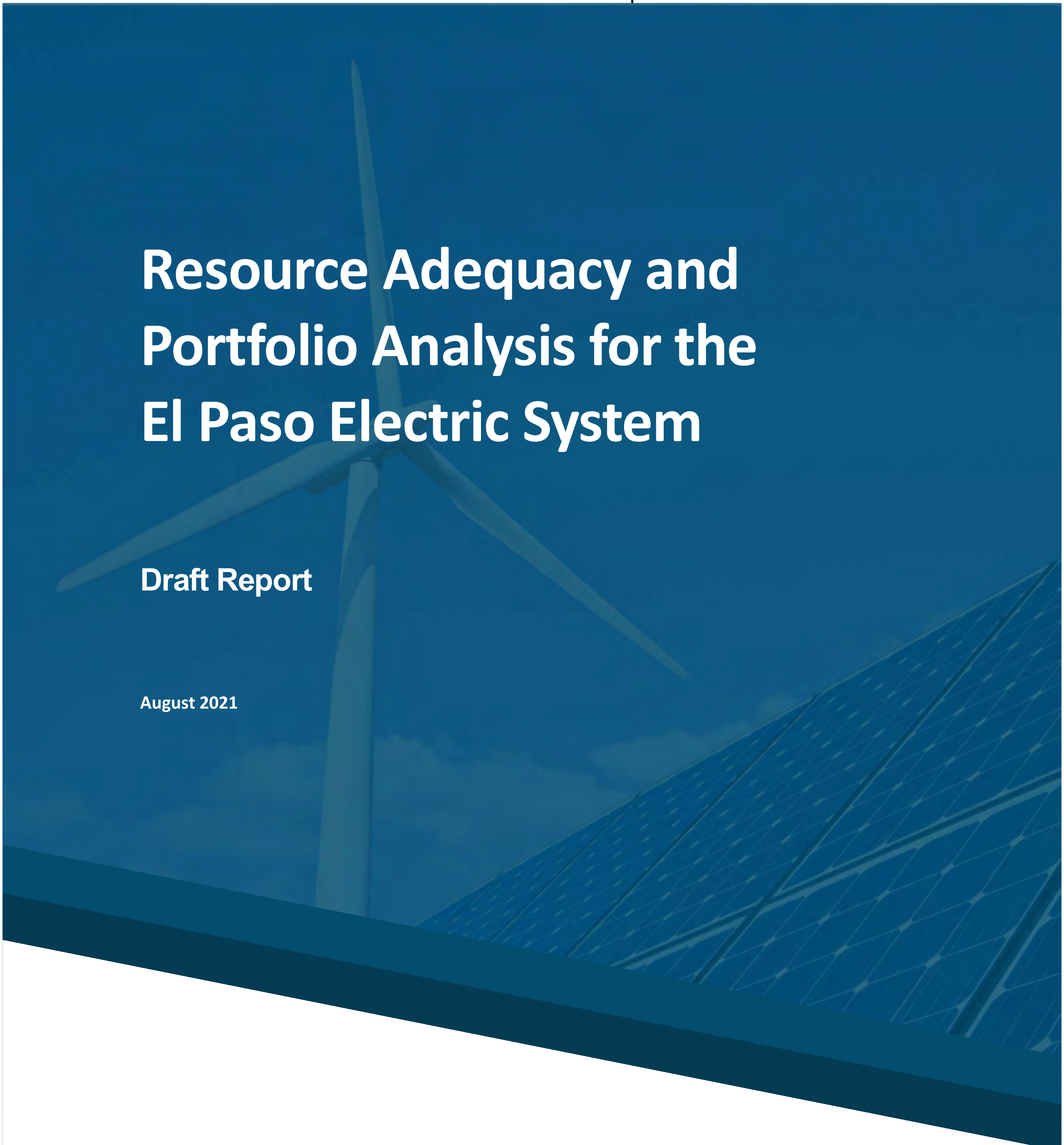

Resource Adequacy and Portfolio Analysis for the El Paso Electric System

Draft Report

August 2021

Energy+Environmental Economics

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Acronym and Abbreviation Definitions

Acronym	Definition
ABQ	Albuquerque
ATB	Annual Technology Baseline
BTM	Behind-the-meter
CC	Combined Cycle
COD	Commercial Operation Date
CO_2	Carbon Dioxide
CT	Combustion Turbine
DAFOR	Derated Adjusted Forced Outage Rate
DG	Distributed Generation
DR	Demand Response
DSM	Demand-side Management
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EP	El Paso
EPE	El Paso Electric
EUE	Expected Unserved Energy
EV	Electric Vehicle
Geo	Geothermal
GHG	Greenhouse Gas
H_2	Hydrogen
IC	Interconnection
ICAP	Installed Capacity
IRP	Integrated Resource Plan
ISO	Independent System Operator
kW	Kilowatt
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LTO	Loss to Others
MMT	Million Metric Tons
MW	Megawatt
MWh	Megawatt-hour
NM	New Mexico
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
PCAP	Perfect Capacity
PRM	Planning Reserve Margin
PV	Photovoltaic or Present Value
REA	Renewable Energy Act
RTO	Regional Transmission Organization
ST	Steam Turbine
TX	Texas

Executive Summary

This study by Energy and Environmental Economics, Inc. (E3) details analysis that E3 performed to support the El Paso Electric Company's (EPE or El Paso Electric) 2021 Integrated Resource Plan (IRP) filing. E3 utilized its modeling software in combination with E3-developed inputs and inputs provided by El Paso Electric to identify optimal long-term resource portfolios for the period through 2045. El Paso Electric utilized these portfolio results directly in its IRP filing.

El Paso Electric is an electric utility providing generation, transmission, and distribution service to customers in western Texas and southern New Mexico. Customers in New Mexico account for approximately 20% of its system load. E3 developed optimal long-term resource portfolios for the entire system that minimize cost while ensuring compliance with all New Mexico and Texas policy requirements and maintaining reliability for all customers.

There are several factors that drive El Paso electric's long-term resource needs. El Paso Electric has several thermal units that are scheduled to retire over the next two decades. In addition, El Paso Electric expects continued growth in load, which together with resource retirements, drives a need for new resources to ensure reliability for customers. Maintaining reliability has always been paramount for long-term resource planning, but its importance has been underlined by recent widespread outage events in other parts of Texas and in California.

Another factor driving long-term planning is the change in market conditions. Over the next two decades, El Paso Electric expects gas prices to rise and the cost of renewable and storage resources to fall. These trends impact the optimal mix of generating resources over time. In addition, El Paso Electric must add renewable and zero-carbon resources to comply with clean energy policies in New Mexico and Texas. Notably, the New Mexico Renewable Energy Act (REA), as amended since El Paso Electric's previous IRP, requires El Paso Electric to supply New Mexico customers with a growing share of renewable energy and to supply New Mexico customers with 100% zero-carbon energy by 2045.

El Paso Electric already has a less carbon intensive portfolio than most other utilities, given its reliance on energy from nuclear, natural gas, and renewable energy sources. E3 estimates that El Paso Electric's current energy supply for retail customers in New Mexico and Texas is made up of more than 60% zero-carbon energy. Between now and 2023, El Paso Electric is adding 270 MW of additional solar resources and 50 MW of paired battery storage to its system. Given the factors highlighted above, El Paso Electric will continue adding more renewable resources, which will cause the share of zero-carbon energy on its system to grow over time.

In this study, E3 utilized robust modeling tools and industry best practices to quantify future system needs and develop optimal least-cost resource portfolios. E3 performed four analyses:

1. **Planning reserve margin (PRM)** – Quantification of the PRM that is required to maintain resource adequacy and ensure reliability for the system.
2. **Effective load carrying capability (ELCC)** – Quantification of the contribution of resources – both existing and new – toward the PRM requirement for ensuring reliability.

3. **Portfolio analysis** – Identification of long-term resource additions that minimize cost while ensuring reliability and satisfying New Mexico and Texas clean energy requirements.
4. **Sensitivity analysis** – Assessment of changes to the portfolio that would result from changes to key planning assumption.

The results of these analyses are summarized below.

Planning Reserve Margin (PRM)

The use of a PRM requirement to determine resource adequacy needs is common among utilities and grid operators throughout the industry. Starting in 2025, El Paso Electric plans to meet a 2-day-in-10-year (0.2 loss of load expectation, or 0.2 LOLE) reliability standard, meaning that there can be up to two days per year with outages, on average. Starting in 2030, El Paso Electric plans to meet a 1-day-in-10-year (0.1 LOLE) reliability standard, meaning there can be up to one day per year with outages, on average. The 0.1 LOLE reliability standard is more common practice in the industry for long-term resource planning.

To quantify the PRM requirement needed to meet this standard, E3 utilized its RECAP model, a loss-of-load probability (LOLP) model that has been used to evaluate the resource adequacy of electric systems across North America, including in California, Nevada, the Pacific Northwest, the Upper Midwest, Florida, and Canada. RECAP simulates resource availability for the electric system with a specific set of generating resources and loads under a wide variety of weather conditions, incorporating weather-matched load and renewable profiles, time-sequential dispatch logic for energy storage, and stochastic forced outages of generation resources. By simulating the system under hundreds of years' worth of conditions with different combinations of these factors, RECAP provides a statistically robust estimation of the PRM required to meet a reliability standard. Table 4-3 shows the PRM results for the El Paso Electric system.

Table 4-3. Planning Reserve Margin Requirements

Metric	Units	2025	2030
Loss of Load Expectation (LOLE)	days/yr	0.2	0.1
Expected System Median Peak	MW	2,245	2,420
Planning Reserve Margin	%	10%	13%
Total Perfect Capacity Need	MW	2,472	2,732

The quantification of the PRM depends on the accounting framework that's used for counting contributions of resources toward the PRM. In this study, E3 utilized a perfect capacity (PCAP) accounting framework, meaning that all resources – including renewable, storage, demand response, and thermal resources – are counted toward the PRM based on their effective load carrying capability (ELCC).

Effective Load Carrying Capability (ELCC)

ELCC has been increasingly recognized by the industry as the preferred method for measuring resources' firm capacity contribution to system reliability. E3 used RECAP to quantify ELCCs by evaluating how much firm capacity a resource can displace to maintain the desired LOLE targets. By simulating the EPE system across a wide range of potential system conditions, RECAP captures the limitations of resources and quantifies their contribution towards resource adequacy. Figure 0-1 and Figure 5-3 below show the ELCCs for solar, storage, and wind for the El Paso Electric system. Section 2.2 contains results for other resources such as thermal and demand-side resources.

Figure 0-1. Cumulative ELCC of Solar and Storage Resources

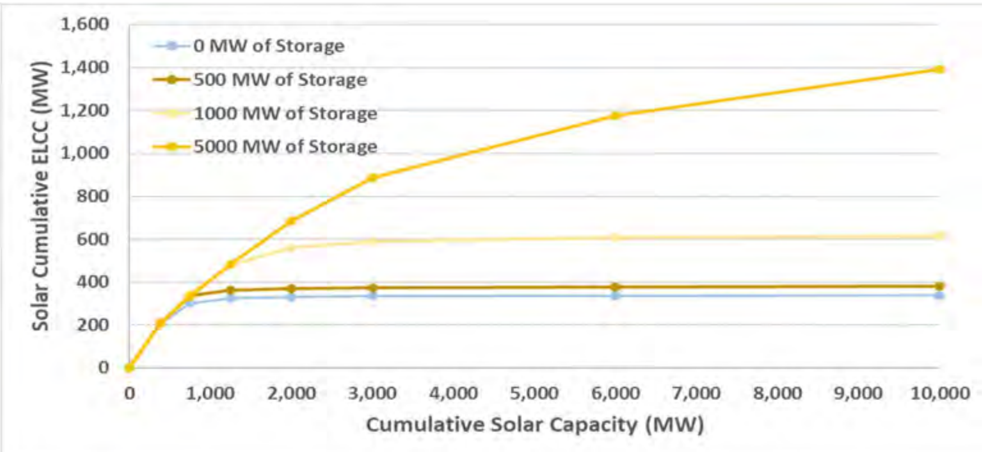
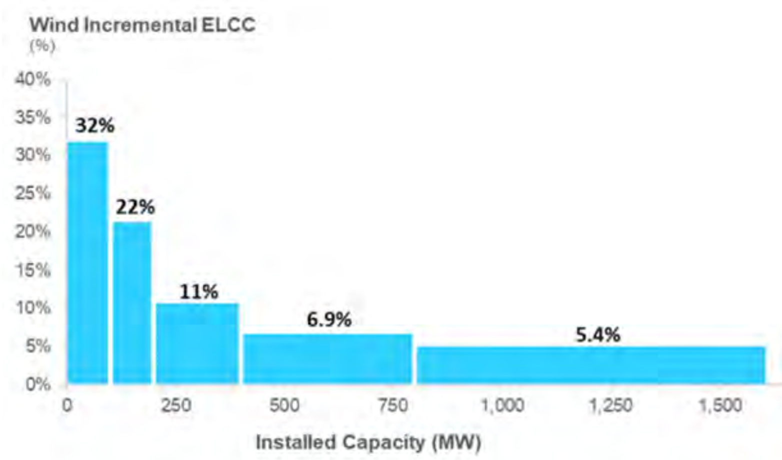


Figure 5-3. Wind Incremental ELCC



Portfolio Analysis

After quantifying the PRM requirement and resource ELCCs, E3 performed resource portfolio optimization using its RESOLVE model. RESOLVE is an electricity system capacity expansion model that identifies economically optimal long-term resource and transmission investments subject to reliability, technical, and policy constraints. RESOLVE considers both the fixed and operational costs of different portfolios and is specifically designed to simulate power systems operating under high penetrations of renewable energy and energy storage resources.

The study considers several resource options for meeting future resource needs. The study includes a range of renewable resource options, including solar photovoltaic (at nine potential locations), wind (at three potential locations), geothermal (at two potential locations), and biomass. The study also includes the option to select transmission upgrades to develop and deliver energy from remote renewable resources. In addition to renewable resources, the study considers storage, natural gas, and demand resource options to meet future needs. For five existing thermal units that are scheduled to retire in the near-term, the study considers the option to extend their lifetimes by five years.

One of the key modeling constraints is ensuring that El Paso Electric's future resource portfolio complies with clean energy requirements in New Mexico and Texas while ensuring fair cost allocation between the two jurisdictions. Compared to the Texas renewable energy requirement, the New Mexico REA is more stringent, requiring an increasing share of retail sales to be supplied by renewable sources and requiring 100% of retail sales to be supplied by zero-carbon energy sources by 2045. If there are incremental costs associated with satisfying the New Mexico REA, then those costs must be allocated to New Mexico.

E3's analysis includes four cases that use different approaches to model a portfolio that meets REA requirements:

1. **Least-Cost (LC)** – This case does not impose any constraints on the resource portfolio beyond reliability requirements.
2. **Least-Cost + REA Resources (LC+REA)** – This case reoptimizes the portfolio of the Least-Cost case to add additional renewables and storage resources dedicated to serving New Mexico customers to satisfy New Mexico's REA requirements.
3. **Separate System Planning (SPP)** – This case models the New Mexico and Texas systems independently without allowing interactions between them.

In addition, E3 modeled another separate system planning case (SPP H2) in which hydrogen generation is available for selection as a clean firm resource on the system. More information on these cases can be found in Table 6-3.

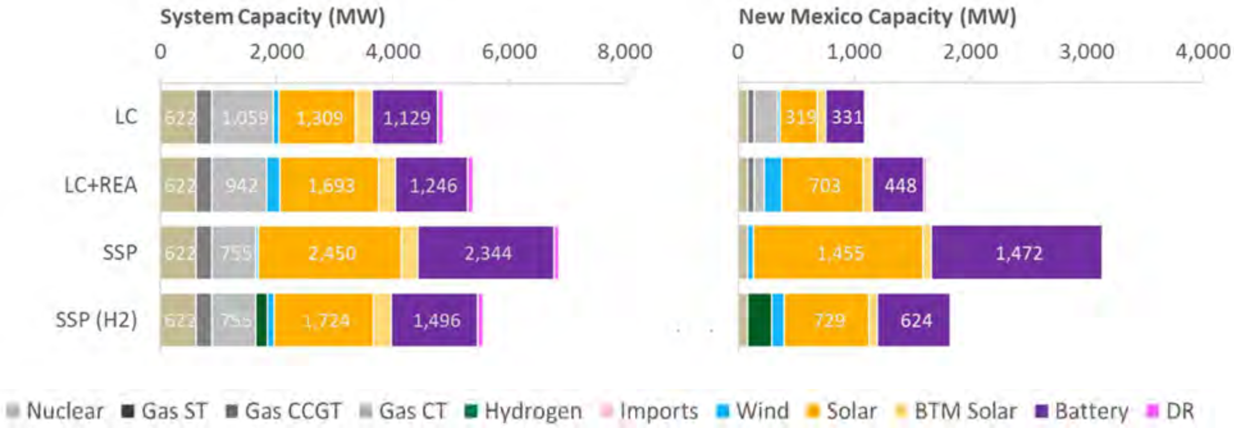
Table 6-3. REA Cases Analyzed

	Least-Cost ("LC")	Least-Cost + REA Resources ("LC+REA")	Separate System Planning ("SSP")
Portfolio Optimization	Least-cost system optimization	Reoptimize Least-Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM Zero-Carbon Generation Balancing Period	Annual	Annual	Hourly
NM and TX Capacity Pooling to Ensure Reliability	✓	✓	✗
Resource Allocation	Resources allocated proportionally	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM Allocated New Gas Capacity	✓	✗	✗

Figure 6-7 shows the overall resource capacity in 2040 for each REA case. Most resource additions in the Least-Cost case are renewable generation, storage, or demand response. Gas capacity is added to ensure reliability. Compared to the LC case, the LC+REA cases adds incremental solar, storage, and wind that were not selected in the LC case but are added as dedicated New Mexico resources to meet REA targets in the LC+REA case. This additional renewable and storage procurement reduces the amount of gas resources needed for meeeting reliability needs. By 2040, the remaining gas resources for New Mexico in the LC+REA are included for reliability purposes and rarely dispatched, enabling the New Mexico portfolio to have zero-carbon energy serving 100% of retail sales on annual basis. Section 6.4.2 discusses these results in more detail.

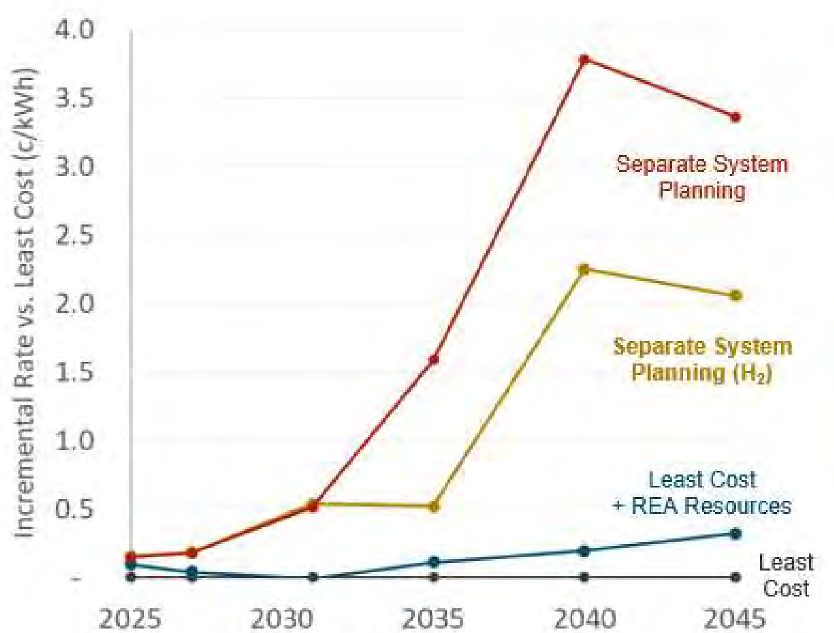
The SPP case procures significantly more resources solar and storage resources, which are needed to enable the New Mexico separate system to balance on an hourly basis without any gas generation, as well as to meet reliability needs as a standalone system without capacity pooling. These incremnetal resources and associated costs are assigned to New Mexico customers. The addition of a moderate amount of zero-carbon dispatchable hydrogen generation to the New Mexico separate system in the SSP H2 case significantly reduces the amount of storage and solar required compared to the SSP case, because the H2 generation can cover the infrequent longer-duration events that are challenging for reliability on the New Mexico separate system.

Figure 6-7. Capacity in 2040 by REA



See Figure 6-10 for the cost impact by year for each of the REA cases evaluated. This chart focuses on the impact to El Paso Electric's New Mexico customers. All cost impacts are calculated based on the difference in annual cost for New Mexico customers relative to the Least-Cost case, divided by the annual New Mexico retail sales (in kWh). This gives an incremental rate impact (in cents/kWh) for New Mexico customers.

Figure 6-10. New Mexico Customer Rate Impact (Relative to Least-Cost Case)



The Least-Cost case is shown with zero incremental cost in all years. Notably, the LC+REA case has a incremental cost that is only 0.2 cents per kWh more than the Least-Cost in 2040. By contrast, the SSP case is the most expensive case modeled, with incremental cost for New Mexico customers of 0.5 cents per kWh in 2030, and over 3.5 cents per kWh by 2040 compared to the Least-Cost case. In this case, the significant additional storage and solar required to ensure reliability without capacity pooling and without any gas generation in any hour results in a significant increase in costs.

By contrast, the SSP case is the most expensive case modeled. Its incremental cost for New Mexico customers compared to the Least-Cost case starts at small amounts in the 2020s but rises to 0.5 cents per kWh in 2030, and to over 3.5 cents per kWh by 2040. In this case, the significant additional storage and solar required to ensure reliability without capacity pooling and without any gas generation in any hour results in a significant increase in costs.

Adding the option to burn green hydrogen in the SSP H2 case substantially moderates the cost increase compared to SSP case after 2030, because dispathable H2-fired generation is a lower-cost option compared with the very large solar and storage build in the SSP case for meeting New Mexico's reliability needs with zero-carbon sources in all hours. The reduction provided by adding a H2 option is most pronounced in 2040 and 2045, when the clean energy targets are tightest and the implied cost of the SSP case is highest. Even with the hydrogen option, the SPP H2 case is still higher in cost than the LC+REA case, despite providing a similar overall zero carbon percentage results for 2030 and 2040. This comparison indicates that significant cost efficiency can be gained from capacity pooling and annual versus hourly zero-carbon balancing, even if a separate New Mexico system has a hydrogen technology option avaiable.

Sensitivity Analysis

In addition to the REA cases, E3 performed analysis on several sensitivity cases to evaluate uncertainties in key planning assumptions and their impacts on the system portfolio. For each sensitivity case, E3 varied one or more inputs from the Least-Cost case and reoptimized for the period 2025-2045 to determine a new optimal portfolio. Sensitivity cases analyzed in this study include different assumptions for load growth, demand-side resource growth, gas resource availability, fuel prices, carbon pricing, renewable and storage technology costs, and carbon reduction targets.

Among the sensitivities, the most significant deviation from the portfolio of the Least-Cost case occurs in the cases with more stringent carbon reduction targets. At lower carbon reduction targets, the changes to the portfolio and the impacts to cost are small. As the carbon reduction target approaches 100% by 2040, the changes are more significant. For example, to achieve a 100% carbon reduction target by 2040 relying only on renewable and storage resources, El Paso Electric must build significant amounts of renewable and storage resources to eliminate all carbon emissions while ensuring reliability. The rate impact in 2040 for this sensitivity is 5.8 ₵/kWh. If El Paso Electric can utilize turbines fueled by green hydrogen as a zero-carbon resource, then the rate impact drops to 1.2₵/kWh as less renewable and storage resources are needed to achieve the same carbon reduction and reliability levels.

Key Findings

The following are key findings in this study:

+ For the El Paso Electric system, a PRM of 10% is needed to ensure a 2-day-in-10-year reliability standard, or 0.2 LOLE, in 2025. A PRM of 13% is needed to ensure a 1-day-in-10-year reliability standard, or 0.1 LOLE, in 2030 and beyond.

+ Storage, renewable, and demand response resources can contribute meaningfully toward the PRM requirement, but their contributions decline as their penetration levels increase. Solar can mitigate ELCC declines for storage, and vice versa, as the two resources can together help meet daytime and nighttime reliability needs.

+ Solar and storage resources account for the largest share of resource additions in optimal long-term resource portfolios. Solar is a low-cost resource, while storage helps with integrating solar resources and meeting nighttime energy needs. Wind, demand response, and gas resource additions also contribute to future system needs.

+ Different approaches to modeling the New Mexico REA result in different portfolios and costs to New Mexico customers. Across the three approaches analyzed in this study, separate system planning results in the biggest rate impact to New Mexico customers because they do not reap the benefits of balancing loads and resources within a larger planned system. The Least-Cost + REA case has a much smaller impact and, unlike the Least-Cost case, does not allocate any new gas resource costs to New Mexico customers.

+ Without the option to add new firm zero-carbon resources, such as plants that burn green hydrogen, achieving deep decarbonization levels beyond state policy requires significant overbuilds of renewable and storage resources, resulting in a high impact on total cost and customer rates.

1 Introduction

1.1 Purpose of Study

In this study, E3 performed analysis to support El Paso Electric's 2021 Integrated Resource Plan (IRP) filing. E3 utilized its proprietary modeling software in combination with E3-developed inputs and inputs provided by El Paso Electric to identify optimal long-term resource portfolios. El Paso Electric utilized these portfolio results directly in its IRP filing.

1.2 Scope of Analysis

In this study, E3 performed four analyses:

4. **Planning reserve margin (PRM)** – Quantification of the PRM that is required to maintain resource adequacy and ensure reliability for the system.
5. **Effective load carrying capability (ELCC)** – Quantification of the contribution of resources – both existing and new – toward the PRM requirement for ensuring reliability.
6. **Portfolio analysis** – Identification of long-term resource additions that minimize cost while ensuring reliability and satisfying New Mexico and Texas clean energy requirements.
7. **Sensitivity analysis** – Assessment of changes to the portfolio that would result from changes to key planning assumption.

The PRM and ELCC results feed directly into the resource portfolio analyses and serve as the basis for ensuring resource adequacy.

1.3 Resource Adequacy

The ability to provide reliable electric service is a fundamental requirement for utilities. Electricity permeates modern society, providing essential services throughout all sectors of the economy. When the reliability of an electric system is compromised, the consequences can be dire. The outages in Texas that occurred in February 2021 provide a powerful example of how failure to maintain reliability can impose significant costs on society and, in extreme cases, result in loss of life. "Resource adequacy" is the ability of an electric power system's resources – including generation, storage, and demand response – to serve load across a broad range of weather and system operating conditions, subject to a long-run reliability standard.

No electricity system is perfectly reliable; there is always some chance that generator failures and/or extreme weather conditions impacting supply and demand could compound on one another to result in loss of load. The resource adequacy of a system thus depends on the characteristics of its load – seasonal patterns, weather sensitivity, hourly patterns – as well as its resources – size, dispatchability, outage rates, and other limitations on availability such as the variable and intermittent production of renewable resources. Ensuring an appropriate level of resource adequacy is an important goal for utilities seeking to provide both reliable and affordable service to their customers.

Resource adequacy can be measured using a variety of statistical metrics that describe the expected frequency, duration, and magnitude of loss of load events that may occur when available generation is insufficient to meet system needs. While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so. Today, most utilities in the United States use a “one day in ten year” standard, which allows for up to one day with outages every ten years on average.

1.3.1 Planning Reserve Margin

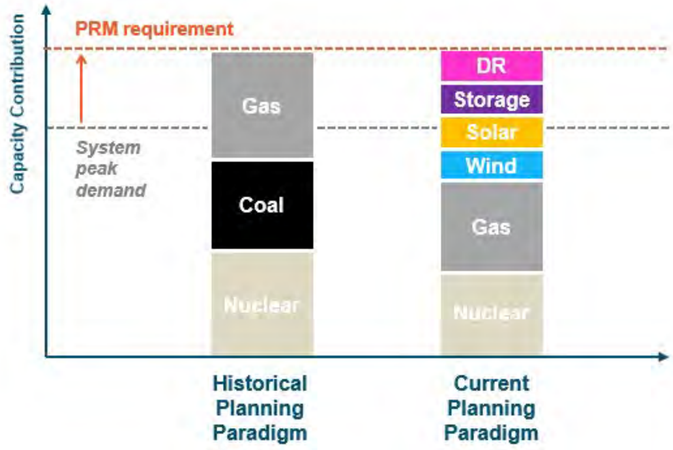
To maintain resource adequacy, most utilities rely on a planning reserve margin (PRM) requirement, which establishes the total need for capacity as a function of the system’s expected peak demand. By maintaining a margin of capacity above expected peak demands, this approach has allowed utilities to supply loads reliably under most circumstances despite the potential for extreme loads, generator outages, and other factors that limit the availability of supply.

PRM requirements currently in use across the industry vary considerably across utilities. While different methods have been used to derive PRM requirements, the industry best practice for resource adequacy is to use a loss of load probability (LOLP) model to determine a system’s PRM requirement so that it is aligned with a statistical standard for reliability. LOLP models simulate the availability of electric supply to meet demand across a broad range of conditions, accounting for factors such as weather-driven load variability, forced outages of power plants, the natural variability of resources like wind and solar PV, and operating constraints for resources like hydro and storage.

1.3.2 Resource Accounting Conventions

Historically, to satisfy the PRM and ensure resource adequacy, most utilities have relied primarily on firm resources – resources that can dispatch when needed and for any duration of time. However, utilities are increasingly adding and relying on dispatch-limited resources – such as solar, wind, energy storage – whose ability to generate varies based on time of day, season, state of charge, or other factors. As a result, the capacity contributions of these resources towards resource adequacy requirements are typically lower than traditional firm resources. Figure 1-1 shows the shift in planning paradigm from one that relies predominantly on firm resources to one that relies increasingly on dispatch-limited resources. Regardless of the paradigm, the contribution of resources toward the PRM, or their capacity contribution, must be sufficient to ensure resource adequacy.

Figure 1-1. Illustrative Industry Planning Paradigm for Planning Reserve Margin



Utilities and other planning entities use different conventions for determining the capacity contribution of resources toward the PRM:

+ **Dispatch-limited resources:**
    - **1) Effective load carrying capability:** The capacity contribution is determined based on rigorous loss-of-load probability modeling, as described in Section 1.3.3. This metric is the most accurate measure of a resource's contribution to the PRM.
    - **2) Other metrics:** The capacity contribution is based on other metrics, which are less accurate than the effective load carrying capability method.
+ **Firm resources:**
    - **1) Effective load carrying capability:** The capacity contribution is determined based on rigorous loss-of-load probability modeling, as described in Section 1.3.3. Because of forced outage rates, the capacity contribution is less than the rated capacity of the resource.
    - **2) Rated capacity:** The capacity contribution is equivalent to the rated capacity of the resource.

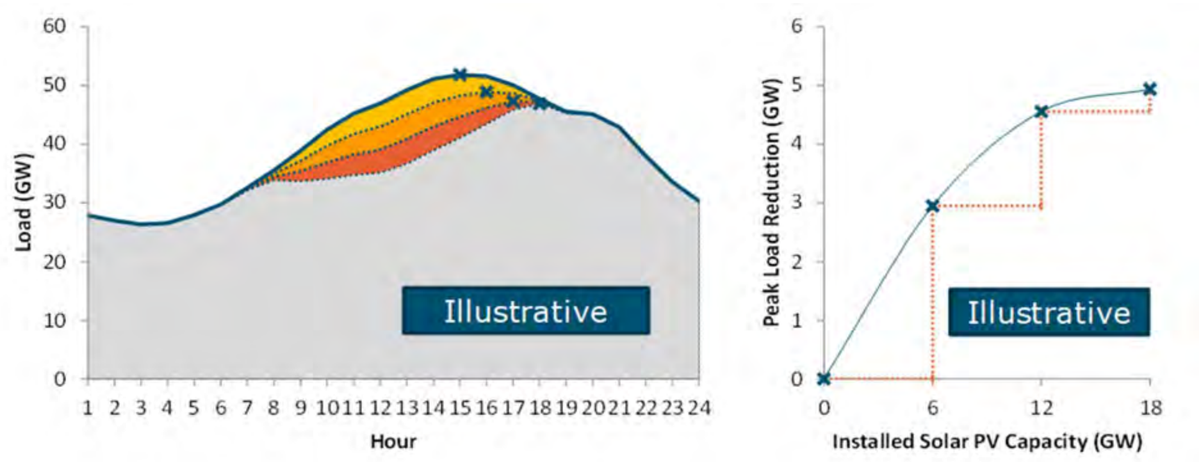
For dispatch-limited resources, the effective load carrying capability is the most accurate way to quantify the capacity contribution. For firm resources, there are two options for determining the capacity contribution: effective load carrying capability and rated capacity. If firm resources are counted toward the PRM based on their effective load carrying capability, then the PRM that satisfies the reliability target is considered a perfect capacity (PCAP) PRM. If firm resources are counted toward the PRM based on their rated capacity, then the PRM that satisfies the reliability target is considered an installed capacity (ICAP) PRM. Both PRM accounting conventions are valid and will result in the same level of resource adequacy if the PRM is calculated based on the reliability target. The only difference is how firm resources are counted toward the PRM. The PCAP PRM is lower than the ICAP PRM, but under the PCAP PRM accounting convention, firm resources' capacity contributions are lower than their rated capacities. This study utilizes the PCAP PRM accounting convention.[1]

1.3.3 Effective Load Carrying Capability

The contribution of dispatch-limited resources towards a utility's resource adequacy needs is typically less than their full operating capacity. For variable renewable resources like wind and solar, this occurs because their output is variable, and their capability to generate at the times needed for resource adequacy is typically less than their rated capacity. For energy storage, the "duration" – a measure of the amount of time a storage device can discharge at full capacity before its state of charge is exhausted – may limit its ability to produce power when needed. Demand response programs typically have similar limitations on the duration of calls, as well as on the number of calls. Evaluating the extent to which these resources can contribute to resource adequacy therefore requires a rigorous analytical framework that properly captures their limitations and performance characteristics. This framework must account for two key dynamics that impact the capacity contributions of these resources.

