2026 INTEGRATED RESOURCE PLAN

APPENDICES

September 1, 2026

PNM®

Powering New Mexico, *Together*

Appendices

APPENDIX A: ACRONYMS

AAR	Ambient Adjusted Ratings
AC	Alternating Current
ACCC	Advanced conductor
ADMS	Advanced Distribution Management Systems
AFC	Available Flowgate Capacity
AMI	Advanced Metering Infrastructure
APS	Arizona Public Service Company
ATB	Annual Technologies Baseline
ATC	Available Transfer Capability
BA	Balancing Area
BAA	Balancing Authority Area
BESS	Battery Energy Storage System
BTM	Behind-The-Meter
CAES	Compressed Air Energy Storage
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Frequency Index
CAISO	California Independent System Operator
CAPEX	Capital Expenditures
CAPS	Corrective Action Plans
CC	Combined Cycle
CCN	Certificate of Public Convenience & Necessity
CCS	Carbon Capture and Storage
CS	Community Solar
CT	Combustion Turbines
CTP	Current Trends and Policy
DC	Direct Current
DCU	Digital Control Unit
DER	Distributed Energy Resources
DG	Distributed Generation
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
DSP	Distribution System Plan
E3	Energy and Environmental Economics, Inc.
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EIP	Eastern Interconnect Project
ELCC	Effective Load Carrying Capacity
EPE	El Paso Electric Company
EPRI	Electric Resource Power Institute
ERCOT	Electric Reliability Council of Texas
ESA	Energy Storage Agreement
ESIG	Energy Systems Integration Group
ETA	Energy Transition Act
EUE	Expected Unserved Energy
EUEA	Efficient Use of Energy Act
FACTS	Flexible AC Transmission Systems
FCPP	Four Corners Power Plant
FEOC	Foreign Entity of Concern
FERC	Federal Energy Regulatory Commission
FSP	Facilitated Stakeholder Process
GET	Grid Enhancing Technology
GHG	Greenhouse Gas
GIA	Generator Interconnection Agreement
GWh	Gigawatt-hours
HB	House Bill
HEG	High Economic Growth
HVAC	Heating, Ventilation and Air Conditioning
HVDC	High-Voltage Direct Current
IAS	Iron-Air Storage
IBR	Inverter Based Resource
ICAP	Installed Capacity
ICF	Inner City Fund/ICF International
IEEE	Institute of Electrical and Electronics Engineers
ILR	inverter loading ratio
IM	Independent Monitor
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	Independent System Operators
ISP	Integrated System Plan
ITC	Investment Tax Credit
kV	Kilovolt
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
LDES	Long-Duration Energy Storage
LED	Light Emitting Diode
LEG	Low Economic Growth
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
LM	Load Management
LOLE	loss of load expectation
LOLH	Loss-of-Load-Hours
LOLP	Loss of Load Probability
LTCE	Long Term Capacity Expansion
M+	Markets Plus
MCEP	Most Cost-Effective Portfolio
MOD	Modeling, Data, and Analysis NERC standards
MV90	Interval meter data collection system/model designation
MWh	Megawatt-hours

NAESB North American Standards Board
NEPA National Environmental Policy Act
NERC North American Electric Reliability Corporation
NLR National Laboratory of the Rockies
NMAC New Mexico Administrative Code
NMPRC New Mexico Public Regulation Commission
NMSA New Mexico Statutes Annotated
NMWEC New Mexico Wind Energy Center
NO_x Nitrogen Oxides
NPV Net Present Value of Revenue Requirements
O&M Operating and Maintenance
OATT Open Access Transmission Tariff
OBBBA One Big Beautiful Bill Act
PCM Production Cost Modeling
PEGS Prewitt Escalante Generating Station
PHS Pumped Hydro Storage
PNM Public Service Company of New Mexico
PPA Power Purchase Agreement
PRAC Pricing Advisory Committee
PRC Protection and Control NERC Standards family
PRM Planning Reserve Margin
PSH Pumped Storage Hydro
PST Phase Shifting Transformer
PTC Production Tax Credit
PV photovoltaic
PVNGS Palo Verde Nuclear Generating Station
PVRR Present Value Revenue Requirement
RA Resource Adequacy
RAS Remedial Action Schemes
RCCS Albuquerque power factor control system
RECs Renewable Energy Certificates
RETA Renewable Energy Transmission Authority
RFI Request for Information
RFP Request for Proposal
ROWE Regional Organization for Western Energy
RPS Renewables Portfolio Standard
RSG Reserve Sharing Group
RTCA Real-Time Contingency Analysis
RTO Regional Transmission Organizations
SA Supplemental Analysis
SAIDI System Average Interruption Duration Index
SAIFI System Average Interruption Frequency Index
SB Senate Bill
SCADA Supervisory Control and Data Acquisition
SERVM Strategic Energy & Risk Valuation Model
SJGS San Juan Generating Station
SMR Small Modular Reactor
SO_2 Sulfur Dioxides
SO_x Sulfur Oxides
SPP Southwest Power Pool
SPS Southwestern Public Service
SVC Static Var Compensator
SWPG SouthWestern Power Group
SWRA Southwest Resource Adequacy Study
T&D Transmission and Distribution Systems
TAG Technical Assessment Guide
TEP Transportation Electrification Plan
TOD Time-of-Day
TOU Time-of-Use
TPL Transmission Planning Standard
TSGT Tri-State Generation & Transmission
TTC Total Transfer Capability
TWTC Western Transmission Consortium
UCAP Unforced Capacity
VEF Valencia Energy Facility
VPP Virtual Power Plant
VSC Voltage Source Converter
WAPA Western Area Power Administration
WECC Western Electricity Coordinating Council
WEIM Western Energy Imbalance Market
WEIS Western Energy Imbalance Service
WHEV Whole House Electric Vehicle
WPP Western Power Pool
WRAP Western Resource Adequacy Program
XEG Extreme Economic Growth

APPENDIX B: GLOSSARY OF TERMS

The following terms and acronyms are used throughout this report. Entries are listed alphabetically by full term, with the corresponding acronym shown in parentheses where one is used.

