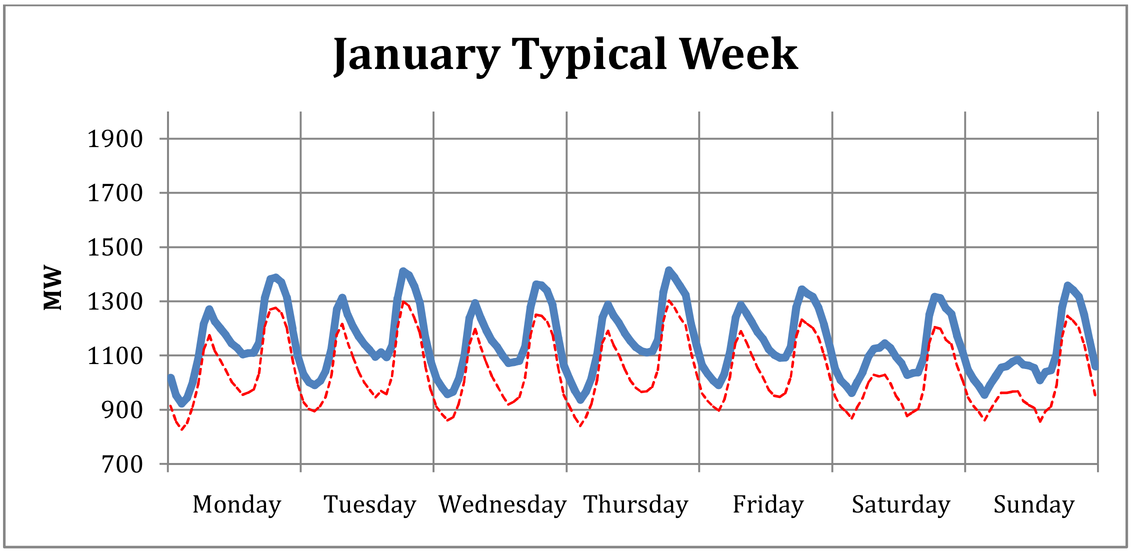
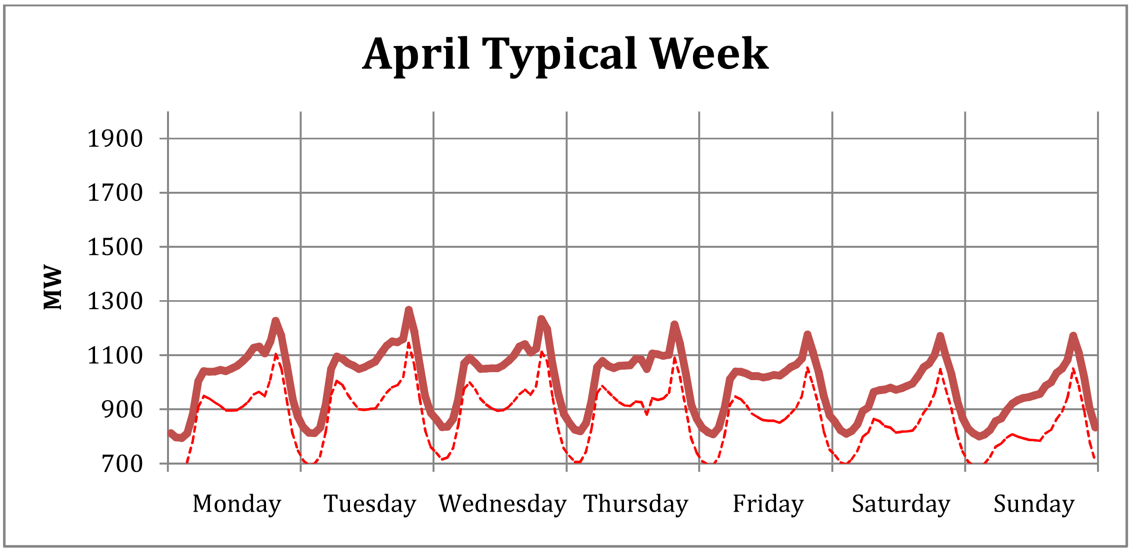
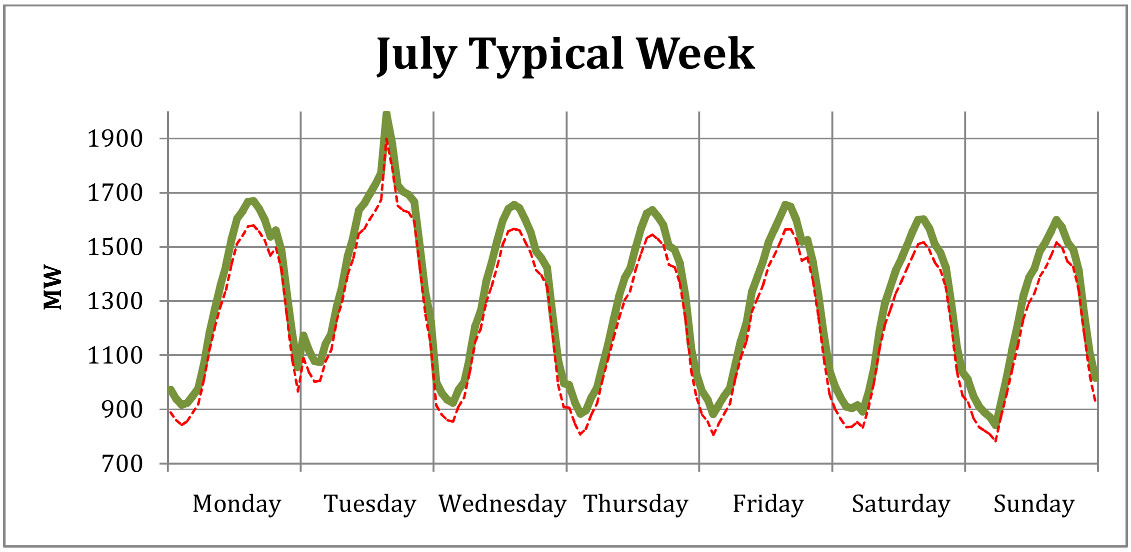
Energy Efficiency Programs (incremental)	(177,224)	(243,425)	(290,477)	(340,052)	(382,803)	(409,961)	(433,376)	(472,673)	(517,091)	(552,300)	(571,078)	(588,905)	(597,810)	(600,864)	(599,768)	(601,863)	(592,774)	(561,967)	(518,335)	(493,331)
Distributed Generation (incremental)	(65,046)	(79,032)	(88,808)	(92,410)	(92,410)	(91,948)	(91,488)	(91,031)	(90,575)	(90,122)	(89,672)	(89,224)	(88,777)	(88,334)	(87,892)	(87,452)	(87,015)	(86,580)	(86,147)	(85,716)
Net System Total	9,945,237	10,067,063	10,143,159	10,230,525	10,280,369	10,331,314	10,408,994	10,449,880	10,490,671	10,557,272	10,679,126	10,783,921	10,904,582	11,028,693	11,140,043	11,293,166	11,425,205	11,574,292	11,722,751	11,859,419

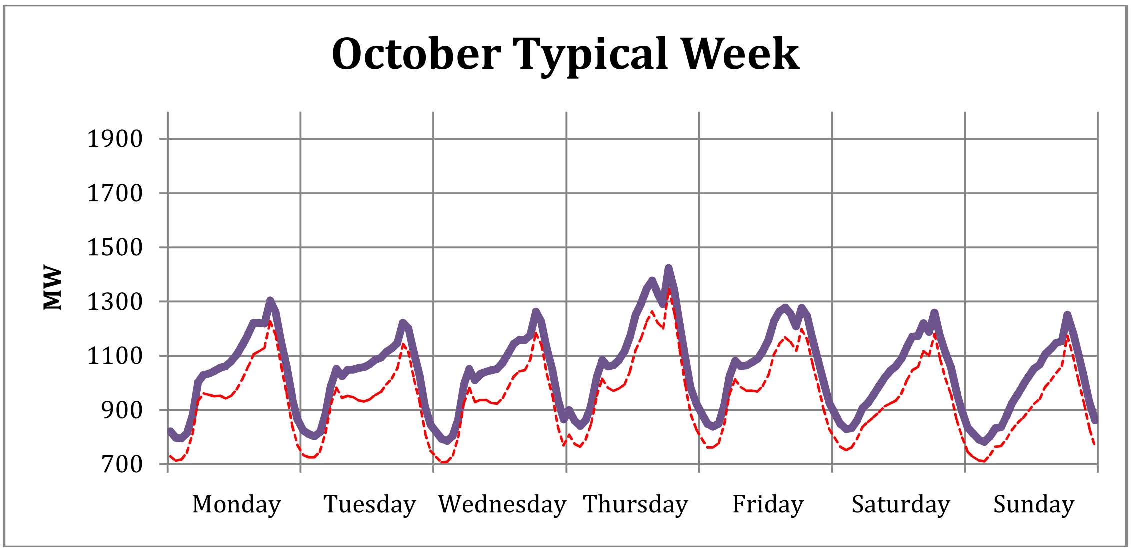
The following figures show a typical week load profile on PNM's system in January, April, July and October to illustrate the variability of load on the system due to season of year as well as the differences in load variability during the day and week during those months. Dotted lines illustrate the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







July Typical Week
1900
1700
1500
1300
1100
900
700
MW
Monday
Tuesday
Wednesday
Thursday
Friday
Saturday
Sunday



October Typical Week
1900
1700
1500
1300
1100
900
700
MW
Monday
Tuesday
Wednesday
Thursday
Friday
Saturday
Sunday

New Resource Alternatives - Natural Gas

Resource Name	Aeroderivative	Small Gas Turbine	Large Gas Turbine (SJGS)	Large Gas Turbine	Large Gas Turbine (SJGS)	Large Gas Turbine	1x1 Combined Cycle Self Build	1x1 Combined Cycle Self Build	Reciprocating Engines
Capital/Non-Fuel Revenue Requirements									
IRP Reference Year	2014	2014	2014	2014	2014	2014	2014	2014	2014
Construction Escalation, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
O&M Escalation, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Total Plant Cost, $000's	62,541	135,493	146,642	136,642	162,644	153,585	331,136	341,303	134,376
AFUDC, $000's	3,205	7,198	7,690	7,165	21,152	19,789	31,255	44,063	7,046
Total Capital+AFUDC, $000's	65,746	142,692	154,331	143,807	183,797	173,373	362,391	385,366	141,422
Total Capital+AFUDC, $/kW	1,644	1,679	1,079	1,006	1,038	979	1,780	1,545	1,521
Total Capital NPV Strat Input, $000's	$ 77,300	$ 164,094	$ 181,459	$ 169,183	$ 216,743	$ 204,446	$ 441,981	$ 469,631	$ 166,307
IRP Performance and O&M									
IRP Size, MW	40	85	143	143	177	177	204	250	93
Year 1st Available	2016	2017	2017	2017	2017	2017	2018	2018	2017
Fixed O&M*, $000's/yr	$ 1,482	$ 2,996	$ 3,822	$ 3,822	$ 4,101	$ 4,101	$ 9,142	$ 12,290	$ 3,797
Fixed O&M*, $/kW-yr	$ 37.04	$ 35.24	$ 28.68	$ 28.68	$ 23.16	$ 23.16	$ 44.91	$ 49.26	$ 40.83
Fixed O&M*, k$/yr									
Variable O&M, $/MWh	$ 4.77	$ 3.63	$ 9.69	$ 9.69	$ 8.23	$ 8.23	$ 2.55	$ 3.94	$ 1.05
Variable O&M, k$/yr									
Equivalent Availability	95%	95%	95%	95%	95%	95%	95%	89%	98%
Heat rate, Btu/kWh	9,800	9,150	10,142	10,142	9,790	9,790	7,104	6,946	8,900
Water usage rate, gal/MWh	90	150	50	50	50	50	150	150	-
PPA Alternatives									
IRP Reference Year									
PPA Alternative - LCOE ($/MWh) @ IRP									
Emissions Data									
CO(lbs/MWh)	0.12	0.28	0.18	0.18	0.17	0.17	0.12	0.11	0.26
NOx (lbs/MWh)	0.08	0.11	0.39	0.39	0.37	0.37	0.08	0.05	3.65
Particulate (lbs/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00
SO2 (lbs/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2 (lbs/MWh)	1140	1115	1300	1300	1245	1245	845	820	980
Mercury (lbs/kWh)									

** FOM includes operations and maintenance, property taxes and gas reservation fees if applicable*

Natural Gas Cont.		New Resource Alternatives - Coal & Nuclear			New Resource Alternatives - Renewables			
2nd Aeroderivative (La Luz II)	1x1 Market Combined Cycle Participation	Coal w/carbon capture	Nuclear	Palo Verde 3 (2,500 $/kW)	Solar Trough	Solar Trough (storage)	Solar PV	Solar PV
2014	2014	2014	2014	2014	2014	2014	2014	2014
2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
54,172	173,000	886,819	964,048	303,493	190,863	333,109	39,629	40,620
2,776		152,112	256,318	-	18,015	31,441	1,141	1,170
56,948	173,000	1,038,932	1,220,366	303,493	208,878	364,550	40,771	41,790
1,424	692	5,195	6,102	2,265	4,178	7,291	2,039	2,089
$ 66,977	$ 211,565	$ 1,265,520	$ 1,365,379	$ 334,800	$ 207,821	$ 362,706	$ 38,612	$ 43,351
40	250	200	200	134	50	50	20	20
2017	2016	2020	2020	2015	2018	2018	2016	2017
$ 1,333	$ 10,410	$ 20,212	$ 24,811	$ 28,751	$ 18,184	$ 19,954	$ 422	$ 432
$ 33.34	$ 41.64	$ 101.06	$ 124.06	$ 215	$ 363.69	$ 399.09	$ 21.08	$ 21.60
				$ 28,751				
$ 4.77	$ 2.60	$ 9.30	$ 5.64		$ 3.22	$ 2.04	$ -	$ -
0.95	95%	92%	94%	98%				
9,800	7,000	13,250	10,510	10,300				
90	150	540	420	23				
0.12	0.12	0.00						
0.08	0.08	0.47						
0.00	1.00	0.27						
0.00	0.00	0.25						
1140	845	280						

Renewables Cont.			Regional Haze Alternatives			
Wind	**Biomass**	**Geothermal**	**SNCRs on SJGS U2&3 (78 MW to SJ4)**	**SNCRs on SJGS U2&3 (132 MW to SJ4)**	**SCRs on Four Corners U4**	**SCRs on Four Corners U5**
	See Data Below		2014	2014	2014	2014
			2.5%	2.5%	2.5%	2.5%
			2.5%	2.5%	2.5%	2.5%
			$ 73,808	$ 81,352	$ 34,058	$ 31,096
			$ 4,181	$ 4,896	$ 4,224	$ 3,857
			$ 77,989	$ 86,248	$ 38,282	$ 34,953
					$ 391	$ 343
			$ 85,514	$ 93,956	$ 39,611	$ 36,170
			443	497	98	102
			2018	2018	2017	2018
					$ 564	$ 564
2014	2014	2014				
$ 44.41	$ 110.47	$ 131.49				
	0.10					
	0.70					
	0.23					
	0.13					
	2,728					

APPENDIX E: FUEL PRICES AND CO_2 PRICES

MarketLink Scenarios: An Overview

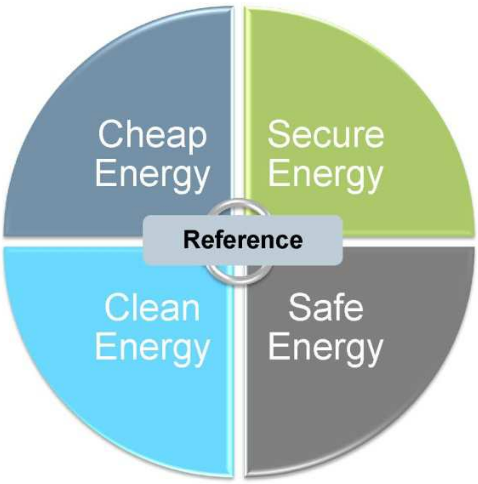
Pace Global's MarketLink scenarios are a set of four internally-consistent states of the world developed against a backdrop of changing policy frameworks over time

- The prevalence of certain geopolitical, environmental, and macroeconomic conditions can lead policy makers to focus near-term on one of several competing aspects of energy policy:
  - Costs
  - Environmental Protection
  - Energy Security
  - Safety
- As the geopolitical, environmental, and economic conditions change, energy policy is likely to shift away from the predominant near-term focus into other competing objectives
  - Market and regulatory response feedbacks over time
- Each scenario is developed by carefully evaluating the relationships and correlations between energy policy and the fundamentals of fuel and power markets
- The scenarios are intended to push the envelope of potential outcomes; in other words, they are plausible, but low probability

MarketLink Scenarios: Alternative Energy Market Futures

Focus on low cost energy; weak environmental regulation; few coal retirements; few renewables

Near term shock to oil and gas prices results in push for diverse domestic supply; opposition to exports, low gas prices longer term



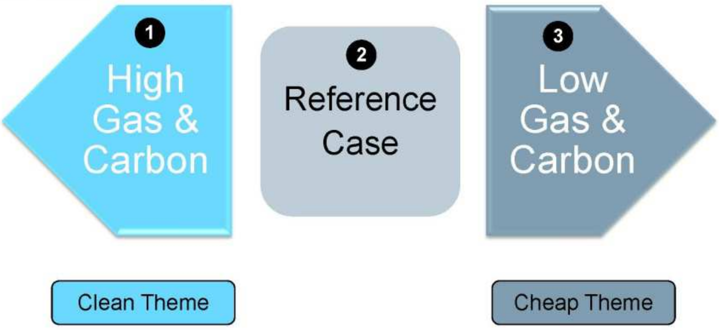
Strong environmental policy results in high CO_2 price, many coal retirements, and significant renewable expansion; power sector demand and fracking ban results in high gas prices

Nuclear phase out with continued pressure on coal capacity; flat demand growth; pressure on gas prices

Theme Development for IRP Analysis

- Pace Global and PNM identified natural gas price and carbon price as the two major drivers of portfolio performance
- The "Clean" and "Cheap" MarketLink themes drive gas and carbon prices in opposite directions, based on the underlying economic and regulatory drivers. These themes were used to define the selection of scenarios for use in the analysis.