First, the capacity contributions of a specific resource type tend to diminish with increasing levels of penetration. Figure illustrates this phenomenon by plotting the effect of increasing levels of solar PV production on the "net peak" demand – gross load less dispatch-limited resources. While the first increments of solar PV provide significant capacity value because of their coincidence with peak demand, at high penetrations, the net peak shifts into the early evening when the sun is setting or has already set, such that further additions provide little to no incremental capacity value to the system.

Figure 1-2. Illustrative Example of Solar PV Ability to Reduce Net Peak Load[2]

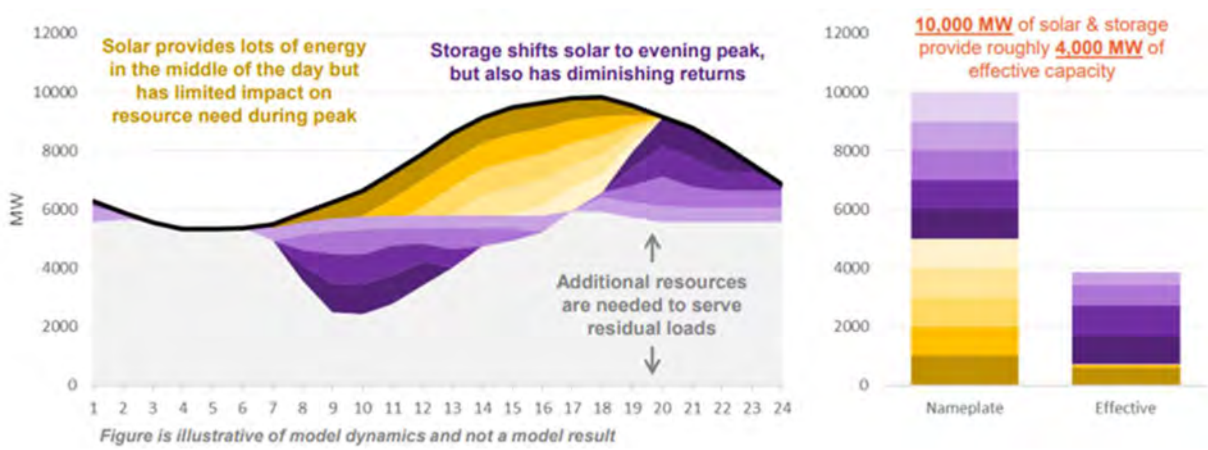


Second, the contribution of a resource towards system resource adequacy depends on the characteristics of the other resources in the portfolio; that is, resources have interactive effects with one another such

[1] While the study utilizes the PCAP PRM convention, it is straightforward to convert the resulting PCAP PRM to an ICAP PRM.
[2] This example is illustrative and does not reflect El Paso Electric data.

that a portfolio of resources may provide a capacity contribution that is greater than (or smaller than) the sum of its parts. Figure illustrates this phenomenon for a portfolio comprising solar PV and storage resources. In this example, the combined portfolio of solar PV and storage provide a larger reduction in the net peak demand of the system due to their synergistic interactive effects; the solar production during the day effectively narrows the breadth of the net peak, allowing more efficient use of the energy storage. The synergistic interactive effects are sometimes referred to as "diversity benefit" because the diverse characteristics results in a greater contribution to resource adequacy

Figure 1-3. Illustration of Diversity Benefit from Addition of Solar and Storage Resources[2]



To account for these complex and interactive dynamics, this study relies on effective load carrying capability (ELCC) to quantify the contributions of various dispatch-limited resources towards El Paso Electric's PRM requirement. The ELCC method is increasingly becoming the industry standard, especially in systems with high levels of dispatch-limited resources. ELCC is defined as the quantity of "perfect" capacity that could be replaced or avoided by a non-firm resource while providing equivalent system reliability. For example, an ELCC value of 50% would mean that the addition of 100 MW of a variable resource could displace the need for 50 MW of perfect capacity without an impact on reliability.

Accurately quantifying ELCC values requires the use of loss-of-load-probability (LOLP) models, which simulate the balance of available supply and demand across a broad range of weather conditions to ensure that the modeling appropriately captures the performance of resources during periods of system stress, including capturing the effects of any correlations (positive or negative) that might exist between dispatch-limited resource production and load.

1.4 Organization of Report

The remainder of the report is organized as follows:

- Section 2 describes the methodology for the analyses;
- Section 3 details the load and resources assumptions that are utilized;

- Section 4 provides the results of the PRM analysis;
- Section 5 provides the results of the ELCC analysis;
- Section 6 provides the results of the portfolio analysis; and
- Section 7 provides the results of the sensitivity analysis.

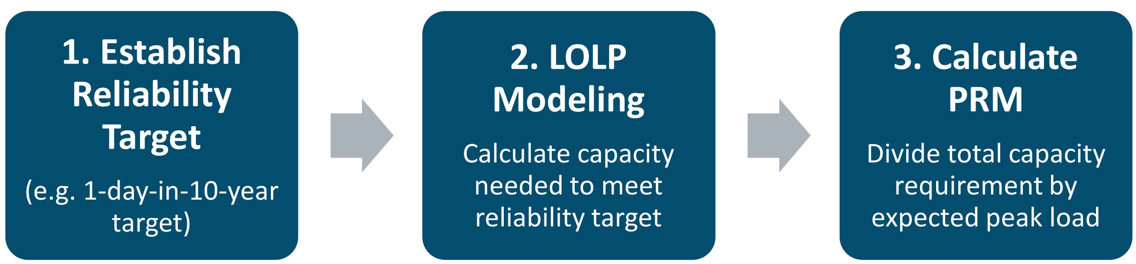
2 Methodology

This section describes the methodology for the Planning Reserve Margin, Effective Load Carrying Capability, and Resource Portfolio Optimization analyses. Each subsection describes the methodology, inputs, and outputs for the analyses.

2.1 Planning Reserve Margin

E3 calculated the planning reserve margin (PRM) for El Paso Electric in two years: 2025 and 2030. The planning margin ensures that, if satisfied, the El Paso Electric system can ensure reliability, subject to a reliability target. Figure 2-1 shows the steps for calculating the PRM, and the following sections describe each step in detail.

Figure 2-1. PRM Calculation Steps



2.1.1 Reliability Target

El Paso Electric has directed E3 to utilize a 2-day-in-10-year reliability target for 2025 in the near term and to utilize a 1-day-in-10-year reliability target for 2030 and beyond. The 2-day-in-10-year reliability target means that, on average, there can only be two days with outage events every ten years. This corresponds to a 0.2 loss-of-load expectation (LOLE). The 1-day-in-10-year reliability target means that, on average, there can only be on day with outage events every ten years and corresponds to 0.1 LOLE. Transitioning from a target of 0.2 LOLE in 2025 to a target of 0.1 LOLE in 2030 allows for a gradual shift toward the more stringent target.

While there is no universal reliability target in use throughout the industry, the most common target utilized by utilities and program administrators in North America is the 1-day-in-10-year standard, or 0.1 LOLE. Table 2-1 shows a survey of reliability targets used throughout the industry.

Table 2-1. Survey of Reliability Targets Used by Utilities and Grid Operators

Utility	Reliability Metric	Reliability Target
Arizona Public Service Co	LOLE	0.1 days/yr
Duke Energy Carolinas	LOLE	0.1 days/yr
Duke Energy Progress	LOLE	0.1 days/yr
Nova Scotia Power, Inc.	LOLE	0.1 days/yr
Portland General Electric	LOLH[3]	2.4 hours/yr
Public Service Company of New Mexico[4]	LOLE	0.2 days/yr
Public Service Company of Colorado	LOLE	0.1 days/yr
Puget Sound Energy	LOLP[5]	5% per yr
ISO/RTO/Grid Operator	**Reliability Metric**	**Reliability Target**
Alberta Electric System Operator	EUE[6]	800 MWh/yr (0.0014%)
Electric Reliability Council of Texas[7]	N/A	N/A
Florida Reliability Coordinating Council	LOLE	0.1 days/yr
ISO New England[8]	LOLE	0.1 days/yr
Midcontinent ISO	LOLE	0.1 days/yr
New York ISO[8]	LOLE	0.1 days/yr
PJM[8]	LOLE	0.1 days/yr
Southwest Power Pool	LOLE	0.1 days/yr

2.1.2 Loss-of-Load Probability Modeling

E3 utilized RECAP, a proprietary loss-of-load probability (LOLP) model, to determine the PRM for the El Paso Electric system. RECAP simulates the availability of electric supply to meet demand across a broad range of conditions, accounting for factors such as weather-driven variability of electric demand, forced outages of power plants, the natural variability of resources such as wind and solar, and operating constraints for resources like storage and demand response. These simulations determine the likelihood and magnitude of loss of load – energy demand that cannot be served – and provide the basis for calculating the PRM.

RECAP simulates hundreds of "years" of potential conditions using stochastic techniques to appropriately capture the risk of tail events (e.g., higher load and lower renewable output than expected).[9] RECAP

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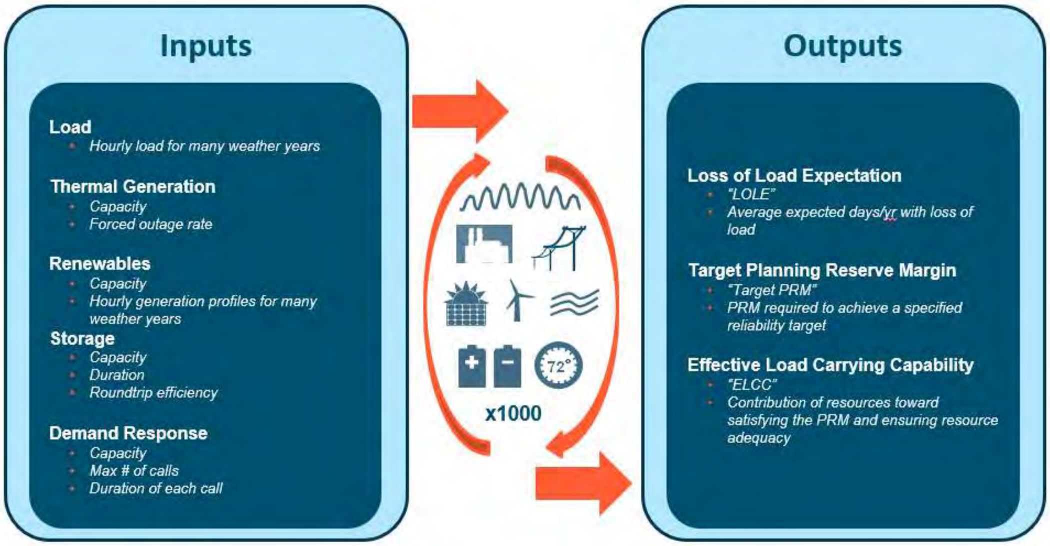
3 Loss-of-load hours (LOLH) corresponds to the expected number of hours per year that system needs exceed available generation.
4 PNM recently indicated its future intention to shift towards a standard of 0.1 days per year in a recent filing.
5 Loss-of-load probability (LOLP) corresponds to the probability that system needs exceed available generation over the course of a year.
6 Expected unserved energy (EUE) corresponds to the expected total quantity of unserved energy (MWh) over a year due to system needs exceeding available generation.
7 ERCOT has eschewed a formal standard for resource adequacy and instead relies upon the energy market to provide a competitive market pricing signal for resource adequacy
8 In jurisdictions with centralized capacity markets, the reliability standard is used to calibrate a PRM target, which is subsequently used as the basis for the creation of a demand curve for capacity.
9 In this approach, each "year" represents a different realization of conditions on the El Paso Electric system over the course of a year. Factors that will vary from one "year" to the next include underlying weather patterns – and by extension, load and renewable profiles – and the occurrence of power plant outages.

simulates the system[10] each hour of a year and repeats this process thousands of times with different system conditions (see Figure 2-2). This ensures that RECAP captures a wide distribution of potential outcomes, including tail events. Correlations are enforced within the model to ensure linkage among load, weather, and renewable generation conditions, based on historical observations.

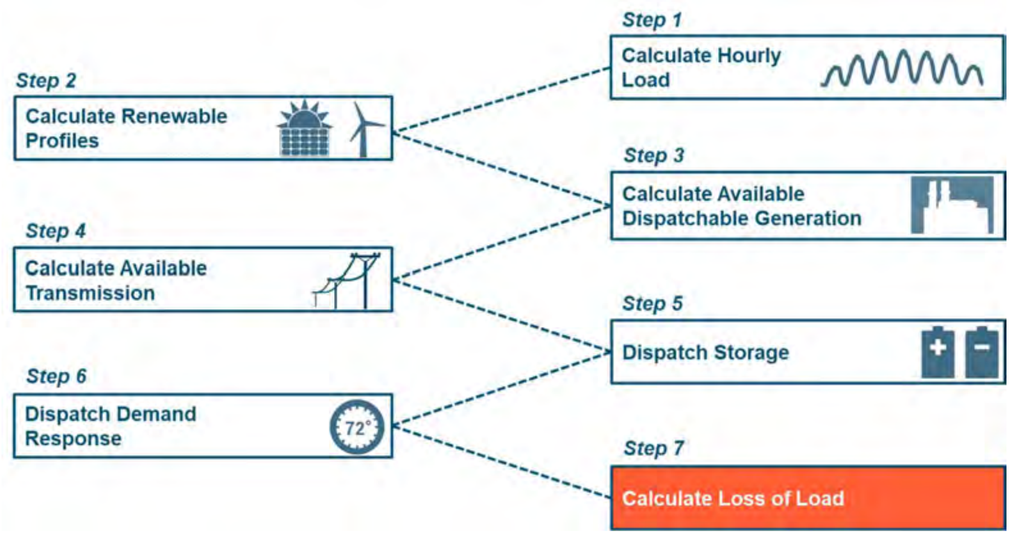
Figure 2-2. RECAP Model Overview



For each simulation year, RECAP conducts a Monte-Carlo time-sequential simulation of loads, renewable output, and resource availability (see Figure 2-3). Energy storage charges from renewable generation during daytime hours and discharges to meet any residual load. RECAP tracks the state of charge of energy storage resources to ensure their operations respect physical limitations. Demand response resources serve as a last resort and are constrained by limitations on the number and durations of calls. If there is a period during which the supply of resources is inadequate to meet the load requirement, there is a loss of load event.

[10] RECAP does not simulate the economic dispatch or operations of the electric system but focuses on whether the total available resources is sufficient to meet load. In this respect, RECAP does not provide an economic comparison among different resources but can be used to assess their contributions to resource adequacy.

Figure 2-3. RECAP Simulation Steps



RECAP determines the frequency, duration, and magnitude of loss of load events across all simulation years. RECAP then calculates the loss of load expectation (LOLE), which is the expected number of days per year on which resources would be insufficient to meet loads.

2.1.3 Planning Reserve Margin Calculation

The results of RECAP can also be translated into a simpler and more widely used PRM requirement, a target for system reliability expressed as a percentage requirement above expected peak demand. PRM requirements are used by many utilities and independent system operators (ISOs) in their administration of resource adequacy requirements. Thus, RECAP also expresses its outputs in terms of the PRM:

- The achieved PRM of a system is calculated based on the summation of capacity provided by all resources; in this study, all resources are rated based on their effective load carrying capability (ELCC), as further described in Section 2.2. This total amount of capacity is divided by the expected peak to determine the PRM of the system.
- The PRM requirement of a system (i.e., the PRM needed to achieve the reliability target) is calculated by adding or removing generic perfect capacity resources[11] to the system as needed to achieve the desired reliability target. The PRM for this adjusted system then represents the reserve margin needed to meet the reliability target.

[11] "Perfect capacity" describes a hypothetical resource that is available at full capacity all hours of the year. While no resource is truly perfect, this hypothetical resource provides a useful benchmark against which to measure the capacity value of real-world resources.

2.1.4 Model Inputs

Table 2-2 lists the inputs that are utilized in the PRM study and where the inputs are described in more detail in this report.

Table 2-2. Inputs for the PRM Study

Input Category	Input	Section with Additional Detail
Load	Load forecast (2021-2040)	Section 3.1
	Historical hourly load (2010-2019)	Section 4.1
	Operating reserve requirements	Section 4.2
Weather	Historical temperature data (1950-2019)	Section 4.1

2.1.5 Model Outputs

The primary outputs from the PRM study are the following:

- PRM requirement in 2025 that, if met, satisfies the reliability target of 0.2 LOLE
- PRM requirement in 2030 that, if met, satisfies the reliability target of 0.1 LOLE

2.2 Effective Load Carrying Capability

E3 evaluated the effective load carrying capability (ELCC) for several resource types. The ELCC determines how much a particular resource or set of resources can contribute to the PRM for ensuring resource adequacy. The ELCC for a particular resource (or set of resources) is calculated through a three-part process (see Figure 2-4):

1. The system is simulated without the specified resource in RECAP to determine the LOLE of the system. If the resulting LOLE does not match the specified reliability target, the system is "adjusted" to meet the target reliability standard (e.g., 0.1 days/yr). This adjustment occurs through the addition (or removal) of a perfect capacity resource[12] to achieve the desired reliability standard.
2. The specified resource is added to the system and the LOLE is recalculated. This will result in a reduction in the system's LOLE, as the amount of available capacity has increased.
3. Perfect capacity resources are removed from the system until the LOLE returns to the specified reliability target. The amount of perfect capacity removed from the system represents the ELCC of the specified resource (measured in MW); this metric can also be translated to a percentage value by dividing by the installed capacity of the specified resource.

[12] A perfect capacity resource is a resource that can generate on demand and has no forced outage rate. In this study, it is used as a placeholder and is used to calculate the ELCC for dispatch-limited resources.

Figure 2-4. Iterative Approach to Determining Effective Load Carrying Capability

This methodology ensures that the ELCC of a resource corresponds to its contribution towards resource adequacy. By simulating the EPE system across a wide range of potential system conditions, RECAP captures the limitations of dispatch-limited resources and quantifies their contribution towards resource adequacy by measuring their substitutability for perfect capacity.

The following sections describe the methodology undertaken for different resources, as well as the model inputs and outputs.

2.2.1 Dispatch-Limited Resources

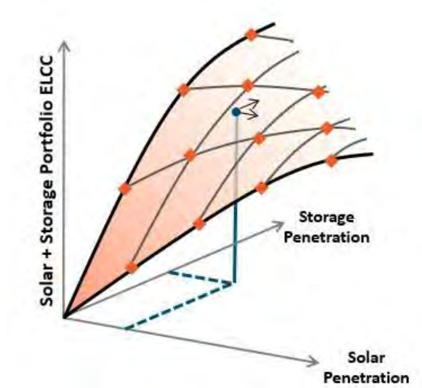
As discussed in Section 1.3.3, the ELCC of dispatch-limited resources depends on the penetration level of the resource within the portfolio. With each addition of a particular type of resource, the total ELCC in MW (or capacity contribution) increases, but the incremental ELCC from each successive addition decreases. To account for this effect, E3 calculated the ELCC for multiple tranches of each dispatch limited resource – solar PV, storage, wind, geothermal and demand response. E3 selected tranches such that the ELCC results span a wide range of penetration levels for each resource.

2.2.2 Surface for Solar and Storage

As discussed in Section 1.3.3, the ELCC of dispatch-limited resources depends on the penetration levels of other resources within the portfolio and some resources may have synergistic interactive effects or diversity value when added to the system together. Solar PV and storage in particular can have a meaningful diversity benefit at higher penetration levels. To account for this effect, E3 calculated an ELCC surface for solar and storage.

Figure illustrates the ELCC surface for solar and storage conceptually, where the x-axis and y-axis correspond to solar and storage capacity and the z-axis corresponds to the total ELCC in MW. E3 calculated the ELCC for various penetration levels of solar PV and storage capacity to trace out the surface. Because the two resources are being added together to the system, the ELCC captures any diversity benefits.

Figure 2-5. Illustrative Solar and Storage Surface



2.2.3 Thermal Resources

As discussed in Section 1.3.2, this study uses a PCAP as the PRM accounting convention. As a result, thermal resources are counted toward the PRM based on their ELCC. Because thermal resources have forced outages, the ELCC is less than 100%. To quantify the ELCC of thermal resources, E3 followed the same three-step process described above.

2.2.4 Model Inputs

Table 2-3 lists the inputs that are utilized in the ELCC study and where the inputs are described in more detail in this report.

Table 2-3. Inputs for the ELCC Study

Category	Input	Location in Report
Load	Load forecast (2030)	Section 3.1
	Historical hourly load (2010-2019)	Section 4.1
	Operating reserve requirements	Section 4.2
Weather	Historical temperature data (1950-2019)	Section 4.1
Thermal Resources	Net dependable capacity	Sections 3.2 & 3.3
	Forced outage rate	Section 5.2
Renewable Resources	Nameplate capacity	Sections 3.2 & 3.3
	Historical hourly solar insolation and wind speed data for locations	Section 3.4
	Hourly generation profile for geothermal resources	Section 3.4.3
Energy Storage Resources	Nameplate capacity (charge & discharge)	Section 3.3
	Roundtrip efficiency	Section 3.5.1
	Duration (hours)	Section 3.5.1
Demand Response	Maximum capacity	Section 3.5.3
	Maximum # of calls per week/month/year	Section 3.5.3
	Maximum duration of each call	Section 3.5.3

2.2.5 Model Outputs

The ELCC study quantifies the ELCC for the following resources:

+ Solar PV
+ Storage
+ Geothermal
+ Wind
+ Demand Response
+ Thermal Resources

The ELCC for all of these resources, except for thermal resources, depends on the penetration level of the resource (i.e., how much capacity there is relative to load). E3 quantified the ELCC for resources in 2030, but the load conditions are different in other years. At higher load levels in future years, for a given capacity level of a resource, the ELCC of that resource would be slightly higher because its penetration is slightly lower relative to 2030 conditions. E3 accounts for this effect by adjusting the ELCC of resources based on changes in load relative to 2030 conditions.

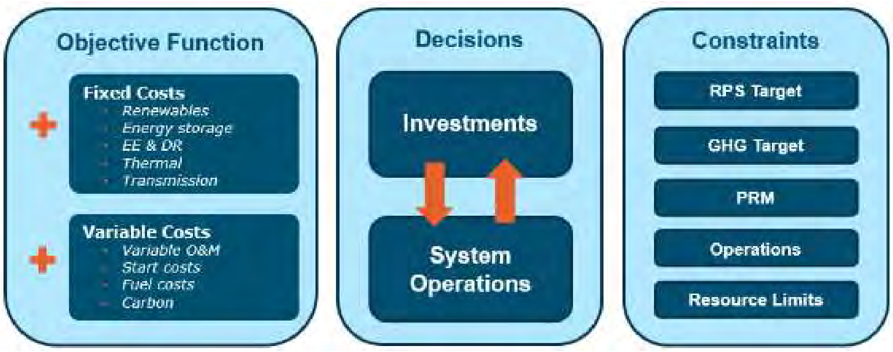
2.3 Resource Portfolio Optimization

2.3.1 Resource Portfolio Optimization

E3 performed resource portfolio optimization in this study using its RESOLVE model. RESOLVE is an electricity system capacity expansion model that identifies economically optimal long-term generation and transmission investments subject to reliability, technical, and policy constraints. RESOLVE considers both the fixed and operational costs of different portfolios over the lifetime of the resources and is specifically designed to simulate power systems operating under high penetrations of renewable energy and electric energy storage. By co-optimizing investment and operations decisions in one stage, the model directly captures dynamic trade-offs between them, such as energy storage investments vs. renewable curtailment/overbuild. The model uses weather-matched load and renewable data and simulates interconnection-wide operations over a representative set of sample days in each year. The model captures the dynamic contribution of renewable and energy storage resources to the system that vary as a function of their penetration, specifically in terms of capacity requirements toward the planning reserve margin.

Figure provides an overview of the RESOLVE model including the objective function, key model decisions and the constraints imposed.

Figure 2-6. Overview of the RESOLVE Model



2.3.2 Objective Function

The objective function minimizes net present value (NPV) of electricity system costs over the planning horizon,[13] which is the sum of fixed costs and variable costs, subject to various constraints. Fixed costs include both the investment costs of new generation and storage resources, associated transmission costs required with the generation resources, as well as fixed operating and maintenance costs of new and existing resources. Variable costs comprise variable operating and maintenance costs and fuel costs, including start costs.

2.3.3 Operations Module

For the representative set of sample days each year, hourly operations are simulated through economic dispatch of existing and new resources in order to meet load. The dispatch logic depends on the type of resource. Solar and wind resources have fixed generation profiles based on the resource location and have the ability to be curtailed when total generation exceeds load. Most thermal resources like natural gas turbines are operated flexibly while meeting operating constraints such as minimum generation level, maximum ramp rate, minimum up and down time. Palo Verde Nuclear Generating Station is modeled as a baseload resource, generating power at its nameplate capacity during all hours except during planned

[13] This study has a planning horizon of 2021-2045. This twenty-five-year period captures the 2045 requirement for zero-carbon energy in the New Mexico Renewable Energy Act (REA).

outages for refueling. Energy storage resources like batteries increase load when charging and can serve load when discharging, maintaining charge parity over each sample day.

2.3.4 Constraints

RESOLVE layers investment decisions on top of the operational model described above. Each new investment identified in RESOLVE has an impact on how the system operates; the portfolio of investments, as a whole, must satisfy a number of additional conditions.

+ **Planning reserve margin (PRM)**: When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet the annual system peak load plus an additional specified amount of PRM requirement. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted more compared to thermal generations because the uncertainties of generation during peak hours.

+ **Renewables Portfolio Standard (RPS) requirements:** RESOLVE enforces an RPS requirement as a percentage of retail sales to ensure that the total quantity of energy procured from renewable resources meets the RPS target in each year. RESOLVE has the ability to flag which resources can contribute to an RPS requirement, which enables policies like a Clean Energy Standard (CES), where nuclear resources are eligible to contribute to the target, to be modeled. Note that the RPS or CES requirement does not apply to all the cases modeled.

+ **Greenhouse gas emissions cap**: RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio. As the name suggests, the emission cap type policy requires that annual emissions generated in the entire system be less than or equal to the designed maximum emissions cap. In its most extreme form, a greenhouse cap at zero emissions would preclude all power-sector emissions, though some “zero-emission” fuels such as hydrogen still qualify. Note that the greenhouse gas cap does not apply to all the cases modeled.

2.3.5 Day Sampling

Computation can be challenging for a model like RESOLVE that makes both investment and operational decisions across a long period of time. To alleviate this challenge, instead of simulating the system operation for an entire year, a subset of days is modeled to approximate the annual operating costs. In order to approximate the annual system operating costs while simulating only a subset of the number of days in a year, RESOLVE relies on a pre-processing sampling algorithm to select a combination of days whose characteristics are, together, representative of the conditions experienced by an electricity system over the course of multiple years. This pre-processing step uses optimization to sample a subset of conditions that, when taken in aggregate and weighted appropriately, provide a reasonable representation of the breadth of load, wind, and solar conditions observed in the historical record. A multi-objective optimization model is used to pick a set of days (and associated weights) to match historical conditions for key indicators while also minimizing the number of days selected. The process for selecting the set of representative days follows several steps:

1. **The candidate pool of days is created:** Load, wind, and solar profiles are sampled from historical timeseries data as a representative sample of shapes. Load data was gathered from El Paso Electric, while wind and solar data were gathered from National Renewable Energy Laboratory (NREL) databases.
2. **Key variables are selected as indicators of system conditions:** In this study, the variables used to characterize the representation of a sample include: (1) distributions of hourly load, wind and solar production; (2) 2030 hypothetical net load; and (3) "month-day type" classification (i.e., January-weekday). This study prioritizes fit on the distributions for future load, wind, solar, and net load conditions, as these factors have a significant effect on the operations of the electric system.
3. **Optimization model selects an optimal set of days:** From the candidate pool of days established in the first step, the optimization selects a set of days while minimizing the absolute errors for each of the criteria. If optional day types have been assigned by the user, the day selection algorithm will attempt to select at least one of each day type in the final sample. In this case, the day type was defined as "month-day type" (i.e., January-weekday) with some days denoted as a peak day. The output from the optimization algorithm includes a set of days, as well as associated weights through which those days may be weighted to represent a historic average year. An optimization model is used in the day sampling process.

2.3.6 Scenarios

The complete list of scenarios modeled in RESOLVE is summarized in Table 2-4.

Table 2-4. List of Scenarios

Scenario	Description
Least-Cost (Reference Case)	Least-cost optimization used as reference case for all sensitivities
Least-Cost Case + REA Resources[14]	Additional resources added to Least-Cost Case for New Mexico REA
Separate System Planning	New Mexico system planned separately for purposes of satisfying REA
80% Clean by 2035	80% zero-carbon energy
20% GHG Reduction by 2040	20% reduction in greenhouse gas emissions
40% GHG Reduction by 2040	40% reduction in greenhouse gas emissions
60% GHG Reduction by 2040	60% reduction in greenhouse gas emissions
80% GHG Reduction by 2040	80% reduction in greenhouse gas emissions
90% GHG Reduction by 2040	90% reduction in greenhouse gas emissions
100% GHG Reduction by 2040	100% reduction in greenhouse gas emissions
100% GHG Reduction by 2040 (w/ H_2)	100% reduction in greenhouse gas emissions with hydrogen
Low Load Growth	3-4% higher native system load forecast
High Load Growth	3-4% lower native system load forecast
High Distributed Generation (DG)	High DG forecast
High Demand-Side Management (DSM)	More smart thermostats, doubling of energy efficiency
No New Gas	No new gas after Newman 6
No Lifetime Extensions	All plants retire as scheduled
High Gas Price	Gas prices 15% higher
Low Carbon Price	$8 per metric ton of carbon dioxide in 2010, rising at 2.5% per year
Mid Carbon Price	$20 per metric ton of carbon dioxide in 2010, rising at 2.5% per year
High Carbon Price	$40 per metric ton of carbon dioxide in 2010, rising at 2.5% per year
Low Technology Cost	Lower technology cost declines for renewable and storage resources

2.3.7 Model Inputs

Table 2-5 lists the inputs that are utilized in the resource portfolio optimization study and where the inputs are described in more detail in this report.

[14] The Least-Cost case has enough renewable energy to satisfy the renewable energy requirements for customers in the Texas jurisdiction. As a result, this case does not need to add additional resources for the purpose of satisfying Texas renewable energy requirements.

Table 2-5. Inputs for the Resource Portfolio Optimization Study

Input	Location in Report
Load	Section 3.1
Existing Resources	Section 3.2
Planned Resources	Section 3.3
Candidate Resources	Sections 3.4 and 3.5
Transmission	Section 3.6
Planning Reserve Margin	Section 4.3
Effective Load Carrying Capability	Section 5
Candidate Resource Costs	Section 8
Fuel Prices	Appendix B: Price Assumptions
Market Prices	Appendix B: Price Assumptions

2.3.8 Model Outputs

RESOLVE produces many results, from technology level unit commitment decisions to total carbon emission in the system. This extensive information gives users a complete view of the future system and makes RESOLVE versatile for different analysis. The following list of outputs is produced by RESOLVE and are the subject of discussion and interpretation in this study:

+ **Total system cost ($/yr):** RESOLVE reports the total annual system costs in the study footprint to provide service to its customers. This study focuses on the relative differences in system costs among scenarios, generally measuring changes in the relative to the Reference case. The cost impacts for each scenario comprise changes in fixed costs (capital and fixed O&M costs for new generation resources, new energy storage devices, and the required transmission resources with the new generation) and operating costs (variable O&M costs and fuel costs).

+ **Greenhouse gas emissions (MMT CO_2):** This result summarizes the total annual carbon emission in the system. By comparing the carbon emissions and total resource costs between different scenarios, we can conclude the relative effectiveness of the strategic measure in enabling carbon reductions.

+ **Resource additions and retirements for each period (MW):** The cumulative additions and retirements by resource type show the optimal strategy to meet future load given any emissions constraints.

+ **Annual generation by resource type (GWh):** Energy balance shows the annual system load and energy produced by each resource type in each modeled year. It provides insights from a different angle than capacity investments. It can help answer questions like: Which types of resources are dispatched more? How do the dispatch behaviors change over the years?