A

Accredited Capacity: The amount of capacity that each generation resource contributes to meeting PNM's planning reserve margin requirement. This is typically less than a generator's nameplate capacity to reflect the various limitations and constraints on each resource that may impact its ability to generate when needed. See also unforced capacity and effective load carrying capability.

ACE Diversity Interchange: Power system control areas within three major (and essentially separate) areas of North America are interconnected electrically, thus enjoying vastly improved reliability and economy of operation compared to operating in isolation. Each must continually balance load, interchange, and generation to minimize adverse influence on neighboring control areas and interconnection frequency. Area control error (ACE) and area diversity interchange (ADI) offer a means of reducing this control burden without undue investment or sacrifice by any participant in a group. (Source: IEEE, http://ieeexplore.ieee.org/Xplore/login.jsp?url=/iel1/59/8797/00387953.pdf?arnumber=387953)

Action Plan Period: The three-year period immediately following IRP filing during which PNM executes near-term implementation activities identified in the Action Plan.

Advanced Conductor (ACCC): High-capacity transmission conductor designs that increase line thermal capability and reduce losses relative to conventional conductors, often used to reconductor existing corridors.

Advanced Distribution Management Systems (ADMS): Integrated software platforms used to monitor, control, and optimize distribution system operations, including outage management, switching, and voltage control.

Advanced Metering Infrastructure (AMI): Networked metering systems that provide two-way communication and interval consumption data between customer meters and the utility.

Aeroderivative: A type of gas turbine used for electrical power generation.

Arizona Public Service Company (APS): The largest electric utility in Arizona and a regional interconnected neighbor and joint-participant with PNM in several generating and transmission facilities.

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

Available Flowgate Capability (AFC): The remaining transfer capability of a defined flowgate that is available for additional commercial transmission service.

Available Transfer Capability (ATC): The transfer capability remaining in the physical transmission network for further commercial activity, above already committed uses.

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

B

Balancing Authority (BA): The entity responsible for balancing generation, load, and interchange within its defined electrical boundary in real time.

Balancing Authority Area (BAA): The collection of generation, transmission, and load within the metered boundaries of a Balancing Authority.

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

Battery Energy Storage System (BESS): An electrochemical storage resource that charges and discharges electricity to provide energy, capacity, and ancillary services.

Behind-The-Meter (BTM): Any electricity generation, storage, or energy management system located on the customer's side of the utility revenue meter — meaning the energy produced or stored is consumed on-site and never passes through (or is measured by) the utility's meter before reaching the customer's load.

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

C

California Independent System Operator (CAISO): The independent system operator managing the bulk transmission grid and wholesale markets for most of California, and the operator of the Western Energy Imbalance Market and EDAM.

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

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

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

Capital Expenditures (CapEx): Funds a company spends to acquire, upgrade, construct, or maintain long-term physical assets—such as buildings, equipment, machinery, land, or infrastructure—that provide value over multiple years rather than being consumed within a single accounting period.

Carbon Capture and Sequestration (CCS): A technology that allows for carbon dioxide to be captured during the combustion of fossil fuels and subsequently stored in underground geologic formations, reducing and/or eliminating greenhouse gas emissions resulting from fossil fuel combustion.

Carbon Dioxide (CO2): An important greenhouse gas because it is thought to contribute to global warming. An NMPRC Order in Case No. 06-00448-UT requires that electric utilities use standardized prices for carbon emissions in their IRP filing of $8, $20, and $40 per metric ton for their low, medium, and high price sensitivities, respectively.

Certificate of Public Convenience and Necessity (CCN): NMPRC authorization required for a utility to construct or own certain new generation or infrastructure.

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

Combined Cycle (CC): A thermal generating configuration in which combustion turbine exhaust heat is recovered to drive a steam turbine, improving overall efficiency.

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

Combined Cycle with Carbon Capture and Sequestration (CC-CCS): A combined-cycle generating unit equipped with post-combustion carbon capture and geologic sequestration of the captured carbon dioxide.

Combustion Turbine (CT): A gas-fired generating unit that produces electricity directly from expanding combustion gases, typically used for peaking and flexible operation.

Compound Annual Growth Rate (CAGR): The constant annual rate at which a quantity would need to grow to move from its beginning value to its ending value over a period.

Compressed Air Energy Storage (CAES): A form of energy storage that uses surplus electricity to compress air to a high pressure; air is subsequently stored in subterranean geologic formations and can later be withdrawn to power an electric turbine. Because of the requirement for specific geologic formations, CAES is highly site-specific but can provide durations of 24 hours or longer depending on site characteristics.

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

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

Cost Causation: The ratemaking principle that utility costs should be assigned to the customers or customer classes whose energy usage, peak demand characteristics, service requirements, or other behaviors create the need for those costs, thereby promoting equitable and economically efficient rates.

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

Current Trends and Policy (CTP): The planning future that reflects presently enacted policy and expected market and technology trends, used as the reference case in the analysis.

Customer Average Interruption Duration Index (CAIDI): A reliability metric representing the average outage duration experienced by customers who were interrupted during a reporting period.

D

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

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

Demand Side Management (DSM): The portfolio of energy efficiency, load management, and demand response programs used to modify the level and shape of customer demand.

