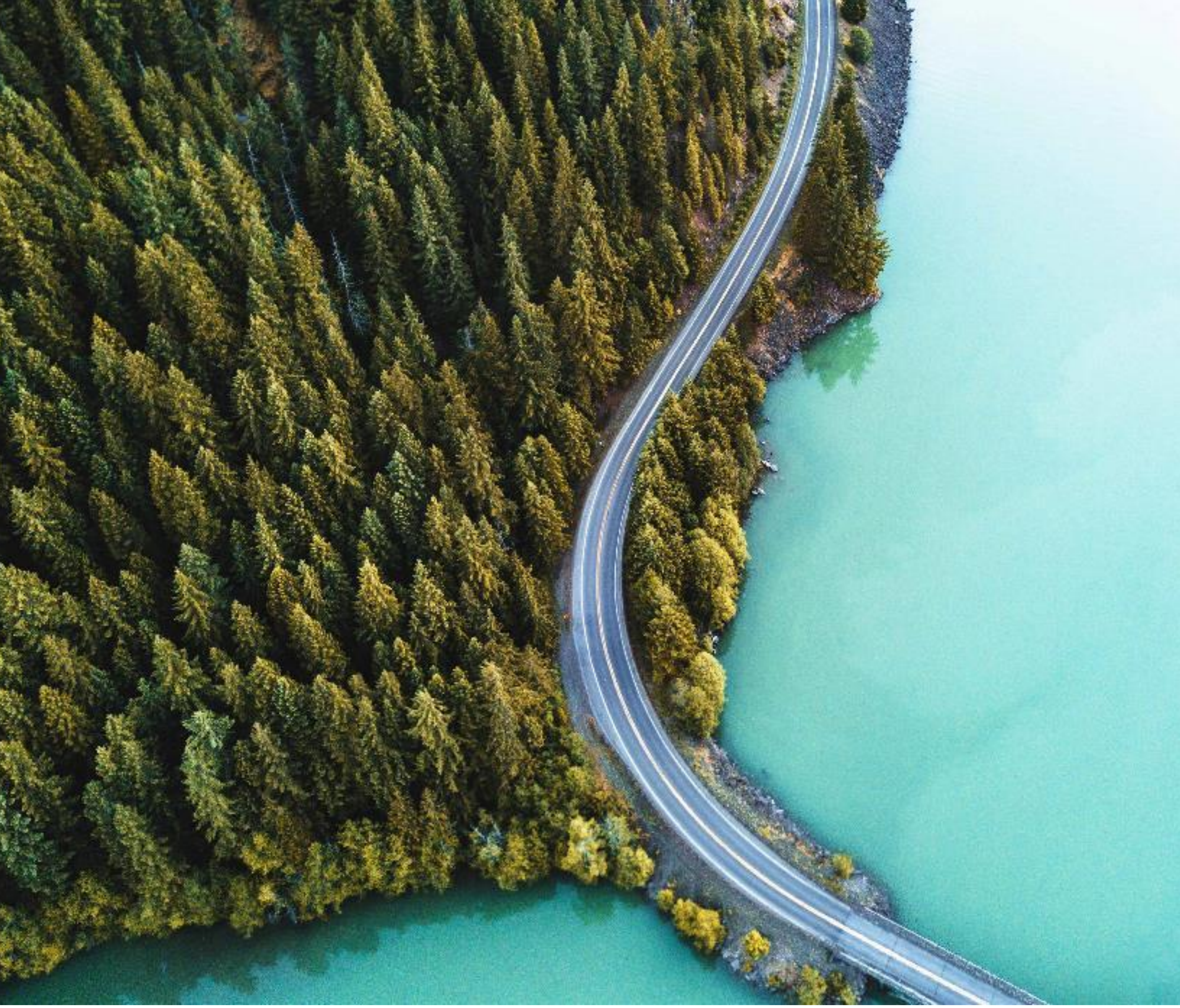

Los Alamos County Department of Public Utility
Los Alamos National Lab

2022 Integrated Resource Plan

June 2022

FTI CONSULTING

EXPERTS WITH IMPACT™

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Acronyms

AGA – American Gas Association

AMI – Advanced metering infrastructure

ATB – Annual Technology Baseline

ATC – Around the clock

BA – Balancing authority

BART – Best Available Retrofit Technology

BPU – Los Alamos County Board of Public Utilities

CAGR – Compound annual growth rate

CAISO – California Independent System Operator

CAPEX – Capital expansion

CC – Combined cycle

CCUS – Carbon capture utilization and storage

CES – Clean energy standard

CFPP – Carbon-free power project

CGTG – Combustion gas turbine generator

COD – Commercial operation date

COV – County-owned vehicle

CPI – Consumer price index

CPUC – California Public Utility Commission

DER – Distributed energy resources

DOE – Department of Energy

DPU – Los Alamos County Department of Public Utilities

DR – Demand response

ECA – Electric Energy and Power Coordination Agreement

EE – Energy efficiency

EIA – Energy Information Administration

EIM – WECC Energy Imbalance Market

ELCC – Effective load-carrying capability

EPA – United States Environmental Protection Agency

EV – Electric Vehicle

FER – Future Energy Resources

FOM – Fixed operating and maintenance

GHG – Greenhouse gas

GOV – government-owned vehicle

GW – Gigawatt

GWh – Gigawatt-hour

IEPR – California Integrated Energy Policy Report

INL – Idaho National Laboratory

IRP – Integrated resource plan

ITC – Investment Tax Credit

kWh – Kilowatt-hour

LAC – Los Alamos County

LANL – Los Alamos National Laboratory

LARES - Los Alamos Resiliency, Energy and Sustainability task force

LCOE – Levelized cost of energy

LRS – Laramie River Station

MMBtu – Million British thermal units

MW – Megawatt

MWh – Megawatt-hour

NERC – North American Electric Reliability Corporation

NITSA – Network-integrated transmission service agreement

NPV – Net present value

NREL – National Renewable Energy Laboratory

NWPP – Northwest Power Pool

O&M – Operations and Maintenance

PEEC – Pajarito Environmental Education Center

PNM – Public Service Company of New Mexico

POV – Personal-owned vehicle

PPA – Power Purchase Agreement

PRM – Planning reserve margin

PSH – Pumped storage hydro

PTC – Production Tax Credit

PV – Photovoltaic (solar)

R&D – Research and Development

RICE – Reciprocating internal combustion engine

RPS – Renewable Portfolio Standard

SCGT – Simple-cycle gas turbine

SJGS – San Juan Generating Station

SHP - Sustainable Hydro Power

SMR – Small modular (nuclear) reactor

SRSG – Southwest Reserve Sharing Group

STA – Southern Technical Area

TOU – Time of use

UAMPS – Utah Associated Municipal Power Systems

VOM – Variable operating and maintenance costs

WAPA – Western Area Power Administration

WARA – Western Assessment of Resource Adequacy

WECC – Western Electricity Coordinating Council

YOY – Year-on-year

ZEV – Zero-emission vehicle

Chapter 1: Executive Summary

Climate change, technology, policy, and customer choice are drastically reshaping the energy landscape in the Western Electricity Coordinating Council ("WECC") footprint. Extreme weather events such as cold snaps, heat waves, and drought lead to increasing demand and resource variability. Unprecedented transformation continues to reinvigorate and challenge the sector, including: new load patterns and levels due to electrification of transportation, heating, cooling, and buildings; significant growth of renewables, underpinned by deep decarbonization policies and aspirations; increasing grid complexity driven by rapidly deployed intermittent resources and accelerated retirements of baseload resources; increasing price volatility with negative and scarcity pricing; and regulatory and legislative proceedings that continue to shape the utility space.

Given such context, the Los Alamos County ("LAC") Department of Utilities ("DPU") and the Los Alamos National Lab ("LANL") jointly conduct the 2022 Integrated Resource Plan ("IRP") to comprehensively address the near-term and long-term resource strategies for the Los Alamos Power Pool ("LAPP") in the planning horizon of 2022 – 2041. LAC and LANL seek to address several important needs of the power pool, including rate stability; resilliency and reliability; mitigating the risks driven by market volatility (due to a deepening duck curve and growing market-wide resource imbalances); decarbonization goals; and clean energy standards for energy consumed by federal agencies.

LAC and LANL 2022 IRP Objectives and Process

This IRP considers the electricity demand from residential, commercial, industrial customers, electric vehicles ("EVs"), as well as potential residential and industrial electrification. The IRP takes a least-cost and technology-agnostic approach to meet the carbon neutral goal by 2040 for LAC and 100 percent renewable goal by 2035 for LANL. These goals are critical to LAPP's continued environmental leadership in supporting the New Mexico's Energy Transition Act (SB 489), which calls for 100 percent zero-carbon resources for investor-owned utilities by 2045 and rural electric cooperatives by 2050.

Equally important is the core purpose of the LAPP to provide electricity to the customers in a reliable and cost-effective manner. The LAC and LANL 2022 IRP underscores six objectives: i) manage cost in a prudent manner; ii) meet sustainability goals; iii) mitigate risks; iv) improve operational flexibility and reduce operational exposure; v) improve reliability; and vi) build a resilient portfolio with diversified and complementary resources. Exhibit 1 presents the key objectives and metrics in the IRP.

Exhibit 1: LAPP IRP Key Objectives and Metrics

	Objectives	Objective Direction	Metrics
Trade Offs	1. Cost	↓	1.1 Net Present Value (NPV) of portfolio cost ($)
	2. Sustainability	↑	2.1 All portfolios meet RPS standards: ○ LAC net carbon zero electricity by 2040 ○ LANL 100 percent renewable by 2035
	3. Risks	↓	3.1 Annual average market exposure (MWh) 3.2 Stochastic simulation of portfolio cost ($)
	4. Operational Exposure	↓	4.1 New resources subject to transmission (MW) 4.2 Weather dependent new resources (MW)
	5. Reliability	↑	5.1 Average Planning Reserve Margin (%) 5.2 Dispatchable new resources (MWh/day)
	6. Diversification	↑	6.1 Number of new generation types

The IRP develops portfolio options based on commercially available utility-scale resources. The analysis is based on the best available information at the time of resource plan analysis, recognizing that the industry is rapidly evolving with new policy, cost trends, and technology breakthroughs. The IRP culminates in a 20-year roadmap for LAPP, a 5-year action plan, and important pivot strategies to allow for practical implementations. LAPP plans to update the IRP every three years, or as new information becomes available, or when circumstances change, such as material changes in policy, market, load, resources, and commercially available, cost competitive, utility-scale technologies.

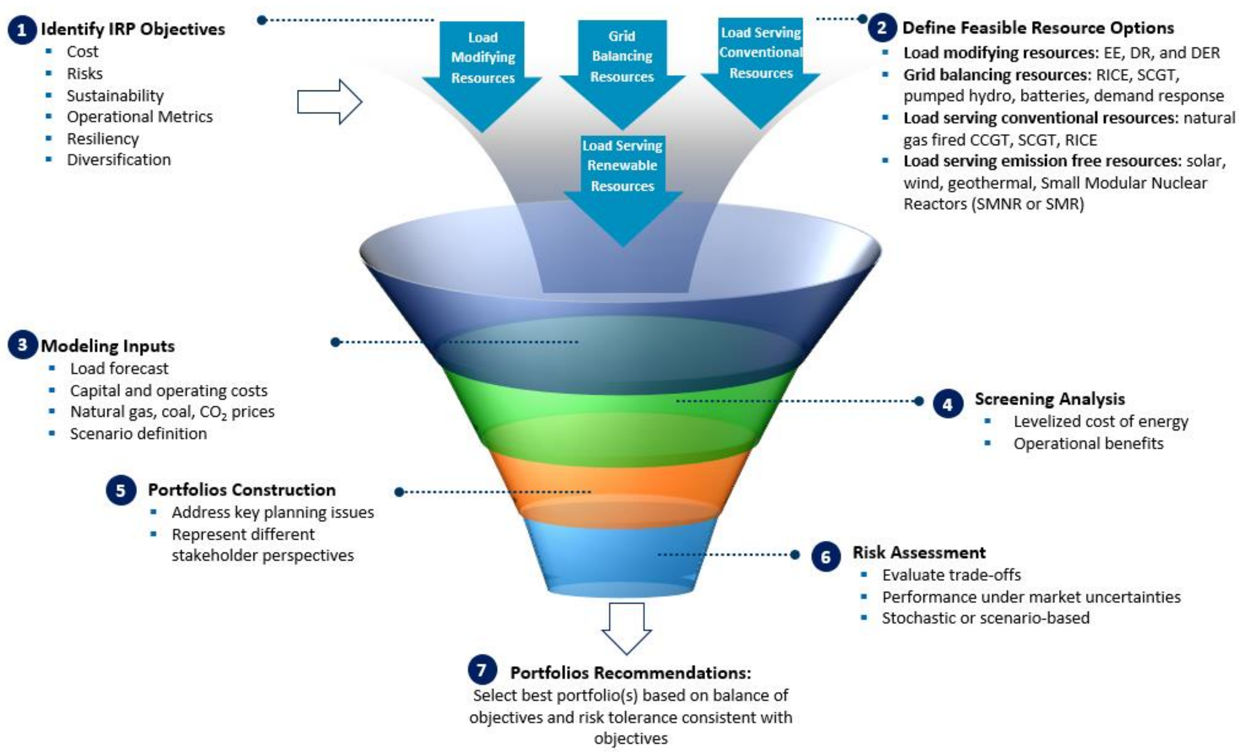
During this resource planning process, LAC and LANL have benefited from feedback from the public, customers, stakeholders, and the Los Alamos County Board of Public Utilities ("BPU") through three presentation and discussion sessions at the 50 percent milestone in November 2021, and the 90 percent milestone in March and April 2022.

Evaluation Process

LAPP must make resource decisions under many market, load, and resource uncertainties. LANL's load growth are largely driven by mission-based projects, which drive significant load growth when materialize, but historically have been below forecasted levels. The trajectory and growth of transportation, residential, and commercial electrification have wide ranges, as they are driven by policy, incentives, infrastructure, and costs, which are factors out of LAC's and LANL's control. The resource solutions often present tradeoffs between costs, sustainability, risks, operation, reliability, and other utility objectives. To assess the merits of the portfolio solutions systematically and objectively, FTI applied its structured process that includes the following steps as illustrated in Exhibit 2 to develop the Preferred Resource Plan that would best meet the goals for LAC and LANL:

- Identify IRP objectives and metrics;
- Define feasible resource options;
- Develop load forecasts (LAC and LANL), capital costs, fuels prices, and CO_2 price forecasts;
- Define three planning scenarios;
- Perform screening analysis of new resources;
- Construct deterministic portfolios for three planning scenarios;
- Conduct stochastic risk analysis of candidate portfolios;
- Recommend Preferred Resource Plan and pivot strategies.

Exhibit 2: IRP Approach and Process



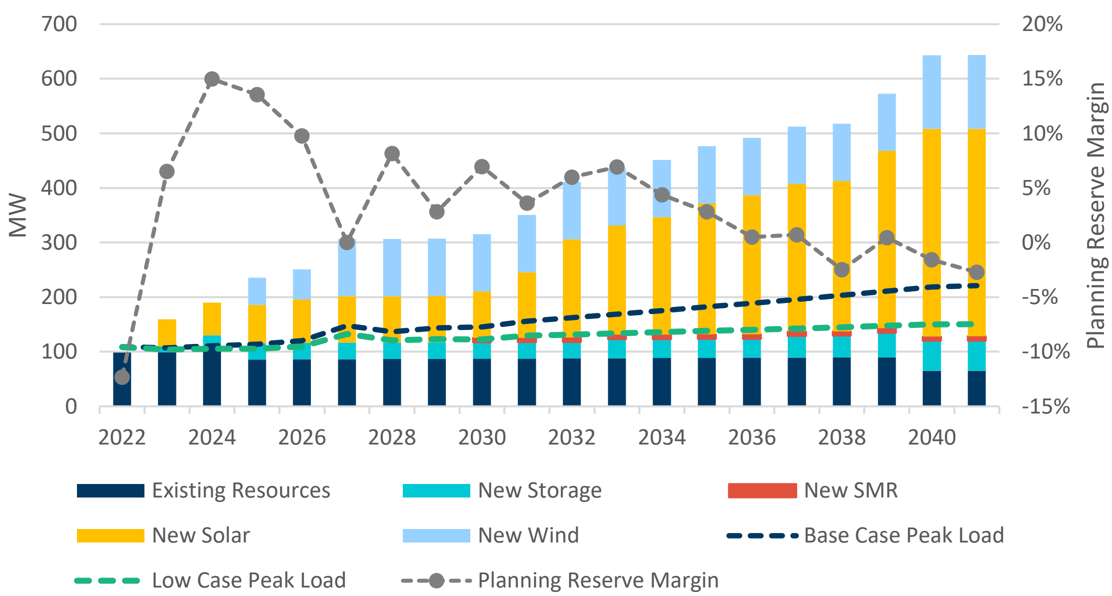
Preferred Portfolio

The IRP recommends mitigating near-term risks and avoiding long-term risks by building or contracting for a total of 55 megawatts ("MW") battery storage, 380 MW solar, 135 MW wind, and 8 MW nuclear small modular reactor ("SMR") during the planning horizon to achieve an average annual planning reserve margin ("PRM") of 4 percent. Exhibit 3 shows the cumulative new builds summary for the Preferred Resource Plan. Exhibit 4 shows the Preferred Resource Plan resources, LAPP peak load, and PRM.

Exhibit 3: LAC and LANL IRP Preferred Resource Plan Cumulative New Builds Summary

Year	Storage	Solar	Wind	SMR	Total
	MW	MW	MW	MW	MW
2025	30	70	50	0	150
2027	30	85	105	0	220
2030	30	85	105	8	228
2035	35	240	105	8	388
2040	55	380	135	8	578
2041	55	380	135	8	578

Exhibit 4:Preferred Resource Plan Resources, LAPP Peak Load, and PRM



5-year Action Plan and Pivot Strategies

Consistent with the North American Electric Reliability Corporation ("NERC") 2021 Long-term Reliability Assessment[1] findings, and WECC 2021 Western Assessment of Resource Adequacy[2] recommendations, the IRP recommends mitigating near-term risks by incorporating 220 MW of new builds or contracts by 2027 in the Preferred Resource Plan. With the planned retirement of San Juan Generation Station Unit 4 in 2022 and the bridge Power Purchase Agreement ("PPA") expiration in 2025, it is very important for LAPP to secure new power supplies to serve its growing load.

Battery Storage

The Preferred Resource Plan recommends incorporating 30 MW utility-scale 4-hour lithium-ion battery storage to the LAPP portfolio by 2025 to manage the intermittency of new wind and solar resources. There have been incidents of grid battery fire (such as the one occurred at an Arizona Public Service facility),[3] so the technical risks should be carefully evaluated and mitigated during procurement and operation. LAPP should monitor the cost of battery-grade lithium carbonate, which has been rising and volatile in the past year due to global supply and demand imbalances.

In the long term, LAPP should monitor the long duration storge options including flow batteries, and seasonal storage options including green hydrogen, as hydrogen infrastructure is being built out in the WECC. When cost-effective, long duration storage options are important to mitigate risks of loss of load and prevent renewables curtailments when the outputs exceed demand or transmission capacity.

Simple Cycle Gas Turbine

The overall performance of the Preferred Resource Plan is closely followed by portfolios that incorporate simple cycle gas turbine ("SCGT") to the LAPP portfolio to address near-term resource adequacy, provide regulation services, voltage support, and operating reserves. This suggests opportunities to enhance the Preferred Resource Plan by incorporating SCGT. The size of the SCGT should be evaluated based on the load growth, the need to manage hourly and seasonal imbalances, and the benefit-cost tradeoff based on concrete bids from technology providers.

[1] 2021 Long-Term Reliability Assessment, NERC, December 2021. Accessed at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

[2] 2021 Western Assessment of Resource Adequacy, WECC, 2021. Accessed at https://www.wecc.org/Administrative/WARA%202021.pdf

[3] McMicken Battery Energy Storage System Event Technical Analysis and Recommendations. July 2020. https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Newsroom/McMickenFinalTechnicalReport.ashx?la=en&hash=50335FB5098D9858BFD276C40FA54FCE

Over the long term (post 2030), LAPP preserves the optionality to evaluate feasibility to convert SCGT to hydrogen if the infrastructure is commercially available and fuel supply is cost-effective and reliable.

Solar and Wind

The Preferred Resource Plan recommends 85 MW solar, and 105 MW wind builds by 2027. LAPP should evaluate proposals based on tradeoffs of price, performance, and transmission needs. If wind projects cannot be competitively procured due to lack of availability, transmission constraints, or high all-in costs with firm transmission, alternative options of solar and battery storage should be pursued. Solar projects are subject to cost uncertainties due to contemplated anti-dumping and countervailing duties.

Small Modular Reactor

The Preferred Resource Plan includes the 8 MW SMR through a long-term contract from the Carbon Free Power Project ("CFPP"), which is developed by the public power consortium Utah Associated Municipal Power Systems ("UAMPS") for a planned commercial operation by 2030.[4] The IRP recommends LAC to continue to pursue risk mitigation measures to protect ratepayers from potential cost overruns and schedule delays.

[4] https://www.nuscalepower.com/projects/carbon-free-power-project

Chapter 2: Introduction

Los Alamos County

Los Alamos County is located on the Pajarito Plateau, in the mountains of Northern New Mexico. It is approximately 90 miles north of Albuquerque, 35 miles northwest from Santa Fe, and 55 miles southwest from Taos. At 7,355 feet altitude, Los Alamos is "big pine" country, with a mild, four-season climate. Los Alamos is surrounded by National Forest, National Park, Pueblo, and other Federal lands. It is the smallest county in New Mexico at 109 square miles. Los Alamos County has a population of approximately 19,330 people (2021 census estimate), with two communities: the town-site of Los Alamos and White Rock (southeast of Los Alamos).

Los Alamos National Laboratory

LANL is the largest employer in Los Alamos County. The lab employees commute daily from Northern New Mexico, Santa Fe, and the Albuquerque metro area to the lab.

LANL's mission is to solve national security challenges through simultaneous excellence in nuclear security; mission-focused science, technology, and engineering; mission operations; and community relations. LANL is committed to make energy decisions consistent with the Department of Energy's ("DOE") 2021 Climate Action Plan to reduce greenhouse gas ("GHG") emissions and manage the short and long-term effects of climate change on its mission, policies, programs, and operations. LANL's energy must reliably support its mission critical projects.

Electric Coordination Agreement

LAC and LANL have pooled their generation resources under an Electric Energy and Power Coordination Agreement ("ECA") since 1985. Under the ECA, the power outputs are distributed to LAC and LANL according to their respective load requirements. Traditionally, LANL has consumed about 80 percent of the total energy produced or purchased by LAPP. The current ECA term is through June 30, 2025. At the time of this IRP, LAC and LANL are working together to navigate the resource and load imbalances.

Chapter 3: Objectives and Considerations

LAC and LANL identified the planning objectives, reflecting stakeholders' perspectives, the core mission of the power pool, and utility planning best practices. The IRP approach uses transparent and quantifiable metrics to objectively assess the tradeoffs of different resource decisions based on a least-cost and technology-agnostic analytical framework. The LAC and LANL 2022 IRP considers six categories of core objectives to manage cost in a prudent manner, mitigate risk, improve operational flexibility, address reliability needs, while meeting sustainability goals with diversified and complementary resources. Exhibit 5 outlines the six categories and nine metrics that are used to evaluate the portfolios to arrive at the Preferred Resource Plan that balances many competing goals.

Cost Metric

The Net Present Value ("NPV") of portfolio costs is calculated as the revenue requirement (including fixed operating and maintenance costs, variable operating and maintenance costs, fuel cost, and PPA cost) at a five percent discount rate during the planning horizon (2022 – 2041).

Sustainability Metric

The sustainability metric is calculated as the average annual LAPP renewable goal requirement minus carbon-free generation from owned and contracted resources. A negative number represents LAPP selling into the market on a net annual basis whereas a positive number represents LAPP being a net purchaser from the market. All the portfolios are designed to meet the sustainability goals: LAC's carbon-neutral by 2040 and LANL's 100 percent renewable goal by 2035. Given such, all portfolios are given equal ranking.

Risk Metrics

The IRP incorporates two risks metrics:

- The average annual market exposure is calculated as the average annual LAPP load (native load and battery load) minus generation from owned and contracted resources. A negative number shows that LAPP sells into the market on a net annual basis whereas a positive number shows that LAPP procures from the market.
- The portfolio costs for peak month July 2032 are calculated through the stochastic simulations of wind, solar, hydro production, and gas prices.

Operational Metrics

The IRP incorporates two operational metrics:

- The new resources subject to transmission metric is calculated as the total installed capacity of new resources based on the following transmission reliance percentages: new battery storage (0 percent), solar (50 percent), wind (100 percent), simple-cycle gas turbine ("SCGT") (0 percent), reciprocating internal combustion engine ("RICE") (0 percent) and small modular nuclear reactor ("SMR") (100 percent).
- The weather dependent new resources metric is calculated as the total installed capacity of new wind and solar resources, as both are weather-dependent.

Reliability Metrics

The IRP incorporates two reliability metrics:

- The Planning Reserve Margin ("PRM") metric is calculated as the percentage of peak serving capacity above peak demand. PRM is typically used in IRPs to determine a load serving entity's peak serving resource needed above annual peak load.
- The dispatchable new resources metric is calculated as the dispatchable megawatt-hour ("MWh") per day, with new battery storage at 4 hours per day, and SCGT, RICE, and SMR at 24 hours per day.

Diversification Metrics

The diversification metric is calculated as the number of new resource types in each portfolio.