- Three scenarios were deployed:



Reference Case

Conditions	Short Term 2013-2015	Mid Term 2016-2025	Long Term 2026-2035
Environmental Regulations	➢MATS remains on track for 2016 implementation	➢Possibility of additional regulations, e.g. revised CSAPR	➢Gradual tightening of emissions restrictions
Natural Gas Prices (HH and Permian)	➢NYMEX Forwards to 2015	➢Gas prices move towards range of $5-6/MMBtu	➢Gas price increases towards a range of $6-7/MMBtu
Gas Market Factors	➢Modest growth in Permian gas production, declining San Juan production	➢Growth, then plateau, of Gulf Coast LNG and Mexican pipeline exports	➢Production costs edge up as associated gas development declines
CO2 Prices	➢No CO2 regime	➢Modest CO2 regime starts in 2020 (~$10/tonne)	➢CO2 prices above $30/tonne in the 2030s
PRB Coal Price	➢PRB 8800|0.80 in the range of $12-14/ton plus transport	➢ PRB 8800|0.80 in the range of $15/ton plus transport	➢PRB 8800|0.80 in the range of $13-14/ton plus transport
National Coal Retirements	➢Announced (up to 25 GW)	➢10-15 GW (up to 40 GW cumulative)	➢30-50 GW (up to 90 GW cumulative)
Regional Power Sector Load Growth	➢Base load growth (1.5%)	➢Base load growth (1%), increased efficiency saps growth	➢Base load growth (0.5%), demand side management and efficiency stall most load growth
Power Sector Expansion	➢Continued replacement of coal fired generation with gas. Moderate expansion of solar and wind	➢Renewable penetration increases with 15-20% of load outside of SERC and RFC being met by renewables	➢Coal replacement with gas and continued build out of wind and solar throughout the country.

Note: All values represented in 2012$

Low Gas & Carbon Scenario

PACE GLOBAL A Siemens Business

Conditions	Short Term 2013-2015	Mid Term 2016-2025	Long Term 2026-2035
Environmental Regulations	➢ Potential delays/extensions for MATS compliance	➢No new environmental regulations	➢Limited environmental regulations
Natural Gas Prices (HH and Permian)	➢ Gas prices remain <$4/MMBtu	➢ ~$4-5/MMBtu as LNG exports begin	➢ Gas price gradually increases to $6/MMBtu
Gas Market Factors	➢Rapid decline in San Juan Basin production; accelerated growth in pipeline exports	➢Sustained growth of Gulf Coast LNG exports; robust associated gas development	➢Production costs edge up as associated gas development declines
CO2 Prices	➢ No CO2 regime	➢ No CO2 regime	➢ CO2 price introduced ($10/tonne)
PRB Coal Price	➢PRB 8800|0.80 in the range of $11-13/ton plus transport	➢ PRB 8800|0.80 in the range of $14-18/ton plus transport	➢PRB 8800|0.80 >$20/ton a short ton plus elevated transportation costs, due to high demand
National Coal Retirements	➢Announced, with some reversals (up to 15 GW)	➢Limited coal retirements, <5GW (up to 20 GW cumulative). Mostly due to local and regional growth factors.	➢ Slight increase in coal retirements as concern for environment grows. 10-15GW (up to 35 MW cumulative) of older less efficient plants
Regional Power Sector Load Growth	➢Low load growth (0%-0.5%)	➢Demand growth recovery (1.5%)	➢Demand growth recovery (2%)
Power Sector Expansion	➢Replacement of coal retirements with gas and renewables in advanced development	➢Gas build out to meet demand growth with moderate expansion of wind in Midwest and solar in Southwest	➢Limited renewable expansion; demand growth met through gas generation.

Note: All values represented in 2012$

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High Gas & Carbon Scenario

PACE GLOBAL A Siemens Business

Conditions	Short Term 2013-2015	Mid Term 2016-2025	Long Term 2026-2035
Environmental Regulations	➢MATS remains on track for 2016 implementation	➢Continued new regulations: revised CSAPR, regional haze, ash disposal, Federal RPS	➢Regulations increasingly restrict ability of coal-fired plants to remain economical
Natural Gas Prices (HH and Permian)	➢Gas price rises to $5/MMBtu	➢ Power sector demand and fracking restrictions result in price runups to $10/MMBtu	➢ Some feedback to revert back to $7-8/MMBtu levels
Gas Market Factors	➢Supply/demand similar to reference case; many states move to ban or sharply restrict fracking	➢EPA institutes fracking restrictions; drilling declines by 50%; LNG export construction stops; LNG imports increase	➢EPA relaxes some drilling restrictions; rapid recovery of San Juan Basin CBM, other dry gas production
CO2 Prices	➢ Federal CO2 policy passed	➢ Federal carbon policy starts in 2018 (~$35/tonne by 2025)	➢ CO2 prices reach $55/tonne
PRB Coal Price	➢PRB 8800|0.80 in the range of $12-14/ton plus transport	➢ PRB 8800|0.80 in the range of $12-14/ton plus transport	➢PRB 8800|0.80 in the range of $10-12/ton plus softened transport costs
National Coal Retirements	➢Announced retirements	➢Stricter policy, including CO2, drives up to 140 GW of coal (cumulative) out by 2025	➢ Stricter policy, including CO2, drives up to 170 GW of coal (cumulative) out through 2035
Regional Power Sector Load Growth	➢ Load recovery (1.25%)	➢Efficiency/DSM penetration (0.5%)	➢Efficiency/DSM penetration (-0.5%)
Power Sector Expansion	➢Gas replaces retired coal with renewables significantly increasing share in West and Midwest	➢Federal RPS sets 15% floor with most states, outside of SERC and RFC, reaching >25%	➢Strict environmental regulations and storage advances drive cost of renewables below fossil generation driving >30% penetration

Note: All values represented in 2012$

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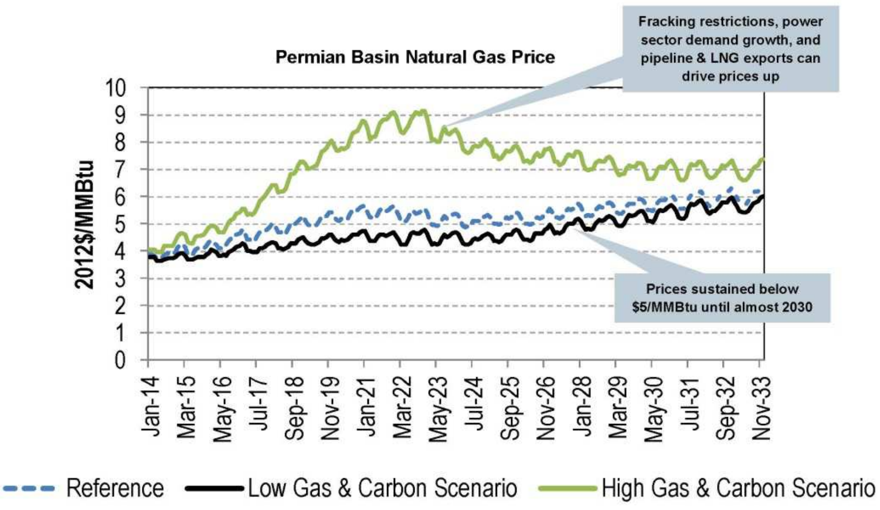
Natural Gas Prices across Scenarios



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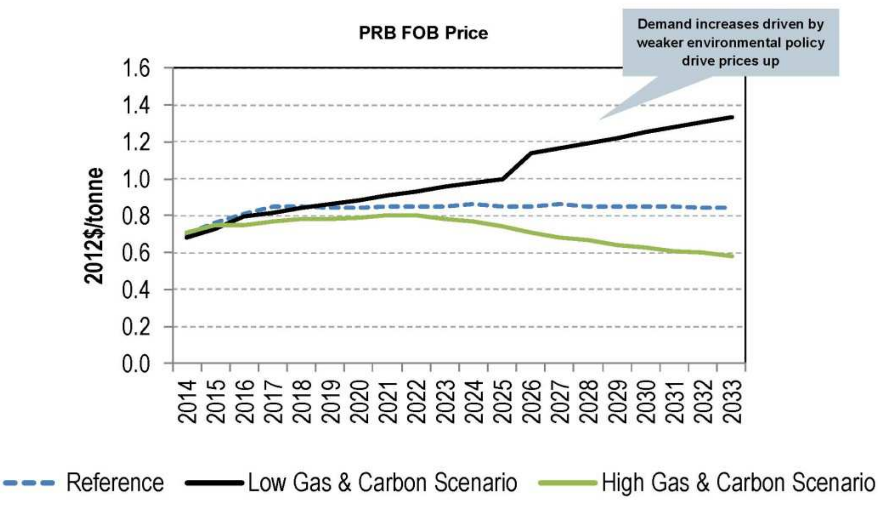
Coal Prices across Scenarios



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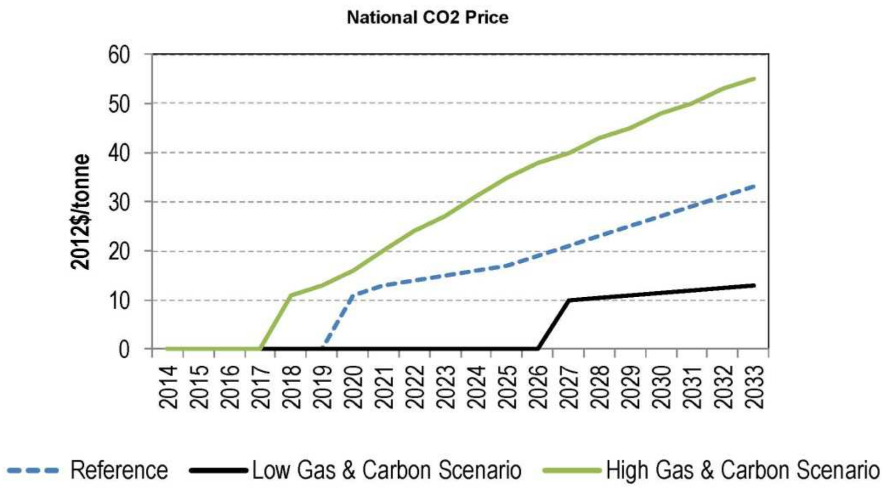
CO2 Prices across Scenarios



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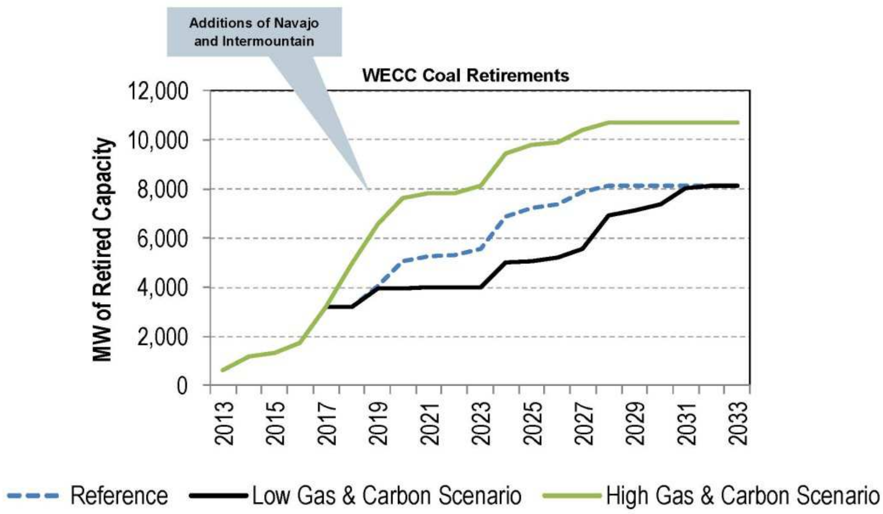
WECC Coal Retirements across Scenarios



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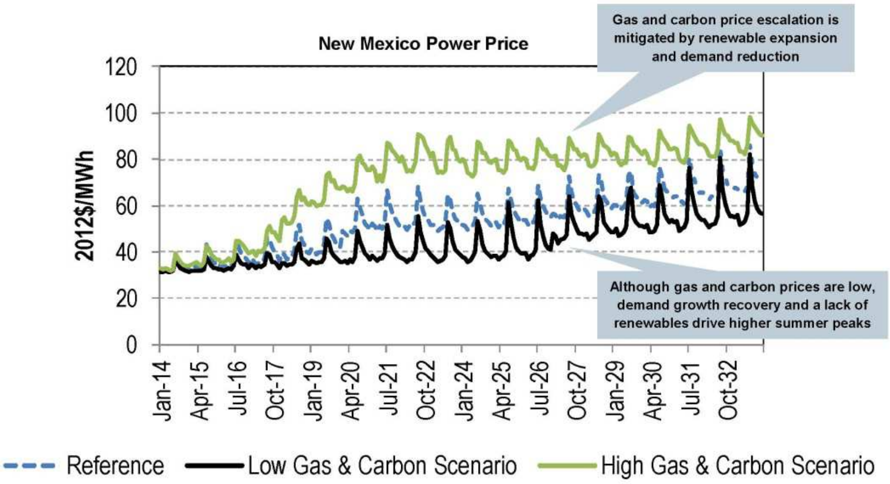
Power Prices across Scenarios



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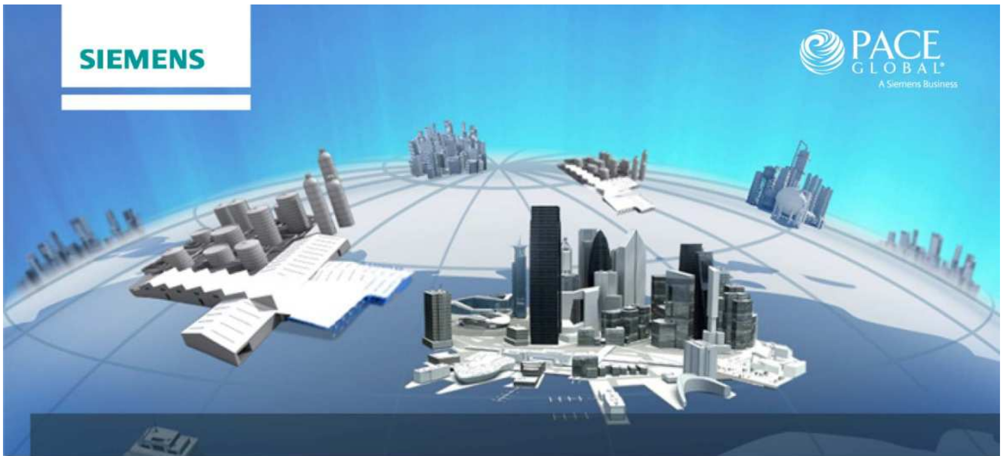

Appendix: Modeling Methodology

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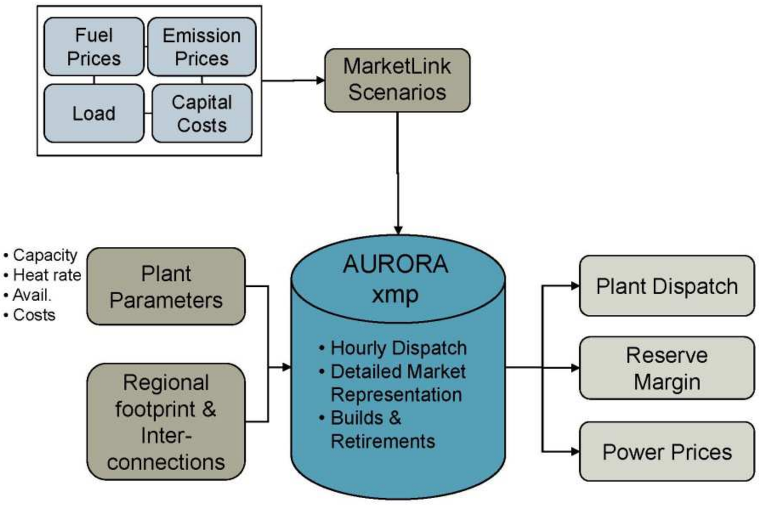
Pace Global Power Market Analysis Process



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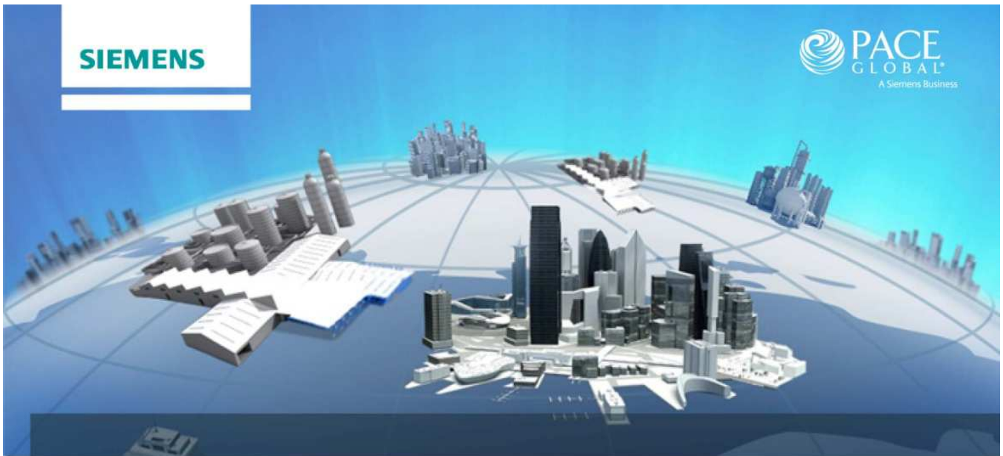

Appendix: Macroeconomic Conditions

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Low Gas & Carbon Scenario – U.S. Macroeconomic and Policy Conditions

Conditions	Short Term 2013-2015	Mid Term 2016-2025	Long Term 2026-2035
Key Drivers	➢ Weak economic recovery places focus on cheap energy	➢ Weak economic recovery ➢ Free trade policies dominate	➢ Moderate economic growth
Key Energy Policy Components	➢ No new regulations other than MATS	➢ Limited support for renewable energy and emissions regulations	➢ Growing but limited environmental policy focus
Fuel and Emission Prices	➢ No CO2 regime ➢ Low fuel prices (gas below $4/MMBtu)	➢ No CO2 regime ➢ Gas prices remain low ($4-5/MMBtu) as LNG exports begin ➢ Coal prices begin to rise due to increased demand and exports	➢ CO2 price introduced ($10/tonne) ➢ Gas price increases to $6/MMBtu as demand grows ➢ Demand for eastern coals declines while PRB demand remains strong
Power Generation Impacts	➢ Low load growth driven by weak economic growth ➢ Low power prices ➢ Announced coal retirements	➢ Electricity demand grows with no focus on efficiency measures ➢ Limited coal retirements	➢ Electricity demand continues to grow rapidly ➢ Slight increase in coal retirements as concern for environment grows

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High Gas & Carbon Scenario – U.S. Macroeconomic and Policy Conditions

