San Juan Replacement Study

An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station

Prepared on Behalf of Sierra Club

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EXECUTIVE SUMMARY

In June 2017, Public Service Company of New Mexico (PNM) released an Integrated Resource Plan (IRP) and its resulting **"Most Cost-Effective Portfolio" (MCEP)**. PNM's MCEP includes the proposed retirement of the remaining units at San Juan Generating Station (SJGS) in 2023 and the addition of new gas turbines and reciprocating engines constituting 456 megawatts (MW) in that same year.

There are other resource portfolio options for replacing retiring coal capacity that are less expensive than PNM's proposed MCEP, both for the PNM system and for New Mexico ratepayers as a whole. Solar and wind energy, in combination with utility-scale battery storage, are increasingly out-competing gas-fired alternatives (natural gas plants) around the country. The costs for clean resources have declined steeply in recent years, and the performance of these combined portfolios allow for the provision of reliable energy and capacity even considering the variable nature of generation from renewable resource components. Several utilities in the Southwest have recently published long-term resource plans that select renewables and battery storage instead of gas-fired generation.[1]

Synapse conducted a rigorous, scenario-based modeling analysis to evaluate low-carbon resource portfolios as potential cost-effective alternatives to PNM's proposal of 456 MW of new gas. Our portfolios assessed combinations of renewable energy, utility-scale battery storage, and demand response. Our resulting **Clean Energy Resource Portfolio (CERP),** including new solar photovoltaics (PV), New Mexico wind, and battery storage met PNM's load and reliability needs without additional gas—at a lower cost than PNM's proposed MCEP.

In our modeling of both PNM's preferred plan and our alternative portfolio, we included New Mexico's relatively progressive energy efficiency resource plans and PNM's baseline small-scale solar PV projection. Thus, our net load forecasts are identical in each scenario. More specifically:

- We used an advanced energy system model to calculate the year-by-year and net present value (NPV) of PNM's preferred MCEP resources as outlined in its 2017 IRP, and an alternative renewables-focused portfolio (the CERP) based on a reasonable build-out of New Mexico renewable energy and demand response, as well as storage resources.
- The lower-cost alternative portfolio only builds carbon-free resources, whereas the MCEP relies on gas-fired generation resources. PNM's 2017 IRP states that, when considering resource options that provide the same level of service and reliability, the utility should select the resource that minimizes environmental impact.

[1] Nevada Energy and Xcel Energy in Colorado. See Section 2.2 for full description.

- On a PNM-allocated basis, the Clean Energy Resource Portfolio is $94 million or 1.5 percent less expensive than PNM's MCEP alternative through 2036. For the State of New Mexico, the alternative portfolio is 0.3 percent less expensive than PNM's MCEP through 2036.

- PNM's MCEP scenario includes a 456 MW gas resource addition to meet regional reliability requirements. Synapse's Clean Energy Resource Portfolio effectively supplants this new gas with incremental builds of solar PV (300 MW), utility-scale battery storage (180 MW), and demand response (19 MW) through 2023.[2]

- After 2032, the CERP builds additional wind resources (following the 2031 Four Corners retirement) and additional solar PV, battery, and demand response resources (to maintain reliability and meet energy requirements). These renewable resources can more efficiently meet changing system conditions than the larger-scale gas-fired generating units in PNM's MCEP.

- The CERP utility-scale battery storage additions can meet ancillary service requirements, in addition to providing firm capacity for peak periods when wind and solar resource output may vary.

- PNM, and the entire state of New Mexico, can lower resource portfolio costs even further if the utilities improve coordination of reserves and optimize reliability requirements across the region.

Note that the bids that PNM received in response to its 2017 Request for Proposals (RFP) for replacement resources are confidential, and Synapse did not have access to the bid responses when conducting this analysis. As a result, this study does not purport to provide an analysis of the economics of portfolios using the prices and constraints contained in the RFP bid responses. Instead, this analysis is an apples-to-apples comparison of PNM's 2017 IRP portfolio with a portfolio that uses exclusively carbon-free resources. This analysis is therefore illustrative of the potential advantages of a carbon-free replacement portfolio relative to a portfolio reliant on new gas.

[2] CERP solar, wind, and demand response resource amounts are incremental to existing capacity in the baseline scenario.

1. INTRODUCTION

In June 2017, PNM released the 2017 Integrated Resource Plan, resulting in what PNM termed "The Most Cost-Effective Portfolio" or MCEP. The 2017 IRP found that it was cost-effective to retire PNM's remaining 497 MW share of units 1 and 4 at the San Juan Generating Station (SJGS)[3] at the expiration of PNM's current fuel contract with Westmoreland in 2022. The IRP's "Most Cost-Effective Portfolio" proposed replacing the lost capacity in 2023 with 456 MW of new gas turbines and reciprocating engines, and it included additional gas-fired generation in later years of the planning period.

In November 2017, PNM issued a Request for Proposals to explore other cost-effective combinations of resources to fill the capacity gap from SJGS's proposed retirement. The RFP encouraged consideration of renewables and storage in a portfolio that would satisfy PNM's energy, capacity, and flexibility needs. The results of this RFP, including which types of resources have made it into final consideration, have not yet been made public.

Sierra Club retained Synapse Energy Economics to assess if there are other resource options beyond gas-powered units that meet both PNM's performance requirements and are cost-effective for PNM and New Mexico ratepayers. To answer that question, Synapse performed a rigorous, scenario-based analysis to evaluate alternative, low-carbon resources such as renewables, storage, and other demand-side management (DSM) strategies to meet reliability requirements and provide energy replacement after SJGS proposed retirement.

This report provides background on alternatives to gas-fired generators for new resource selection, describes Synapse's modeling approach, defines the scenarios we used, and presents the results of our analysis.

[3] PNM owns 497 MW of 847 MW at SJGS.

2. BACKGROUND: ALTERNATIVES TO GAS-FIRED GENERATION

2.1. Overview

As utilities have retired coal generators, they have historically turned to gas-fired generation (natural gas plants) as a relatively simple default replacement. The technology is well understood and readily available. However, it is increasingly apparent that gas generation is not necessarily the least-cost option in all cases. A series of recent utility planning processes have started to show that renewable energy, storage, and demand-side resources can out-compete gas, and a 2018 study demonstrated that new gas plants could become economically "stranded" before the end of their depreciable lives when compared against new energy options.[4]

Best practices for utility electric system planning dictate that utilities develop resource plans or IRPs that consider *all* available resource options to meet customer needs, including renewable energy, battery storage, and DSM. The result of the IRP process should therefore be the portfolio of supply- and demand-side resources that meets the utility's energy, capacity, and reliability needs at the lowest cost. However, Synapse's recent experience reviewing IRPs and other long-term planning documents around the United States reveals that most utilities still rely on new gas-fired generating resources to meet capacity needs. In part, this reliance on gas as a default is driven by limitations in utility models: many legacy electric system models are limited in their ability to comprehensively model the performance of variable renewables and storage.

Taking into account the falling cost of renewable energy and storage, rigorous modeling assessments increasingly show that gas-fired generation is not always a least-cost build option. Solar and wind, both alone and when coupled with battery storage, are increasingly cost competitive with gas-fired resources around the country—and they meet utility performance needs. This is driven, in part, by the steep cost declines for solar, wind, and battery technologies over the past few years.[5] As a result, forward-leaning utilities in the Southwest have published long-term resource plans that select renewables and battery storage as alternatives to gas-fired generation.[6,7]

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[4] Rocky Mountain Institute. 2018. The Economics of Clean Energy Portfolios. Available at https://rmi.org/insight/the-economics-of-clean-energy-portfolios/

[5] See, for example:

- Lazard' Levelized Cost of Storage Analysis - Version 3.0. November 2017.
- Lazard's Levelized Cost of Energy Analysis - Version 11.0. November 2017.
- National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) 2018 release.
- Lawrence Berkeley National Laboratory and U.S. Department of Energy, 2017 Wind Technologies Report.
- Lawrence Berkeley National Laboratory and U.S. Department of Energy, Utility Scale Solar: Empirical Trends in Project Technology, Cost, Performance and PPA Pricing in the United States – 2018 Edition. September 2018.

[6] NV Energy. May 31, 2018. "NV Energy announces largest clean energy investment in Nevada's history." Available at: https://www.nvenergy.com/about-nvenergy/news/news-releases/nv-energy-announces-largest-clean-energy-investment-in-nevadas-history.

Synapse was retained to review PNM's 2017 IRP and assess if customer needs could be met cost-effectively with a portfolio of non-gas options. Synapse analyzed PNM's service territory within the state of New Mexico using reasonable renewable and battery storage assumptions and found that an alternative **Clean Energy Resource Portfolio** with solar, wind, and battery storage—without additional gas-fired generation capacity—provides the same level of generation, capacity, and reliability as PNM's proposed MCEP, at a lower net cost to consumers.

2.2. Low Renewable and Storage Costs Have Changed Utility Resource Planning

The falling price of renewable energy and utility-scale storage has started to fundamentally change the resource planning landscape. IRPs increasingly review a wider range of renewable energy options and assess the impact of storage on the ability to utilize that renewable energy.

The outcomes of IRPs are largely driven by input assumptions, and to a lesser extent by the type of electricity system model used. In particular, the costs of technologies and resources are key drivers, as are plant operational characteristics. It is essential to incorporate all potential resource options into an IRP, use the most up-to-date cost assumptions, and run sensitivities to bound the uncertainty on future renewable costs or regional operations. If the utility does not consider all resource options, especially low-cost renewables and battery storage, the resulting resource plans may fail to consider least-cost, least-risk options. In addition, the use of appropriate model constructs that can capture the benefits of storage and the integration of renewable energy are critical in contemporary resource planning. A failure to consider a range of resources, use up-to-date costs, and appropriate models can mean higher costs for the utility, higher rates for customers, and unnecessary carbon emissions when fossil resources are selected over clean energy resources.

Lazard, Lawrence Berkeley National Laboratory (LBNL), and other leading industry experts regularly publish resource cost data that can be utilized for cost assumptions. Additionally, utilities can and should use competitive procurement through RFPs to provide guidance regarding the present costs of contracted renewable and storage resources.

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[7] Pyper, J. August 29, 2018. "Xcel to Replace 2 Colorado Coal units with Renewables and Storage." *GreenTech Media*. Available at https://www.greentechmedia.com/articles/read/xcel-retire-coal-renewable-energy-storage#gs.qrZct6U.

Renewable plus storage prices have reached a record low….and prices continue to fall

In September 2018, Bloomberg New Energy Finance published a report showing that solar with batteries can be cheaper than a new combined cycle gas plant, particularly in the Southwest.[8] A series of new solar plus storage or wind plus storage projects in the western United States supports this assertion:

- In Arizona, a 100 MW solar farm with 25 MW of 4-hour battery storage will come online in 2021 at $36 per megawatt hour (MWh). This Power Purchase Agreement (PPA) price is well below the $47 price that Bloomberg cites for a new combined cycle gas plant.[9]
- Tucson Electric signed a contract with NextEra for a 100 MW solar farm with 30 MW of 4-hour battery storage price at "significantly less than $45/MWh."[10]
- Xcel Energy solicited bids for renewables plus 4-hour battery storage. The median solar plus storage bids came back at $36 per MWh, and wind plus storage bids came back at $21 per MWh.[11,12]

Some western utilities have selected renewables plus storage to replace retiring coal capacity in their long-term resource plans

In addition to the low-cost PPAs discussed above, utilities in Colorado and Nevada are now among the first to use renewables plus battery storage to replace retiring coal units. Specifically:

- NV Energy filed a resource plan that included more than 1,001 MW of solar coupled with 100 MW of 4-hour battery storage. These projects are spread across six PPAs and require an investment of around $2 billion; however, no other cost or price information has been released.[13]
- Under Xcel's Colorado Clean Energy Plan, the two coal units at Comanche Generating Station in Pueblo County (660 MW) will be replaced with renewables and battery storage. The project costs around $2.5 billion and will include 1,131 MW of wind, 707 MW of solar PV, and 275 MW of battery storage. Xcel estimates that the replacement of

[8] Eckhouse, B. Sept 17, 2018. "Solar with batteries cheaper than gas in parts of U.S. southwest." *Bloomberg New Energy Finance*. Available at https://www.bloomberg.com/news/articles/2018-09-17/solar-with-batteries-cheaper-than-gas-in-parts-of-u-s-southwest.

[9] *Id*.

[10] Maloney, P. May 30, 2017. "How can Tucson Electric get solar + storage for 4.5 cents/kWh?" *Utility Dive*. Available at https://www.utilitydive.com/news/how-can-tucson-electric-get-solar-storage-for-45kwh/443715/.

[11] Deign, J. January 8, 2018. "Xcel attracts 'unprecedented' low prices for solar and wind paired with storage." *GreenTech Media*. Available at https://www.greentechmedia.com/articles/read/record-low-solar-plus-storage-price-in-xcel-solicitation#gs.nTvSyFQ.

[12] *Id*.

[13] NV Energy. May 31, 2018. "NV Energy announces larges clean energy investment in Nevada's history." Available at: https://www.nvenergy.com/about-nvenergy/news/news-releases/nv-energy-announces-largest-clean-energy-investment-in-nevadas-history.

coal with renewables plus storage will save ratepayers between $213 and $374 million.[14]

PNM's requirements can be met through renewables and battery storage at a lower cost than PNM's MCEP

The PPAs and utility plans discussed above are all located in the western and southwestern United States and provide a reasonable proxy for the cost of solar and battery storage projects in New Mexico. The solar and the battery storage costs that PNM modeled, especially the battery costs that the utility attributed to "battery acquisitions in neighboring service territories,"[15] are significantly higher than these regional benchmarks. The discrepancy is partially due to steep price declines between the 2016 information upon which the IRP is based, and in part appears to reflect an IRP assumption of storage prices above even contemporaneous benchmarks.

Synapse used the EnCompass electric-system capacity expansion model to determine a least-cost resource plan with regionally accurate and up-to-date solar, wind, and battery storage cost information. The resulting portfolio, the CERP, meets reliability needs and replaces the capacity and energy gap created by the proposed retirement of SJGS with battery storage, utility-scale solar, and a small amount of incremental wind (see Chapter 3 for full results). Although we made multiple gas-fired generating resources available to the model in several scenarios, none were selected by the model in the least-cost portfolio to meet near-term energy, capacity, or reliability requirements.