Exhibit 5: IRP Key Objectives and Metrics

	Objective & Metrics	Description
1. Cost	1.1 Net Present Value (NPV) of portfolio cost ($)	1.1 The NPV of portfolio costs is calculated as the revenue requirement (including fixed operating and maintenance costs, variable operating and maintenance costs, fuel cost, and PPA cost) at a five percent discount rate during the planning horizon (2022 – 2041).
2. Sustainability	2.1 All portfolios meet RPS standards: ○ LAC net carbon zero electricity by 2040 ○ LANL 100 percent renewables by 2035	2.1 The sustainability metric is calculated as the average annual LAPP renewable goal requirement minus carbon-free generation from owned and contracted resources. A negative number represents LAPP selling into the market on a net annual basis whereas a positive number represents LAPP being a net purchaser from the market. All the portfolios are designed to meet the sustainability goals: LAC's carbon-neutral by 2040 and LANL's 100 percent renewable goal by 2035. Given such, all portfolios are given equal ranking.
3. Risks	3.1 Annual average market exposure (MWh) 3.2 Stochastic simulation of portfolio cost ($)	3.1 The average annual market exposure is calculated as average annual LAPP load (native load + battery load) minus generation from owned and contracted resources. A negative number shows that LAPP sells into the market on a net annual basis whereas a positive number would show that LAPP procures from the market. 3.2 The portfolio costs for peak month July 2032 is calculated through the stochastic simulations of wind, solar, hydro production, and gas prices.
4. Operational Exposure	4.1 New resources subject to transmission (MW) 4.2 Weather dependent new resources (MW)	4.1 The new resources subject to transmission metric is calculated as the total installed capacity of new resources based on the following transmission reliance percentages: new battery storage (0 percent), solar (50 percent), wind (100 percent), SCGT (0 percent), reciprocating internal combustion engine ("RICE") (0 percent) and SMR (100 percent). 4.2 The weather dependent new resources metric is calculated as the total installed capacity of new wind and solar resources, as both are weather-dependent.
5. Reliability	5.1 Average Planning Reserve Margin (%) 5.2 Dispatchable new resources (MWh/day)	5.1 Planning Reserve Margin metric is calculated as the percentage of peak serving capacity above peak demand. PRM is typically used in IRPs to determine a load serving entity's peak serving resources needed above annual peak. 5.2 The dispatchable new resources metric is calculated as the dispatchable MWh per day, with new battery storage at 4 hours per day, and SCGT, RICE, and SMR at 24 hours per day.
6. Diversification	6.1 Number of new generation types	6.1 The diversification metric is calculated as the number of new resource types in each portfolio.

Chapter 4: State of the World Scenarios

LAC operates in the Western Electricity Coordinating Council ("WECC") footprint, a grid which exhibits increasing uncertainties and complexity. In this IRP, LAC, and LANL must account for a myriad of key drivers, including changing load patterns, extreme weather events, current and future technological advancements in cost and performance, environmental mandates, regulatory directives, and evolving customer preference. Energy market participants face many uncertainties when making planning and future investment decisions. LAC aims to identify a robust mix of generation resources to provide reliable electric service to customers in a cost-effective and carbon neutral manner, under different macroeconomic, regulatory, and technological outlooks.

Three state of the world scenarios, as presented in Exhibit 6, encompass a wide range of potential economic, commodity, policy, incentives, and technology considerations.

- The Base Case reflects moderate commodity prices, current policies, mandates, incentives including Investment Tax Credits ("ITC") and Production Tax Credits ("PTC"), expected load growth, techonlogy expectations consistent with widespread adoption of current technology choices with an expected level of innovation, and sustained levels of public and private research and development ("R&D").
- The High Case reflects higher load growth driven by robust economic activities, higher commodity prices due to higher demand and economic growth, increased penetration of electric vehicles, green hydrogen generation, capture and utilization of carbon dioxide, demand responsive smart-applicances, and electrification of facility heating, coupled with decreased investment in the oil and gas sector. Similar to the Base Case, the High Case reflects current policies, mandates, and federal incentives, though in the High Case renewables demands are higher due to higher load. The High Case entails higher capital costs for new builds due to decreased public and prviate R&D.
- The Low Case reflects lower commodity prices due to lower demand driven by conservation and policy. Unlike the Base Case and High Case, which assume current policies, the Low Case assumes accelerated policies, mandates, and federal incentives for renewables and energy transition. The Low Case assumes high conservation, low load growth, an accelerated pace for innovation, and increased public and private R&D leading to rapid cost and performance improvement of technologies and market success of currently unproven innovations.

Exhibit 6: State of the World Scenarios

	BASE CASE	HIGH CASE	LOW CASE
FUEL PRICES	50th percentile of stochastic simulation	90th percentile of stochastic simulation	15th percentile of stochastic simulation
CARBON PRICES	California: 2019 Integrated Energy Policy Report ("IEPR") Carbon Price Projections Mid Price Scenario No federal carbon program	California: 2019 IEPR Carbon Price Projections High Price Scenario No federal carbon program	California: 2019 IEPR Carbon Price Projections Low Price Scenario No federal carbon program
CAPEX	National Renewable Energy Laboratory ("NREL") 2021 Annual Technology Baseline ("ATB") Moderate Scenario	NREL 2021 ATB Conservative Scenario	NREL 2021 ATB Advanced Scenario
ITC AND PTC	Current policy of ITC and PTC	Current policy of ITC and PTC	Extend the ITC and PTC (by two years)
RPS AND CES	Renewables meet the state Renewable Portfolio Standard ("RPS") No national Clean Energy Standard ("CES")	RPS targets are the same as Base Case Renewable demands are higher due to higher load No national CES	RPS targets are the same as Base Case National CES of 100% by 2035
LOAD	Moderate peak load and energy demand growth	High peak load and energy demand growth	Low peak load and energy demand growth

Gas Price Forecasts

FTI applies the Geometric Brownian Motion log-normal process to propagate fuel price paths and distributions. The stochastic approach incorporates pricing seasonality, volatility, the correlation structure of futures contracts, and uncertainties associated with black swan events, such as weather or forced pipeline outages. Specifically, changes in price are composed of a deterministic component that is driven by the market, and a stochastic component, which is a mathematically defined variance term. To calibrate the simulation model, FTI uses historical settled prices to estimate the prompt, prompt + 1, prompt + n month contracts volatilities and correlations. For each forward contract, the following equation is used to propagate prices:

$$F^{i}{}_{t+1} = F^{i}{}_{t} \times \exp\left(-\frac{{\sigma^{i}_{t}}^{2}}{2} \times \Delta t + \sigma_t^{\,i} \times N^{i}(0,1) \times \sqrt{\Delta t}\right)$$

- F^it is the forward price at time t, with superscript "i" referring to a forward contract of a commodity.
- σ^it is the volatility of the forward contract at time t.

- N^i (0,1) is a zero mean and unit variance Gaussian random number.
- The random numbers N^i (0,1) for multiple forward contracts are correlated with one another based a correlation matrix.
- The starting prices F^0t for the forward contracts are the market prices observed at the time of price propagation.

This process is repeated 3,000 times to generate a distribution of fuel prices. Exhibit 7 and Exhibit 8 show the results of simulated Henry Hub gas monthly and annual prices during 2021 – 2041, respectively. The High Case is set at 90th percentile level, Base Case price at the average level, and Low Case price at the 15th percentile level. Delivered gas prices are derived based on basis differential to Henry Hub and benchmarked off the latest Energy Information Administration's ("EIA") form 923 reports for regulated generation units.

Exhibit 7: Henry Hub Gas Monthly Price Forecasts

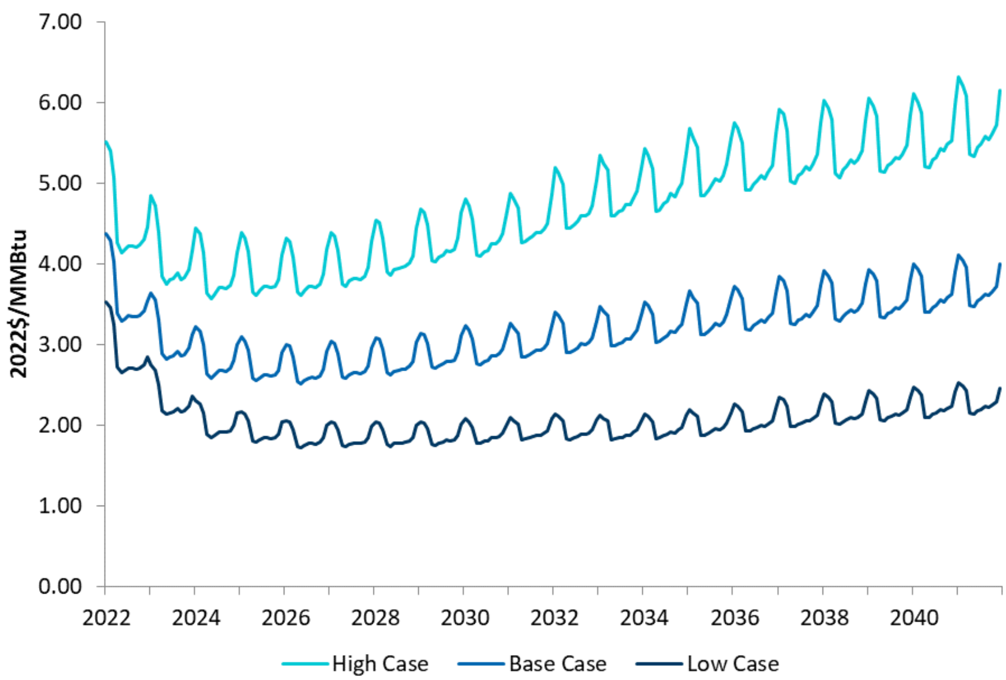
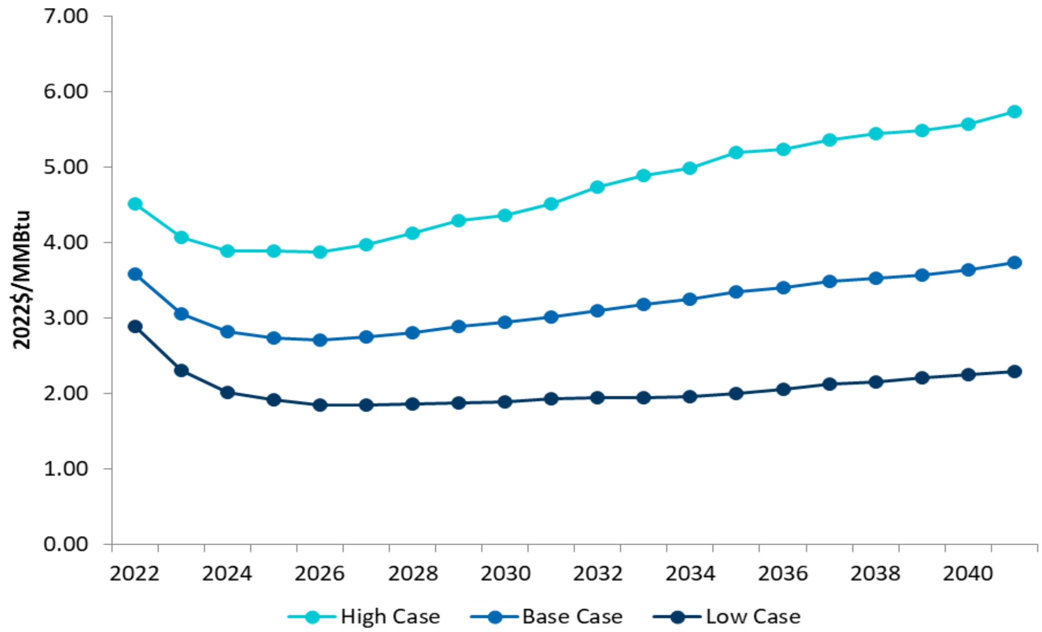


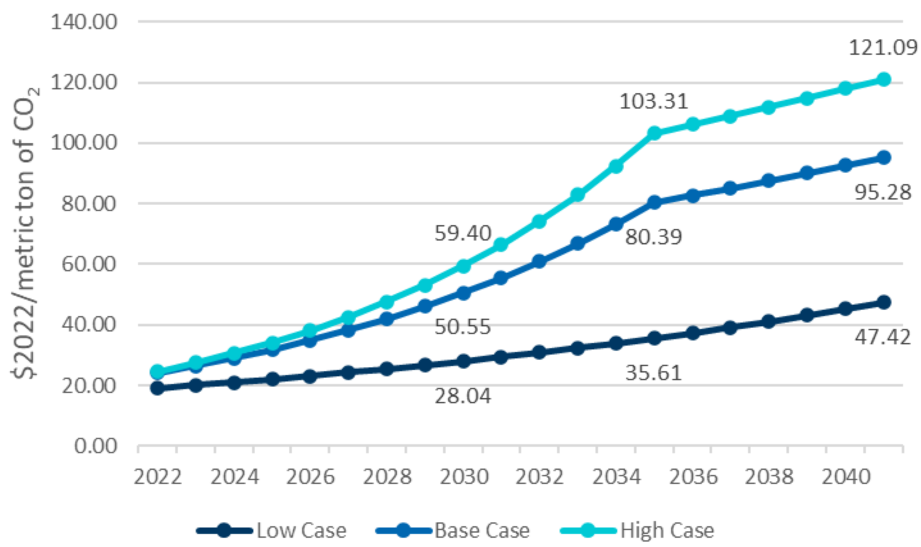
Exhibit 8: Henry Hub Gas Annual Price Forecasts



Carbon Price Forecasts

An important goal of the IRP is for LAC to achieve carbon neutrality by 2040, and LANL to achieve 100 percent renewable generation by 2035. Carbon prices add to the cost and risk of carbon emitting generation resources. The Low Case carbon assumptions are based on 2021 California Integrated Energy Policy Report ("IEPR") low-price scenario, i.e., auction reserve price (floor price), escalated at 5 percent plus inflation measured by the all-urban Consumer Price Index ("CPI"), reaching $47 per metric ton in 2041 in real 2022 dollars. The Base Case carbon price assumptions are based on 2021 IEPR mid-price scenario, i.e., the Tier 1 price which is the average of auction reserve price and price ceiling for all years, reaching $95 per metric ton in 2041. The High Case carbon price assumptions are based on 2021 IEPR high-price scenario, i.e., Tier 2 price which is estimated at the three-quarter point of the auction reserve price and the price ceiling in all years, reaching $121 per metric ton in 2041. Exhibit 9 presents the price assumptions for all three cases. These carbon prices are modeled for the California market, which impacts the overall WECC market. No national carbon prices are assumed.

Exhibit 9: Carbon Price Assumptions



Utility-scale Solar PV CAPEX and LCOE Projections

Utility-scale solar photovoltaics ("PV") capital costs are projected to continue to decline with increased production and more widespread installation. Based on the latest National Renewable Energy Laboratory ("NREL") 2021 Annual Technology Baseline ("ATB"),[5] the utility-scale solar PV capital expenditures ("CAPEX"), which include overnight capital costs and construction costs, is expected to decline from $1,482 per kW in 2020 to $594 per kW in the Low Case, $754 per kW in the Base Case, and $1,033 per kW in the High Case by 2041, as shown in Exhibit 10. This capital costs decline leads to an overall reduction of levelized cost of energy ("LCOE") from an estimated $39 per MWh in 2020 (at assumed 26-percent capacity factor, and 5-percent weighed average cost of capital) to $15 per MWh in the Low Case, $20 per MWh in the Base Case, and $28 per MWh in the High Case by 2041 as shown in Exhibit 11.

It should be noted that the CAPEX and LCOE projections are the latest estimates from an industry perspective and may not fully and accurately reflect the options or costs available to the County. In general, the development costs in the County's market are higher due to supply chain interruptions, tightness of labor, and overall, more expensive site acquisition costs.

[5] NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

Exhibit 10: Utility-scale Solar PV CAPEX Projections

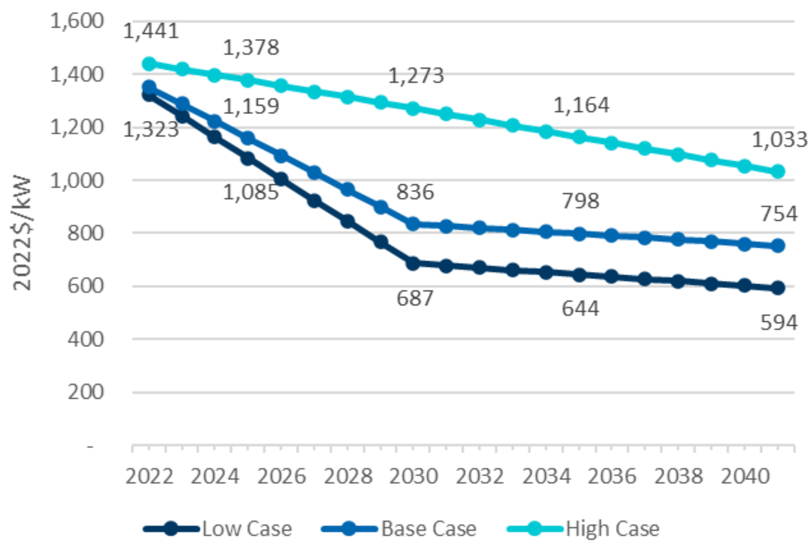
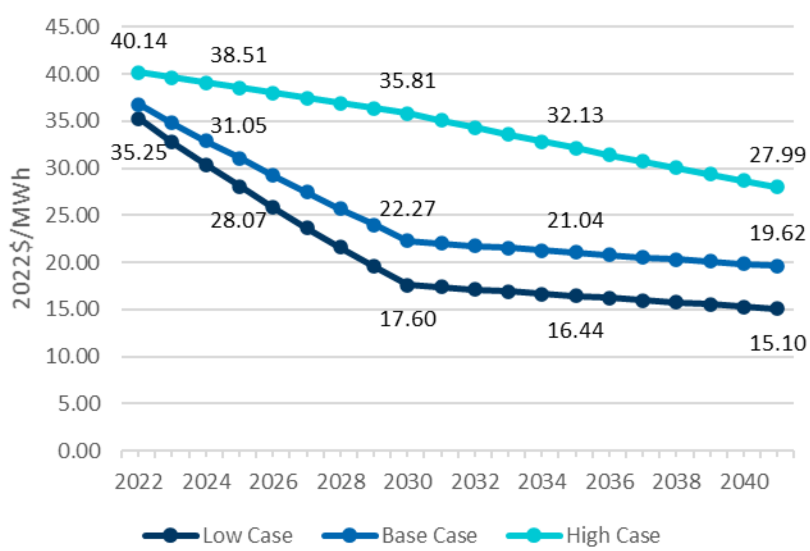


Exhibit 11: Utility-scale Solar PV LCOE Projections

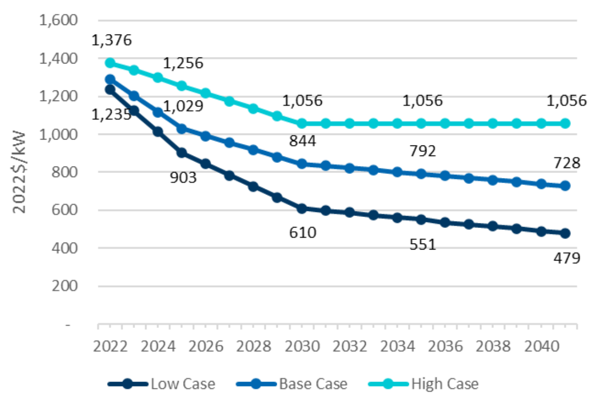


Utility-scale Battery Storage CAPEX and LCOE Projections

Similarly, utility-scale lithium-ion battery storage capex is projected to continue to decline with increased production, and more widespread installation. The cost of battery-grade lithium carbonate has been rising and volatile in the past year due to supply chain interruptions, competition from EV, global supply and demand imbalances.

The utility-scale 4-hour lithium-ion battery storage capex includes the battery component, which currently accounts for slightly over half of the total capex and other costs including the balance of the plant, inverter, installation fees, and interconnection fee, etc. Based on the latest NREL 2021 ATB, the utility-scale 4-hour battery storage capex is expected to decline from current levels to $479 per kW in the Low Case, $728 per kW in the Base Case, and $1,056 per kW in the High Case by 2041, as shown in Exhibit 12.

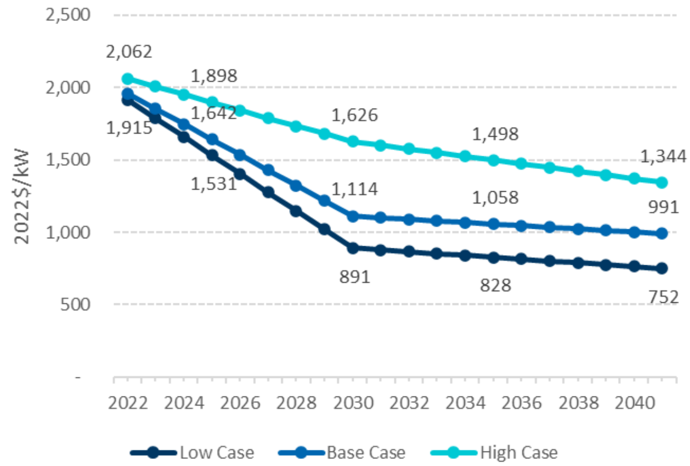
Exhibit 12: Utility-scale 4-hour Lithium-ion Battery Storage CAPEX Projections



Utility-scale PV-plus-Battery CAPEX and LCOE Projections

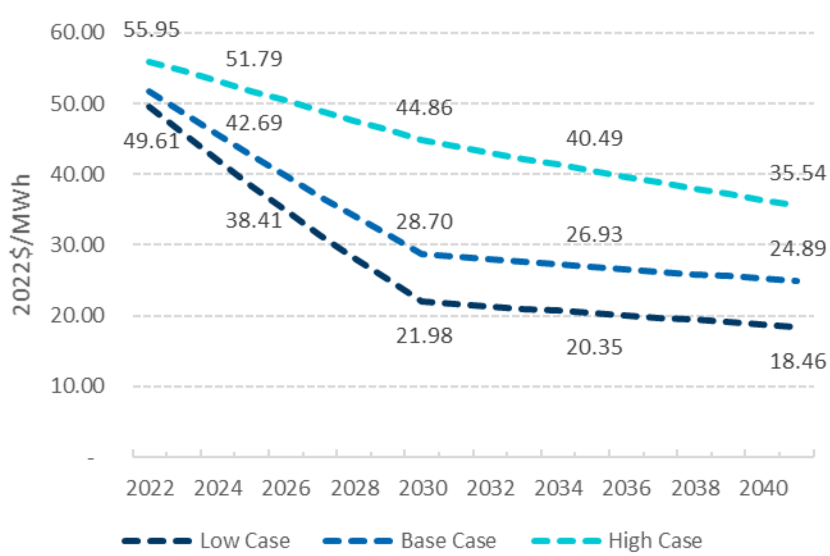
Many WECC utilities have increasingly procured solar plus storage, which involves many different configurations and sizes of the PV and battery components. For this analysis, we assume a representative utility-scale PV-plus-battery technology in a DC-coupled system with one-axis tracking PV and 4-hour lithium-ion battery storage sharing a single bidirectional inverter. The PV-plus-battery technology is represented as having a 130-MW_{DC} PV array, a 4-hour 50-MW_{AC} battery, and a shared 100-MW_{AC} inverter. According to the NREL 2021 ATB, the capex of PV-plus-battery is expected to decline from current levels to $752 per kW in the Low Case, $991 per kW in the Base Case, and $1,344 per kW in the High Case by 2041 as shown in Exhibit 13.

Exhibit 13: Utility-scale PV-plus-Battery CAPEX Projections



The LCOE of a DC-coupled PV-plus-battery technology is a function of the CAPEX costs, operating and maintenance ("O&M") costs, capacity factor, and efficiency assumptions. Assuming a 25-percent capacity factor for solar PV, an 87-percent round-trip efficiency for batter storage, and a 4.3-percent weighted average cost of capital in 2020, the LCOE of a representative PV-plus-battery with zero charging from the grid is expected to decline from current levels to $18 per MWh in the Low Case, $25 per MWh in the Base Case, and $36 per MWh in the High Case by 2041 as shown in Exhibit 14.

Exhibit 14: Utility-scale PV-plus-Battery LCOE Projections



Onshore Wind CAPEX and LCOE Projections

The land-based wind capex is expected to decline from $1,431 per kW in 2020 to $650 per kW in the Low Case, $911 per kW in the Base Case, and $1,018 per kW in the High Case by 2041, as shown in Exhibit 15. The LCOE, assuming a 42-percent capacity factor and a 5-percent weighted average cost of capital, is expected to decline from $31 per MWh in 2020 to $14 per MWh in the Low Case, $21 per MWh in the Base Case, and $25 per MWh in the High Case by 2041, as shown in Exhibit 16.