Conditions	Short Term 2013-2015	Mid Term 2016-2025	Long Term 2026-2035
Key Drivers	➢ Strong economic and political conditions ripe for environmental regulations	➢ Economic conditions strong	➢ OECD economic growth declines
Key Energy Policy Components	➢ Strong support for stringent environmental regulation ➢ Strong anti-fossil fuel orientation	➢ OECD largely agrees to common 80% by 2050 carbon target	➢ OECD carbon goals moderated, 50% by 2050 carbon target
Fuel and Emission Prices	➢ Federal CO2 policy passed ➢ Increased gas demand results in higher gas prices ➢ Reduced demand for coal	➢ Federal carbon policy starts in 2018 (~$35/tonne by 2025) ➢ Increasing gas prices (at times reaching $10/MMBtu) ➢ Declining coal use domestically, exports continue	➢ CO2 prices reach $55/tonne ➢Gas prices moderate to $7-8/MMBtu level ➢ Significant coal demand decrease
Power Generation Impacts	➢ Economic recovery leads to strong power demand growth ➢ Environmental policies to drive massive coal retirements	➢ Efficiency policies and load reduction measures result in declining load ➢ Coal retirements reach 140 GW (cumulative) by 2025	➢ Load growth continues to be negative ➢ Coal retirements reach 170 GW (cumulative)

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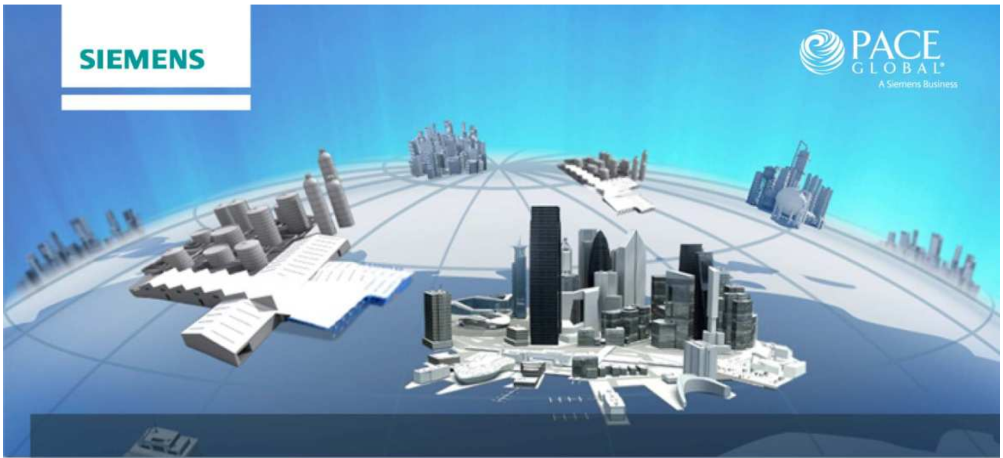
SIEMENS



Appendix: Retirement List

Reference Case Retirement List - WECC

Name	Retirement Date	Retirement Year	Size (MWs)
Apache Station	12/31/2027	2027	350
Arapahoe	5/31/2014	2014	44
Arapahoe	12/31/2019	2019	109
Argus Cogeneration Plant	12/31/2017	2017	50
Ben French	12/31/2015	2015	22
Boardman (OR)	12/30/2020	2020	585
Carbon (UT)	12/31/2014	2014	172
Catalyst Paper Snowflake	12/31/2015	2015	27
Catalyst Paper Snowflake	12/31/2017	2017	46
Centralia Complex	12/31/2019	2019	688
Centralia Complex	12/31/2024	2024	688
Cherokee (CO)	12/30/2016	2016	152
Cholla	12/31/2028	2028	110
Colstrip Energy	12/31/2019	2019	42
Dave Johnston	12/31/2024	2024	212
Dave Johnston	12/31/2023	2023	220
East Third Street	12/31/2022	2022	21
Four Corners	8/31/2013	2013	560
H Wilson Sundt Generating Station	12/31/2021	2021	156
Hayden	12/31/2028	2028	184
J E Corette Plant	12/31/2027	2027	154
Kucc	12/31/2015	2015	50
Kucc	12/31/2017	2017	75
Lamar Plant	12/31/2016	2016	25
Loveridge Road	12/31/2016	2016	20
Martin Drake	12/31/2015	2015	46
Martin Drake	12/31/2016	2016	77
Martin Drake	12/31/2026	2026	131
MT Poso Cogeneration	12/31/2021	2021	57
Naughton	12/31/2020	2020	370
Neil Simpson	3/20/2014	2014	19
Neil Simpson II	12/31/2025	2025	80
Nichols Road Power Plant	12/31/2019	2019	20
Osage (WY)	3/21/2014	2014	30
Phillips 66 Carbon Plant	12/31/2016	2016	19
Port of Stockton District Energy Facility	12/31/2020	2020	51
Raton	12/31/2015	2015	7
Ray D Nixon	12/31/2025	2025	208
Reid Gardner	12/30/2014	2014	330
Reid Gardner	12/30/2017	2017	265
Rio Bravo Jasmin	12/31/2016	2016	33
Rio Bravo Poso	12/31/2016	2016	45
San Juan	12/30/2017	2017	815
Stockton Cogeneration Co	12/31/2023	2023	63
Sunnyside Cogeneration Associates	12/31/2025	2025	51
Torrance Refinery	12/31/2016	2016	8
Valmont	12/31/2017	2017	186
W N Clark	12/31/2013	2013	43
Wilbur East Power Plant	12/31/2016	2016	20
Wilbur West Power Plant	12/31/2020	2020	21
Wyodak	12/31/2024	2024	335
Yellowstone Energy LP	12/31/2024	2024	65

*Note that the San Onofre Nuclear Generation Station (SONGS) in California is retired across all cases.

Low Gas & Carbon Scenario Retirement List - WECC

Name	Retirement Date	Retirement Year	Size (MWs)	Date Change from Reference
Apache Station	12/31/2027	2027	350	
Arapahoe	5/31/2014	2014	44	
Arapahoe	12/31/2028	2028	109	X
Argus Cogeneration Plant	12/31/2017	2017	50	
Ben French	12/31/2015	2015	22	
Boardman (OR)	12/31/2028	2028	585	X
Carbon (UT)	12/31/2014	2014	172	
Catalyst Paper Snowflake	12/31/2015	2015	27	
Catalyst Paper Snowflake	12/31/2017	2017	46	
Centralia Complex	12/31/2019	2019	688	
Centralia Complex	12/31/2024	2024	688	
Cherokee (CO)	12/30/2016	2016	152	
Cholla	12/31/2028	2028	110	
Colstrip Energy	12/31/2019	2019	42	
Dave Johnston	12/31/2031	2031	432	X
East Third Street	12/31/2032	2032	21	X
Four Corners	8/31/2013	2013	560	
H Wilson Sundt Generating Station	12/31/2030	2030	156	X
Hayden	12/31/2028	2028	184	
J E Corette Plant	12/31/2029	2029	154	X
Kucc	12/31/2015	2015	50	
Kucc	12/31/2017	2017	75	
Lamar Plant	12/31/2016	2016	25	
Loveridge Road	12/31/2016	2016	20	
Martin Drake	12/31/2015	2015	46	
Martin Drake	12/31/2016	2016	77	
Martin Drake	12/31/2026	2026	131	
MT Poso Cogeneration	12/31/2021	2021	57	
Naughton	12/31/2028	2028	370	X
Neil Simpson	3/20/2014	2014	19	
Neil Simpson II	12/31/2030	2030	80	X
Nichols Road Power Plant	12/31/2019	2019	20	
Osage (WY)	3/21/2014	2014	30	
Phillips 66 Carbon Plant	12/31/2016	2016	19	
Port of Stockton District Energy Facility	12/31/2032	2032	51	X
Raton	12/31/2015	2015	7	
Ray D Nixon	12/31/2031	2031	208	X
Reid Gardner	12/30/2014	2014	330	
Reid Gardner	12/30/2017	2017	265	
Rio Bravo Jasmin	12/31/2016	2016	33	
Rio Bravo Poso	12/31/2016	2016	45	
San Juan	12/30/2017	2017	815	
Stockton Cogeneration Co	12/31/2032	2032	63	X
Sunnyside Cogeneration Associates	12/31/2025	2025	51	
Torrance Refinery	12/31/2016	2016	8	
Valmont	12/31/2017	2017	186	
W N Clark	12/31/2013	2013	43	
Wilbur East Power Plant	12/31/2016	2016	20	
Wilbur West Power Plant	12/31/2020	2020	21	
Wyodak	12/31/2024	2024	335	
Yellowstone Energy LP	12/31/2029	2029	65	X

*Note that the San Onofre Nuclear Generation Station (SONGS) in California is retired across all cases.

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High Gas & Carbon Scenario Retirement List - WECC

Name	Retirement Date	Retirement Year	Size (MWs)
Apache Station	12/31/2027	2027	350
Arapahoe	5/31/2014	2014	44
Arapahoe	12/31/2019	2019	109
Argus Cogeneration Plant	12/31/2017	2017	50
Ben French	12/31/2015	2015	22
Boardman (OR)	12/30/2020	2020	585
Carbon (UT)	12/31/2014	2014	172
Catalyst Paper Snowflake	12/31/2015	2015	27
Catalyst Paper Snowflake	12/31/2017	2017	46
Centralia Complex	12/31/2019	2019	688
Centralia Complex	12/31/2024	2024	688
Cherokee (CO)	12/30/2016	2016	152
Cholla	12/31/2028	2028	110
Colstrip Energy	12/31/2019	2019	42
Dave Johnston	12/31/2024	2024	212
Dave Johnston	12/31/2023	2023	220
East Third Street	12/31/2022	2022	21
Four Corners	8/31/2013	2013	560
H Wilson Sundt Generating Station	12/31/2021	2021	156
Hayden	12/31/2028	2028	184
J E Corette Plant	12/31/2027	2027	154
Kucc	12/31/2015	2015	50
Kucc	12/31/2017	2017	75
Lamar Plant	12/31/2016	2016	25
Loveridge Road	12/31/2016	2016	20
Martin Drake	12/31/2015	2015	46
Martin Drake	12/31/2016	2016	77
Martin Drake	12/31/2026	2026	131
MT Poso Cogeneration	12/31/2021	2021	57
Naughton	12/31/2020	2020	370
Neil Simpson	3/20/2014	2014	19
Neil Simpson II	12/31/2025	2025	80
Nichols Road Power Plant	12/31/2019	2019	20
Osage (WY)	3/21/2014	2014	30
Phillips 66 Carbon Plant	12/31/2016	2016	19
Port of Stockton District Energy Facility	12/31/2020	2020	51
Raton	12/31/2015	2015	7
Ray D Nixon	12/31/2025	2025	208
Reid Gardner	12/30/2014	2014	330
Reid Gardner	12/30/2017	2017	265
Rio Bravo Jasmin	12/31/2016	2016	33
Rio Bravo Poso	12/31/2016	2016	45
San Juan	12/30/2017	2017	815
Stockton Cogeneration Co	12/31/2023	2023	63
Sunnyside Cogeneration Associates	12/31/2025	2025	51
Torrance Refinery	12/31/2016	2016	8
Valmont	12/31/2017	2017	186
W N Clark	12/31/2013	2013	43
Wilbur East Power Plant	12/31/2016	2016	20
Wilbur West Power Plant	12/31/2020	2020	21
Wyodak	12/31/2024	2024	335
Yellowstone Energy LP	12/31/2024	2024	65
Navajo	12/31/2019	2019	750
Intermountain	12/31/2018	2018	1800

*Note that Navajo and Intermountain are additional plants for retirement beyond the Reference Case.
*Note that the San Onofre Nuclear Generation Station (SONGS) in California is retired across all cases.

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Monthly Coal Prices - San Juan Generating Station

4 Unit Operation

	Base $/mmBtu	Incremental $/mmBtu	January	February	March	April	May	June	July	August	September	October	November	December
2014	$2.71	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91
2015	$2.99	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96
2016	$3.12	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02
2017	$3.31	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08
2018	$3.53	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15
2019	$3.60	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17
2020	$3.68	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19
2021	$3.75	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22
2022	$3.83	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24
2023	$3.92	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27
2024	$4.00	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29
2025	$4.09	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32
2026	$4.18	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34
2027	$4.28	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37
2028	$4.37	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40
2029	$4.47	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
2030	$4.56	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45
2031	$4.66	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48
2032	$4.77	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51
2033	$4.87	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54

Monthly Coal Prices - San Juan Generating Station

2 Unit Operation

	Base $/mmBtu	Incremental $/mmBtu	January	February	March	April	May	June	July	August	September	October	November	December
2014	$2.71	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91	$0.91
2015	$2.99	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96
2016	$3.12	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02
2017	$3.31	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08
2018	$3.90	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15
2019	$3.98	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17	$1.17
2020	$4.06	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19
2021	$4.14	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22
2022	$4.23	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24
2023	$4.32	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27
2024	$4.42	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29
2025	$4.52	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32
2026	$4.62	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34
2027	$4.72	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37
2028	$4.82	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40
2029	$4.93	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
2030	$5.04	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45	$1.45
2031	$5.15	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48
2032	$5.26	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51
2033	$5.37	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54

Monthly Coal Prices - Four Corners

	$/mmBtu	January	February	March	April	May	June	July	August	September	October	November	December
2014	$1.96	$1.96	$1.96	$1.96	$1.96	$1.96	$1.96	$1.96	$1.96	$1.96	$1.96	$1.96	$1.96
2015	$2.03	$2.03	$2.03	$2.03	$2.03	$2.03	$2.03	$2.03	$2.03	$2.03	$2.03	$2.03	$2.03
2016	$2.31	$2.31	$2.31	$2.31	$2.31	$2.31	$2.31	$2.31	$2.31	$2.31	$2.31	$2.31	$2.31
2017	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64
2018	$2.73	$2.73	$2.73	$2.73	$2.73	$2.73	$2.73	$2.73	$2.73	$2.73	$2.73	$2.73	$2.73
2019	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83
2020	$2.92	$2.92	$2.92	$2.92	$2.92	$2.92	$2.92	$2.92	$2.92	$2.92	$2.92	$2.92	$2.92
2021	$3.02	$3.02	$3.02	$3.02	$3.02	$3.02	$3.02	$3.02	$3.02	$3.02	$3.02	$3.02	$3.02
2022	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13
2023	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21
2024	$3.29	$3.29	$3.29	$3.29	$3.29	$3.29	$3.29	$3.29	$3.29	$3.29	$3.29	$3.29	$3.29
2025	$3.37	$3.37	$3.37	$3.37	$3.37	$3.37	$3.37	$3.37	$3.37	$3.37	$3.37	$3.37	$3.37
2026	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45
2027	$3.54	$3.54	$3.54	$3.54	$3.54	$3.54	$3.54	$3.54	$3.54	$3.54	$3.54	$3.54	$3.54
2028	$3.63	$3.63	$3.63	$3.63	$3.63	$3.63	$3.63	$3.63	$3.63	$3.63	$3.63	$3.63	$3.63
2029	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72
2030	$3.81	$3.81	$3.81	$3.81	$3.81	$3.81	$3.81	$3.81	$3.81	$3.81	$3.81	$3.81	$3.81
2031	$3.91	$3.91	$3.91	$3.91	$3.91	$3.91	$3.91	$3.91	$3.91	$3.91	$3.91	$3.91	$3.91
2032	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00
2033	$4.10	$4.10	$4.10	$4.10	$4.10	$4.10	$4.10	$4.10	$4.10	$4.10	$4.10	$4.10	$4.10

Monthly Uranium Prices - Palo Verde

	$/mmBtu	January	February	March	April	May	June	July	August	September	October	November	December
2014	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74
2015	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81
2016	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85
2017	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89
2018	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95
2019	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04
2020	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07
2021	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10
2022	$1.13	$1.13	$1.13	$1.13	$1.13	$1.13	$1.13	$1.13	$1.13	$1.13	$1.13	$1.13	$1.13
2023	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15
2024	$1.18	$1.18	$1.18	$1.18	$1.18	$1.18	$1.18	$1.18	$1.18	$1.18	$1.18	$1.18	$1.18
2025	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21
2026	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24
2027	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27	$1.27
2028	$1.30	$1.30	$1.30	$1.30	$1.30	$1.30	$1.30	$1.30	$1.30	$1.30	$1.30	$1.30	$1.30
2029	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34	$1.34
2030	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37	$1.37
2031	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40	$1.40
2032	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44	$1.44
2033	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48

APPENDIX F: SCENARIO RESULTS ANALYSES SUMMARIES

		1		2		3		4
LOAD COMPARISON - 78 MW TO SJ4								
Scenario Description	**Reserve Margin**	**CURRENT LOAD FORECAST**	**Reserve Margin**	**IRP HIGH LOAD**	**Reserve Margin**	**IRP MID LOAD**	**Reserve Margin**	**IRP LOW LOAD**
Load Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
Gas Pricing		PACE Reference		PACE Reference		PACE Reference		PACE Reference
CO2		PACE Reference ($11 in 2020)		PACE Reference ($11 in 2020)		PACE Reference ($11 in 2020)		PACE Reference ($11 in 2020)
Energy Efficiency Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
PV DG Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	18.0%		13.4%		14.7%		15.2%	
2015	17.8%	Red Mesa (102 MW)	13.0%	Red Mesa (102 MW)	15.5%	Red Mesa (102 MW)	17.1%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	15.5%	Aeroderivative (40 MW)	18.8%	Aeroderivative (40 MW)	21.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	14.6%	San Juan BART	18.4%	San Juan BART	21.1%	San Juan BART
2018	14.6%	Large GT (177 MW)	14.7%	Large GT (177 MW)	15.2%	Large GT (143 MW)	14.1%	Palo Verde 3 (134 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Solar PV Tier 2 (80 MW)
				Solar PV Tier 2 (60 MW)				
2019	14.4%	Solar PV Tier 2 (60 MW)	14.1%		14.8%		14.4%	
2020	14.2%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (20 MW)	14.7%		15.2%	
		Solar PV Tier 3 (20 MW)						
2021	14.2%	Solar PV Tier 3 (60 MW)	14.0%	Solar PV Tier 3 (20 MW)	14.5%	Wind (100 MW)	15.2%	
2022	14.3%	Solar PV Tier 3 (60 MW)	14.1%	Solar PV Tier 3 (20 MW)	14.3%		15.4%	
2023	20.4%	Large GT (177 MW)	14.3%	Solar PV Tier 3 (40 MW)	14.5%	Solar PV Tier 2 (20 MW)	15.2%	
2024	18.2%		14.1%	Solar PV Tier 3 (40 MW)	14.1%		14.5%	
2025	15.9%		20.9%	Large GT (177 MW)	14.1%	Solar PV Tier 2 (20 MW)	14.0%	Wind (100 MW)
2026	21.3%	Large GT (177 MW)	19.8%	Wind (100 MW)	14.1%	Solar PV Tier 2 (20 MW)	14.4%	Solar PV Tier 3 (40 MW)
		Wind (100 MW)						
2027	18.8%		18.4%		14.5%	Solar PV Tier 2 (20 MW)	14.0%	Solar PV Tier 3 (20 MW)
						Solar PV Tier 3 (20 MW)		
2028	16.4%		17.2%		14.3%	Solar PV Tier 3 (20 MW)	14.5%	Solar PV Tier 3 (40 MW)
2029	14.1%		15.5%		14.4%	Solar PV Tier 3 (40 MW)	14.4%	Solar PV Tier 3 (40 MW)
2030	15.3%	Reciprocating Engines (93 MW)	14.2%		14.5%	Solar PV Tier 3 (40 MW)	15.5%	2nd Aeroderivative (40 MW)
2031	14.8%	2nd Aeroderivative (40 MW)	17.3%	Reciprocating Engines (93 MW)	15.8%	2nd Aeroderivative (40 MW)	14.6%	
				Solar PV Tier 3 (20 MW)		Solar PV Tier 3 (20 MW)		
2032	14.2%	Aeroderivative (40 MW)	15.5%		14.2%		14.9%	Aeroderivative (40 MW)
2033	15.0%	Small GT (85 MW)	14.3%		15.1%	Aeroderivative (40 MW)	14.1%	
PRESENT VALUE PORTFOLIO COST		**$6,848,233,021**		**$6,655,342,435**		**$6,567,026,200**		**$6,245,453,116**
5% Tail (Risk)		**$192,988,325**		**$178,451,023**		**$184,893,407**		**$165,188,615**
20-Year Loss of Load (Hours)		**28.39**		**47.63**		**64.68**		**93.25**
20-Year CO2 (Metric Tons)		**101,289,756**		**100,064,035**		**101,692,115**		**95,834,605**