+ **Renewable curtailment (GWh):** RESOLVE estimates the amount of renewable curtailment that would be expected in each year of the analysis as a result of "oversupply"—when the total amount of must-run and renewable generation exceeds regional load plus export capability—

based on its hourly simulation of operations. As the primary renewable integration challenge at high renewable penetrations, this measure is a useful proxy for renewable integration costs.

+ **Market purchases (MW):** RESOLVE estimates hourly market purchases from WECC via Path 47 intertie that are found to be economic in meeting El Paso Electric’s load. Projected wholesale market prices at the Palo Verde hub in WECC are specified exogenously for the snapshot years based on a broader regional analysis of the future western grid using production simulation software.

+ **Average and marginal greenhouse gas abatement cost ($/metric ton):** RESOLVE results can also be used to estimate average and marginal costs of greenhouse gas abatement by comparing the amount of greenhouse gas abatement achieved (relative to a Reference Case) and the incremental cost (relative to that same case).

3 Loads and Resources

This section describes the characteristics of the El Paso Electric system. These characteristics and any associated assumptions serve as the basis for the study results. Loads comprise the sources of energy demand that must be satisfied in the future. Resources encompass various generating resources – existing and new – that can be operated to satisfy energy demand and other system planning requirements. Section 3.1 describes loads. Sections 3.2-3.5 describe resources, including existing, planned, and candidate. Section 3.6 describes transmission.

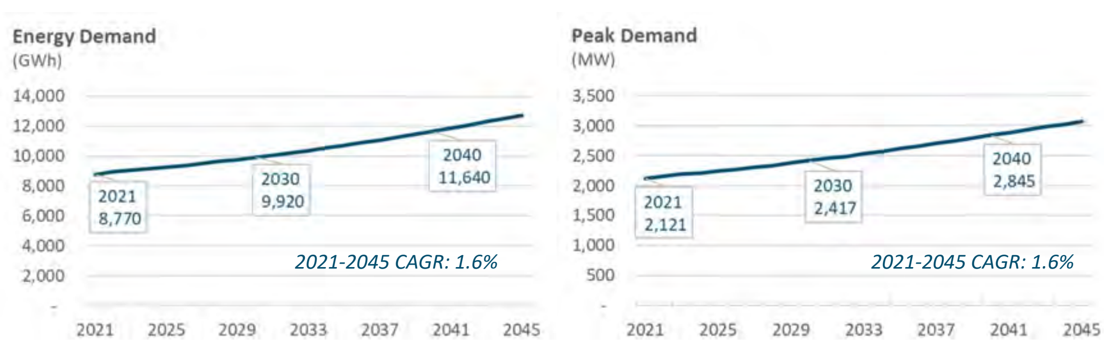
3.1 Loads

This section provides an overview of the load forecast and load profile used in this study. This forecast includes a base load energy forecast, described in Section 3.1.1, and a load forecast for electric light duty vehicles, described in Section 3.1.2.

3.1.1 Base Load Energy Demand

Figure shows the El Paso Electric forecast for annual energy demand and peak demand, excluding electric vehicle loads, which are described in Section 3.1.2. El Paso Electric's load forecast goes through 2040 and is described in more detail in El Paso Electric's IRP. E3 trended the load forecast for an additional five years to extend it through 2045.

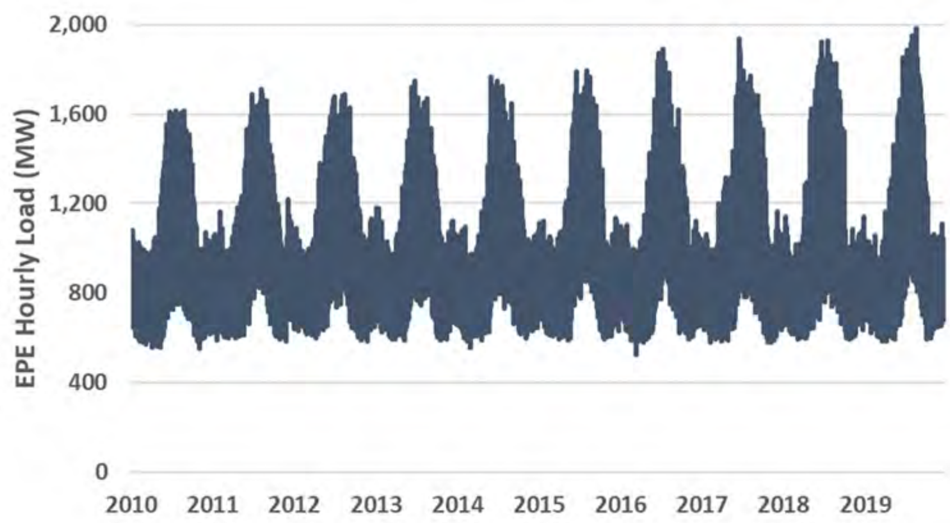
Figure 3-1. El Paso Electric Load Forecast[15]



To create an hourly shape for load that reflects an extended record of system conditions, E3 gathered historical hourly load data from El Paso Electric for the years 2010-2019 (see Figure).

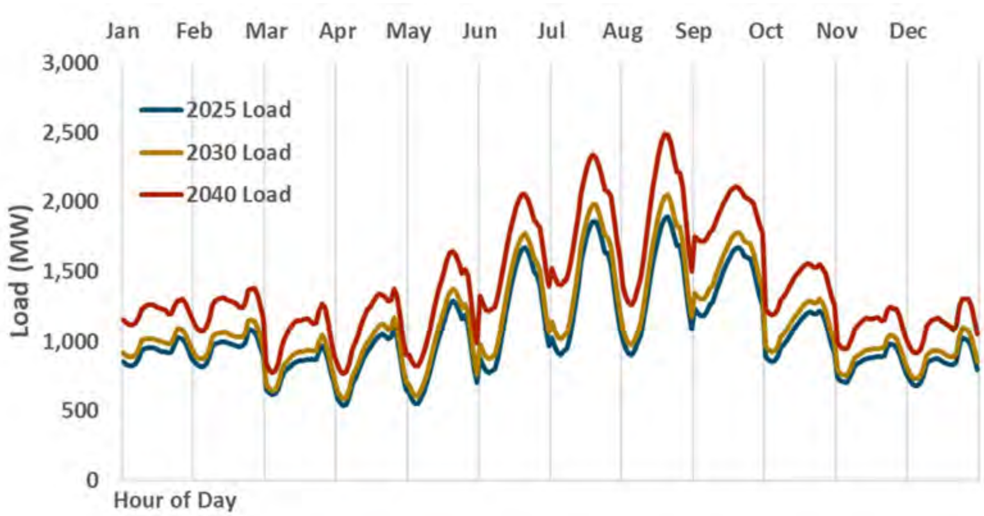
[15] These load forecast charts correspond to native system load, less incremental energy efficiency. In this study, incremental distributed generation is treated as a supply-side resource and thus is not included in these charts.

Figure 3-2. Historical Hourly Load of El Paso Electric from 2010 to 2019



E3 utilized the historical system load data to simulate system load across a range of potential weather conditions, using weather data for 1950-2019. For the analysis period (2021-2045), E3 scaled the simulated load profiles to match El Paso Electric's monthly peak and energy demand forecasts. Figure shows the average daily load profile by month in 2021, 2030, and 2040. Energy demand is significantly higher during summer months when building cooling demand is high.

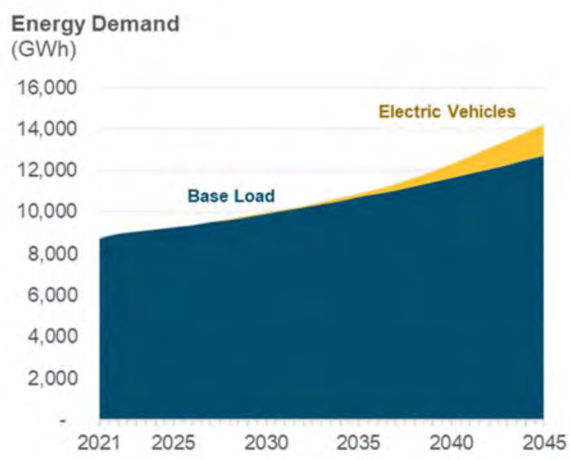
Figure 3-3. Average Daily Load by Month in 2021, 2030, and 2040



3.1.2 Electric Vehicle Energy Demand

Figure 3-4 shows the El Paso Electric forecast for annual energy demand for light duty electric vehicles. El Paso Electric's load forecast goes through 2040 and is described in more detail in El Paso Electric's IRP. E3 trended the load forecast for an additional five years to extend it through 2045.

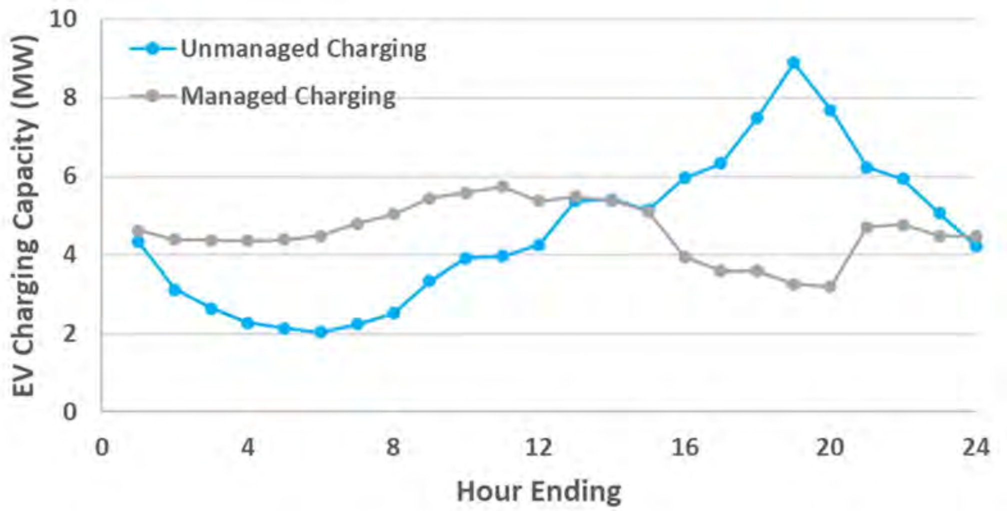
Figure 3-4. El Paso Electric Energy Forecast Including Electric Vehicles[16]



E3 developed a managed charging profile for electric vehicles based on driving data from the National Highway Traffic Safety Administration (NHTSA) and an assumption that time-of-use pricing or other programs would be in place to incentivize most customers to shift electric vehicle charging away from peak load hours. Figure shows the managed charging profile compared with an unmanaged charging profiles for a summery weekday. The unmanaged charging profile assumes that drivers are not sensitive to the price signal or rate schedule and charge their vehicles whenever more charge is needed. The managed charging profile has a much flatter load profile and significantly reduces the impact of electric vehicles on peak demand hours in the late afternoon and early evening.

[16] These load forecast charts correspond to native system load, less incremental energy efficiency. In this study, incremental distributed generation is treated as a supply-side resource and thus is not included in these charts.

Figure 3-5. EV Charging Shape – Summer Weekday in 2030



3.2 Existing Resources

3.2.1 Existing Thermal Resources

Table 3-1 lists El Paso Electric's existing thermal generating resources. El Paso Electric currently has 1,422 MW of natural gas-fired generating capacity and 622 MW of nuclear generating capacity in its resource portfolio.

Table 3-1. Existing Thermal Resources

Resource	Jurisdiction	Fuel	Type	Summer Net Capacity (MW)	COD Year	Planned Retirement Year[17]	Age at Retirement
Rio Grande 6	System	Gas	ST	45	1957	Inactive Reserve[18]	63
Rio Grande 7	System	Gas	ST	46	1958	2022	64
Rio Grande 8	System	Gas	ST	144	1972	2033	61
Rio Grande 9	System	Gas	CT	88	2013	2058	45
Newman 1	System	Gas	ST	73	1960	2022	62
Newman 2	System	Gas	ST	73	1963	2022	59
Newman 3	System	Gas	ST	90	1966	2026	60
Newman 4	System	Gas	2x1 CC	227	1975	2026	51
Newman 5	System	Gas	2x1 CC	266	2009	2061	52
Copper	System	Gas	CT	63	1980	2030	50
Montana 1	System	Gas	CT	88	2015	2060	45
Montana 2	System	Gas	CT	88	2015	2060	45
Montana 3	System	Gas	CT	88	2016	2061	45
Montana 4	System	Gas	CT	88	2016	2061	45
Palo Verde 1	System	Nuclear	ST	207	1986	2045	59
Palo Verde 2	System	Nuclear	ST	208	1986	2046	60
Palo Verde 3	TX[19]	Nuclear	ST	207	1988	2047	59

Five generators are scheduled to retire prior to 2030, including Newman units 1-4 and Rio Grande unit 7. Together, the generating capacity at these units amounts to 509 MW, which is about 25% of today's total thermal generating capacity. For these units, E3 modeled the potential to extend their lifetimes by five years in all scenarios except for one ("No Lifetime Extensions"). There are incremental capital and operations and maintenance (O&M) costs to keep these units online for additional years. These assumptions are listed in Appendix A: Candidate Resource Assumptions.

3.2.2 Existing Renewable Resources

Table 3-2 lists El Paso Electric's existing renewable resources. El Paso Electric currently has 115 MW of solar PV generating capacity in its resource portfolio.

[17] For modeling purposes, E3 assumed that all generators remain online through the end of their planned retirement years.
[18] EPE filed for an application with NMPRC for abandonment on Oct 6, 2020 (Case No. 20-00194-UT). RG 6 is no longer included in EPE Official L&R.
[19] In all cases, no capacity from Palo Verde 3 is assigned to New Mexico jurisdiction customers. Palo Verde 3 is included in the modeling, but it is assumed that it serves Texas jurisdiction customers.

Table 3-2. Existing Renewable Resources

Resource	Resource Type	Nameplate Capacity (MW)	Jurisdiction	Planned Retirement Year[20]
Hatch	Solar	5	NM	2036
Chaparral	Solar	10	NM	2037
Airport	Solar	12	NM	2037
Roadrunner	Solar	20	NM	2031
Macho Springs	Solar	50	System[21]	2034
Newman[22]	Solar	10	TX	2044
Texas Community	Solar	3	TX	2047
Holloman	Solar	5	NM	2048

3.3 Planned Resources

Table 3-3 lists El Paso Electric's planned resources – resources that are either under contract or under development and are expected online. El Paso Electric plans to add 270 MW of solar PV, 50 MW of storage, and 228 MW of natural gas-fired capacity by 2023.

Table 3-3. Planned Resources

Resource	Resource Type	Nameplate Capacity (MW)	Jurisdiction	COD	Planned Retirement Year[23]
Buena Vista Energy Center 1	Solar/Storage	100/50	System[21]	May 2022	2042
Buena Vista Energy Center 2	Solar	20	NM	May 2022	2042
Hecate Energy Santa Teresa 1	Solar	100	System21	Dec. 2022	2042
Hecate Energy Santa Teresa 2	Solar	50	NM	Dec. 2022	2042
Newman 6	Gas Peaker	228	TX[24]	May 2023	2063

3.4 Candidate Renewable Resources

This study considers several renewable resources as future resource addition options, including solar (at nine locations), wind (at three locations), geothermal (at two locations), and biomass. Figure 3-6 shows the levelized costs of these resources. The levelized cost cannot be utilized in isolation as the basis for portfolio selection because it does not account for all costs, including the potential need for distribution and/or transmission upgrades, nor does it account for the benefits of resources, which depend on their

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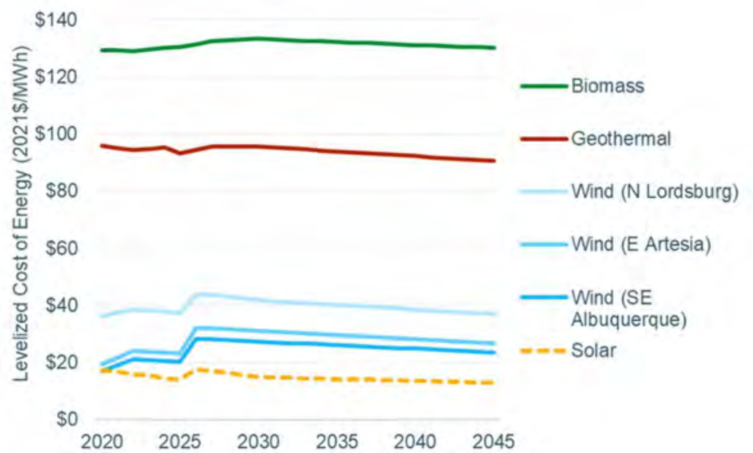
[20] For resources under contract, the retirement year corresponds to the final year of the contract. For modeling purposes, E3 assumed that all generators remain online through the end of their planned retirement years.
[21] System allocation for TX/NM corresponds to approximately 80/20.
[22] Newman Solar allocates 8 MW to Texas and 2 MW to the EPE Community Solar Program.
[23] For resources under contract, the retirement year corresponds to the final year of the contract. For modeling purposes, E3 assumed that all generators remain online through the end of their planned retirement years.
[24] Newman Unit 6 was rejected by the New Mexico Public Regulations Committee. EPE plants to continue permitting and planning for construction of Newman 6 to serve Texas customers' energy demand in 2023 and beyond.

operating characteristics and ability to serve load. The $/kW-yr levelized cost is the direct resource portfolio optimization input for all resources. Resource costs are described in more detail in Appendix A: Candidate Resource Assumptions. The following sections describe each of the candidate renewable resources in more detail.

Figure 3-6. Levelized Cost of Renewable Resources



3.4.1 Solar PV

The study considers candidate solar PV resources in nine different zones, which span a wide geographic area across El Paso Electric's service area. Each zone differs in the hourly profile of solar production, the amount of headroom on the transmission system, and the cost to upgrade transmission to increase headroom. Table 3-4 lists the different zones, and Section 3.6 describes the transmission characteristics of each zone.

Table 3-4. Solar PV Candidate Resource Zones

Resource Zone	State	Coordinates[25]	Capacity Factor[26]
Eastside	TX	(31.7, -106.1)	33.2%
Van Horn	TX	(31.0, -104.8)	31.9%
Holloman	NM	(32.9, -106.0)	32.3%
Santa Teresa	TX	(31.8, -106.7)	33.1%
Hatch	NM	(32.7, -107.2)	32.5%
Luna	NM	(32.3, -107.6)	32.5%
Hidalgo	NM	(32.4, -108.6)	32.7%
Chaparral	NM	(32.1, -106.4)	32.7%
Las Cruces Airport	NM	(32.3, -106.9)	33.0%

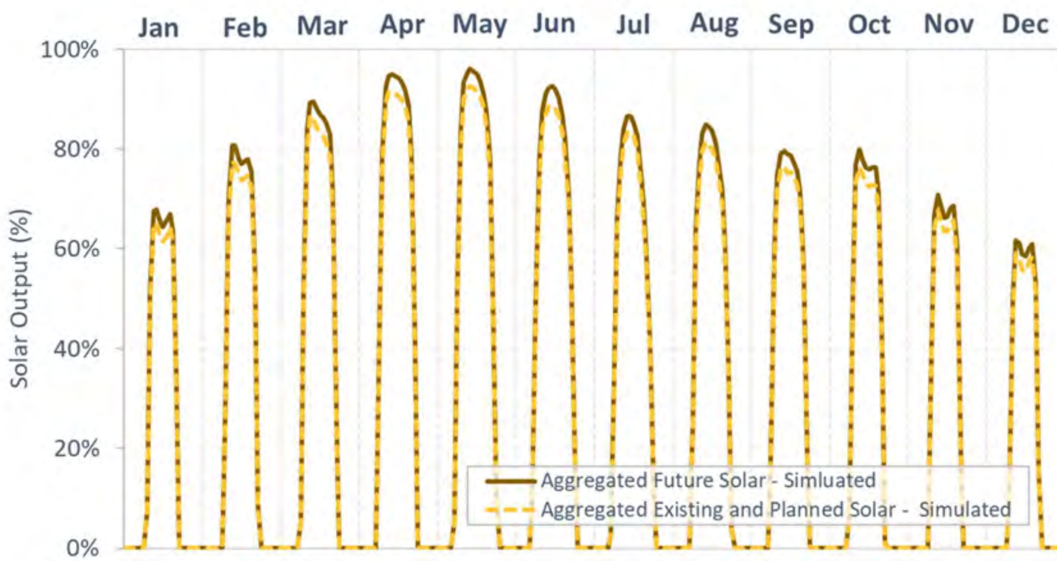
E3 simulated hourly solar generation profiles for each solar PV zone. E3 used hourly insolation data from the National Solar Radiation Database (NSRDB) for the years 2008 to 2018 to create production profiles using the System Advisor Model (SAM) from the National Renewable Energy Laboratory (NREL). SAM produces hourly energy generation using hourly locational insolation and temperature data, PV panel type, tilt, inverter loading ratio, and system characteristics.

The solar production profile for each zone differs hour to hour based on historical weather observations, but the average production profile over the course of a year is similar across the different zones. Figure 3-7. shows the average daily production profile for each month, averaging across the different zonal profiles.

[25] These locations are not meant to represent precise future project locations. The coordinates are used to simulate representative profiles for the corresponding resource zone.

[26] The capacity factor is the ratio of average annual power output, excluding any potential curtailment, to the maximum power output. The capacity factor does not correspond to the ELCC of a resource because the ELCC depends on a resource's ability to reduce loss-of-load events, which depends on the magnitude and timing of a resource's generation.

Figure 3-7. Average Simulated Solar PV Profile by Month



3.4.2 Wind

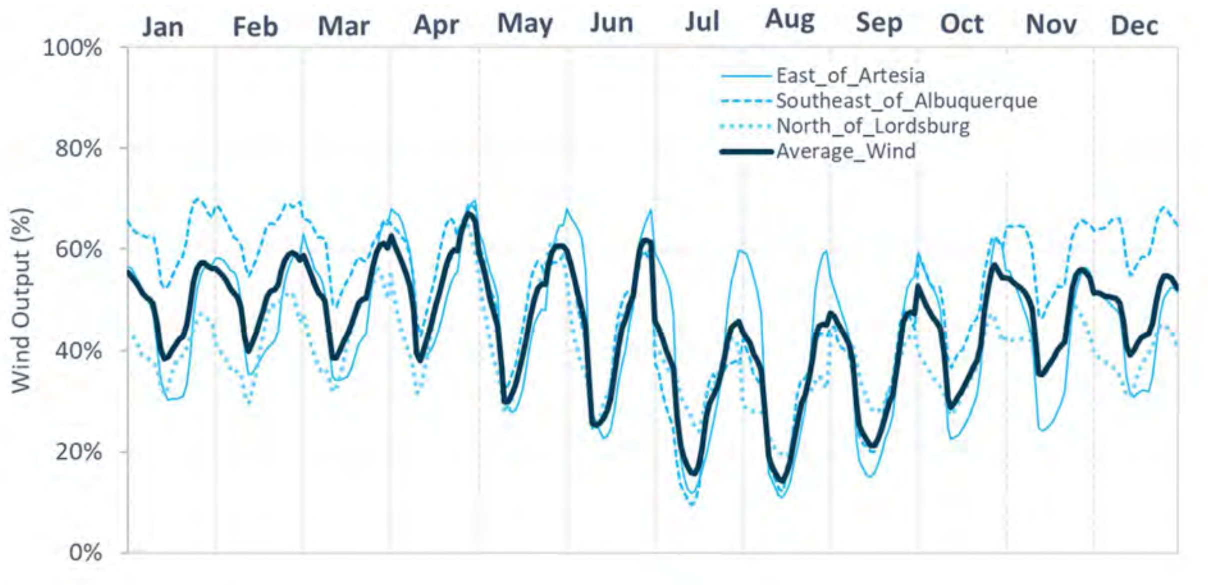
The study considers candidate wind resources in three different zones, which include areas with high-quality wind resources. Each zone differs in the timing and magnitude of wind production. For all wind zones, incremental transmission is needed to deliver the wind energy to El Paso Electric's load centers. Table 3-5 lists the different zones, and Section 3.6 describes the transmission characteristics of each zone.

Table 3-5. Wind Candidate Resource Zones

Resource Zone	State	Coordinates[25]	Capacity Factor[26]
East of Artesia	NM	(33.2, -104.0)	44.1%
North of Lordsburg	NM	(32.3, -107.8)	37.1%
Southeast of Albuquerque	NM	(34.8, -105.2)	50.8%

E3 simulated hourly wind generation profiles for each wind zone. To do this, E3 utilized hourly weather data from the Wind Integration National Dataset Toolkit from NREL for the years 2007 to 2013. The wind production profile for each zone differs hour to hour based on historical weather observations, but the average seasonal and daily patterns are relatively similar across the different zones. Figure shows the average daily production profile for each month, averaging across the different zonal profiles.

Figure 3-8. Average Simulated Wind Profiles by Month



3.4.3 Geothermal

The study considers candidate geothermal resources in two different zones. Table 3-6 lists the different zones, and Section 3.6 describes the transmission characteristics of each zone.

Table 3-6. Geothermal Resource Zones

Resource Zone	State	Capacity Factor[26]
Northwest El Paso	NM	80.0%
Southeast of Albuquerque	NM	80.0%

Figure shows the average daily geothermal production profile for each month. E3 utilized a profile from Black & Veatch's Western Renewable Energy Zones (WREZ) model that corresponds to the production profile expected for geothermal in New Mexico. The profile shows variations by season and time of day. Generation is lower during summer months and during daytime hours when temperatures are higher. This is because the plant's efficiency decreases as temperature increases. The annual capacity factor is 80%.

Figure 3-9. Average Simulated Geothermal Profile by Month

3.4.4 Biomass

The study considers biomass as a candidate resource. A biomass plant would burn organic material to generate electricity.

3.4.5 Hydrogen

The study assumes all new natural gas combustion turbines can be converted to burn renewable hydrogen fuel, also known as "green hydrogen." In addition, some scenarios also assume existing natural gas turbines can be retrofitted to burn renewable hydrogen fuel. In this study, all hydrogen fuel is produced from dedicated renewable resources and thus is "green hydrogen." The hydrogen fuel price assumptions are described in more detail in Appendix B: Price Assumptions.

3.5 Other Candidate Resources

In addition to renewable resources, the study also considered storage, natural gas, and demand resources as candidate resource options. All costs are summarized in Appendix A: Candidate Resource Assumptions.

3.5.1 Storage

Two types of new storage resources are considered in the study: standalone storage and storage paired with solar. Paired storage resources have lower costs because they leverage shared facilities with solar PV resources (e.g., interconnection, inverter) and can take advantage of the investment tax credits (ITC). In both instances, the storage resources are assumed to have a duration of 4 hours and a round-trip efficiency of 85%.

3.5.2 Natural Gas

New natural gas combustion turbines are included as resource options in some of the scenarios. The cost of natural gas combustion turbines includes capital expenditures, fixed operating and maintenance (O&M), gas pipeline reservation fees, variable O&M costs, and fuel costs, including startup costs. As discussed in Section 3.4.5, the study assumes that all new natural gas combustion turbines could be retrofitted to run on green hydrogen fuel in the future.

3.5.3 Demand Response

For demand response, this study considers the potential to expand El Paso Electric's smart thermostat program. Up to 25 MW of capacity can be added by 2030 and up to 50 MW by 2040. The smart thermostat program allows for up to twelve calls during the summer, with each call lasting at most four hours.

3.6 Transmission

The study included a simplified representation of the existing transportation topology, described in Section 3.6.1, as well as the option to expand transmission capacity between simplified transmission zones, described in Section 3.6.2.

3.6.1 Existing Transmission

El Paso Electric's existing transmission topology provides access to local generating resources close to load centers as well as remote generation from the Palo Verde Generating Station via Path 47.

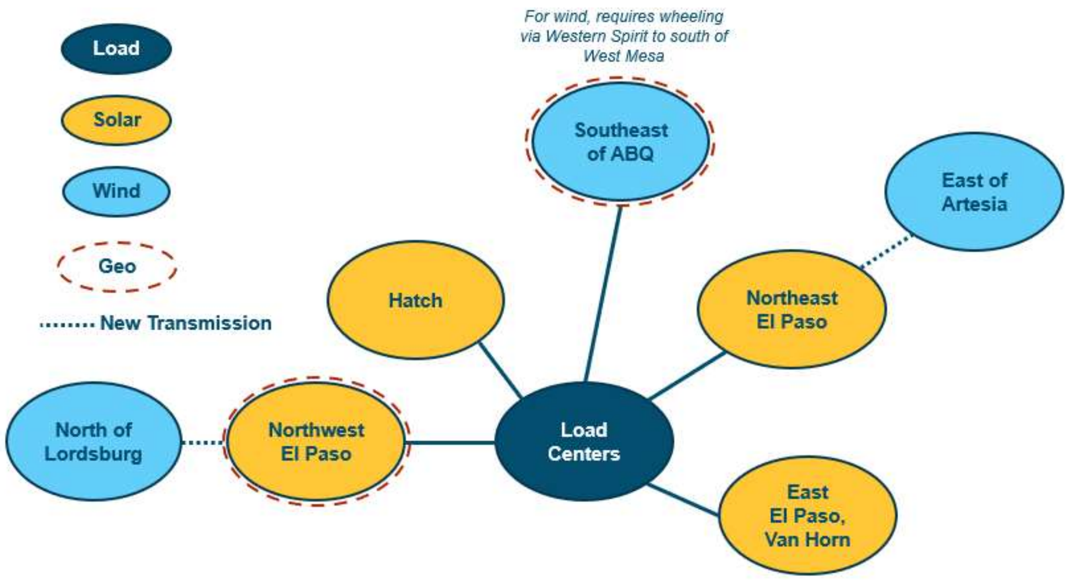
In this study, El Paso Electric's local generating resources are located within the El Paso Electric zone. In addition to the local resources, Path 47 allows imports of both power from the Palo Verde Generating Station and from unspecified imports via spot market purchases. All market purchases are priced based on E3's market price forecast for the Palo Verde hub, which is described in more detail in Appendix B: Price Assumptions. Imports via Path 47 are limited at El Paso Electric's share of firm transmission rights, which is 645 MW. This capacity is used in most hours to import power from El Paso Electric's share of Palo Verde (622 MW). Unspecified imports via spot market purchases are not a sizable portion when all three Palo Verde units are operational, but their share could increase when there is a refueling outage at one of the Palo Verde units, which could occur in fall or spring, depending on the refueling schedule.

El Paso Electric also has 133 MW of transmission capacity to the Eastern Interconnect via the Eddy line. In this study, the line is used for reliability purposes only.

3.6.2 Transmission Expansion

The study includes the option to make upgrades to El Paso Electric's existing transmission system for purposes of integrating a greater share of remote renewable resources. Figure shows renewable zones for candidate renewable resources.

Figure 3-10. Renewable Energy Zones and Transmission Expansion Options



Some of these zones have availability capacity to integrated remote renewable resources, while others would require upgrades, or in some cases new lines, to integrate remote resources. The amount of available capacity, as well as the cost of upgrading the transmission system, is summarized in Table 3-7.

Table 3-7. Transmission Upgrade Costs for Candidate Renewable Resources

Transmission Zone	Downstream Transmission Zone	Assumed Available Capacity Before Upgrades (MW)	Upgrade Length (miles)	Upgrade Voltage (kV)	Upgrade cost ($/MW-yr)[27]
Load Centers	n/a	120	n/a	n/a	n/a
Northeast El Paso	Load Centers	100	75	115	$22.5
East El Paso	Load Centers	100	40	115	$22.5
Van Horn	Load Centers	40	120	115	$30.7
Hatch	Load Centers	40	25	115	$30.7
Northwest El Paso	Load Centers	200	55	345	$55.5
North of Lordsburg	Northwest El Paso	0	50	345	$41.5
East of Artesia	Northeast El Paso	0	200	345	$56.9
Southeast of ABQ[28]	Load Centers	300	125	345	$65.4

[27] These upgrade costs are estimated based on data from El Paso Electric. Any potential transmission upgrades in the future would require more detailed engineering and cost estimate analysis.

[28] Separate from transmission investments, procuring wind in this location would require wheeling power over the Western Spirit line to El Paso Electric transmission facilities. The modeling assumes a rate of $35,912/MW-yr, which corresponds to the wheeling rate for Public Service Company of New Mexico (PNM).

4 Planning Reserve Margin Results

This section presents the planning reserve margin (PRM) results for the system. Section 1.3.1 describes the PRM conceptually, and Section 2.1 describes the methodology.