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

Direct Load Control (DLC): A demand-side program in which the utility or its agent directly cycles or curtails customer end-use equipment during system peaks or events.

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

Distributed Energy Resources (DER): Smaller-scale generation, storage, and controllable load resources connected at the distribution level or behind the customer meter.

Distributed Generation: Electric generation that is sited at a customer's premises, providing energy to the customer load at that site and/or providing electric energy for use by multiple customers in contiguous distribution substation areas.

Distribution System Plan (DSP): The forward-looking plan describing distribution system needs, investments, and DER integration, filed with the Commission and coordinated with the IRP.

Duty Cycle: Generating facility design that determines how a facility is operated. Duty cycle classifications for firm resources include baseload, intermediate, and peaking; non-firm resources are generally classified as intermittent or storage.

Dynamic Balancing Resources: Resources that provide operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of PNM's carbon-free resources will not coincide naturally with electricity demand. Examples include shorter-duration energy storage, aeroderivative combustion turbines, and demand response.

E

Eastern Interconnect Project (EIP): The transmission project and associated facilities providing an interconnection between the Eastern and Western Interconnections in eastern New Mexico.

Effective Load Carrying Capability (ELCC): A statistical measure used to translate the contributions of non-firm resources toward resource adequacy into equivalent "perfect" capacity, derived through loss of load probability modeling. The use of ELCC allows the planning reserve margin requirement to capture system needs across all conditions.

Efficient Use of Energy Act (EUEA): New Mexico statute requiring utilities to invest a minimum percentage of retail sales revenue in energy efficiency and load management programs.

El Paso Electric Company (EPE): An investor-owned electric utility serving west Texas and southern New Mexico and a neighboring interconnected system to PNM.

Electric Power Research Institute (EPRI): An independent, nonprofit research organization that conducts research and development on electricity generation, delivery, and use.

Electric Reliability Council of Texas (ERCOT): The independent system operator and grid operator for most of Texas, comprising a separate interconnection from the Western and Eastern Interconnections.

Electric Vehicle (EV): A vehicle propelled wholly or partly by electricity drawn from onboard batteries charged from the grid.

Electric Vehicle Time-of-Day (EV-TOD): A rate design that varies the price of electricity used for vehicle charging by time period to shift charging away from system peaks.

Electrolysis: A process by which electricity is used to split water molecules into hydrogen and oxygen; the hydrogen can subsequently be used to generate electricity in thermal generators or fuel cells or used for other applications.

Emergency Energy: Energy purchases to meet unserved load.

EnCompass: The primary resource portfolio modeling software that PNM uses for resource plan optimization. The model includes both capacity expansion and production simulation functionality.

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

Energy and Environmental Economics, Inc. (E3): An energy consulting firm providing resource adequacy, capacity value, and electric-sector modeling and analysis.

Energy Efficiency (EE): Measures, including energy conservation measures or programs that target consumer behavior, equipment, or devices, that result in a decrease in consumption of electricity without reducing the amount or quality of energy services, as defined by the IRP Rule.

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

Energy Storage: Various technologies that allow for the storage of surplus electricity so that it can later be provided back to the grid. See also compressed air energy storage, flow battery, iron-air storage, liquid air energy storage, lithium-ion battery, and pumped hydro storage.

Energy Storage Agreement (ESA): A contractual agreement between two parties (often a utility and a developer) through which the utility assumes the rights to the output produced by a specific energy storage resource.

Energy Systems Integration Group (ESIG): A nonprofit educational and technical association focused on the integration of variable and distributed resources into power systems.

Energy Transition Act (ETA): 2019 New Mexico legislation establishing carbon-free generation milestones, RPS targets, and the 2045 100% carbon-free requirement for electric utilities.

Equivalent Availability Factor (EAF): The proportion of hours in a given time period that a resource is available to generate at full capacity.

Expected Unserved Energy (EUE): A probabilistic measure of the amount of load shed that a portfolio of resources might experience, as measured in the expected amount of load that cannot be served. See also resource adequacy, loss of load expectation, and loss of load hours.

Extended Day-Ahead Market (EDAM): A voluntary day-ahead wholesale market offered by CAISO that extends day-ahead unit commitment and transfer optimization across participating Western balancing authorities.

Extreme Economic Growth (XEG): A planning scenario reflecting very high load growth driven by large economic development additions such as data centers and manufacturing.

F

Facilitated Stakeholder Process (FSP): A structured, third-party facilitated engagement process used to gather and incorporate stakeholder input into the planning process.

Federal Energy Regulatory Commission (FERC): Federal agency that regulates interstate transmission and wholesale electricity markets and approves NERC reliability standards.

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

Firm Generating Resources: Generating resources capable of producing stable, predictable output over sustained periods of time (absent forced outages), which typically include nuclear, coal, and natural gas and may in the future include hydrogen and various long-duration storage technologies.

Fixed Cost: Costs that are independent of output. See also variable costs.

Flexible AC Transmission Systems (FACTS): Power-electronic devices that dynamically control voltage, impedance, or phase angle to increase transfer capability and controllability of AC transmission.

Flow Battery: A form of chemical storage that can be used to store surplus electricity and discharge back to the grid. Flow batteries are anticipated to provide storage duration in the range of 8–10 hours.

Focus Period: A look-ahead window representing the target in-service timeframe for resources solicited under the current Action Plan's RFP.

Forced Outage Rate: Percentage of time a unit is not operational when it is expected to be in service.

Foreign Entity of Concern (FEOC): A statutory designation restricting eligibility for federal tax credits and incentives where specified foreign ownership, control, or supply relationships exist.