Notes:

1. All portfolios assume net retirement of 340 MW at San Juan Generating Station

		5		6		7
PRICE COMPARISON - 78 MW TO SJ4						
Scenario Description	**Reserve Margin**	**PACE REFERENCE GAS/CARBON**	**Reserve Margin**	**PACE HIGH GAS/CARBON**	**Reserve Margin**	**PACE LOW GAS/CARBON**
Load Forecast		Current		Current		Current
Gas Pricing		PACE Reference		PACE High Gas		PACE Low Gas
CO2		PACE Reference ($11 in 2020)		PACE High Carbon ($11 in 2018)		PACE Low Carbon ($10 in 2027)
Energy Efficiency Forecast		Current		Current		Current
PV DG Forecast		Current		Current		Current
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	18.0%		18.0%		18.0%	
2015	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	17.8%	San Juan BART	17.8%	San Juan BART
2018	14.6%	Large GT (177 MW)	14.8%	Large GT (177 MW)	14.6%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
				Wind (100 MW)		
2019	14.4%	Solar PV Tier 2 (60 MW)	14.7%	Solar PV Tier 2 (60 MW)	14.4%	Solar PV Tier 2 (60 MW)
2020	14.2%	Solar PV Tier 2 (20 MW)	14.4%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (20 MW)
		Solar PV Tier 3 (20 MW)		Solar PV Tier 3 (20 MW)		Solar PV Tier 3 (20 MW)
2021	14.2%	Solar PV Tier 3 (60 MW)	15.5%	Solar PV Tier 3 (100 MW)	14.2%	Solar PV Tier 3 (60 MW)
2022	14.3%	Solar PV Tier 3 (60 MW)	14.5%	Solar PV Tier 3 (20 MW)	20.9%	Large GT (177 MW)
2023	20.4%	Large GT (177 MW)	20.6%	Large GT (177 MW)	18.9%	
2024	18.2%		18.5%		16.8%	
2025	15.9%		16.1%		14.4%	
2026	21.3%	Large GT (177 MW)	21.3%	Large GT (177 MW)	19.7%	Large GT (177 MW)
		Wind (100 MW)				
2027	18.8%		18.8%		17.2%	
2028	16.4%		16.4%		14.8%	
2029	14.1%		14.1%		14.1%	Solar PV Tier 3 (60 MW)
						Wind (100 MW)
2030	15.3%	Reciprocating Engines (93 MW)	15.3%	Reciprocating Engines (93 MW)	15.3%	Reciprocating Engines (93 MW)
2031	14.8%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)
2032	14.2%	Aeroderivative (40 MW)	14.2%	Aeroderivative (40 MW)	14.2%	Aeroderivative (40 MW)
2033	15.0%	Small GT (85 MW)	15.0%	Small GT (85 MW)	15.0%	Small GT (85 MW)
PRESENT VALUE PORTFOLIO COST	**$6,848,233,021**		**$7,664,015,969**		**$6,238,315,880**	
5% Tail (Risk)	**$192,988,325**		**$307,295,100**		**$126,455,860**	
20-Year Loss of Load (Hours)	**28.39**		**24.41**		**27.92**	
20-Year CO2 (Metric Tons)	**101,289,756**		**99,247,138**		**102,933,175**	

Notes:

1. All portfolios assume net retirement of 340 MW at San Juan Generating Station

		8		9		10
IRP EE COMPARISONS - 78 MW TO SJ4						
Scenario Description	**Reserve Margin**	**EE MID + 78 MW TO SJ4**	**Reserve Margin**	**EE LOW + 78 MW TO SJ4**	**Reserve Margin**	**EE HIGH + 78 MW TO SJ4**
Load Forecast		Current Forecast		Current Forecast		Current Forecast
Gas Pricing		PACE Reference		PACE Reference		PACE Reference
CO2		PACE Reference ($11 in 2020)		PACE Reference ($11 in 2020)		PACE Reference ($11 in 2020)
Energy Efficiency Forecast		Current Forecast		2014 IRP Low		2014 IRP High
PV DG Forecast		Current Forecast		Current Forecast		Current Forecast
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	18.0%		18.1%		18.1%	
2015	17.8%	Red Mesa (102 MW)	17.9%	Red Mesa (102 MW)	17.9%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	20.1%	Aeroderivative (40 MW)	20.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	18.2%	San Juan BART	18.3%	San Juan BART
2018	14.6%	Large GT (177 MW)	14.9%	Large GT (177 MW)	15.0%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
2019	14.4%	Solar PV Tier 2 (60 MW)	14.0%	Solar PV Tier 2 (40 MW)	14.3%	Solar PV Tier 2 (40 MW)
2020	14.2%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (40 MW)	14.5%	Solar PV Tier 2 (40 MW)
		Solar PV Tier 3 (20 MW)				
2021	14.2%	Solar PV Tier 3 (60 MW)	14.4%	Solar PV Tier 3 (60 MW)	14.3%	Solar PV Tier 3 (40 MW)
				Wind (100 MW)		Wind (100 MW)
2022	14.3%	Solar PV Tier 3 (60 MW)	14.0%	Solar PV Tier 3 (40 MW)	14.1%	Solar PV Tier 3 (40 MW)
2023	20.4%	Large GT (177 MW)	20.2%	Large GT (177 MW)	20.4%	Large GT (177 MW)
2024	18.2%		17.9%		18.2%	
2025	15.9%		15.8%		16.2%	
2026	21.3%	Large GT (177 MW)	14.1%	Solar PV Tier 3 (40 MW)	14.2%	Solar PV Tier 3 (20 MW)
		Wind (100 MW)				
2027	18.8%		19.2%	Large GT (177 MW)	19.4%	Large GT (177 MW)
2028	16.4%		16.8%		17.0%	
2029	14.1%		14.4%		14.7%	
2030	15.3%	Reciprocating Engines (93 MW)	15.5%	Reciprocating Engines (93 MW)	14.3%	2nd Aeroderivative (40 MW)
						Solar PV Tier 3 (20 MW)
2031	14.8%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)	14.1%	Aeroderivative (40 MW)
						Solar PV Tier 3 (20 MW)
2032	14.2%	Aeroderivative (40 MW)	15.3%	Small GT (85 MW)	15.3%	Reciprocating Engines (93 MW)
2033	15.0%	Small GT (85 MW)	14.6%	Aeroderivative (40 MW)	16.0%	Small GT (85 MW)
PRESENT VALUE PORTFOLIO COST	**$6,848,233,021**		**$6,855,984,733**		**$6,802,493,410**	
5% Tail (Risk)	**$192,988,325**		**$193,948,886**		**$190,532,254**	
20-Year Loss of Load (Hours)	**28.39**		**27.49**		**27.22**	
20-Year CO2 (Metric Tons)	**101,289,756**		**101,108,278**		**100,494,186**	

Notes:

1. All portfolios assume net retirement of 340 MW at San Juan Generating Station

		11		12		13
IRP MID LOAD COMPARE - 78 MW TO SJ4						
Scenario Description	**Reserve Margin**	**PACE REFERENCE GAS/CARBON**	**Reserve Margin**	**PACE HIGH GAS/CARBON**	**Reserve Margin**	**PACE LOW GAS/CARBON**
Load Forecast		2014 IRP Mid Load		2014 IRP Mid Load		2014 IRP Mid Load
Gas Pricing		PACE Reference		PACE High Gas		PACE Low Gas
CO2		PACE Reference ($11 in 2020)		PACE High Carbon ($11 in 2018)		PACE Low Carbon ($10 in 2027)
Energy Efficiency Forecast		2014 IRP Mid Load		2014 IRP Mid Load		2014 IRP Mid Load
PV DG Forecast		2014 IRP Mid Load		2014 IRP Mid Load		2014 IRP Mid Load
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	14.7%		14.7%		14.7%	
2015	15.5%	Red Mesa (102 MW)	15.5%	Red Mesa (102 MW)	15.5%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	18.8%	Aeroderivative (40 MW)	18.8%	Aeroderivative (40 MW)	18.8%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	18.4%	San Juan BART	18.4%	San Juan BART	18.4%	San Juan BART
2018	15.2%	Large GT (143 MW)	14.1%	Palo Verde 3 (134 MW)	15.2%	Large GT (143 MW)
		Palo Verde 3 (134 MW)		Solar PV Tier 2 (80 MW)		Palo Verde 3 (134 MW)
				Solar PV Tier 3 (100 MW)		
				Wind (100 MW)		
2019	14.8%		14.3%	Solar PV Tier 3 (20 MW)	14.8%	
2020	14.7%		14.1%		14.7%	
2021	14.5%	Wind (100 MW)	14.2%	Solar PV Tier 3 (20 MW)	14.2%	
2022	14.3%		14.0%		14.0%	
2023	14.5%	Solar PV Tier 2 (20 MW)	15.5%	2nd Aeroderivative (40 MW)	14.3%	Solar PV Tier 2 (20 MW)
2024	14.1%		15.1%		14.6%	Solar PV Tier 2 (20 MW)
2025	14.1%	Solar PV Tier 2 (20 MW)	14.4%		14.6%	Solar PV Tier 2 (20 MW)
2026	14.1%	Solar PV Tier 2 (20 MW)	18.1%	Reciprocating Engines (93 MW)	14.6%	Solar PV Tier 2 (20 MW)
2027	14.5%	Solar PV Tier 2 (20 MW)	17.3%		14.3%	Solar PV Tier 3 (20 MW)
		Solar PV Tier 3 (20 MW)				
2028	14.3%	Solar PV Tier 3 (20 MW)	16.4%		14.0%	Solar PV Tier 3 (20 MW)
2029	14.4%	Solar PV Tier 3 (40 MW)	15.5%		14.2%	Solar PV Tier 3 (40 MW)
2030	14.5%	Solar PV Tier 3 (40 MW)	14.5%		14.2%	Solar PV Tier 3 (40 MW)
2031	15.8%	2nd Aeroderivative (40 MW)	17.2%	Small GT (85 MW)	15.3%	2nd Aeroderivative (40 MW)
		Solar PV Tier 3 (20 MW)				Wind (100 MW)
2032	14.2%		15.6%		14.2%	Solar PV Tier 3 (20 MW)
2033	15.1%	Aeroderivative (40 MW)	14.6%		15.1%	Aeroderivative (40 MW)
PRESENT VALUE PORTFOLIO COST	**$6,567,026,200**		**$7,339,474,778**		**$5,954,966,528**	
5% Tail (Risk)	**$184,893,407**		**$290,795,781**		**$128,488,524**	
20-Year Loss of Load (Hours)	**64.68**		**76.40**		**77.04**	
20-Year CO2 (Metric Tons)	**101,692,115**		**96,402,152**		**104,052,427**	

Notes:

1. All portfolios assume net retirement of 340 MW at San Juan Generating Station

IRP HIGH LOAD COMPARE - 78 MW TO SJ4

		14		15		16
Scenario Description	**Reserve Margin**	**PACE REFERENCE GAS/CARBON**	**Reserve Margin**	**PACE HIGH GAS/CARBON**	**Reserve Margin**	**PACE LOW GAS/CARBON**
Load Forecast		2014 IRP High Load		2014 IRP High Load		2014 IRP High Load
Gas Pricing		PACE Reference		PACE High Gas		PACE Low Gas
CO2		PACE Reference ($11 in 2020)		PACE High Carbon ($11 in 2018)		PACE Low Carbon ($10 in 2027)
Energy Efficiency Forecast		2014 IRP High Load		2014 IRP High Load		2014 IRP High Load
PV DG Forecast		2014 IRP High Load		2014 IRP High Load		2014 IRP High Load
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	13.4%		13.4%		13.4%	
2015	13.0%	Red Mesa (102 MW)	13.0%	Red Mesa (102 MW)	13.0%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	15.5%	Aeroderivative (40 MW)	15.5%	Aeroderivative (40 MW)	15.5%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	14.6%	San Juan BART	14.6%	San Juan BART	14.6%	San Juan BART
2018	14.7%	Large GT (177 MW)	14.5%	Large GT (143 MW)	14.7%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
		Solar PV Tier 2 (60 MW)		Solar PV Tier 2 (80 MW)		Solar PV Tier 2 (60 MW)
				Solar PV Tier 3 (20 MW)		
				Wind (100 MW)		
2019	14.1%		14.5%	Solar PV Tier 3 (20 MW)	14.1%	
2020	14.2%	Solar PV Tier 2 (20 MW)	14.4%	Solar PV Tier 3 (20 MW)	14.2%	Solar PV Tier 2 (20 MW)
				Solar PV Tier 3 (60 MW)		
2021	14.0%	Solar PV Tier 3 (20 MW)	15.3%		14.0%	Solar PV Tier 3 (20 MW)
2022	14.1%	Solar PV Tier 3 (20 MW)	14.8%		14.1%	Solar PV Tier 3 (20 MW)
2023	14.3%	Solar PV Tier 3 (40 MW)	14.5%	Solar PV Tier 3 (20 MW)	14.3%	Solar PV Tier 3 (40 MW)
2024	14.1%	Solar PV Tier 3 (40 MW)	21.4%	Large GT (177 MW)	14.1%	Solar PV Tier 3 (40 MW)
2025	20.9%	Large GT (177 MW)	20.1%		20.9%	Large GT (177 MW)
2026	19.8%	Wind (100 MW)	18.7%		19.6%	
2027	18.4%		17.3%		18.1%	
2028	17.2%		16.2%		17.0%	
2029	15.5%		14.5%		15.3%	
2030	14.2%		17.2%	Reciprocating Engines (93 MW)	14.2%	Wind (100 MW)
2031	17.3%	Reciprocating Engines (93 MW)	15.9%		16.9%	Reciprocating Engines (93 MW)
		Solar PV Tier 3 (20 MW)				
2032	15.5%		14.1%		15.0%	
2033	14.3%		14.5%	2nd Aeroderivative (40 MW)	14.3%	Solar PV Tier 3 (20 MW)
PRESENT VALUE PORTFOLIO COST		**$6,655,342,435**		**$7,444,459,550**		**$6,071,805,454**
5% Tail (Risk)		**$178,451,023**		**$290,185,977**		**$117,328,381**
20-Year Loss of Load (Hours)		**47.63**		**42.44**		**48.53**
20-Year CO2 (Metric Tons)		**100,064,035**		**96,934,053**		**101,121,354**

Notes:
1. All portfolios assume net retirement of 340 MW at San Juan Generating Station

		17		18		19
IRP LOW LOAD COMPARE - 78 MW TO SJ4						
Scenario Description	**Reserve Margin**	**PACE REFERENCE GAS/CARBON**	**Reserve Margin**	**PACE HIGH GAS/CARBON**	**Reserve Margin**	**PACE LOW GAS/CARBON**
Load Forecast		2014 IRP Low Load		2014 IRP Low Load		2014 IRP Low Load
Gas Pricing		PACE Reference		PACE High Gas		PACE Low Gas
CO2		PACE Reference ($11 in 2020)		PACE High Carbon ($11 in 2018)		PACE Low Carbon ($10 in 2027)
Energy Efficiency Forecast		2014 IRP Low Load		2014 IRP Low Load		2014 IRP Low Load
PV DG Forecast		2014 IRP Low Load		2014 IRP Low Load		2014 IRP Low Load
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	15.2%		15.2%		15.2%	
2015	17.1%	Red Mesa (102 MW)	17.1%	Red Mesa (102 MW)	17.1%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	21.1%	Aeroderivative (40 MW)	21.1%	Aeroderivative (40 MW)	21.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	21.1%	San Juan BART	21.1%	San Juan BART	21.1%	San Juan BART
2018	14.1%	Palo Verde 3 (134 MW)	14.4%	Palo Verde 3 (134 MW)	14.1%	Palo Verde 3 (134 MW)
		Solar PV Tier 2 (80 MW)		Solar PV Tier 2 (80 MW)		Solar PV Tier 2 (80 MW)
				Wind (100 MW)		
2019	14.4%		14.6%		14.4%	
2020	15.2%		15.5%		15.2%	
2021	15.2%		17.2%	Solar PV Tier 3 (60 MW)	15.2%	
2022	15.4%		17.4%		15.4%	
2023	15.2%		17.7%	Solar PV Tier 3 (20 MW)	15.2%	
2024	14.5%		17.1%		14.5%	Solar PV Tier 3 (20 MW)
2025	14.0%	Wind (100 MW)	16.8%	Solar PV Tier 3 (20 MW)	14.3%	Solar PV Tier 3 (20 MW)
2026	14.4%	Solar PV Tier 3 (40 MW)	17.2%	Solar PV Tier 3 (40 MW)	14.1%	Solar PV Tier 3 (40 MW)
2027	14.0%	Solar PV Tier 3 (20 MW)	16.2%		14.3%	Solar PV Tier 3 (20 MW)
						Solar PV Tier 3 (40 MW)
2028	14.5%	Solar PV Tier 3 (40 MW)	15.6%		14.2%	2nd Aeroderivative (40 MW)
2029	14.4%	Solar PV Tier 3 (40 MW)	14.4%		14.2%	
2030	15.5%	2nd Aeroderivative (40 MW)	15.5%	2nd Aeroderivative (40 MW)	15.2%	
2031	14.6%		14.6%		14.3%	
2032	14.9%	Aeroderivative (40 MW)	14.9%	Aeroderivative (40 MW)	14.7%	Aeroderivative (40 MW)
2033	14.1%		14.1%		14.1%	Wind (100 MW)
PRESENT VALUE PORTFOLIO COST		**$6,245,453,116**		**$6,974,290,224**		**$5,694,410,334**
5% Tail (Risk)		**$165,188,615**		**$263,916,249**		**$105,713,464**
20-Year Loss of Load (Hours)		**93.25**		**75.30**		**111.23**
20-Year CO2 (Metric Tons)		**95,834,605**		**92,789,332**		**97,703,344**