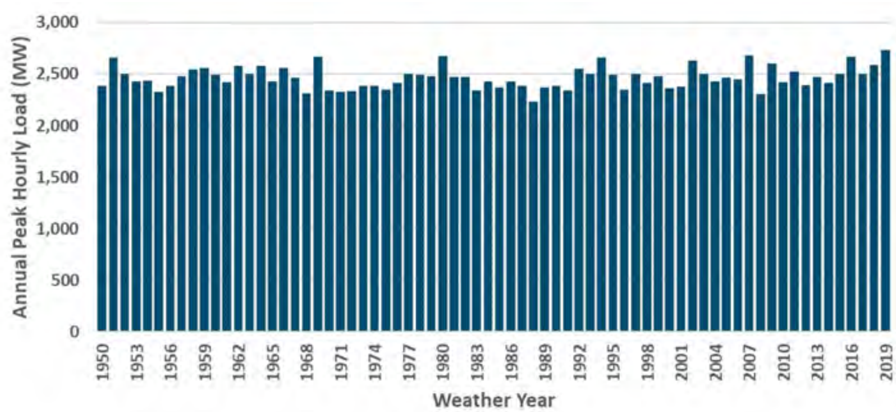
4.1 Load Simulation

In this study, energy demand includes two components: base load and electric vehicle (EV) energy demand. Distributed generation from existing facilities is included in the base load energy demand, whereas generation from new facilities is treated as energy supply and is not netted against energy demand.

For base load energy demand, E3 utilized ten years of El Paso Electric load data (2010-2019) and 70 years of weather data (1950-2019) to simulate the system under a wide variety of weather conditions, specifically 70 weather years. For EV load, E3 utilized a managed charging profile. Section 3.1 describes the load forecast and load profiles in more detail.

In each weather year, the annual peak demand varies naturally due to the differences in weather patterns – particularly, due to differences in the highest summer temperatures. Figure shows the peak loads – including base load and EV energy demand – for these different weather year conditions, assuming 2030 economic conditions. Some weather years have higher peaks, while others have lower peaks. This study captures the distribution of peak load variability related to weather by simulating load across these 70 weather years.

Figure 4-1. Simulated 2030 Peak Load under Weather Conditions from 1950-2019



The reliability needs of the EPE system today are largely driven by summer peak load events. Table 4-1 contextualizes the magnitude and frequency of gross peak load events for the El Paso Electric system. A

1-in-2 peak load signifies that the annual peak load will exceed this value every other year due to weather variability, while the 1-in-10 peak load signifies that the annual peak will reach this level (or higher) one out of every ten years due to weather variability. The year-to-year peak load variability has a direct impact on the PRM because the PRM must be large enough to ensure that there is enough capacity to meet load during hotter-than-usual years and satisfy the reliability target.

Table 4-1. Distribution of Gross Peak Load Extreme Events in 2030

Metric	Simulated Peak Load for 2030 (MW)
1-in-2 Peak	2,462
1-in-5 Peak	2,553
1-in-10 Peak	2,631
1-in-20 Peak	2,668

4.2 Operating Reserves

In addition to serving load, the system must also maintain a minimum level of operating reserves to respond in the event of contingency events and to balance short-term, sub-hourly fluctuations in load and generation. In this study, E3 utilized El Paso Electric's operating reserve requirements for spinning reserves and regulating reserves (see Table 4-2). If the system cannot serve load while maintaining these operating reserve levels in each hour, then RECAP registers a loss-of-load event.

Table 4-2. Operating Reserve Assumptions for PRM Study

Reserve Type	Description	Quantity
Spinning	Serves as a buffer due to uncertainty related to load levels and generator availability	3.5% of load
Regulating	Ensures balancing of the system on short timescales (e.g., intra-5-minute periods)	35 MW

4.3 Planning Reserve Margin Requirement

E3 calculated the PRM in 2025 and 2030 using RECAP based on the load simulations, operating reserve requirements, and resources. Table 4-3 shows the resultant requirements. In 2025, a PRM of 10% is needed to ensure a 2-day-in-10-year reliability standard, or 0.2 LOLE. In 2030, a PRM of 13% is needed to ensure a 1-day-in-10-year reliability standard, or 0.1 LOLE.

Table 4-3. Planning Reserve Margin Requirements

Metric	Units	2025	2030
Loss of Load Expectation (LOLE)	days/yr	0.2	0.1
Expected System Median Peak	MW	2,245	2,420
Planning Reserve Margin	%	10%	13%
Total Perfect Capacity Need	MW	2,472	2,732

5 Effective Load Carrying Capability Results

This section presents the effective load carrying capability (ELCC) results for renewable, storage, demand response, and thermal resources. Section 1.3.3 describes ELCC conceptually, and Section 2.2 describes the methodology.

5.1 Renewable, Storage, and Demand Response Effective Load Carrying Capability

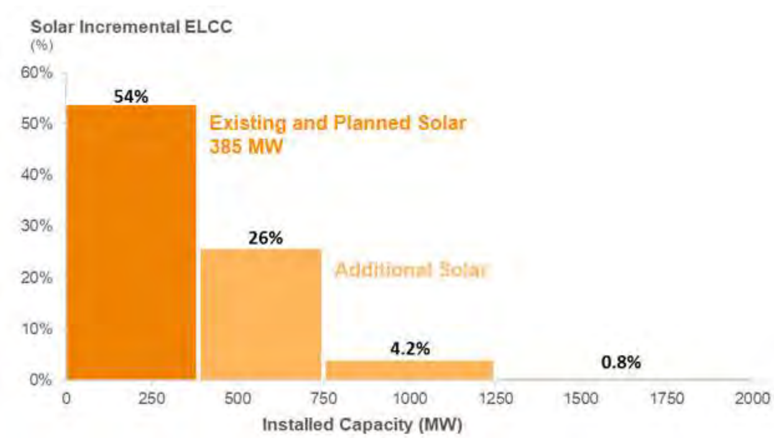
5.1.1 Solar PV

As discussed in Section 1.3.3, solar PV and storage resources have an ELCC diversity benefit. In this study, E3 accounted for this diversity benefit and including it in the resource portfolio optimization analysis. This section presents the ELCC results for solar PV assuming no storage is added to the system. Section 5.1.3 presents the results for solar PV and storage resources, including the ELCC diversity benefit.

Figure shows the incremental ELCC for standalone solar added to the system in incremental tranches. The ELCC for existing and planned utility-scale solar resources, which total 385 MW, is 54%. This means that these resources contribute approximately 208 MW toward satisfying the system PRM.

For subsequent tranches of standalone solar, the incremental ELCC declines. As the system adds more solar PV, without adding storage resources, the system reduces the likelihood of loss of load during daytime hours but does not have an impact on nighttime hours. With increasing solar PV capacity, the incremental ELCC declines because the timing of need for capacity shifts to hours when there is little to no solar PV generation.

Figure 5-1. Standalone Solar Incremental ELCC

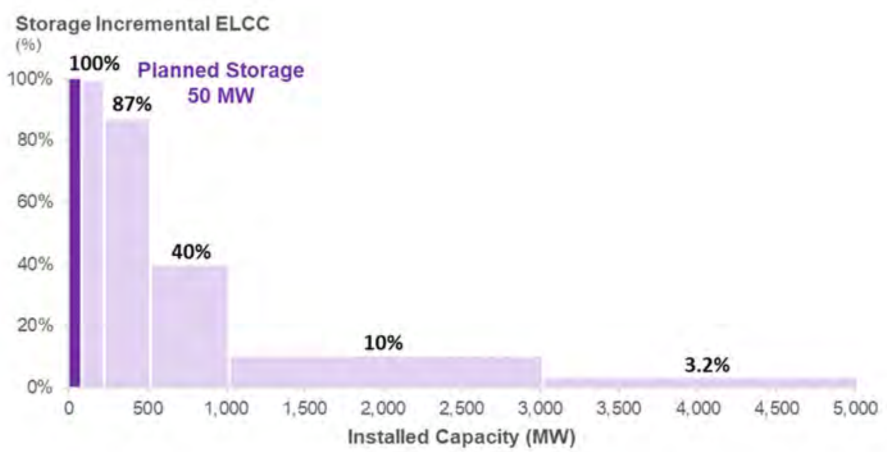


5.1.2 Storage

This section presents the ELCC results for storage assuming no solar PV is added to the system. Section 5.1.3 presents the results for solar PV and storage resources, including the ELCC diversity benefit.

Figure shows the incremental ELCC for four-hour battery storage added to the system in incremental tranches. The ELCC for the planned storage facility, which totals 50 MW, is close to 100%, meaning the nearly the entire 50 MW counts toward satisfying the system PRM.

Figure 5-2. Standalone 4-hour Storage Incremental ELCC



5.1.3 Solar and Storage Surface

As discussed in Section 1.3.3, solar PV and storage resources have an ELCC diversity benefit. In this study, E3 accounted for this diversity benefit by developing a solar-storage ELCC surface and including it in the resource portfolio optimization analysis. Section 2.2.2 describes the ELCC surface concept in more detail.

Table 5-1 shows the ELCC surface results for solar PV and storage, which includes the ELCC diversity benefit. For a given amount of solar PV and storage capacity on the system, the table provides the total ELCC contribution of these resources. The ELCC diversity benefit for solar PV and storage grows at higher penetration levels. For example, with 2,000 MW of solar PV and 1,000 MW of storage, the ELCC diversity benefit is 1,215 – 330 – 656 = 229 MW,[29] and with 10,000 MW of solar and 5,000 MW of storage, the diversity benefit is 2,312 – 338 – 920 = 1,054 MW.[30]

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[29] The ELCC of 2,000 MW of standalone solar is 330 MW. The ELCC of 1,000 MW of standalone storage is 656 MW. Accounting for the ELCC diversity benefit, the total ELCC for 2,000 MW of solar PV and 1,000 MW of storage is 1,215 MW. The difference between the sum of the standalone ELCCs and the combined ELCC is the diversity benefit.

[30] The ELCC of 10,000 MW of standalone solar is 338 MW. The ELCC of 5,000 MW of standalone storage is 920 MW. Accounting for the ELCC diversity benefit, the total ELCC for 10,000 MW of solar PV and 5,000 MW of storage is 2,312 MW. The difference between the sum of the standalone ELCCs and the combined ELCC is the diversity benefit.

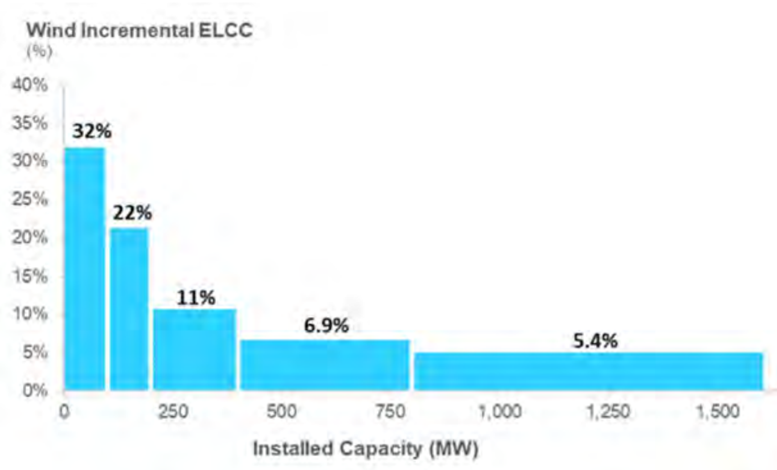
Table 5-1. Solar and Storage Cumulative ELCC (MW)

Cumulative ELCC (MW)		Solar Cumulative Capacity (MW)							
		0	385	750	1,250	2,000	3,000	6,000	10,000
Storage Cumulative Capacity (MW)	0	0	208	303	324	330	335	336	338
	50	50	258	353	374	380	384	386	388
	200	199	407	504	523	530	535	536	538
	500	459	667	796	821	829	832	837	838
	1,000	656	864	999	1,135	1,215	1,244	1,264	1,270
	3,000	855	1,063	1,179	1,326	1,505	1,655	1,844	1,942
	5,000	920	1,128	1,254	1,403	1,605	1,806	2,096	2,312

5.1.4 Wind

Figure shows the incremental ELCC for wind resources. El Paso Electric does not have any existing or planned wind resources. The first tranche of wind capacity would have an ELCC of 32%. Whereas solar PV generation is more coincident with energy demand for cooling buildings, wind generation is higher during non-summer months and at nighttime, resulting in a lower incremental ELCC at low penetration levels. Subsequent tranches of wind provide the declining incremental capacity value, similar to the effect observed for solar PV.

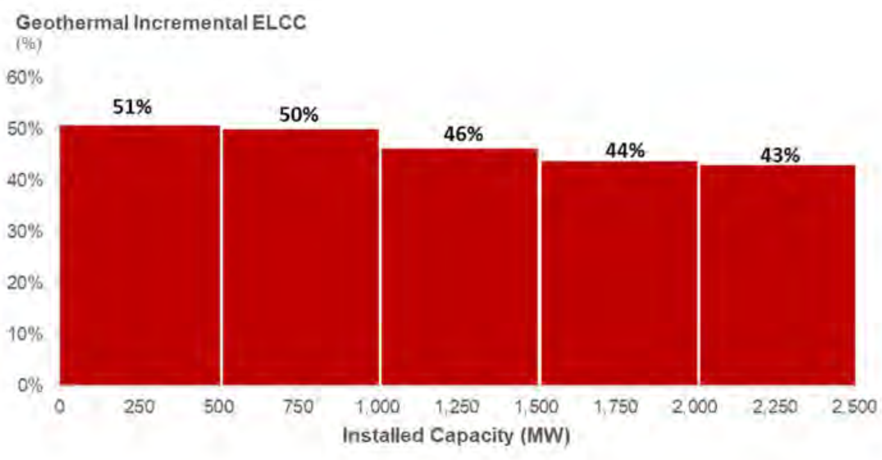
Figure 5-3. Wind Incremental ELCC



5.1.5 Geothermal

Figure shows the incremental ELCC for geothermal resources. El Paso Electric does not have any existing or planned geothermal resources. Although the capacity factor of geothermal is 80%, the output profiles have a negative correlation with the load profile, with lower output levels during daytime hours in the summer. For this reason, the ELCC of geothermal is lower than its capacity factor, starting at approximately 50% for the first tranche. Because the geothermal generation profile remains above 40% during all hours, its incremental ELCC does not drop by as much as that of other dispatch-limited resources.

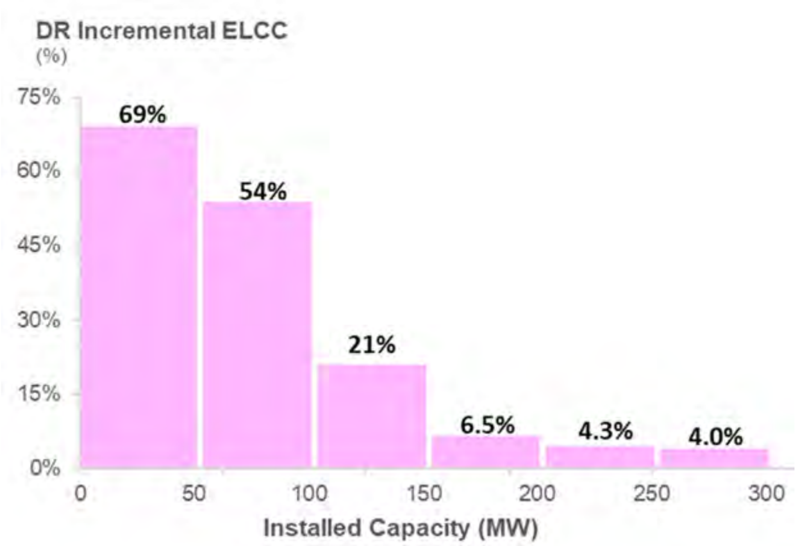
Figure 5-4. Geothermal Incremental ELCC



5.1.6 Demand Response

Figure shows the incremental ELCC for demand response. Because the number of calls is limited to twelve calls per summer and the duration of calls is limited to four hours, the ELCC of demand response is less than 100%. The first tranche has an ELCC of 69%. Beyond this level, the ELCC drops further because the subsequent tranches are not as effective at reducing loss of load events, which may last longer than four hours.

Figure 5-5. Demand Response Incremental ELCC



5.2 Thermal Effective Load Carrying Capability

Table 5-2 lists the ELCC results for the existing and planned thermal resources. Because the thermal resources have forced outages, the ELCC is less than 100%. In addition to forced outages at the plant, Palo Verde also includes the effect of potential outages on transmission lines that transport the power to El Paso Electric's load centers.

Table 5-2. ELCC for Thermal Units[31]

Resource	Summer Capacity (MW)	ELCC (MW)	ELCC (%)
Rio Grande 7	46	42	91%
Rio Grande 8	144	130	90%
Rio Grande 9	86	78	90%
Newman 1	73	67	91%
Newman 2	73	67	91%
Newman 3	90	82	91%
Newman 4	227	197	87%
Newman 5	266	239	90%
Newman 6	228	206	90%
Copper	63	57	90%
Montana 1	88	79	90%
Montana 2	88	79	90%
Montana 3	88	79	90%
Montana 4	80	72	90%
Palo Verde	622	587	94%

[31] E3 calculated specific ELCC values for Rio Grande 7, Newman 1-4, and Palo Verde. The ELCC values for all other units are based on the average ELCC across all units.

6 Portfolio Analysis

This section presents resources portfolios for the El Paso Electric system, including resource portfolios specific to the New Mexico jurisdiction. Section 6.1 summarizes the results of the Least-Cost case. Section 6.2 describes technical aspects of the New Mexico's Renewable Energy Act (REA) that could impact the optimal portfolio selection. Section 6.3 describes three different REA cases and how they could impact the resource portfolio for the New Mexico jurisdiction. Section 6.4 presents the results of each of the REA case, and Section 6.5 presents the detailed results for one of the cases.

6.1 Least-Cost Case

The Least-Cost case does not impose any constraints on the resource portfolio beyond reliability requirements. This case identifies the optimal least-cost portfolio before considering clean energy requirements or allocation of resources between the New Mexico and Texas jurisdictions. These considerations are discussed in detail in subsequent sections.

The Least-Cost case provides a reference point for comparing all other REA cases. If additional constraints are added to the Least-Cost case, such as more aggressive clean energy policies, then the resulting optimal portfolio will be more expensive because the Least-Cost case already has a least-cost optimal mix of resources. By comparing alternative cases to the Least-Cost case, the analysis can identify the impacts of these additional constraints. Alternative cases are discussed in Sections 6.3 and 7.

6.1.1 Resource Additions and Retirements

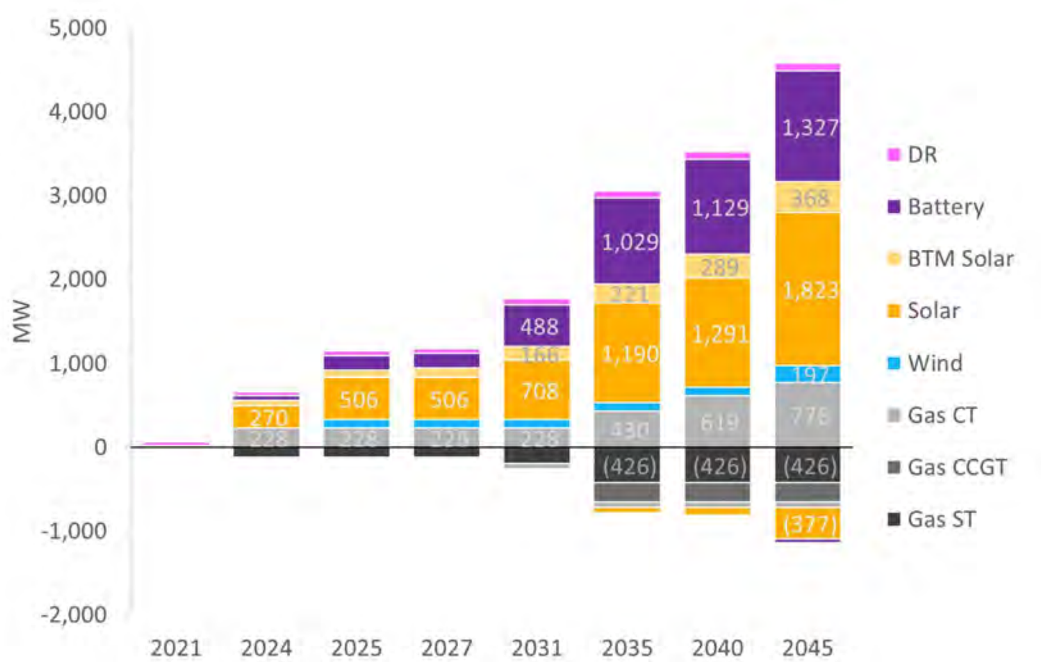
See Figure 6-1 for the cumulative resource additions and retirements through 2045 in the Least-Cost case. The additions through 2024 are planned resources, including the Newman 6 unit, solar and storage capacity, and demand response capacity. In 2025, the first year of the resource portfolio optimization, EPE would add 236 MW of solar, 127 MW of storage, and 102 MW of wind capacity.

In the period 2026-2031, EPE would add 202 MW of solar and 311 MW of storage, in part to replace thermal capacity retirements. The storage resources contribute to the reliability needs created by load growth and thermal retirements and assist with the integration of increasing levels of renewable generation.

In the period 2032-2045, EPE would add 1,114 MW of solar, 839 MW of storage, 96 MW of wind, and 548 MW of gas combustion turbine (CT) capacity. Over this period, significantly more thermal units retire. While the solar, storage, and wind resources contribute to replacing this capacity and satisfying the PRM, the optimal least-cost portfolio also adds gas plant capacity to ensure reliability.

Through 2045, most additions more than 80% of all resource additions are renewable generators, storage, or demand response. Through 2045, gas resources account for most resource retirements.

Figure 6-1. Cumulative New & Retired Capacity in Least-Cost Case



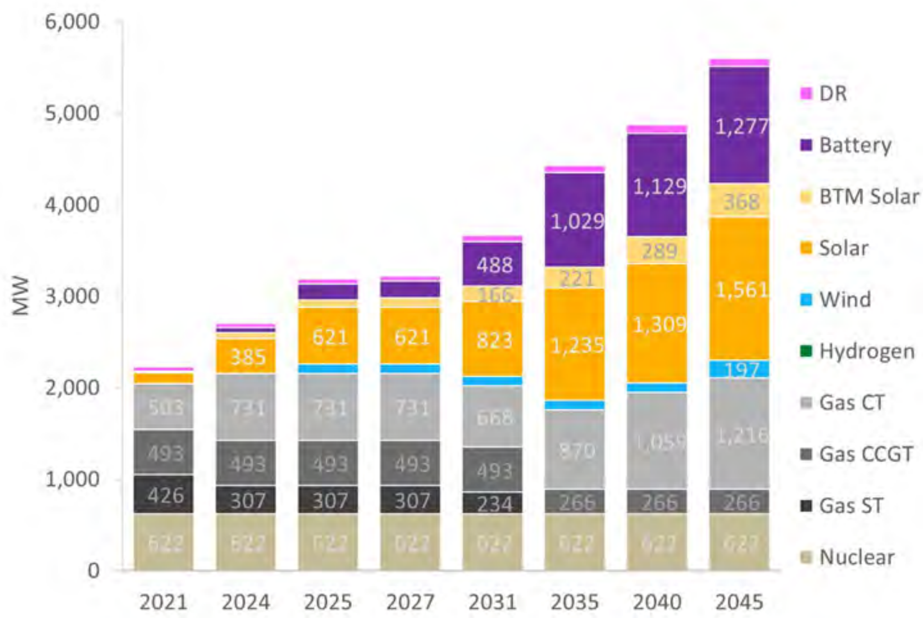
6.1.2 Total Capacity

See Figure 6-2 for the total capacity through 2045 in the Least-Cost case. In addition to resource additions and retirements discussed in the previous section, this figure includes resources that are online today and will remain online through the planning horizon.

This figure shows a significant transition in the resource mix through 2045. Currently, El Paso Electric's resource portfolio consists mostly of thermal capacity from nuclear units at Palo Verde and natural gas plants. Through 2045, the diversity within the resource portfolio increases as solar, storage, wind, and demand responses resources are added. By 2025, solar capacity approximates EPE's share of capacity at Palo Verde. By 2035, solar capacity exceeds gas capacity. Storage capacity increases in tandem with solar capacity. Storage resources help shift solar generation from periods of abundant solar generation (i.e., daytime) to periods of low solar generation (i.e., nighttime).

Natural gas capacity increases with the addition of Newman 6 but then declines through 2035. Natural gas capacity increases again during the periods 2035-2045 but remains below 2024 levels in 2045.

Figure 6-2. Total Capacity in Least-Cost Case



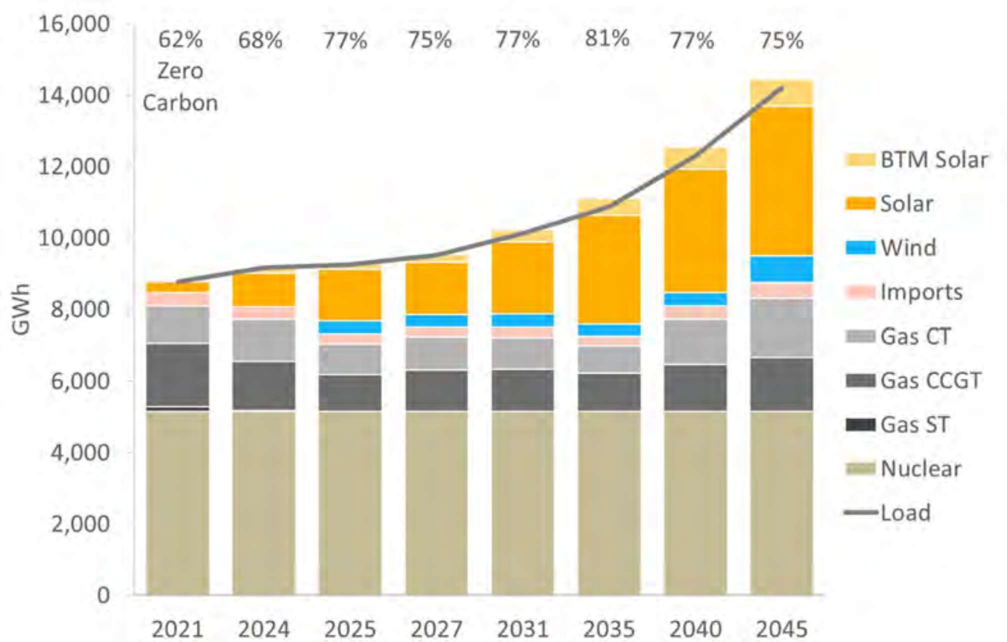
6.1.3 Generation Mix

See Figure 6-3 for the annual generation through 2045 in the Least-Cost case. This shows the amount of generation by resource, based on optimal hourly dispatch dynamics.

The EPE system already has a high share of zero-carbon energy with the generation from Palo Verde. Between the generation from Palo Verde and solar facilities, the share of total generation from zero-carbon energy sources is estimated to be 62% in 2021. Despite energy demand increasing through 2045, the share of energy from zero-carbon energy sources increases to 75% or higher in the 2025-2045 period. This is because renewable generation accounts for an increasing share of the energy mix through 2045.

Generation from natural gas plants decreases through 2025, remains relatively constant through 2035, and then rises through 2045. This generation occurs during periods of insufficient energy available from other resources, including nuclear, renewables, and storage. While more renewable and storage capacity could be added to reduce gas generation further, this would add costs and thus is not part of the optimal least-cost portfolio. Further reductions in gas generation are explored through several carbon reduction sensitivities, which are discussed in Section 7.1.

Figure 6-3. Annual Generation in Least-Cost Case



6.1.4 Planning Reserve Margin and Reliability

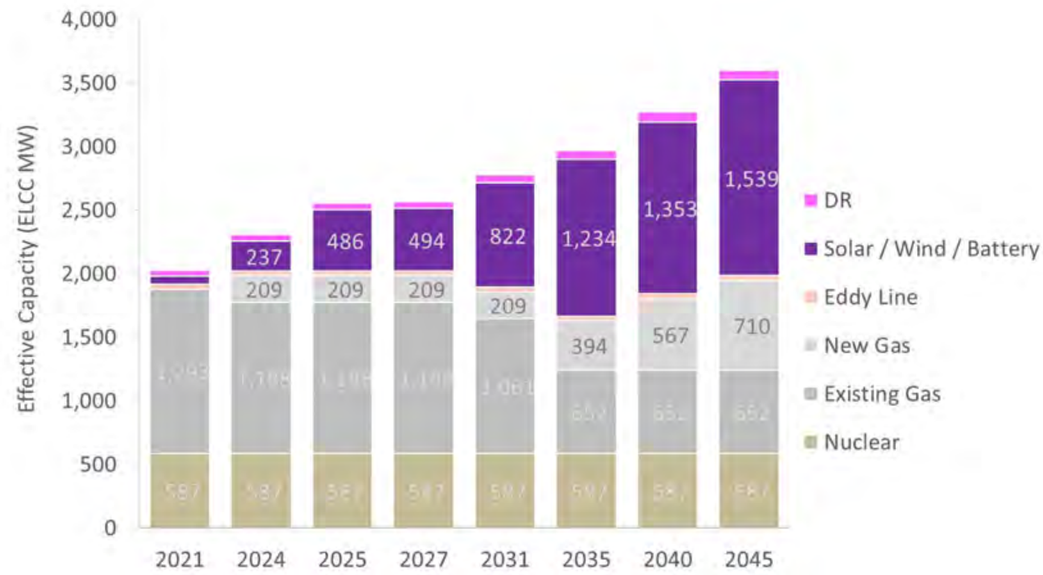
See Figure 6-4 for the effective capacity through 2045 in the Least-Cost case. The effective capacity is the amount of capacity that can be counted toward the PRM for ensuring reliability.

The minimum requirement for effective capacity is a function of peak energy demand and the PRM. As discussed in Section 3.1.1, peak demand grows through 2045. As discussed in Section 4.3, the PRM increases from 11% in 2025 to 13% in 2030. These two factors result in an increase in the requirement for effective capacity over time.

In addition to the increase in this requirement over time, the retirement of existing capacity results in an increasing need for new resources to ensure reliability. The amount of effective capacity from existing resources declines by 105 MW between 2021 and 2024, by 127 MW between 2027 and 2031, and by 409 MW between 2031 and 2035.

The growing capacity need is met through a combination of renewables, storage, demand response, and gas resource additions. Renewable and storage resources account for approximately 80% of effective capacity additions by 2031 and more than 70% by 2045. While the total effective capacity for renewable and storage resources increases through 2045, the effective capacity per nameplate capacity declines. As discussed in Section 5.1, this occurs because the incremental ELCC of these resources declines with penetration. The optimal least-cost solution adds gas resources 2035-2045 to contribute additional effective capacity.

Figure 6-4. Effective Capacity in Least-Cost Case



6.2 REA Requirements

For investor-owned electric utilities in New Mexico, the state's REA establishes the following targets for renewable and carbon-free energy:

- Renewable energy must comprise at least
  - 40% of all retail sales of electricity in New Mexico by 2025;
  - 50% of all retail sales of electricity in New Mexico by 2030; and
  - 80% of all retail sales of electricity in New Mexico by 2040 (provided that compliance until 2047 does not require the utility to displace zero-carbon resources).
- Zero carbon resources must supply 100% of all retail sales of electricity in New Mexico by 2045.

El Paso's anticipated portfolio in 2040 for serving New Mexico customers includes nuclear generation from Palo Verde (units 1 and 2) that accounts for more than 20% of New Mexico retail sales, leaving less than 80% of New Mexico retail sales to be supplied by renewables. Therefore, this study assumes that, by 2040, the full remainder of retail sales not served by zero-carbon nuclear resources must be met with renewable energy. The study models this consideration by requiring that, in 2040*,* El Paso Electric must begin serving 100% of retail sales in New Mexico using zero-carbon resources (including nuclear generation).

As discussed below, different approaches exist to model a portfolio that meets REA's requirements, particularly for a utility like El Paso Electric that serves customers in multiple states. Defining the approach used is required to model an optimal portfolio that meets these requirements.

System-Wide Renewable Procurement vs. State-Specific Portfolios for REA Requirements

As noted in Section 6.1, the Least-Cost case does not impose any specific constraints for meeting clean energy requirements but selects resources solely for minimizing cost while maintaining reliability.

Nevertheless, the resulting system-wide portfolio selected generates total renewable energy in 2040 for the El Paso Electric system that exceeds the sum of renewable energy required to serve 80% of El Paso Electric's retail sales in New Mexico plus the renewable energy required for compliance with Texas policies.

Under this total system approach, the Least-Cost case would meet both states' renewable procurement targets in the aggregate. Dual-state compliance would be demonstrated through the assignment of Renewable Energy Credits (RECs). El Paso Electric's portfolio of renewable resources would deliver energy to its system and generate the total number of RECs, which would be assigned between Texas and New Mexico in amounts required for each state's policy.

Under a state-specific portfolio approach, El Paso Electric renewable and zero-carbon resources would also be procured first for the combined Texas and New Mexico system and then would be allocated proportionally between New Mexico and Texas based on each states' share of overall El Paso Electric load. Under this approach, if New Mexico's proportionally allocated quantity of the system-wide renewable energy procurement is not enough to meet the REA requirement, then El Paso Electric would need to procure additional renewable resources that are specifically designated and assigned to El Paso Electric's New Mexico customers. Additional costs associated with these New Mexico-designated resources would also be assigned to El Paso Electric's New Mexico load customers.

This study has modeled each of these approaches in separate cases.