Four Corners Power Plant (FCPP): A coal-fired generating station in northwestern New Mexico in which PNM holds an ownership interest.

G

Generator Interconnection Agreement (GIA): The contract establishing the terms, facilities, and cost responsibility for connecting a generating facility to the transmission system.

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

Greenhouse Gas (GHG): Atmospheric gases such as carbon dioxide and methane that trap heat and are tracked as emissions in resource planning.

Grid Modernization Statute (Section 62-8-13 PUA): 2020 New Mexico law encouraging utility investment in grid modernization projects, including AMI, that benefit customers and the state.

Grid-Enhancing Technologies (GETs): Hardware and software solutions such as dynamic line ratings, power flow control, and topology optimization that increase utilization of existing transmission.

H

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

High Economic Growth (HEG): A planning scenario assuming stronger-than-expected economic and load growth relative to the reference forecast.

High-Voltage Direct Current (HVDC): A transmission technology that converts AC to DC for long-distance or asynchronous transfers, providing controllable power flow.

House Bill (HB): Proposed legislation originating in the House of Representatives of the state legislature or Congress.

House Bill 93 (HB 93): New Mexico legislation requiring advanced grid technology plans, enabling cost recovery for grid modernization projects, and authorizing self-sourced microgrids.

Hydrogen: A carbon-free fuel that may be used to generate electricity through either combustion in a thermal resource or use in a fuel cell. While direct use of hydrogen to generate electricity does not produce carbon emissions, the fuel may have implied emissions embedded in it depending on how it was produced.

Hydrogen-Ready Combustion Turbine: A peaking resource that generates electricity through combustion of a blend of hydrogen and natural gas and that may be retrofit in the future to operate using 100% hydrogen fuel.

I

ICF International (ICF): A global consulting firm providing energy market, load forecasting, and regulatory analysis services.

Independent Monitor (IM): A third party retained to oversee a competitive procurement or planning process and report on its fairness and objectivity.

Independent Power Producer (IPP): Third-party producers who sell capacity and/or energy to utilities.

Independent System Operator (ISO): An independent entity that operates the transmission grid and administers wholesale markets on a nondiscriminatory basis.

Inflation Reduction Act (IRA): Federal legislation passed in 2022 that created broad tax credits and other financial incentives to support the development of clean energy resources.

Infrastructure Investment and Jobs Act (IIJA): Federal legislation providing funding to the energy sector in support of industrial development, complementing the Inflation Reduction Act.

Installed Capacity (ICAP): A legacy capacity-accounting convention counting resources at full nameplate or seasonal rating, with unavailability embedded in the reserve margin.

Institute of Electrical and Electronics Engineers (IEEE): A professional association that develops widely used technical standards for electric power equipment, reliability metrics, and interconnection.

Integrated Resource Plan (IRP): The long-range plan evaluating supply-side and demand-side resource portfolios to meet forecasted customer needs at least cost and acceptable risk.

Integrated System Planning (ISP): A coordinated process in which a utility develops a single long-term plan that links together the different elements of its system, which may include generation, transmission, distribution, and customer programs.

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

Inverter-Based Resource (IBR): A generating or storage resource that connects to the grid through power electronic inverters, such as solar, wind, and batteries.

Investment Tax Credit (ITC): A federal tax credit based on the capital cost of an eligible generating or storage facility.

Iron-Air Energy Storage: A form of energy storage that utilizes the natural rusting process to store electricity. Iron-air storage is a long-duration storage technology that typically has a duration of 100 hours.

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

J

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

L

Large Generator Interconnection Agreement (LGIA): The FERC pro forma agreement governing interconnection of generating facilities larger than 20 MW.

Large Generator Interconnection Procedures (LGIP): The FERC pro forma procedures governing study, queuing, and cost allocation for large generator interconnection requests.

Lawrence Berkeley National Laboratory (LBNL): A U.S. Department of Energy national laboratory that publishes widely used research on electricity markets, renewables, and grid planning.

Levelized Cost of Energy (LCOE): The constant per-unit cost of energy that recovers all lifecycle capital and operating costs of a resource on a present-value basis.

Linear Generator: A type of thermal generating resource that uses combustion of various fuels to drive the oscillation of copper coils attached to magnets; the back-and-forth motion of the magnets produces electricity. Linear generators are expected to be capable of operating using multiple fuels.

Liquid Air Energy Storage (LAES): A form of energy storage that uses surplus electricity to chill air to very low temperatures so that it can be stored in liquid phase and subsequently depressurized to power an electric turbine. LAES is expected to provide storage duration of approximately 8–10 hours.

Lithium-Ion Battery: A form of chemical storage that can be used to store surplus electricity and discharge back to the grid. Lithium-ion batteries are typically configured to provide storage with duration up to four hours.

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

Load Factor: Peak demand divided by average demand.

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

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

Load-Following Resource: A resource with a response rate that can meet normal fluctuations in load.

Long-Duration Energy Storage (LDES): Storage technologies capable of sustained discharge over many hours or days, used to address extended periods of low renewable output.

Long-Term Capacity Expansion (LTCE): The optimization modeling that selects the least-cost mix and timing of new resources over the long-range planning horizon.

Loss of Load Expectation (LOLE): A probabilistic measure of the expected frequency that a portfolio of resources would have insufficient capability to serve loads, as measured in expected number of days per year. See also resource adequacy, expected unserved energy, and loss of load hours.

Loss of Load Hours (LOLH): A probabilistic measure of the amount of time that a portfolio of resources would have insufficient capability to serve loads, as measured in expected number of hours per year. See also resource adequacy, loss of load expectation, and expected unserved energy.