Notes:

1. All portfolios assume net retirement of 340 MW at San Juan Generating Station

		20		21		22		23
IRP STANDARIZED CARBON EMISSION COST PORTFOLIOS - 78 MW TO SJ4								
Scenario Description	**Reserve Margin**	**$0 CO2 COST**	**Reserve Margin**	**$8 C02 COST**	**Reserve Margin**	**$20 CO2 COST**	**Reserve Margin**	**$40 CO2 COST**
Load Forecast		Current Forecast		Current Forecast		Current Forecast		Current Forecast
Gas Pricing		PACE Reference Case		PACE Reference		PACE Reference		PACE Reference
CO2		None		$8 Beginning 2010 (2.5% annual esc)		$20 Beginning 2010 (2.5% annual esc)		$40 Beginning 2010 (2.5% annual esc)
Energy Efficiency Forecast		Current Forecast		Current Forecast		Current Forecast		Current Forecast
PV DG Forecast		Current Forecast		Current Forecast		Current Forecast		Current Forecast
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 78 MW to SJ4
2014	18.0%		18.0%		18.0%		18.0%	
2015	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	17.8%	San Juan BART	17.8%	San Juan BART	19.6%	San Juan BART
								Solar PV Tier 2 (40 MW)
								Wind (100 MW)
2018	15.0%	Large GT (143 MW)	15.3%	Large GT (143 MW)	14.8%	Large GT (177 MW)	19.9%	Large GT (177 MW)
		Large GT (177 MW)		Large GT (177 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
				Wind (100 MW)		Wind (100 MW)		Solar PV Tier 2 (40 MW)
								Solar PV Tier 3 (80 MW)
2019	14.1%	Solar PV Tier 2 (40 MW)	14.4%	Solar PV Tier 2 (40 MW)	14.7%	Solar PV Tier 2 (60 MW)	18.6%	Solar PV Tier 3 (40 MW)
2020	14.1%	Solar PV Tier 2 (40 MW)	14.3%	Solar PV Tier 2 (40 MW)	14.4%	Solar PV Tier 2 (20 MW)	17.1%	
						Solar PV Tier 3 (20 MW)		
2021	14.1%	Solar PV Tier 3 (60 MW)	14.4%	Solar PV Tier 3 (60 MW)	14.5%	Solar PV Tier 3 (60 MW)	16.0%	Solar PV Tier 3 (20 MW)
2022	14.2%	Solar PV Tier 3 (60 MW)	14.4%	Solar PV Tier 3 (60 MW)	14.5%	Solar PV Tier 3 (60 MW)	14.5%	
2023	20.3%	Large GT (177 MW)	20.5%	Large GT (177 MW)	20.6%	Large GT (177 MW)	20.6%	Large GT (177 MW)
2024	18.1%		18.4%		18.5%		18.5%	
2025	15.8%		16.0%		16.1%		16.1%	
2026	14.1%	Solar PV Tier 3 (20 MW)	14.1%	Solar PV Tier 3 (20 MW)	21.3%	Large GT (177 MW)	21.3%	Large GT (177 MW)
		Wind (100 MW)						
2027	19.2%	Large GT (177 MW)	19.2%	Large GT (177 MW)	18.8%		18.8%	
2028	16.8%		16.8%		16.4%		16.4%	
2029	14.4%		14.4%		14.1%		14.1%	
2030	15.7%	Reciprocating Engines (93 MW)	15.7%	Reciprocating Engines (93 MW)	15.3%	Reciprocating Engines (93 MW)	15.3%	Reciprocating Engines (93 MW)
2031	15.1%	2nd Aeroderivative (40 MW)	15.1%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)
2032	14.6%	Aeroderivative (40 MW)	14.6%	Aeroderivative (40 MW)	14.2%	Aeroderivative (40 MW)	14.2%	Aeroderivative (40 MW)
2033	15.3%	Small GT (85 MW)	15.3%	Small GT (85 MW)	15.0%	Small GT (85 MW)	15.0%	Small GT (85 MW)
PRESENT VALUE PORTFOLIO COST		**$6,080,612,976**		**$6,709,264,773**		**$7,584,993,273**		**$8,950,846,867**
20-Year Loss of Load (Hours)		**28.65**		**24.91**		**24.24**		**20.61**
20-Year CO2 (Metric Tons)		**112,780,612**		**111,019,974**		**99,297,132**		**94,052,307**

Notes:

1. All portfolios assume net retirement of 340 MW at San Juan Generating Station

		24		25		26		27
LOAD COMPARISON - 132 MW TO SJ4								
Scenario Description	**Reserve Margin**	**CURRENT LOAD FORECAST**	**Reserve Margin**	**IRP HIGH LOAD**	**Reserve Margin**	**IRP MID LOAD**	**Reserve Margin**	**IRP LOW LOAD**
Load Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
Gas Pricing		PACE Reference		PACE Reference		PACE Reference		PACE Reference
CO2		PACE Reference ($11 in 2020)		PACE Reference ($11 in 2020)		PACE Reference ($11 in 2020)		PACE Reference ($11 in 2020)
Energy Efficiency Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
PV DG Forecast		Current		2014 IRP High Load		2014 IRP Mid Load		2014 IRP Low Load
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	18.0%		13.4%		14.7%		15.2%	
2015	17.8%	Red Mesa (102 MW)	13.0%	Red Mesa (102 MW)	15.5%	Red Mesa (102 MW)	17.1%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	15.5%	Aeroderivative (40 MW)	18.8%	Aeroderivative (40 MW)	21.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	14.6%	San Juan BART	18.4%	San Juan BART	21.1%	San Juan BART
2018	17.2%	Large GT (177 MW)	15.1%	Large GT (177 MW)	14.3%	Palo Verde 3 (134 MW)	14.6%	Palo Verde 3 (134 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Solar PV Tier 2 (80 MW)		Solar PV Tier 2 (20 MW)
						Solar PV Tier 3 (20 MW)		
2019	14.8%		14.5%		14.5%	Solar PV Tier 3 (20 MW)	14.8%	
2020	14.1%	Solar PV Tier 2 (20 MW)	14.6%	Solar PV Tier 2 (20 MW)	14.3%		15.7%	
2021	14.7%	Solar PV Tier 2 (60 MW)	14.2%	Wind (100 MW)	14.4%	Solar PV Tier 3 (20 MW)	15.7%	
2022	14.2%	Solar PV Tier 3 (40 MW)	14.4%	Solar PV Tier 2 (20 MW)	14.2%		15.9%	
2023	14.0%	Solar PV Tier 3 (60 MW)	14.2%	Solar PV Tier 2 (20 MW)	14.3%	Solar PV Tier 3 (20 MW)	15.6%	
		Wind (100 MW)						
2024	19.9%	Large GT (177 MW)	14.2%	Solar PV Tier 2 (20 MW)	14.4%	Solar PV Tier 3 (20 MW)	15.0%	
				Solar PV Tier 3 (20 MW)				
2025	17.5%		14.0%	Solar PV Tier 3 (40 MW)	14.3%	Solar PV Tier 3 (20 MW)	14.2%	
2026	15.1%		14.2%	Solar PV Tier 3 (60 MW)	14.1%	Solar PV Tier 3 (20 MW)	14.2%	Solar PV Tier 2 (20 MW)
2027	14.4%	2nd Aeroderivative (40 MW)	14.7%	2nd Aeroderivative (40 MW)	15.4%	2nd Aeroderivative (40 MW)	14.3%	Solar PV Tier 2 (20 MW)
						Wind (100 MW)		Wind (100 MW)
2028	19.4%	Large GT (177 MW)	14.0%	Solar PV Tier 3 (20 MW)	14.6%		14.4%	Solar PV Tier 2 (20 MW)
2029	16.9%		20.1%	Large GT (177 MW)	15.6%	Aeroderivative (40 MW)	14.3%	Solar PV Tier 3 (40 MW)
2030	14.5%		18.7%		14.6%		14.5%	Solar PV Tier 3 (40 MW)
2031	14.8%	Aeroderivative (40 MW)	17.4%		17.2%	Small GT (85 MW)	14.1%	Solar PV Tier 3 (20 MW)
		Solar PV Tier 3 (40 MW)						
2032	16.3%	Reciprocating Engines (93 MW)	15.6%		15.6%		14.5%	2nd Aeroderivative (40 MW)
2033	14.0%		14.3%		14.7%		14.7%	Solar PV Tier 3 (40 MW)
PRESENT VALUE PORTFOLIO COST		**$6,852,061,359**		**$6,660,633,231**		**$6,549,065,930**		**$6,271,415,605**
5% Tail (Risk)		**$189,983,119**		**$174,878,601**		**$179,613,771**		**$172,178,315**
20-Year Loss of Load (Hours)		**32.15**		**52.44**		**127.93**		**112.85**
20-Year CO2 (Metric Tons)		**103,932,981**		**101,877,265**		**101,660,462**		**100,243,825**

Notes:

1. All portfolios assume net retirement of 286 MW at San Juan Generating Station

		28		29		30
PRICE COMPARISON - 132 MW TO SJ4						
Scenario Description	**Reserve Margin**	**PACE REFERENCE GAS/CARBON**	**Reserve Margin**	**PACE HIGH GAS/CARBON**	**Reserve Margin**	**PACE LOW GAS/CARBON**
Load Forecast		Current		Current		Current
Gas Pricing		PACE Reference		PACE High Gas		PACE Low Gas
CO2		PACE Reference ($11 in 2020)		PACE High Carbon ($11 in 2018)		PACE Low Carbon ($10 in 2027)
Energy Efficiency Forecast		Current		Current		Current
PV DG Forecast		Current		Current		Current
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	18.0%		18.0%		18.0%	
2015	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	17.8%	San Juan BART	17.8%	San Juan BART
2018	17.2%	Large GT (177 MW)	15.8%	Large GT (143 MW)	17.2%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
				Wind (100 MW)		
2019	14.8%		14.2%	Solar PV Tier 2 (20 MW)	14.8%	
2020	14.1%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (40 MW)	14.1%	Solar PV Tier 2 (20 MW)
2021	14.7%	Solar PV Tier 2 (60 MW)	15.4%	Solar PV Tier 2 (20 MW)	14.7%	Solar PV Tier 2 (60 MW)
				Solar PV Tier 3 (80 MW)		
2022	14.2%	Solar PV Tier 3 (40 MW)	14.4%	Solar PV Tier 3 (20 MW)	14.2%	Solar PV Tier 3 (40 MW)
2023	14.0%	Solar PV Tier 3 (60 MW)	20.5%	Large GT (177 MW)	20.3%	Large GT (177 MW)
		Wind (100 MW)				
2024	19.9%	Large GT (177 MW)	18.4%		18.2%	
2025	17.5%		17.0%	Solar PV Tier 3 (40 MW)	15.8%	
2026	15.1%		14.6%		14.4%	Solar PV Tier 3 (40 MW)
2027	14.4%	2nd Aeroderivative (40 MW)	19.7%	Large GT (177 MW)	19.5%	Large GT (177 MW)
2028	19.4%	Large GT (177 MW)	17.2%		17.1%	
2029	16.9%		14.9%		14.7%	
2030	14.5%		14.0%	2nd Aeroderivative (40 MW)	14.1%	2nd Aeroderivative (40 MW)
						Wind (100 MW)
2031	14.8%	Aeroderivative (40 MW)	15.5%	Reciprocating Engines (93 MW)	15.6%	Reciprocating Engines (93 MW)
		Solar PV Tier 3 (40 MW)				
2032	16.3%	Reciprocating Engines (93 MW)	15.0%	Aeroderivative (40 MW)	14.3%	Solar PV Tier 3 (40 MW)
2033	14.0%		15.7%	Small GT (85 MW)	14.0%	Aeroderivative (40 MW)
						Solar PV Tier 3 (20 MW)
PRESENT VALUE PORTFOLIO COST		**$6,852,061,359**		**$7,670,910,744**		**$6,223,888,831**
5% Tail (Risk)		**$189,983,119**		**$310,713,271**		**$119,567,189**
20-Year Loss of Load (Hours)		**32.15**		**28.82**		**32.81**
20-Year CO2 (Metric Tons)		**103,932,981**		**101,648,873**		**106,463,398**

Notes:

1. All portfolios assume net retirement of 286 MW at San Juan Generating Station

		31		32		33
IRP EE COMPARISONS - 132 MW TO SJ4						
Scenario Description	**Reserve Margin**	**EE MID + 132 MW TO SJ4**	**Reserve Margin**	**EE LOW + 132 MW TO SJ4**	**Reserve Margin**	**EE HIGH + 132 MW TO SJ4**
Load Forecast		Current Forecast		Current Forecast		Current Forecast
Gas Pricing		PACE Reference		PACE High Gas		PACE Low Gas
CO2		PACE Reference ($11 in 2020)		PACE High Carbon ($11 in 2018)		PACE Low Carbon ($10 in 2027)
Energy Efficiency Forecast		Current Forecast		2014 IRP Low		2014 IRP High
PV DG Forecast		Current Forecast		Current Forecast		Current Forecast
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	18.0%		18.1%		18.1%	
2015	17.8%	Red Mesa (102 MW)	17.9%	Red Mesa (102 MW)	17.9%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	20.1%	Aeroderivative (40 MW)	20.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	18.2%	San Juan BART	18.3%	San Juan BART
2018	17.2%	Large GT (177 MW)	17.5%	Large GT (177 MW)		Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)	17.7%	Palo Verde 3 (134 MW)
2019	14.8%		15.2%			
2020	14.1%	Solar PV Tier 2 (20 MW)	14.6%	Solar PV Tier 2 (20 MW)	15.4%	
2021	14.7%	Solar PV Tier 2 (60 MW)	14.4%	Solar PV Tier 2 (40 MW)	14.2%	Solar PV Tier 2 (40 MW)
2022	14.2%	Solar PV Tier 3 (40 MW)	14.2%	Solar PV Tier 2 (20 MW)	14.2%	Solar PV Tier 2 (40 MW)
				Solar PV Tier 3 (20 MW)	14.3%	
2023	14.0%	Solar PV Tier 3 (60 MW)	14.1%	Solar PV Tier 3 (60 MW)	14.0%	Solar PV Tier 3 (60 MW)
		Wind (100 MW)		Wind (100 MW)	14.2%	
2024	19.9%	Large GT (177 MW)	19.8%	Large GT (177 MW)		Solar PV Tier 3 (80 MW)
						Wind (100 MW)
2025	17.5%		17.7%		14.0%	2nd Aeroderivative (40 MW)
2026	15.1%		15.0%		19.2%	Large GT (177 MW)
2027	14.4%	2nd Aeroderivative (40 MW)	14.1%	Solar PV Tier 3 (60 MW)	16.8%	
2028	19.4%	Large GT (177 MW)	19.0%	Large GT (177 MW)	14.5%	
2029	16.9%		16.6%		19.4%	Large GT (177 MW)
2030	14.5%		14.0%		16.9%	
2031	14.8%	Aeroderivative (40 MW)	15.3%	Reciprocating Engines (93 MW)	14.7%	
		Solar PV Tier 3 (40 MW)				
2032	16.3%	Reciprocating Engines (93 MW)	14.3%	2nd Aeroderivative (40 MW)	15.8%	Reciprocating Engines (93 MW)
2033	14.0%		15.1%	Small GT (85 MW)	15.0%	Aeroderivative (40 MW)
PRESENT VALUE PORTFOLIO COST		**$6,852,061,359**		**$6,857,828,377**		**$6,805,874,228**
5% Tail (Risk)		**$189,983,119**		**$189,705,039**		**$185,217,517**
20-Year Loss of Load (Hours)		**32.15**		**33.91**		**35.28**
20-Year CO2 (Metric Tons)		**103,932,981**		**104,390,462**		**103,163,243**

Notes:

1. All portfolios assume net retirement of 286 MW at San Juan Generating Station

		34		35		36
IRP MID LOAD COMPARE - 132 MW TO SJ4						
Scenario Description	**Reserve Margin**	**PACE REFERENCE GAS/CARBON**	**Reserve Margin**	**PACE HIGH GAS/CARBON**	**Reserve Margin**	**PACE LOW GAS/CARBON**
Load Forecast		2014 IRP Mid Load		2014 IRP Mid		2014 IRP Mid
Gas Pricing		PACE Reference		PACE High Gas		PACE Low Gas
CO2		PACE Reference ($11 in 2020)		PACE High Carbon ($11 in 2018)		PACE Low Carbon ($10 in 2027)
Energy Efficiency Forecast		2014 IRP Mid Load		2014 IRP Mid Load		2014 IRP Mid Load
PV DG Forecast		2014 IRP Mid Load		2014 IRP Mid Load		2014 IRP Mid Load
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	14.7%		14.7%		14.7%	
2015	15.5%	Red Mesa (102 MW)	15.5%	Red Mesa (102 MW)	15.5%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	18.8%	Aeroderivative (40 MW)	18.8%	Aeroderivative (40 MW)	18.8%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	18.4%	San Juan BART	18.4%	San Juan BART	18.4%	San Juan BART
2018	14.3%	Palo Verde 3 (134 MW)	14.0%	Palo Verde 3 (134 MW)	14.3%	Palo Verde 3 (134 MW)
		Solar PV Tier 2 (80 MW)		Solar PV Tier 2 (80 MW)		Solar PV Tier 2 (80 MW)
		Solar PV Tier 3 (20 MW)		Wind (100 MW)		Solar PV Tier 3 (20 MW)
2019	14.5%	Solar PV Tier 3 (20 MW)	14.2%	Solar PV Tier 3 (20 MW)	14.5%	Solar PV Tier 3 (20 MW)
2020	14.3%		14.0%		14.3%	
2021	14.4%	Solar PV Tier 3 (20 MW)	15.2%	Solar PV Tier 3 (60 MW)	14.4%	Solar PV Tier 3 (20 MW)
2022	14.2%		15.0%		14.2%	
2023	14.3%	Solar PV Tier 3 (20 MW)	15.1%	Solar PV Tier 3 (20 MW)	14.3%	Solar PV Tier 3 (20 MW)
2024	14.4%	Solar PV Tier 3 (20 MW)	14.7%		14.4%	Solar PV Tier 3 (20 MW)
2025	14.3%	Solar PV Tier 3 (20 MW)	15.1%	Solar PV Tier 3 (40 MW)	14.3%	Solar PV Tier 3 (20 MW)
2026	14.1%	Solar PV Tier 3 (20 MW)	14.3%		14.1%	Solar PV Tier 3 (20 MW)
2027	15.4%	2nd Aeroderivative (40 MW)	15.4%	2nd Aeroderivative (40 MW)	15.1%	2nd Aeroderivative (40 MW)
		Wind (100 MW)				
2028	14.6%		14.6%		14.3%	
2029	15.6%	Aeroderivative (40 MW)	15.6%	Aeroderivative (40 MW)	15.3%	Aeroderivative (40 MW)
2030	14.6%		14.6%		14.3%	
2031	17.2%	Small GT (85 MW)	17.2%	Small GT (85 MW)	17.0%	Small GT (85 MW)
2032	15.6%		15.6%		15.4%	
2033	14.7%		14.7%		14.4%	
PRESENT VALUE PORTFOLIO COST		**$6,549,065,930**		**$7,333,364,517**		**$5,957,446,318**
5% Tail (Risk)		**$179,613,771**		**$289,503,354**		**$111,117,600**
20-Year Loss of Load (Hours)		**127.93**		**103.09**		**141.42**
20-Year CO2 (Metric Tons)		**101,660,462**		**99,334,406**		**103,396,434**

Notes:

1. All portfolios assume net retirement of 286 MW at San Juan Generating Station

		37		38		39
IRP HIGH LOAD COMPARE - 132 MW TO SJ4						
Scenario Description	**Reserve Margin**	**PACE REFERENCE GAS/CARBON**	**Reserve Margin**	**PACE HIGH GAS/CARBON**	**Reserve Margin**	**PACE LOW GAS/CARBON**
Load Forecast		2014 IRP High Load		2014 IRP High Load		2014 IRP High Load
Gas Pricing		PACE Reference		PACE High Gas		PACE Low Gas
CO2		PACE Reference ($11 in 2020)		PACE High Carbon ($11 in 2018)		PACE Low Carbon ($10 in 2027)
Energy Efficiency Forecast		2014 IRP High Load		2014 IRP High Load		2014 IRP High Load
PV DG Forecast		2014 IRP High Load		2014 IRP High Load		2014 IRP High Load
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	13.4%		13.4%		13.4%	
2015	13.0%	Red Mesa (102 MW)	13.0%	Red Mesa (102 MW)	13.0%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	15.5%	Aeroderivative (40 MW)	15.5%	Aeroderivative (40 MW)	15.5%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	14.6%	San Juan BART	14.6%	San Juan BART	14.6%	San Juan BART
2018		Large GT (177 MW)	14.4%	Large GT (143 MW)	15.1%	Large GT (177 MW)
	15.1%	Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
				Solar PV Tier 2 (20 MW)		
				Wind (100 MW)		
2019	14.5%		14.6%	Solar PV Tier 2 (20 MW)	14.5%	
2020	14.6%	Solar PV Tier 2 (20 MW)	14.7%	Solar PV Tier 2 (20 MW)	14.6%	Solar PV Tier 2 (20 MW)
2021	14.2%	Wind (100 MW)	16.8%	Solar PV Tier 2 (20 MW)	14.6%	Solar PV Tier 2 (20 MW)
				Solar PV Tier 3 (80 MW)		
2022	14.4%	Solar PV Tier 2 (20 MW)	16.3%		14.2%	
2023	14.2%	Solar PV Tier 2 (20 MW)	15.9%	Solar PV Tier 3 (20 MW)	14.7%	Solar PV Tier 2 (40 MW)
2024	14.2%	Solar PV Tier 2 (20 MW)	14.7%		14.5%	Solar PV Tier 3 (40 MW)
		Solar PV Tier 3 (20 MW)				
2025	14.0%	Solar PV Tier 3 (40 MW)	14.5%	Solar PV Tier 3 (40 MW)	14.3%	Solar PV Tier 3 (40 MW)
2026	14.2%	Solar PV Tier 3 (60 MW)	21.2%	Large GT (177 MW)	21.0%	Large GT (177 MW)
2027	14.7%	2nd Aeroderivative (40 MW)	19.8%		19.6%	
2028	14.0%	Solar PV Tier 3 (20 MW)	18.6%		18.4%	
2029	20.1%	Large GT (177 MW)	16.9%		16.7%	
2030	18.7%		15.5%		15.4%	
2031	17.4%		14.2%		14.0%	
2032	15.6%		14.1%	2nd Aeroderivative (40 MW)	14.4%	2nd Aeroderivative (40 MW)
						Solar PV Tier 3 (20 MW)
2033	14.3%		14.5%	Aeroderivative (40 MW)	14.1%	Solar PV Tier 3 (40 MW)
PRESENT VALUE PORTFOLIO COST		**$6,660,633,231**		**$7,453,129,805**		**$6,061,500,557**
5% Tail (Risk)		**$174,878,601**		**$285,921,364**		**$139,626,518**
20-Year Loss of Load (Hours)		**52.44**		**49.31**		**57.08**
20-Year CO2 (Metric Tons)		**101,877,265**		**99,599,570**		**105,756,803**

Notes:

1. All portfolios assume net retirement of 286 MW at San Juan Generating Station

		40		41		42
IRP LOW LOAD COMPARE - 132 MW TO SJ4						
Scenario Description	**Reserve Margin**	**PACE REFERENCE GAS/CARBON**	**Reserve Margin**	**PACE HIGH GAS/CARBON**	**Reserve Margin**	**PACE LOW GAS/CARBON**
Load Forecast		2014 IRP Low Load		2014 IRP Low Load		2014 IRP Low Load
Gas Pricing		PACE Reference		PACE High Gas		PACE Low Gas
CO2		PACE Reference ($11 in 2020)		PACE High Carbon ($11 in 2018)		PACE Low Carbon ($10 in 2027)
Energy Efficiency Forecast		2014 IRP Low Load		2014 IRP Low Load		2014 IRP Low Load
PV DG Forecast		2014 IRP Low Load		2014 IRP Low Load		2014 IRP Low Load
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	15.2%		15.2%		15.2%	
2015	17.1%	Red Mesa (102 MW)	17.1%	Red Mesa (102 MW)	17.1%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	21.1%	Aeroderivative (40 MW)	21.1%	Aeroderivative (40 MW)	21.1%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	21.1%	San Juan BART	21.1%	San Juan BART	21.1%	San Juan BART
2018	14.6%	Palo Verde 3 (134 MW)	14.0%	Palo Verde 3 (134 MW)	14.6%	Palo Verde 3 (134 MW)
		Solar PV Tier 2 (20 MW)		Wind (100 MW)		Solar PV Tier 2 (20 MW)
2019	14.8%		14.3%		14.8%	
2020	15.7%		15.2%		15.7%	
			18.9%	Solar PV Tier 2 (80 MW)		
2021	15.7%			Solar PV Tier 3 (20 MW)	15.7%	
2022	15.9%		19.1%		15.9%	
2023	15.6%		19.4%	Solar PV Tier 3 (20 MW)	15.6%	
2024	15.0%		18.7%		15.0%	
2025	14.2%		19.0%	Solar PV Tier 3 (40 MW)	14.2%	
2026	14.2%	Solar PV Tier 2 (20 MW)	19.4%	Solar PV Tier 3 (40 MW)	14.2%	Solar PV Tier 2 (20 MW)
2027	14.3%	Solar PV Tier 2 (20 MW)	19.0%	Solar PV Tier 3 (20 MW)	14.0%	Solar PV Tier 2 (20 MW)
		Wind (100 MW)				
2028	14.4%	Solar PV Tier 2 (20 MW)	18.3%		14.2%	Solar PV Tier 2 (20 MW)
2029	14.3%	Solar PV Tier 3 (40 MW)	17.1%		14.1%	Solar PV Tier 3 (40 MW)
2030	14.5%	Solar PV Tier 3 (40 MW)	16.1%		14.3%	Solar PV Tier 3 (40 MW)
2031	14.1%	Solar PV Tier 3 (20 MW)	15.2%		14.4%	Solar PV Tier 3 (40 MW)
2032	14.5%	2nd Aeroderivative (40 MW)	15.6%	2nd Aeroderivative (40 MW)	14.8%	2nd Aeroderivative (40 MW)
2033	14.7%	Solar PV Tier 3 (40 MW)	14.7%		14.5%	Solar PV Tier 3 (20 MW)
PRESENT VALUE PORTFOLIO COST	**$6,271,415,605**		**$7,015,201,260**		**$5,695,589,197**	
5% Tail (Risk)	**$172,178,315**		**$265,315,113**		**$103,198,141**	
20-Year Loss of Load (Hours)	**112.85**		**82.55**		**131.18**	
20-Year CO2 (Metric Tons)	**100,243,825**		**95,423,199**		**101,928,820**	

Notes:

1. All portfolios assume net retirement of 286 MW at San Juan Generating Station

		43		44		45		46
IRP STANDARIZED CARBON EMISSION COST PORTFOLIOS - 132 MW TO SJ4								
Scenario Description	Reserve Margin	**$0 CO2 COST**	Reserve Margin	**$8 C02 COST**	Reserve Margin	**$20 CO2 COST**	Reserve Margin	**$40 CO2 COST**
Load Forecast		Current Forecast		Current Forecast		Current Forecast		Current Forecast
Gas Pricing		PACE Reference Case		PACE Reference		PACE High Gas		PACE Low Gas
CO2		None		$8 Beginning 2010 (2.5% annual esc)		$20 Beginning 2010 (2.5% annual esc)		$40 Beginning 2010 (2.5% annual esc)
Energy Efficiency Forecast		Current Forecast		Current Forecast		Current Forecast		Current Forecast
PV DG Forecast		Current Forecast		Current Forecast		Current Forecast		Current Forecast
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	18.0%		18.0%		18.0%		18.0%	
2015	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	17.8%	San Juan BART	17.8%	San Juan BART	19.6%	San Juan BART
								Solar PV Tier 2 (40 MW)
								Wind (100 MW)
2018	17.7%	Large GT (143 MW)	17.7%	Large GT (143 MW)	17.5%	Large GT (177 MW)	19.8%	Large GT (143 MW)
		Large GT (177 MW)		Large GT (177 MW)		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
						Wind (100 MW)		Solar PV Tier 2 (40 MW)
								Solar PV Tier 3 (40 MW)
2019	15.3%		15.5%	Wind (100 MW)	15.1%		19.0%	Solar PV Tier 3 (60 MW)
2020	14.5%	Solar PV Tier 2 (20 MW)	14.0%		14.3%	Solar PV Tier 2 (20 MW)	17.5%	
2021	14.4%	Solar PV Tier 2 (40 MW)	14.6%	Solar PV Tier 2 (60 MW)	14.2%	Solar PV Tier 2 (40 MW)	15.9%	
2022	14.1%	Solar PV Tier 2 (20 MW)	14.3%	Solar PV Tier 2 (20 MW)	14.4%	Solar PV Tier 2 (20 MW)	14.4%	
		Solar PV Tier 3 (20 MW)		Solar PV Tier 3 (20 MW)		Solar PV Tier 3 (40 MW)		
2023	14.2%	Solar PV Tier 3 (80 MW)	14.4%	Solar PV Tier 3 (80 MW)	14.0%	Solar PV Tier 3 (60 MW)	20.5%	Large GT (177 MW)
2024	20.1%	Large GT (177 MW)	20.3%	Large GT (177 MW)	19.9%	Large GT (177 MW)	18.4%	
2025	17.7%		17.9%		17.5%		16.5%	Solar PV Tier 3 (20 MW)
2026	15.3%		15.5%		15.1%		14.6%	Solar PV Tier 3 (20 MW)
2027	14.0%	Solar PV Tier 3 (40 MW)	14.0%	Solar PV Tier 3 (40 MW)	14.4%	2nd Aeroderivative (40 MW)	19.7%	Large GT (177 MW)
		Wind (100 MW)						
2028	19.0%	Large GT (177 MW)	19.0%	Large GT (177 MW)	19.4%	Large GT (177 MW)	17.2%	
2029	16.6%		16.6%		16.9%		14.9%	
2030	14.2%		14.2%		14.5%		14.0%	2nd Aeroderivative (40 MW)
2031	15.7%	Reciprocating Engines (93 MW)	15.7%	Reciprocating Engines (93 MW)	14.4%	Aeroderivative (40 MW)	15.5%	Reciprocating Engines (93 MW)
						Solar PV Tier 3 (20 MW)		
2032	15.1%	2nd Aeroderivative (40 MW)	15.1%	2nd Aeroderivative (40 MW)	15.8%	Reciprocating Engines (93 MW)	15.0%	Aeroderivative (40 MW)
2033	14.4%	Aeroderivative (40 MW)	14.4%	Aeroderivative (40 MW)	14.0%	Solar PV Tier 3 (20 MW)	15.7%	Small GT (85 MW)
PRESENT VALUE PORTFOLIO COST		**$6,030,664,726**		**$6,680,384,820**		**$7,597,910,882**		**$8,998,395,304**
20-Year Loss of Load (Hours)		**33.50**		**29.60**		**28.34**		**23.93**
20-Year CO2 (Metric Tons)		**116,406,094**		**114,605,554**		**102,706,175**		**96,508,560**

Notes:

1. All portfolios assume net retirement of 286 MW at San Juan Generating Station

		47		48
DROUGHT SENSITIVITIES				
Scenario Description	**Reserve Margin**	**DROUGHT + 78 MW TO SJ4**	**Reserve Margin**	**DROUGHT + 132 MW TO SJ4**
Load Forecast		Current Forecast		Current Forecast
Gas Pricing		PACE Reference		PACE Reference
CO2		PACE Reference ($11 in 2020)		PACE Reference ($11 in 2020)
Energy Efficiency Forecast		Current Forecast		Current Forecast
PV DG Forecast		Current Forecast		Current Forecast
SCRs/SNCRs at San Juan		SNCR's on 1 & 4		SNCR's on 1 & 4
San Juan Investment Recovery		$16,401,523		$16,401,523
SJ Retirements/Unit 4 Addition		Units 2 & 3 (Dec 2017) + 78 MW to SJ4		Units 2 & 3 (Dec 2017) + 132 MW to SJ4
2014	18.0%		18.0%	
2015	17.8%	Red Mesa (102 MW)	17.8%	Red Mesa (102 MW)
		2015 Solar (23 MW)		2015 Solar (23 MW)
2016	19.9%	Aeroderivative (40 MW)	19.9%	Aeroderivative (40 MW)
		Solar PV Tier 1 (40 MW)		Solar PV Tier 1 (40 MW)
2017	17.8%	San Juan BART	17.8%	San Juan BART
2018	14.6%	Large GT (177 MW)	17.2%	Large GT (177 MW)
		Palo Verde 3 (134 MW)		Palo Verde 3 (134 MW)
2019	14.4%	Solar PV Tier 2 (60 MW)	14.8%	
2020	14.2%	Solar PV Tier 2 (20 MW)	14.1%	Solar PV Tier 2 (20 MW)
		Solar PV Tier 3 (20 MW)		
2021	14.2%	Solar PV Tier 3 (60 MW)	14.7%	Solar PV Tier 2 (60 MW)
2022	14.3%	Solar PV Tier 3 (60 MW)	14.2%	Solar PV Tier 3 (40 MW)
2023	20.4%	Large GT (177 MW)	14.0%	Solar PV Tier 3 (60 MW)
				Wind (100 MW)
2024	18.2%		19.9%	Large GT (177 MW)
2025	15.9%		17.5%	
2026	21.3%	Large GT (177 MW)	15.1%	
		Wind (100 MW)		
2027	18.8%		14.4%	2nd Aeroderivative (40 MW)
2028	16.4%		19.4%	Large GT (177 MW)
2029	14.1%		16.9%	
2030	15.3%	Reciprocating Engines (93 MW)	14.5%	
2031	14.8%	2nd Aeroderivative (40 MW)	14.8%	Aeroderivative (40 MW)
				Solar PV Tier 3 (40 MW)
2032	14.2%	Aeroderivative (40 MW)	16.3%	Reciprocating Engines (93 MW)
2033	15.0%	Small GT (85 MW)	14.0%	
PRESENT VALUE PORTFOLIO COST		**$6,917,332,357**		**$6,923,389,733**
5% Tail (Risk)		**$201,030,708**		**$200,887,094**
20-Year Loss of Load (Hours)		**94.34**		**102.51**
20-Year CO2 (Metric Tons)		**101,108,278**		**102,490,633**

Appendix G: Rules and Regulations

In addition to the IRP Rule requirements, the IRP must comply with EE requirements, environmental regulations, renewable energy requirements, system reliability standards, and Commission orders, including orders approving stipulated agreements. The following paragraphs review each of the additional resource planning considerations.

Overview of Applicable Regulatory Requirements Relevant to the IRP

The following rules and regulations are applicable to the IRP:

* Efficient Use of Energy Act, NMSA 62.17.1 et seq.
* FERC Order No. 888 - http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp
* FERC Order No. 890 - http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp
* FERC Order No. 1000 – Transmission Planning and Cost Allocation Rule
* Case 2740 – Person Peaking Unit Cobisa
* Case 3137 Stipulation Transition Plan
* Case 04-00315-UT – TNMP Acquisition
* Case 06-00448-UT –Staged Standardized Carbon Emissions Costs
* Case 08-00305-UT – Resource Stipulation
* Case 10-00037-UT – 2011 Renewable Energy Plan
* Case 12-00317-UT – PNM Energy Efficiency Programs
* Case 13-00183-UT – 2014 Renewable Energy Plan

Energy Efficiency Requirements

The EUEA and the EE Rule (17.7.2 NMAC) require utilities to include cost-effective EE and DR programs in their resource portfolios and establish cost-effectiveness as a mandatory criterion for all programs. The EUEA and the EE Rule require utilities to file an annual EE Program Report with the NMPRC.