2.3. Resource Alternatives in PNM MCEP

PNM's MCEP in the 2017 IRP proposes retiring the remaining Units 1 and 4 of SJGS and replacing the capacity with new gas turbines and reciprocating engines. The plan also selects large-scale solar and wind resources and other peaking gas resources. Battery storage was noticeably absent from PNM's preferred portfolio.

Table 1 provides the full list of resources PNM modeled and selected. While this result would not have been surprising five years ago, it is surprising today. Given falling storage and renewable energy costs and the demonstrated capacity and ancillary service benefits of storage resources, the absence of battery storage in a long-term plan—especially for a utility in the Southwest with access to premium solar and wind resources—raises questions about the core input assumptions and modeling methodology that PNM used.

[14] Pyper, J. 2018. "Xcel to Replace 2 Colorado Coal units with Renewables and Storage." GTM. August 29, 2018. Available at https://www.greentechmedia.com/articles/read/xcel-retire-coal-renewable-energy-storage#gs.qrZct6U

[15] PNM 2017 IRP, page 67.

Table 1: New resource alternatives modeled by PNM

Resource	Size (MW)	Capital Cost ($/kW)	PPA Price ($/MWh)
Resources selected by IRP model and included in MCEP			
Gas-fired generation			
Aeroderivatives - Small	40	$1,150	
Gas Turbines - Large	187	$753	
Reciprocating Engines	41	$1,218	
Rio Bravo (CC) Expansion	210	$800	
Renewables			
Solar Photovoltaic Tracking	50	$1,388	
Solar Photovoltaic Tracking	100	$1,388	
Solar Photovoltaic for RPS	50	$1,447	
Wind	100		$47
Resources available for IRP model but not selected			
Gas-fired generation			
Aeroderivatives - Large	85	$1,065	
Gas Turbine - Small	140	$934	
Combined Cycle - New Build	289	$1,023	
Combined Cycle - Existing	250	$700	
Nuclear leases[16]			
Palo Verde - Unit 1	104	$1,306	
Palo Verde - Unit 2	10	$1,306	
Renewables			
Battery Storage 2-Hour	2	$1,892	
Battery Storage 4-Hour	40	$2,925	
Solar Photovoltaic Tracking	10	$1,441	
Solar Power Tower	100		$185
Geothermal	15		$85

Source: PNM 2017 IRP.

Alternative Resource Costs

PNM relies on conservative and outdated renewable and battery storage costs for its IRP

Solar: The solar costs in PNM's IRP were 25–33 percent higher than the $1,100 per kilowatt (kW) costs from industry expert Lazard's 2017 Levelized Cost of Energy report (see Table 2). PNM sourced its costs

[16] PNM reported the capital cost of Palo Verde nuclear leases as $2,500/kWh in the 2017 IRP. The utility acknowledged at a hearing on 6/7/2018 that the value of $2,500 was listed erroneously in the IRP, and $1,306 was in fact the value the utility modeled.

from a 2016 RFP. Given rapidly declining solar costs, however, these values should be updated to reflect current, region-specific costs.

Table 2: PNM costs and updated renewable costs

Resource	PNM Size (MW)	PNM Capital Cost	Synapse Modeled Size (MW)	Updated Capital Cost ($/kW)	Synapse Source
Solar	10 50 100	$1,441 $1,388 $1,388	20	$1,100	Lazard, Levelized Cost of Energy 2017
Wind	100	PPA: $46.85/ MWh	100	$1,590	LBNL Wind Technology Markets Report, 2016
2-Hour Battery	2	$1,892	NA	-	Lazard, Levelized Cost of Storage 3.0. Synapse Expert Analysis.
4-Hour Battery	4	$2,583	10	$1,166	

Wind: The wind PPA prices in PNM's IRP ($46.85 per MWh) were only slightly higher than the prices reported by industry expert LBNL in its 2017 Wind Market Report (approximately $40 per MWh for the West). PNM sourced these wind PPA prices from the 2016 RFP. Wind prices have declined more slowly than solar prices over the past two years, and so PNM's prices are reasonable assumptions.

Battery Storage: PNM's IRP provides little detail on the source of the battery storage costs, stating only that costs reflect battery acquisitions in neighboring service territories and were verified using the EPRI cost database. These costs of $1,892 per kW for a 2 MW 2-hour battery and $2,925 per kW for a 40 MW 4-hour battery are considerably higher than PNM's cost for gas-fired generation resources, so it follows that the MCEP did not select battery storage. These capital costs were also higher compared to industry standard estimates. In its Levelized Cost of Storage Analysis (3.0), Lazard reported an observed overnight capital cost of $1,338–$1,700 in 2017 for lithium ion batteries used in a peaker replacement use-case and estimated a cost of $1,166 for 2018. PNM's modeled capital and levelized costs were 60 percent and 150 percent higher than these estimates, respectively.

Alternative Resource Operational Characteristics

PNM used conservative operational assumption to model alternative resource options

Wind: PNM assigned wind an Effective Load Carrying Capacity (ELCC) or firm peak contribution of 5 percent across all years and at all penetrations. This assumption is unexpected given that PNM states in the IRP that wind resources can contribute more to system needs as the "net peak" shifts toward the afternoon.[17] This is due in part to inclusion of more solar PV resources on the system.[18] By relying on a

[17] Net peak: the peak requirement for generation, net of other must-take resources.
[18] PNM 2017 IRP, Appendix P, "PNM 2017 Reliability and System Flexibility Study," page 30.

flat 5 percent ELCC, PNM undervalues wind's contribution to resource adequacy requirements later in the modeling period.

Solar: It is unclear what firm capacity contribution PNM assigned to solar in its resource modeling. There are several different firm capacity assumptions listed throughout the IRP, including:

- In the *Strategist Inputs – Global Model Assumptions* table in Appendix H (page 53-54), PNM lists an ELCC of 35 percent for all new solar PV.
- In the *New Resource Alternatives Performance Data* table in Appendix K (page 93-94), PNM lists firm capacity contributions of solar starting at 71 percent and falling to 20 percent at higher penetrations (Table 3).

Table 3: Solar ELCC assumptions from PNM's IRP appendix

Solar Tier	ELCC
Tier 2: 80 MW	71%
Tier 3: 140 MW	52%
Tier 4: >80 MW	20%

- In the *Effective Load Carrying Capacity* section of Appendix K (page 96), PNM states that current solar installations provide an ELCC of 76 percent for tracking system and 56 percent for fixed-tilt systems at 4pm. PNM also provides a table of *2018 Solar Energy Production Over Peak Hours* which shows the MW of installed PV required to shift the daily peak by an hour (Table 4).

Table 4: Solar energy production over peak hours

Hour Ending (MST)	Solar PV Peak Contribution	Incremental solar PV needed to shift peak (MW)
4PM	67%	62
5PM	56%	100
6PM	35%	270
7PM	9%	0

It is reasonable to assume that solar PV's contribution to peak will decrease as the peak shifts later in the day. However, the utility must also account for the impact of renewable resource pairing with battery storage, which allows generation output to more effectively align with peak. PNM's MCEP scenario does not include battery storage.

Battery Storage: PNM modeled battery storage in the IRP as a conventional, utility-scale "small" (2 MW, 2-hour) or "large" (40 MW, 4-hour) resource. Our CERP explicitly uses utility-scale battery storage (a total of 180 MW of 10 MW, 4-hour battery storage resources) as part of the CERP. Some utilities have expressed concern that combined solar and battery storage systems (paired "behind-the-meter", or BTM) are unable to charge during extended low-solar periods. The storage modeled here, as well as in

PNM's IRP utility-scale modeling, does not rely on behind-the-meter solar/storage combinations, and the concern does not affect our conclusions.

Utilities in neighboring regions have explored solar paired with storage in BTM configurations for the purposes of capturing the value of the federal Investment Tax Credit (ITC) on both the solar and storage. Utilities modeling these resources have occasionally noted that because the storage resources are behind the meter, the batteries cannot be charged from other grid resources, somewhat reducing the benefit of these storage options. In this exercise, we do not explicitly test paired solar-storage configurations; the model determines that our utility-scale storage options are cost-effective in the CERP.

3. RESULTS

3.1. Summary

PNM's preferred portfolio includes 456 MW of gas turbines and reciprocating engines to fill a capacity gap that would arise if the remaining units at SJGS retire in 2023. The Synapse team developed optimized build paths for renewable and battery resources and analyzed resource portfolio scenarios with updated, region-specific cost and operational information. We tested alternative resource scenarios against PNM's MCEP to determine the least-cost plan. We maintained a constant set of reliability requirements across all scenarios, including requirements for regulation up, regulation down, spinning reserves, contingency reserves, and reserve margins for PNM in all years.

Our modeling results show that PNM's MCEP does not represent the most cost-effective resource mix for the region. A resource portfolio with a combination of battery storage, utility-scale wind and solar, and increased demand response can meet PNM's energy, capacity, and reliability needs at a lower cost than PNM's proposed gas-fired generation resources. More specifically:

- The alternative portfolio (the CERP) uses an incremental 300 MW of solar PV, 180 MW of utility-scale battery storage, and 19 MW of demand response by 2023. This portfolio meets capacity and energy needs and provides reliable service in place of PNM's MCEP, which relies on 456 MW of gas-fired peaking capacity.[19]

- After 2032, the CERP builds additional wind resources (following PNM's assumed 2031 Four Corners Retirement), and additional solar PV, battery, and demand response resources (to maintain reliability and meet energy requirements). These renewable resources can meet changing system conditions more efficiently than the larger-scale gas units in PNM's MCEP.

- The CERP utility-scale battery storage additions can meet ancillary service requirements, in addition to providing firm capacity for peak periods when wind and solar resource output may vary.

- The lower-cost alternative portfolio only builds carbon-free resources, whereas the MCEP relies on gas-fired generation resources. PNM's IRP states that, when considering resource options that provide the same level of service and reliability, the utility should select the resource that minimizes environmental impacts.

- For PNM, the CERP is 1.5 percent less expensive than PNM's MCEP alternative through 2036. For the State of New Mexico, the alternative portfolio is 0.3 percent less expensive than PNM's MCEP.

In this section we will review the full set of modeling results for the 2018–2036 IRP period. Although we evaluated multiple scenarios and sensitivities, we will focus our discussion on the baseline scenario and

[19] The CERP solar, wind, and demand response resource amounts listed here are incremental to amounts already contained in the baseline scenario.

the CERP. We will review the results for both New Mexico and for PNM in the years leading up to the proposed retirement of SJGS in 2023, and we will also review the results through 2036 and discuss how they can inform long-term planning processes.

3.2. Resource Portfolio Requirements

PNM's IRP projected a system-wide increase in peak demand, even as overall load growth slows and energy sales stagnate. PNM's current resource portfolio relies on reduced demand through energy efficiency policies, nuclear, coal, and natural gas fuels, exchanges with neighboring regions, and solar PV and wind. PNM's assessed future capacity needs in the IRP were focused around 2023 when SJGS is proposed to retire. To fill the resulting capacity gap, PNM modeled 456 MW of fossil-fuel-fired peaking units. In reality, this capacity can be provided by gas turbines (or other gas peaking resources), demand response, battery storage, solar PV, and wind resources. Neither PNM nor Synapse considered coal and nuclear capacity as new resources. In the 2017 IRP, PNM targets a minimum 13 percent planning reserve for its service territory.[20]

3.3. Scenario Results

Baseline (PNM MCEP)

Capacity

PNM's baseline scenario (MCEP) relies on two large (187 MW) gas turbines and two small (41 MW) reciprocating engines to replace SJGS at its proposed retirement date in 2023. Beyond 2023, the baseline scenario includes one large gas turbine build in 2028 when the Valencia PPA expires, another large gas turbine build in 2030—presumably to meet projected demand growth—and a third large gas turbine build in 2032 when Four Corners retires. The plan also includes a build-out of small gas reciprocating engines (40 MW) to provide peaking capacity and installation of 490 MW of utility-scale solar and 380 MW of utility-scale wind over the planning horizon (Table 5). The new gas-fired generation capacity contributes to meeting the ancillary service requirements.

PNM's MCEP contains no battery storage, and wind deployment is relatively low due to the low ELCC assigned to wind capacity. The utility's solar deployment assumptions are also conservative and, without battery storage modeled on the system, the solar resources have a limited ability to provide peaking capacity in the winter months.

Elsewhere in New Mexico, El Paso Electric has planned a series of 281 MW combined cycle expansion projects for 2022, 2024, and 2028. The utility also has a total of 392 MW of solar PV projects and 130 MW of wind projects planned between 2024 and 2034. Additionally, the Valencia Energy Facility PPA for 144 MW will become available to the rest of the state in 2029. These resources are locked into the

[20] PNM 2017 IRP, page 28.

model for all scenarios. Full capacity results for PNM and New Mexico are displayed in Figure 1 through Figure 4 and Table 6 through Table 7.