Annual vs. Hourly Generation Balancing for REA Requirements

Additionally, the REA 100% zero-carbon target for 2045 could be evaluated (a) on a total annual generation basis, or (b) on an hourly generation basis. Each of these approaches was analyzed in this study for modeling zero-carbon generation to serve El Paso Electric's New Mexico load starting in 2040 (including El Paso Electric's generation from Palo Verde). These two approaches are summarized in more detail below in Table 6-1.

Table 6-1. Implications of Annual vs. Hourly Balancing for Zero-Carbon Energy

Annual balancing	Hourly balancing
New Mexico-allocated zero-carbon resources must generate enough energy on an annual basis to match the REA target	New Mexico-allocated zero-carbon resources must serve New Mexico energy demand in all hours of the year
Natural gas resources and/or imports can serve New Mexico's energy needs in some hours if that generation is offset by additional zero-carbon generation in other hours (which can be used to serve El Paso Electric's loads in Texas or exported)	El Paso Electric's New Mexico load cannot be served by gas resources or unspecified imports in any hour of the year
Annual balancing allows New Mexico customers to receive the benefits of being served by a larger system	Hourly balancing would be a more stringent approach because it would not allow for balancing between New Mexico and Texas resources

Capacity Pooling

When evaluating reliability, a single portfolio of resources serving a larger total customer load level typically will perform more reliably than two smaller groupings of resources separately serving two sub-areas of load. The larger single system allows for resources available in one part of the system to be used to help maintain reliability in the other part of the system, effectively "pooling capacity" for reliability purposes. For these reasons, when capacity pooling is assumed for planning purposes, fewer total resources will be needed for the combined system (and costs will be lower) to maintain a given level of expected reliability, compared to what would be needed for two sub-systems operating independently

For this analysis, El Paso Electric is modeled in the Least-Cost case with capacity pooling enabled between its Texas and New Mexico jurisdictions for reliability purposes. This study also models a case without capacity pooling, which would reflect a more stringent approach to New Mexico's clean energy policy in which resources assigned to El Paso Electric's Texas jurisdiction – which could include gas resources – would not be allowed to provide support to New Mexico loads, even for reliability purposes. Further description of capacity pooling is provided below in Figure 6-5 and Table 6-2.

Figure 6-5. Capacity Pooling Options Considered in the Study

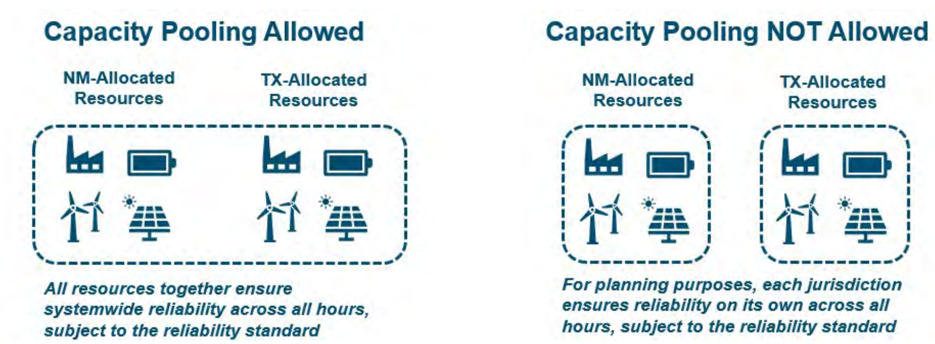


Table 6-2. Implications of Capacity Pooling for Portfolio

Capacity Pooling Allowed	Capacity Pooling NOT Allowed
For reliability planning purposes, El Paso Electric's NM and TX loads can be served by NM resources, TX resources, and/or system resources. If the NM jurisdiction doesn't have enough resources to satisfy load in an hour, then it can rely on TX resources, and vice versa	For reliability planning purposes, TX and NM must each have enough resources separately to ensure reliability across a range of potential conditions without relying on the other jurisdiction (i.e., on a standalone basis)
NM and TX customers incur costs for their proportional share of total system reliability needs	NM customers would incur costs for dedicated resources sufficient to maintain reliability without needing to call upon TX resources in any hour, and vice versa

6.3 REA Cases

In this study, El Paso Electric's REA requirements were modeled at varying levels of stringency under three separate cases. These cases have meaningful implications on how planning is performed for New Mexico customers, the resulting portfolio that is procured, and the resulting costs.

The three REA cases are summarized in Table 6-3.

Table 6-3. REA Cases Analyzed

	Least-Cost ("LC")	Least-Cost + REA Resources ("LC+REA")	Separate System Planning ("SSP")
Portfolio Optimization	Least-cost system optimization	Reoptimize Least-Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM Zero-Carbon Generation Balancing Period	Annual	Annual	Hourly
NM and TX Capacity Pooling to Ensure Reliability	✓	✓	✗
Resource Allocation	Resources allocated proportionally	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM Allocated New Gas Capacity	✓	✗	✗

All three cases above exclude the potential for burning green hydrogen fuel as a zero-carbon fuel. An additional case titled "SSP H2" models the Separate System Planning (SSP) case with identical assumptions as the SSP case but with green hydrogen fuel available.

6.3.1 Least-Cost (LC)

In the Least-Cost case, El Paso Electric procures renewable energy on a system-wide basis, exceeding the sum of renewable energy needed to serve 80% of El Paso Electric's New Mexico loads plus El Paso Electric's Texas renewable energy requirement. This case assumes that this form of renewable procurement will satisfy REA compliance. The case also supplies sufficient zero-carbon energy to serve 100% of El Paso Electric's New Mexico loads starting in 2040 and allows pooling of capacity resources. The portfolio optimization is conducted for El Paso Electric's entire service area, and resources (including potential new gas capacity) are allocated to the Texas and New Mexico jurisdictions based on an approximately proportional load share. This case results in the lowest overall system cost.

6.3.2 Least-Cost Plus REA Resources (LC+REA)

In this case, additional zero-carbon resources are dedicated to serving New Mexico customers. Separate resource portfolios for each state are developed in three steps in this case. First, a preliminary portfolio of new resources is selected based solely on minimizing costs; this portfolio matches the resources that were selected in the Least-Cost case. Second, the resources from this preliminary portfolio are allocated between Texas and New Mexico proportionally to the size of El Paso Electric's customer loads in each state.

More of El Paso Electric's customers are in Texas than in New Mexico, so this allocation results in a larger share of renewable energy being allocated to Texas and a lower amount of renewable energy allocated to New Mexico. To has sufficient zero-carbon energy to meet the REA targets, the model must select an additional amount of renewable resources in the third step. These incremental resource additions and associated costs are fully dedicated to New Mexico. New gas capacity can be selected in this case, but it is exclusively assigned to Texas customers, and the total quantity of new gas additions in the model is not allowed to exceed the amount of new gas that was allocated to Texas from the preliminary portfolio. This case allows pooling of capacity resources for reliability purposes.

6.3.3 Separate System Planning (SSP)

As the most stringent approach, the Separate System Planning (SSP) case models the Texas and New Mexico jurisdictions as two separate systems that do not interact with each other for energy transactions or for reliability planning.

This case requires zero-carbon generation for New Mexico in all hours in 2040 and beyond. While the Least-Cost and LC+REA cases described are evaluated based on the renewable and clean energy available as a percentage of retail sales, the SSP case requires that 100% of energy generation for the New Mexico system, including transmission and distribution losses, must be zero-carbon in every hour for 2040.

While zero-carbon energy can be exported from the New Mexico system in an hour when it has more than is needed for loads, these exports do not enable it to have non-zero-carbon imports (or generate from carbon-emitting local resources) in different hours, because the requirement applies individually to every hour of the year. Capacity pooling for reliability purposes is not allowed in this case, and no new gas resources are allocated to New Mexico.

6.3.4 Separate System Planning with Hydrogen (SSP H2)

The first three REA cases (LC, LC+REA, and SSP) do not include the option to burn green hydrogen as a zero-carbon fuel. This final case (SSP H2) reflects all the same assumptions as the SPP case, but it allows green hydrogen to be combusted as a zero-carbon fuel.

6.4 REA Case Results

This section compares the resource capacity, generation, and cost of each of the REA cases described above.[32] For each case, this section highlights the changes to the portfolio of the El Paso Electric system as a whole, as well as the resources and costs allocated to El Paso Electric's New Mexico customers.

6.4.1 Capacity

See Figure 6-6 for the capacity (in MW) of El Paso Electric's resource portfolio in 2031 under each REA case. The left panel of the figure shows the capacity of all of El Paso Electric's resources in each case. In the right panel, the chart shows the capacity allocated to El Paso's New Mexico loads.

In the Least-Cost case, new resources are allocated to New Mexico proportional to New Mexico's share of load.[33] In the LC+REA case, any resource additions that are incremental to the LC case are needed to comply with the REA and thus are allocated to New Mexico loads.

Compared to the Least-Cost case (which was described in detail in 6.1.2), the Least-Cost Plus REA Resources case procures a similar amount of most resources on a system-wide basis for 2031, but adds an additional 101 MW of wind procurement (203 MW in LC+REA vs. 102 MW in LC). The New Mexico capacity in the right panel shows that all of this incremental wind procurement is assigned to New Mexico (which shows 122 MW of wind in LC+REA vs. 20 MW in LC). In the portfolio optimization, the additional wind resources added enable the model to select 28 MW less solar (795 MW in LC+REA vs. 823 in LC) and less less storage resources while still meeting the renewable procurement and reliability goals. Similar reductions are also reflected in the NM share of capacity in LC+REA.

The SSP case must procure more solar (859 MW vs. 823 MW) and more storage (591 MW vs. 488 MW) resources for the system than the Least-Cost case, and most of these changes are reflected as additions in the New Mexico system's portfolio. These incremental renewable procurement levels would be needed to be on a trajectory to have zero-carbon energy serve New Mexico's load on an hourly basis by 2045, and to have resources to maintain reliability planning targets without capacity pooling of resources with Texas. By contrast, the LC and LC+REA cases are able to export renewables from New Mexico to Texas in some hours and import enegy in others hours as long as the system supplies 100% of New Mexico cusomers' annual retail load using zero-carbon resources on an net basis by 2045; also, the LC and LC+REA cases use

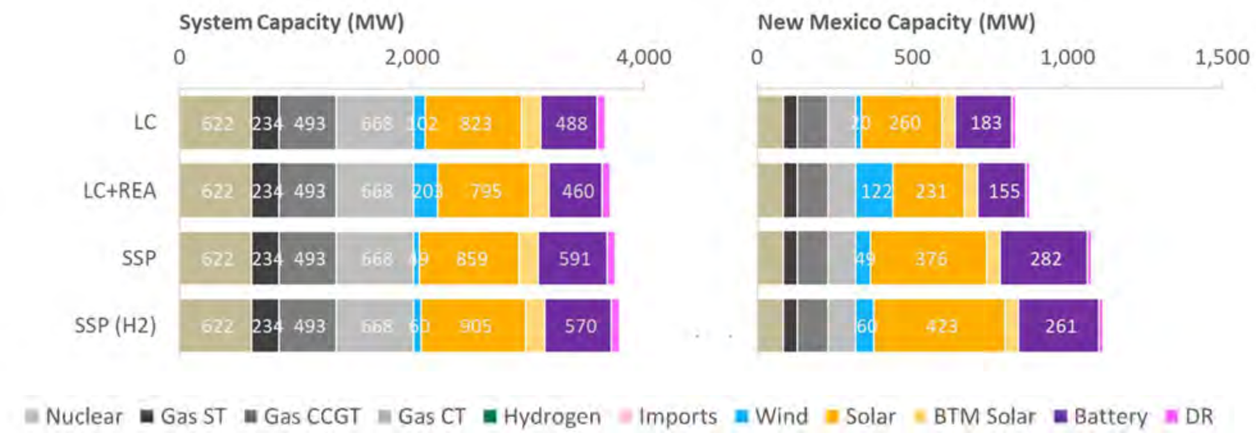
[32] E3 presented draft results for the REA cases at the 2021 El Paso Electric Company Integrated Resource Plan Public Participation June 2021 Meeting. This report presents final results for the REA cases.

[33] Any resources that already have been procured on behalf of New Mexico customers are allocated 100% to New Mexico customers.

capacity pooling to reduce the amount of resouces for reliabiltiy needs. The SSP case selects slightly fewer wind resources than in the LC case (likely because more storage was selected for reliability, which shifts economics in favor of solar), but the full 49 MW wind procurement is allocated to New Mexico to serve its rising clean energy target (and stringency for hourly balancing).

The SSP H2 case selects fewer storage resources in 2031 beause the model optimization is able to anticipate that in 2040 it will be able to use dispatchable H2-fired generation as a complement to renewables and storage to meet the hourly zero-carbon energy balancing and and reliability needs of El Paso Electric's New Mexico system. Less storage is needed for New Mexico for this study year (since H2 is going to provide carbon-free dispatchable capacity later), but this also means that slightly more solar must be added in the SSP H2 case to meet the renewable energy target, because the lower storage addition produces in more renewable curtialment.

Figure 6-6. Capacity in 2031 by REA Case



See Figure 6-7 for each REA case's total capacity for the year 2040. Portfolio results in this year diverge more signifcantly between cases than in 2031 because the zero-carbon energy requirement modeled for New Mexico loads is 100% in 2040.

Figure 6-7. Capacity in 2040 by REA Case

Nuclear ■ Gas ST ■ Gas CCGT ■ Gas CT ■ Hydrogen ■ Imports ■ Wind ■ Solar ■ BTM Solar ■ Battery ■ DR

The Least-Cost case's system-wide capacity for 2040 is described in detail in section 6.1.2. Incremental resources selected by the optimization have been allocated proportionally to loads (less output of existing dedicated resources) to produce El Paso Electric's New Mexico capacity for this case, which has a signifcant quantity of solar and storage resources by this year.

Compared to the LC case, the LC+REA case adds more solar (1,639 MW vs. 1,309 MW) and storage (1,246 MW vs. 1,129 MW), as well as a modest amount of additional wind. These incremental additions would be needed as dedicated New Mexico resources to produce sufficient renewable energy under this approach to modeling REA. In the LC+REA case, the additional renewable and storage procurement enables a reduction in the amount of gas resources needed for reliability purposes (942 MW of gas CTs in LC+REA vs. 1,059 MW in LC). Also, the New Mexico portfolio in the LC+REA case has a smaller amount of remaining gas resources, which are included for reliability purposes and rarely dispatched (as discussed in section 6.4.2), enabling the portfolio to serve 100% of New Mexico customers' annual retail load using zero carbon resources with annual balancing.

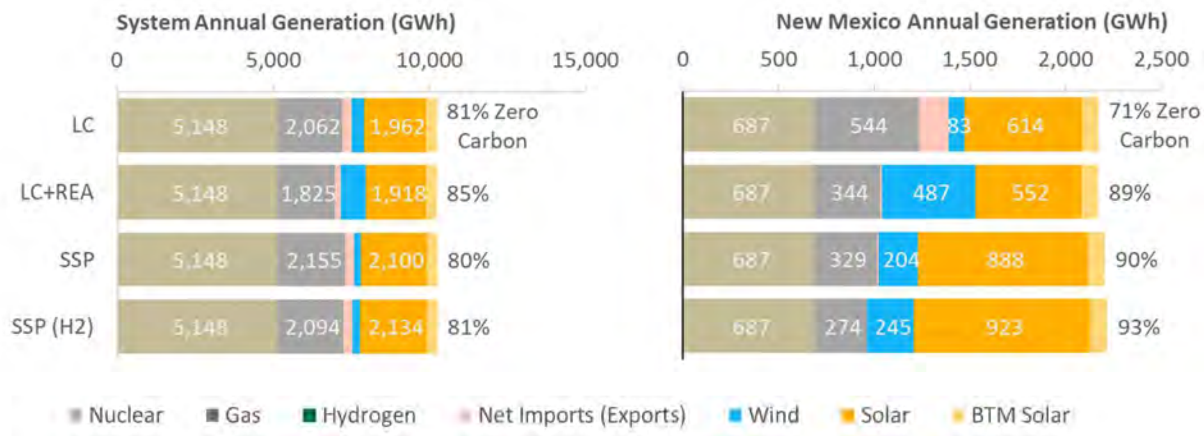
The SSP case must procure significantly more solar resources (2,450 MW total) and storage (2,344 MW total) on a system-wide basis, and the majority of these incremental resources are allocated to New Mexico loads to enable New Mexico to balance on an hourly basis without any gas generation and to meet a reliability needs as a standalone system without capacity pooling. These large additions are needed for infrequent longer-duration events where the New Mexico separate system needs energy (from clean energy sources for every hour) but faces lower renewable output and/or plant outages. In this case, the additonal solar resources are needed in New Mexico to ensure that there is a clean energy source capable of charging the additional storage. As a result of the storage and solar additions, system-wide gas capacity (755 MW) is also lower in the SSP case and entirely assigned to Texas.

The addition of a moderate amount of zero-carbon, dispatchable hydrogen generation to the New Mexico separate system in the SSP H2 case significantly reduces the amount of solar and stroage needed for reliability compared to the SSP case, because the H2 generation can cover the infrequent, longer-duration events that challenge reliability on the New Mexico separate system.

6.4.2 Generation

See Figure 6-8 for a comparison of annual generation in 2031 under each REA case. The left panel shows the energy in GWh from each fuel type for the El Paso Electric system overall, and also reports the percentage of this energy generation that comes from zero carbon sources. Net imports are shown in the chart and are not treated as clean energy for this calculation.

Figure 6-8. Annual Generation in 2031 by REA Case



The Least-Cost case includes 81% zero carbon generation for 2031. After allocating to New Mexico's loads, zero-carbon resources comprise 71% of New Mexico's annual energy, a lower share than the overall system primarily due to New Mexico's smaller ownership share of Palo Verde nuclear resources as a zero-carbon source. This results in a proportionally higher need for imports and gas dispatch in New Mexico's share of the system even though New Mexico has more dedicated solar resources.

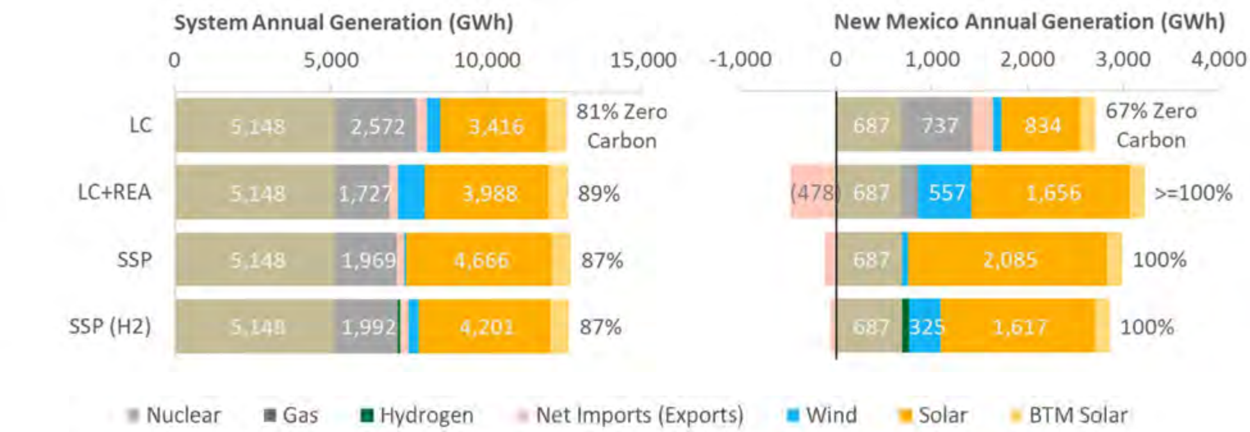
The LC+REA case raises the zero-carbon share of generation to 85% for El Paso Electric overall, and to 89% for El Paso Electric's New Mexico loads. This increase is primarily driven by the additional wind resources procured to meet EA requirements (in an assigned-resource approach) beyond those in the LC case; this additional wind energy reduces the amount of energy generation that is needed from gas units in this case.

The SSP case selects more solar resources assigned to serve the New Mexico loads and also assigns a higher share of the overall wind procurement to New Mexico. The additions result in only 1 percent higher zero-carbon generation for New Mexico compared the LC+REA case (90% vs. 89%), however, because the SSP case does not benefit from efficiencies of coordinated balancing between the two portions of the system and therefore faces higher potenital renewable energy curtailment in each portion of the system.

The SSP H2 case has similar generation levels as the SSP case on a system-wide basis, but the slightly higher solar build for New Mexico results in slightly lower gas dispatch.

See Figure 6-9 for annual generation totals by REA case for the 2040 period. In the Least-Cost case, the cost minimized portfolio selection results in total renewable energy procurement that exceeds the sum of renewable energy required for New Mexico loads plus the Texas renewable energy target. Zero-carbon resources again comprise 81% of total generation in this case, the same level as for 2031. New Mexico's share of zero-carbon generation is slightly lower in this year (67%) for the LC case because load growth leads to Palo Verde nuclear generation representing a smaller share of overall generation.

Figure 6-9. Annual Generation in 2040 by REA Case



In the LC+REA case, zero-carbon energy rises to 89% of El Paso Electric's system-wide dispatch and represents over 100% of New Mexico's share of annual generation, after accounting for the impact of renewable energy net exports from New Mexico to El Paso's Texas loads or to other utilities in the West. As previously noted, a higher amount of renewable generation capacity was procured in this case (and assigned to New Mexico) and the increased storage allows this generation to not be curtailed as heavily.

The SSP case results in 87% zero-carbon generation for El Paso Electric overall in 2040 (higher than the LC case but lower than the LC+REA case). New Mexico's significant solar and storage resource build allows that portion of the system to balance load with no gas generation in any hour, resulting in a 100% zero-carbon generation level.

The SSP H2 case has a similar generation mix as the SPP case (since the Texas portion of the system is held separate and unaffected) but H2 capacity (and a need for a small amount of H2 energy production) allows the New Mexico portion of the system to reach 100% zero-carbon despite a lower amount of solar output.

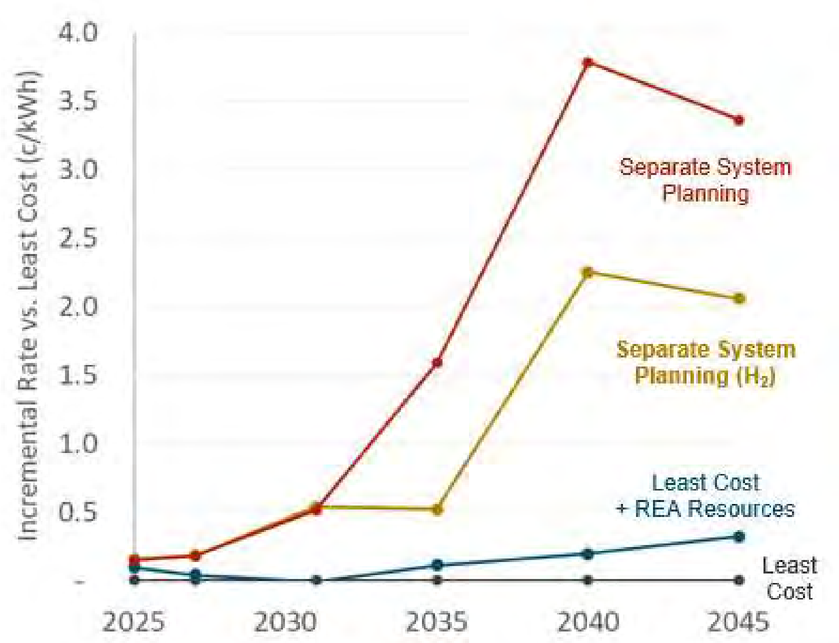
6.4.3 Cost

See Figure 6-10 for the cost impact by year for each of the REA cases evaluated. This chart focuses on the impact to El Paso Electric's New Mexico customers. All cost impacts are calculated based on the difference in annual cost for New Mexico customers relative to the Least-Cost case, divided by the annual New Mexico retail sales (in kWh). This gives an incremental rate impact (in cents/kWh) for New Mexico customers.

The Least-Cost portfolio is, by definition, shown with zero incremental cost in all years. Notably, however, the LC+REA case has only a small incremental cost impact (less than 0.2 cents per kWh in 2040) compared with the Least-Cost case. This result indicates that the LC+REA approach would allow El Paso Electric to increase the share of zero-carbon resources for New Mexico from approximately 70% in the Least-Cost case to 89% in 2030 and 100% in 2040, with a relatively minor impact on total costs.

By contrast, the SSP case is the most expensive case modeled. Its incremental cost for New Mexico customers compared to the Least-Cost case starts at small amounts in the 2020s but rises to 0.5 cents per kWh in 2030, and to over 3.5 cents per kWh by 2040. In this scenario, the significant additional storage and solar required to ensure reliability without capacity pooling and without any gas generation in any hour results in a significant increase in costs. Adding the option to burn green hydrogen in the SSP H2 case substantially moderates the cost increase compared to SSP case after 2030, but the SSP H2 case is still higher in cost than the LC+REA case, despite providing a similar share of energy from zero carbon resources.

Figure 6-10. New Mexico Customer Rate Impact (Relative to Least-Cost Case)

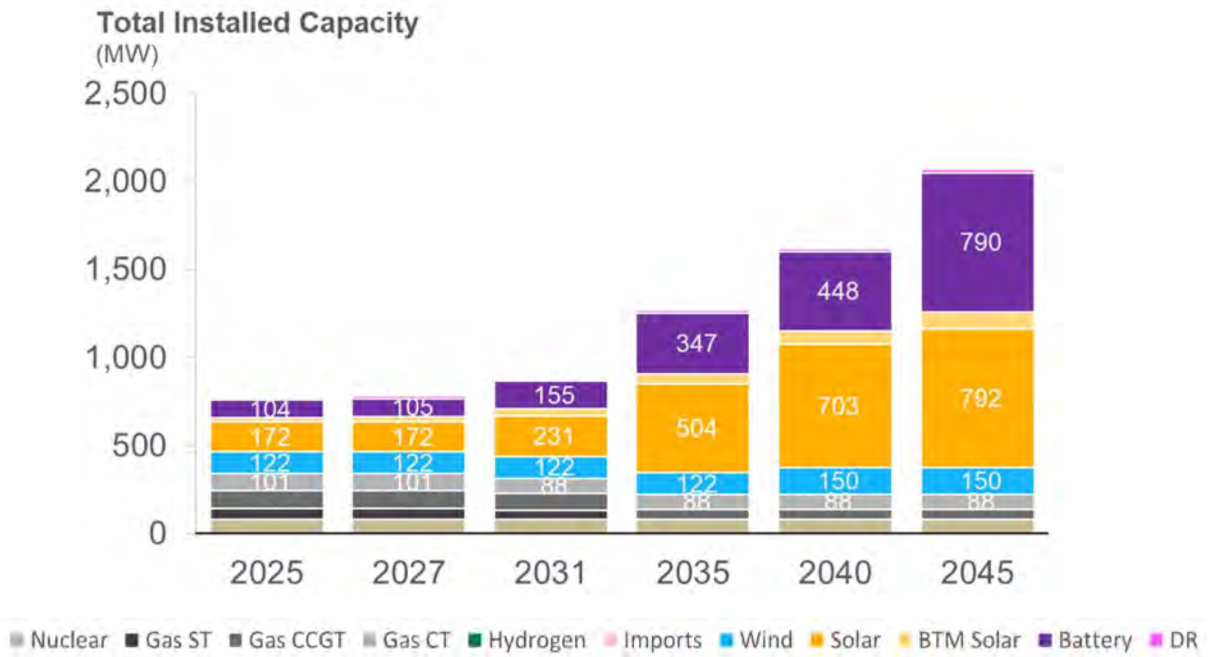


6.5 Least-Cost + REA Detailed Results

This section presents the year-by-year results for New Mexico in the Least-Cost + REA Resources case. This case adds incremental resources that are dedicated to the New Mexico jurisdiction while limiting cost impacts considerably compared with the Separate System Planning case.

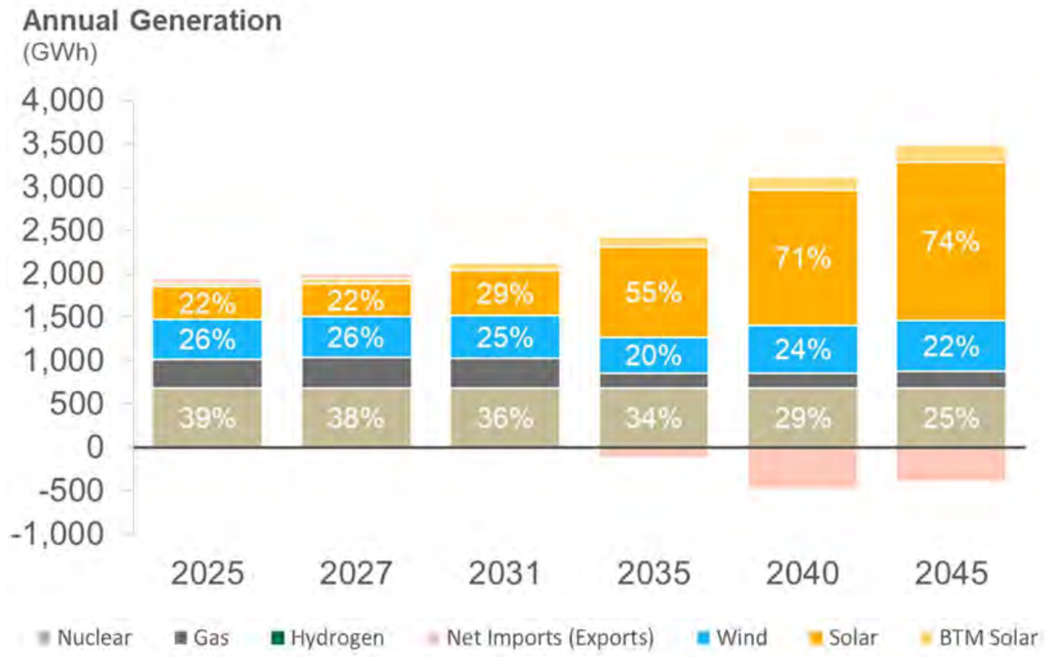
See Figure 6-11 for the total capacity for the New Mexico jurisdiction through 2045. No additional gas capacity is allocated to the New Mexico jurisdiction, and the amount of gas capacity declines as units retire. In 2025, more than 100 MW each of solar, storage, and wind capacity is dedicated to the New Mexico jurisdiction. The capacity for each of these resources grows through 2045, with solar and storage accounting for most capacity additions.

Figure 6-11. Capacity for NM Jurisdiction in Least-Cost + REA Case



See Figure 6-12 for the annual generation for the New Mexico jurisdiction through 2045. The figure shows the amount of renewable generation as a proportion of retail sales in all years. As the amount of renewable generation increases, the share of gas generation declines. In 2040 and 2045, when the 100% zero-carbon energy requirement is imposed in this case, there is still some gas generation. This gas generation helps satisfy load in some hours, while additional renewable generation in other hours exceeds New Mexico load and more than offsets this gas generation.

Figure 6-12. Annual Generation for NM Jurisdiction in Least-Cost + REA Case[34]



[34] The chart shows percentages for renewable and nuclear generation. This is the generation expressed as a percentage of retail sales for the New Mexico jurisdiction.

7 Sensitivity Analysis

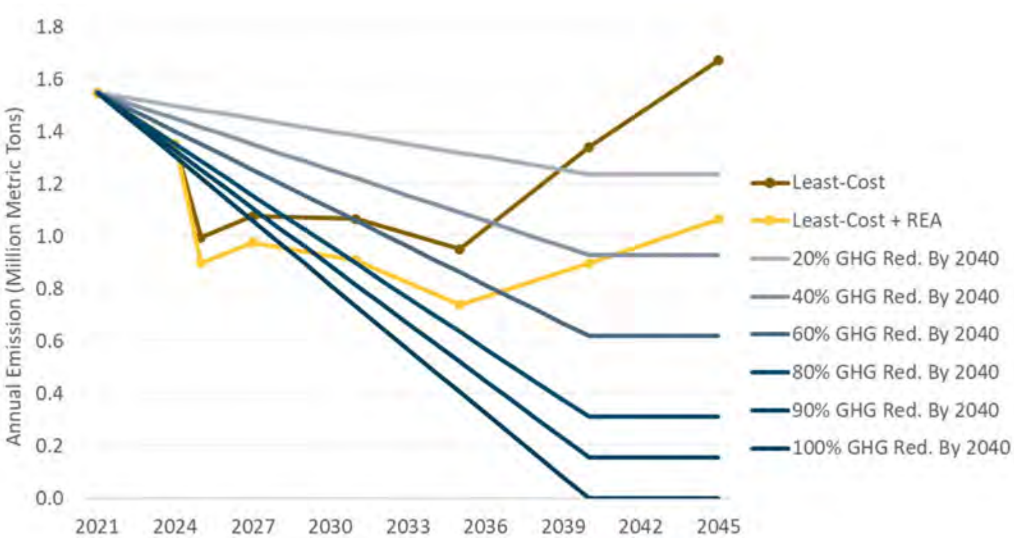
In addition to the REA cases, E3 performed analysis on several sensitivity cases to evaluate uncertainties in key planning assumptions and their impacts on the system portfolio. For each sensitivity case, E3 varied one or more inputs from the Least-Cost case and reoptimized for the period 2025-2045 to determine a new optimal portfolio. Any differences in the portfolio between the Least-Cost case and the sensitivity cases indicate the impact of the changes to planning assumptions. Sensitivity cases analyzed in this study include:

- Carbon reduction sensitivities
- Load and demand-side resource sensitivities
- Gas resource sensitivities
- Gas and carbon price sensitivities
- Technology cost sensitivity

7.1 Carbon Reduction Sensitivities

E3 assessed several greenhouse gas (GHG) reduction trajectories for the El Paso Electric system, ranging from 20% to 100% reductions by 2040 (see Figure 7-1). E3 first modeled the El Paso Electric system in 2021 to determine the emissions associated with serving retail load in this year. This emissions level serves as the baseline for calculating future emissions reductions under the different trajectories through 2040.