Exhibit 15: Onshore Wind CAPEX Projections

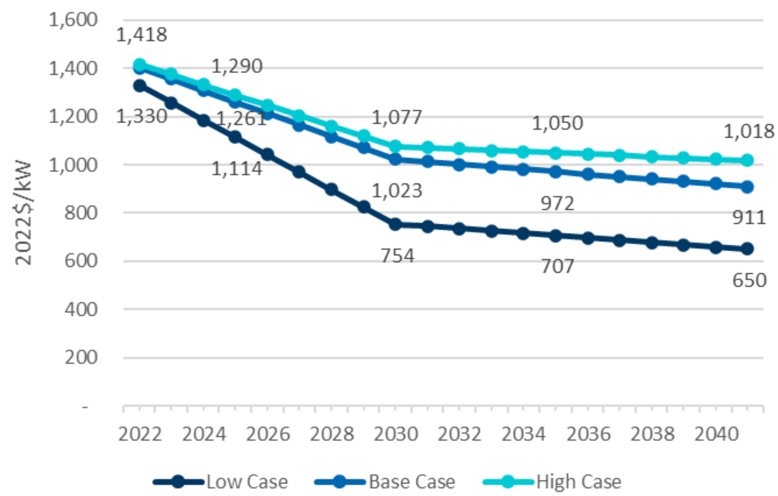
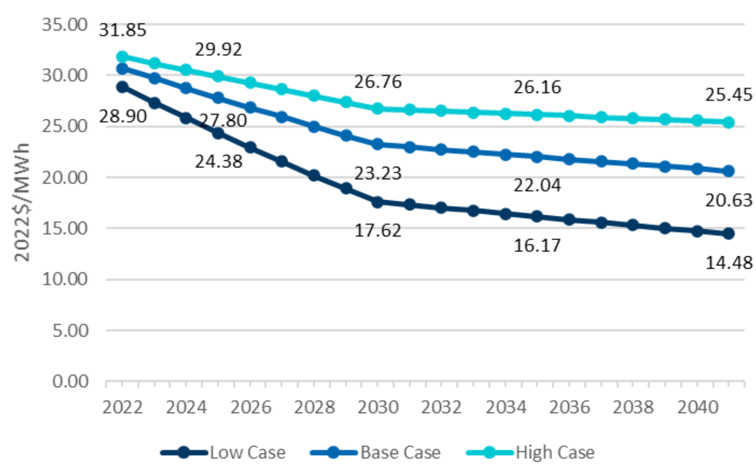


Exhibit 16: Onshore Wind LCOE Projections



Investment Tax Credits and Production Tax Credits

The Base Case and High Case assume current solar ITC and wind PTC incentives. The Consolidated Appropriations Act, 2021 (the Act), which was signed into law on December 27, 2020, extended the ITC for solar projects for two years at a 26 percent rate through the end of 2022, with a step down to 22 percent for projects that start construction in 2023. For solar facilities that commence construction in 2024 or thereafter, the amount of the ITC will drop to 10 percent. The wind PTC provides an inflation adjusted tax credit of $0.025 per kilowatt-hour ("kWh") in 2019$'s for 10 years after commercial online date. The Act extended the PTC for wind projects at a 60 percent rate of the full credit amount, or $0.018 per kWh for projects that start construction by end of 2021. The Low Case assumes a 2-year extension of current PTC policies.

Renewable Portfolio Standards and Clean Energy Standard

The WECC footprint includes diverse Renewable Portfolio Standards ("RPS") mandates with some states having no RPS mandates and other states having the highest RPS goals in the country. For example, Idaho and Wyoming have no RPS mandates. Oregon has a 50 percent RPS by 2040; New Mexico, Washington, and California each have a 100 percent RPS by 2045; and Nevada has a 100 percent RPS by 2050. The Base, High, and Low Cases all assume the current RPS mandates as shown in Exhibit 17. The Base Case and High Case assume no national Clean Energy Standard ("CES"), while the Low Case assumes national CES of 100 percent by 2035 as shown in Exhibit 18, with qualifying resources of solar, wind, hydro, geothermal, nuclear, and carbon capture utilization and storage ("CCUS").

Exhibit 17: WECC Footprint RPS Assumptions

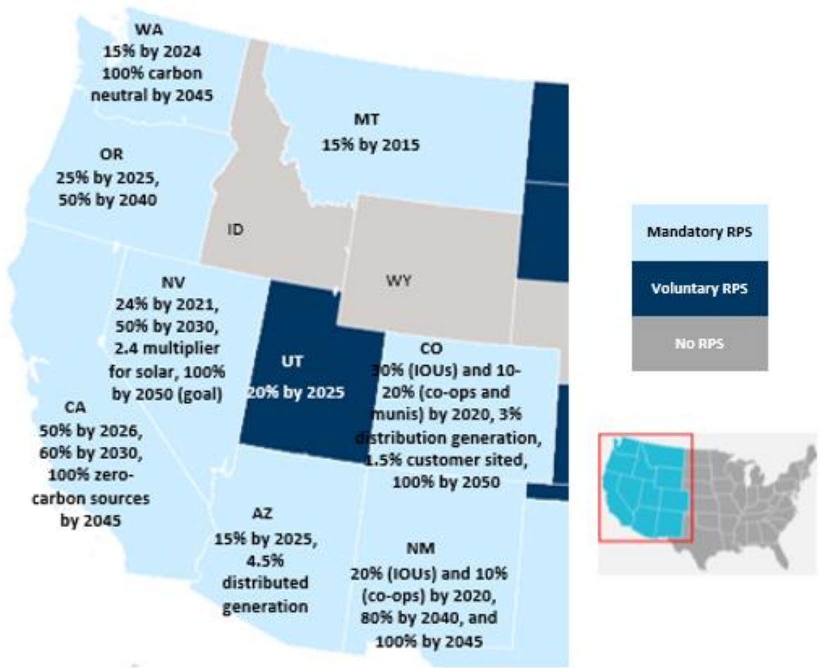
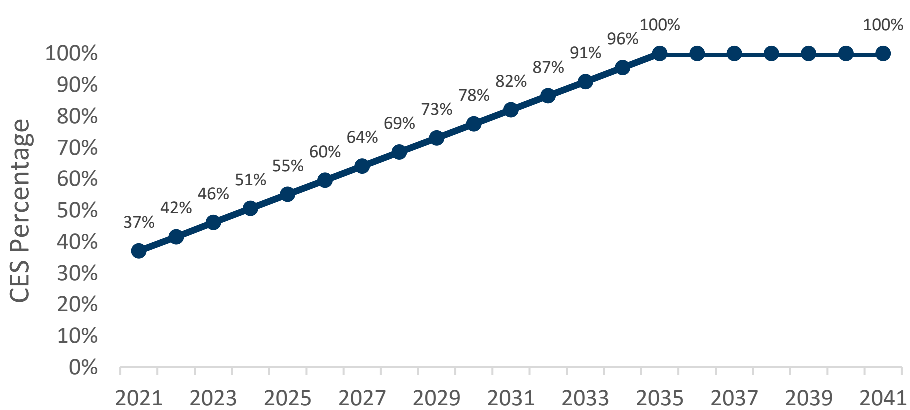


Exhibit 18: Low Case CES Assumptions



Chapter 5: WECC Market Assessment

Los Alamos County's Balancing Authority ("BA"), Public Service Company of New Mexico ("PNM"), is in the Southwest Reserve Sharing Group ("SRSG"), one of the three reserve sharing groups in WECC in addition to the California Independent System Operator ("CAISO") and the Northwest Power Pool ("NWPP"). Exhibit 19 shows the three WECC Reserve Sharing Groups.

Exhibit 19: WECC Reserve Sharing Groups

Resources Challenges

The North American Electric Reliability Corporation ("NERC")'s 2021 Long-term Reliability Assessment has shown that CAISO, NWPP, and SRSG all face potential load loss hours in the near term (2022 – 2024). The NERC 2021 study finds:

- *Energy risks are present today as electricity resources are insufficient to manage the risk of load loss when wide-area heat events occur.*
- *Risk is most acute in late afternoon since there are energy limitations as solar PV resource output diminishes. Energy analysis shows up to 10 hours of load loss beginning in 2022 and as much as 75,000 MWh of unserved energy in extreme conditions in 2024.*

- *Flexible resources that can be dispatched to counter solar PV behavior and be relied upon with assured fuel supplies are needed to reduce the load-loss risk and serve energy demand in all seasons and time periods.*

The 2021 Western Assessment of Resource Adequacy ("WARA") concludes that resource adequacy risks to reliability are likely to increase over the next 10 years. WECC recommends entities take immediate action to mitigate near-term risks and prevent long-term risks. The WECC 2021 WARA report recommends utilities:

- *Calculate planning reserve margins based on energy instead of capacity.*
- *Use the most strained (variable) times on the system to determine the PRMs instead of relying on the assumption that if the peak is covered all other times will be covered too; and*
- *Regularly recalibrate PRM when there are significant changes to resources or demand that may increase the variability on the system.*

Climate change and extreme weather (cold snaps, heat waves, and drought, etc.) lead to increasing demand volatility and resource variability. Transportation electrification and Distributed Energy Resources ("DERs") will continue to modify load patterns and levels. Large, planned baseload resource retirements, which include 2.3 gigawatts ("GW") of nuclear at Diablo Canyon by 2024 – 2025, 3.5 GW of coal-fired generation by 2026, and 3 GW coastal gas-fired generation resources during 2024 – 2029 due to once-through cooling regulation, contribute to declining reserve margins and pose supply-side challenges.

Due to lack of storage and redundancy in gas infrastructure, the gas supply in the Southwest is susceptible to disruptions. Gas supply curtailments could impact power generation during winter peaks. Potential closure of the Aliso Canyon gas storage facility in California could further stress the power grid.

Drought Conditions

The combination of low hydro output and high demand poses challenges to utility resource planning. In 2021, WECC hydro generation declined by 40 percent from 2020 levels due to drought conditions. As a result, hydro accounted for 16 percent of total WECC generation in 2021, in comparison to over 22 percent in 2020. Exhibit 20 shows the comparison between 2020 and 2021 hydro generation levels. Exhibit 21 shows the U.S. drought condition map for week of July 13, 2021.

Exhibit 20: WECC 2020 – 2021 Hydro Generation

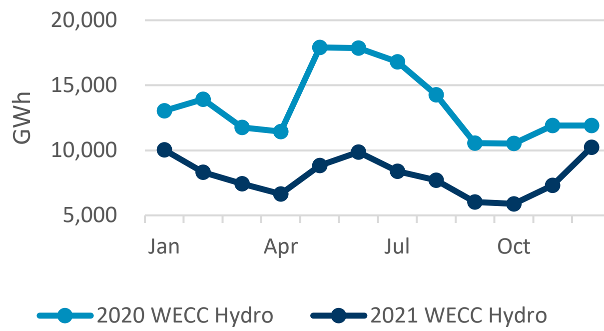
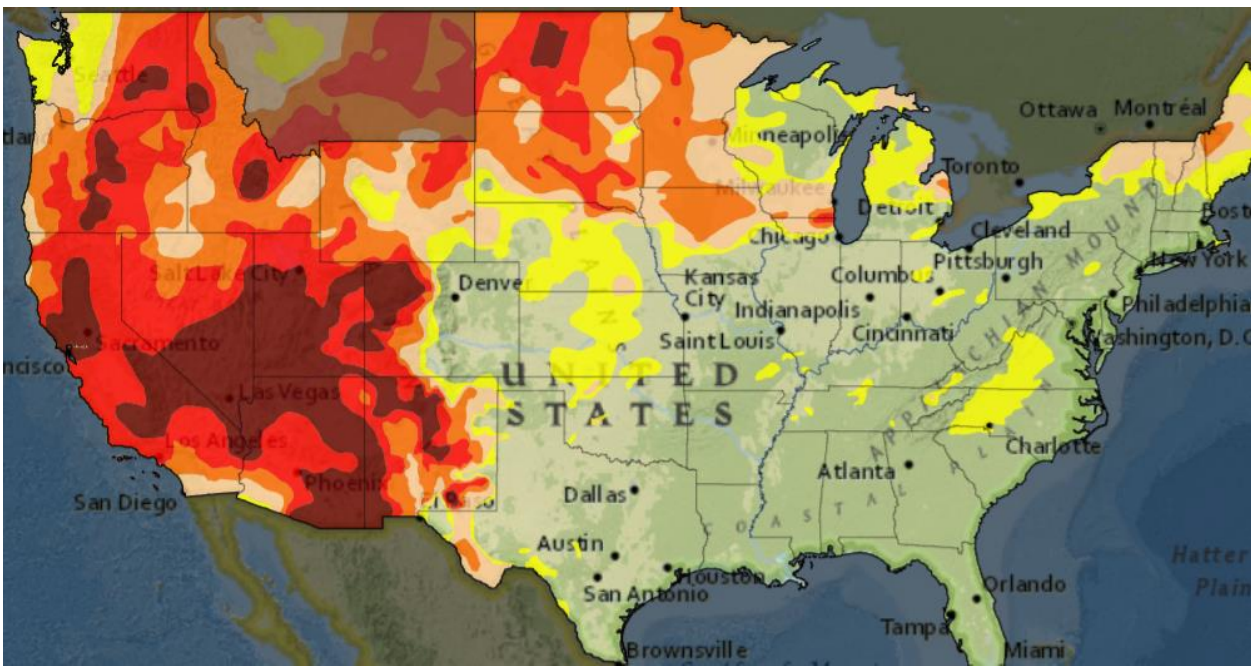


Exhibit 21: U.S. Drought Conditions Map for the Week of July 13, 2021



PNM Balancing Area

Evolving load and resource variability drives higher peak prices and lower off-peak prices in the PNM BA area. The PNM BA area has experienced increasing power prices from an annual average of $27 per MWh in 2016 to $50 per MWh in 2021 as shown in Exhibit 22. The drought conditions have in general correlated with higher power prices. As shown in Exhibit 23, the PNM BA area had a maximum price of $1,342 per MWh and a minimum price of negative $17 per MWh in 2020, with a total of 35 hours above $300 per MWh and 106 hours of negative prices. The PNM BA area had a maximum price of $961 per MWh and a minimum price of negative $6 per MWh in 2021, with a total of 27 hours above $300 per MWh and 51 hours of negative prices. These price patterns will continue to evolve as New Mexico faces capacity shortages, with coal retirements in the PNM BA area not yet refilled with new resources. PNM's plans to make up the capacity shortfall includes increased imports, battery storage projects, and renewables. With increasing intermittent renewable generation on the system, the Effective Load Carrying Capability ("ELCC") of solar and wind decreases. Exhibit 24 shows the hourly and monthly average prices for 2021, with hour 18 to 21 showing the highest average prices, more than double the average prices during hour 9 to 14.

Exhibit 22: Historical Average PNM Four Corners Prices

$/MWh	2016	2017	2018	2019	2020	2021	Avg
Jan	26	32	32	38	27	30	**31**
Feb	22	26	29	70	24	62	**37**
Mar	18	21	28	35	25	28	**26**
Apr	18	24	24	22	19	32	**24**
May	21	28	20	17	17	31	**23**
Jun	29	32	27	23	22	49	**31**
Jul	33	35	70	31	28	67	**43**
Aug	34	44	63	32	73	59	**48**
Sep	31	37	33	34	43	66	**40**
Oct	32	36	38	33	40	60	**39**
Nov	26	31	47	38	35	56	**37**
Dec	33	29	50	36	36	60	**39**
Avg	**27**	**31**	**38**	**34**	**32**	**50**	**35**

Exhibit 23: 2020 – 2021 PNM Four Corners Prices

	Max	**Min**	**Average**	**> $300/MWh**	**Negative Prices**
	$/MWh	$/MWh	$/MWh	Hours	Hours
2021	961	(6)	50	27	51
2020	1,342	(17)	32	35	106

Exhibit 24: 2021 PNM Four Corners Prices

		Month												Avg
	$/MWh	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
	0	32	74	34	38	36	46	58	56	63	61	56	55	**50**
	1	30	51	32	36	34	41	54	51	59	59	52	53	**46**
	2	29	48	31	34	32	39	50	49	57	56	51	50	**44**
	3	29	46	30	33	31	38	48	48	56	54	50	49	**43**
	4	29	47	31	33	31	37	47	47	55	54	51	49	**42**
	5	29	50	33	35	33	38	48	48	57	55	53	51	**44**
	6	33	78	38	40	36	41	50	51	61	61	60	57	**50**
	7	39	99	45	44	36	45	57	56	70	71	68	72	**58**
	8	38	67	37	37	27	32	46	48	62	72	61	70	**50**
	9	28	38	24	26	20	29	42	41	48	57	48	58	**38**
	10	20	25	16	21	18	29	43	40	44	47	41	52	**33**
Hour	11	19	20	12	17	16	29	44	41	43	42	37	48	**31**
	12	17	17	9	15	15	32	48	44	45	40	36	45	**30**
	13	14	15	7	14	16	36	54	48	50	40	36	43	**31**
	14	15	14	7	14	18	41	59	52	55	42	37	43	**33**
	15	18	17	8	15	20	44	64	57	60	44	43	48	**37**
	16	26	28	11	17	22	50	71	63	66	49	56	60	**43**
	17	38	54	17	20	22	53	76	66	71	56	75	78	**52**
	18	46	125	33	30	30	61	87	75	89	79	93	95	**70**
	19	44	153	49	46	44	89	128	102	130	94	81	82	**86**
	20	41	135	53	58	60	124	173	106	106	84	73	77	**90**
	21	39	114	46	54	58	90	109	83	86	76	69	73	**74**
	22	37	97	42	46	48	70	86	73	78	73	63	67	**65**
	23	33	79	37	41	40	50	67	60	68	66	58	61	**55**
	Avg	**30**	**62**	**28**	**32**	**31**	**49**	**67**	**59**	**66**	**60**	**56**	**60**	**50**

State and utility level mandates drive new builds in Desert Southwest. New Mexico state RPS, as well as investor-owned utility and Public Power RPS goals drive resource decisions in the region. Exhibit 25 shows the New Mexico state and surrounding representative utilities' RPS goals.

Exhibit 25: New Mexico State and Surrounding Representative Utilities RPS Goals

State and Utilities	Renewables Portfolio Standard Target
New Mexico	Energy Transition Act calls for 100 percent zero-carbon resources for investor-owned utilities by 2045, and rural electric cooperatives by 2050.
PNM	100% by 2040 Voluntary; 100% by 2045 Mandatory
El Paso Electric	100% by 2045
Southwestern Public Service	100% by 2045
Arizona Public Service	100% by 2050
Tucson Electric Power	80% reduction in CO_2 emissions by 2035
Salt River Project	90% reduction in CO_2 emissions by 2050

The PNM BA area near term capacity shortages are expected to moderate after replacement resources are integrated into the grid. FTI forecasts an average price of $39 per MWh in the Base Case, an average of $52 per MWh in the High Case, and an average of $21 per MWh in the Low

Case in 2025 (in real 2022 dollars unless otherwise noted). Exhibit 26 and Exhibit 27 show the average annual and monthly power price forecasts for the PNM BA area for the three cases.

Exhibit 26: PNM BA Area Annual Power Price Forecasts

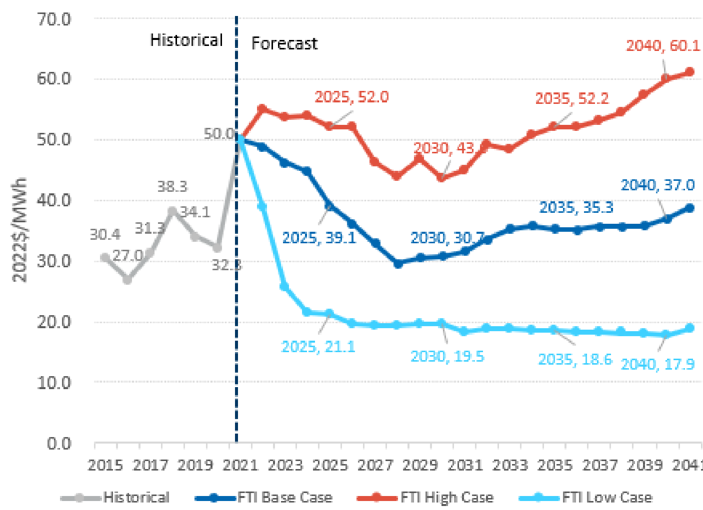
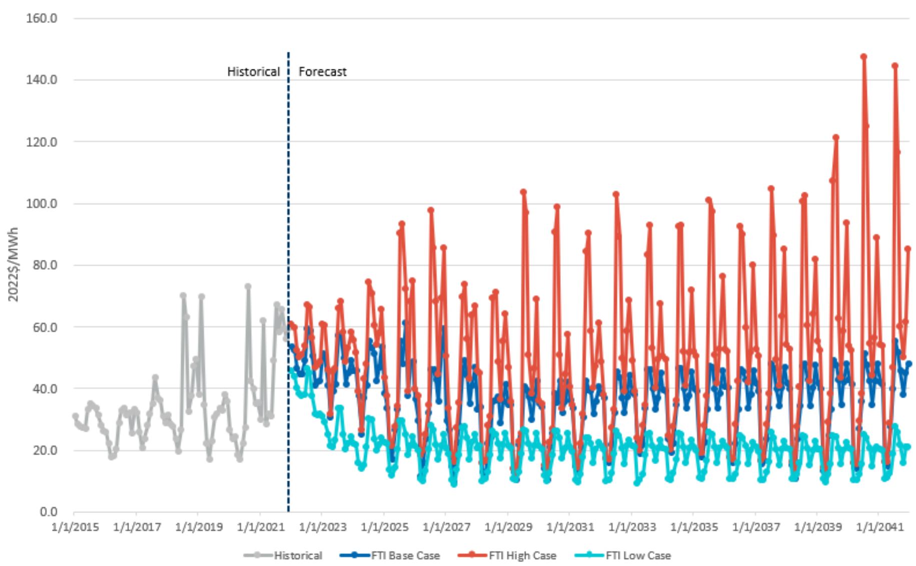


Exhibit 27: PNM BA Area Monthly Power Price Forecasts



WECC Energy Imbalance Market Considerations

LAC and LANL are concerned with the availability of real-time market purchases and bilateral trading in the WECC Energy Imbalance Market ("EIM"). CAISO's "Duck Curve" impacts the requirements for new resources. The WECC market conditions directly impact DPU's cost of serving its load, and its ability to balance resource and load in real time. Currently, the DPU does not have explicit PRM requirements. During the August 2020 heatwave, which drove up market prices exponentially, the DPU was greatly impacted due to market exposure at the time. The impact was magnified by the DPU's largest resource tripping off-line and the curtailment of its other coal resource in Wyoming. In addition to meeting peak load, DPU's resources must have the flexibility to balance short-term and multi-hour ramps in net load and to manage potential over-generation. These operational issues will become more significant as DPU integrates more renewables into its system.

For this IRP, LAPP considers implementing a positive PRM, consistent with best practices of utilities in the same market footprint and WECC recommendations. Resource planners use planning reserves to ensure that adequate capacity will be available to meet peak demand each year over a long-term planning horizon. A positive PRM provides the extra resources necessary to account for peak loads that are higher than forecasted and for unplanned outages of generation and transmission resources.

Chapter 6: LAPP Existing and Planned Resources

Demand Side Resources

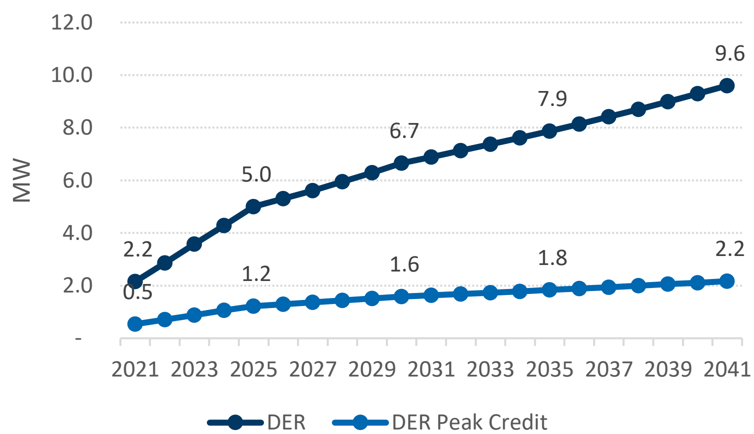
LAC continues to evaluate demand-side technology options including distributed energy resources, energy efficiency ("EE"), and demand response ("DR") programs. The County currently has 2.2 megawatt ("MW") installed rooftop solar DER in the service territory and projects the DER to grow to 5 MW by 2025 and 10 MW by 2041, as shown in Exhibit 29. This IRP models the DER as an aggregate solar resource and applies a typical solar profile in New Mexico.

In addition, LAC is participating in the energy efficiency educational program campaign through Pajarito Environmental Education Center ("PEEC"), evaluating the proposed Utah Associated Municipal Power Systems ("UAMPS") rebate program, and proposed advanced metering infrastructure ("AMI") time of use ("TOU") rates for peak reduction. Exhibit 28 outlines LAPP's existing and proposed demand-side programs.

Exhibit 28: LAPP Existing and Planned Demand Side Programs

Resources	Considerations
Distributed Energy Resources ("DER")	5 MW by 2025 and 10 MW by 2041
Energy Efficiency ("EE")	Load forecast is after EE impact
Demand Response ("DR")	No existing DR program

Exhibit 29: Solar DER Capacity Projection



Existing and Proposed Supply Side Resources

As a load serving entity, LAC has a mix of generation assets, including coal generation purchase power agreements ("PPAs"), hydro, solar, firm renewables PPA, around-the-clock ("ATC") PPA, and SMR PPA. LANL owns a gas-fired combustion turbine and has planned a 10 MW solar project. Exhibit 30 summarizes the existing and planned resources in LAPP. Historically, San Juan Generation Station ("SJGS") Unit 4 has served over a third of the total peak load, and the County has proactively entered two PPAs to replace the load serving capacity and energy in the interim.

Exhibit 30: LAPP Existing and Planned Supply Resources

Resources		Status	Ownership	Capacity (MW)
LANL	TA-3 Combustion Turbine	Operating	Own	25.0
	Western	Operating	PPA	10.1
	LANL Solar	COD in 2024	Own	10.0
LAC	San Juan Generation Station Unit 4	Retire in 2022	Own	36.0
	Laramie River Station	Operating	PPA	10.0
	Western	Operating	PPA	1.5
	El Vado	Operating	Own	3.6
	Abiquiu	Operating	Own	4.6
	Wind & Solar PPA	COD in Q1 2022	PPA	15.0
	Solar	Operating	Own	1.0
	ATC PPA	2022-2024	PPA	25.0
	CFPP SMR	2030	PPA	8.0

LAC Coal Generation Facilities and PPA

LAC has positions in two coal-fired power plants. It has a 7.5 percent ownership share (or 36 MW) of SJGS Unit 4, a 507-MW plant operated by PNM. SJGS generates power using bituminous coal from the San Juan Coal Mine. The County has formally made the decision to exit the SJGS project at the expiration of the current project participation agreement in 2022. SJGS has an estimated heat rate of 11,546 Btu per kWh, a cost of delivered coal at $2.2 per million British thermal units (“MMBtu”), non-fuel variable operating and maintenance costs (“VOM”) at $4.07 per MWh, and fixed operating and maintenance costs (“FOM”) at $54 per kW-year.