Table 5: Baseline firm capacity additions (MW) from PNM's 2017 IRP MCEP

Firm Capacity (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Gas-fired generation																			
Large GT (187 MW)						374					187		187		374				
Aeroderivative Small (40 MW)									40								40	40	
Reciprocating Engines (41 MW)						82													
Rio Bravo CC Expansion																			210
Solar																			
Data Center 20 MW Solar						11.0													
Data Center 30 MW Solar	22.8		22.8	22.8															
Data Center 40 MW Solar		30.4			30														
NM Solar PV Large (18)							17.5					17.5							
NM Solar PV Large (35)								35.0											
NM Solar PV Large (5)												5.0							
NM RPS Solar		16.0																	
Wind																			
Data Center 50 MW Wind		2.5	2.5	2.5															
Data Center 30 MW Wind					1.5														
NM Large Wind (5)															5.0				
NM Large Wind (18)																		18.0	

Figure 1: PNM firm capacity - baseline (MCEP)

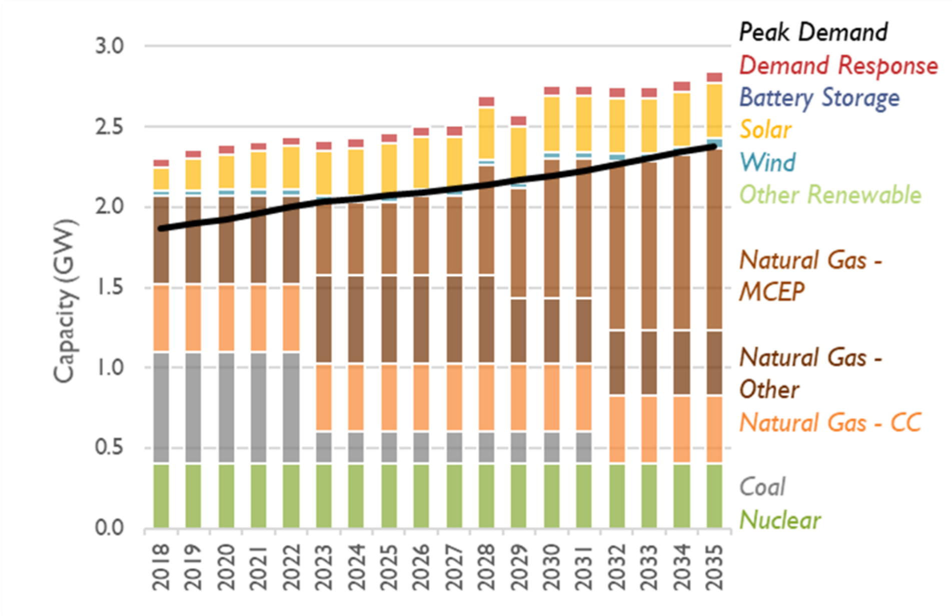


Figure 2: New Mexico firm capacity - baseline (MCEP)

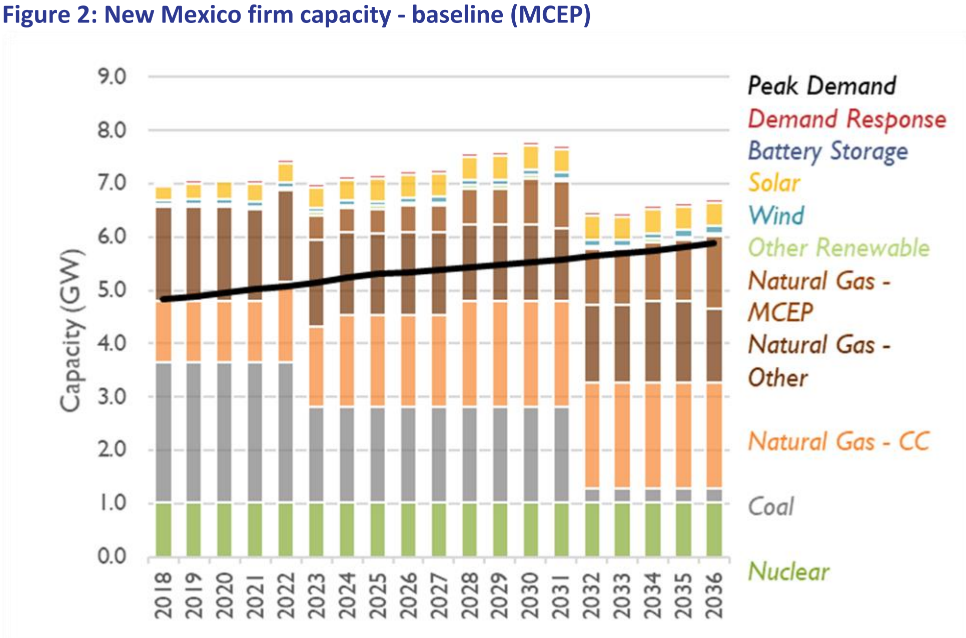


Figure 3: PNM nameplate capacity - baseline (MCEP)

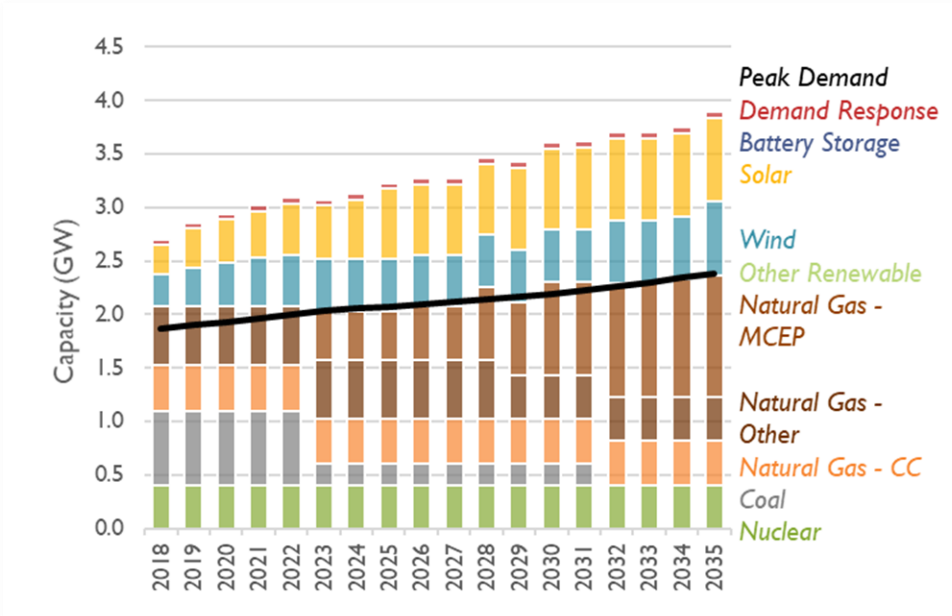


Figure 4: New Mexico nameplate capacity - baseline (MCEP)

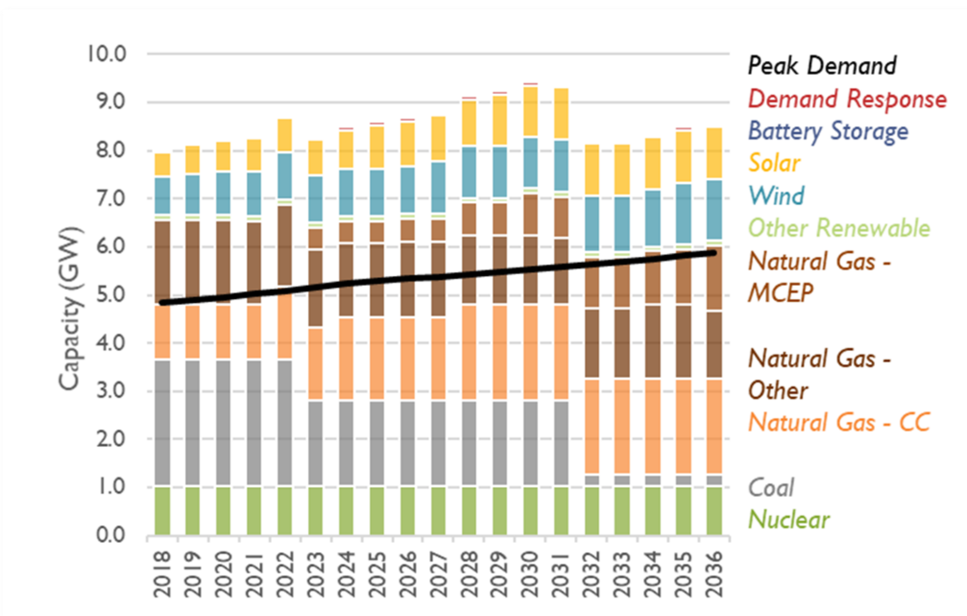


Table 6: PNM firm capacity - baseline (MCEP)

Firm Capacity (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Nuclear	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402
Coal	697	697	697	697	697	200	200	200	200	200	200	200	200	200	0	0	0	0	0
NGCC	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422
Other NG	552	552	552	552	552	552	552	552	552	552	552	408	408	408	408	408	408	408	268
MCEP Nat'l Gas	0	0	0	0	0	456	456	456	496	496	683	683	870	870	1,057	1,057	1,097	1,137	1,347
Wind	28	31	33	36	37	37	37	37	37	37	37	37	37	37	42	42	42	60	60
Solar	146	199	222	240	269	278	295	329	327	326	326	350	350	349	348	348	347	346	346
Other Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	54	56	57	59	61	63	64	66	68	70	70	70	70	70	70	70	70	70	70
Total Firm Capacity	2,302	2,359	2,386	2,408	2,440	2,411	2,429	2,464	2,505	2,505	2,692	2,572	2,759	2,758	2,749	2,749	2,788	2,845	2,915
Peak Demand	1,871	1,900	1,926	1,961	1,999	2,033	2,053	2,071	2,093	2,114	2,138	2,168	2,193	2,225	2,265	2,304	2,343	2,381	2,423
Reserve Margin	23.1%	24.2%	23.9%	22.8%	22.1%	18.6%	18.3%	19.0%	19.7%	18.5%	25.9%	18.6%	25.8%	24.0%	21.4%	19.3%	19.0%	19.5%	20.3%

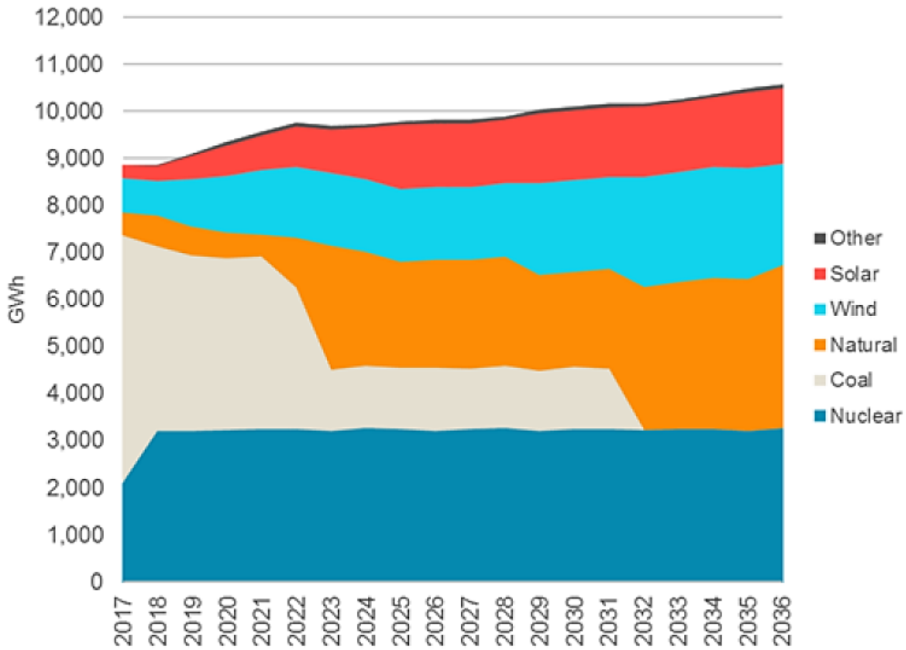
Table 7: New Mexico firm capacity - baseline (MCEP)

Firm Capacity (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Nuclear	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Coal	2,634	2,634	2,634	2,634	2,634	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	247	247	247	247	247
NGCC	1,152	1,152	1,152	1,152	1,505	1,505	1,714	1,714	1,714	1,714	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995
Other NG	1,756	1,756	1,756	1,710	1,710	1,636	1,560	1,546	1,572	1,572	1,427	1,427	1,427	1,366	1,454	1,454	1,542	1,542	1,402
MCEP Nat'l Gas	0	0	0	0	0	456	456	456	496	496	683	683	870	870	1,057	1,057	1,097	1,137	1,347
Wind	73	76	78	81	82	82	82	82	82	104	104	104	104	104	109	109	109	127	127
Solar	255	310	333	343	369	376	393	430	429	430	428	451	452	450	445	441	437	433	429
Other Renewable	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	58	59	61	63	65	67	69	71	72	74	74	74	74	74	74	74	74	74	74
Total Firm Capacity	7,012	7,071	7,099	7,067	7,449	6,993	7,144	7,170	7,236	7,261	7,582	7,606	7,793	7,730	6,466	6,462	6,585	6,639	6,705
Peak Demand	4,833	4,894	4,950	5,015	5,080	5,154	5,234	5,303	5,349	5,384	5,426	5,487	5,540	5,581	5,642	5,692	5,752	5,820	5,880
Reserve Margin	45.1%	44.5%	43.4%	40.9%	46.7%	35.7%	36.5%	35.2%	35.3%	34.9%	39.7%	38.6%	40.7%	38.5%	14.6%	13.5%	14.5%	14.1%	14.0%

Generation

PNM's baseline scenario (MCEP) relies on gas-fired generation resources (combined cycles, gas turbines, and other peaking resources) to fill the energy gap from the proposed retirement of the SJGS units in 2023 (see Figure 5 for PNM's projected energy mix). The utility also relies on a gradual deployment of wind and solar to fill the remaining energy balance. The IRP assumes that remaining coal at Four Corners is phased out by 2032.

Figure 5: PNM's energy mix



Source: PNM's 2017 IRP, page 132.

Synapse calibrated the baseline scenario against the actual generation mix and import balance reported for PNM's system in 2017. Our baseline modeling results show that PNM will also rely on imports to meet its energy needs and will shift from being a net energy exporter to a net energy importer after 2023. PNM's IRP does not explicitly include imports as a significant part of the utility's energy mix.[21] Imports could prove to be a lower cost energy resource than energy from one of the new gas turbines. Figure 6 and Figure 7 display full generation results for both PNM and New Mexico.

[21] It is unclear which resources displayed in PNM's IRP in "Figure 51: PNM Energy Mix" represent imports.