Loss of Load Probability (LOLP): The probability that available generating resources will be insufficient to serve load in a given period.

Low Economic Growth (LEG): A planning scenario assuming weaker-than-expected economic and load growth relative to the reference forecast.

Low-Cost Carbon-Free Energy Resources: Resources with the capability to produce clean energy to meet a majority of customers' energy needs throughout the year. Examples available today include solar PV, wind, and energy efficiency.

M

Marginal Cost: The highest system resource cost for the hour.

Markets Plus (M+): The day-ahead and real-time wholesale market service offered by the Southwest Power Pool for participants in the Western Interconnection.

Modeling, Data, and Analysis (MOD): The NERC Reliability Standards family governing transmission modeling data, transfer capability methodology, and data reporting.

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

Most Cost-Effective Portfolio (MCEP): The resource portfolio identified through the planning analysis as meeting requirements at the lowest reasonable cost and risk.

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

MV-90 Interval Data System (MV90): The interval meter data collection and translation system used to retrieve and process recorded load data.

N

Nameplate Capacity: The rated output of an electrical generator; it can also refer to the rated capacity of a power plant (also referred to as installed capacity).

National Environmental Policy Act (NEPA): The federal statute requiring environmental review of major federal actions, including permitting of transmission and generation facilities on federal land.

National Laboratory of the Rockies (NLR): A research institution referenced in the analysis as a source of technical study work.

Net Present Value: The difference between the present value of cash inflows and the present value of cash outflows.

Net Present Value of Revenue Requirements (NPV): The present value of the stream of costs that customers would pay over the study period, used to compare portfolios on a consistent basis.

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

New Mexico Administrative Code (NMAC): The compilation of adopted rules of New Mexico state agencies, including the rules of the New Mexico Public Regulation Commission.

New Mexico Public Regulation Commission (NMPRC): The state agency that reviews, accepts, and regulates PNM's IRP, rate cases, and resource applications.

New Mexico Statutes Annotated (NMSA): The official compilation of New Mexico statutory law.

New Mexico Wind Energy Center (NMWEC): A wind generating facility in eastern New Mexico from which PNM procures energy.

Non-Firm Resources: Generating resources with limitations on their ability to produce sustained, constant production of energy, including wind and solar (whose intermittency and variability limit their production) and storage and demand response (whose limited duration affects their ability to produce power for sustained periods).

Non-Spinning Reserves: The extra generating capacity that is not currently synchronized with the system but can become available after a short delay.

North American Electric Reliability Corporation (NERC): The FERC-certified Electric Reliability Organization that develops and enforces mandatory Bulk Electric System reliability standards.

North American Energy Standards Board (NAESB): The industry body that develops voluntary wholesale and retail business practice standards for the electricity and natural gas industries.

O

One Big Beautiful Bill Act (OBBBA): Federal legislation that accelerates the phase-out of clean energy tax credits established under the IRA and imposes new Foreign Entity of Concern (FEOC) restrictions.

Open Access Transmission Tariff (OATT): The FERC pro forma tariff under which PNM provides non-discriminatory transmission service to retail and wholesale customers.

Operating and Maintenance (O&M): The recurring non-fuel costs of operating, maintaining, and servicing generating and delivery facilities.

P

Palo Verde Nuclear Generating Station (PVNGS): The nuclear generating station in Arizona in which PNM holds an ownership and leasehold interest.

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

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

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

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

Phase Shifting Transformer (PST): A transformer that adjusts phase angle across a transmission path to control real power flow between parallel paths.

Photovoltaic (PV): Solar generating technology that converts sunlight directly into electricity using semiconductor cells.

Planning Period: The future period for which a utility develops its IRP. For purposes of the IRP Rule, the planning period is 20 years.

Planning Reserve Margin (PRM): A measure of the amount of capacity in a portfolio in excess of a utility's peak demand. The capacity contributions of different resource types are measured using effective load carrying capability (renewables, storage, and demand response) and unforced capacity (nuclear, coal, and gas), allowing the PRM to reflect supply needs across all hours of the year. See also resource adequacy.

Plug-In Hybrids: Hybrid automobiles whose batteries are recharged by plugging into an electric socket.

Point-to-Point Transmission Service: Delivery of power from one location to another, without branching to other locations.

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

Power Purchase Agreement (PPA): A contractual agreement between two parties (often a utility and a developer) through which the utility assumes the rights to energy and/or capacity provided by a specific generating resource.

Present Value Revenue Requirement (PVRR): A calculation of the cumulative revenue requirement over the planning horizon, discounted to the beginning of the period based on a specified discount rate, typically the utility's weighted average cost of capital.

Prewitt Escalante Generating Station (PEGS): A generating facility in western New Mexico evaluated in PNM's resource portfolios.

Pricing Advisory Committee (PRAC): The advisory group that reviews and provides input on pricing and rate design matters.

Production Cost Modeling (PCM): Chronological simulation of unit commitment and economic dispatch used to estimate production costs, emissions, and system operations.

Production Tax Credit (PTC): A federal tax credit earned per unit of electricity generated by an eligible facility over a defined period.

Protection and Control (PRC): The NERC Reliability Standards family governing protection systems, relay settings, and remedial action schemes.

Public Service Company of New Mexico (PNM): The regulated electric utility serving retail customers across New Mexico and the entity submitting this plan.

Public Utility: As defined by the IRP Rule, public utility or utility has the same meaning as in the Public Utility Act, except that it does not include a distribution cooperative utility, as defined in the Efficient Use of Energy Act.