LAC has a 10-MW, “life-of-the-plant” PPA with Laramie River Station (“LRS”) in Wheatland Wyoming through an agreement with Lincoln Electric System. LRS generates power with subbituminous coal from the Antelope Coal Mine and North Antelope Rochelle Mine. It has complied with an Environmental Protection Agency (“EPA”) Best Available Retrofit Technology (“BART”) ruling; retrofit costs were completely expensed as of December 2019. LRS is currently planned to be in service until 2040 – 2042. Consistent with Future Energy Resources (“FER”) recommendation, LAC plans to exit LRS when most economical between now and 2042. LRS has an estimated heat rate of 10,329 Btu per kWh, cost of delivered coal at $1.1 per MMBtu, non-fuel variable VOM at $3.88 per MWh and FOM at $54 per kW-year.

LAC Hydroelectric Generation Facilities

LAC owns two local hydroelectric power plants. The Abiquiu hydroelectric plant has an estimated summer capacity of 15 MW and winter capacity of 2 MW. El Vado hydroelectric plant has an estimated summer capacity of 9 MW and winter capacity of 2 MW.[6] On a ten-year average, the combined generation is approximately 70 gigawatt-hours ("GWh") per year, though their output varies considerably and will decline if drought conditions persist. The debt services on both plants have been fully paid off, providing low-cost renewable power to LAC and LANL. LAC plans to keep ownership of these two facilities to help meet the carbon neutral goal by 2040.

LAC Firm Solar and Wind PPA

Besides owning a small solar resource of 1 MW, LAC has entered a 15-year PPA with Uniper Global Commodities that will provide the County with 15 MW ATC firm wind and solar energy. The resource is expected to achieve commercial operation in 2022. LAC has the option to extend the PPA after its initial term. Under the agreement, renewable energy will be sourced from two power-generation facilities now under construction in New Mexico. Solar power will be supplied from a project in northwest San Juan County with wind power coming from a generation center in central New Mexico. During hours when there is insufficient generation from wind and solar sources to meet demand, Uniper will arrange alternate supply from its portfolio of traditional energy resources. For any excess wind or solar generation above 15 MW in any hour, LAC holds the right of refusal.

LAC ATC PPA

To replace the capacity and energy shortage after SJGS Unit 4 retirement, LAC contracted for 25 MW of around the clock PPA which provides approximately 28 percent renewable energy during 2022 – 2024.

Proposed Carbon Free Power Project

LAC recently became a member of the Utah Associated Municipal Power Systems, which serves municipal utilities in eight western states. UAMPS is developing the Carbon Free Power Project, the nation's first-generation small modular reactor nuclear plant, to be located at the Idaho National Laboratory ("INL") near Idaho Falls, Idaho. It will be compromised of 12 modules of 77 MW nuclear power, capable of generating 924 MW. As part of the CFPP's goal to advance state and national efforts to reduce carbon emissions and increase air quality, the power generated by

[6] El Vado Hydroelectric Plant is typically offline during November to March.

the small modular reactor is 100 percent carbon free. The U.S. Department of Energy intends to draw from two modules of the 12-module NuScale SMR plant at the INL site developed by UAMPS.

The CFPP project plans to be commercially online in 2030. Work is underway at the site to develop the Combined Operating License Application for the Nuclear Regulatory Commission. LAC plans to acquire partial ownership of the plant. Based on the project developer, the PPA price is expected to be $58 per MWh, assuming a 40-year debt service and estimated 95 percent capacity factor. Given that the project is in the development stage, the IRP models different subscription levels:

- 0 MW, if LAC pulls out of the commitment;
- 8 MW, reflecting current plan;
- 36 MW, accounting for a full replacement of SJGS unit 4.

LANL Generation Facilities

LANL has a behind-the-meter TA-3 combustion gas turbine generator ("CGTG") with a summer capacity of 21 MW and winter capacity of 25 MW. The permit for the generator allows for a run-time of 5,000 hours per year. The TA-3 CGTG has an estimated heat rate of 7,000 Btu per kWh, non-fuel VOM of $2.2 per MWh, and FOM of $36 per kW-year.

Western Area Power Administration ("WAPA") Hydropower Allocation

In addition to above-mentioned owned and contracted generation resources, LAC purchases approximately 1 MW of hydro power from WAPA, and LANL purchases approximately 33 MW. LAC receives a seasonal contract rate of delivery of 1.5 MW in the winter and 982 kW in the summer, with a Sustainable Hydro Power entitlement of approximately 3,028 MWh in the winter season and 2,070 MWh in the summer season from WAPA.

LANL receives a seasonal contract rate of delivery of 10.6 MW in the winter and 9 MW in the summer, with a Sustainable Hydro Power ("SHP") entitlement of approximately 35,446 MWh in the winter season and 34,540 MWh in the summer season from WAPA. The estimated cost of energy for the WAPA contract is $14.54 per MWh, and the contract is expected to be renewed upon its expiration.

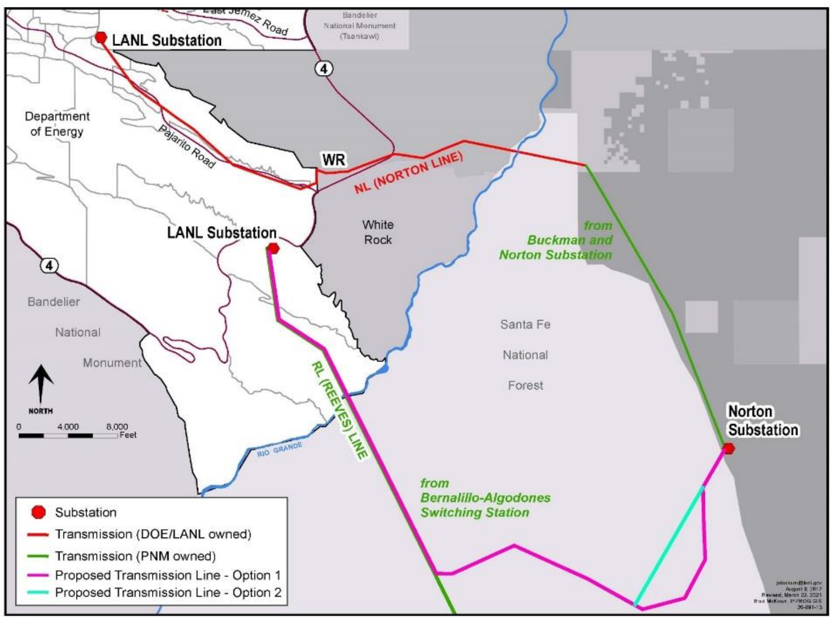
Transmission Resources

The County is within the PNM Balancing Area and has a Network Integrated Transmission Service Agreement ("NITSA") with PNM. LAC also has transmission service agreements with Jemez Electric co-op and NORA Electric Co-op to deliver the power from the hydroelectric facilities into the Los Alamos load center. In addition, LAC has a 10 MW firm point-to-point transmission service agreement from Ault to San Juan for the delivery of the LRS power. The County purchases

Ancillary Service Schedules 1 through 4 from PNM and is a member of the Southwest Reserve Sharing Group for spinning reserves, schedule 5 and 6. LANL owns and operates approximately 20 miles of 115kV transmission line with two interconnections with the PNM Balancing Authority. The substations are referred to as the Norton and the Southern Technical Area ("STA") substations. The community of White Rock is served from a substation of the LANL 115kV transmission line. Los Alamos Town is served from a LANL substation inside Tech Area, TA-3. LANL operates a Static VAR Compensator that provides voltage support for a portion of the PNM BA area and qualifies for a 2.0 MW credit for transmission import power.

The LAPP transmission capacity is currently at 116 MW and will expand to 200 MW once the EPCU project is completed in July 2028. Exhibit 31 shows the LAPP transmission expansion options.

Exhibit 31: LAPP Transmission Expansion Options



Source: NEPA Scoping Briefing, Project Environmental Assessment, May 6, 2021.

Chapter 7: Supply-side Utility-scale Technology Screening

LAPP considers a wide range of utility-scale technology options as potential additions. Exhibit 32 shows the resource options and considerations in the IRP. The technology options are evaluated based on key characteristics including environmental performance, level of deployment, location, interconnection difficulty, dispatchability, and levelized cost of energy (“LCOE”).

FTI conducted technology screening to identify technically feasible and commercially viable generation resources that could be used as building blocks to construct candidate portfolios. For this reason, the technology screening focuses on resource options that could meet LAPP’s new generation resource requirements, including:

- Size of the new resources, which is informed by factors including load profile, existing resources retirement, and PPA expiration, etc.
- Generator characteristics including ramping rates, dispatchability, compatibility with carbon neutral goals
- Local considerations: altitude, pressure, natural wind or solar resources, etc.

Baseload Resources: Gas-fired combined cycle (“CC”) resources are not considered because of the carbon neutral goal. Firmed renewables options, including wind and solar PPA (similar to the Uniper contract), and solar firmed with battery storage are both considered. Geothermal resources are evaluated in the screening process, but not moved forward in the portfolios due to their high cost, high dependence on geography, and low availability of projects. Fuel cells are to be monitored, as the current technology are implemented in DOE labs and other facilities at a small scale.

Peaking Resources: Gas-fired RICE and SCGT resources are considered for the desired dispatchability and balancing function. Among different options of storage, lithium-ion battery is considered with a 4-hour duration. LAC and LANL expects to consider long duration storage in future IRP updates when long duration storage becomes cost competitive and commercially available. Pumped hydro storage is evaluated in the screening process, but not considered in the portfolios due to its high cost, high dependency on geography, low availability of projects, and complexity with ownership of water rights. Vanadium redox flow batteries are included in the screening process, but not considered in the portfolios due to their high cost and low availability of projects.

Intermittent Resources: Utility-scale solar and wind are both considered in this IRP.

Exhibit 32: IRP Supply Side Technology Options

Types		Resources	Considerations
Baseload	Thermal	Combined Cycle (CC)	Inconsistent with carbon neutral goal
		Laramie River Station (LRS)	Exit when economical, no later than 2042
	Nuclear	Carbon Free Power Project (CFPP)	Subscription levels: 0, 8, 36 MW
	Hybrid	ATC PPA with 28% Renewable	Near term bridge PPA to replace San Juan Unit 4
	Firm Renewables	Solar + Wind	Uniper contract + more
		Solar + Battery	Solar weather dependent
		Geothermal	High cost, opportunistic and geography dependent
		Fuel Cells	< 5 MW size, implemented in other national labs
Peaking	Thermal	Reciprocating Internal Combustion Engine (RICE)	Explore in IRP for dispatchability and balancing
		Simple Cycle Gas Turbine (SCGT)	Explore in IRP for dispatchability and balancing
	Storage	Pumped Hydro	Cost and ownership of water rights; Opportunistic and geography dependent
		Lithium-ion Battery	Duration considerations
		Vanadium Redox Flow Battery	High-cost; lack of actual projects development
Intermittent	Renewables	Solar (onsite or offsite)	Weather dependent
		Onshore Wind	Weather dependent; transmission constraints

Wind Resources

New utility-scale wind builds are modeled at a 40 percent capacity factor, 30-year life, with capital costs and fixed operating costs metrics from NREL 2021 ATB. New utility-scale wind builds are modeled according to current PTC provisions of 1¢–2¢ per kilowatt-hour for 10 years after commercial operation date (“COD”), allowing a 4-year safe harbor provision. Exhibit 33 shows the capex and PTC assumptions for new wind resources.

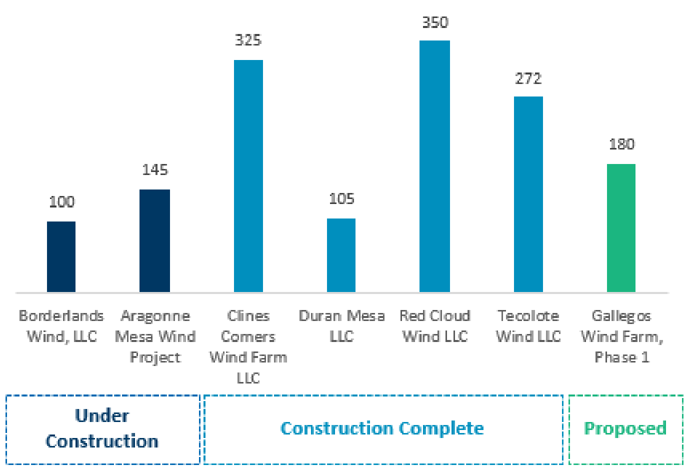
Currently, close to 1,477 MW of utility-scale wind capacity is in the New Mexico development pipeline, with 245 MW under construction, 1,052 MW completed construction, and 180 MW proposed. Exhibit 34 shows the capacity of the recently constructed and proposed wind projects in New Mexico.

Exhibit 33: Wind Resources CAPEX and PTC Assumptions

COD Year	CAPEX Base Case 2022$/kW	CAPEX High Case 2022$/kW	CAPEX Low Case 2022$/kW	FOM 2022$/kW-year	Capacity Factor %
2022	1,404	1,418	1,330	45	40%
2025	1,261	1,290	1,114	44	40%
2030	1,023	1,077	754	42	40%
2035	972	1,050	707	40	40%
2040	921	1,023	660	39	40%

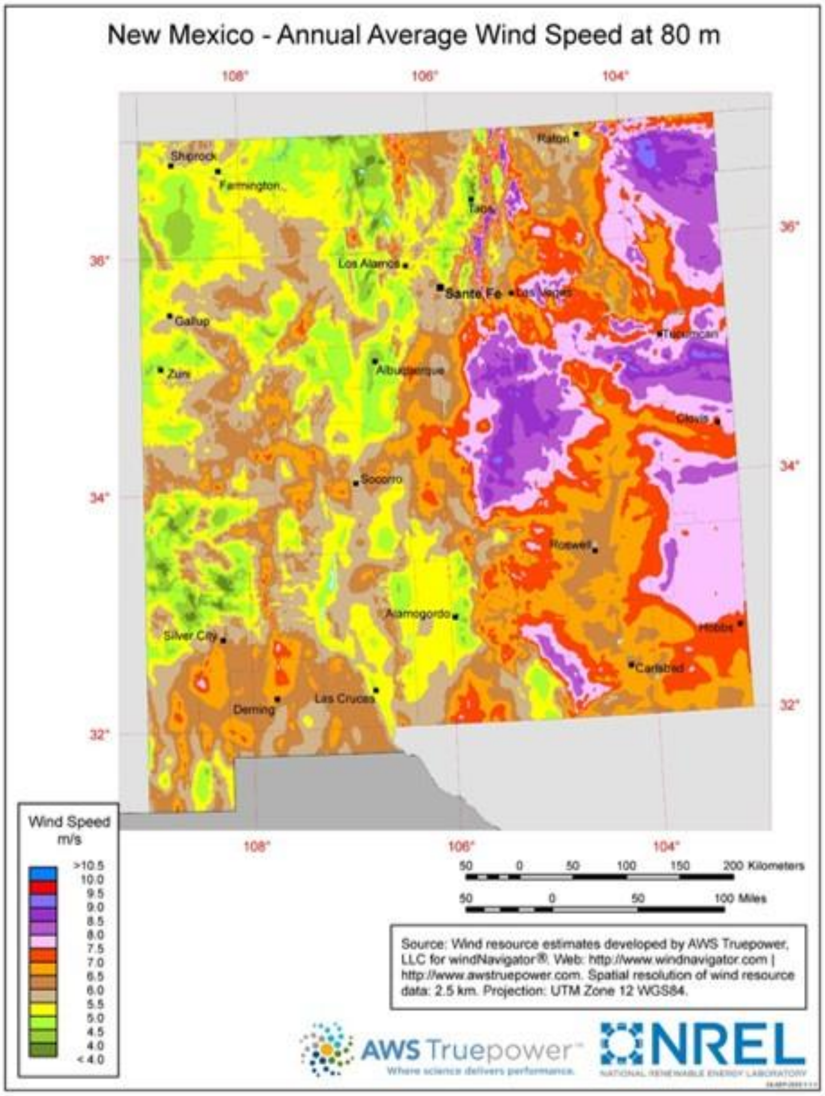
Construction Start Date	Level of PTC Received (%, cents/kWh)
Jan 1 – Dec 31, 2018	60%, 1.5 cents/kWh
Jan 1 – Dec 31, 2019	40%, 1.0 cents/kWh
Jan 1 – Dec 31, 2020	60%, 1.5 cents/kWh
Jan 1 – Dec 31, 2021	60%, 1.5 cents/kWh

Exhibit 34: New Wind Projects in New Mexico



Eastern New Mexico has favorable wind resources, with predicted average annual wind speeds above 6.5 meters per second at an 80-meter height. Exhibit 35 shows the wind resources in New Mexico. New transmission will be needed to bring new wind generation to serve LAC and LANL load because the transmission between eastern New Mexico and Albuquerque is fully subscribed. Opportunities for projects that could be developed on sites with existing transmission or in locations that are not transmission constrained are limited. The LAPP transmission capacity is currently at 116 MW and will expand to 200 MW once the EPCU project is completed in July 2028. The new wind capacity is subject to this transmission constraint.

Exhibit 35: New Mexico Wind Resources Map



Sources: NREL, Wind Exchange, https://windexchange.energy.gov/maps-data/89

New Mexico wind resources typically have lower generation during peak hours (07:00 – 22:00) than off-peak hours. Wind resources have the lowest average capacity factor during the peak hours (07:00 – 22:00) of the summer peak months (June – September). Exhibit 36 shows the monthly and hourly capacity factors of New Mexico wind resources.

Exhibit 36: New Mexico Wind Resources Monthly and Hourly Capacity Factors

Capacity Factor (%)	Month												Avg
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
0	60%	56%	57%	60%	49%	56%	47%	44%	40%	57%	56%	61%	**53%**
1	59%	54%	60%	62%	49%	60%	48%	39%	44%	56%	56%	60%	**54%**
2	60%	52%	57%	57%	51%	57%	49%	41%	42%	53%	56%	55%	**52%**
3	55%	51%	58%	52%	50%	57%	48%	38%	42%	52%	55%	56%	**51%**
4	58%	52%	57%	53%	51%	51%	48%	34%	42%	50%	56%	51%	**50%**
5	56%	53%	55%	52%	46%	54%	46%	36%	38%	47%	55%	50%	**49%**
6	55%	52%	56%	49%	42%	46%	38%	32%	36%	47%	52%	52%	**46%**
7	56%	51%	48%	36%	32%	28%	21%	11%	24%	44%	53%	49%	**38%**
8	49%	44%	31%	29%	30%	32%	18%	12%	13%	25%	40%	45%	**31%**
9	36%	40%	26%	30%	26%	28%	16%	12%	11%	21%	24%	36%	**25%**
10	32%	39%	28%	32%	26%	27%	13%	9%	12%	23%	24%	33%	**25%**
11	31%	39%	33%	32%	26%	24%	14%	9%	12%	23%	26%	31%	**25%**
12	30%	40%	33%	31%	30%	25%	14%	9%	12%	22%	25%	33%	**25%**
13	32%	39%	39%	31%	34%	24%	18%	13%	12%	21%	26%	36%	**27%**
14	34%	39%	37%	35%	37%	28%	22%	14%	17%	21%	27%	37%	**29%**
15	35%	39%	40%	37%	35%	31%	24%	16%	23%	22%	28%	34%	**30%**
16	33%	40%	38%	37%	31%	36%	31%	21%	24%	25%	25%	32%	**31%**
17	41%	39%	33%	42%	34%	35%	29%	24%	21%	25%	36%	42%	**33%**
18	48%	42%	36%	37%	36%	43%	29%	30%	31%	37%	46%	49%	**39%**
19	53%	45%	39%	42%	37%	47%	34%	36%	38%	44%	53%	54%	**44%**
20	57%	48%	40%	40%	39%	46%	35%	40%	42%	49%	57%	55%	**46%**
21	57%	54%	44%	47%	43%	51%	37%	45%	40%	51%	58%	57%	**49%**
22	60%	56%	51%	55%	45%	55%	41%	43%	41%	56%	59%	58%	**52%**
23	61%	56%	50%	53%	47%	56%	44%	50%	45%	57%	58%	57%	**53%**
Avg	**48%**	**47%**	**44%**	**43%**	**39%**	**42%**	**32%**	**27%**	**29%**	**39%**	**44%**	**47%**	**40%**

Source: FTI simulation of the Sagamore Wind project using NREL Wind Integration National Dataset

Solar PV Resources

New utility-scale solar PV builds are modeled at 26 percent capacity factor, 30-year life, with capital costs and fixed operating costs assumptions based on NREL 2021 ATB. New utility-scale solar PV builds are modeled according to current ITC provisions, which amount to a tax credit of 10 to 26 percent based on construction start year and a 4-year safe harbor provision. Exhibit 37 shows the capex and ITC assumptions for new solar PV projects.

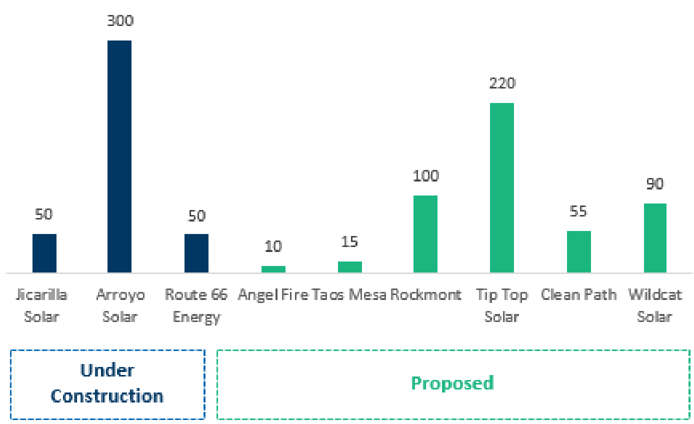
Close to 889 MW of utility-scale solar capacity is in the New Mexico development pipeline, with 400 MW under construction, and 489 MW proposed. Exhibit 38 shows the capacity of the under construction and proposed solar PV projects in New Mexico.

Exhibit 37: Solar PV Resources CAPEX and ITC Assumptions

COD Year	CAPEX Base Case	CAPEX High Case	CAPEX Low Case	FOM	Capacity Factor
	2022$/kW	2022$/kW	2022$/kW	2022$/kW-year	%
2022	1,353	1,441	1,323	24	26%
2025	1,159	1,378	1,085	22	26%
2030	836	1,273	687	18	26%
2035	798	1,164	644	17	26%
2040	761	1,054	602	17	26%

Construction Start Year	2022	2023	2024 and after
Solar ITC	26%	22%	10%

Exhibit 38: New Solar PV Projects in New Mexico



Southern New Mexico has favorable solar resources. Solar's performance across the state is less differentiated than wind. Exhibit 39 shows the solar resources in New Mexico. New transmission will be needed to bring new solar generation to serve LAC and LANL load, if built out of the service territory. Several developers are exploring opportunities for projects that could be developed on sites with existing transmission or in locations that are not transmission constrained.

Even though solar resources generally generate during the peak hours (7:00 – 22:00), they are typically not reliable to serve the super peak hours (13:00 – 20:00) after 17:00. Exhibit 40 shows the solar PV monthly and hourly capacity factor in New Mexico.

Exhibit 39: New Mexico Solar Resources Map

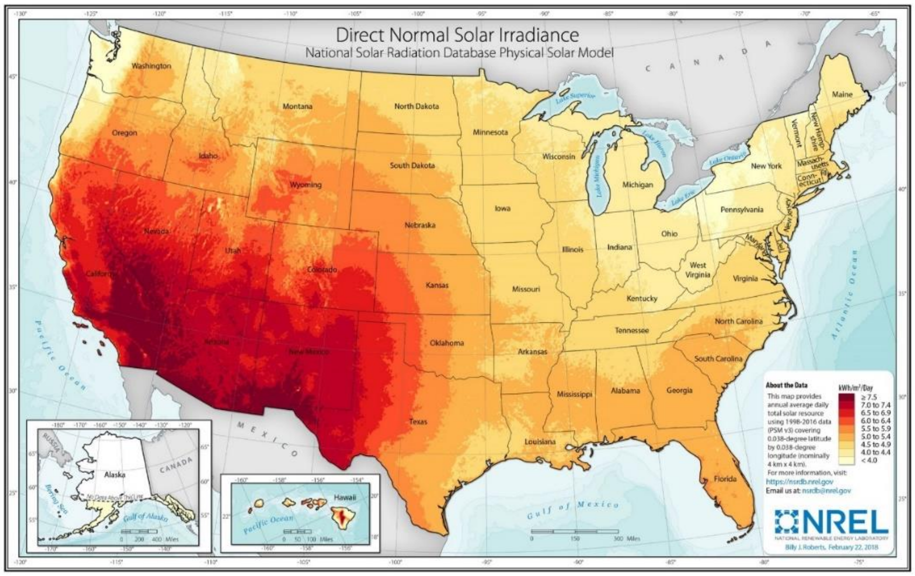


Exhibit 40: New Mexico Solar PV Monthly and Hourly Capacity Factors

Capacity Factor (%)	Month												Avg
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
5	0%	0%	0%	1%	24%	31%	22%	1%	0%	0%	0%	0%	**7%**
6	0%	0%	14%	42%	55%	60%	56%	45%	37%	14%	0%	0%	**27%**
7	5%	40%	61%	60%	70%	73%	72%	61%	59%	55%	39%	12%	**51%**
8	45%	62%	74%	67%	68%	78%	77%	68%	66%	67%	52%	40%	**64%**
9	50%	67%	79%	64%	64%	76%	79%	72%	66%	68%	54%	42%	**65%**
10	50%	69%	75%	64%	66%	74%	75%	69%	66%	62%	49%	44%	**64%**
11	49%	62%	75%	61%	65%	74%	65%	60%	64%	59%	47%	43%	**60%**
12	45%	56%	68%	60%	69%	61%	63%	58%	56%	57%	46%	43%	**57%**
13	46%	60%	71%	56%	57%	60%	57%	41%	61%	57%	49%	46%	**55%**
14	47%	59%	68%	51%	64%	61%	59%	44%	53%	60%	49%	49%	**55%**
15	46%	56%	64%	54%	62%	53%	58%	33%	51%	58%	47%	46%	**52%**
16	34%	50%	54%	42%	60%	48%	56%	41%	44%	45%	26%	22%	**44%**
17	0%	11%	38%	30%	47%	35%	43%	28%	31%	2%	0%	0%	**22%**
18	0%	0%	0%	2%	23%	21%	26%	7%	0%	0%	0%	0%	**7%**
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
Avg	17%	25%	31%	27%	33%	33%	34%	26%	27%	25%	19%	16%	26%

Data source: FTI simulation of solar array based on historical Los Alamos weather data with NREL's System Advisor

Utility-scale Lithium-Ion Battery Storage

New utility-scale 4-hour lithium-ion battery storage builds are modeled at 85 percent efficiency, 15-year life, with capital costs and fixed operating costs metrics from NREL 2021 ATB. New utility-scale battery builds are modeled according to current ITC provisions (if developed as a hybrid project with solar) of a tax credit at 10 to 26 percent based on construction start year, allowing a 4-year safe harbor provision. Exhibit 41 shows the capex and ITC assumptions for battery storage.