Figure 6: PNM annual generation - baseline (MCEP)

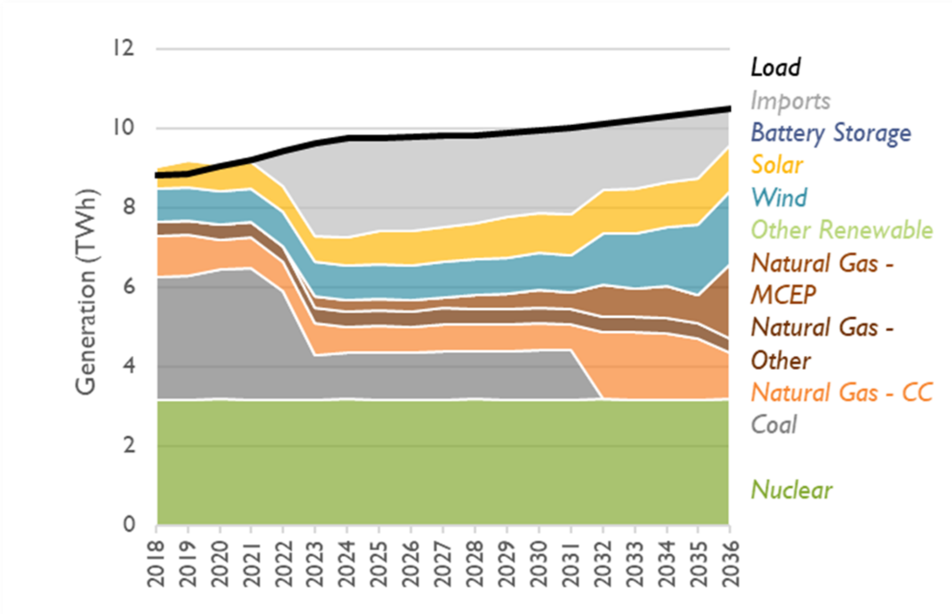
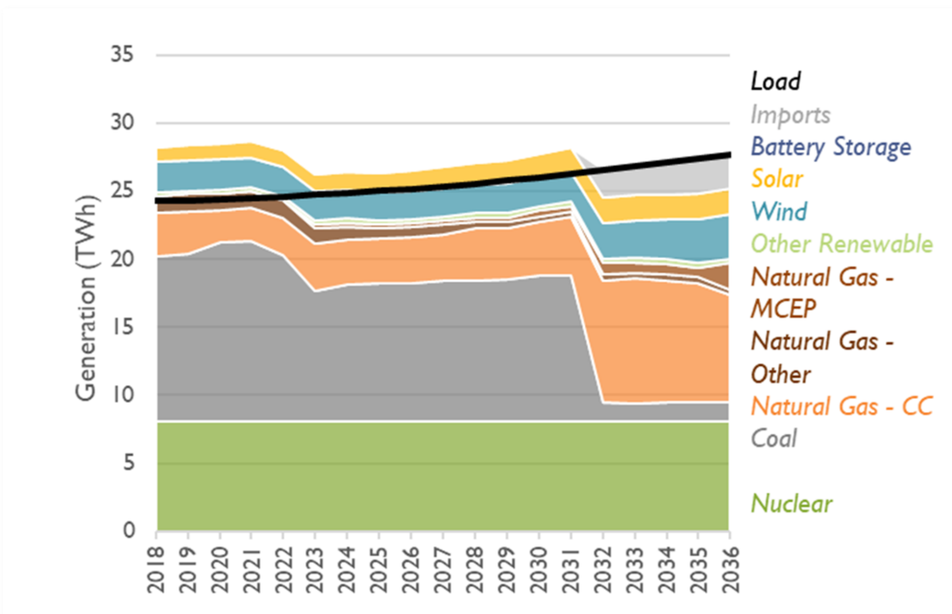


Figure 7: New Mexico annual generation - baseline (MCEP)



Reserve Margin

The baseline scenario maintains a reserve margin of 18-26 percent for PNM over the model planning horizon, well above PNM's identified requirements. The reserve margin for New Mexico is even higher, remaining between 35 percent and 45 percent until the retirement of Four Corners in 2032.[22,23] If SJGS retires in 2023 we would expect to see the reserve margin drop significantly. However, the addition of the MCEP gas-fired generation resources brings it back up to around 36 percent.

Clean Energy Resource Portfolio (CERP)

Capacity

The CERP relies on 180 MW of 4-hour lithium ion utility-scale battery storage, 20 MW of incremental demand response resources, and 142 MW of firm utility-scale solar (i.e., 300 MW of nameplate solar) to meet PNM's 2023 capacity needs. Beyond 2023, the CERP deploys additional demand response resources in 20 MW increments and several more blocks of battery storage. The CERP also includes another 104 MW of firm solar capacity and a series of wind blocks with 600 MW of firm wind capacity after the retirement of Four Corners. These renewables are incremental to the 490 MW of utility-scale solar and 380 MW of utility-scale wind PNM has already planned over the planning horizon (see Table 8 for the CERP build-out schedule).

The battery storage resources in this portfolio are directly controlled by the utility. They serve as firm capacity. They therefore contribute to meeting peak period capacity requirements and provide valuable regulation up and down ancillary services. The batteries are generally charged by solar resources (because solar has zero marginal cost), however they are not necessarily directly paired with solar resources. This means the batteries can technically be charged by any resource. Synapse modeled the batteries this way so that they can provide capacity value even when planning for the worst-case scenario of solar resource availability, such as a sustained week of stormy or cloudy weather. Full capacity results for PNM and New Mexico are displayed in Figure 8 through Figure 11, Table 9, and Table 10.

It is important to note that this is not an "optimized" portfolio for PNM or the state of New Mexico. It is an alternative resource portfolio that meets PNM's energy, capacity, and reliability needs at a lower cost and with a lower environmental impact than PNM's MCEP. Because of New Mexico's excessive reserve margin, an "optimal" portfolio would re-allocate existing surplus capacity to New Mexico's utilities to meet energy, capacity, and reliability needs. Therefore, an optimal portfolio for New Mexico utilities would not require significant new capacity additions.

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[22] This includes all resources that are physically located in the state of New Mexico, as well as capacity outside the state owned by New Mexico utilities.

[23] The state reserve margin does drop back to 14-15 percent after 2032; however, these results will likely change when full resources plans for all New Mexico utilities are completed for the post-2032 time-period.

Table 8: CERP firm capacity additions (MW)

Firm Capacity (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
MCEP Solar																			
Data Center 20 MW Solar						11													
Data Center 30 MW Solar	22.8		22.8	22.8															
Data Center 40 MW Solar		30.4			30.4														
NM Solar PV Large (18)							17.5					17.5							
NM Solar PV Large (35)								35.0											
NM Solar PV Large (5)												5.0							
NM RPS Solar		16.0																	
MCEP Wind																			
Data Center 50 MW Wind		2.5	2.5	2.5															
Data Center 30 MW Wind					1.5														
NM Large Wind (5)															5.0				
NM Large Wind (18)																		18.0	
Model Selections																			
New Wind Block (100)															150.0	60.0	90.0	150.0	150.0
4-Hour Battery															200.0				
Demand Response*															23.2				
Portfolio Locked-in to Meet PNM Reserve Margin																			
4-Hour Battery					180.0							60.0		20.0					
Solar Block 1						56.8													
Solar Block 2						72.8													
Solar Block 3						16.0						104.0		8.0					
Demand Response*						23.2			23.2	23.2	23.2		23.2						

**Demand response capacity listed here is incremental to PNM's baseline demand response projection. "Firm capacity" accounts for the contribution of renewable resources to meeting peak load.*

Figure 8: PNM firm capacity - CERP

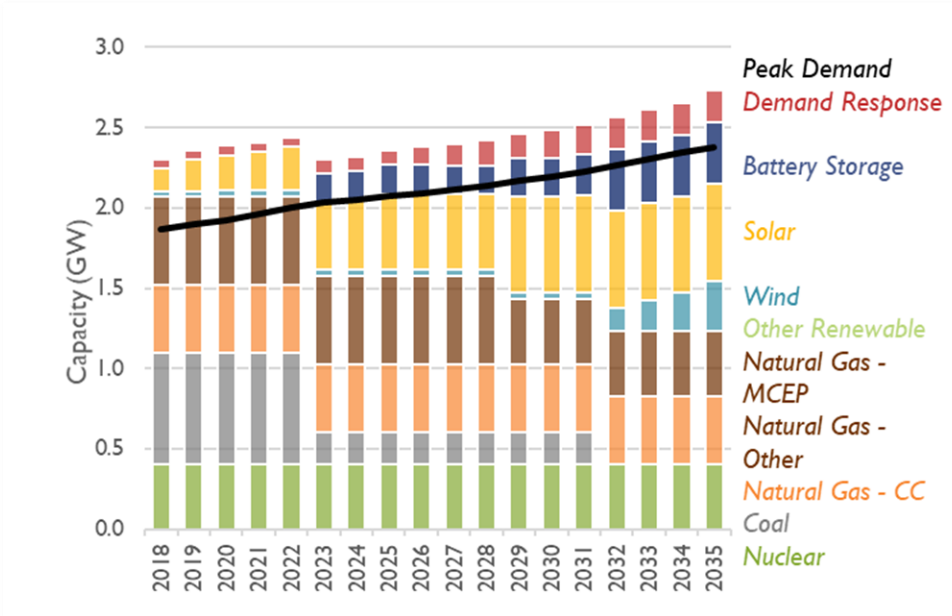


Figure 9: New Mexico firm capacity – CERP

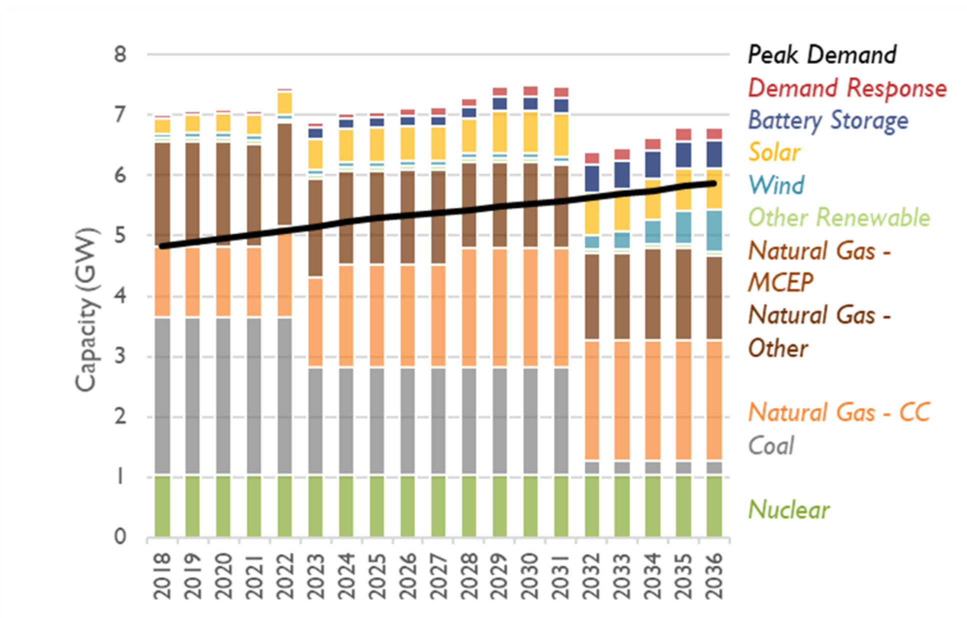


Figure 10: PNM nameplate capacity - CERP

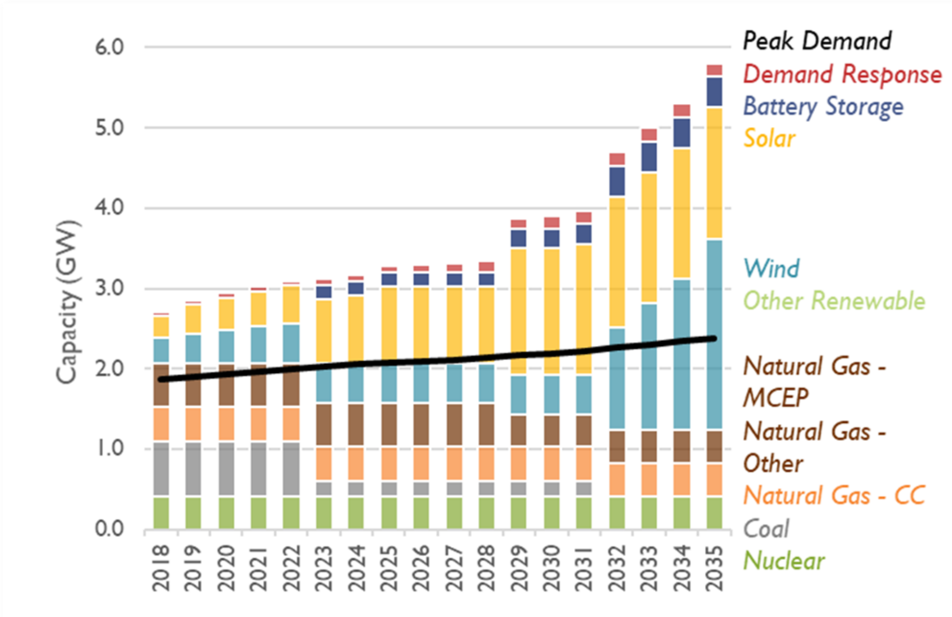


Figure 11: New Mexico nameplate capacity - CERP

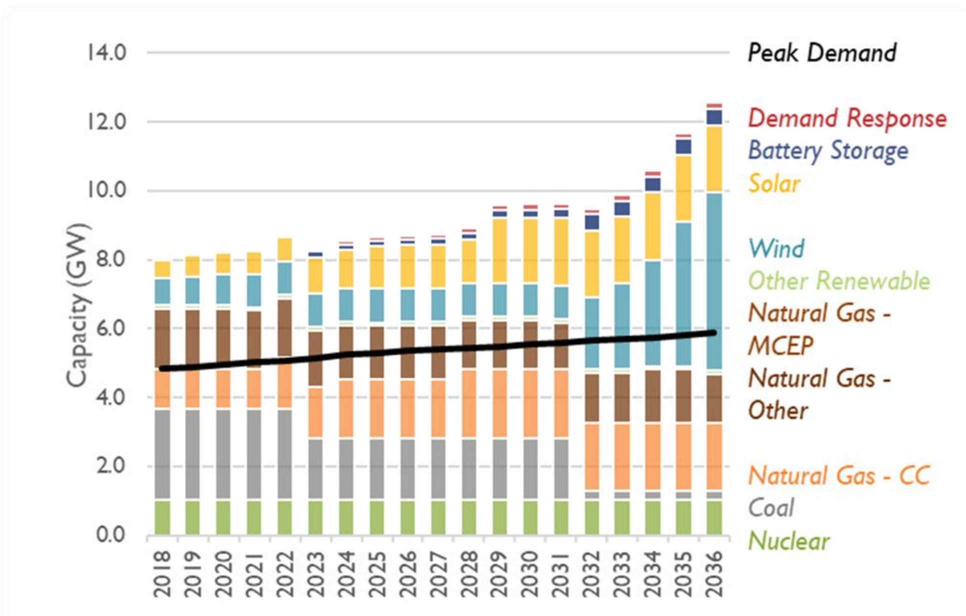


Table 9: PNM firm capacity - CERP

Firm Capacity (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Nuclear	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402
Coal	697	697	697	697	697	200	200	200	200	200	200	200	200	200	0	0	0	0	0
NGCC	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422
Other NG	552	552	552	552	552	552	552	552	552	552	552	408	408	408	408	408	408	408	268
MCEP Nat'l Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	28	31	33	36	37	37	37	37	37	37	37	37	37	37	147	192	237	315	465
Solar	146	199	222	240	269	424	440	474	473	472	472	599	600	607	606	605	605	604	603
Other Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Battery Storage	0	0	0	0	0	180	180	180	180	180	180	240	240	260	380	380	380	380	380
Demand Response	54	56	57	59	61	84	86	88	111	135	157	157	178	178	200	200	200	200	200
Total Firm Capacity	2,302	2,359	2,386	2,408	2,440	2,302	2,320	2,356	2,378	2,400	2,422	2,465	2,488	2,515	2,565	2,610	2,654	2,731	2,741
Peak Demand	1,871	1,900	1,926	1,961	1,999	2,033	2,053	2,071	2,093	2,114	2,138	2,168	2,193	2,225	2,265	2,304	2,343	2,381	2,423
Reserve Margin	23.1%	24.2%	23.9%	22.8%	22.1%	13.3%	13.0%	13.8%	13.6%	13.6%	13.3%	13.7%	13.4%	13.0%	13.3%	13.3%	13.3%	14.7%	13.1%