Figure 7-1. Emission Limits for Carbon Reduction Sensitivities



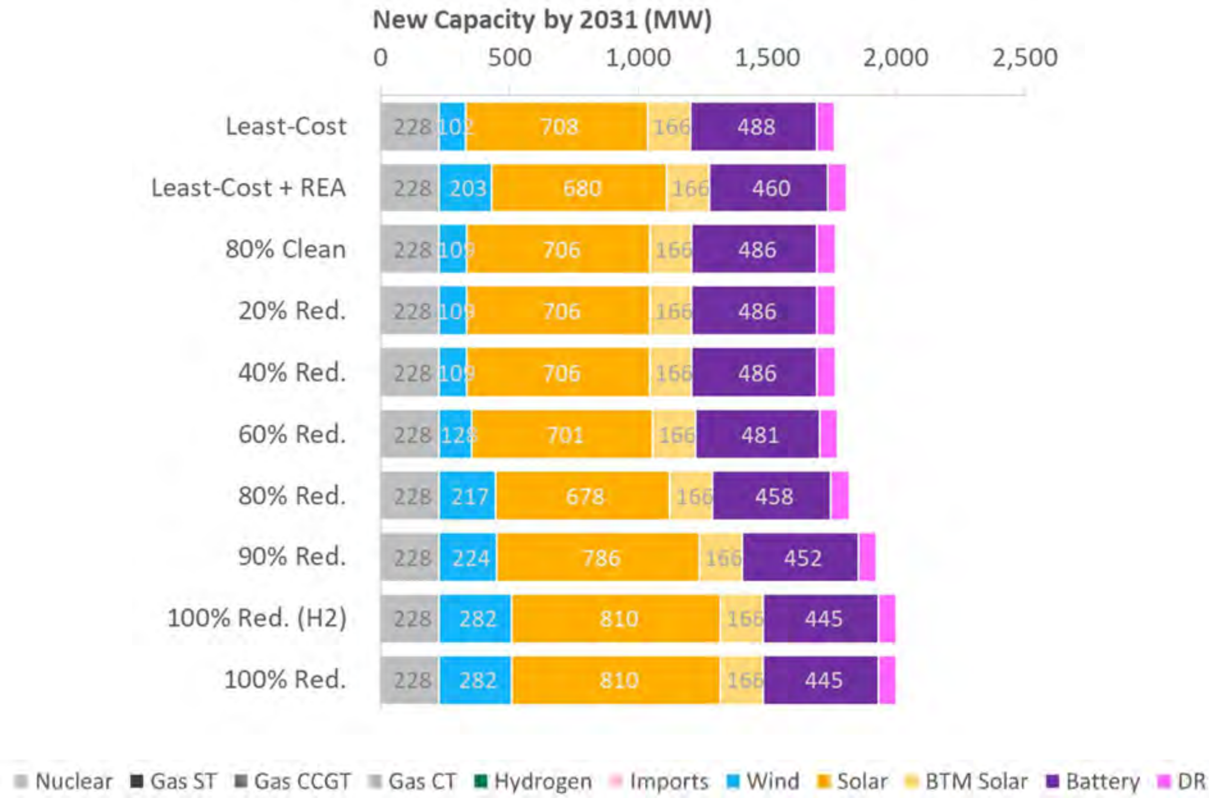
Modeling a range of carbon reduction trajectories serves two primary purposes. First, it helps inform how the cost of the EPE portfolio changes as a function of greenhouse reduction levels. This cost-carbon relationship can help guide future portfolio decisions. Second, there is a possibility that the federal government establishes carbon reduction requirements (or similar clean energy policies) that would require EPE to reduce emissions from the portfolio beyond levels that would result from existing state policies. These sensitivities, along with the carbon price sensitivities in Section 7.4, provide insights into how the portfolio could evolve under such policies.

The remainder of this section presents a summary of the results of the carbon reduction sensitivities, as well as a sensitivity that requires the portfolio to reach 80% zero-carbon energy by 2035 ("80% Clean").[35] The summary includes capacity and energy charts for 2031 and 2040, as well as a chart that illustrates the relationship between cost and carbon.

See Figure 7-2 for the cumulative resource additions through 2031. The portfolios in the 80% Clean and 20% to 60% Carbon Reduction sensitivities are similar to that of the Least-Cost case. This is because near-term renewable additions in the Least-Cost case already result in a reduction of carbon emissions in 2031 from the 2021 baseline emissions level. As shown in Figure 7-1 above, the Least-Cost case goes beyond the emissions reduction trajectory for the 60% Carbon Reduction sensitivity in 2031. Similarly, the 80% Carbon Reduction portfolio is similar to the Least-Cost Plus REA Resources case, as the latter achieves emissions reductions in 2031 that are very close to the trajectory for the 80% Carbon Reduction sensitivity. For the 90% and 100% reduction portfolios, more renewable resources are added to the system to further reduce emissions. These renewable resources also contribute to the reliability requirement and thus reduce some of the need for incremental storage capacity. Across all sensitivities, no new gas capacity is added by 2031 beyond Newman 6.

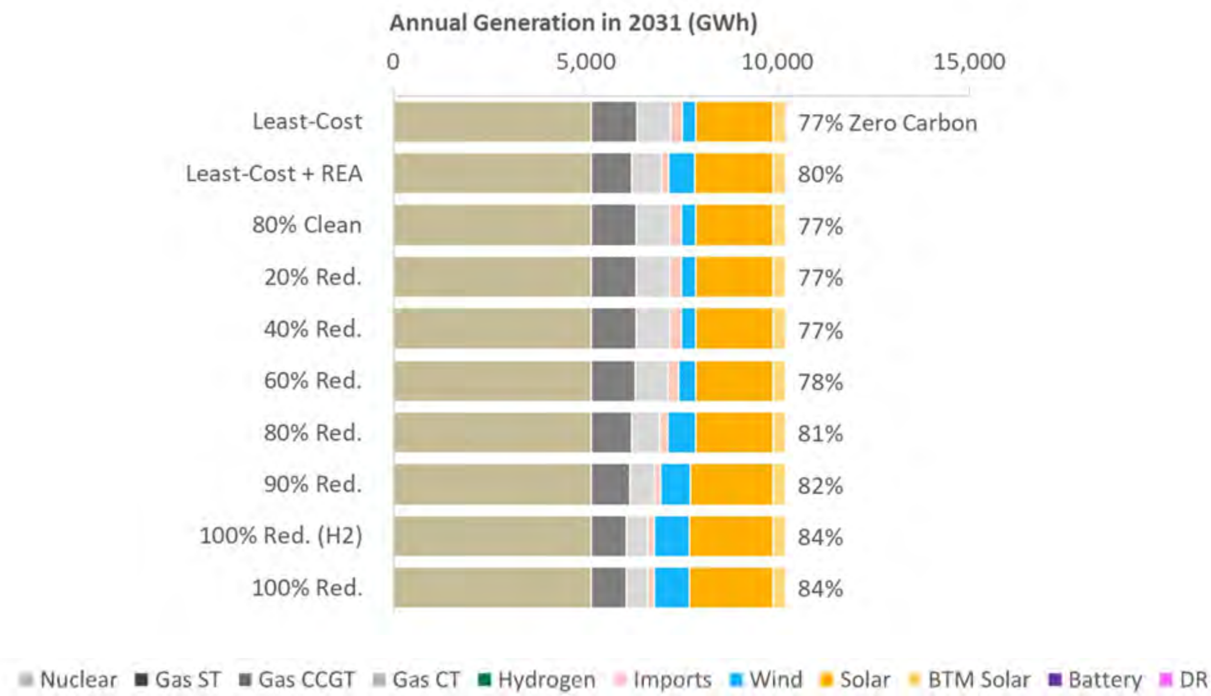
[35] E3 presented draft results for the carbon reduction sensitivities at the 2021 El Paso Electric Company Integrated Resource Plan Public Participation March 2021 Meeting. This report provides final results for the carbon reduction sensitivities.

Figure 7-2. Cumulative New Capacity by 2031 for Carbon Reduction Sensitivities



See Figure 7-3 for the annual generation mix in 2031. The shares of generation from zero-carbon energy sources in the 80% Clean and 20% to 60% Carbon Reduction cases are close to that of the Least-Cost case (77%). In the more stringent emission reduction sensitivities, which have more renewable resource additions, the percentage of zero-carbon energy increases to over 80%.

Figure 7-3. Annual Generation in 2031 for Carbon Reduction Sensitivities



See Figure 7-4 and Figure 7-5 for the cumulative resource additions through 2040. Figure 7-5 includes the most extreme sensitivity, 100% Carbon Reduction (no H_2). Compared to 2031, there is much more divergence in the resource portfolios in 2040 because the clean energy targets become binding in all sensitivities. As the stringency of the requirement increases, the resource portfolio has more renewable and storage resources, and less gas plant additions. At the 100% carbon reduction level, almost all additions beyond Newman 6 are renewable and storage resources. The large difference in resource additions between the two 100% Carbon Reduction sensitivities highlights the benefits of a clean, firm resource – in this study, hydrogen-powered plants – in achieving a fully decarbonized system. Without such a resource, supplying 100% zero-carbon energy while ensuring reliability across all hours requires a significant overbuild of renewable and storage resources.

Figure 7-4. Cumulative New Capacity by 2040 for Carbon Reduction Sensitivities

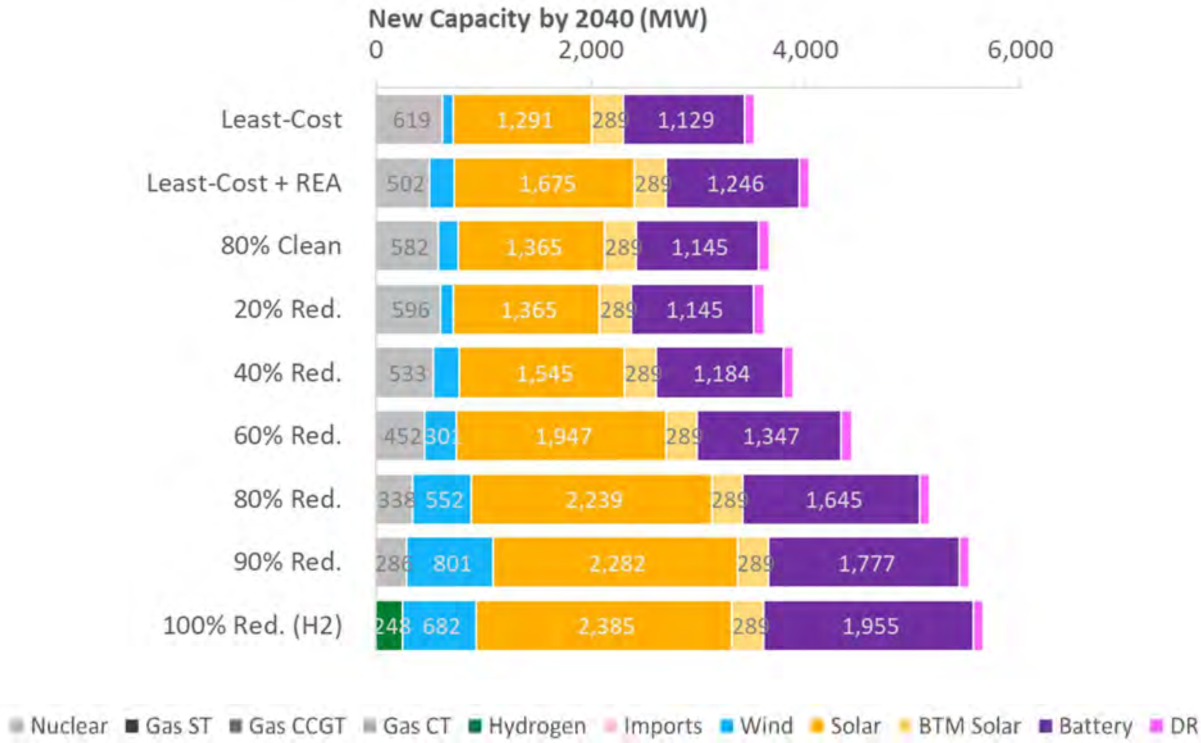
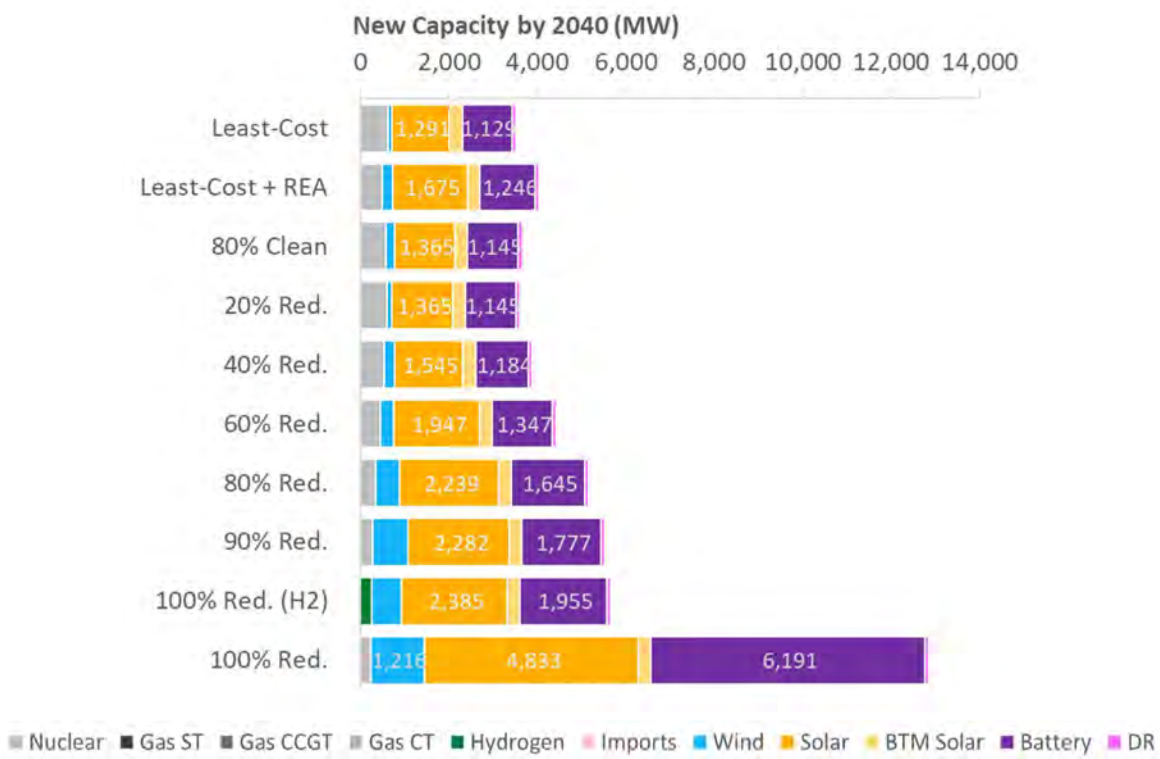
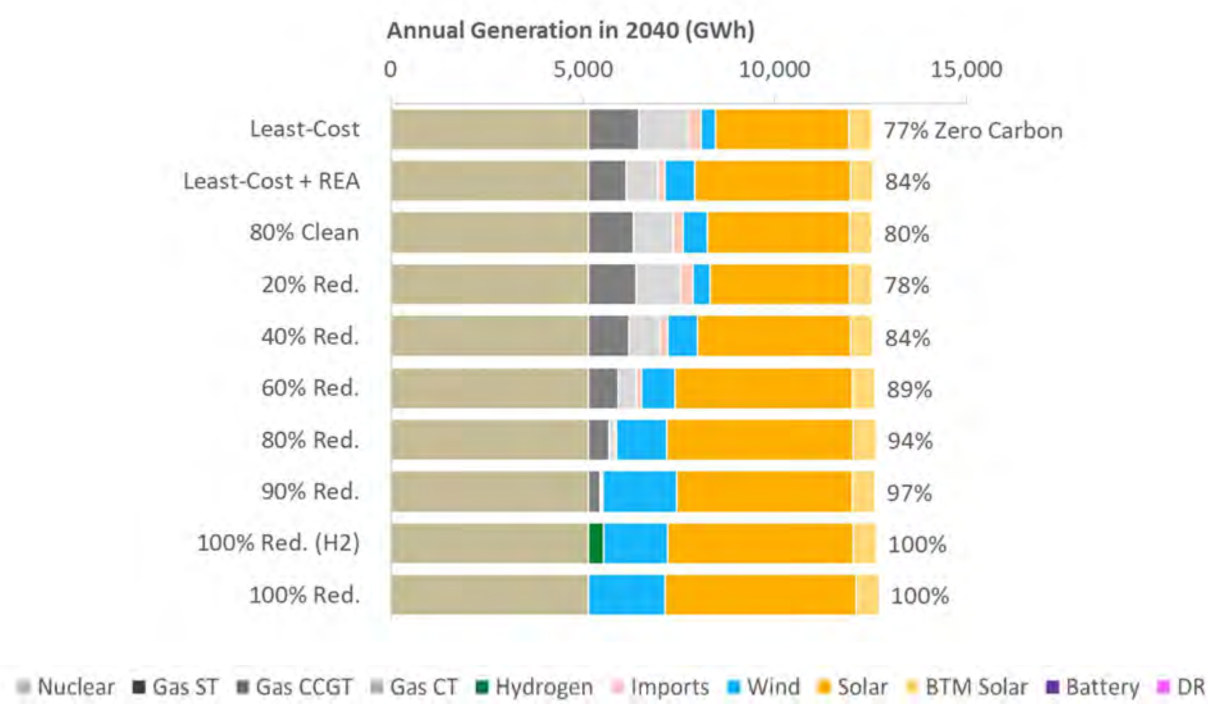


Figure 7-5. Cumulative New Capacity by 2040 for Carbon Reduction Sensitivities



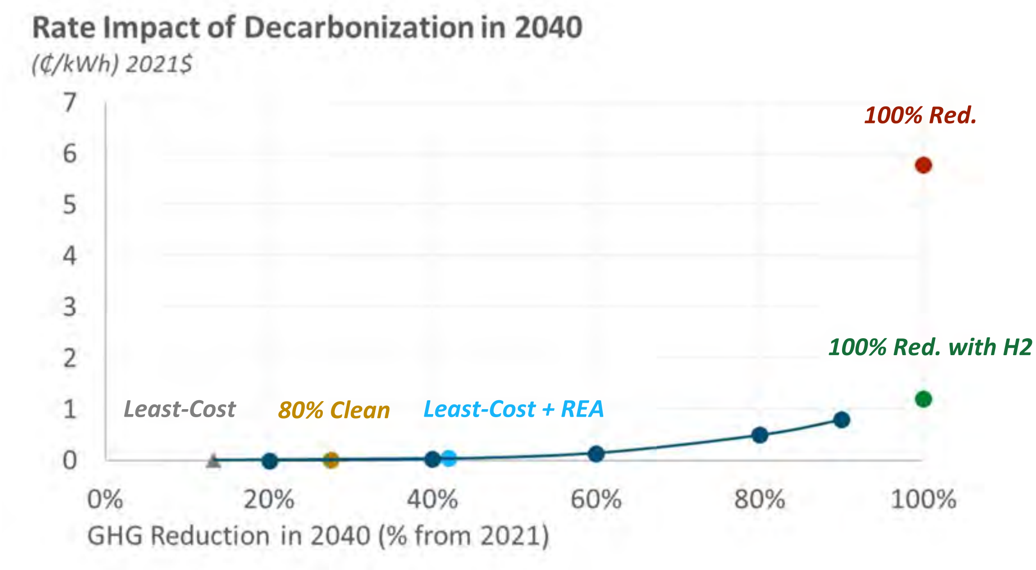
See Figure 7-6 for the annual generation mix in 2040 across carbon reduction sensitivities. Gas generation and market imports decline as the stringency of the targets increases. In the 100% Carbon Reduction (H_2) case, nuclear, wind, and solar resources make up most of the energy supply. Given the high cost of hydrogen, hydrogen-burning plants only dispatch when the system does not have sufficient energy supply from other resources and thus have low capacity factors. In the 100% Carbon Reduction (no H_2) sensitivity, the only resources available to serve load besides nuclear are wind and solar facilities.

Figure 7-6. Annual Generation in 2040 for Carbon Reduction Sensitivities



The cost of the EPE portfolio under these sensitivities is another important factor to consider. Figure shows the incremental average system rate impact relative to the Least-Cost case, as well as the reduction in GHG emissions, for the above sensitivities in 2040. The Least-Cost case results in 13% GHG reductions. The 20% and 40% reduction sensitivities, 80% Clean, and Least-Cost Plus REA cases achieve higher GHG reduction levels with relatively small impacts to rates. Further emission reductions lead to higher rate impacts. The 90% Carbon Reduction sensitivity has an additional cost of 0.8 ₵/kWh. The rate impacts are higher still for the 100% Carbon Reduction sensitivities, with the rate impact for the sensitivity without hydrogen (5.8 ₵/kWh) being significantly higher than the rate impact for the sensitivity with hydrogen (1.2₵/kWh). As discussed above, the sensitivity without hydrogen results in significant overbuilds of renewable and storage resources to ensure reliability without firm generating capacity. This results in the large rate impact.

Figure 7-7. Incremental Rate Impact in 2040 for Carbon Reduction Sensitivities



7.2 Load and Demand-Side Resource Sensitivities

One key planning assumption that drives future resource needs is the load forecast. There are several uncertain factors within the load forecast, including end-use energy demand, distributed generation (DG) deployment levels, and demand-side management (DSM) deployment levels. Each of these factors is tested through the following sensitivities:

- **High Distributed Generation (DG)**
  EPE provided a high forecast for the deployment of DG, which is more than double the level in the Least-Cost case. Figure 7-8 compares the DG levels in the high DG sensitivity and the Least-Cost case, which is labeled as "Reference" in the figures in this section.

- **High Demand-Side Management (DSM)**
  In the High DSM sensitivity, EPE assumed that smart thermostats gain market adoption faster than in the Least-Cost case and would ultimately rise to 60 MW of capacity rather than 50 MW in the Least-Cost case (see Figure 7-9). This sensitivity also assumes a doubling of incremental energy efficiency levels compared with what's assumed in the Least-Cost case (see Figure 7-10).

- **Low Load Growth** and **High Load Growth**
  EPE developed load forecasts for low and high load growth sensitivities. Figure and Figure 7-12 compare the load forecast for energy and demand, respectively, between the sensitivities and the Least-Cost.

Load and demand-side resource forecasts beyond 2040 were assumed to have the same growth rate as that between 2039 and 2040.[36]

Figure 7-8. Distributed Generation Capacity in the High DG Sensitivity

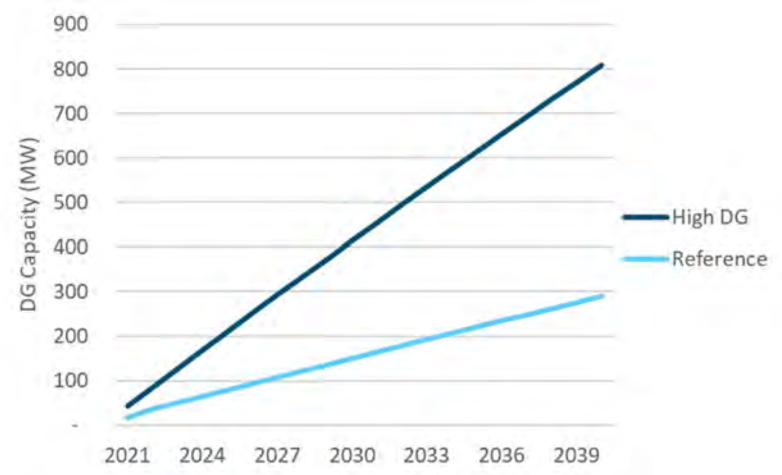
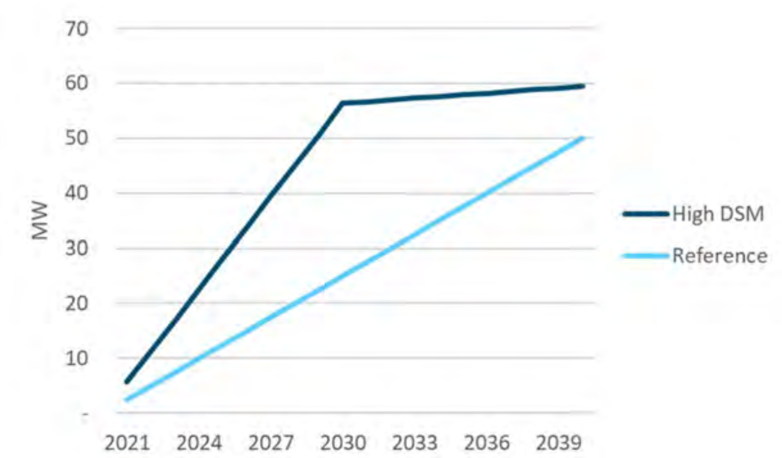


Figure 7-9. Smart Thermostat Capacity in the High DSM Sensitivity



[36] The capacity for smart thermostats remains constant at the 2040 level.

Figure 7-10. Incremental Energy Efficiency in the High DSM Sensitivity Scenario

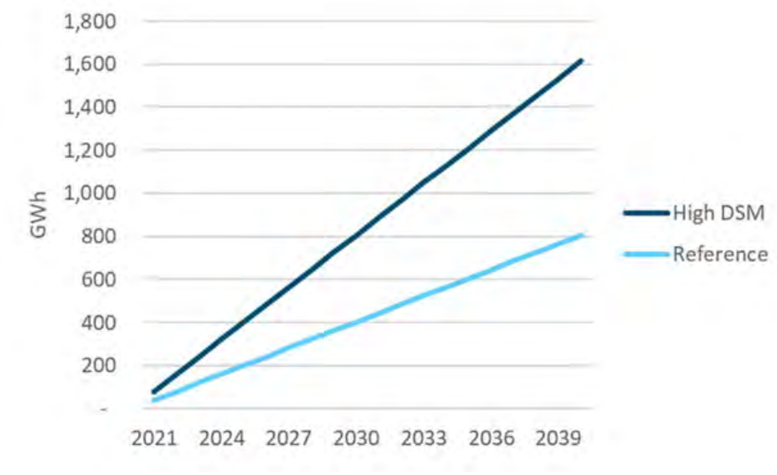
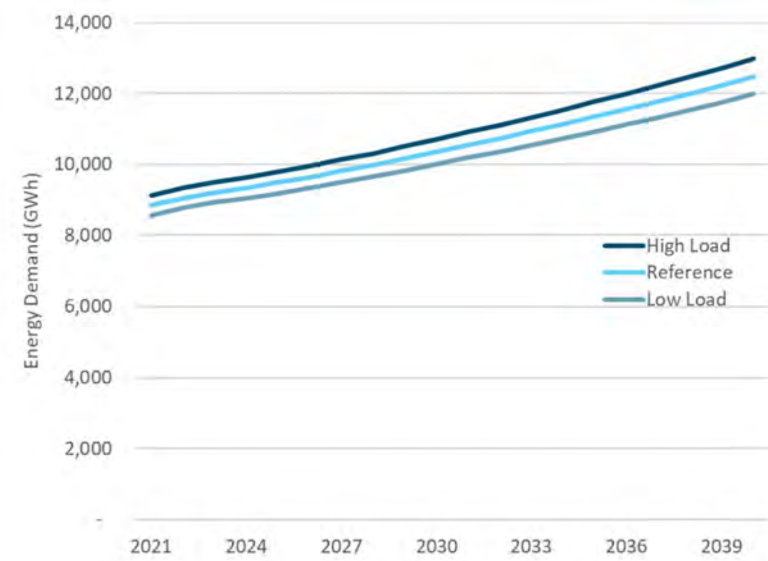
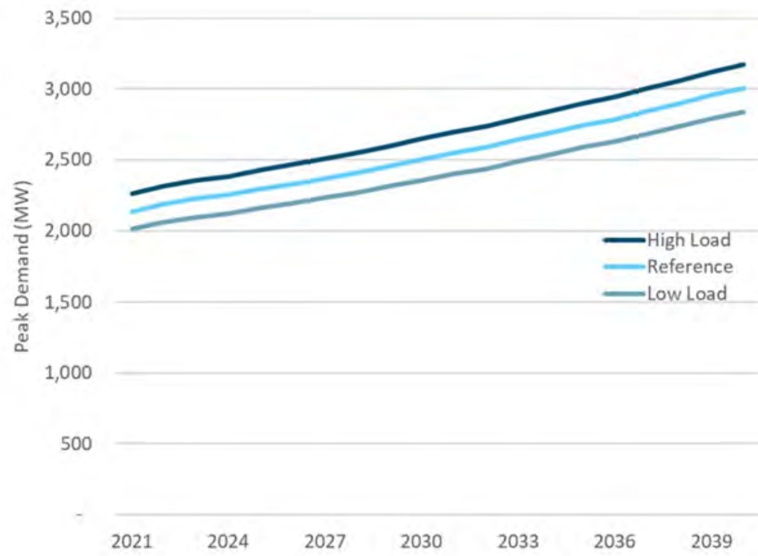


Figure 7-11. Native System Load Forecast[37] for Energy in Load Sensitivities



[37] Native system forecast does not include the impact of energy efficiency (EE), distributed generation (DG), and electric vehicles (EV). These components are accounted for separately and do not change in the Low Load or High Load sensitivities.

Figure 7-12. Native System Load Forecast[37] for Demand in Load Sensitivities



See Figure 7-13 and Figure 7-14 for the cumulative resource additions through 2031 and 2040, respectively. In the High DG sensitivity, the additional DG in the system displaces the need for some utility-scale solar, but otherwise has a similar portfolio to that of the Least-Cost case. In the High DSM and Low Load sensitivities, reduced load across all hours leads to less capacity additions across all resources.[38] By contrast, the higher demand in the High Load sensitivity leads to more capacity additions across all resources.

See Figure 7-15 and Figure 7-16 for the annual generation mix in 2031 and 2040, respectively. In the high DG sensitivity, the generation mix is almost the same as the Least-Cost case, as DG replaces utility-scale solar, which has a similar production profile. In the High DSM and Low Load sensitivities, the percentage of zero-carbon energy is lower than that in the Least-Cost case because of lower renewable energy levels and higher gas dispatch. The High Load sensitivity has a slightly higher zero-carbon energy share than the Least-Cost case in 2031 due to more renewable resources in the near-term and a slightly lower clean percentage in 2040 as more gas is added.

[38] BTM solar capacity remains at the levels that are forecast by EPE and does not vary in these scenarios.