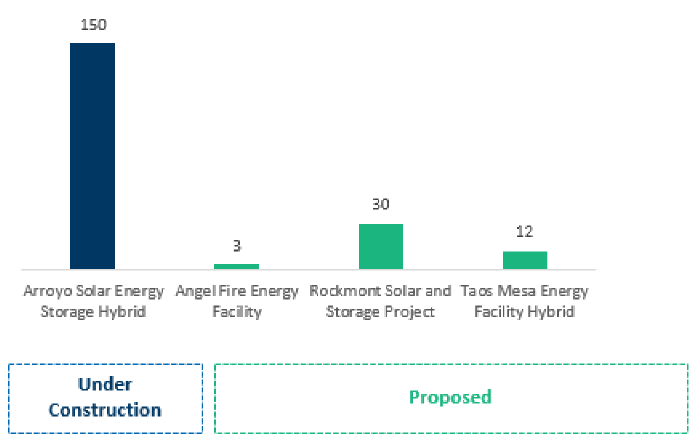
195 MW of utility-scale battery storage capacity is in the New Mexico development pipeline, with 150 MW currently under construction and 45 MW proposed. Exhibit 42 shows the capacity of the under construction and proposed battery storage projects in New Mexico.

Exhibit 41: Battery Storage CAPEX and ITC Assumptions

COD Year	**CAPEX Base Case**	**CAPEX High Case**	**CAPEX Low Case**	**FOM**	**Efficiency**
	2022$/kW	2022$/kW	2022$/kW	2022$/kW-year	%
2022	1,293	1,376	1,235	34	85%
2025	1,029	1,256	903	31	85%
2030	844	1,056	610	26	85%
2035	792	1,056	551	26	85%
2040	739	1,056	489	26	85%

Construction Start Year	**2022**	**2023**	**2024 and after**
Battery ITC (if hybrid with solar)	26%	22%	10%

Exhibit 42: New Battery Storage Projects in New Mexico



Gas-fired Peaking Resources

Due to the challenges of integrating large quantities of intermittent resources and the need to address resource adequacy, provide regulation services, voltage support, and operating reserves, the IRP considers two types of gas-fired peaking units that could be built on site: reciprocating internal combustion engine ("RICE") with a block size of 18 MW and heat rate of 8,295 Btu per kWh; and simple cycle gas turbine ("SCGT") with a block size of 12 MW and heat rate of 9,124 Btu per kWh. Exhibit 43 shows the projected cost and performance of gas-fired peaking units included in this IRP.

Exhibit 43: Projected Costs and Performance of Gas Peaking Units

Technology	Size MW	Heat Rate (Btu/kWh)	CAPEX (2022 $/kW)	VOM (2022 $/MWh)	FOM (2022 $/kW-yr)
RICE	18	8,295	1,905	6.0	37.1
SCGT	12	9,124	1,228	5.0	17.2

Data source: EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021

Geothermal Resources

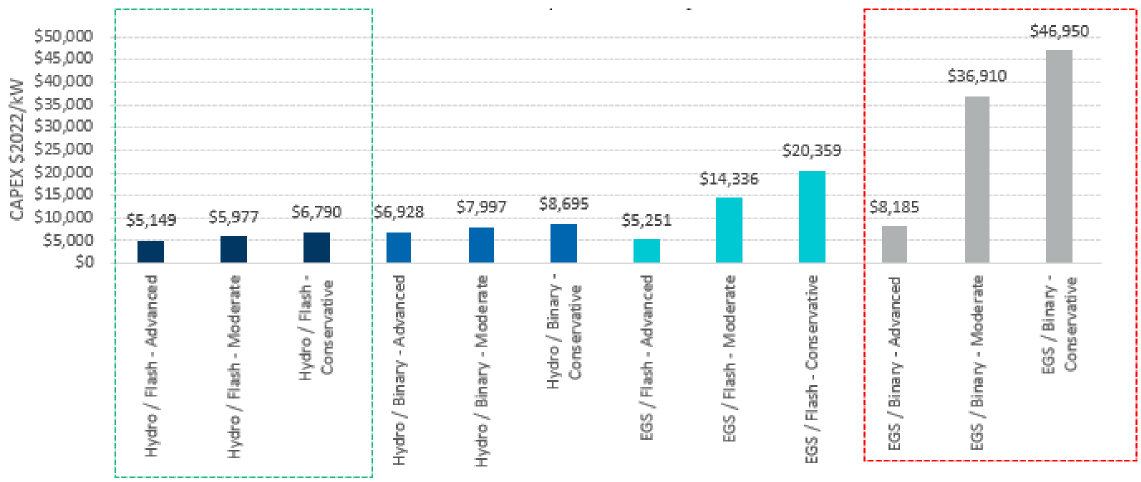
Geothermal resources provide carbon-free base load energy. Currently, there are approximately 4 GW of installed geothermal capacity in the U.S., with over 70 percent of located in California. As part of an ongoing effort to ensure electricity reliability in the state and meet clean energy goals, California Public Utilities Commission ("CPUC") has set goals of procuring 1 GW of geothermal resources by 2028.

Exhibit 44 shows the geothermal technology summary and Exhibit 45 shows the capital cost summary. After screening, geothermal is not considered in the portfolios due to the high capital costs, high dependency on geography, and low availability of projects.

Exhibit 44: Geothermal Technology Summary

		Hydrothermal Naturally occurring zones of Earth-heated circulating fluid that can be exploited for electricity generation	**Enhanced Geothermal Systems (EGS)** Naturally occurring zones of heat but lack sufficient fluid flow and require engineering to enhance permeability.
Binary	Use a heat exchanger and secondary working fluid. This technology generally applies to lower-temperature systems (<200°C) due to the current maximum operating temperature of pumping technology.	**2nd Tier**	**Highest Cost** **4th Tier**
Flash	Flash plants generate steam through a pressure change of the thermal fluid that directly drives a turbine. This technology generally applies to higher-temperature systems.	**Lowest Cost** **1st Tier**	**3rd Tier**

Exhibit 45: Geothermal Capital Costs Summary



Pumped Storage Hydro and Flow Battery Storage

Pumped storage hydro ("PSH") typically provides six to 20 hours hydraulic reservoir storage, which is highly valuable with increasing renewable penetration in WECC. PSH exhibits high upfront costs, with ranges depending on the geological conditions and technology. Configurations may include open-loop and closed loop; turbine technologies offer different features and capabilities, including fixed speed, advanced speed, and ternary. Currently PSH projects provides around 23 GW in the U.S.

Flow battery, or redox flow battery (after reduction–oxidation), is a type of electrochemical cell where chemical energy is provided by two chemical components dissolved in liquids that are pumped through the system on separate sides of a membrane. Flow battery storage currently has high costs and limited opportunities.

Exhibit 46 shows the cost for PSH and flow battery storage in comparison to lithium-ion battery storage. IRP recommends monitoring opportunities of PSH and flow battery storage in future IRP updates.

Exhibit 46: PSH and Flow Battery Storage Capital Costs Summary

Installed Energy Storage System Cost

Year	Technology	Low	Base	High
		$/kWh	*$/kWh*	*$/kWh*
	Lithium ion LFP	326	385	438
2020	Lithium ion NMC	330	395	457
	Redox Flow	466	517	569
	PSH	325	512	563

Year	Technology	Low	Base	High
		$/kWh	*$/kWh*	*$/kWh*
	Lithium ion LFP	236	270	312
2030	Lithium ion NMC	241	282	320
	Redox Flow	347	414	466
	PSH	325	512	563

Installed Energy Storage System Cost

Year	Technology	Low	Base	High
		$/kW	*$/kW*	*$/kW*
	Lithium ion LFP	1,302	1,541	1,752
2020	Lithium ion NMC	1,320	1,581	1,827
	Redox Flow	1,863	2,070	2,277
	PSH	1,301	2,046	2,250

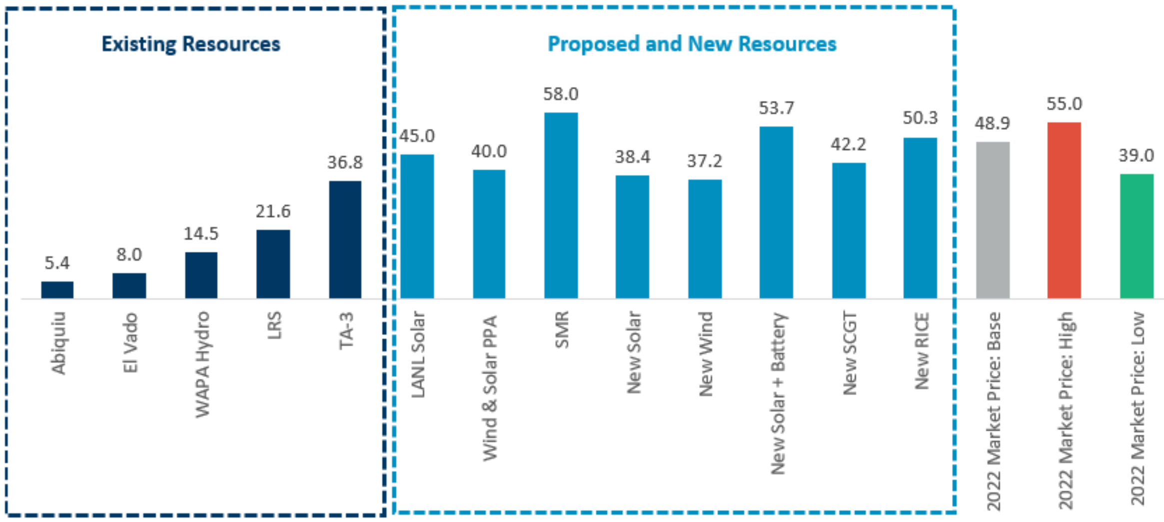
Year	Technology	Low	Base	High
		$/kW	*$/kW*	*$/kW*
	Lithium ion LFP	944	1,081	1,249
2030	Lithium ion NMC	965	1,128	1,279
	Redox Flow	1,388	1,655	1,864
	PSH	1,301	2,046	2,250

Note: LFP = lithium-ion iron phosphate; NMC = nickel manganese cobalt
Data source: Pacific Northwest National Laboratory, "2020 Grid Energy Storage Technology Cost and Performance Assessment “, December 2020

Levelized Cost of Energy

LAPP existing baseload and low-cost resources will be supplemented with new resources candidates to serve load and achieve sustainability goals. As part of the screening analysis, the IRP assessed the LCOE based on important cost and performance assumptions including capital expenditures, operations and maintenance costs, capacity factor, financing assumptions, and delivered fuel costs. Exhibit 47 shows the existing, proposed, and new resource candidates LCOE in $2022 per MWh. The new solar, wind, and solar plus battery LCOE estimates are based on NREL 2021 ATB for projects achieving commercial online in 2022. SCGT and RICE LCOE estimates are inclusive of fixed operating and maintenance costs, variable operating and maintenance costs, fuel costs, and a capacity factor of 20 percent.

Exhibit 47: Existing, Proposed, and New Resource Candidates LCOE



Chapter 8: Energy Demand and Use Patterns

Load Profiles

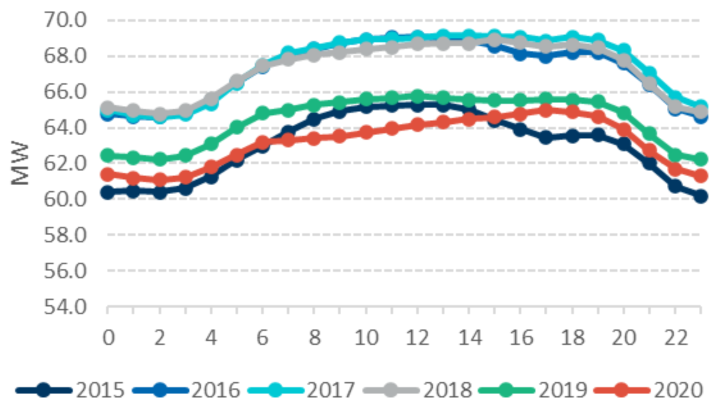
LAC and LANL have partnered to combine the resources and share the costs within the Los Alamos Power Pool. The current ECA is effective through June 30, 2025, and both parties are expecting a renewal of the ECA to continue resource and cost sharing in the LAPP. The cost of transmission is distributed to the parties based on the coincident peak demand for each month, while the cost of energy is allocated based on a direct measure of use (in megawatt hour or MWh).

Exhibit 48 presents the maximum, minimum, and average hourly load of LAPP during 2015 – 2020. Exhibit 49 shows the average hourly load profile during 2015 – 2020. The impacts of COVID-19 caused the load in 2020 to be the lowest of the period. LANL and LAC loads exhibit different hourly load profiles, with LANL loads peaking during the day when the air conditioning and the laboratory equipment are in use, and LAC loads peaking in the evening when residents return home from work. For the IRP analysis, the production cost model applies 8760 profiles that properly reflect the hourly and seasonal shapes of the respective LAC and LANL loads.

Exhibit 48: Historical LAPP Peak Load and Energy Demand Summary (2015 – 2020)

LAPP Demand	Unit	2015	2016	2017	2018	2019	2020
Hourly Maximum	MW	88	88	90	92	89	87
Hourly Minimum	MW	42	44	43	44	44	45
Hourly Average	MW	63	67	68	67	64	63

Exhibit 49: 2015 – 2020 LAPP Hourly Energy Demand Summary



Load Forecast

LAC and LANL peak load and energy demand is subject to different drivers: LAC load is driven by population growth and commercial activity, while LANL load is driven by mission change or operational tempo. Exhibit 50 and Exhibit 51 show the historical LAC and LANL peak load and energy demand, with LANL's peak load representing approximately 80 percent of the LAPP coincident peak load. The LAPP coincident peak load was 85 MW, and energy consumption was 550 GWh in 2020. LAC's annual energy use is approximately 120 GWh, serving approximately 8,500 customers.

Exhibit 50: LAC and LANL Coincident Peak Load

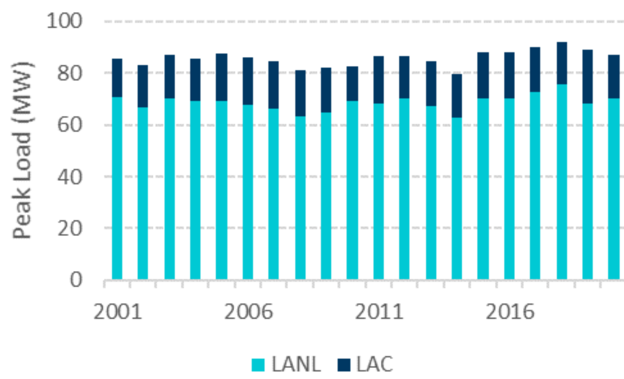


Exhibit 51: LAC and LANL Historical Energy Demand

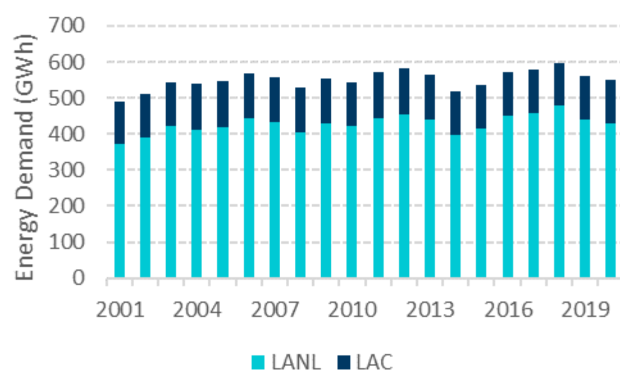


Exhibit 52 presents the minimum, average, and maximum rolling 9-year compound annual growth rate ("CAGR") of peak load and energy demand during 2001 – 2020 for LAC and LANL, respectively, in comparison to the CAGR of Base Case load projection during 2022 – 2030. The LAC Base Case CAGR for peak load falls within the range of rolling 9-year CAGRs calculated from historical data. For LAC energy demand, LANL peak load and energy demand, the Base Case CAGR for 2022 – 2030 is above the CAGR for any historical 9-year rolling period observed in the historical data. Similarly, Exhibit 53 presents the minimum, average, maximum year-on-year ("YOY") growth rates of peak and energy during 2001 – 2020 for LAC and LANL, respectively, in comparison to the YOY growth rates of Base Case load projection during 2022 – 2030.

Exhibit 52: Comparison of Base Case CAGR vs. Historical CAGRs

Compound Annual Growth Rates		LAC Peak	LAC Energy	LANL Peak	LANL Energy
2001 – 2020 Historical	Minimum CAGR	-2.9%	-1.1%	-2.1%	-1.4%
	Average CAGR	0.3%	-0.1%	-0.2%	0.5%
	Maximum CAGR	2.8%	1.0%	0.9%	1.7%
2022 – 2030 Projection	Base Case CAGR	2.7%	1.7%	2.9%	4.2%

Exhibit 53: Comparison of Base Case YOY Growth Rates vs. Historical Growth Rates

Year-On-Year Growth Rates		LAC Peak	LAC Energy	LANL Peak	LANL Energy
2001-2020 Historical	Historical Minimum YOY Growth	-25.6%	-3.5%	-9.6%	-9.7%
	Historical Average YOY Growth	1.7%	0.2%	0.1%	0.9%
	Historical Maximum YOY Growth	40.5%	5.1%	12.3%	8.5%
2022-2030 Projection	Base Case Minimum YOY Growth	1.0%	1.0%	-5.8%	-1.9%
	Base Case Average YOY Growth	2.7%	1.7%	3.3%	4.8%
	Base Case Maximum YOY Growth	9.2%	4.3%	27.3%	37.2%

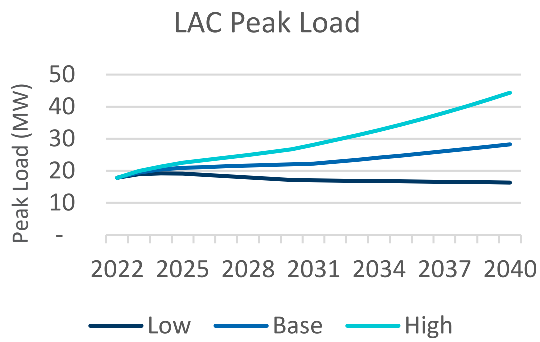
Based on these analyses, the differences between the minimum and average, and maximum and average load growth CAGRs as presented in Exhibit 54 were applied to determine the High Case and Low Case peak load and energy demand growth rates assumptions. The resulting annual Low Case, Base Case, and High Case peak load and energy demand forecasts are shown in Exhibit 55 and Exhibit 56 for LAC and LANL, respectively. Exhibit 57 and Exhibit 58 shows the monthly peak load and energy demand forecast for LAPP. The load stretching algorithm detailed in the California Public Utility Commission's Guidance for Production Cost Modeling and Network Reliability Studies[7] was used to translate the monthly total energy and peak load forecasts into an hourly forecast, using the 2019 LAPP hourly load shapes.

Exhibit 54: High Case and Low Case Growth Rates Percentage Difference from Base Case

Difference from the Base Case	LAC Peak	LAC Energy	LANL Peak	LANL Energy
Low Case	-3.2%	-1.0%	-1.9%	-1.9%
High Case	2.5%	1.1%	1.1%	1.2%

[77] "Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions Guidance for Production Cost Modeling and Network Reliability Studies, March 29, 2019" 2.6.3 Linear Stretching of Consumption Shapes to Forecast Years

Exhibit 55: LAC Peak Load and Energy Demand Forecast



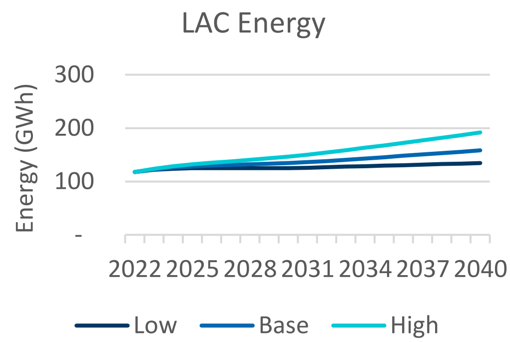
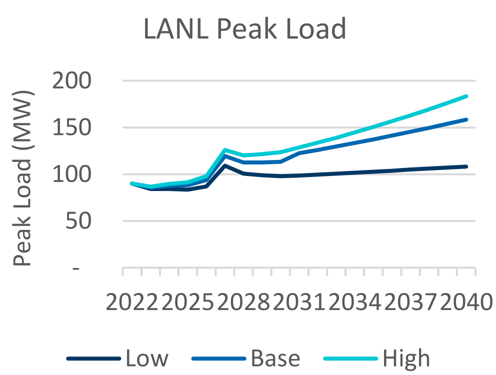


Exhibit 56: LANL Peak Load and Energy Demand Forecast



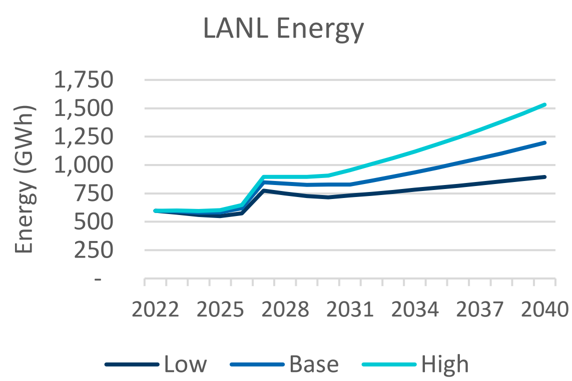


Exhibit 57: LAPP Peak Load Forecast

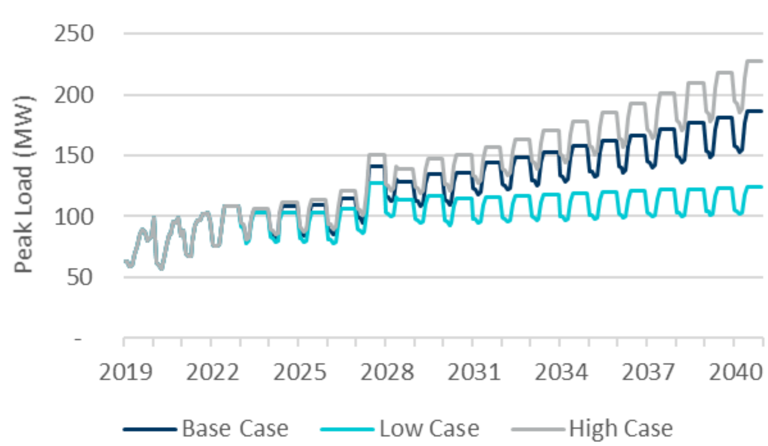
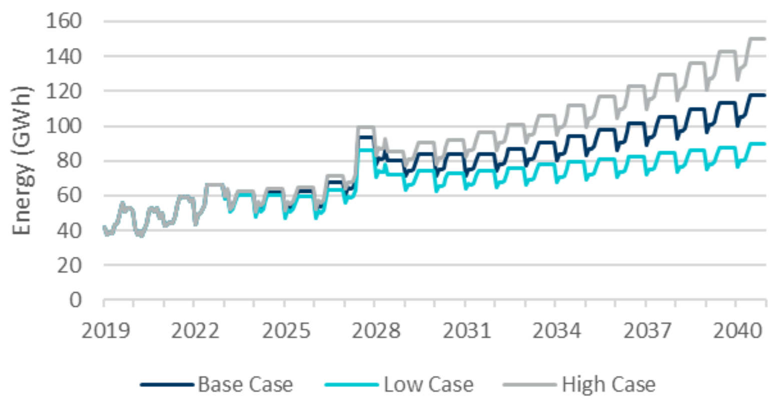


Exhibit 58: LAPP Energy Forecast



Chapter 9: Electric Vehicle Load Forecast

Transmission to zero-emission vehicles ("ZEVs") represent an opportunity and critical step for LAC and LANL to reduce GHG emissions from the transportation sector and work towards broader carbon neutrality goals. According to the Los Alamos Resiliency, Energy and Sustainability ("LARES") task force 2021 report, GHG emissions caused by transportation make up roughly 30 percent of overall emissions, and single occupant vehicles are a major contributor. Besides community-based decarbonization approaches including increasing access and utilization of public transportations and commuting on bicycles, the transition to ZEV for fleets owned by LAC and LANL, vehicles owned by the employees and the public in the LAC service territory will be a key driver in transportation sector decarbonization.