Table 10: New Mexico firm capacity - CERP

Firm Capacity (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Nuclear	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Coal	2,634	2,634	2,634	2,634	2,634	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	247	247	247	247	247
NGCC	1,152	1,152	1,152	1,152	1,505	1,505	1,714	1,714	1,714	1,714	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995
Other NG	1,756	1,756	1,756	1,710	1,710	1,636	1,560	1,546	1,572	1,572	1,427	1,427	1,427	1,366	1,454	1,454	1,542	1,542	1,402
MCEP Nat'l Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	73	76	78	81	82	82	82	82	82	82	82	82	82	82	237	297	387	555	705
Solar	255	310	333	343	369	521	538	576	574	575	573	701	701	707	703	699	694	690	686
Other Renewable	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Battery Storage	0	0	0	0	0	180	180	180	180	180	180	240	240	260	460	460	460	460	460
Demand Response	58	59	61	63	65	90	92	94	119	144	167	167	190	190	214	214	214	214	214
Total Firm Capacity	7,012	7,071	7,099	7,067	7,449	6,886	7,037	7,063	7,112	7,138	7,296	7,483	7,507	7,472	6,394	6,450	6,623	6,787	6,793
Peak Demand	4,833	4,894	4,950	5,015	5,080	5,154	5,234	5,303	5,349	5,384	5,426	5,487	5,540	5,581	5,642	5,692	5,752	5,820	5,880
Reserve Margin	45.1%	44.5%	43.4%	40.9%	46.7%	33.6%	34.5%	33.2%	33.0%	32.6%	34.5%	36.4%	35.5%	33.9%	13.3%	13.3%	15.2%	16.6%	15.5%

Generation

The CERP relies predominately on solar and wind resources to meet the system's energy needs from the proposed retirement of the SJGS (Figure 12 and Figure 13). PNM's imports fall significantly relative to the baseline results and the utility becomes a net exporter of excess solar and wind capacity after 2030. Reliance on gas-fired generation resources is much lower than in the baseline, as no new gas-fired generation is added to the system and, once again, all coal is phased out by 2032.

Figure 12: PNM annual generation - CERP

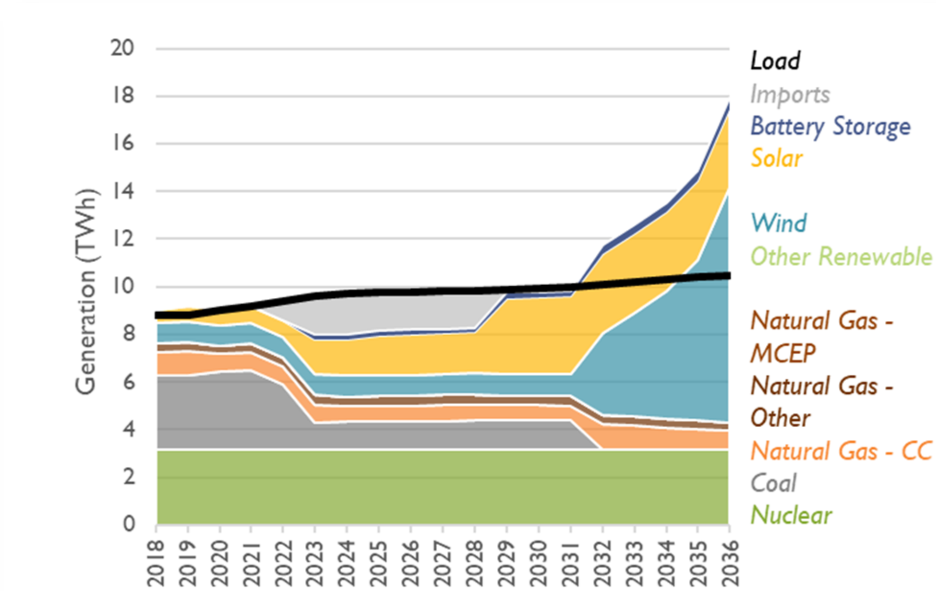
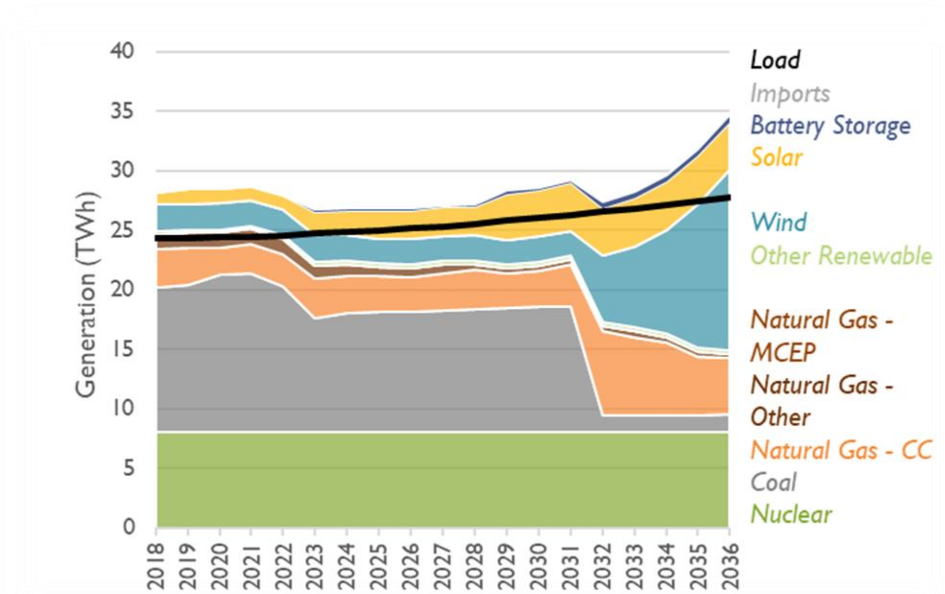


Figure 13: New Mexico annual generation - CERP



Reserve Margin

The resources in the CERP allow PNM to sustain a reserve margin above 13 percent for the entire planning horizon. The portfolio relies on 356 MW of firm renewable capacity to replace the capacity from the proposed retirement of SJGC, compared with 456 MW in the MCEP. The reserve margin in the rest of New Mexico drops a small amount relative to the baseline scenario. However, because PNM targets a 13 percent reserve margin for its own system, the state reserve margin remains above 33 percent until the retirement of Four Corners in 2032. Again, we note that an "optimal" portfolio for New Mexico would allow for the reallocation of existing surplus capacity, rather than allowing utilities to build in excess of cumulative requirements.

Other Scenarios and Sensitivities

In addition to the baseline and CERP scenarios, we tested an alternative resource portfolio where both renewables and gas-fired generation resources from PNM's MCEP were available to the model. The results from this scenario were very close to the CERP. As discussed above, New Mexico does not need additional capacity to meet its reserve margin until 2032, and therefore no additional resources (gas-fired or otherwise) were selected for inclusion in any optimized portfolio prior to 2032.

3.4. Daily Results

Figure 14 and Figure 16 display the baseline daily dispatch resource mix for the state of New Mexico. They show results for both a representative peak winter day and a peak summer day in 2023 after SJGS's proposed retirement. In the baseline scenario, New Mexico relies on gas-fired generation resources to meet peak demand. Solar and wind resources are not firmed up with battery storage, and therefore PNM is not fully capturing peak contribution benefits from solar (especially in the winter months).

Including battery storage on the system allows the utility to minimize both curtailment of solar generation and the need to pair solar capacity with fast-ramping gas-fired peaking capacity to avoid grid disruption as solar production falls in the evening.

In the CERP, battery storage complements the system's solar and wind resources. In summer, the battery charges during the off-peak daytime and nighttime hours and discharges during the evening peak. In the winter months, the battery discharges over the entire peak period (Figure 15) including morning and evening hours. In the summer months, solar PV is still generating electricity as the evening peak begins and the battery is not immediately needed (Figure 17). However, as solar begins to ramp down later in the evening, the battery is available to discharge and replace the energy production that has fallen off from solar.

Figure 14: New Mexico daily dispatch for January 2023, baseline (MCEP)

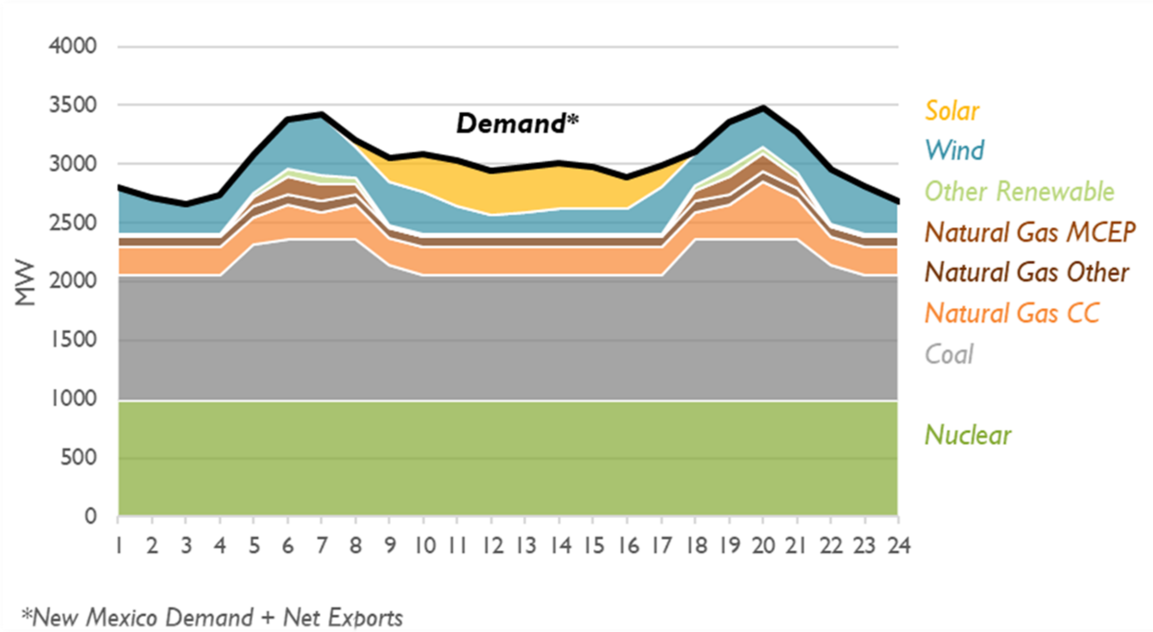


Figure 15: New Mexico daily dispatch for January 2023, CERP

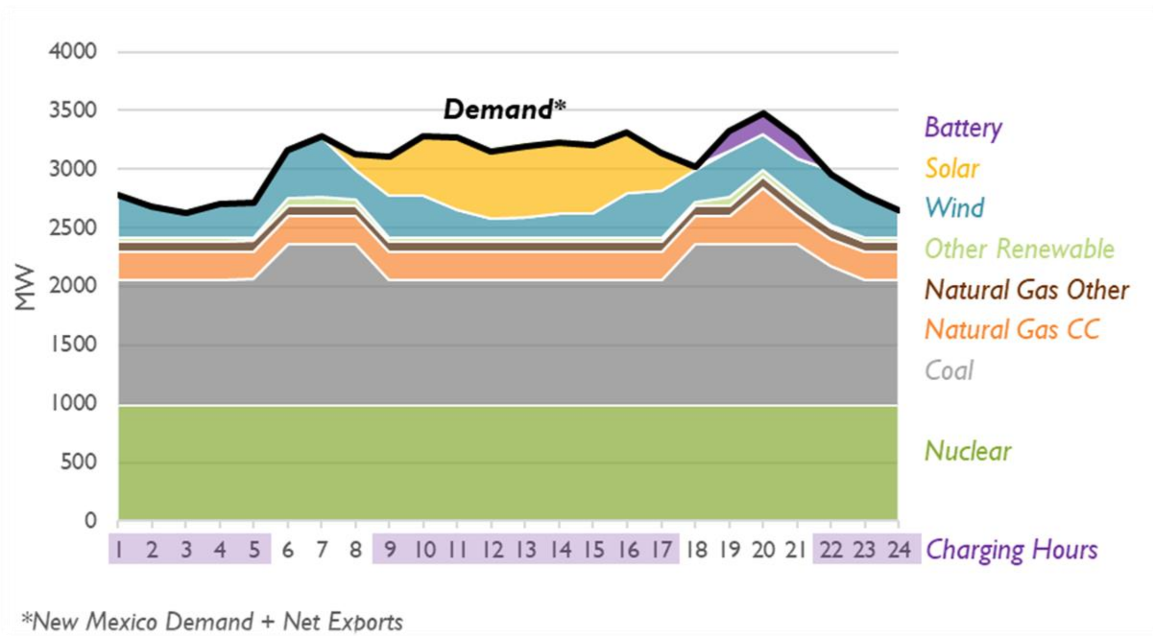


Figure 16: New Mexico daily dispatch for July 2023, (MCEP)