The EUEA requires utilities to realize energy savings of at least 5% by 2014 and 8% by 2020 based on 2005 retail sales, or energy sales to end users, subject to the cost-effectiveness and achievability criteria. In addition, the EUEA requires the NMPRC to balance customer and shareholder interests by removing any disincentives or barriers to implementation, and by providing incentives to promote demand-side resources. Amendments to the EUEA in 2013 also require utilities to invest 3% of retail sales revenues in energy efficiency and demand response programs, which provides consistency in the level of spending that can be expected over time. The Energy Efficiency Rule allows PNM to earn incentives on cost-effective load management programs through an approved tariff rider.

National Ambient Air Quality Standards (NAAQS) Under the Clean Air Act

The federal Clean Air Act (CAA) governs air quality in this country. The purpose of the act is to protect and enhance the quality of the Nation's air resources to promote public health and welfare. The provisions of the CAA are implemented in federal regulations developed by the Environmental Protection Agency (EPA). These regulations are applied and enforced by individual states under EPA-approved state plans. The National Ambient Air Quality Standard (NAAQS) program, a centerpiece of the CAA, addresses air pollutants commonly referred to as Criteria Pollutants, considered harmful to human health and the environment. The EPA sets ambient concentration thresholds for these pollutants at levels that protect human health with an adequate margin of safety, and reviews these standards every five years to determine if they need to be revised. The NAAQS emissions of most concern relative to PNM's operations are nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM), and ozone. Once EPA establishes a NAAQS, states have primary responsibility for implementation. Each state must develop regulations designed to ensure attainment and maintenance of these standards. The NAAQS are also protected under the CAA by the federal New Source Review (NSR) preconstruction permitting programs. In attainment areas, the permitting program is knows as Prevention of Significant Deterioration (PSD), whereas, permitting in non-attainment areas requires the installation of Lowest Achievable Emission Rate (LAER) technology. These programs apply to new sources or sources seeking to expand.

This program requires more stringent control technologies on new and modified sources that are included in air permits issued by the state. The CAA also gives EPA authority to limit emissions from air pollutants coming from specific sources such as fossil-fueled generating plants. The 1990 CAA Amendments required EPA to identify categories of industrial sources that emit any one of 187 listed hazardous air pollutants (HAPs) and reduce pollution by requiring these sources to install controls or change operations.

Currently, most electric generation comes from firing fossil fuels such as coal plants and natural gas plants. These plants are subject to regulation under the CAA. The cost of compliance with the CAA is a necessary factor that is considered in the IRP process. The CAA regulations are subject to change, which affects cost estimates for compliance. The trend in recent years has been towards more regulation of air emissions from fossil fuel sources.

Regional Haze

Regional haze refers to the impacts to visibility caused by multiple sources over a wide area. Haze degrades visibility and is created when sunlight encounters tiny pollution particles in the air. Some light is absorbed by particles and other light is scattered away before it reaches an observer. More pollutants mean more absorption and scattering of light, which reduce the clarity and color of what we see.

In 1977, the CAA set a goal to remedy any existing visibility impairment and prevent any future impairment from manmade pollution at 156 mandatory Class I Federal Areas (national parks and wilderness areas) across the U.S. In 1999, EPA developed a regional haze program and regional haze rules under the Clean Air Act. The rule directs each of the 50 states to address regional haze. Specifically, states are required to establish goals for improving visibility in national Class I areas and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment in their own states and for preventing degradation in other states.

The final Regional Haze Rule was promulgated in July 2005 along with guidelines for Best Available Retrofit Technology (BART) determinations for appropriate pollution controls at BART-eligible facilities. The rule requires states to identify certain industrial facilities and power plants that impact visibility in the 156 Class I areas and then determine the type of emission controls that constitute BART for each specific facility. To enable a state to determine BART for a facility, the facility submits a BART analysis that includes a recommendation for BART.

Both San Juan Generating Station (SJGS) and the Four Corners Power Plant were identified by the New Mexico Environment Department and EPA Region 9, respectively, as BART-eligible sources. After conducting a BART analysis, both facilities are required to add emission controls to address the Regional Haze regulation. The New Mexico Environmental Improvement Board (EIB) approved the NMED determination that the shutdown of Units 2 and 3 and the addition of selective non-catalytic reduction (SNCR) for NOx control on Units 1 and 4 constitutes BART for SJGS. EPA is currently reviewing this determination and published a proposed rule on May 12, 2014 which, if adopted, will approve the state plan. A final decision on the state plan is expected by October 2014. EPA has issued its final BART determination for Four Corners Power Plant that included two compliance alternatives. The owners of the plant selected the alternative that required the plant to shutdown Units 1, 2 and 3 by January 1, 2014 and install selective catalytic reduction (SCR) post-combustion NOx controls on each of Units 4 and 5. Actual shutdown of Units 1, 2 and 3 occurred on December 30, 2013.

Ozone Standard

The EPA has established a NAAQS ambient concentration limit for ground-level ozone. Ground level or "bad" ozone is created by chemical reactions between NOx and volatile organic compounds (VOC) in the presence of sunlight. In 2008, EPA lowered the ozone NAAQS to 0.075 ppm which is the current standard. In January 2010, EPA announced that it was considering lowering the 8-hour ozone standard even further to a range of 0.060 to 0.070 ppm. These levels were expected to result in a significant increase in ozone non-attainment areas across the U.S. In September 2011, President Obama instructed EPA to delay revision of the standard until the end of the normal five-year review cycle. EPA and the states are currently implementing the 2008 standard. A revised ozone standard is now expected to be proposed in 2014 and finalized in 2015. Depending upon the level at which the revised ozone NAAQS is set, it is possible that some counties within New Mexico may become non-attainment for ozone. If so, the

NMED will need to develop overall reduction plans for any non-attainment area. PNM believes the BART controls on Units 1 and 4 and the shutdown of Units 2 and 3 should allow SJGS to be compliant with a new lower ozone standard. With the installation of the SCRs on Units 4 and 5 and the shutdown of Units 1, 2 and 3, the Four Corners Power Plant should also be well-positioned to comply.

Hazardous Air Pollutants (Including Mercury)

On December 16, 2011, EPA approved the Mercury and Air Toxics Standards (MATS) rule to establish national emission limitations and work practices for electric generating units (EGU) to control certain HAPs. The rule sets standards to limit or reduce emissions of heavy metals, including mercury, arsenic, acid gases and other HAPs from power plants. Facilities generally have up to four years to demonstrate compliance with the emission standards established in the rule. The pollutants covered under the MATS rule that are emitted from PNM's power generation fleet are PM (surrogate for non-mercury (Hg) hazardous air pollutant metals), SO_2 (surrogate for hydrogen chloride) and mercury (requiring a minimum 91% control efficiency). The pollution control equipment currently used at the SJGS meets the EGU MATS emissions standards. With regard to mercury, stack testing performed for EPA during the MATS rulemaking process showed that SJGS achieved a mercury removal rate of 99% or greater. APS has determined that no additional equipment will be required at Four Corners Power Plant Units 4 and 5 to comply with the rule.

Coal Ash

On May 4, 2010, EPA released its proposed rule on the regulation of coal combustion byproducts (CCBs) such as coal ash. The proposal includes two options for regulation of coal ash:

1) The regulation of CCBs as a hazardous waste under the Resource Conservation and Recovery Act (RCRA)
2) The regulation of CCBs as a non-hazardous solid waste under RCRA

In 2012, EPA was sued by a number of parties, including environmental and industry groups, in the District Court for the District of Columbia. The litigation, among other things, sought to force EPA to take final action regarding the classification of CCBs. On January 29, 2014, EPA entered into a consent decree with parties to publish a final rule no later than December 19, 2014. The proposed CCB regulations by EPA could impact SJGS and the Four Corners Power Plant. At SJGS, CCBs are currently used as reclamation material in the mine pits of the adjacent San Juan Mine. At Four Corners Power Plant, CCBs are disposed of in ash ponds and dry storage areas and a portion is also sold for beneficial use (e.g. as a constituent in concrete production). If CCBs are regulated as hazardous waste, mine placement, ash pond storage and other current disposal practices may no longer be allowed. Under this scenario, the costs associated with the handling and disposal of CCBs will increase.

The scope of future regulation of CCB disposal remains uncertain. Depending on how CCBs are regulated, the cost of regulatory compliance will vary widely. Section 11: *Scenario Analysis* details how various outcomes for coal ash were modeled in the IRP.

Climate Change

On June 2, 2014, EPA announced the proposed Clean Power Plan that will regulate carbon dioxide (CO_2) emissions from existing electric generating units. The overall goal of the plan is to cut CO_2 emissions from the power sector by 30 percent (averaged across all states) by 2030 from 2005 levels. EPA is using its authority under section 111(d) of the Clean Air Act to issue these proposed regulations.

The Clean Power Plan consists of two main elements:

- State-specific emission rate-based CO_2 goals (measured in lb CO_2/MWh)
- Guidelines for development, submission and implementation of state plans to achieve state goals.

EPA has proposed the following emissions standard for New Mexico (carbon intensity goal expressed as lb/MWh):

- 2020-2029 (interim goal): 1107 lb CO2/MWh
- 2030 (final goal): 1048 lb/MWh

States like New Mexico must develop a compliance plan to meet the goal through measures that reflect their particular circumstances and policy objectives. In compliance plans, states are required to propose either of two types of measures to achieve the emission rate goal: 1) a combination of emission limitations that apply to affected sources and other measures that have the effect of reducing carbon emissions from affected sources, or 2) solely emission limitations that apply directly to the affected source.

The interim or "phase-in" period is 2020 to 2029. Each state must meet their interim emission rate goal on average over this period. Progress toward this average goal will be demonstrated for every two rolling calendar years starting January 1, 2020, with the first report due in 2022. Progress is measured by comparing emission performance achieved to projected performance. The final emissions rate goal must be achieved in 2030 and beyond. Compliance is measured on a three-year rolling average basis, starting January 1, 2030.

PNM is optimistic that emission reductions resulting from the planned closure of SJGS Units 2 and 3 would count toward meeting New Mexico's standard. However, there is still uncertainty regarding how the credit for planned shutdowns will apply. This uncertainty is likely to continue until 2016 or later when New Mexico develops and submits the state 111(d) plan for complying with the proposed rule to EPA. PNM is not yet taking a definitive position on the rule until the company has a complete and thorough analysis of the proposal and its implications to the company, industry and PNM customers.

The Clean Power Plan proposed rule was published in the Federal Register on June 19, 2014. EPA is accepting comments on the proposed rule until October 16, 2014. EPA will also hold four public hearings on the proposed rule the week of July 28, 2014 in Atlanta, GA, Denver, CO, Pittsburgh, PA and Washington, DC.

Under the May 9, 1992 United Nations Framework Convention on Climate Change, the U.S. government committed to stabilizing GHG concentrations at specified levels. Since that time, the U.S. Congress has considered various proposals to regulate GHG emissions, but none have been passed into law thus far.

On June 25, 2013, President Obama announced the President's Climate Action Plan to reduce U.S. greenhouse (GHG) gas emissions by 17 percent below 2005 levels by 2020. President's plan was presented as a series of Executive Actions to reduce carbon pollution, prepare the U.S. for the impacts of climate change, and lead international efforts to address global climate change.

As part of the Climate Action Plan, the President issued a Presidential Memorandum directing the EPA to move forward with completion of carbon emission standards for the power sector. The memorandum required EPA to reissue the proposed greenhouse gas (GHG) emission standards for new fossil-fuel power plants under Section 111(b) of the Clean Air Act. The original draft rule was published in April 13, 2012. EPA re-proposed the rule in September 2013.

The proposed New Source Performance Standards (NSPS) for new fossil-fired sources is an emission standard for new coal-fired power plants and gas-fired power plants. New coal or gas fired facilities must meet a carbon dioxide (CO2) emission standard of 1100 lb/MWh. For coal fired plants, the proposal is based upon carbon capture and sequestration technology that is not widely deployed and has not yet been demonstrated to be commercially available nor cost-effective for electric generation. Under the NSPS for new sources, EPA proposes separate GHG standards for base-load and intermediate natural gas-fired generating units. These standards require natural gas-fired power plants to use modern, efficient combined-cycle technology. Simple cycle gas turbines would generally be excluded from the NSPS if they are used as a peaking plant and sell less than one-third of their potential output to the electric grid.

With respect to existing sources, EPA issued a proposed "Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" under Section 111(d) of the CAA, for existing power plants on June 2, 2014. The final rule is expected by no later than June 1, 2015. EPA has directed states to submit their Section 111(d) implementation plans to the agency by no later than June 30, 2016 unless the state files for an extension. Nationwide, by 2030, this rule would achieve CO2 emission reductions from the power sector of approximately 30 percent from CO2 emission levels in 2005.

The proposed guidelines are based on and would reinforce the actions already being taken by states and utilities to upgrade aging electricity infrastructure with 21st century technologies. The guidelines would ensure that these trends continue in ways that are consistent with the long-term planning and investment processes already used in this sector, to meet both region- and state-specific needs. The proposal provides flexibility for states to build upon their progress, and the progress of cities and towns, in addressing GHGs. It also allows states to pursue policies to reduce carbon pollution that: 1) continue to rely on a diverse set of energy resources, 2) ensure electric system reliability, 3) provide affordable electricity, 4) recognize investments that states and power companies are already making, and 5) can be tailored to meet the specific energy, environmental and economic needs and goals of each state. Thus, the proposed guidelines would achieve meaningful CO2 emission reduction while maintaining the reliability and affordability of electricity in the U.S.

As part of Section 111(d) compliance, PNM supports credit for planned actions involving changes to the composition of a utility's generating fleet. The retirement of two units at San Juan is the most significant action the company will undertake that results in a substantial reduction in CO2 emissions- 50% reduction from total plant emissions and an approximately 23% reduction from PNM's system-wide emissions. PNM believes the shutdown of Units 2 and 3 should be counted towards compliance with the Section 111(d) rule.

EPA's regulatory actions will clearly restrict GHG emissions from fossil fueled generation. Future emissions reductions of GHG are likely to have significant costs, which must be considered in resource planning.

Renewable Energy Requirements

The New Mexico REA and Renewable Energy Rule (17.9.572 NMAC) establish PNM's Renewable Portfolio Standard (RPS). Each year, PNM files an annual Renewable Energy Portfolio Report and a Renewable Energy Portfolio Procurement Plan to request NMPRC approval for resource additions that are necessary to maintain compliance with this standard.

Subject to the Reasonable Cost Threshold (RCT), the RPS Rule outlines renewable energy requirements that are a function of PNM's retail energy sales. The RPS requires a resource portfolio that includes renewables that meet the following thresholds:

- No less than 10% of retail energy needs for calendar years 2011 through 2014;
- No less than 15% of retail energy needs for calendar years 2015 through 2019;
- No less than 20% of retail energy needs for calendar year 2020 and subsequent years

According to section 17.9.572.16.A(5) of the REA, a renewable portfolio plan should be, "…reasonable as to its terms and conditions considering price, costs of interconnection and transmission, availability, dispatch ability, renewable energy certificate values and portfolio diversification requirements". The REA and Rule 572 also provide cost-based exclusions for large non-governmental customers.

Renewable Energy Diversity Requirements

The Renewable Energy Rule was amended in December 2012 to require a fully diversified renewable energy portfolio which is defined as one that includes:

- Wind resources of no less than 30% of the RPS requirement;
- Solar resources of no less than 20%;
- Non-wind, non-solar resources of no less than 5%; and
- DG resources of no less than 1.5% from 2011 through 2014, and no less than 3% thereafter.

Reasonable Cost Threshold

The RPS Rule states that a public utility shall not be required to add renewable energy to its electric energy supply portfolio or achieve a fully diversified portfolio at a cost above the RCT. Thus, the RCT relieves the utility of the obligation to add renewable resources if the customer rate impact of doing so exceeds 3% starting in 2013. The amendments to the RPS Rule in December 2012 clarify that the rate impact test is based on the actual rate impact to customers in the projected plan year using a traditional revenue requirements impact approach for all resources, including regulatory assets previously authorized and used to satisfy the RPS, but not including normalizations, annualizations and out of period adjustments, and including avoided fuel and purchased power costs, environmental credits pursuant to compliance rules in effect during the plan year and costs for capacity, transmission, or distribution that can be shown to result in actual reductions in costs to ratepayers. (17.9.572.14.C NMAC)

STIPULATED AGREEMENTS ADDRESSING RESOURCE PLANNING AND RESERVE MARGINS

Two stipulated agreements entered into in connection with NMPRC cases, and approved by the Commission, affect PNM's 2011 IRP planning with respect to Reserve Margin Requirements

1. Case 3137 Stipulation Transition Plan Filed Pursuant to the Electric Utility Industry Restructuring Act of 1999 and approved by the NMPRC on January 28, 2003

   The Stipulation in Case 3137 included several elements that impact resource planning. The Stipulation identified which loads and resources are to be included in jurisdictional resource planning. It identifies the jurisdictional load as New Mexico retail load and wholesale firm requirement customers contracted to be supplied by PNM prior to September 2, 2002.

   The Stipulation also established a 15% reserve margin and provided the amount of capacity from each resource that should be counted against the reserve requirement, taking into account the fact that the availability of renewable resources during the peak demand period will vary due to their intermittent characteristics.

2. Case No. 08-00305-UT, the Resource Stipulation, approved by the NMPRC on May 26, 2009.

   The Resource Stipulation required that beginning with the 2011 IRP, PNM will use a planning reserve margin of 13% of peak demand, but not less than 250 MW of planning reserve capacity. Additionally, the City of Aztec was added as a wholesale customer that PNM must plan for as part of its jurisdictional load.

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 the 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[4] (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[5], 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[6] (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 sub-regional determination of resource adequacy, rather than an

[4] See BAL-001-0_1a.pdf

[5] See BAL-002-1.pdf and BAL-002-WECC-1.pdf

[6] See TPL-001-0.1 through TPL-004-0 standards

individual utility evaluation of resource adequacy. The purpose, as stated in the Reliability Assessment Guide book[7], 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 sub-region 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 U.S.

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 on-line within ten 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.

[7] See Reliability Assessment Guidebook v1.2

Other System Reliability Standards

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

Qualitative Analysis

Qualitative risk analysis captures risks that are not readily quantifiable, yet should be considered in the development of the most cost-effective resource portfolio. PNM has considered risks in the areas of operation, economic, financial, behavioral, technology and regulations, which are detailed in Section 2, *The Most Cost-Effective Resource Portfolio*. The optimal portfolio reduces risk and has known mitigation strategies.