This IRP forecasts the energy demand and peak load resulting from EV adoption in LAPP during the 20-year forecast period of 2021 to 2041. The assessment considers the fleet composition, fuel economy, vehicle charging patterns, and adoption rates that are differentiated by vehicle class – with light-duty vehicle achieving higher adoption rates earlier than medium- and heavy-duty vehicles.

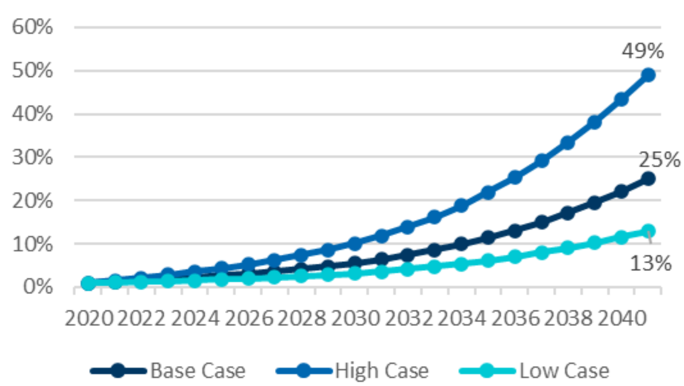
Finally, transportation electrification will only be meaningful if the incremental demand is served with emission-free generation resources, which include hydro, nuclear, wind, and solar. For this reason, this IRP sets the constraints to have the incremental load from EVs to be served by 100 percent renewable resources.

LAC Forecast

County Owned Vehicles

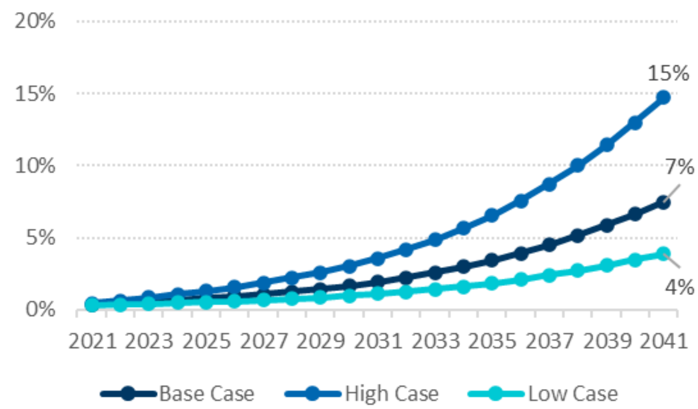
Los Alamos County's fleet is currently comprised of 128 light-duty, 78 medium-duty, and 29 heavy-duty vehicles. The county has projected the county-owned vehicles ("COVs") EV penetration rates of 25 percent for light-duty vehicles, and 7.5 percent for medium- and heavy-duty vehicles by 2041 in the Base Case. The High Case assumes doubling the penetration rates of the Base Case and the Low Case assumes half of the penetration rates of the Base Case. Exhibit 59 and Exhibit 60 presents the penetration rates for light-, medium- and heavy-duty vehicles, respectively. The projected energy demand and peak load are then derived based on benchmark mileage and energy consumption presented in the U.S. Energy Information Administration's 2021 Annual Energy Outlook reference case.[8] The hourly charging pattern reflects a before and after work hours charging, consistent with typical work vehicle schedules.

Exhibit 59: LAC COV Light-Duty EV Penetration Rates



[8] 2021 Annual Energy Outlook, Tables 37 and 41. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=47-AEO2021&cases=ref2021&sourcekey=0, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=51-AEO2021&cases=ref2021&sourcekey=0, U.S. Energy Information Administration.

Exhibit 60: LAC COV Medium- and Heavy-Duty EV Penetration Rates



Personal Owned Vehicles

This IRP projected the LAC EV Personal Owned Vehicles ("POVs") based on the population data from the U.S. Census Bureau 2020 Decennial Census Redistricting data[9] along with national cars per-capita statistics from the Federal Highway Administration[10] to forecast the total vehicle counts for the population in Los Alamos County from 2021 – 2041. The county further projected the POVs EV penetration rates of 21 percent by 2041 in the Base Case, and 31 percent in the High Case, and 8 percent in the Low Case.

The projected energy demand and peak load are then derived based on benchmark mileage and energy consumption presented in the U.S. Energy Information Administration's 2021 Annual Energy Outlook reference case.[11] The hourly charging shape within the day comes from research prepared for the California Public Utility Commission.[12] The shape generally allocates most charging to late evenings and the middle of the night before the morning commute, has a brief increase in hourly shares of vehicle charging load in the midday as vehicles are parked, and then has a rapid escalation in the late evening once drivers arrive at home.

COV and POV EV Projections

From COV and POV EV adoptions discussed above, LAC forecasts total additional annual electricity demand from personal vehicle electrification at 21 GWh by 2041 with an estimated

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[9]2020: Decennial Census Redistricting Data, Los Alamos County. https://data.census.gov/cedsci/table?q=los%20alamos%20county%20population&tid=DECENNIALPL2020.P1, U.S. Census Bureau.
[10] Highway Statistics 2019. https://www.fhwa.dot.gov/policyinformation/statistics.cfm, Federal Highway Administration.
[11] 2021 Annual Energy Outlook, Tables 37 and 41. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=47-AEO2021&cases=ref2021&sourcekey=0, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=51-AEO2021&cases=ref2021&sourcekey=0, U.S. Energy Information Administration.
[12] https://www.cpuc.ca.gov/General.aspx?id=6442461894

peak load of 5.2 MW. In the High Case, the total additional annual electricity demand from EVs is forecasted to reach 31 GWh by 2041 with an estimated peak load of 7.7 MW. In the Low Case, the total additional annual electricity demand is forecasted to reach 8 GWh by 2041 with an estimated peak load of 2.0 MW. Exhibit 61 and Exhibit 62 present the LAC COV and POV EV electricity demand and peak load forecasts.

Exhibit 61: LAC COV and POV EV Electricity Demand Forecast

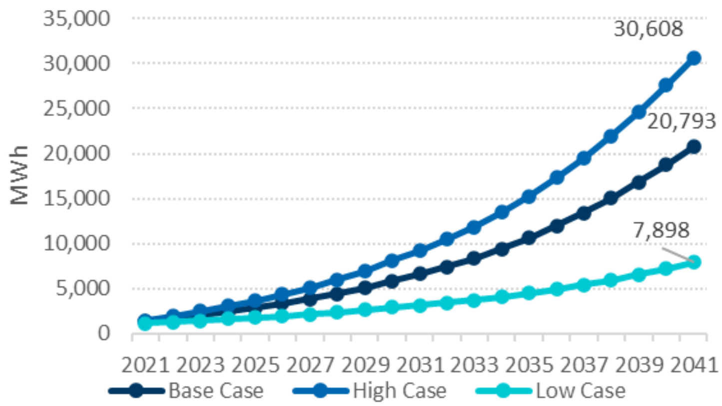
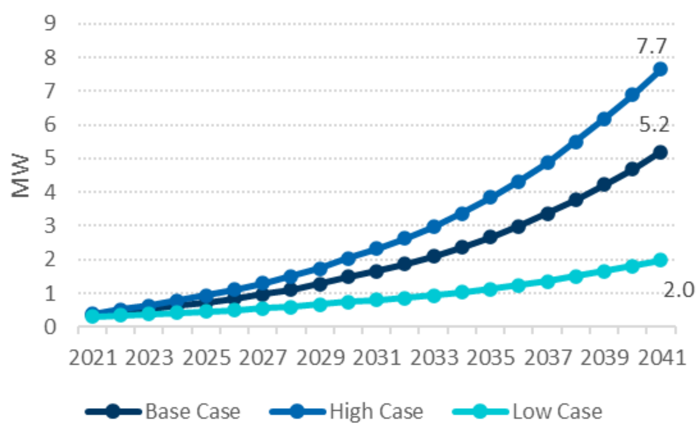


Exhibit 62: LAC COV and POV EV Peak Load Forecast



LANL Forecast

LANL has the objective of transitioning to ZEVs for light-duty vehicles of no less than 10 percent by 2023; 40 percent by 2026; and 100 percent by 2035; medium and heavy-duty vehicles of no less than 10 percent by 2030; 30 percent by 2035; 75 percent by 2040; and 100 percent by 2045.

For this IRP, LANL projects 100 percent EV adoption for light-duty vehicles in its government owned fleet by 2030 in the High Case, 50 percent in the Base Case, and 25 percent in the Low

Case. In addition, the employee-owned vehicles will be charged on site subject to charging infrastructure availability. Exhibit 63 and Exhibit 64 present the LANL government owned vehicles ("GOVs") and POVs EV energy demand and peak load forecasts, respectively.

Exhibit 63: LANL GOV and POV EV Electricity Demand Forecast

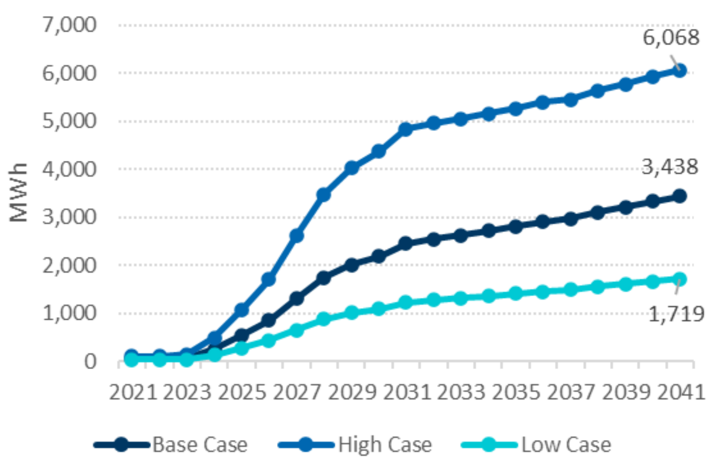
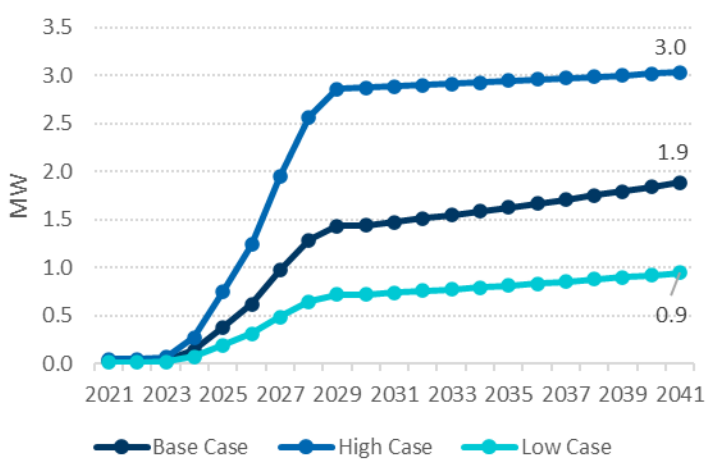


Exhibit 64: LANL GOV and POV EV Peak Load Forecast



LAPP Forecast

In the Base Case, LAPP forecasts total additional annual electricity demand from EV to reach 24 GWh by 2041 with a peak load of 5.8 MW. In the High Case, the total additional annual electricity demand from EV is forecasted to reach 37 GWh by 2041 with a peak load of 8.6 MW. In the Low Case, the total additional annual electricity demand from EV is forecasted to reach 10 GWh by 2041 with a peak load of 2.3 MW. Exhibit 65 and Exhibit 66 present the LAPP EV energy demand and peak load forecasts.

Exhibit 65: LAPP EV Demand Forecast

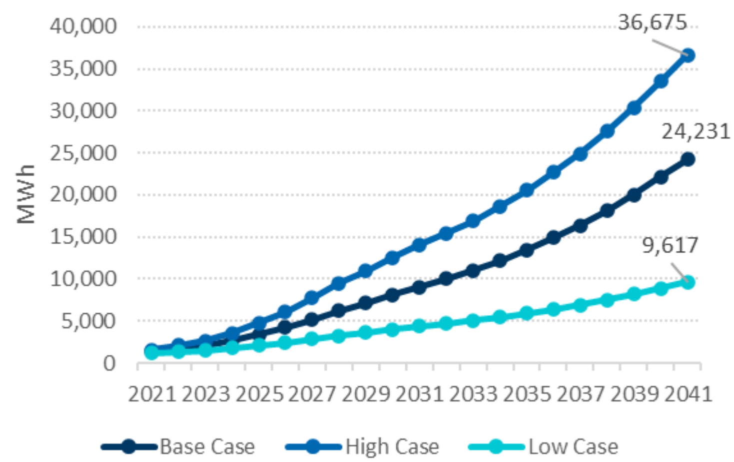
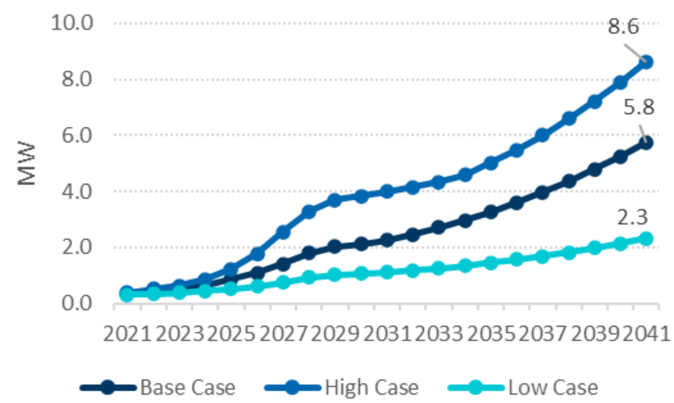


Exhibit 66: LAPP EV Peak Load Forecast



Chapter 10: Building Electrification Load Forecast

LARES Task Force has recently shared with the LAC some preliminary intent to reduce natural gas consumption, with detailed recommendations still under development while LAC develops its IRP.

Residential, commercial, and industrial electrification is a pathway for reducing natural gas consumption and GHG emissions. For LAC and LANL, this could be potentially achieved through an effective combination of strategy, policy, and incentives, with practical consideration of technology and infrastructure readiness, and benefit to cost economics.

Electrification will only be meaningful if the incremental demand is served with emission-free generation resources, which include hydro, nuclear, wind, and solar. For this reason, this IRP sets the constraints to have the incremental load from natural gas reduction to be served by 100 percent renewable resources.

LAC Forecast

LAC's natural gas load is projected to grow at 0.5 percent through 2041. Without the benefit of the specific policy recommendations from the LARES Task Force, this IRP evaluated three high-level natural gas reduction scenarios:

- Base Case: 40 percent of the load currently served by natural gas or 55 GWh to be electrified by 2041
- High Case: 56 percent of the load currently served by natural gas or 76 GWh to be electrified by 2041
- Low Case: 10 percent of the load currently served by natural gas to be electrified or 14 GWh by 2041.

These scenarios provide indicative ranges of the potential load impact resulting from appliance replacement and adopting higher energy efficiency standards in buildings to minimize the environmental impacts of energy use. It should be noted that the base and high conversion scenarios assume advances in the research and development of new technologies. It is not certain that these aspirational technologies will develop at the pace predicted here, and so the Base and High Cases should not be viewed as a "reference case." The Low Case reflects the continued rollout of existing technologies. Additionally, the Low Case assumes that some of the switch from natural gas will take place in ways besides electrification, like substitution with hydrogen gas.

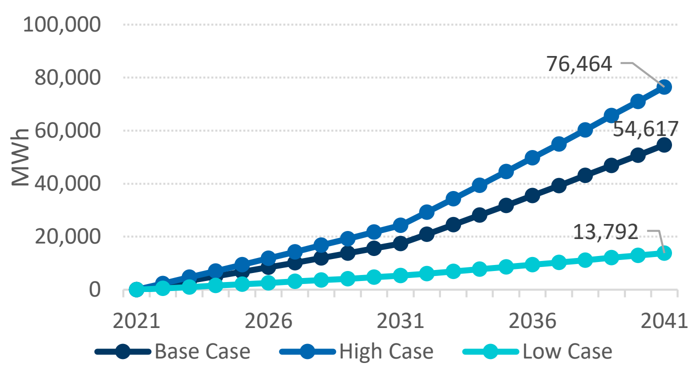
By 2070, the County assumed that all the remaining fossil energy demand (after energy efficiency adjustments) for residential and commercial customers would be electrified or otherwise substituted. Electrification begins in 2022 at a low rate in the first 10 years and then accelerates during the last 10 years of this planning horizon. The analysis takes into consideration the estimated technical lifespan of space and water heating equipment and does not assume heating systems in working order to be replaced before obsolescence. The efficiency of conversion in the County is assumed at an average of 48.8 percent, based on the key findings from the EIA 2021 Annual Energy Outlook report,[13] which estimated the relative efficiency of electrified heat pumps versus natural gas space heating solutions. The American Gas Association ("AGA") has estimated

[13] 2021 Annual Energy Outlook, Table 22. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=32-AEO2021&cases=ref2021&sourcekey=0, U.S. Energy Information Administration.

in its Implications of Policy-Driven Residential Electrification report,[14] that electrified heat pumps are generally more efficient in warmer ambient temperature conditions and less efficient in colder ambient temperature conditions. New Mexico's weather conditions present opportunity for building electrification.

In the Base Case, LAC forecasts total additional annual electricity demand from electrification to reach 55 GWh by 2041 with an estimated peak load of 11 MW. In the High Case, the total additional annual electricity demand from electrification is forecasted to reach 76 GWh by 2041 with an estimated peak load of 16 MW. In the Low Case, the total additional annual electricity demand from gas conversion is forecasted to reach 27 GWh by 2041 with an estimated peak load of 3 MW. Exhibit 67 and Exhibit 69 present the LAC building electrification energy demand and peak load forecasts. Exhibit 68 shows the County's cumulative natural gas electrification conversion rates during the planning horizon.

Exhibit 67: LAC Natural Gas Electrification Demand Forecast



[14] Implications of Policy-Driven Residential Electrification, Page 16, Figure 1-4. https://www.aga.org/globalassets/research--insights/reports/aga_study_on_residential_electrification.pdf American Gas Association.

Exhibit 68: LAC Natural Gas Electrification Cumulative Conversion Rates

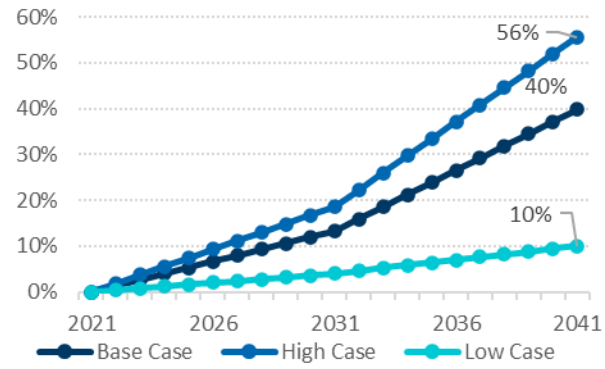
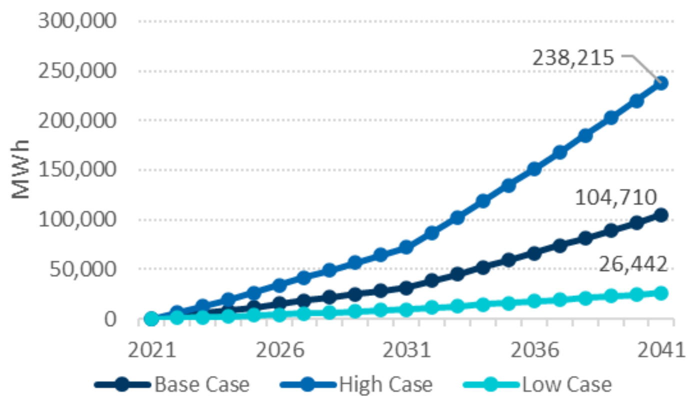


Exhibit 69: LAC Electrification Peak Load Forecast



LANL Forecast

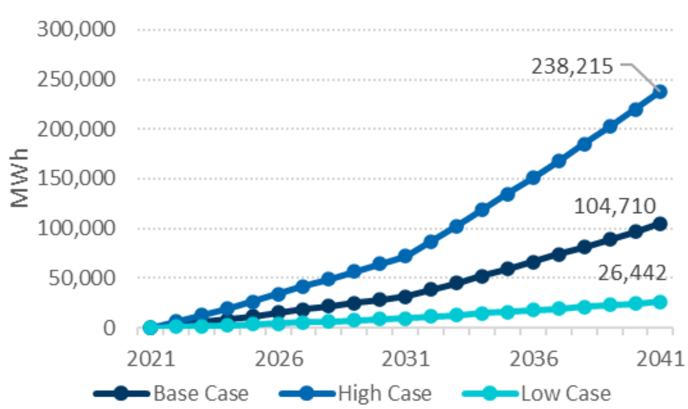
Under the Base Case and Low Case, LANL has the same conversion targets as LAC, but it targets 90 percent conversion by 2041 in the High Case, assuming this could be enabled through a combination of policy incentives and technological breakthroughs. This report models the High Case electrification goal at 90 percent, assuming substitute sources like hydrogen can fill the remaining gap. LANL and LAC have gas loads with demand patterns. LANL's gas demand is mainly during working hours, whereas LAC gas demand usually peaks in the morning and evening when customers return home from work. The hourly shape of LANL's gas demand could have important implications on electricity prices under the electrification scenarios, and the feasibility of potential replacements, such as wind and solar generation.

LANL forecasts its gas demand growth at 17 percent over the next five years, then leveling out to near the U.S. average growth of long-term gas demand growth, estimated at 1 percent annually. The efficiency of conversion for LANL is assumed at an average of 75 percent, based on the key findings from the EIA 2021 Annual Energy Outlook report,[15] which estimated the relative efficiency of electrified hot water boilers versus natural gas boilers.

In the Base Case, LANL forecasts total additional annual electricity demand from electrification to reach 105 GWh by 2041 with an estimated peak load of 21 MW. In the High Case, the total additional annual electricity demand from electrification is forecasted to reach 238 GWh by 2041, with an estimated peak load of 49 MW. In the Low Case, the total additional annual electricity demand from gas conversion is forecasted to reach 26 GWh by 2041 with an estimated peak load of 5 MW. The Low Case assumes that other pathways such as hydrogen economy make meaningful contributions in natural gas replacement.

Exhibit 70 and Exhibit 72 present the LANL building electrification energy demand and peak load forecasts. Exhibit 71 shows LANL's cumulative natural gas electrification conversion rates during the planning horizon.

Exhibit 70: LANL Natural Gas Electrification Demand Forecast



[15] 2021 Annual Energy Outlook, Table 22. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=32-AEO2021&cases=ref2021&sourcekey=0, U.S. Energy Information Administration.

Exhibit 71: LANL Natural Gas Electrification Cumulative Conversion Rates

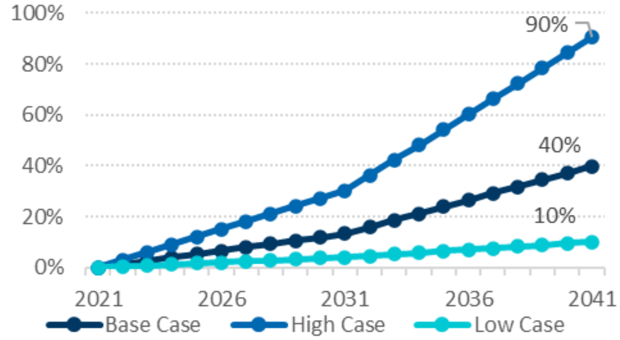
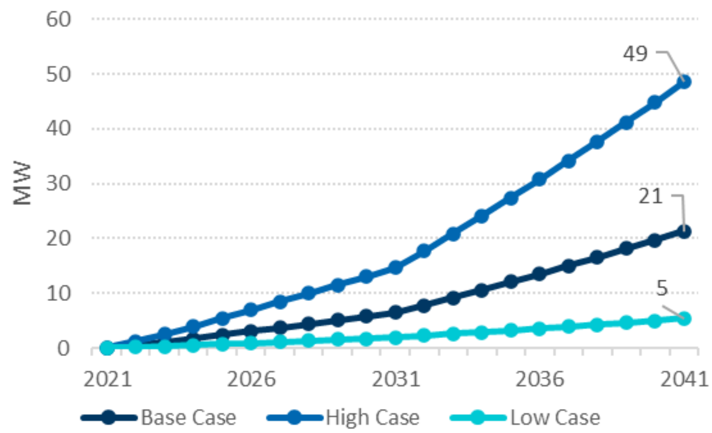


Exhibit 72: LANL Electrification Peak Load Forecast



LAPP Forecast

In the Base Case, LAPP forecasts total additional annual electricity demand from electrification to reach 159 GWh by 2041 with a peak load of 32 MW. In the High Case, the total additional annual electricity demand from electrification is forecasted to reach 315 GWh by 2041 with a peak load of 64 MW. In the Low Case, the total additional annual electricity demand from gas conversion is forecasted to reach 54 GWh by 2041 with a peak load of 11 MW. Exhibit 73 and Exhibit 74 present the LAPP building electrification energy demand and peak load forecasts.

LAPP will need to closely manage the development of residential and commercial electrification and adequately plan for new and renewable generation resources, either through contracting, or through building onsite renewable generation resources. The increasing load will also have implications on transmission contracts and limits.