Pumped Hydro Storage (PHS): A form of mechanical storage that stores electricity by pumping water into a reservoir and subsequently using that water to generate electricity through hydroelectric turbines. Duration varies based on site-specific parameters and hydrologic conditions but can range from short (under 8 hours) to long (100+ hours) depending on reservoir size.

Q

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

R

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

Reactive Compensation and Control System (RCCS): The reactive power compensation and voltage control equipment installed to support the Albuquerque metropolitan load center.

Real-Time Contingency Analysis (RTCA): Continuous operational analysis that evaluates system response to potential contingencies to identify reliability violations before they occur.

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

Regional Entity: One of the regional organizations with which NERC works to improve the reliability of the bulk power system. Members come from all segments of the electric industry, including investor-owned utilities, federal power agencies, rural electric cooperatives, municipal and provincial utilities, independent power producers, power marketers, and end-use customers.

Regional Haze: Visibility impairment produced by activity that emits fine particles and their precursors over a geographic area.

Regional Organization for Western Energy (ROWE): The independent regional organization formed to govern Western wholesale market services.

Regional Transmission Organization (RTO): A FERC-approved entity that operates transmission facilities and administers markets across a multi-utility region.

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

Remedial Action Scheme (RAS): An automatic protection scheme that takes predetermined corrective action following specified system conditions to maintain reliability.

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

Renewable Energy Procurement Plan (REPP): PNM annual filing at the NMPRC that discusses plans to meet the Renewable Portfolio Standard set by the NMPRC.

Renewable Energy Transmission Authority (RETA): The New Mexico state authority created to facilitate financing and development of transmission and storage projects serving renewable resources.

Renewable Portfolio Standard (RPS): Statutory targets (e.g., 50% by 2030, 80% by 2040) requiring utilities to serve a defined percentage of retail sales with renewable energy.

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

Request for Information (RFI): A process by which a utility issues a solicitation to project developers to provide information on potential new resources for the purpose of gathering market intelligence. PNM periodically issues RFIs to ensure that planning assumptions reflect the best and most current available information in the market.

Request for Proposals (RFP): A process in which a utility issues a solicitation to developers to provide competitive bids for potential resources that will be evaluated by the utility to fill a specified procurement need.

Reserve Sharing Group (RSG): A group of balancing authorities that collectively share contingency reserve obligations and support one another following resource loss.

Resilience: As defined by FERC, the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.

Resource Adequacy (RA): The ability of a portfolio of resources to supply enough generation to meet demand across the year according to a predetermined reliability standard. PNM's standard for resource adequacy is based on a loss of load expectation of 0.1 days per year. To meet this standard, PNM plans to meet a minimum planning reserve margin requirement.

Retail Sales: The sale of energy to end users.

Revenue Requirement: Total sum of annual costs for meeting the system's energy requirements with all resources. This includes costs associated with existing utility-owned resources (depreciation and taxes, operations and maintenance, and fuel costs), existing power purchase agreements and energy storage agreements, and the costs of all new future resources included in the planning horizon.

Round Trip Efficiency (RTE): The percentage of electricity retrieved from an energy storage system compared to the total energy put into it during a full charge and discharge cycle.

S

San Juan Generating Station (SJGS): The retired coal-fired generating station in northwestern New Mexico formerly operated by PNM.

Scenario: A combination of sensitivity values used to generate portfolios.

Senate Bill (SB): Proposed legislation originating in the Senate of the state legislature or Congress.

Senate Bill 170 (Utility Pre-Deployment Act) (SB 170): 2025 New Mexico legislation authorizing utilities to develop infrastructure in advance of a binding customer commitment for certified economic development projects, subject to NMPRC approval.

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

Small Modular Reactor (SMR): A factory-fabricated nuclear generating technology with modular units of substantially smaller output than conventional reactors.

Solar Photovoltaic (Solar PV): Electric generation that uses photovoltaic panels to convert sunlight directly to energy.

Southwest Power Pool (SPP): The regional transmission organization serving the central United States and the administrator of Markets Plus and the Western Energy Imbalance Service.

SouthWestern Power Group (SWPG): The developer of transmission and generation projects in the desert Southwest, including the Bowie and associated transmission projects.

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

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

Statement of Need: As defined by the IRP Rule, a description and explanation of the amount and the types of new resources, including the technical characteristics of any proposed new resources, to be procured, expressed in terms of energy or capacity, necessary to reliably meet an identified level of electricity demand in the planning horizon and to effect state policies. The Statement of Need is one of the primary outputs of the IRP process.

Static Var Compensator (SVC): A power-electronic device that rapidly supplies or absorbs reactive power to regulate transmission system voltage.

Steam Turbine (ST): A generating unit that converts thermal energy in steam into rotational energy to drive an electric generator.

Strategic Energy and Risk Valuation Model (SERVM): A probabilistic reliability and production simulation model used to evaluate resource adequacy and capacity contribution.

Supervisory Control and Data Acquisition (SCADA): The operational system that collects real-time telemetry from and issues control commands to field equipment.

Supplemental Analysis (SA): Additional analysis performed beyond the base study scope to address specific questions or stakeholder requests.

System Average Interruption Duration Index (SAIDI): A reliability metric representing the average total outage duration per served customer during a reporting period.

System Average Interruption Frequency Index (SAIFI): A reliability metric representing the average number of sustained interruptions per served customer during a reporting period.

T

Technical Assessment Guide (TAG): The EPRI reference used for generating technology cost and performance characterization.

Thermal Energy Storage: Various energy storage technologies that use electricity to heat materials or working fluids that can be stored at high temperatures and later used to transfer heat to generate electricity using a steam turbine. Thermal energy storage technologies offer potential for long-duration storage, providing duration of up to a week.