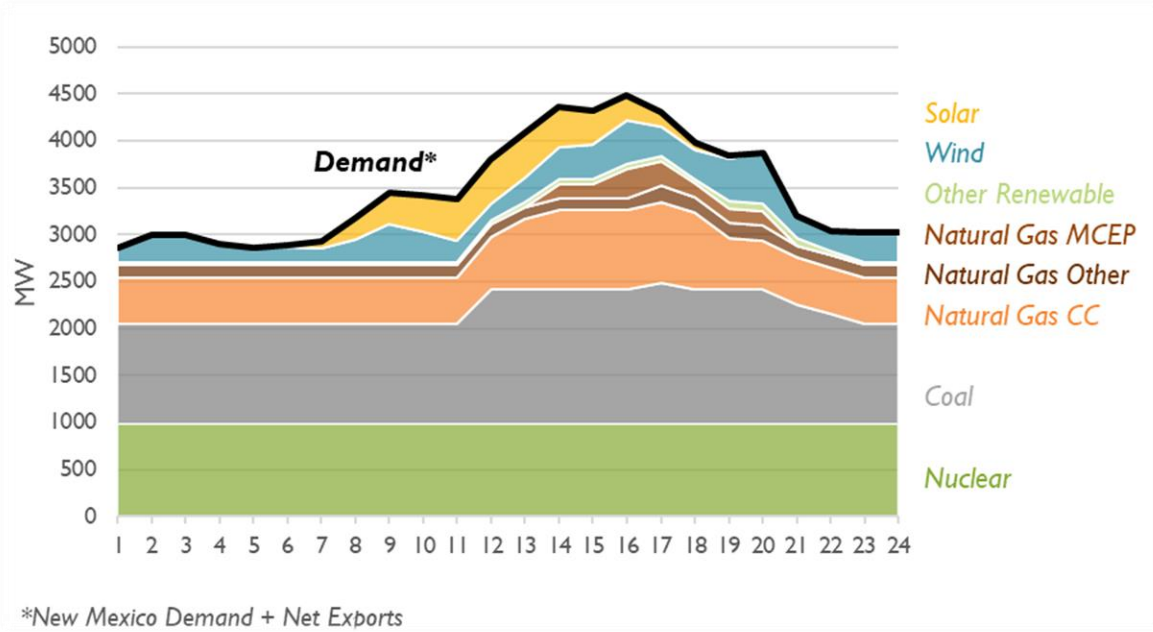
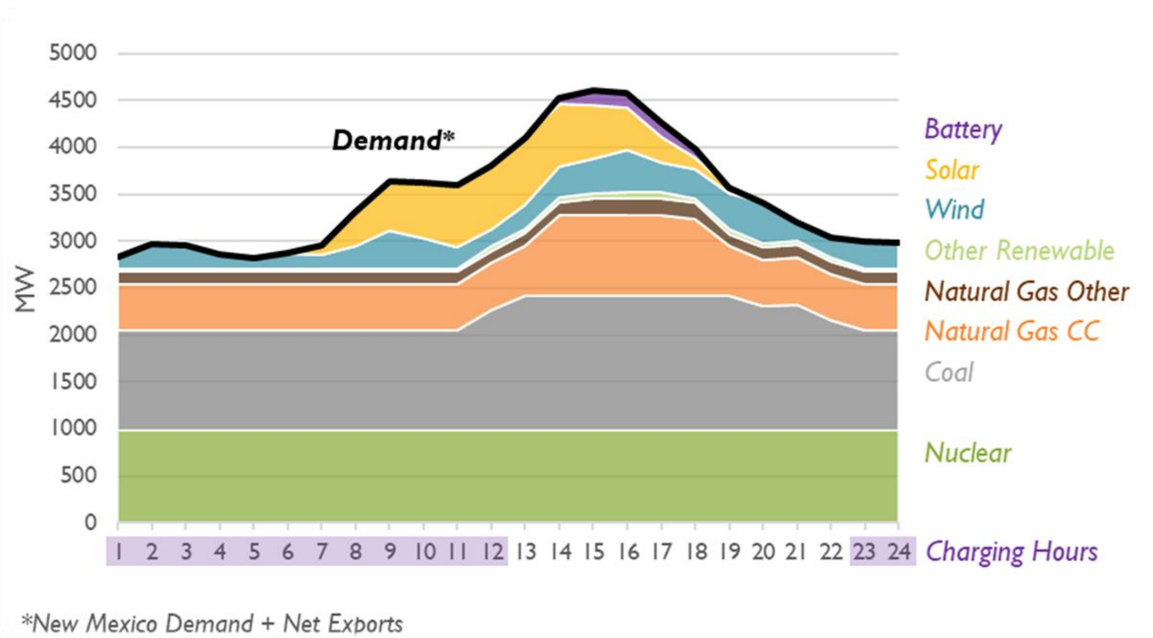


Figure 17: New Mexico daily dispatch for July 2023, CERP



3.5. Net Present Value Results

The NPV for the CERP was 1.49 percent lower than the baseline MCEP scenario for PNM and 0.33 percent lower than the baseline scenario for the entire state of New Mexico.

We calculated the NPV for all scenarios using identical financial and cost assumptions (Table 11) as used by PNM to develop its analysis.[24]

Table 11: NPV results

Scenario	New Mexico NPV ($000)	New Mexico Δ from Baseline	PNM NPV ($000)	PNM Δ from Baseline
Baseline Scenario (MCEP)	$13,241,082		$6,307,766	
CERP	$13,197,447	-$43,635 (0.33%)	$6,213,889	-$93,887 (1.49%)

The NPV for each scenario included all energy costs, fixed costs, new capital expenditures, sustaining capital costs for existing units, DSM program costs, import purchases, and export revenue for PNM's service territory over the time period 2018–2036 (see Table 12 for a description of each component).

[24] The NPV results are calculated with updated renewable cost assumptions for both the baseline and the CERP scenarios.

Table 12: NPV components

Energy costs	Energy costs were output directly from the model and include all fuel costs, non-fuel variable operating costs, and commitment costs (start-up, shut-down).
Fixed costs	Fixed costs were output directly from the model and included all fixed operating costs.
Capital expenditures	Capital expenditures were calculated outside of the model for all new units using $/kW assumptions laid out in Table 1 and Table 2. We applied updated capital cost assumptions for wind and solar to both the alternative resources that we offered the model, and to the renewables in PNM's MCEP.*
Sustaining capital costs	Sustaining capital costs for PNM's existing resources were pulled directly from Appendix K in PNM's IRP. Sustaining capital costs are identical across all scenarios.
Demand side management (DSM)	DSM program costs for energy efficiency and demand response are calculated based on the program budgets PNM published in its 2018 DSM reports. For energy efficiency, we started with the program cost projection for 2019 and escalated it at a rate of 5% per year. Energy efficiency levels are held constant across all scenarios. For demand response, we applied an average program cost of $100/kW to all deployed demand response.** Demand response levels varied across scenarios.
Import purchases and export sales	Import purchases and export sales were calculated based on energy flow exports from the model. Import purchase costs were based on the quantity of energy demanded, and the average production cost from the exporting regions. Export sales revenues were based on the quantity of energy exported, the cost differential between PNM's production costs, and the production cost in the importing regions.

*Note: * We applied updated costs to both sets of resources to isolate the value of an alternative portfolio from the cost savings that would result from modeling the same resource portfolio with lower cost assumption. ** Demand response costs applied are similar to PNM demand response costs.*

The CERP resource portfolio includes a large build-out of renewables, which have high capital costs but low operating costs in comparison to the gas-fired generation resources in the baseline scenario. Capital costs were more than 20 percent higher in the CERP than in the baseline scenario. Energy costs were about a quarter lower and fixed costs were around 4.5 percent lower.

In the baseline scenario, PNM is a net importer with around 7 percent of total costs attributed to import purchases. In the CERP, however, PNM is a net exporter and earns net revenue from exporting generation from low-cost renewables. Overall, the CERP has a lower NPV than the baseline MCEP scenario for both PNM and for the entire state of New Mexico. An optimized scenario that utilized integrated state planning and sharing of reserve could have an even lower NPV than the CERP.

3.6. Capital Cost Sensitivities

Recognizing that the costs of resources have been falling quickly in short periods of time, Synapse conducted capital cost sensitivities on new gas resources to evaluate the impact of potential reduced bids of those resources. We evaluated the capital cost of the Large GT's that PNM has proposed in the MCEP for 2023 and found that bid costs would have to be nearly 65 percent lower than the costs used in PNM's 2017 IRP for the MCEP to become competitive with the CERP (see Table 13).

Table 13: Gas-fired generation capital cost tipping point

New Resource Costs ($2017 real/kW)	Original capital cost	Capital cost decline tipping point	Capital cost at tipping-point
Large GT	$753	65%	$265

Source: Original Large GT capital cost is from the PNM 2017 IRP, Appendix K, p.89.

Synapse also analyzed capital cost sensitivities for the alternative technologies modeled in the clean energy scenario (Table 14). We found that battery storage costs would have to increase by nearly 70 percent, and wind and solar costs would need to increase by more than 30 percent for the CERP to become more expensive than the MCEP.[25]

Table 14: Alternative technology capital cost tipping points

New Resource Costs ($2017 real/kW)	Original cost assumption	Original annual cost decline assumption	Capital cost increase tipping point	Capital cost at tipping-point
4-Hour Battery Storage	$1,166	-5.5%	66.71%	$1,944
Large Solar	$1,100	-2.0%	30.49%	$1,435
Large Wind	$1,590	-1.51%	30.02%	$,2067

In summary, the findings of the CERP are robust to capital cost fluctuations, reduced bids for fossil power plant infrastructure, and higher than expected costs for storage and renewable energy projects. Finally, while not shown here, the CERP is also robust to fuel costs. PNM's proposed MCEP builds peaking combustion turbines, which use relatively little fuel; even substantially lower fuel prices would not displace the storage and renewable energy options found optimal in the CERP.

[25] All technologies were evaluated separately, and cost decline assumptions were not altered.

4. RECOMMENDATIONS

Synapse recommends that PNM seriously consider an alternative resource portfolio with battery storage and renewables in place of the proposed gas-fired generation resources. Specifically, Synapse recommends that PNM:

- Use a modeling construct capable of examining hourly dispatch while selecting optimal resources, rather than continuing to rely on the outdated Strategist model structure. We note that PNM has stated that it is in the process of migrating to the EnCompass modeling platform for the purposes of future resource planning.
- Re-run the modeling with updated resource cost assumptions and sensitivities for solar PV, New Mexico wind, and utility-scale battery storage resources based on the costs that the company received from RFP bids.
- Update wind and solar operational assumptions, particularly around the ELCC of wind as the penetration of solar increases. The company may need to undertake a study or commission independent analysis to inform these modeling updates.
- Assess the opportunity to acquire potentially cost-effective combined utility-scale solar-storage projects, not reviewed in the CERP.
- Research and model battery storage to better understand the different ways that battery storage can integrate with the utility's system to provide value to the grid. This should include a review of battery storage that is of smaller scale and may be customer-sited, as opposed to the utility-scale resource we model in the CERP. The factors to focus on include:
    - where the storage is connected on the customer side of the meter or the utility-side of the meter;
    - whether the batteries are paired with solar or able to charge from any grid resource; and
    - what incentives exist (or could be considered) to increase the likelihood that small-scale battery resources are discharging coincident with the local or PNM system peak (i.e., late afternoon and evening hours).
- Incorporate into the modeling process consideration of firm energy and capacity resources elsewhere in New Mexico and the Southwest that PNM can rely on to meet reliability needs. Right now, PNM resource planning models assign imports zero capacity value to PNM's system.

APPENDIX A: MODELING APPROACH

A.1. The EnCompass Model

EnCompass is a single, fully integrated power system platform that provides an enterprise solution for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning:

- Short-term scheduling including detailed unit commitment and economic dispatch
- Mid-term energy budgeting analysis including maintenance scheduling and risk analysis
- Long-term integrated resource planning including capital project optimization and environmental compliance
- Market price forecasting for energy, ancillary services, capacity, and environmental programs

A.2. Topology

Analysis Footprint

For this modeling analysis, Synapse focused on a detailed representation of the State of New Mexico. We did not model or enforce intra-state constraints that may exist between PNM, Tri-State, El Paso (serving New Mexico and El Paso load), and the other co-ops and load-serving entities in New Mexico. We modeled the entire state, beyond PNM's service territory, to represent the potential for increased statewide planning and operational coordination.