Exhibit 73: LAPP Natural Gas Electrification Demand Forecast

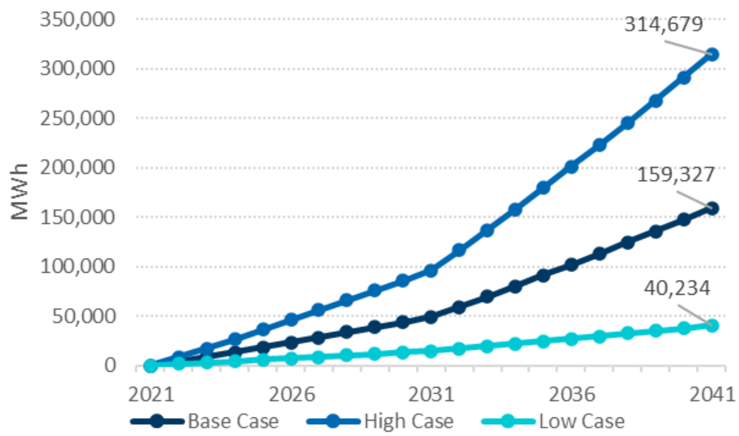
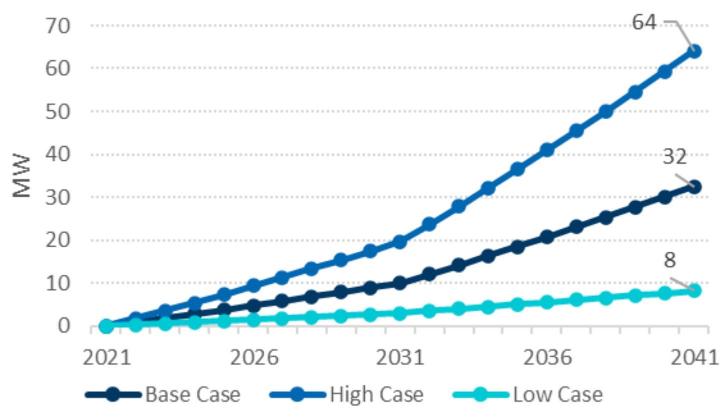


Exhibit 74: LAPP Electrification Peak Load Forecast



Chapter 11: Portfolios Construction through Capacity Expansion

Structured Long-term Capacity Expansion Model in PLEXOS®

Drawing on the insights and data from the technology screening, load forecasts, state of the world scenarios, capital costs and performance metrics of new resources, FTI collaborated with LAC and LANL to construct feasible candidate portfolios. Exhibit 75 provides the model framework for portfolio construction in PLEXOS®. FTI discussed portfolio construction results with DPU and LANL, assessed performance in the deterministic model, and finalized the 12 portfolio candidates for the stochastic analysis.

During the capacity expansion modeling, FTI differentiates planned builds versus economic builds. Planned builds are announced projects that are in advanced development, including those engaged in site preparation, are under construction, or are performing testing. Planned builds represent units that are reasonably certain to come online at a particular date. Specific to the LAPP IRP, these units include the 10 MW of solar at LANL, the LAC ATC contract, and LAC Uniper contract, and the SMR unit at different subscription levels. Economic builds are built by PLEXOS® to satisfy certain constraints in the model such as RPS goals and reserve margin requirements. For the IRP, these include the utility-scale solar, wind, battery, and thermal units.

FTI utilized PLEXOS® for the IRP work, as it is well received by Energy Commissions, Independent System Operators ("ISO"), Regional Transmission Organizations ("RTO"), and utilities. FTI licensed the WECC Zonal Dataset from Energy Exemplar for use in the PLEXOS® software and has fully updated WECC load forecasts and resources using a variety of public data from sources such as FERC, the EIA, the CPUC, and the California Energy Commission as well as Hitachi Energy's Velocity Suite, which was formerly known as Ventyx.

PLEXOS® is a long-term market model that forecasts regional electricity and capacity prices, generation, new builds, and retirements under various fuel, load, and policy scenarios. It represents the electrical power generation and transmission system with realistic, robust concepts of the market and engineering constraints. FTI built a representation of LANL's and DPU's system in PLEXOS® to reflect important factors such as load profiles, generation resources characteristics, renewable profiles, and transmission topology. With the input of load forecasts, delivered gas, coal price forecasts, capital costs of gas-fired generation resources, capital costs of renewable resources, transmission constraints, renewable profiles, generation resource characteristics, and other key inputs, the PLEXOS® model can test the economic, environmental, and reliability performance of each potential portfolio candidates. Exhibit 76 shows the modeled WECC.

Exhibit 75: Structured Long-term Capacity Expansion Model in PLEXOS®

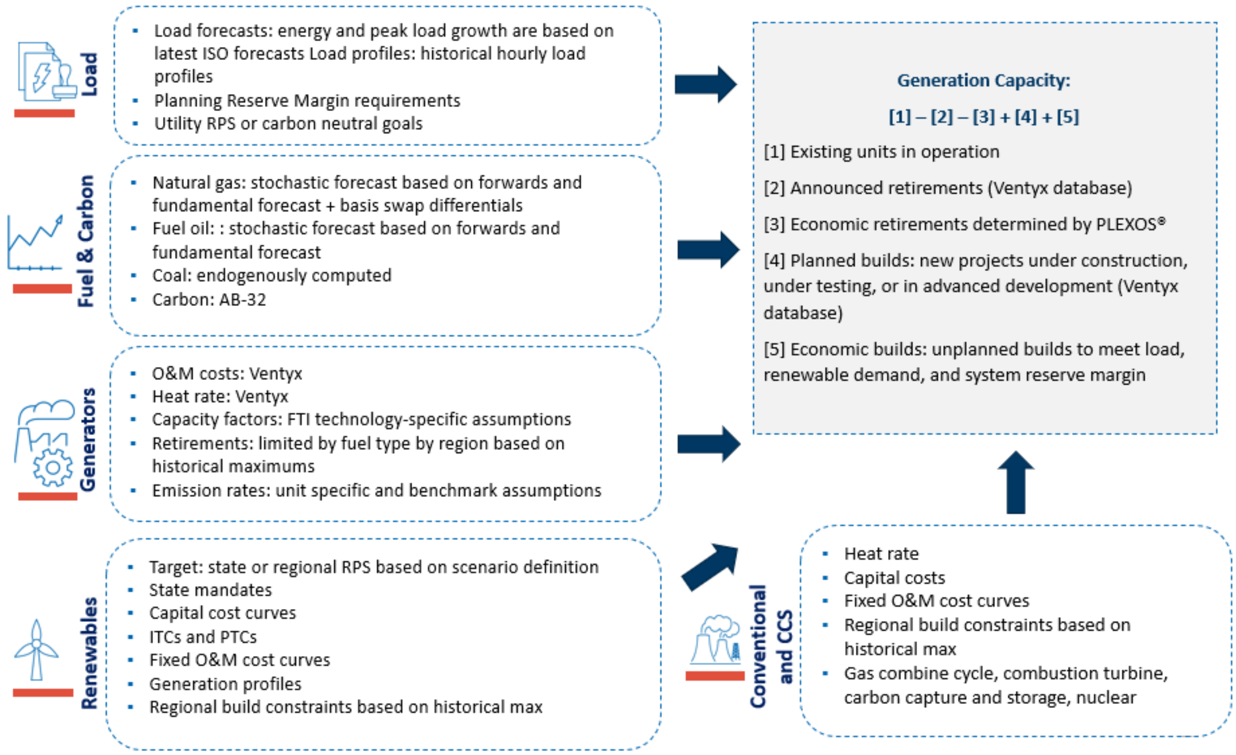
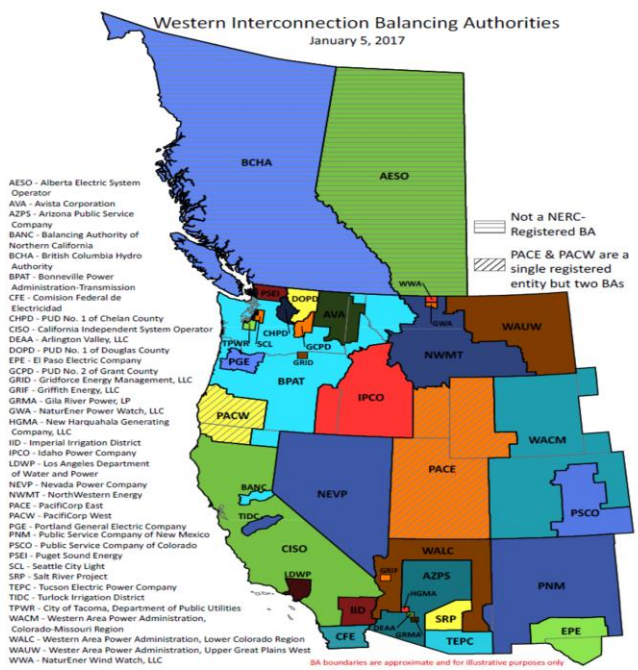


Exhibit 76: PLEXOS® WECC Market Model Coverage

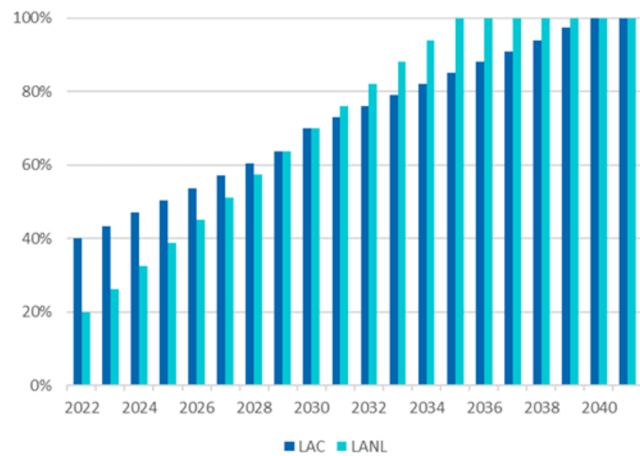


Source: WECC

Capacity Expansion Constraints: RPS and PRM

IRP models the LAC's carbon-neutral goal by 2040 and LANL's 100 percent renewable goal by 2035. The 100 percent renewable power for LANL is a component of the Department of Energy 2021 Climate Adaptation and Resilience Plan, which includes comprehensive decarbonization goals across sectors. Exhibit 77 presents the LAC carbon neutral and LANL renewable goals.

Exhibit 77: LAC Carbon Neutral and LANL Renewable Goals



Currently, the DPU does not have explicit planning reserve margin requirements. With increasing intermittent resources in LAPP portfolio and in the broader WECC footprint, DPU's resources must be able to serve the peak load and have the flexibility to balance short-term and multi-hour ramps in net load. With SJGS, LAPP is expected to have a negative reserve margin by the end of 2022. Considering utility planning best practices and the WECC market risks, this IRP considers two groups of portfolios:

- Portfolios 1, 2, 3, 4, 5, 11, and 12 has average PRM of 4 percent during 2023 – 2041;
- Portfolios 6, 7, 8, 9, 10 have average PRM of 14 – 15 percent during 2023 – 2041.

While the portfolios achieve average PRM goals, the IRP allows for a short position (total capacity of peak serving resources less than the peak load) in certain years. Exhibit 78 presents the average PRM for all portfolios during 2023 – 2041.

Exhibit 78: IRP Portfolios Average PRM Summary

Base Case Average Planning Reserve Margin (2023-2041)		
P1	SMR (8) + solar + wind + storage	4%
P2	SMR (8) + solar + wind	4%
P3	solar + wind + storage	4%
P4	SMR (8) + solar + wind + SCGT	4%
P5	SMR (8) + solar + wind + RICE	4%
P6	SMR (8) + solar + wind + storage	14%
P7	SMR (8) + solar + wind	14%
P8	solar + wind + storage	14%
P9	SMR (8) + solar + wind + SCGT	14%
P10	SMR (8) + solar + wind + RICE	15%
P11	SMR (36) + solar + wind + RICE	4%
P12	SMR (36) + solar + wind + storage	4%

Portfolios Construction Summary

Base Case

Under the Base Case, the cumulative new builds range from 561 MW (Portfolio 12) to 968 MW (Portfolio 7). All portfolios satisfy LAC's carbon neutral and LANL's renewable requirements. Wind builds are assumed to be sourced in resource rich regions such as the east of the state and will require transmission capacity. Exhibit 79 presents the summary of new builds under the Base Case across 12 portfolios. Portfolio 1, 2, 3, 4, 5, 11, and 12 has average PRM of 4 percent during 2023 – 2041. Portfolios 6, 7, 8, 9, and 10 have average PRM of 14 – 15 percent during 2023 – 2041. Solar and wind peak credit is at 17 percent and 29 percent, respectively. Battery storage builds have the flexibility to charge from solar (as a hybrid project) or from the grid.

Exhibit 79: Base Case Portfolios Construction Summary

Portfolio Composition: LAPP Cumulative New Builds during 2022 - 2041		Base Case							
		Avg PRM	BESS	PV	Wind	GT	RICE	SMR	Total
		%	MW	MW	MW	MW	MW	MW	MW
P1	SMR (8)+ solar + wind + storage	4%	55	380	135	0	0	8	**578**
P2	SMR (8) + solar + wind	4%	0	605	200	0	0	8	**813**
P3	solar + wind + storage	4%	70	370	145	0	0	0	**585**
P4	SMR (8) + solar + wind + SCGT	4%	0	480	180	24	0	8	**692**
P5	SMR (8) + solar + wind + RICE	4%	0	500	185	0	18	8	**711**
P6	SMR (8) + solar + wind + storage	14%	65	435	160	0	0	8	**668**
P7	SMR (8) + solar + wind	14%	0	760	200	0	0	8	**968**
P8	solar + wind + storage	14%	90	365	170	0	0	0	**625**
P9	SMR (8) + solar + wind + SCGT	14%	0	635	190	24	0	8	**857**
P10	SMR (8) + solar + wind + RICE	15%	0	650	200	0	18	8	**876**
P11	SMR (36) + solar + wind + RICE	4%	0	420	145	0	18	36	**619**
P12	SMR (36) + solar + wind + storage	4%	35	350	140	0	0	36	**561**

Min	Max
561	968
P12	P7

Low Case

Under the Low Case, the cumulative new builds range from 214 MW (Portfolio 11) to 548 MW (Portfolio 7). All portfolios satisfy LAC's carbon neutral and LANL's renewable requirements. Wind builds are assumed to be sourced in resource rich regions such as the east of the state and will require transmission capacity. Exhibit 80 presents the summary of new builds under the Low Case across 12 portfolios. Portfolio 1, 2, 3, 4, 5, 11, and 12 has average PRM of 4 – 6 percent during 2023 – 2041. Portfolios 6, 7, 8, 9, and 10 have average PRM of 15 percent during 2023 – 2041.

Exhibit 80: Low Case Portfolios Construction Summary

Portfolio Composition: LAPP Cumulative New Builds during 2022 - 2041		**Low Case**							
		Avg PRM	BESS	PV	Wind	GT	RICE	SMR	**Total**
		%	MW	MW	MW	MW	MW	MW	**MW**
P1	SMR (8)+ solar + wind + storage	4%	25	165	90	0	0	8	**288**
P2	SMR (8) + solar + wind	4%	0	220	200	0	0	8	**428**
P3	solar + wind + storage	4%	35	185	100	0	0	0	**320**
P4	SMR (8) + solar + wind + SCGT	4%	0	165	110	24	0	8	**307**
P5	SMR (8) + solar + wind + RICE	4%	0	185	145	0	18	8	**356**
P6	SMR (8) + solar + wind + storage	15%	30	204	120	0	0	8	**362**
P7	SMR (8) + solar + wind	15%	0	340	200	0	0	8	**548**
P8	solar + wind + storage	15%	50	215	125	0	0	0	**390**
P9	SMR (8) + solar + wind + SCGT	15%	0	205	190	24	0	8	**427**
P10	SMR (8) + solar + wind + RICE	15%	0	255	170	0	18	8	**451**
P11	SMR (36) + solar + wind + RICE	6%	0	90	70	0	18	36	**214**
P12	SMR (36) + solar + wind + storage	4%	20	170	50	0	0	36	**276**

Min	**Max**
214	548
P11	P7

High Case

Under the High Case, the cumulative new builds range from 826 MW (Portfolio 12) to 1,538 MW (Portfolio 7). All portfolios satisfy LAC's carbon neutral and LANL's renewable requirements. Wind builds are assumed to be sourced in resource rich regions such as the east of the state and will require transmission capacity. Exhibit 81 presents the summary of new builds under the High Case across 12 portfolios. Portfolio 1, 2, 3, 4, 5, 11, and 12 has average PRM of 4 percent during 2023 – 2041. Portfolios 6, 7, 8, 9, and 10 have average PRM of 15 percent during 2023 – 2041.

Exhibit 81: High Case Portfolios Construction Summary

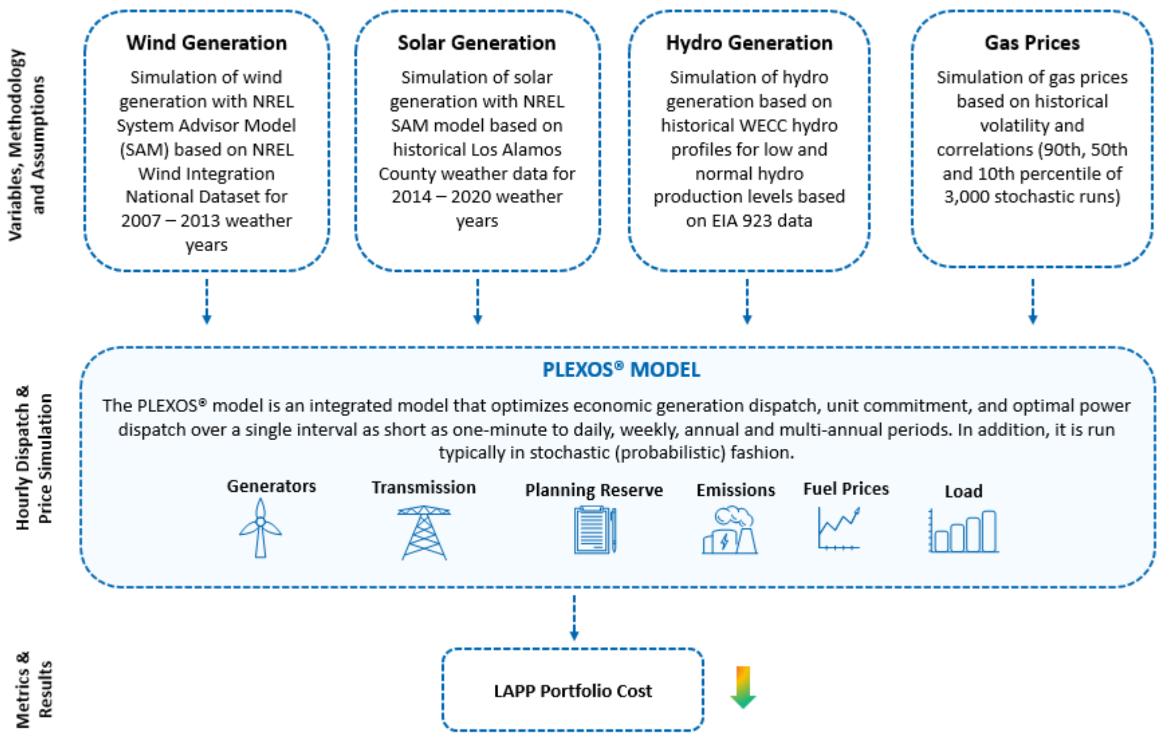
Portfolio Composition: LAPP Cumulative New Builds during 2022 - 2041		**High Case**							
		Avg PRM	BESS	PV	Wind	GT	RICE	SMR	**Total**
		%	MW	MW	MW	MW	MW	MW	**MW**
P1	SMR (8)+ solar + wind + storage	4%	85	590	200	0	0	8	**883**
P2	SMR (8) + solar + wind	4%	0	1,080	200	0	0	8	**1,288**
P3	solar + wind + storage	4%	100	565	200	0	0	0	**865**
P4	SMR (8) + solar + wind + SCGT	4%	0	940	200	24	0	8	**1,172**
P5	SMR (8) + solar + wind + RICE	4%	0	830	195	0	36	8	**1,069**
P6	SMR (8) + solar + wind + storage	15%	90	650	200	0	0	8	**948**
P7	SMR (8) + solar + wind	15%	0	1,330	200	0	0	8	**1,538**
P8	solar + wind + storage	15%	115	630	200	0	0	0	**945**
P9	SMR (8) + solar + wind + SCGT	15%	0	1,165	200	24	0	8	**1,397**
P10	SMR (8) + solar + wind + RICE	15%	0	1,070	200	0	36	8	**1,314**
P11	SMR (36) + solar + wind + RICE	4%	0	700	140	0	36	36	**912**
P12	SMR (36) + solar + wind + storage	4%	55	555	180	0	0	36	**826**

Min	**Max**
826	1,538
P12	P7

Chapter 12: Stochastic Assessment of Candidate Portfolios

To fully capture this volatility, FTI has developed a proprietary process to simulation variability of solar, wind, hydro, and gas prices. Exhibit 82 shows the structured stochastic simulation of key uncertainties.

Exhibit 82: Stochastic Simulation of Key Uncertainties



Stochastic Simulation of Wind Generation

FTI leveraged the NREL Wind Integration National Dataset which includes instantaneous meteorological conditions from computer model output and calculated turbine power for more than 126,000 sites in the continental U.S. for 2007 – 2013. FTI modeled representative profile using the Sagamore Wind project (in East New Mexico, with 80m hub heights and Vestas v90-2.0 turbines) as a proxy, using NREL System Advisor Model ("SAM") to calculate hourly capacity factors for the project for each weather year. FTI applied the simulated wind profiles in the stochastic analysis to assess wind generation variability. Exhibit 83 shows the simulated New Mexico wind capacity factor based on historical weather patterns. Exhibit 84 shows the simulation New Mexico wind profiles in July and January based on historical weather pattern.

Exhibit 83: Simulated New Mexico Wind Capacity Factor

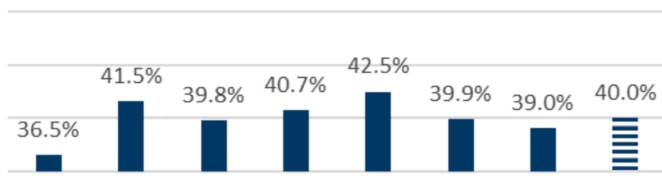
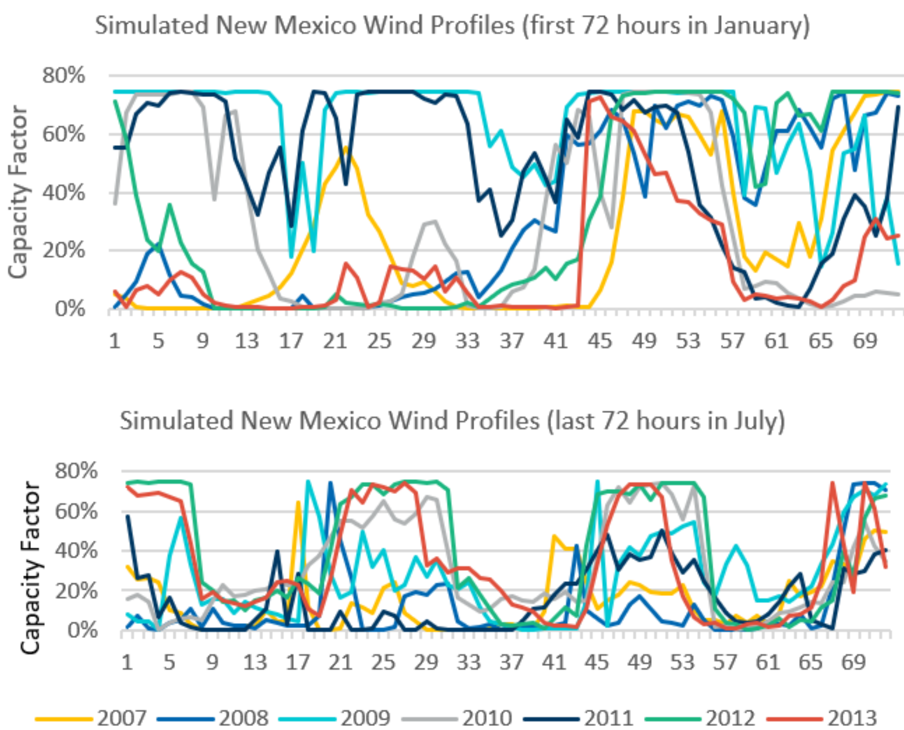


Exhibit 84: Simulated New Mexico Wind Profiles



Stochastic Simulation of Solar Generation

FTI leveraged the NREL SAM to simulate representative solar profiles and hourly capacity factors for solar array based on historical weather data for Los Alamos County during 2014 – 2020. FTI applied the simulated solar profiles in the stochastic analysis to assess solar generation variability. Exhibit 85 shows the simulated New Mexico solar PV capacity factor based on historical weather patterns. Exhibit 86 shows the simulation New Mexico solar PV profiles in July and January based on historical weather pattern.

Exhibit 85: Simulated New Mexico Solar PV Capacity Factor

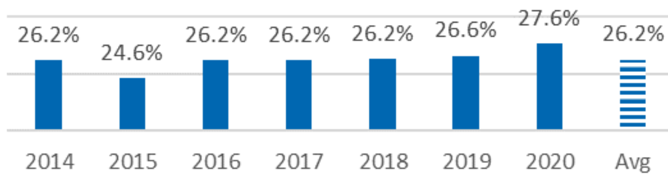
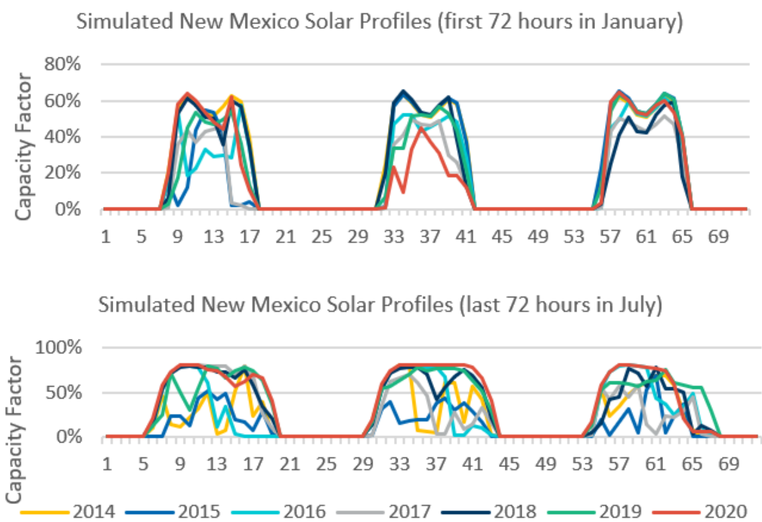


Exhibit 86: Simulated New Mexico Solar PV Profiles



Hydro Generation and Gas Prices

FTI included simulation of hydro generation based on historical WECC hydro profiles for low and normal hydro production levels based on EIA 923 data. PLEXOS® dispatches hydro generation resources dynamically based on prevailing load and prices. An important constraint in the hydro dispatch algorithm is the maximum energy produced for each hydro unit for each month of the year. These monthly generation limits are set using historical monthly generation data from the EIA Form 923 dataset, with normal hydro generation limits set at the average of the previous five years of data while low hydro generation limits set at the minimum year's output.