Time-of-Day (TOD): A rate structure in which the price of electricity varies by defined periods of the day to reflect differences in the cost of service.

Time-of-Use (TOU): A rate structure in which prices vary across defined on-peak, off-peak, and shoulder periods.

Total Transfer Capability (TTC): The maximum amount of power that can be reliably transferred across a defined interface under specified system conditions.

Transmission and Distribution (T&D): The facilities and systems that deliver electricity from generating resources to end-use customers.

Transmission Planning (TPL): The NERC Reliability Standards family establishing performance requirements and study obligations for transmission system planning.

Transportation Electrification Plan (TEP): The utility plan describing programs, infrastructure, and rate designs to support electrification of transportation.

Tri-State Generation and Transmission Association (TSGT): A generation and transmission cooperative serving member distribution cooperatives in New Mexico and neighboring states.

U

Unforced Capacity (UCAP): Installed capacity adjusted downward to reflect forced outage rates and expected availability.

V

Valencia Energy Facility (VEF): A gas-fired generating facility near Belen, New Mexico, from which PNM purchases capacity and energy.

Variable Costs: Costs that change with unit output. See also fixed costs.

Virtual Power Plant (VPP): An aggregation of distributed generation, storage, and flexible load dispatched collectively to provide grid services.

Voltage Source Converter (VSC): An HVDC converter technology that independently controls real and reactive power and can energize weak or passive networks.

W

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

Western Area Power Administration (WAPA): The federal power marketing administration that markets federal hydropower and owns transmission across the western United States.

Western Electricity Coordinating Council (WECC): The regional entity responsible for reliability coordination and standards enforcement across the Western Interconnection.

Western Energy Imbalance Market (WEIM): The CAISO-administered real-time market that economically dispatches participating resources across the West.

Western Energy Imbalance Service (WEIS): The SPP-administered real-time imbalance market serving participants in the Western Interconnection.

Western Power Pool (WPP): The regional organization of Western utilities that administers reserve sharing and the Western Resource Adequacy Program.

Western Resource Adequacy Program (WRAP): The voluntary regional resource adequacy program administered by the Western Power Pool establishing binding seasonal capacity obligations.

Western Transmission Consortium (TWTC): The consortium of Western utilities collaborating on interregional transmission planning and development.

Wheeling: Transportation of electric power over transmission lines.

Whole House Electric Vehicle (WHEV): A residential rate or program category addressing whole-premise service that includes electric vehicle charging load.

Wind: Electric generation fueled by wind turbines.

APPENDIX C: 2026 IRP FACILITATED STAKEHOLDER PROCESS MATERIALS

This appendix provides Gridworks meeting summary materials for PNM's 2026 IRP Facilitated Stakeholder Process.

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GRIDWORKS

PNM's 2026 Integrated Resource Plan – Stakeholder Orientation, Interests, and PNM Vision Workshop #1 (December 9, 2025), Virtual

WORKSHOP SUMMARY

Representatives from 46 organizations attended this workshop to meet the PNM IRP team, hear the PNM's perspective on planning in these times, and present stakeholders' highest-priority topics for upcoming discussions. Over 40 individuals introduced themselves and offered priority topics. The list of participating organizations (excluding PNM, its consultants, and Gridworks) is attached.

MATERIALS

- PNM Slides
- Gridworks Slides
- Workshop Recording
- Website for Stakeholder Process

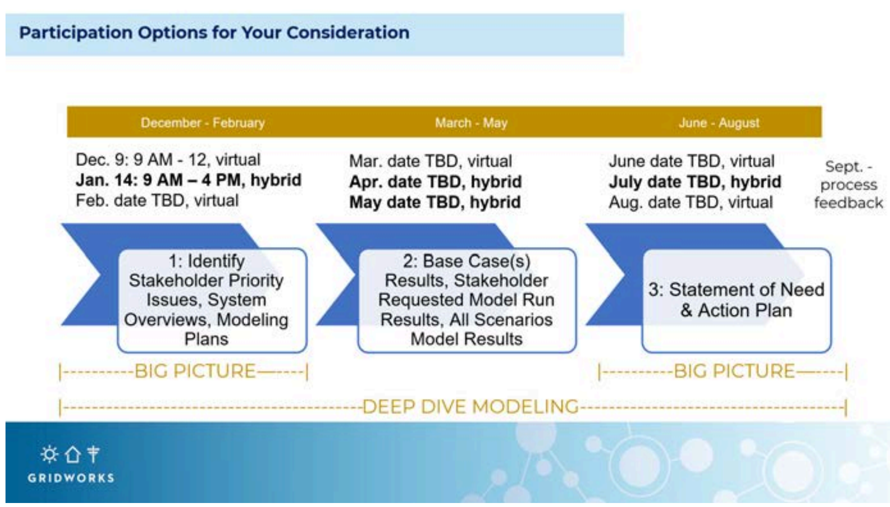
WELCOME AND INTRODUCTION

This orientation workshop, facilitated by the NM PRC-appointed facilitator, Gridworks, had the following objectives:

1. Describe stakeholder process, conceptual schedule, and options for engagement.
2. Meet the PNM IRP team and hear a PNM executive's vision/goals for 2046.
3. Hear and document stakeholders' primary topics of interest.
4. Preview the January workshop.
5. Build relationships and connections.

STAKEHOLDER ENGAGEMENT SCHEDULE AND OPTIONS FOR PARTICIPATION

A three-phase process, spanning the months of December 2025 through August 2026, offers opportunities for participating in "big picture, or" deep dive" modeling discussions or both. These phases are depicted in the figure.