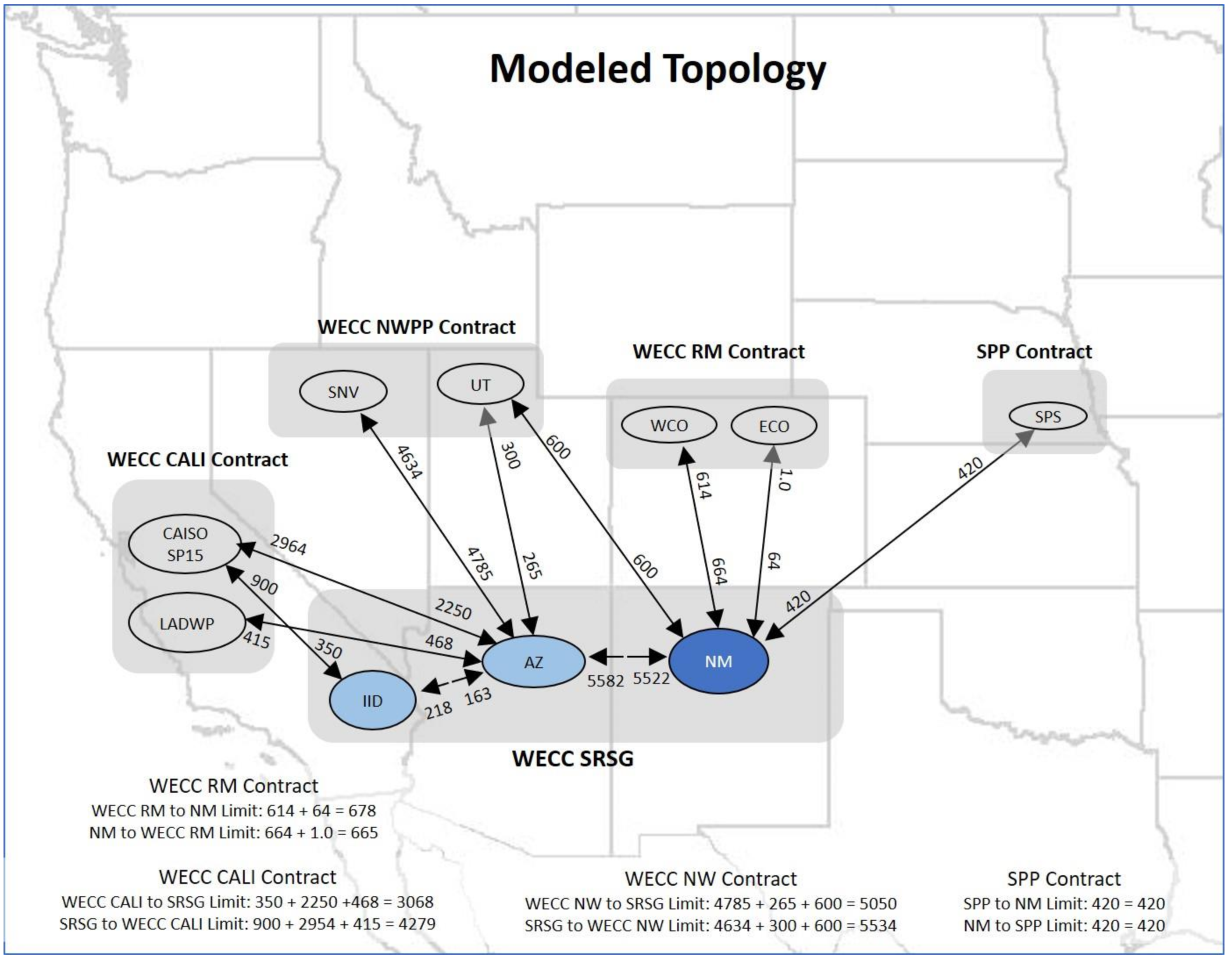
Within the Southwest Reserve Sharing Group (SRSG) region we modeled all individual generating units, including detailed resource cost and operational parameters.[26] SRSG is subject to regional operating reserve requirements and regulation requirements. Planning reserve margins for the New Mexico area reflect PNM's needs (as stated in the IRP), scaled up to the state level (roughly 2.5 times the PNM region). Throughout this report, we present results at both the state and utility level. We report results for New Mexico as they came out of the model with minimal post-processing analysis. The results for PNM required iterative model runs and are reported after post-processing analysis that enforced a minimum planning reserve margin and allocated resource costs between PNM and the rest of New Mexico.

[26] The SRSG region is comprised of a collection of NERC balancing authorities (which cover New Mexico, Arizona, the Imperial Irrigation District in California, and Texas portions of El Paso Electric).

Contract Regions

Synapse modeled the four SRSG-adjacent balancing authorities as four "contract regions," containing seven interconnected areas. Each contract region has designated energy and capacity that it can export to SRSG at a single resource cost profile and a maximum quantity of energy and capacity that it can import from SRSG at the actual modeled cost in the SRSG region. Figure 18 shows the topology and the connection transfer capability.

Figure 18: Modeled topology and area transfer limits (MW)



Transmission Links

The quantity of imports and exports flowing to and from the New Mexico area in the baseline model run is premised on the capacity of the area-to-area connections and the marginal price of energy in each contract region, plus a hurdle rate for transactions. The marginal cost of energy in each of these regions is set at $35 per MWh in 2018 (the approximate price of energy at the Palo Verde hub) and set to escalate over the model time-frame at the same rate as natural gas prices (5 percent per year).

A.3. Input Assumptions – New Mexico and SRSG Regions

Resources

Synapse's model included four broad categories of generation resources within SRSG: (1) existing resources that are currently operating in the region; (2) new projects that PNM and other utilities have planned, which were manually (exogenously) added to the model; (3) new generically defined projects that are available for the model to endogenously build; and (4) demand-side resources (both new and existing), including energy efficiency, demand response, and distributed solar PV. We explain these resources in greater detail below.

Existing Resources

Synapse modeled as individual resources all existing plants and projects in WECC SRSG, which includes New Mexico, Arizona, and the Imperial Irrigation District. In each region abutting WECC SRSG, Synapse created contract regions to represent each region's resource portfolio in the aggregate (as discussed above). We designed the model runs to permit all existing resources to economically retire prior to their scheduled retirement dates.

Synapse validated all existing PNM resources within the New Mexico area (as defined in the Horizons Energy National Database) against the resources in PNM's 2017 IRP (Table 15). We also validated units in El Paso Electric's service territory (based on the Company's 2015 IRP) and all remaining large units in New Mexico.

Table 15: Existing PNM resources

Name	Firm Capacity (MW)	Max Capacity (MW)	Scheduled Retirement Date
Coal Resources			
Four Corners	200	200	2032
San Juan	497	497	2023
Nuclear Resources			
Palo Verde Unit 1 & Unit 2	268	268	
Palo Verde Unit 3	134	134	
Gas-Fired Generation Resources			
Reeves	154	154	
Afton	230	230	
Lordsburg	80	80	
Luna	189	189	
Rio Bravo	138	138	2036
Valencia	150	150	2028
La Luz	40	40	
Renewable Resources			
New Mexico Wind Energy Center (Wind Purchase)	10	200	
Red Mesa (Wind Purchase)	5	100	2036
Prosperity Battery Demo	0.5	0.5	
Utility-Scale Solar PV (various projects)	68	107	
PNM Sky Blue	1	1.5	
Dale Burgett Geothermal Plant	1	4	

New Exogenous Resources

Synapse hard-coded all new resources included in El Paso's 2015 IRP into the model for all scenarios. We also updated information when new information became available and added operation and cost data from the IRP to the existing database.

Synapse added all new resources in PNM's MCEP (Table 16) to the model as resource options. We modeled some of the resources differently across scenarios (see the Scenario Definition section below for more details). We sourced all major operational and cost data for the new plants from PNM's MCEP.

Table 16: PNM resource additions from MCEP

Resource	Firm Capacity (%)	Max Capacity (MW)	Unit Additions	Capital Cost (2017$/kW)
Solar				
Data Center 20 MW Solar	55	20	1 in 2023	$1,388
Data Center 30 MW Solar	76	30	1 in 2018 1 in 2020 1 in 2021	
Data Center 40 MW Solar	76	40	1 in 2019 1 in 2022	
NM Solar PV Large (18)	35	50	1 in 2024 1 in 2029	
NM Solar PV Large (35)	35	100	1 in 2025	
NM Solar PV Large (5)	10	50	1 in 2029	
NM RPS Solar	32	50	1 in 2019	
Wind				
Data Center 50 MW Wind	5	50	1 in 2019 1 in 2020 1 in 2021	PPA, energy price only
Data Center 30 MW Wind	5	30	1 in 2022	
NM Large Wind (5)	5	100	1 in 2032	
NM Large Wind (18)	18	100	1 in 2035	
Gas-fired Generation				
NM Large Gas Turbine (187)		187	2 in 2023 1 in 2028 1 in 2030 2 in 2032	$753
Aeroderivative Small (40 MW)		40	1 in 2026 1 in 2034 1 in 2035	$1,150
Reciprocating Engines (41 MW)		41	2 in 2023	$1,218
Rio Bravo CC Expansion		210	1 in 2036	$800

*Note: Firm capacity % reflects both higher peak load period capacity contribution for single-axis tracking solar PV, and the overall capacity "tier," reflecting lower contributions at higher cumulative penetration levels. See IRP, Appendix K, Table 30, page 93. *Capital costs are from the PNM 2017 IRP, Appendix K. **Synapse applied updated solar costs to all of PNM's solar projects when calculating portfolio NPV's.*

New Endogenous Resources

Synapse allowed the model to choose from among generic solar PV, wind, battery storage, and gas-fired generation projects to replace planned gas-fired generation resources in the CERP, and to fill in future capacity gaps in the MCEP.[27] Generic gas-fired generation projects were available using default Encompass cost and operational parameters. All renewable projects were available to the model with updated cost assumptions from Lazard and LBNL (Table 17).

[27] New coal resources were also available to the model, but none were ever selected.

Table 17: Endogenous resource addition options for New Mexico

Resource	Firm Capacity (%)	Increment Size (MW)	Max Addn's (# units)	Capital Cost (2017$/kW)	Annual Cost Decline (real)	Source (Cost)
Solar						
New Solar Block 1	71	20 MW	4	$1,100	-2.0%	Lazard, Levelized Cost of Energy 2017
New Solar Block 2	52		7			
New Solar Block 3	20		1000 MW/y			
Wind						
New 2019–2021 Wind Block	5	100 MW	1000 MW/y	$1,590	-1.5%	LBNL Wind Tech Mkts 2016
New Post–2022 Wind Block	15					
Battery Storage						
1-Hour Battery	100	10 MW	200 MW/y	$1,166	-5.5%	Lazard, Levelized Cost of Storage 3.0
4-Hour Battery	100					
Gas-fired Generation						
New Combined Cycle	100	702 MW	14	$1,013	-	Horizons Default settings for Encompass Model
New Combined Cycle +15%	100		14	$1,164		
New Combined Cycle + 50%	100		43	$1,518		
New Gas Turbine	100	237 MW	42	$716		
New Gas Turbine + 25%	100		42	$894		
New Internal Combustion Engine	100	85 MW	-	$1,403		

Demand-Side Resources

Synapse hard-coded energy efficiency into the model as an energy resource that directly reduced demand levels. New Mexico currently mandates that utilities spend 3 percent of revenue on demand-side energy efficiency measures, therefore we did not model any additional incremental energy efficiency beyond the levels projected (see the Demand section for the energy efficiency input assumptions).

Synapse modeled both demand response and distributed solar PV as supply-side resources. Specifically, we modeled the firm capacity for demand response and distributed solar PV as a reduction in peak (rather than an increase in capacity). We hard-coded into the model the projected level of demand response and distributed solar PV, with additional incremental levels of both available to the model in some scenarios.

Synapse started with the baseline energy efficiency, demand response, and distributed PV projections that PNM provided in its 2017 IRP. We then scaled the energy and capacity values for New Mexico based on PNM's share of each resource reported to the U.S. Energy Information Administration in 2016 (see Table 18 for DSM deployment assumptions and Table 19 for DSM model inputs).

Table 18: 2016 DSM deployment in New Mexico

DSM Measure	PNM	Rest of New Mexico
Demand Response	93.7%	6.3%
Net Metered Distributed Solar PV	67.3%	32.7%
Energy Efficiency	49.6%	50.4%

Table 19: Total demand response and distributed PV deployment

Year	Demand Response (MW)		Distributed PV (MW)	
	New Mexico	PNM	New Mexico	PNM
2016	64.9	60.8	137.8	92.8
2017	45.0	48.0	184.7	124.4
2018	46.5	49.6	203.8	137.2
2019	48.0`	51.2	221.5	149.2
2020	49.4	52.7	221.5	149.2
2021	51.0	54.4	221.5	149.2
2022	52.5	56.0	224.1	150.9
2023	54.0	57.6	226.7	152.7
2024	55.5	59.2	229.4	154.5
2025	57.0	60.8	232.1	156.3
2026	58.5	62.4	234.8	158.1
2027	60.0	64.0	237.6	160.0
2028	60.0	64.0	240.4	161.9
2029	60.0	64.0	243.3	163.8
2030	60.0	64.0	246.2	165.8
2031	60.0	64.0	249.1	167.7
2032	60.0	64.0	252.1	169.7
2033	60.0	64.0	255.1	171.8
2034	60.0	64.0	258.1	173.8
2035	60.0	64.0	261.2	175.9
2036	60.0	64.0	264.4	178.0

Demand

PNM modeled a mid-load forecast with an average energy growth rate of around 1 percent per year and an average peak demand growth rate of 1.5 percent per year. Synapse relied on the load and energy forecasts sourced from the North American Electric Reliability Corporation Long-Term Reliability Assessment that reflect similar load growth assumptions (starting at 1 percent per year and gradually declining from the 1 percent by 0.01 percent annually) through 2036 (Table 20).

Table 20. New Mexico demand and energy efficiency projection

Year	Demand (GWh)	% increase in demand	EE (GWh)	Net Demand (GWh)	% change in net demand
2018	24,767	-	(487)	24,279	-
2019	25,014	1.00	(688)	24,327	0.19
2020	25,262	0.99	(876)	24,386	0.24
2021	25,510	0.98	(1,046)	24,464	0.32
2022	25,758	0.97	(1,192)	24,566	0.42
2023	26,006	0.96	(1,297)	24,709	0.58
2024	26,254	0.95	(1,398)	24,856	0.59
2025	26,502	0.94	(1,496)	25,006	0.60
2026	26,750	0.94	(1,592)	25,158	0.61
2027	26,997	0.93	(1,662)	25,335	0.71
2028	27,245	0.92	(1,695)	25,551	0.85
2029	27,493	0.91	(1,717)	25,776	0.88
2030	27,741	0.90	(1,725)	26,016	0.93
2031	27,989	0.89	(1,715)	26,274	0.99
2032	28,237	0.89	(1,688)	26,549	1.05
2033	28,485	0.88	(1,645)	26,840	1.10
2034	28,733	0.87	(1,598)	27,134	1.10
2035	28,980	0.86	(1,554)	27,427	1.08
2036	29,228	0.86	(1,511)	27,717	1.06

Synapse also relied on daily load shapes provided by Horizons Energy to optimize daily dispatch decisions (Figure 19 and Figure 20).[28] We compared PNM's sample daily load shapes with Horizon's to ensure alignment between the two sources.[29]

[28] Daily load shapes for PNM were not publicly available.