Figure 7-13. Cumulative New Capacity by 2031 for Load and Demand-Side Resource Sensitivities

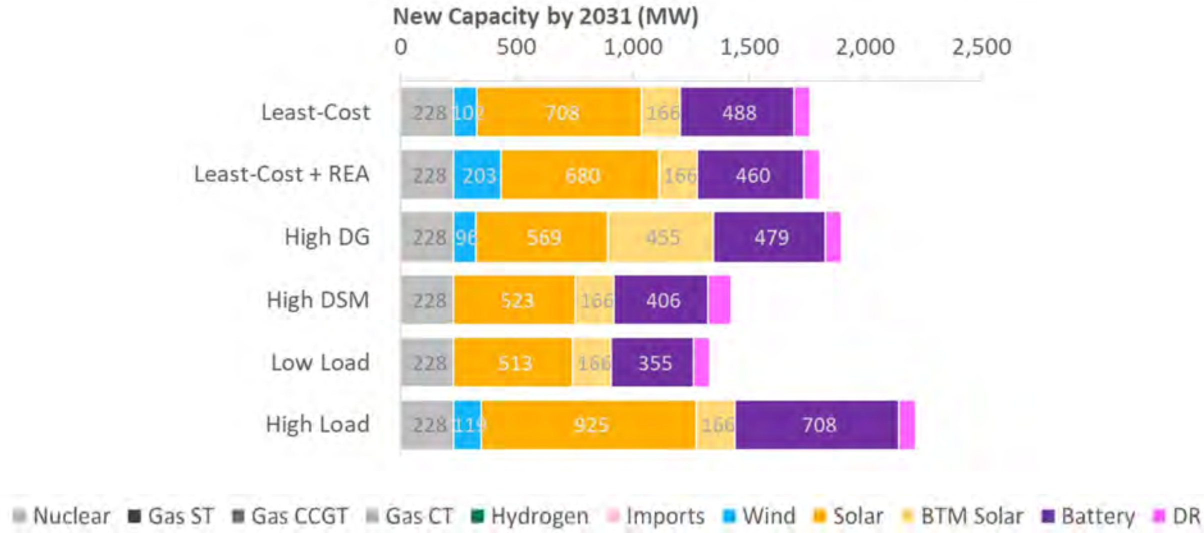


Figure 7-14. Cumulative New Capacity by 2040 for Load and Demand-Side Resource Sensitivities

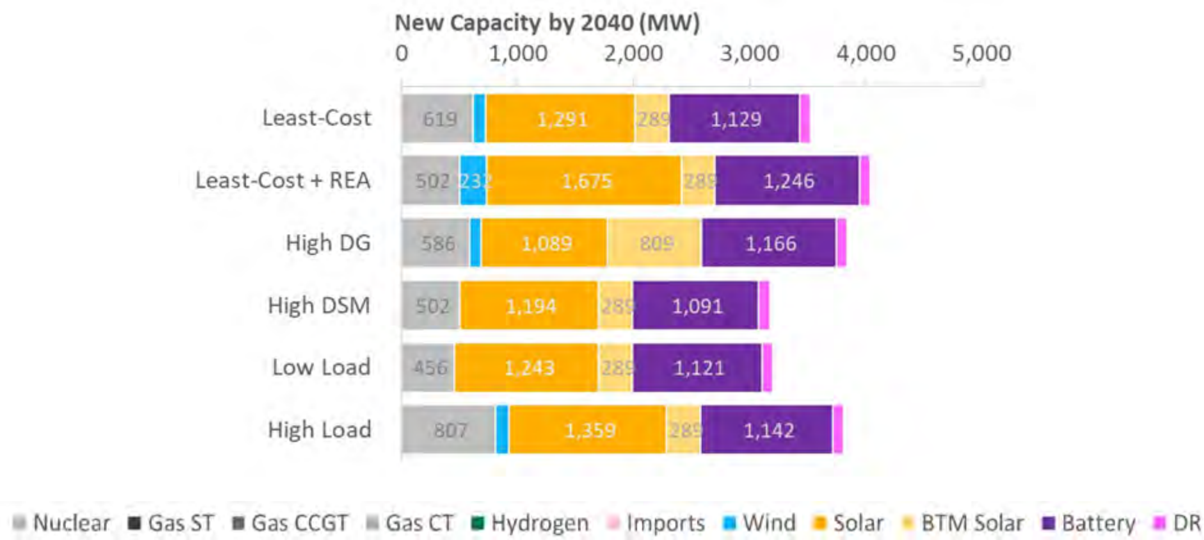


Figure 7-15. Annual Generation in 2031 for Load and Demand-Side Resource Sensitivities

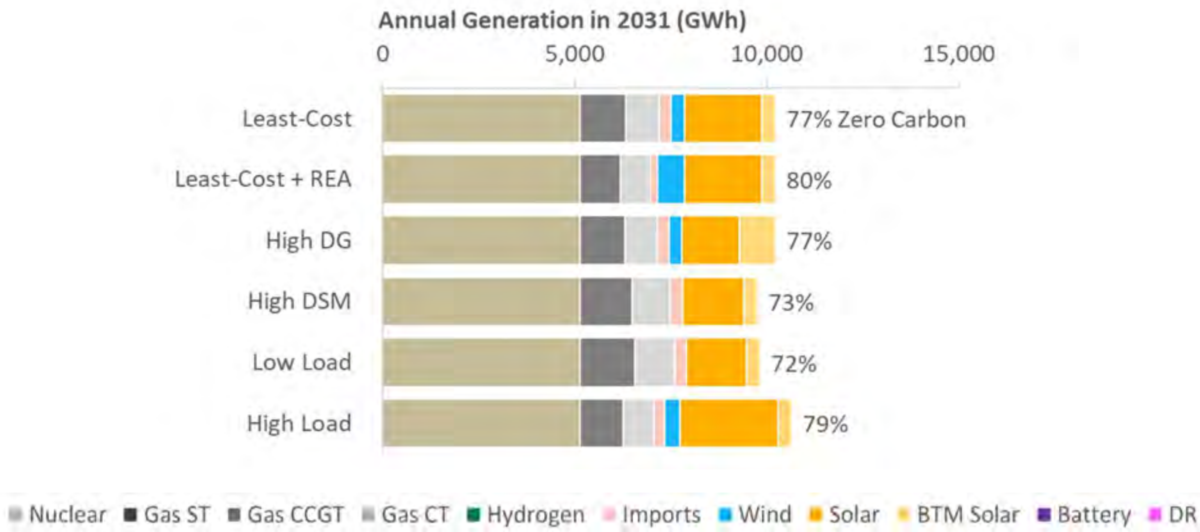
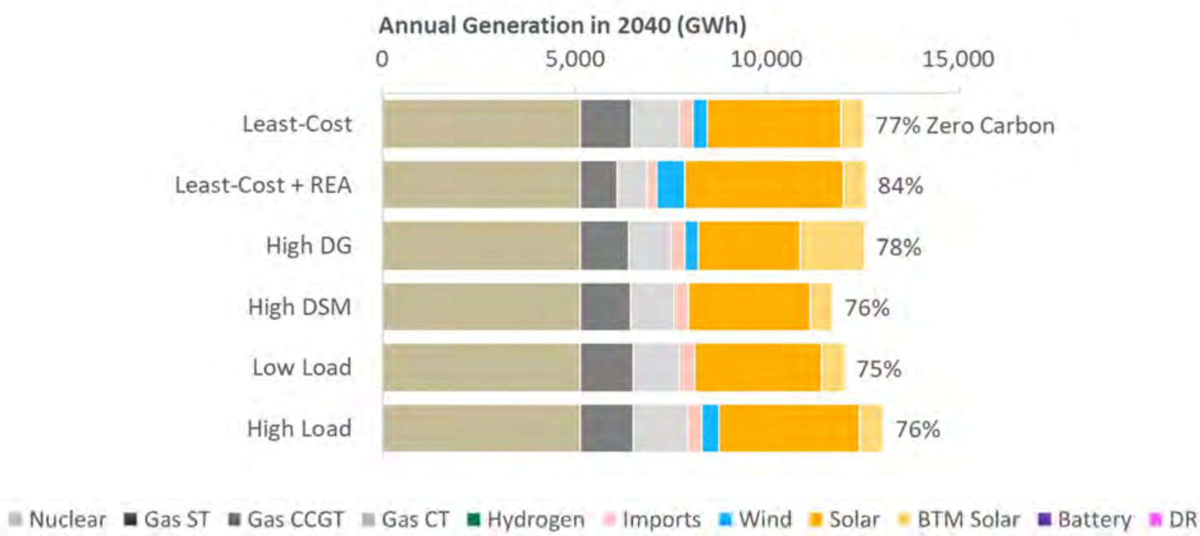


Figure 7-16. Annual Generation in 2040 for Load and Demand-Side Resource Sensitivities



7.3 Gas Resource Sensitivities

Across the REA cases, existing and new gas resources play an important role in ensuring reliability for the overall system. E3 analyzed two sensitivities for gas resource availability to understand the implications of not having some gas resources available to the portfolio:

- **No Lifetime Extensions**
  In the Least-Cost case, the lifetimes for Newman units 1, 3, and 4 are extended by five years. These plant extensions reduce the need for new capacity in the near term. The No Lifetime Extensions sensitivity does not allow for these lifetime extensions. Given the uncertainty in plant conditions and maintenance costs going forward, this sensitivity can help EPE assess which resources are needed without these extensions.

- **No New Gas**
  After the addition of the Newman 6 unit, the portfolio cannot include any new natural gas plant capacity, including capacity that would otherwise serve Texas customers.

See Figure 7-17 and Figure 7-18 for the cumulative resource additions through 2031 and 2040, respectively. In 2031, the No Extension sensitivity has more renewable, storage, and gas additions than the Least-Cost case to make up for the reduction in capacity from the units that retire earlier. However, by 2040, the two portfolios converge, as the gas extensions in the Least-Cost case do not go beyond 2031. For the No New Gas sensitivity, more renewable and storage resources are added to the system than the Least-Cost case to meet load growth and reliability requirements. This is especially evident by the year 2040. Without the option to add gas capacity, the No New Gas sensitivity relies on renewable and storage resources to satisfy the PRM, and these resources' contributions decline with penetration (per the ELCC analysis).

Figure 7-17. Cumulative New Capacity by 2031 for Gas Resource Sensitivities

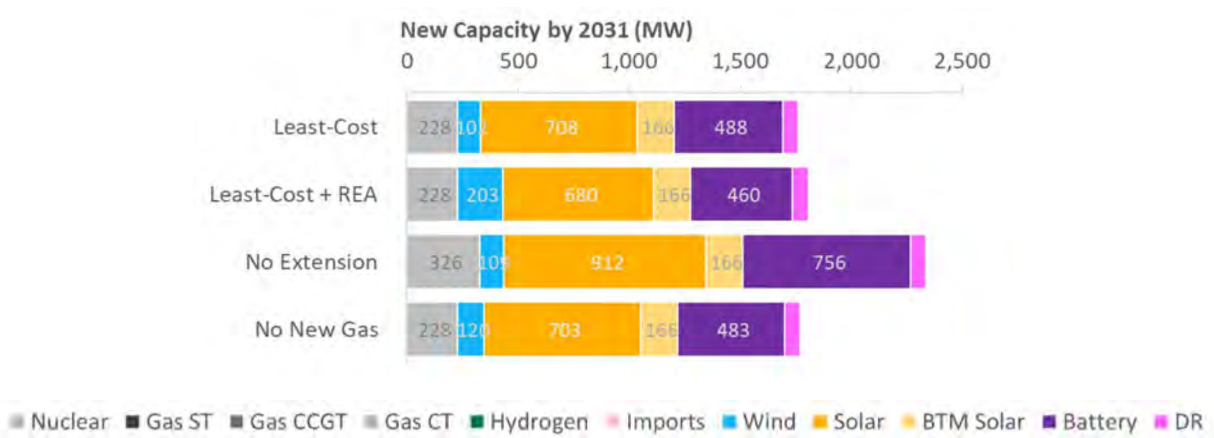
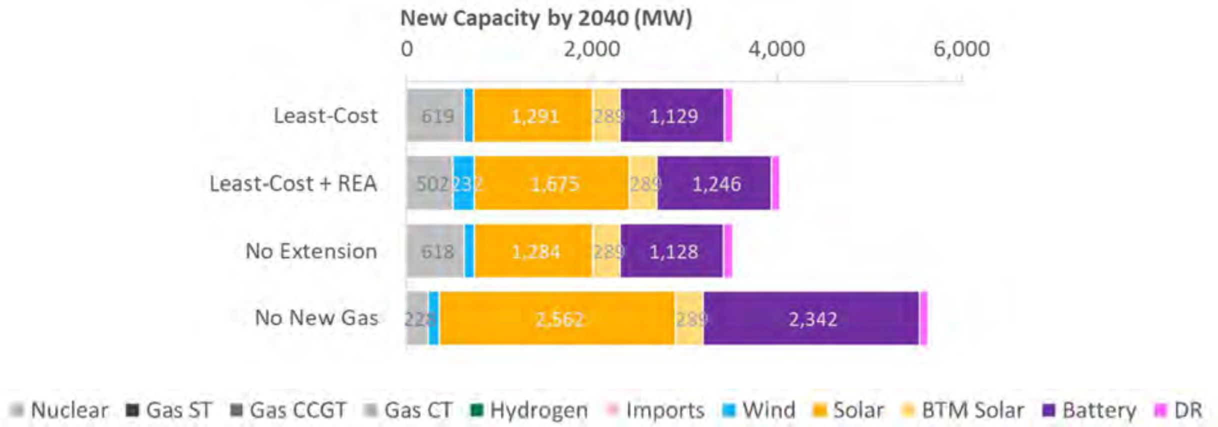


Figure 7-18. Cumulative New Capacity by 2040 for Gas Resource Sensitivities



See Figure 7-19 and Figure 7-20 for the annual generation mix in 2031 and 2040, respectively. The No Extension sensitivity has a higher percentage of zero-carbon energy than the Least-Cost case in 2031 because of larger near-term renewable additions. However, after the extension period, the generation mix is similar. The No New Gas sensitivity has a much greater share of zero-carbon energy in 2040 given the large amount of renewable resources on the system.

Figure 7-19. Annual Generation in 2031 for Gas Resource Sensitivities

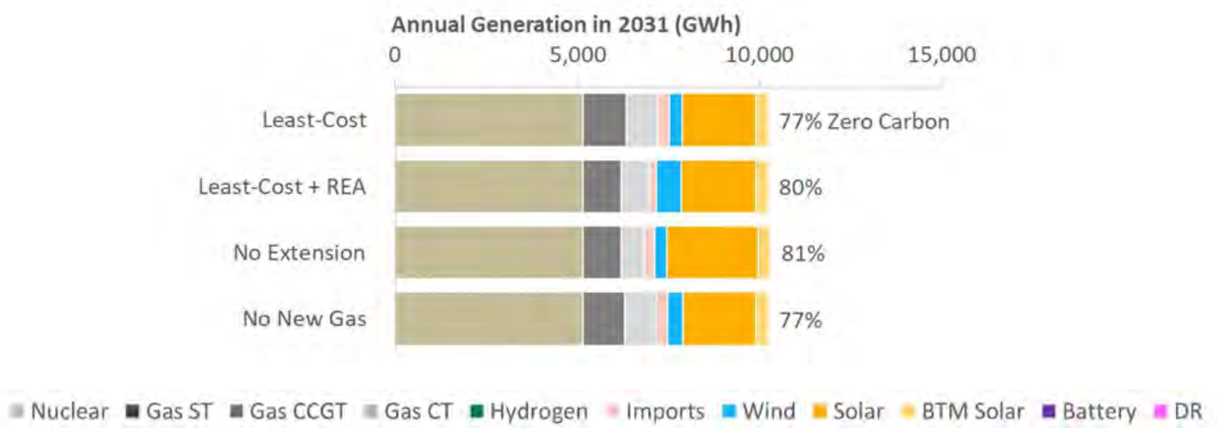
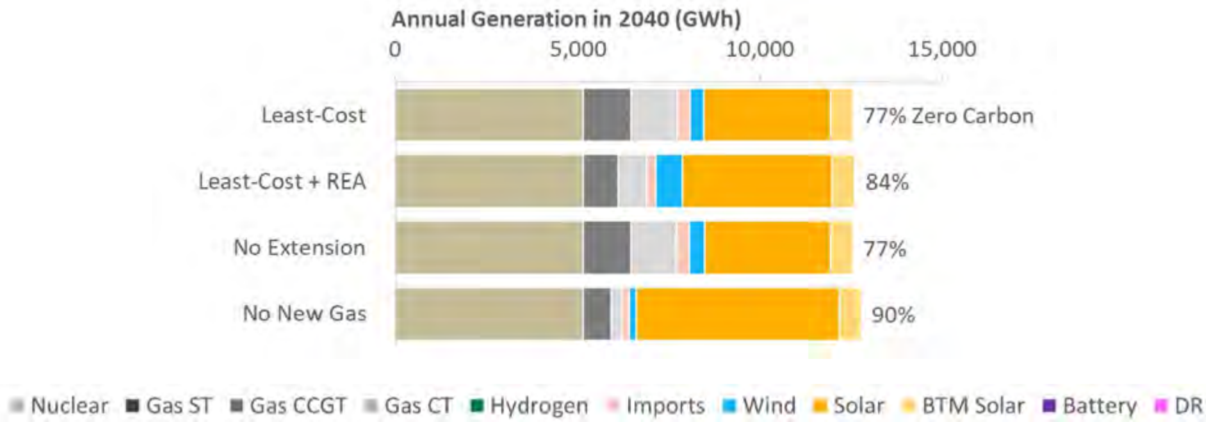
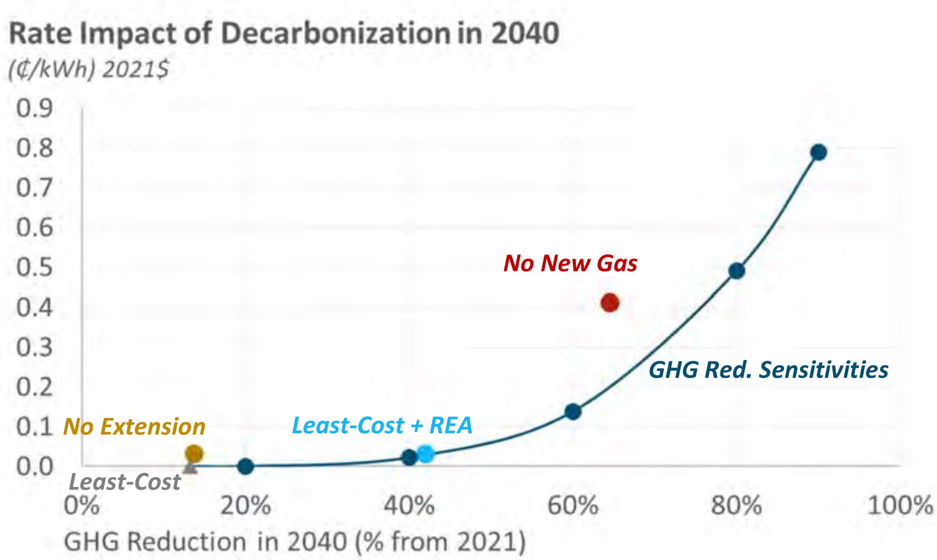


Figure 7-20. Annual Generation in 2040 for Gas Resource Sensitivities



See Figure 7-21 for the incremental rate impact of the gas resource sensitivities relative to the Least-Cost case in 2040. The No Extension sensitivity achieves the same level of carbon reductions as the Least-Cost case because they converge by this year. However, the No Extension sensitivity has slightly higher costs than the Least-Cost case because some of the renewable and storage resources in the No Extension sensitivity come online in earlier years when the resource costs are higher. The No New Gas sensitivity has a cleaner portfolio but also a higher cost than the Least-Cost case due to the overbuild of renewable and storage resources to displace firm gas resources available to the Least-Cost case. Moreover, the No New Gas sensitivity does not compare favorably to the cost-carbon relationship that was identified in the Carbon Reduction sensitivities that allowed for new gas plant additions.

Figure 7-21. Incremental Rate Impact in 2040 for Gas Resource Sensitivities



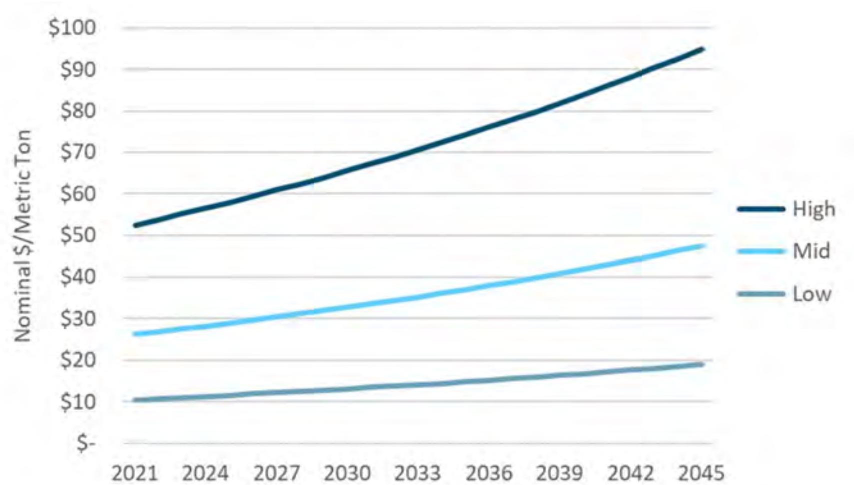
7.4 Gas and Carbon Price Sensitivities

The future market price of natural gas is uncertain. Historical gas prices are volatile, making future projections challenging. E3 tested a high gas price level. In addition, E3 tested different carbon price levels, which reflect the potential for future policies that impose a cost on emitting carbon dioxide from power plants. E3 analyzed four price sensitivities in total related to carbon or gas pricing:

- **Low / Mid / High Carbon Price**
  The New Mexico Public Regulation Commission has published carbon emission prices that should be considered in IRPs. Figure 7-22 shows the low, mid, and high carbon price trajectories. Three sensitivity cases were developed by adding these carbon costs to the Reference Case, which does not include any carbon pricing.

- **High Gas Price**
  Gas prices are 15% higher than those in the Reference Case.

Figure 7-22. Carbon Price Sensitivities



See Figure 7-23 and Figure 7-24 for the cumulative resource additions through 2031 and 2040, respectively. See Figure 7-25 and Figure 7-26 for the annual generation mix in 2031 and 2040, respectively. Introducing carbon prices and increasing gas prices both make gas plant operations more expensive. As a result, the gas and carbon price sensitivities have more renewable resources and less new gas resources in the portfolio than the Least-Cost case. The generation mix also becomes cleaner in these sensitivities as the cost of burning gas is higher than the Least-Cost case. At the price levels tested in these sensitivities, the carbon price sensitivities have a larger impact on the portfolio. However, if higher gas prices were tested, the magnitude of the portfolio changes would increase commensurately.

Figure 7-23. Cumulative New Capacity by 2031 for Gas and Carbon Price Sensitivities

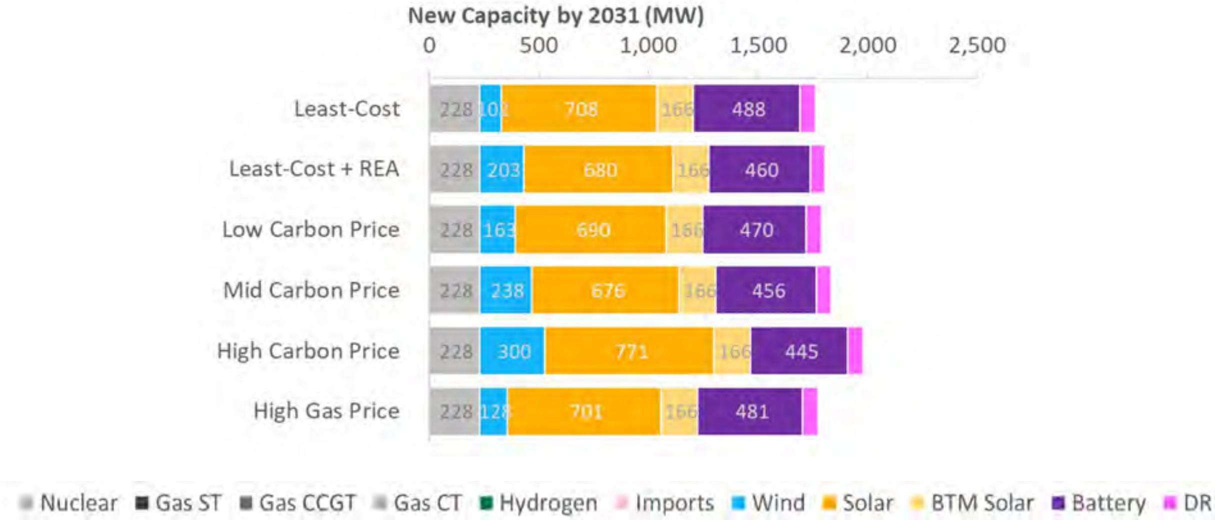


Figure 7-24. Cumulative New Capacity by 2040 for Gas and Carbon Price Sensitivities

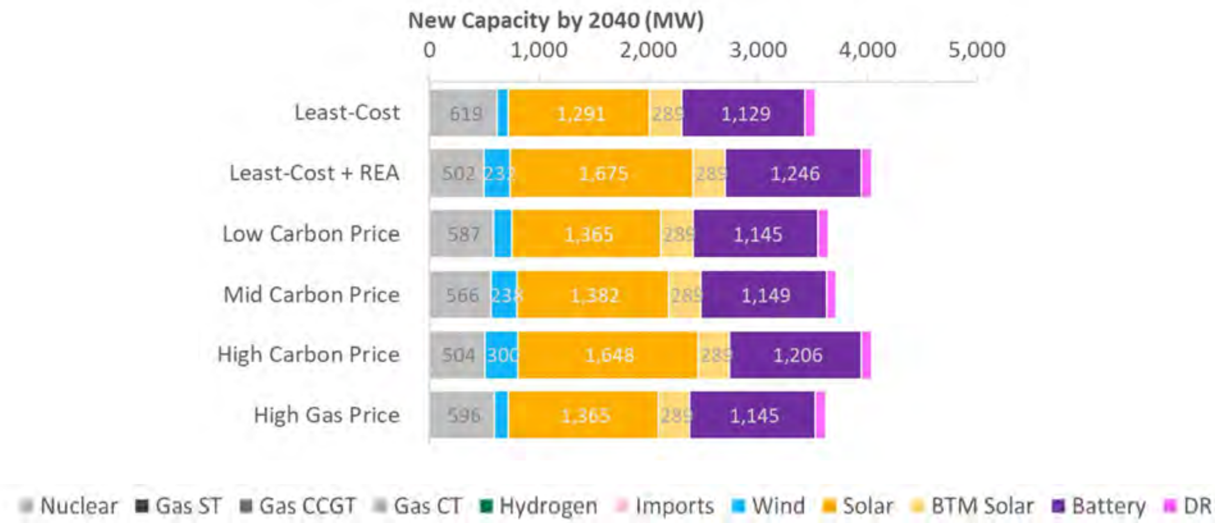


Figure 7-25. Annual Generation in 2031 for Gas and Carbon Price Sensitivities

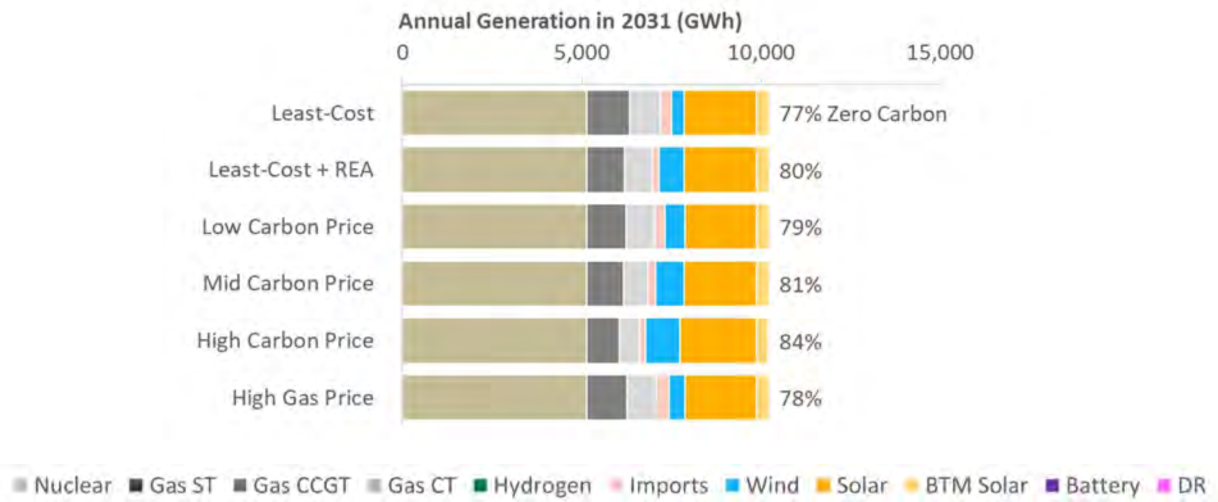
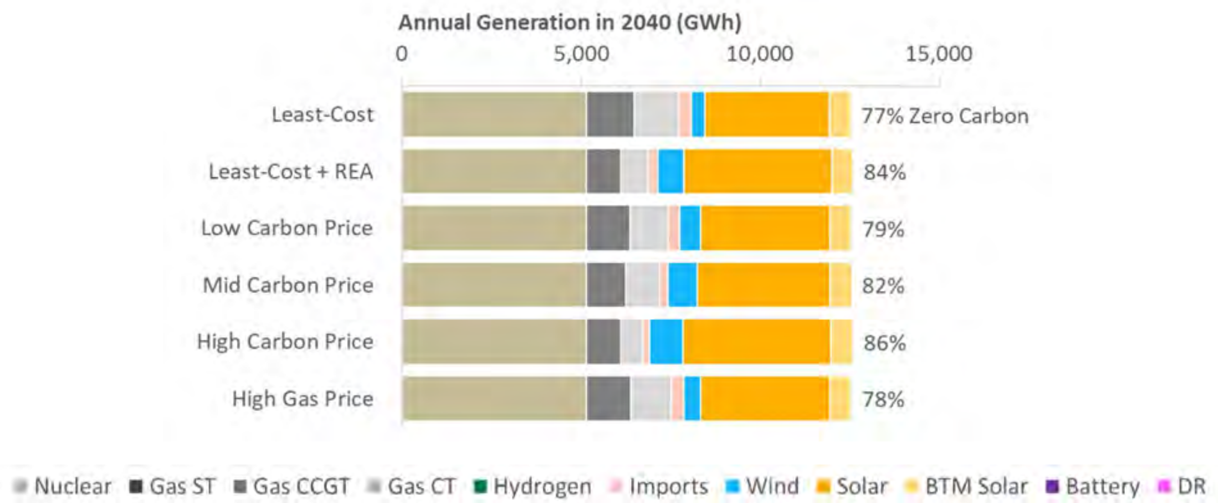


Figure 7-26. Annual Generation in 2040 for Gas and Carbon Price Sensitivities



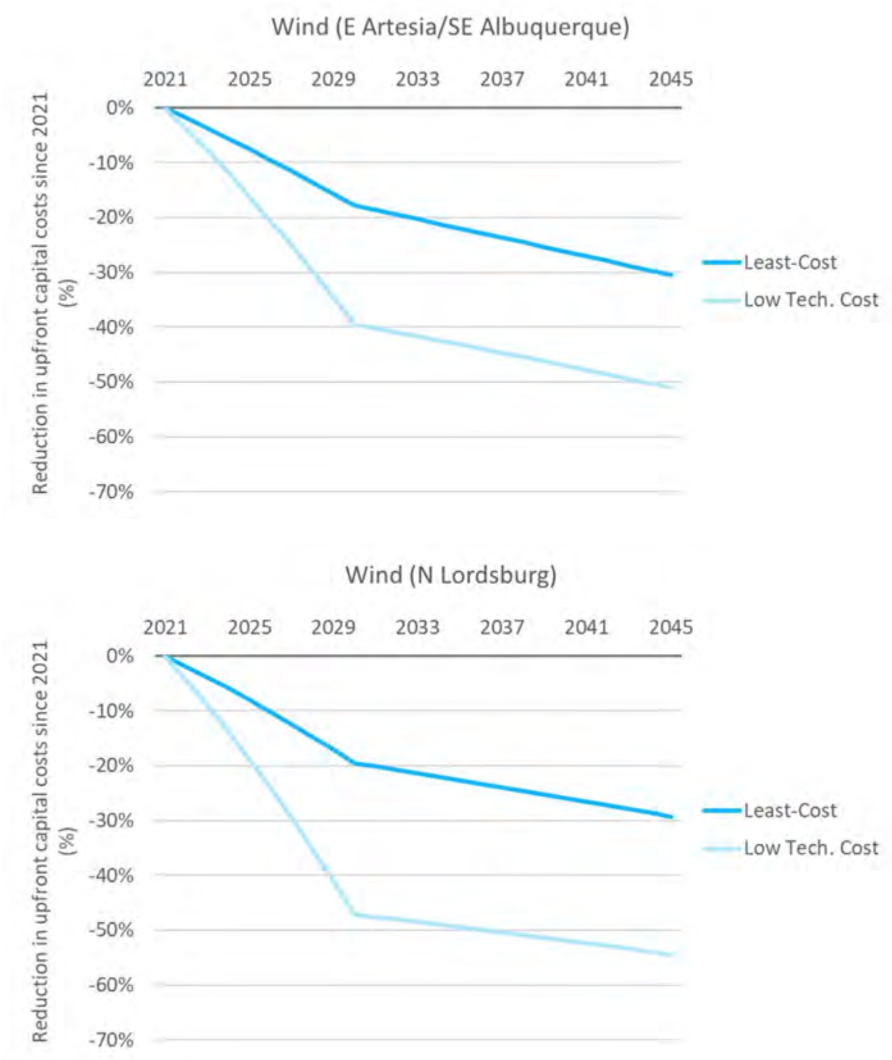
7.5 Technology Cost Sensitivity

The deployment levels of different technologies within an optimal portfolio depend on many factors, but one of the most important is the cost of the technology. In recent years, the cost of renewable and storage resources has fallen dramatically. The Least-Cost, which serves as a reference, anticipates substantial further cost declines through the IRP planning horizon,[39] but these cost declines uncertain. Costs could decline more slowly or more quickly than anticipated. E3 assessed a Low Technology Cost sensitivity,

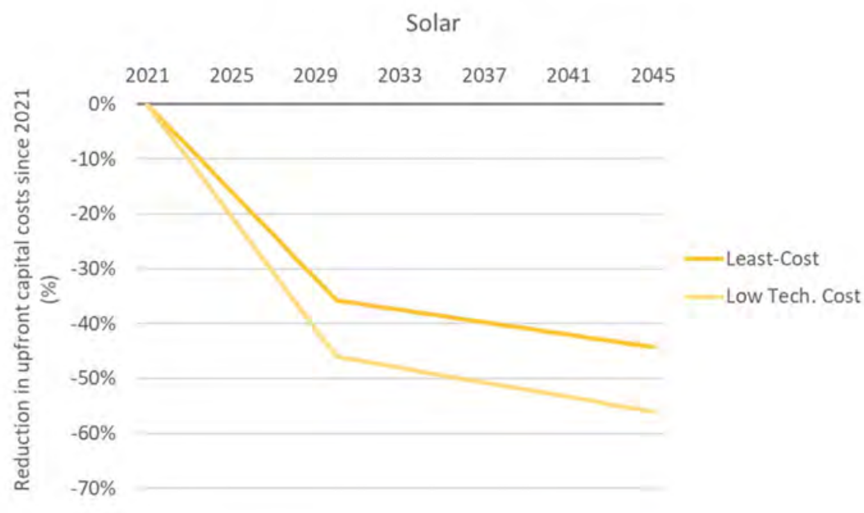
[39] See Appendix A: Candidate Resource Assumptions for renewable and storage cost decline assumptions.