Life-Cycle Costs – The analysis aims to reflect all costs to PNM's customers associated with PNM's electricity supply. The time value of money is recognized by discounting future cash flow. In addition, some effects occur after the 20-year planning period and adjustments are made to account for those. These adjustments include recognition of not fully depreciated asset values, levelized cost streams and others. Also, the analysis identifies costs of power production that do not appear in PNM's direct costs. For example, there is currently no cost for GHG emissions from power plants. The analysis looks at a range of costs for those emissions as discussed in the section on climate change. Costs not affecting PNM's customers are generally excluded, for example, state and federal government subsidies for different generation types that do not lower the utilities' cost for those technologies.

APPENDIX H: ANALYSIS OF EXTERNALITIES AND LIFE-CYCLE COSTS

LIFE CYCLE COST ANALYSIS IN RESOURCE PLANNING

Lifecycle cost analysis (LCC) is a project analysis methodology that considers all costs and benefits. As the name indicates, it is appropriate for evaluating projects or issues that have life-spans with multiple-year durations. Most often, it is used to compare alternative capital investments. The goal is to incorporate all costs/benefits that are associated with the issue/objective to be addressed and the alternative projects being considered to address that issue. The analysis will include project impacts of:

1. Expenses and investments
2. Costs of generating assets:
   - Owning (interest, property tax, insurance, etc.)
   - Operating (fuel, labor),
   - Maintaining
   - Disposing of an asset
3. Revenues, cost savings, and other benefits

Most commonly, projects in electric utility resource planning involve an up-front capital investment that provides benefits over an extended time period. Generally, this is constructing or acquiring a generation resource, but it can also be investments promoting energy efficiency or transmission system improvements. For example, expenditures are required today to build a power plant, but then the plant produces electricity over a life of 30-40 years. Because these costs and benefits occur at different times, recognizing the time value of money (discounting) is a key aspect of LCC.

ELECTRIC UTILITY RESOURCE PLANNING

Electric utilities rank among the most capital intensive industries. Generation assets have multi-year lives, with large power plants expected to last for 40 years or longer. The industry is also significant in size relative to the entire economy. As a result, the investments required to provide generation represent large amounts of money.

There are special considerations for utility planning versus other indicators. As regulated public utilities, electric utility companies have an obligation to serve, meaning that the company must provide service to any new customer locating in the franchise service territory. Also, the utility must supply the amount demanded by each customer at all times. Competitive firms are not required to supply their products to customers under conditions when supply is not available or when sale prices are too low for profitability.

Regulated utility monopolies also cannot set the price of their product. The rates paid by customers are set by the regulatory bodies which have jurisdiction over those sales. For PNM, this is either the NMPRC or the FERC. Utilities also cannot expand their sales by directly capturing market share from other utilities. The utility is limited to operating within its franchise service territory. PNM cannot lure customers away from Arizona Public Service Co. in the way that Pepsi can pull sales away from Coke. Because the level of demand is set by customers, the utility's task is to meet that demand at the lowest cost.

Electric utilities also must meet federal, state and industry reliability standards. There is tremendous benefit to a utility that comes from interconnection with the regional electric grid. When PNM experiences supply interruptions or demand shifts that disrupt its system, PNM is able to draw upon the grid for stabilization and prevention of supply interruption. Participation in the grid is contingent on PNM meeting the reliability standards needed from all utilities to maintain system integrity.

Planning Analysis Methodology

Resource planning by electric utilities, including PNM, generally responds to these special circumstances by applying least-cost analysis for evaluation of resource alternatives.

Objective Function

The objective of PNM's Integrated Resource Plan as set out by the NMPRC is to "identify the most cost-effective portfolio of resources to supply the energy needs of customers." The objective is to achieve the lowest life-cycle cost to ratepayers.

Constraints – Reliability, Regulatory and Financial

Constraints – However, the utility cannot simply pick the lowest cost set of supply resources. It must meet a number of constraints, including:

- Deliver the amount of energy demanded by customers
- Maintain reliability standards (transmission, voltage, load following, reserve margin)
- Comply with RPS and Energy Efficiency requirements
- Financial capacity (credit, resource availability)
- All utility costs are recovered from customers (revenue requirements)

Resource planning models compute life-cycle costs for various resource portfolios. The models then select the lowest cost portfolio that meets the constraints imposed in the analysis. PNM's IRP analysis will use a widely-used planning model named Strategist®, which PNM licenses from Ventyx, Inc.

LONG-LIVED PROJECTS, DISCOUNTING AND NET PRESENT VALUE

EXPENSES AND CAPITAL EXPENDITURES

Generally, cash expenditures will fall into two categories. The first category is expenses, such as labor costs, fuel purchases and other operating costs of the business. The materials or services purchased will be consumed in operations in the near term. The second category is capital investments. These expenditures represent purchases of capital goods such as machinery, buildings, vehicles or some computer software. The defining attribute of a capital investment is that it will provide service to the business for a period greater than one year.

Comparing expenses and capital expenditures requires life-cycle cost analysis. For example, suppose a company has the option of either hiring a worker to stuff bills into envelopes at a cost of $10,000 per year, or purchasing an envelope stuffing machine for $30,000. Least-cost analysis will have to consider how many years of service will be provided by the machine versus the annual repeated expense of the worker.

TIME VALUE OF MONEY

Resource planning alternatives will invariably have different expenditure timelines for acquisitions of new generation plants. Comparing options requires that the timing of cash flows be evaluated on a consistent basis. Discounting cash flows to a "present value" is an analysis technique to recognize the time value of money.

This refers to the fact that a dollar received today is worth more than a dollar to be received in the future. One dollar invested today at a 10% rate of return will grow to $1.10 one year from today. The present value of that future $1.10 is equal to $1.00 today. Discounting all the future cash flows for the expenses and capital expenditures associated with alternative planning portfolios states their life-cycle costs as a comparable present value. For long-lived projects, the discounting effect is substantial. At a 10% discount rate, a dollar of cash flow 20 years from now has a present value of less than 15 cents.

The rate of discount is the measure of the time value of cash flow. The rate of discount used in utility analysis is the cost of capital. Utility companies raise funds from investors to pay for capital investments. These funds are either debt (bonds, bank loans) or equity (stock). Customers do not reimburse the utility immediately for the cost of a power plant, but rather the cost recovery comes through the sale of electricity to customers over the life of the plant. Investors receive a return on their money during that period of investment recovery. The rate of return paid for those funds is the cost of capital.

COST OF CAPITAL

An example calculation of a utility's cost of capital is shown in the table below. It computes a weighted average of the categories of financing the company has used to raise capital. It shows that 46% of this company's capital had been financed through debt and the rest as equity (either preferred stock or common stock). The interest rate or rate of return for these categories differs. The average interest rate on debt in this example is 8.0% and the return on common equity is 10%. The weighted average becomes 8.92% in this example.

	Share	Rate	Cost
Debt	46.00%	8.00%	3.68%
Preferred	4.00%	6.00%	0.24%
Common	50.00%	10.00%	5.00%
Cost of Capital			8.92%

Discount Rate

The discount rate is important in life-cycle cost calculations. Some resource planning choices will involve an option, such as a solar facility that has high up-front investment cost, but low future expenses. An alternative resource may be a natural gas plant that has much lower investment cost, but higher fuel and emission expenses in the future. At times when interest rates and the cost of capital are high, the solar facility suffers because the borrowing costs on the investment are high. Conversely, a period of low interest rates and rising natural gas prices will favor the solar alternative.

Analysis Challenges

There are some situations in life-cycle cost comparisons that pose complications for analysis. Often resource alternatives will have different service lives. A coal plant might have a life of 40 years, while a solar plant may have a useful life of 20 years. Also, a plant may require reclamation expenditures at the end of its life or may have some salvage value at that time. Analysis modeling may use techniques such as terminal or salvage value or replacement costs to make alternatives with different lives comparable.

Levelized life-cycle costs can also be used for evaluating costs for differing asset lives.
Another challenge may arise when two alternatives do not provide comparable electric service. For example, a peaking plant versus a base load plant will have different effects on system reliability. The IRP analysis model assesses the impacts of different resources on system reliability constraints and associated costs or benefits are calculated in the resource evaluation. Similar issues arise when comparing resources that are dispatchable, versus those that are intermittent in their production.

It is important to maintain consistency in scenario assumptions in LCC. Factors such as inflation rates, tax rates, fuel costs and others can affect all portfolios and should be consistent across analyses. Capital budget constraints or other restrictions on how much or how fast new resources can be built or acquired must also be considered.

It is sometimes useful to provide supplementary analysis measures along with the NPV calculation results. These can include financial indicators such as:

- Simple payback
- Discounted payback
- Internal rate of return (IRR)
- Savings to investment ratio
- Levelized annual life-cycle cost

Documentation

Documentation of the life-cycle cost analysis process is important in assuring the validity of the results and also in communicating the conclusions to the intended audience. A project analysis and documentation would typically include some or all of these components:

1. Project Description
2. Identify Alternatives
    a. Base Case, business as usual, multiple alternatives
3. Common Parameters
    a. Study period, base date, discount rate, inflation, tax info
4. Cost/Operational Data
    a. Investment cost estimates, operating expenses, materials,
    b. Useful lives of assets, timing of cash flows
    c. Document sources and verify data accuracy
    d. Revenues and attributes of resource output
5. Calculations and Computations
    a. Discount factors, escalation rates, extrapolations, tax effects
    b. Supplementary calculations
6. Non-monetary Considerations
7. Analysis and Interpretation
    a. Externalities
    b. Risk and volatility
8. Recommendations

Externalities and Socio-Economic Impacts

The goal of life-cycle cost analysis is to examine all costs and benefits associated with the alternatives under consideration. However, some costs/benefits may not have explicit prices. When there are non-priced impacts of a project alternative, they are referred to as externalities. That is, their costs/benefits are external to the financial decision as the costs/benefits fall on other parties or on society in general. The challenge for the planning analyst is to accurately reflect those impacts in the decision evaluations when there are not explicit prices paid or costs assigned to them.

The most frequently cited externalities for resource planning are generating plant emissions. The IRP process uses several methods to include the cost of emissions in the evaluations. In the case of GHG, there is currently no explicit cost for emissions to the utility/ratepayer. To reflect an externality, an emission cost is added to the electricity production that creates those emissions. The NMPRC has directed the use of several different values for that proxy cost in establishing the IRP. Because of the potential high cost of future GHG emission regulation, several sensitivity cases have been done for IRP. Other emissions may also be externality situations, but some emissions have explicit prices or costs. For example, plants that emit SO_2 must install pollution control technology at considerable cost, and must also pay a per unit fee for remaining emissions. The costs of SO_2 are therefore no longer external, but rather are directly part of the cost calculation for a new coal plant. Similarly, water usage, which is often an environmental concern, entails a cost to the utility that is not external to the cost calculations. So not all environmental impacts are externalities and not all externalities are costs. For example, hydro-electric dams produce electricity along with other effects. Flood control, irrigation and recreation are cited as external benefits, while fish habitat and canyon submersion impacts can be external costs.

Another issue is the extent to which socio-economic effects should be considered in life-cycle cost analysis for the IRP. Low income subsidies are often included in electric rate design, but generally do not influence resource planning choices. Similarly, local economic development can be boosted by power plant construction. Should the economic stimulus benefit of a major construction project for a local economy be considered in comparing alternatives?

Finally, economic analysis itself requires time and resources. Analysis modeling is a simplification of all the complexity in the actual operations of the resource portfolio. Considerations of the benefits from additional detail in analysis, as well as the number of scenarios and alternatives examined, should be matched to the time and resources required.

For further reference:

Fuller and Petersen (1995), Life-Cycle Costing Manual for the Federal Energy Management Program

Appendix I: Glossary

AC: Alternating Current; Air Conditioning
ACI: Area Control Error

ADI: ACE Diversity Interchange

Afton: Afton Generating Station (*see also* Afton CC)

AGC: Automatic Generation Control

APS: Arizona Public Service Company

BA & BAC: Balancing Area and Balancing Area Coordinator for the WECC PSA planning process

BACT: Best Available Control Technology
BART: Best Available Retrofit Technology

BB Line: Blackwater-BA Station, 345 kV line

BBER: Bureau of Business and Economic Research at the University of New Mexico

BHP: BHP Billiton, Ltd. parent company of SJCC
Blackwater Station: AC-DC-AC converter station
BNCC: BHP Navajo Coal Company

Btu: British Thermal Unit

CAA: Clean Air Act

Case 3137 Stipulation: Stipulated Agreement that settled Utility Case 3137, which established a 13% reserve margin target.

CC: Combined-cycle
CCB: Coal Combustion Byproducts

CCN: Certificate of Convenience and Necessity

CCS: Carbon capture and sequestration; carbon capture and storage

CO: Carbon monoxide
CO_2: Carbon dioxide.

CPS: Control Performance Standards

CT: combustion turbine

DC: Direct current

Delta-Person: Delta Generator located in Albuquerque at Rio Bravo and I-25

DG: Distributed generation.

DR: Demand response
DSM: Demand side management
DSS: Dynamic Scheduling System

EE: Energy Efficiency.

EGU: Electric Generating Unit

EIP: Eastern Interconnection Project (BB line and Blackwater Station)

EPA: Environmental Protection Agency

EPACT: Energy Policy Act of 2005

EPC: Engineering Procurement and Construction

EPE: El Paso Electric Company

EPNG: El Paso Natural Gas Company
EPRI: Electric Power Research Institute

ERO: Electric Reliability Organization

EUEA: Efficient Use of Energy Act 62-17 NMSA

FERC: Federal Energy Regulatory Commission

FIP: Federal Implementation Plan
FCPP: Four Corners Power Plant

gals: Gallons

Gallup: City of Gallup, NM
GE: General Electric Company

GHG: Greenhouse Gas

GWh: Gigawatt-hour

HAP: Hazardous Air Pollutants

HRSG: Heat Recovery Steam Generator
HVAC: Heating, Ventilation, Air Conditioning

IGCC: Integrated Gasification Combined Cycle plant

IRP: Integrated Resource Plan

kV: Kilovolt; a measure of voltage, 1,000 volts

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

LAER: Lowest Achievable Emission Rate
L&R: Loads and Resources

lbs: Pounds

LM: Load Management

LSE: Load Serving Entity

MACRS: Modified Accelerated Cost Recovery System
MACT: Maximum Achievable Control Technology

MM: Million

MMBtu: Million British Thermal Units, also shown as Mbtu.

MW: Megawatt

MWh: Megawatt-hour

NAAQS: National Ambient Air Quality Standards

NAES: North American Energy Services

NDI: Normal Direct Irradiance

NEC : Navopache Electric Cooperative

NERC: North American Electric Reliability Council

NER: NextEra Energy Resources, LLC, owner of NMWEC and Red Mesa wind facilities
NG: Natural gas; abbreviation used in tables and figures

NITS: Network Integration Transmission Service

NM: New Mexico

NMAC: New Mexico Administrative Code

NMED: New Mexico Environmental Department

NMEIB: New Mexico Environmental Improvement Board

NMGC: New Mexico Gas Company
NMPRC: New Mexico Public Regulation Commission (also referred to as Commission)

NMSU: New Mexico State University

NMWEC: New Mexico Wind Energy Center

NNM System: Northern New Mexico transmission (also referred to as WECC Path 48)

NO_X: Nitrogen oxides

NPV: Present value of net cash flows (net present value)

NRC: Nuclear Regulatory Commission

NSPS: New Source Performance Standards
NSR: New Source Review

NTUA: Navajo Tribal Utility Authority

O&M: Operations and maintenance

OATT: Open Access Transmission Tariff

OLE: Ojo Line Extension

OSM: Office of Surface Mining

PA: Public Advisory

PAFC: Phosphoric acid fuel cell

PEV: Plug-in Electric Vehicle

PM: Particulate matter

PNM: Public Service Company of New Mexico

PNM: PNM Resources Inc.
POD: Point of Delivery

POR: Point of Receipt

PPA: Power Purchase Agreement

PSA: Power Supply Assessment
PSD: Prevention of Significant Deterioration

PV: Photovoltaic

PVNGS: Palo Verde Nuclear Generating Station located near Phoenix, Arizona
RBC: Reliability Based Control

RCRA: Resource Conservation and Recovery Act

RCT: Reasonable Cost Threshold

REA: Renewable Energy Act 62-16 NMSA

REC: Renewable Energy Certificate

Reeves: Reeves Generating Station located in Albuquerque, New Mexico

RFP: Request for Proposals

Renewable Energy Rule: 17.9.572 New Mexico Administrative Code (NMAC)

RPS: Renewable Portfolio Standard

Rule 572: 17.9.572 New Mexico Administrative Code regarding the Renewable Portfolio Standard

SCR: Selective Catalytic Reduction

SIP: State Implementation Plan

SJCC: San Juan Coal Company

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

SMR: Small modular reactor

SNM System: Southern New Mexico transmission (also referred to as WECC Path 47)

SNCR: Selective Non-Catalytic Reduction

SO_2: Sulfur dioxide

SOFC: Solid oxide fuel cell

SPC: Supercritical pulverized coal

SPP: Southwest Power Pool

SPS: Southwestern Public Service Company

SRIP: Solar REC Incentive Program Approved in Case 10-00037-UT for customer sited solar generation

SRSG: Southwest Reserve Sharing Group

STG: Steam turbine generator

SVC: Static VaR Compensator

SWAT: Southwest Area Transmission Planning Oversight Committee

TAG: Technical Assessment Guide (by EPRI)

Tcf: Trillion cubic feet

TEP: Tucson Electric Power Company

TEPPC: Transmission Expansion Planning Policy Committee

TNMP: Texas-New Mexico Power

TOU: Time of Use

TPL: Transmission Planning Standards

TRC: Total Resource Cost – ratio of energy efficiency program benefits to the program cost

TSGT: Tri-State Generation and Transmission Association

U.S.: United States of America

UCT: Utility Cost Test – ratio of energy efficiency utility benefits to the utility program costs

VER: Variable Energy Resources

WAPA: Western Area Power Administration

WECC Path 47: Southern New Mexico transmission (also referred to as SNM System)

WECC Path 48: Northern New Mexico transmission (also referred to as NNM System)

WECC: Western Electricity Coordinating Council

WestConnect: Collaborative group of western utilities providing transmission

APPENDIX J: 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) diversity interchange (ADI) offers 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 other 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. While 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_2production by penalizing power plants for its 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)

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 on-line 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, 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 is independent of output. *Contrast* **variable costs**.

Forced outage rate: Percent 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 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 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 it's 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 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 which would receive special rate and regulatory treatment to support implementation of 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.

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 95^{th} percentile and plotting the mean on the x-axis and the 95^{th} 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 which can be available to a transmission system within ten 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 percent 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