[29] PNM's 2017 IRP, Appendix A. Pages 14-15.

Figure 19: New Mexico January load profile: typical week

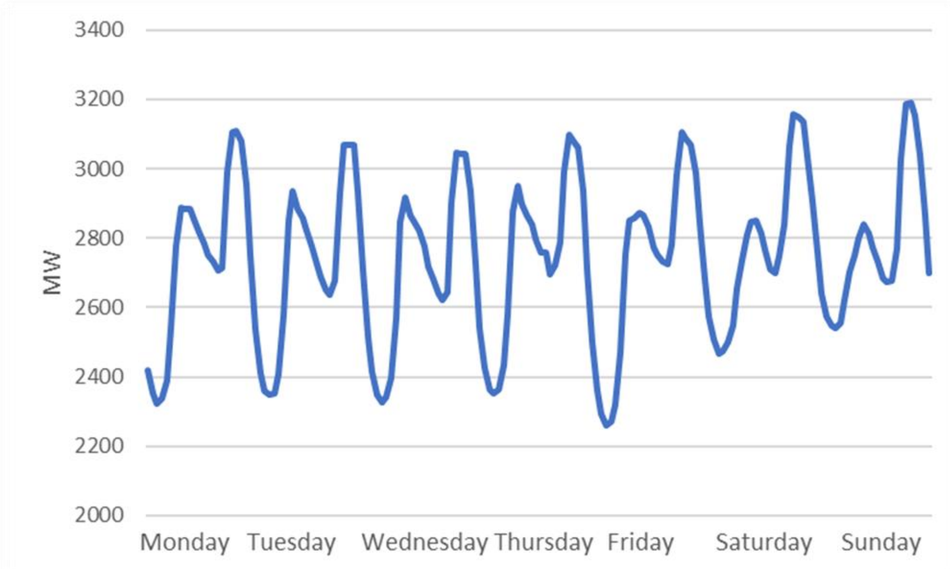
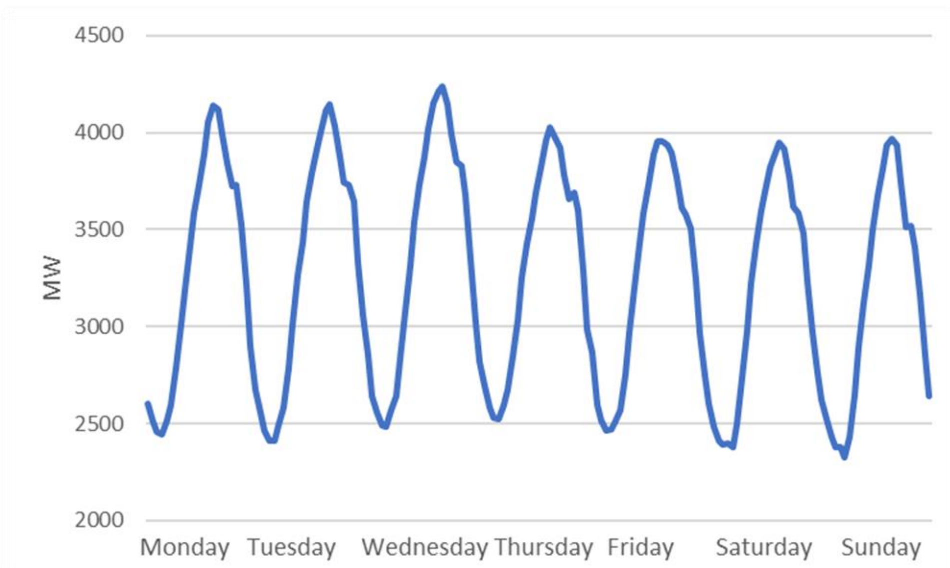


Figure 20: New Mexico July load profile: typical week



Fuel Costs

PNM's natural gas forecast was developed by Pace Global based on NYMEX forwards as of July 2016 (Figure 21). Natural gas prices at the San Juan hub rise from an average of \$2.50–\$3.00 (2015\$) in 2018 to \$4.50–\$5.00 (2015\$) in 2036. For this analysis, we relied on a natural gas forecast developed by Horizons Energy for the Encompass database (Figure 22). The long-term trend in Horizon's price forecast was very similar to the trend in PNM's forecast.

Figure 21: PNM's natural gas forecast ($2015 Real) developed by Pace Global

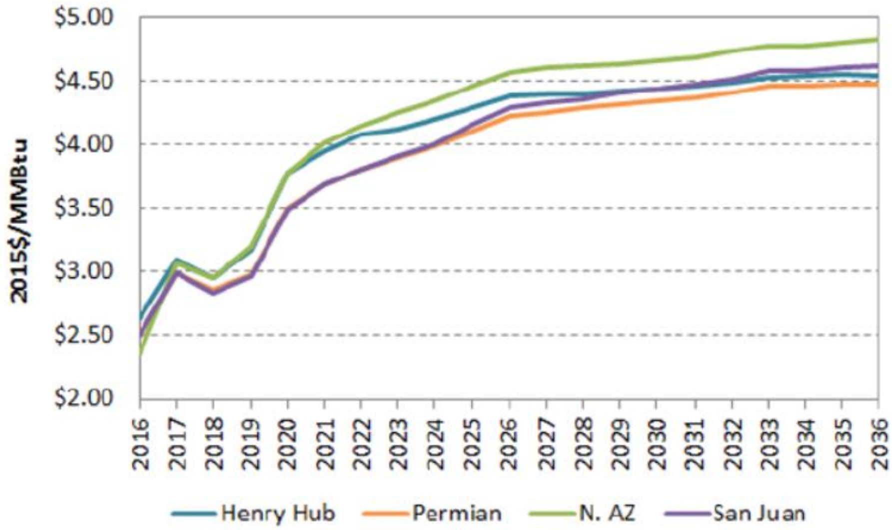
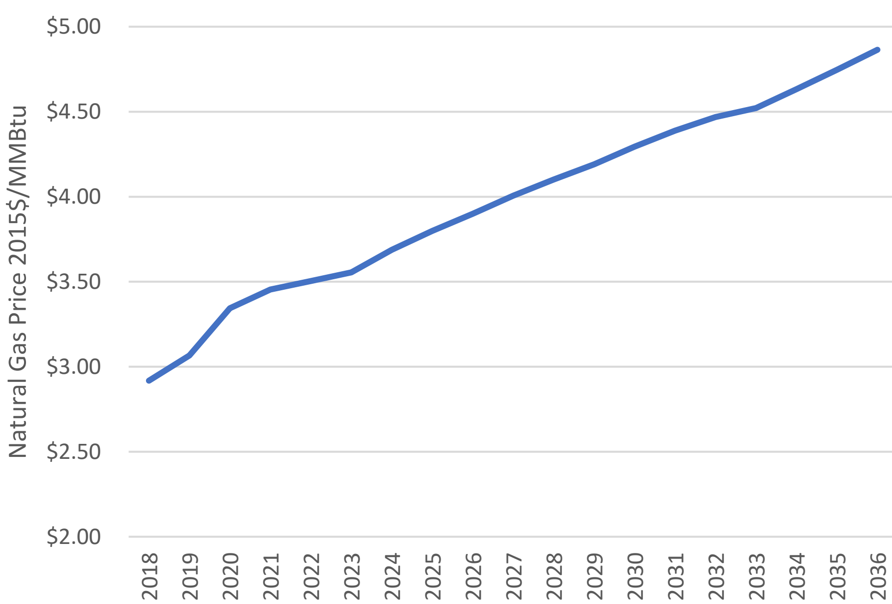


Figure 22: Horizon's natural gas forecast for New Mexico ($2015 real)



Financial Assumptions

Synapse relied on PNM's baseline financial assumptions for the cost of capital, discount rate, and inflation assumptions both in the Encompass model and for all our financial calculations outside the model for both scenarios. We assumed no tax credits from the Investment Tax Credit (ITC) or Production Tax Credit (PTC), and we did not model a carbon price to ensure our results were robust against changes in external tax policies. Any tax credit and carbon tax assumptions will lower the NPV of the CERP even further. Table 21 lists the global financial assumptions.

Table 21. Financial assumptions

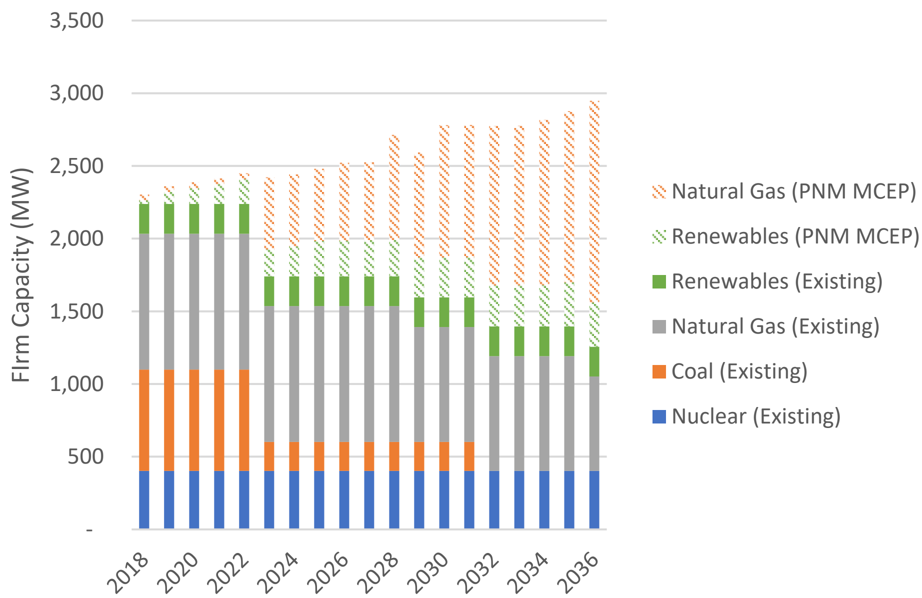
Assumption	Value	Source
Nominal WACC	7.7%	PNM 2017 IRP, Appendix H, p 53-54
Discount Rate for NPV	7.7%	PNM 2017 IRP, Appendix H, p 53-54
Inflation	1.5%	PNM 2017 IRP, Appendix H, p 53-54
ITC	0% beyond 2021	Conservative assumption
PTC	0% beyond 2019	Conservative assumption
CO_2 Price	$0/MWh	Conservative assumption

A.4. Scenario Definition

Synapse modeled one baseline scenario and one alternative clean energy scenario. The CERP evaluated potential resource portfolios to replace the gas-fired generating units proposed in PNM's MCEP.

Baseline Scenario: The baseline scenario is equivalent to PNM's MCEP. In this portfolio, new planned renewable and gas-fired generation projects from PNM's IRP are added to PNM's existing resource portfolio.

Figure 23: PNM MCEP scenario



Clean Energy Resource Portfolio Scenario: The CERP also used PNM's existing resources. Then we added PNM's planned renewable projects. The model then optimized all additional resource decisions. The CERP focused on filling the capacity need left by the proposed retirement of SJGS with renewable resources rather than gas-fired generating plants. The CERP precluded use of gas-fired generation resources. Table 22 outlines the set-up of each scenario.

Figure 24: PNM MCEP renewables (CERP starting point)

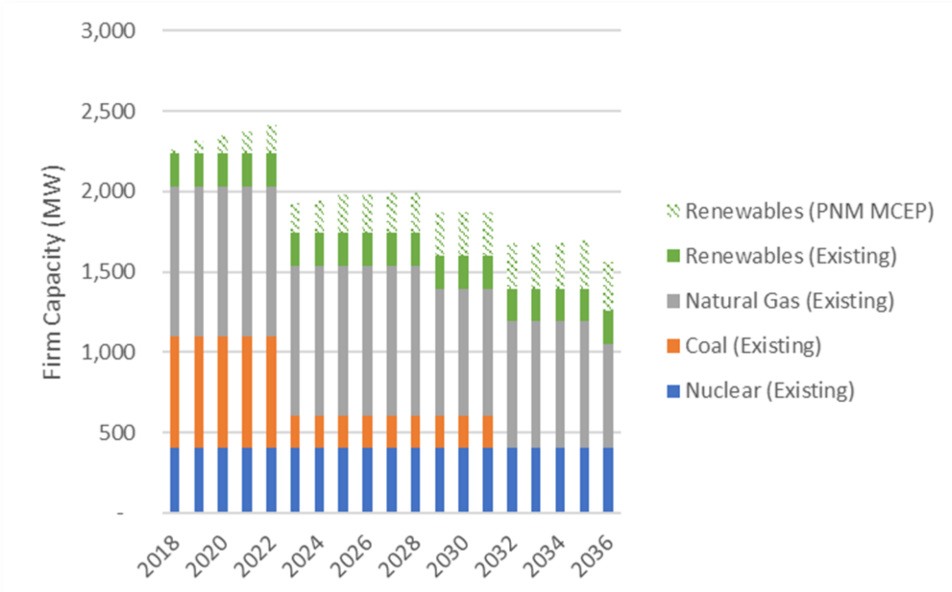


Table 22: Scenario definition

Scenario	Gas-fired generation					Renewables			
	PNM's MCEP gas-fired generation			Generic new gas-fired generation		PNM's MCEP renewable projects		Generic new renewable projects (with updated costs)	
	Lock in all projects	Optimize with projects	Turn off all projects	Optimize with projects	Turn off all projects	Lock in all projects	Turn off all projects	Optimize with projects	Turn off all projects
Baseline scenario (MCEP)	x				x*	x			x
CERP: renewables, no gas-fired generation			x		x	x		x	

*Note: *Generic new gas-fired generation was permitted to fill capacity needs in the rest of New Mexico (outside of PNM).*

A.5. Utility and Regional Reserve Requirements

EnCompass optimized build and dispatch decisions over all regions in the SRSG area to reflect reasonable statewide integrated planning processes. When solving the capacity expansion problem, EnCompass considered a reserve margin of 13 percent for the entire state of New Mexico.

New Mexico maintained a reserve margin above 13 percent in each scenario. However, PNM's resource portfolio alone fell below 13 percent in some scenarios. To enforce the reserve margin requirement, we iterated on the initial results for each scenario by locking in incremental amounts of solar, battery storage, wind, and demand response until we had an economic resource portfolio that met PNM's 13 percent reserve margin target in all years.