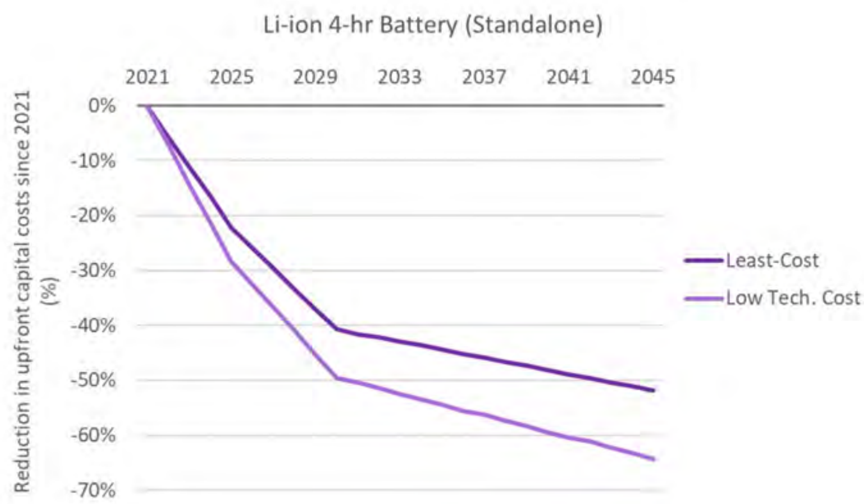
which has renewable and storage costs declining more quickly than in the Least-Cost case.[40] Figure 7-27 shows the change in resources costs by technology relative to the Least-Cost case.

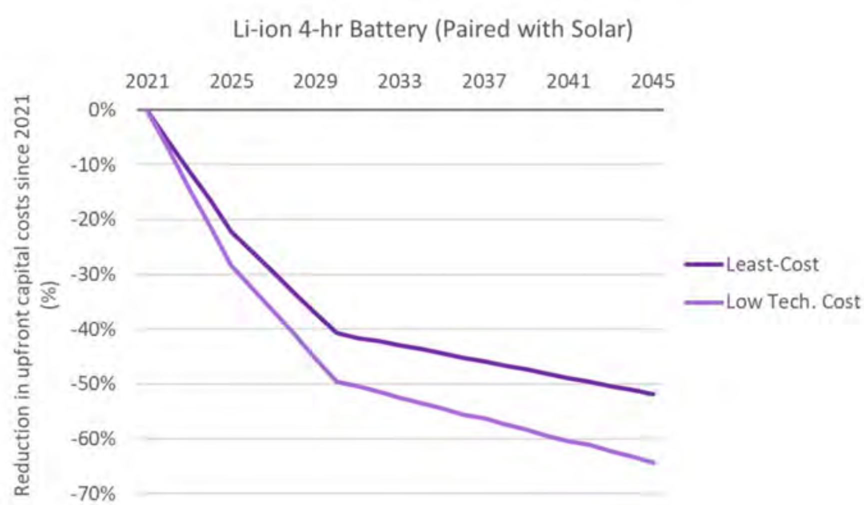
Figure 7-27. Cost Reductions in the Low Technology Cost Sensitivity



[40] The cost declines for the Low Technology Cost sensitivity are based on the "Advanced" trajectory from the NREL ATB, while the cost declines for the Least-Cost case are based on the "Moderate" trajectory from the NREL ATB.


Solar
2021
2025
2029
2033
2037
2041
2045
0%
-10%
-20%
-30%
-40%
-50%
-60%
-70%
Reduction in upfront capital costs since 2021 (%)
Least-Cost
Low Tech. Cost


Li-ion 4-hr Battery (Standalone)
2021
2025
2029
2033
2037
2041
2045
0%
-10%
-20%
-30%
-40%
-50%
-60%
-70%
Reduction in upfront capital costs since 2021 (%)
Least-Cost
Low Tech. Cost


Li-ion 4-hr Battery (Paired with Solar)
2021
2025
2029
2033
2037
2041
2045
0%
-10%
-20%
-30%
-40%
-50%
-60%
-70%
Reduction in upfront capital costs since 2021 (%)
Least-Cost
Low Tech. Cost

See Figure 7-28 and Figure 7-29 for the cumulative resource additions through 2031 and 2040, respectively. Lower technology costs make renewable and storage resources more economical, and thus the Low Technology Cost sensitivity has slightly more renewable additions and less gas additions than the Least-Cost portfolio. The resulting zero-carbon energy levels are also higher in the Low Technology Cost sensitivity (see Figure 7-30 and Figure 7-31). Between the renewable resources, the increase in wind capacity is higher than that of solar due to larger cost reductions.

Figure 7-28. Cumulative New Capacity by 2031 for Low Technology Cost Sensitivity

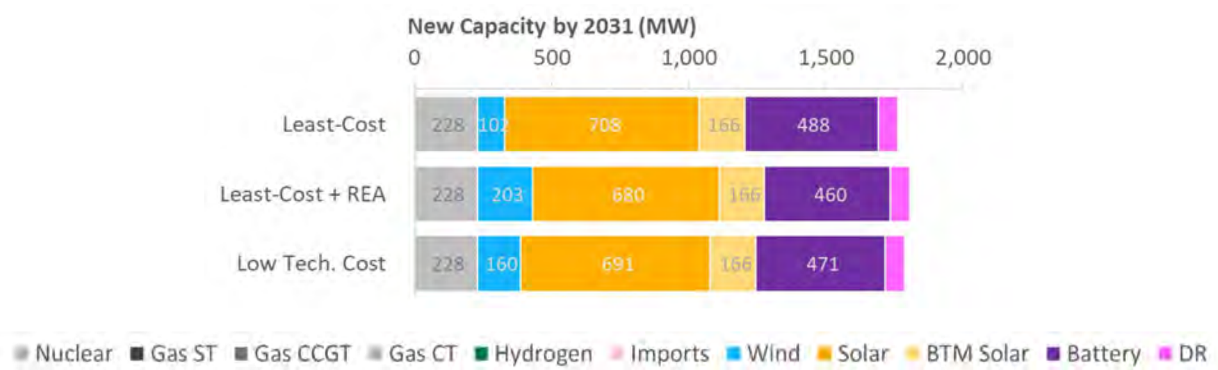


Figure 7-29. Cumulative New Capacity by 2040 for Low Technology Cost Sensitivity

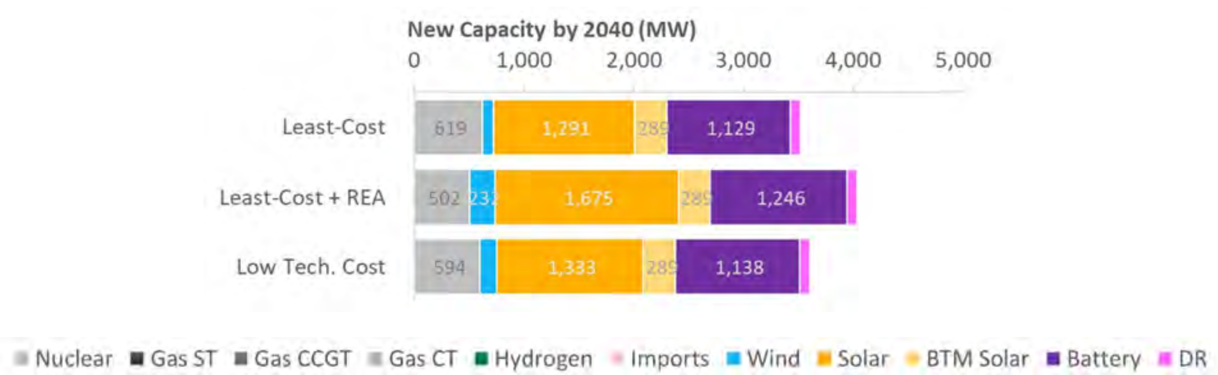


Figure 7-30. Annual Generation in 2031 for Low Technology Cost Sensitivity

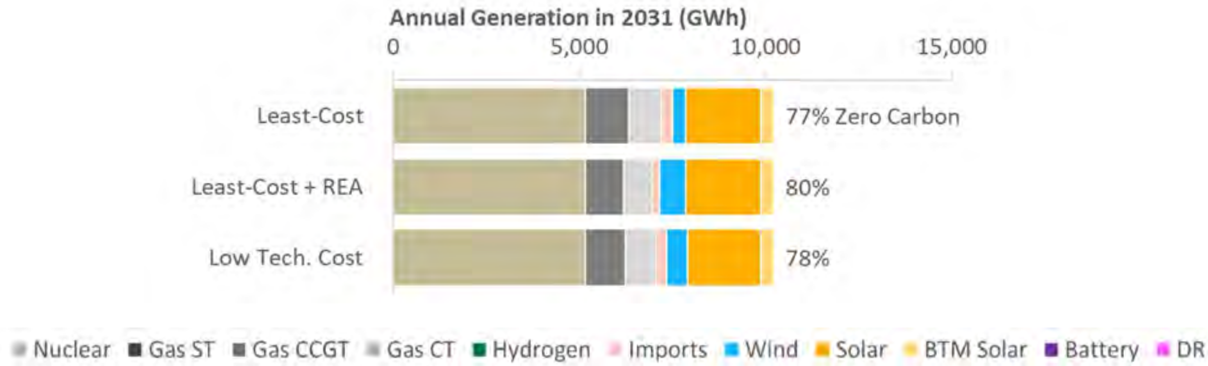
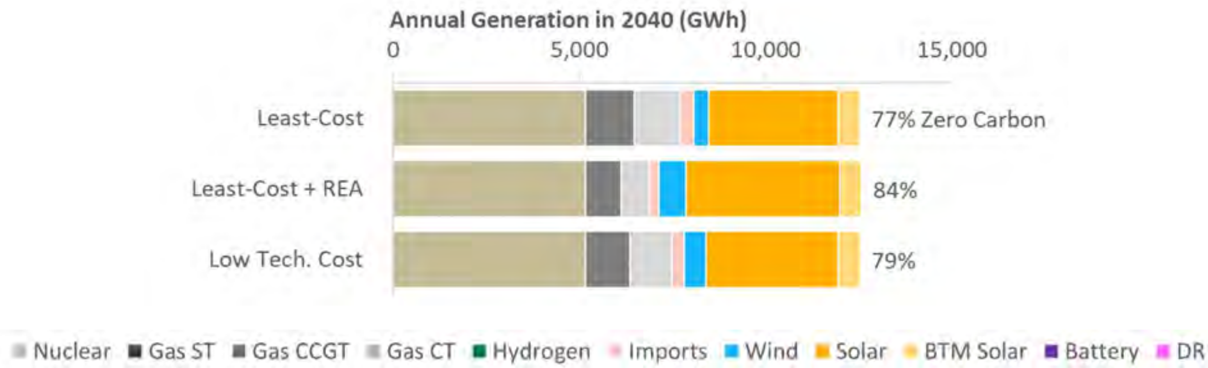


Figure 7-31. Annual Generation in 2040 for Low Technology Cost Sensitivity



8 Appendix A: Candidate Resource Assumptions

This appendix provides the assumptions for all candidate resource options that are considered in the resource portfolio optimization.

Table 8-1 provides the financial life for each resource. This is the period over which all costs for a project must be recovered. For modeling purposes, E3 assumes that gas projects would be financed by El Paso Electric and that renewable, storage, and nuclear projects would be financed by a third party and made available to El Paso Electric via power purchase agreements (PPAs) or tolling agreements.[41] This is a modeling assumption and does not necessarily reflect future financing and ownership structures.

Table 8-1. Financial Life (years)

Resource	Financial Life
Solar	30
BTM Solar	30
Wind	30
Geothermal	25
Biomass	20
Standalone Batteries	20
Paired Batteries	20
Gas Peaker	40
Nuclear (SMR)	30

Table 8-2 provides the upfront capital cost and Table 8-3 provides the fixed operations and maintenance (O&M) cost for each resource over time. E3 utilized the 2020 Annual Technology Baseline (ATB) from the National Renewable Energy Laboratory (NREL)[42] to develop cost assumptions for renewable, gas peaker, and nuclear resources. E3 utilized the Levelized Cost of Storage Version 6.0 report from Lazard[43] to develop cost assumptions for storage resources and applied a cost decline curve over time using data from the NREL ATB. For utility-scale solar resources, E3

[41] A tolling agreement is an agreement under which one entity pays another entity for the rights to utilize and dispatch a power plant to generate electricity.
[42] https://atb.nrel.gov/
[43] https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/

adjusted the upfront capital cost downward so that the levelized cost would align more closely with recent solar power purchase agreement (PPA) pricing.

Table 8-2. Upfront Capital Cost ($/kW) (2021 $)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility-Scale Solar	900	858	815	773	730	688	681	675	669	663	657	651	645	639	633	626	620	614	608	602	596
BTM Solar	1,693	1,607	1,521	1,435	1,350	1,264	1,249	1,234	1,220	1,205	1,190	1,175	1,161	1,146	1,131	1,117	1,102	1,087	1,072	1,058	1,043
Wind (Artesia/ABQ)[44]	1,463	1,431	1,399	1,367	1,333	1,299	1,286	1,273	1,260	1,247	1,234	1,220	1,207	1,194	1,180	1,167	1,153	1,140	1,126	1,113	1,099
Wind (Lordsburg)[45]	1,785	1,743	1,700	1,655	1,609	1,561	1,549	1,537	1,525	1,512	1,500	1,488	1,475	1,463	1,450	1,437	1,424	1,411	1,398	1,385	1,372
Geothermal	8,545	8,451	8,358	8,265	8,172	8,080	8,040	7,999	7,959	7,920	7,880	7,841	7,801	7,762	7,724	7,685	7,647	7,608	7,570	7,532	7,495
Biomass	4,499	4,482	4,464	4,447	4,429	4,407	4,385	4,363	4,339	4,321	4,301	4,275	4,255	4,234	4,209	4,184	4,166	4,142	4,121	4,100	4,081
Standalone Batteries	786	749	712	674	637	599	591	585	576	570	562	553	547	539	533	524	516	510	501	495	487
Paired Batteries	726	691	657	622	588	553	545	540	532	527	519	511	505	497	492	484	476	471	463	457	449
Gas Peaker	1,223	1,214	1,205	1,198	1,194	1,188	1,183	1,178	1,171	1,167	1,164	1,159	1,156	1,153	1,149	1,145	1,143	1,139	1,136	1,133	1,130
Nuclear (SMR)	7,339	7,301	7,257	7,217	7,176	7,126	7,079	7,030	6,979	6,936	6,891	6,836	6,791	6,744	6,691	6,637	6,595	6,544	6,497	6,450	6,406

Table 8-3. Fixed O&M ($/kW-yr) (2021 $)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility-Scale Solar	13	13	12	11	11	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9	9
BTM Solar	12	12	11	10	10	9	9	9	9	9	9	8	8	8	8	8	8	8	8	8	7
Wind	43	43	42	42	42	41	41	41	40	40	40	39	39	39	38	38	38	38	37	37	37
Geothermal	187	186	185	185	184	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Biomass	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Standalone Batteries	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Paired Batteries	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Gas Peaker	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Nuclear (SMR)	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126

[44] This wind resource corresponds to land-based wind class 3 in the NREL ATB.
[45] This wind resource corresponds to land-based wind class 7 in the NREL ATB.

Table 8-4 provides the $/kW-yr levelized cost for each resource over time. The levelized cost reflects the total cost of a resource – including capital costs, fixed O&M, financing costs, taxes, tax credits,[46] etc. – on a levelized basis over the financial lifetime of project. E3 developed a pro forma financial model to determine the total levelized costs for each resource. The $/kW-yr levelized cost is a direct input into the resource portfolio optimization.

Table 8-4. Real Levelized Cost ($/kW-yr) (2021 $)[47]

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility-Scale Solar	48	58	57	55	53	51	51	50	50	50	49	49	48	48	48	47	47	47	46	46	45
BTM Solar	65	87	84	81	77	73	72	71	70	69	69	68	67	66	65	64	63	63	62	61	60
Wind (Artesia/ABQ)	98	133	132	131	130	128	127	126	125	124	123	122	121	120	118	117	116	115	114	113	112
Wind (Lordsburg)	129	150	150	148	146	144	143	142	141	140	139	138	137	136	135	134	133	131	130	129	128
Geothermal	663	672	680	680	680	679	677	675	672	670	667	665	663	660	658	656	653	651	649	646	644
Biomass	440	448	455	458	460	462	460	459	457	456	454	452	451	449	447	445	444	442	441	439	438
Standalone Batteries	90	86	82	77	73	69	68	67	66	66	65	64	63	63	62	61	61	60	59	59	58
Paired Batteries	63	71	68	64	60	56	55	55	54	54	53	52	52	51	51	50	50	49	49	48	47
Gas Peaker[48]	117	116	116	116	116	115	115	114	114	114	113	113	113	113	112	112	112	112	112	111	111
Nuclear (SMR)	652	654	657	660	662	664	661	657	653	650	647	642	639	636	632	628	624	621	617	613	610
Smart Thermostats	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29

Table 8-5 provides the capacity factor for each resource that has a production profile that varies by season and time of day. Section 0 provides more information about the development of profiles for these resources.

[46] E3 assumes that solar projects coming online in 2025 would be eligible for a 26% investment tax credit (ITC) and that projects coming online in later years would be eligible for a 10% ITC. E3 assumes that wind projects coming online in 2025 would be eligible for a 60% production tax credit (PTC) and that projects coming online in later years would not be eligible for the PTC.

[47] The levelized cost includes interconnection costs.

[48] The levelized cost for Gas Peaker includes gas pipeline reservation costs.

Table 8-5. Capacity Factor (%)

Resource	Capacity Factor
Solar[49]	32%
BTM Solar	24%
Wind (Artesia)	44%
Wind (ABQ)	50%
Wind (Lordsburg)	37%
Geothermal	80%

Table 8-6 provides the $/MWh levelized cost of each resource that has a production profile that varies by season and time of day. This data is not a direct model input but is provided to allow for a more intuitive comparison of costs between different resources. The table does not include all resources because some resources' output levels are not based on resource production profiles but instead on system dispatch dynamics. The $/kW-yr levelized cost is the direct resource portfolio optimization input for all resources.

Table 8-6. Real Levelized Cost of Energy ($/MWh) (2021 $)[50]

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Solar	17	21	20	20	19	18	18	18	18	18	18	17	17	17	17	17	17	17	17	16	16
BTM Solar	31	42	41	39	37	35	35	34	34	33	33	33	32	32	31	31	31	30	30	29	29
Wind (Artesia)	25	34	34	34	34	33	33	33	32	32	32	32	31	31	31	30	30	30	30	29	29
Wind (ABQ)	22	30	30	30	30	29	29	29	29	28	28	28	28	27	27	27	27	26	26	26	26
Wind (Lordsburg)	40	46	46	46	45	44	44	44	44	43	43	43	42	42	42	41	41	41	40	40	40
Geothermal	95	96	97	97	97	97	97	96	96	96	95	95	95	94	94	94	93	93	93	92	92

Table 8-7 provides the characteristics for thermal candidate resources. The assumptions are based on data from the NREL ATB.

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[49] The capacity factor for solar PV differs slightly by location. This value is used for illustrative purposes for calculating the levelized cost of energy.
[50] The levelized cost of energy is not a direct model input. Also, the metric does not indicate the value of individual resources, which is determined dynamically through the capacity expansion model. Nevertheless, the metric can be useful for understanding the relative cost of resources.

Table 8-7. Thermal Resource Characteristics

Resource	Heat Rate (MMBtu/MWh)	Variable O&M (2021$/MWh)
Gas Peaker	10.1	$1.17
Biomass	13.5	$5.00
Nuclear (SMR)	10.0	$2.00

Table 8-8 provides lifetime extension assumptions for a subset of existing thermal units. El Paso Electric engaged Burns & McDonnell to determine the capital cost and fixed O&M required to extend the lifetime of these units by five years. E3 utilized these costs to determine whether it would be economic to extend the lifetime of these units.

Table 8-8. Lifetime Extension Costs ($/kW-yr) (2021 $)

Resource	Extension Period	Capital + Fixed O&M
Rio Grande 7	5 years	$114
Newman 1	5 years	$79
Newman 2	5 years	$80
Newman 3	5 years	$58
Newman 4	5 years	$47

Table 8-9 provides the cost assumption for converting a natural gas-fired generating unit to burn hydrogen fuel. This retrofit option is considered in select scenarios with aggressive decarbonization targets.

Table 8-9. Hydrogen Retrofit Cost ($/kW-yr) (2021 $)

Resource	Additional Cost
Gas Plants	$12

9 Appendix B: Price Assumptions

This appendix provides the assumptions for prices utilized in the resource portfolio optimization.

9.1 Fuel Prices

Table 9-1 includes the forecasts for different types of fuel. El Paso Electric provided natural gas price forecasts for GasInter,[51] NewInter,[52] and GasIntra[53] through 2029. E3 trended the gas prices upward through 2045 in line with the Energy Information Administration (EIA) 2020 Annual Energy Outlook (AEO). E3 utilized the uranium price forecast from the EIA 2020 AEO. E3 utilized the biomass price forecast from the 2020 NREL ATB.

E3 forecasted the cost of green hydrogen – hydrogen fuel produced through electrolysis using renewable energy – through 2045. E3 assumed cost declines for electrolyzers and renewable energy over time and utilized these assumptions to determine the cost of producing green hydrogen. The assumptions and methodology are described in more detail in a report that E3 prepared for Advanced Clean Energy Storage (ACES),[54] which is a joint development project between Mitsubishi Hitachi Power Systems Americas, Inc. and Magnum Development, LLC.

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[51] GasInter is interstate gas with service provided by EPNG. This gas is utilized at the Rio Grande power plant.
[52] NewInter is interstate gas with service provided by EPNG. The gas is utilized at Montana and Newman power plants as well as for candidate gas resources
[53] GasIntra is intrastate gas with service provided by Oneok. The gas is utilized at the Newman and Copper power plants.
[54] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

Table 9-1. Fuel Prices ($/MMBtu) (2021 $)

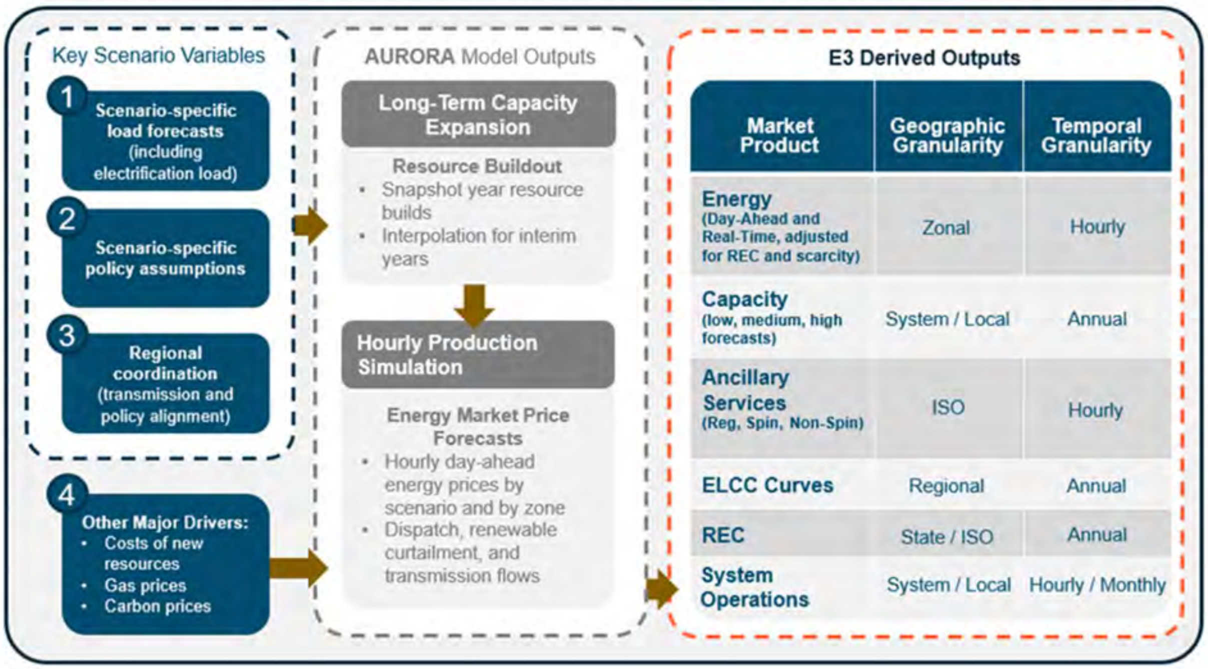
Year	GasInter	NewInter	GasIntra	Uranium	Biomass	Hydrogen
2021	2.84	2.76	2.89	0.71	3.18	27.61
2022	2.48	2.41	2.53	0.71	3.18	26.76
2023	2.52	2.45	2.56	0.71	3.18	25.92
2024	2.58	2.51	2.63	0.71	3.18	25.07
2025	2.67	2.59	2.71	0.71	3.18	24.23
2026	2.74	2.65	2.77	0.71	3.18	23.95
2027	2.85	2.76	2.88	0.72	3.18	23.68
2028	2.94	2.85	2.98	0.72	3.18	23.40
2029	3.00	2.90	3.03	0.72	3.18	23.13
2030	3.06	2.96	3.09	0.72	3.18	22.85
2031	3.13	3.02	3.16	0.72	3.18	22.40
2032	3.19	3.08	3.21	0.72	3.18	21.94
2033	3.24	3.13	3.27	0.73	3.18	21.48
2034	3.30	3.18	3.32	0.73	3.18	21.02
2035	3.35	3.23	3.36	0.73	3.18	20.56
2036	3.39	3.27	3.41	0.73	3.18	20.21
2037	3.44	3.31	3.45	0.73	3.18	19.85
2038	3.48	3.35	3.49	0.73	3.18	19.50
2039	3.51	3.38	3.52	0.74	3.18	19.14
2040	3.55	3.42	3.55	0.74	3.18	18.79
2041	3.55	3.42	3.56	0.74	3.18	18.53
2042	3.58	3.45	3.59	0.74	3.18	18.26
2043	3.61	3.47	3.61	0.74	3.18	18.00
2044	3.63	3.49	3.63	0.75	3.18	17.74
2045	3.66	3.52	3.66	0.75	3.18	17.48

9.2 Wholesale Electricity Prices

In this study, E3 utilized its market price forecasts for the Palo Verde market hub to assess the potential for economic short-term energy purchases. This section describes the methodology the E3 employs to develop its market price forecast. This section also provides a summary of the market prices.

E3 develops unique energy market price forecasts using a hybrid approach which combines capacity expansion, production cost simulation, and post-process calculations to develop robust and expansive views of the future electricity system under high renewable penetration levels. E3 has designed its market price forecasts to be scenario-based, policy-centered, and fundamentals-driven in order to identify, simulate, and evaluate step-changes in market evolution arising from a combination of policy, economic, and technological factors.

Figure 9-1. E3 Modeling Approach for Energy Market Price Forecasting



The price forecasting methodology comprises five principal steps:

+ **Scenario Definition** – design integrated scenarios for the long-run, future trajectory of the market

+ **Model Inputs** – create all parameters required for capacity expansion and production cost simulation, using public and proprietary data (tailored to each scenario)

+ **Long-Term Capacity Expansion** – identify resource additions and retirements based on economics, policy requirements (RPS, GHG standards), and reliability needs (Planning Reserve Margin and effective load carrying capability of each resource). E3 uses Aurora modeling software from Energy Exemplar for capacity expansion and benchmarks the results to E3's proprietary, in-house capacity expansion model RESOLVE, which has been the core modeling tool for much of E3's Integrated Resource Planning work, including E3's ongoing support of the California Public Utility Commission (CPUC) IRP for California

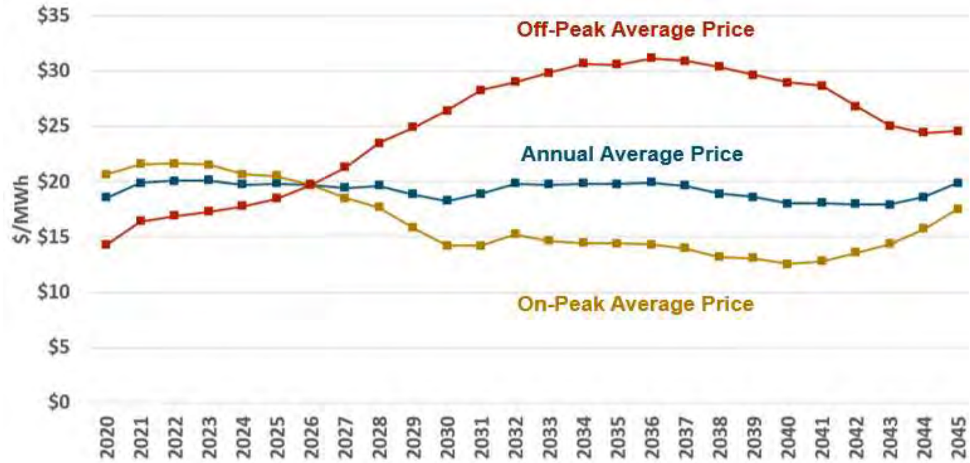
+ **Production Cost Simulation** – simulate day-ahead, zonal energy prices using the Aurora software for each forecast year (2020-2050) and each scenario. Production cost simulation is at the core of E3's 'fundamentals-driven' approach to energy price forecasting because it captures how changes in resources and loads can affect the frequency, magnitude, and shape of energy prices in the long run. The strength of production cost simulation models is the ability to identify and explain step-changes and trends in the market which differ dramatically from past or current relationships (and hence are not well-explained or forecasted by statistical approaches alone).

- A commonly known drawback of production cost simulations, however, is that they tend to ‘over-optimize’ future prices and often fall short in accounting for inefficiencies and volatility driven by real-world market conditions such as scarcity pricing, sub-zonal transmission constraints, and weather variability beyond Typical Meteorological Year (TMY) conditions. Because of these constraints, production cost simulations also do not capture trends in ancillary services pricing particularly well. To build upon the strength of production cost simulations (and industry best-practices), E3 has created a toolkit of post-processing calculations to add back real-world volatility and system constraints into the DA energy price forecasts and to use these prices to derive AS and REC forecasts that are aligned with changing fundamentals but calibrated to historical observations of system dynamics.

+ **Post Processing** – E3 uses the raw outputs of the Aurora production cost simulation to create hourly DA energy prices and to derive prices for ancillary services (regulation up/down, spinning reserves, and non-spinning reserves), real-time 15min energy prices, and forecasts of renewable energy credit (REC) prices. Our post-processing also adjusts the top hours of the DA energy prices to simulate the frequency and magnitude of observed occurrences of scarcity pricing and peak unit dispatch during high-load hours as well as the occurrence of zero and negative pricing during low load hours due to congestion within zones. E3 also uses the day-ahead energy prices to forecast capacity or resource adequacy prices by calculating annual fixed costs of existing and new capacity resources net of energy market participation. Our capacity price forecasts account for going-forward costs of existing resources, the effective load carrying capability (ELCC) of new resources, and forecasted planning reserve margins for the system. We also tailor our price outlook to account for specific market rules and procurement methods (i.e., state-administered resource adequacy programs vs. organized capacity markets).

Figure summarizes E3’s market price forecast for the Palo Verde market hub for on-peak hours (7am-11pm) and off-peak hours (11pm-7am), as well as the overall average price. The market price forecast shows daytime energy prices falling in the next ten years, largely due to the addition of significant quantities of solar PV resources in the Southwest. Concurrently, the market price forecast shows nighttime energy prices increasing, largely due to rising fuel prices and resource retirements.

Figure 9-2. E3 Market Price Forecast for the Palo Verde Market Hub ($/MWh) (2021 $)



10 Appendix C: Detailed Portfolio Results

All portfolio, generation, and cost results are included in an accompanying Excel workbook.