Simulation of gas prices are based on historical volatility and correlations with 3,000 stochastic runs. Inputs into PLEXOS® model are the 90th, 50th, and 15th percentile monthly gas prices for the modeling horizon.

Chapter 13: Portfolios Assessment Results

Summary Results of Key Metrics

This section discusses the key findings and scorecard of all the 12 portfolios across 9 metrics.

Cost Metric

The NPV of portfolio costs is calculated as the revenue requirement (including fixed operating and maintenance costs, variable operating and maintenance costs, fuel cost, PPA costs) at 5 percent discount rate during the planning horizon (2022 – 2041). Portfolio 3 show the lowest NPV of portfolio costs during the planning horizon, followed by Portfolio 4 and 1. Exhibit 87 presents the cost metric summary for the 12 portfolios. The index is calculated to have 0 represent the highest performance, and 10 represent the lowest performance. The portfolios metrics that fall between the highest and lowest performance are evaluated based on their relative positions in the spectrum of each metrics.

Exhibit 87: Cost Metric Results Summary

1. Cost Metric		Avg Planning Reserve Margin (2023-2041)	1.1 NPV of Portfolio Costs (2022-2041)	Index Ranking (0-10 Scale)
Unit		%	2022$	X
P1	SMR (8) + solar + wind + storage	4%	464,710,468	1.49
P2	SMR (8) + solar + wind	4%	496,969,092	4.98
P3	solar + wind + storage	4%	450,953,720	0.00
P4	SMR (8) + solar + wind + SCGT	4%	456,418,199	0.59
P5	SMR (8) + solar + wind + RICE	4%	465,868,051	1.61
P6	SMR (8) + solar + wind + storage	14%	497,999,120	5.09
P7	SMR (8) + solar + wind	14%	543,399,865	10.00
P8	solar + wind + storage	14%	483,496,256	3.52
P9	SMR (8) + solar + wind + SCGT	14%	503,747,665	5.71
P10	SMR (8) + solar + wind + RICE	15%	511,045,469	6.50
P11	SMR (36) + solar + wind + RICE	4%	499,494,579	5.25
P12	SMR (36) + solar + wind + storage	4%	505,339,622	5.88

Sustainability Metric

The sustainability metric is calculated as average annual LAPP renewable goal requirement minus carbon-free generation from owned and contracted resources. A negative number shows that LAPP sells into the market on a net annual basis whereas a positive number would show that LAPP procures from the market. All the portfolios meet the RPS goals: LAC's carbon-neutral by

2040 and LANL's 100 percent renewable goal by 2035. Given such, all portfolios are given equal ranking. Exhibit 88 presents the sustainability metric summary for the 12 portfolios.

Exhibit 88: Sustainability Metric Results Summary

2. Sustainability Metric		Avg Planning Reserve Margin (2023-2041)	2.1 Sustainability	Index Ranking (0-10 Scale)
Unit		%	MWh	X
P1	SMR (8) + solar + wind + storage	4%	-159,836	0.00
P2	SMR (8) + solar + wind	4%	-575,323	0.00
P3	solar + wind + storage	4%	-124,621	0.00
P4	SMR (8) + solar + wind + SCGT	4%	-324,436	0.00
P5	SMR (8) + solar + wind + RICE	4%	-370,426	0.00
P6	SMR (8) + solar + wind + storage	14%	-370,426	0.00
P7	SMR (8) + solar + wind	14%	-816,485	0.00
P8	solar + wind + storage	14%	-197,241	0.00
P9	SMR (8) + solar + wind + SCGT	14%	-557,978	0.00
P10	SMR (8) + solar + wind + RICE	15%	-611,677	0.00
P11	SMR (36) + solar + wind + RICE	4%	-304,989	0.00
P12	SMR (36) + solar + wind + storage	4%	-165,136	0.00

Risk Metrics: Average Annual Market Exposure

The average annual market exposure is calculated as average annual LAPP load (native load + battery load) minus generation from owned and contracted resources. A negative number shows that LAPP sells into the market on a net annual basis whereas a positive number would show that LAPP procures from the market. Portfolio 3 shows the least market exposure, followed by Portfolio 1 and 12. Exhibit 89 presents the average annual market exposure metric summary for the 12 portfolios.

Exhibit 89: Average Annual Market Exposure Metric Results Summary

3. Risk Metrics		Avg Planning Reserve Margin (2023-2041)	3.1 Average Annual Market Exposure (2022-2041)	Index Ranking (0-10 Scale)
Unit		%	MWh	X
P1	SMR (8) + solar + wind + storage	4%	-113,119	0.55
P2	SMR (8) + solar + wind	4%	-570,982	6.74
P3	solar + wind + storage	4%	-72,319	0.00
P4	SMR (8) + solar + wind + SCGT	4%	-353,734	3.80
P5	SMR (8) + solar + wind + RICE	4%	-392,891	4.33
P6	SMR (8) + solar + wind + storage	14%	-210,355	1.87
P7	SMR (8) + solar + wind	14%	-812,145	10.00
P8	solar + wind + storage	14%	-131,142	0.80
P9	SMR (8) + solar + wind + SCGT	14%	-587,275	6.96
P10	SMR (8) + solar + wind + RICE	15%	-634,141	7.59
P11	SMR (36) + solar + wind + RICE	4%	-327,454	3.45
P12	SMR (36) + solar + wind + storage	4%	-125,974	0.73

Risk Metrics: Peak Month Cost

The portfolio costs for peak month July 2032 are calculated through the stochastic simulations of wind, solar, hydro production, and gas prices. Portfolio 4 shows the least peak month portfolio costs, followed by Portfolio 5 and 6. Exhibit 90 presents the peak month cost metric summary for the 12 portfolios.

Exhibit 90: Peak Month Cost Metric Results Summary

3. Risk Metrics		Avg Planning Reserve Margin (2023-2041)	3.2 Portfolio Costs (July 2032)	Index Ranking (0-10 Scale)
Unit		%	2022$	X
P1	SMR (8) + solar + wind + storage	4%	2,894,815	3.08
P2	SMR (8) + solar + wind	4%	3,370,914	8.75
P3	solar + wind + storage	4%	3,025,165	4.63
P4	SMR (8) + solar + wind + SCGT	4%	2,635,406	0.00
P5	SMR (8) + solar + wind + RICE	4%	2,799,195	1.95
P6	SMR (8) + solar + wind + storage	14%	2,913,375	3.31
P7	SMR (8) + solar + wind	14%	3,476,410	10.00
P8	solar + wind + storage	14%	3,156,573	6.20
P9	SMR (8) + solar + wind + SCGT	14%	2,991,232	4.23
P10	SMR (8) + solar + wind + RICE	15%	3,365,264	8.68
P11	SMR (36) + solar + wind + RICE	4%	3,422,607	9.36
P12	SMR (36) + solar + wind + storage	4%	3,330,529	8.27

Operational Metrics: New Resources Subject to Transmission

The new resources subject to transmission metric is calculated as the total installed capacity of new resources based on the following transmission reliance percentage: new battery storage (0 percent), solar (50 percent), wind (100 percent), SCGT (0 percent), RICE (0 percent) and SMR (100 percent). Portfolio 3 includes the least capacity that is subject to transmission, followed by Portfolio 1 and 12. Exhibit 91 presents the new resources subject to transmission metric summary for the 12 portfolios.

Exhibit 91: New Resources Subject to Transmission Metric Results Summary

4. Operational Exposure Metrics		Avg Planning Reserve Margin (2023-2041)	4.1 New Resources Subject to Transmission	Index Ranking (0-10 Scale)
Unit		%	MW	X
P1	SMR (8) + solar + wind + storage	4%	333	0.12
P2	SMR (8) + solar + wind	4%	511	7.00
P3	solar + wind + storage	4%	330	0.00
P4	SMR (8) + solar + wind + SCGT	4%	428	3.80
P5	SMR (8) + solar + wind + RICE	4%	443	4.38
P6	SMR (8) + solar + wind + storage	14%	386	2.15
P7	SMR (8) + solar + wind	14%	588	10.00
P8	solar + wind + storage	14%	353	0.87
P9	SMR (8) + solar + wind + SCGT	14%	516	7.19
P10	SMR (8) + solar + wind + RICE	15%	533	7.87
P11	SMR (36) + solar + wind + RICE	4%	391	2.36
P12	SMR (36) + solar + wind + storage	4%	351	0.81

Operational Metrics: Weather-dependent New Resources

The weather dependent new resources metric is calculated as the total installed capacity of new wind and solar resources, as both are weather-dependent. Portfolio 12 includes the least weather dependent new resources, followed by Portfolio 1 and 3. Exhibit 92 presents the weather-dependent new resources metric summary for the 12 portfolios.

Exhibit 92: Weather-dependent New Resources Metric Results Summary

4. Operational Exposure Metrics		Avg Planning Reserve Margin (2023-2041)	4.2 Weather Dependent New Resources	Index Ranking (0-10 Scale)
Unit		%	MW	X
P1	SMR (8) + solar + wind + storage	4%	515	0.53
P2	SMR (8) + solar + wind	4%	805	6.70
P3	solar + wind + storage	4%	515	0.53
P4	SMR (8) + solar + wind + SCGT	4%	660	3.62
P5	SMR (8) + solar + wind + RICE	4%	685	4.15
P6	SMR (8) + solar + wind + storage	14%	595	2.23
P7	SMR (8) + solar + wind	14%	960	10.00
P8	solar + wind + storage	14%	535	0.96
P9	SMR (8) + solar + wind + SCGT	14%	825	7.13
P10	SMR (8) + solar + wind + RICE	15%	850	7.66
P11	SMR (36) + solar + wind + RICE	4%	565	1.60
P12	SMR (36) + solar + wind + storage	4%	490	0.00

Reliability Metrics: Planning Reserve Margin

Planning Reserve Margin metric is calculated as the percentage of peak serving capacity above peak demand. PRM is typically used in IRPs to determine a load serving entity's peak serving resource need above typical annual peak. Portfolio 10 exhibits the highest average planning reserve margin during 2023 – 2041, followed by Portfolio 6, 7, 8 and 9. While the portfolios achieve average PRM goals, the IRP allows a short position (i.e., total capacity of peak serving resources less than the peak load) in certain years. Exhibit 93 presents the PRM metric summary for the 12 portfolios.

Exhibit 93: Planning Reserve Margin Metric Results Summary

5. Reliability Metrics		5.1 Avg Planning Reserve Margin (2023-2041)	Index Ranking (0-10 Scale)
Unit		%	X
P1	SMR (8) + solar + wind + storage	4.28%	9.31
P2	SMR (8) + solar + wind	3.54%	9.98
P3	solar + wind + storage	3.98%	9.58
P4	SMR (8) + solar + wind + SCGT	3.59%	9.93
P5	SMR (8) + solar + wind + RICE	3.52%	10.00
P6	SMR (8) + solar + wind + storage	14.49%	0.14
P7	SMR (8) + solar + wind	14.33%	0.29
P8	solar + wind + storage	14.23%	0.37
P9	SMR (8) + solar + wind + SCGT	14.22%	0.38
P10	SMR (8) + solar + wind + RICE	14.65%	0.00
P11	SMR (36) + solar + wind + RICE	3.87%	9.68
P12	SMR (36) + solar + wind + storage	4.25%	9.34

Reliability Metrics: Dispatchable New Resources

The dispatchable new resources metric is calculated as the dispatchable resources of new battery storage at 4 hours per day, SCGT, RICE, and SMR at 24 hours per day. Portfolio 11 includes the largest dispatchable new resources, followed by Portfolio 12 and 4. Exhibit 94*Exhibit* 93 presents the dispatchable new resources metric summary for the 12 portfolios.

Exhibit 94: Dispatchable New Resources Metric Results Summary

5. Reliability Metrics		Avg Planning Reserve Margin (2023-2041)	5.2 Dispatchable New Resources	Index Ranking (0-10 Scale)
Unit		%	MWh/ day	**X**
P1	SMR (8) + solar + wind + storage	4%	412	8.01
P2	SMR (8) + solar + wind	4%	192	10.00
P3	solar + wind + storage	4%	280	9.20
P4	SMR (8) + solar + wind + SCGT	4%	768	4.78
P5	SMR (8) + solar + wind + RICE	4%	624	6.09
P6	SMR (8) + solar + wind + storage	14%	452	7.64
P7	SMR (8) + solar + wind	14%	192	10.00
P8	solar + wind + storage	14%	360	8.48
P9	SMR (8) + solar + wind + SCGT	14%	768	4.78
P10	SMR (8) + solar + wind + RICE	15%	624	6.09
P11	SMR (36) + solar + wind + RICE	4%	1,296	0.00
P12	SMR (36) + solar + wind + storage	4%	1,004	2.64

Diversification Metric

The diversification metric is calculated as the number of new generation types in each portfolio. Portfolio 1, 4, 5, 6, 9, 10, 11 and 12 includes the four different new generation types, and the rest of the portfolios includes three different new generation types. Exhibit 95 presents the diversification metric summary for the 12 portfolios.

Exhibit 95: Diversification Metric Results Summary

6. Diversification Metric		Avg Planning Reserve Margin (2023-2041)	6.1 Number of New Resource Types	Index Ranking (0-10 Scale)
Unit		%	Number	x
P1	SMR (8) + solar + wind + storage	4%	4	0.00
P2	SMR (8) + solar + wind	4%	3	1.00
P3	solar + wind + storage	4%	3	1.00
P4	SMR (8) + solar + wind + SCGT	4%	4	0.00
P5	SMR (8) + solar + wind + RICE	4%	4	0.00
P6	SMR (8) + solar + wind + storage	14%	4	0.00
P7	SMR (8) + solar + wind	14%	3	1.00
P8	solar + wind + storage	14%	3	1.00
P9	SMR (8) + solar + wind + SCGT	14%	4	0.00
P10	SMR (8) + solar + wind + RICE	15%	4	0.00
P11	SMR (36) + solar + wind + RICE	4%	4	0.00
P12	SMR (36) + solar + wind + storage	4%	4	0.00

Portfolio Assessment Dashboard

The overall ranking considers a total of nine metrics across six equally weighted objective categories, including costs, sustainability, risks, operational, reliability, and diversification. Portfolio 1 (4 percent PRM, 55 MW battery storage, 380 MW solar, 135 MW wind, 8 MW SMR) shows the highest overall performance, followed by Portfolio 3, 8, and 4. Exhibit 96 presents the portfolio dashboard summary.

Exhibit 96: Portfolio Dashboard Summary

Metrics	Index (0 = highest performance, 10 = lowest performance)										
	1. Costs	2. Sustainability	3. Risks		4. Operational Exposure		5. Reliability		6. Diversification	Weighted Sum	Overall Rank
	1.1 NPV	2.1 Sustainability	3.1 Market Exposure	3.2 Portfolio Costs	4.1 New Resources Subject to Transmission	4.2 Weather Dependent New Resources	5.1 Planning Reserve Margin	5.2 Dispatchable New Resources	6.1 New Resource Types		
Weight	**16.67%**	**16.67%**	**8.33%**	**8.33%**	**8.33%**	**8.33%**	**8.33%**	**8.33%**	**16.67%**	**100%**	
P1	1.49	0.00	0.55	3.08	0.12	0.53	9.31	8.01	0.00	2.05	1
P2	4.98	0.00	6.74	8.75	7.00	6.70	9.98	10.00	1.00	5.09	11
P3	0.00	0.00	0.00	4.63	0.00	0.53	9.58	9.20	1.00	2.16	2
P4	0.59	0.00	3.80	0.00	3.80	3.62	9.93	4.78	0.00	2.26	4
P5	1.61	0.00	4.33	1.95	4.38	4.15	10.00	6.09	0.00	2.84	7
P6	5.09	0.00	1.87	3.31	2.15	2.23	0.14	7.64	0.00	2.29	5
P7	10.00	0.00	10.00	10.00	10.00	10.00	0.29	10.00	1.00	6.02	12
P8	3.52	0.00	0.80	6.20	0.87	0.96	0.37	8.48	1.00	2.23	3
P9	5.71	0.00	6.96	4.23	7.19	7.13	0.38	4.78	0.00	3.51	9
P10	6.50	0.00	7.59	8.68	7.87	7.66	0.00	6.09	0.00	4.24	10
P11	5.25	0.00	3.45	9.36	2.36	1.60	9.68	0.00	0.00	3.08	8
P12	5.88	0.00	0.73	8.27	0.81	0.00	9.34	2.64	0.00	2.80	6

IRP Portfolio Dashboard: Weighting Sensitivities

After presenting the preliminary IRP results to LAPP, FTI developed three sensitivity cases based on stakeholder inputs.

Exhibit 97 presents the three weighting sensitivities proposed by LANL and LAC, including emphasis on reducing market exposure, emphasis on reducing weather exposure, and emphasis on dispatchability. Portfolios 1, 3, and 4 consistently rank as the overall top portfolios. Exhibit 98 presents the portfolio dashboard for the sensitivity cases in comparison to the Base Case.

Exhibit 97: Weighting Sensitivities

	Category	1. Cost	2. Sustainability	3. Risks		4. Operational Exposure		5. Reliability		6. Diversification	Total
	Metrics	1.1 NPV	2.1 Sustainability	3.1 Portfolio Costs	3.2 Market Exposure	4.1 New Resources Subject to Transmission	4.2 Weather Dependent New Resources	5.1 Planning Reserve Margin	5.2 Dispatchable New Resources	6.1 New Resource Types	
Sensitivities	Base Case	16.67%	16.67%	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	16.67%	100%
	Emphasis on Reducing Market Exposure	13.6%	13.6%	6.8%	25.00%	6.8%	6.8%	6.8%	6.8%	13.6%	100%
	Emphasis on Reducing Weather Exposure	13.6%	13.6%	6.8%	6.8%	6.8%	25.00%	6.8%	6.8%	13.6%	100%
	Emphasis on Dispatchability	13.6%	13.6%	6.8%	6.8%	6.8%	6.8%	6.8%	25.00%	13.6%	100%

Exhibit 98: Portfolio Dashboard Summary of Weighting Sensitivities

Sensitivity		Base Case	Emphasis on Reducing Market Exposure	Emphasis on Reducing Weather Exposure	Emphasis on Dispatchability
Weighting		equal weight across six categories	heavy weight 3.2 Market Exposure	heavy weight 4.2 Weather Dependent New Resources	heavy weight 5.2 Dispatchable New Resources
P1	SMR (8) + solar + wind + storage	1	2	1	4
P2	SMR (8) + solar + wind	11	11	11	11
P3	solar + wind + storage	2	1	2	8
P4	SMR (8) + solar + wind + SCGT	4	6	6	2
P5	SMR (8) + solar + wind + RICE	7	7	8	7
P6	SMR (8) + solar + wind + storage	5	4	4	5
P7	SMR (8) + solar + wind	12	12	12	12
P8	solar + wind + storage	3	3	3	6
P9	SMR (8) + solar + wind + SCGT	9	9	9	9
P10	SMR (8) + solar + wind + RICE	10	10	10	10
P11	SMR (36) + solar + wind + RICE	8	8	7	1
P12	SMR (36) + solar + wind + storage	6	5	5	3

Chapter 14: Preferred Resource Plan and Pivot Strategies

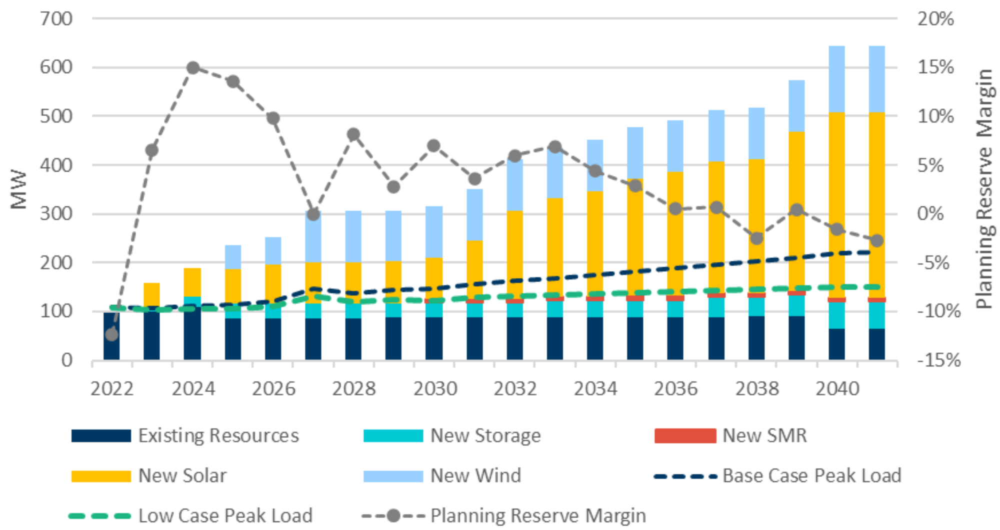
Preferred Resource Plan

The IRP recommends mitigating near-term risks and avoiding long-term risks by building a total of 55 MW battery storage, 380 MW solar, 135 MW wind, and 8 MW SMR during the planning horizon to achieve an average annual planning reserve margin of 4 percent. Exhibit 99 shows the Preferred Resource Plan cumulative new builds summary. Exhibit 100 shows the Preferred Resource Plan resources, LAPP peak load, and PRM.

Exhibit 99: LAC and LANL IRP Preferred Resource Plan Cumulative New Builds Summary

Year	Storage	Solar	Wind	SMR	Total
	MW	MW	MW	MW	MW
2025	30	70	50	0	150
2027	30	85	105	0	220
2030	30	85	105	8	228
2035	35	240	105	8	388
2040	55	380	135	8	578
2041	55	380	135	8	578

Exhibit 100: Preferred Resource Plan Resources, LAPP Peak Load, and PRM



5-year Action Plan and Pivot Strategies

Consistent with the NERC 2021 Long-term Reliability Assessment[16] findings, and WECC 2021 Western Assessment of Resource Adequacy[17] recommendations, the IRP recommends mitigating near-term risks by incorporating 220 MW new builds by 2027 in the Preferred Resource Plan. With the SJGS Unit 4 retirement in 2022, and the bridge PPA expiration in 2025, it is every important for LAPP to secure new power supplies to serve a growing load.

Battery Storage

The Preferred Resource Plan recommends incorporating 30 MW utility-scale 4-hour lithium-ion battery storage to the LAPP portfolio by 2025 to manage the intermittency of new wind and solar resources. There have been incidents of grid battery fire (such as the one occurred at an Arizona Public Service facility),[18] so the technical risks should be carefully evaluated and mitigated during procurement and operation. LAPP should monitor the cost of battery-grade lithium carbonate, which has been volatile in the past year due to supply and demand imbalances.

In the long term, LAPP should monitor the long duration storge options including flow battery, and seasonal storage options including green hydrogen, as hydrogen infrastructures are being

[16] 2021 Long-Term Reliability Assessment, NERC, December 2021. Accessed at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf
[17] 2021 Western Assessment of Resource Adequacy, WECC, 2021. Accessed at https://www.wecc.org/Administrative/WARA%202021.pdf
[18] McMicken Battery Energy Storage System Event Technical Analysis and Recommendations. July 2020. https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Newsroom/McMickenFinalTechnicalReport.ashx?la=en&hash=50335FB5098D9858BFD276C40FA54FCE

built out in the WECC footprint. When cost-effective, long duration storage options are important to mitigate risks of loss of load and prevent renewables curtailments when the outputs exceed demand or transmission capacity.

Simple Cycle Gas Turbine

The overall performance of the Preferred Resource Plan is closely followed by portfolios that incorporates SCGT to the LAPP portfolio to address near-term resource adequacy, provide regulation services, voltage support, and operating reserves. This suggests opportunities to enhance the Preferred Resource Plan by incorporating SCGT. The size of the SCGT should be evaluated based on the load growth, the need to manage hourly and seasonal imbalances, and the benefit-cost tradeoff based on concrete bids from technology providers.

Over the long term (post 2030), LAPP preserves the optionality to evaluate feasibility to convert SCGT to hydrogen if the infrastructures are commercially available, and fuel supply is cost-effective and reliable.

Solar and Wind

The Preferred Resource Plan recommends 85 MW solar, and 105 MW wind builds by 2027. LAPP should evaluate proposals based on tradeoffs of price, performance, and transmission needs. If wind projects cannot be competitively procured due to lack of availability, transmission constraints, or high all-in costs with firm transmission, alternative options of solar and battery storage should be explored. Solar projects are subject to cost uncertainties due to contemplated anti-dumping and countervailing duties.

Small Modular Reactor

The Preferred Resource Plan includes the 8 MW SMR through a long-term contract. The project is developed by the public power consortium Utah Associated Municipal Power Systems with planned commercial operation by 2030.[19] The IRP recommends LAC to continue pursue risk mitigation measures to protect ratepayers from potential cost overruns and schedule delays.

[19] https://www.nuscalepower.com/projects/carbon-free-power-project