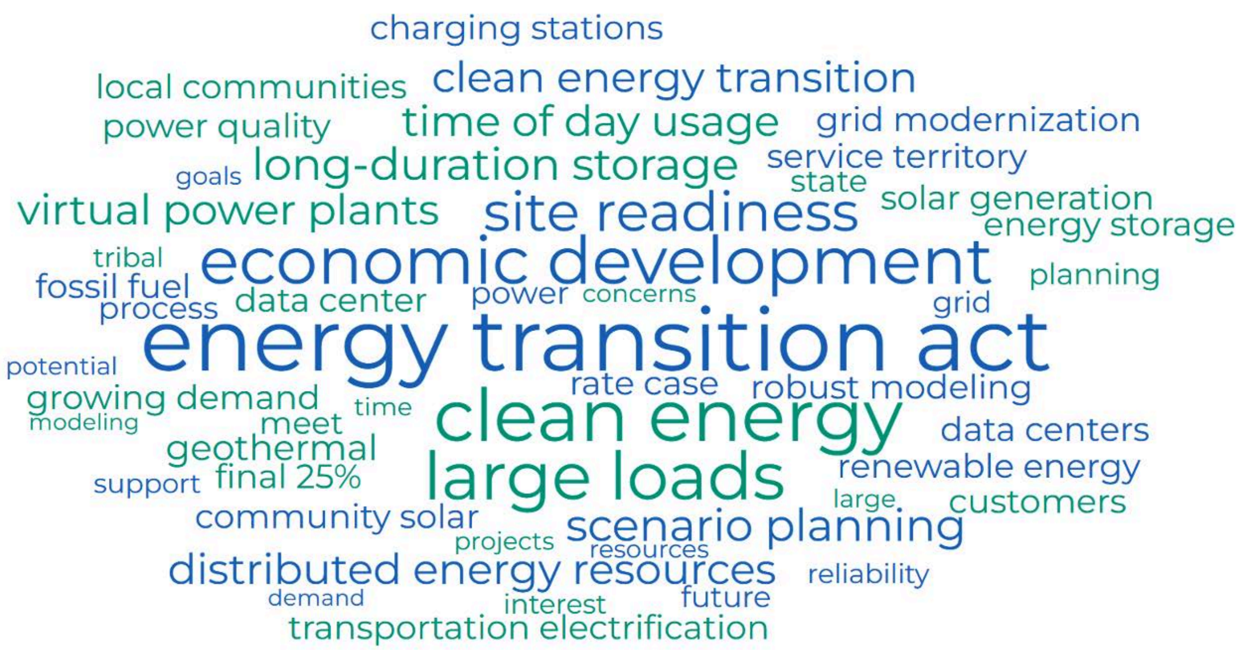


PNM TEAM AND PLANNING CONTEXT

Tom Duane (PNM's Director of Integrated Resource Planning) introduced the IRP team and supporting teams. Laurie Williams (Senior Vice President of Integrated Planning and Transmission Development) described the drivers for and benefits of moving from Integrated Resource Planning to Integrated System Planning, which PNM is moving toward in this and subsequent IRP cycles. She explained the need to balance considerations of environmental footprint, reliability, and customer cost. She summarized challenges and opportunities for the utility. Tom also provided an update on actions from the prior (2023) IRP, resource additions in process, and other pending resource and transmission filings.

STAKEHOLDER PRIORITY TOPICS

The remainder of the meeting was an opportunity for stakeholders to introduce themselves and offer a topic that is of most interest to them in this planning process. Forty individuals spoke, with interests ranging from power readiness needs to environmental progress to modeling approaches. Top interests are depicted in the "word cloud" below.



Key themes offered by the group include:

- Energy Transition Act. PNM's plans to continue the clean energy transition and do so affordably. Final 25% to decarbonization. Impacts of climate change are recognized in modeling assumptions. Grid modernization.
- Economic development. Preparation for future growth, power availability, and staying competitive. Site readiness. Power needs for expansion.

- Integration of demand side resources. Distributed energy, virtual power plants, and clean energy technologies. Modeling and valuing.
- Tribal perspectives. Restoration after wildfires, universal service/upgraded service on tribal lands, tribal energy sovereignty
- New technology options. Long-duration storage, geothermal. Modeling tools that co-optimize generation, transmission, storage, and large loads.
- Consumer and public communication. Examples include time-of-day rates and how we get our power.
- First timers. Understand what is happening, learn from the experience, ensure we are prepared for our future, and assess the impacts on my organization and me.

NEXT STEPS
A summary of this workshop is available at [Gridworks Website - PNM IRP](https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/)
(https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/)

The next workshop will be held on January 14, 2026, from 9 AM to 4 PM
- CNM Workforce Training Center, Albuquerque, and via Zoom (with limited interaction capabilities)
- **In-person attendance is highly recommended.**
- The purpose is to build a foundation of knowledge on the PNM system, opportunities, challenges, available resources, and requirements. Participants will also be asked to choose between big-picture and deep-dive modeling.

Questions, concerns, and suggestions are welcome via info@gridworks.org or by contacting Margie Tatro at mtatro@gridworks.org or 505-205-0838.

GRIDWORKS

WORKSHOP #1 PARTICIPATING ORGANIZATIONS (Excluding PNM, its consultants, and facilitators)

174 Power Global
350 New Mexico
Advanced Energy United
AES Corp
AzCPA
BP/Shell
City of Albuquerque
Clean Energy Buyers Association
Clean Energy Coalition of Santa Fe County
Coalition for Community Solar Access
Customers
Energy Strategies
Form Energy
GridLab
Hanwha Renewables
Hecate Energy
Mescalero Apache Telecom, Inc.
META
New Mexico Gas Co.
New Mexico Partnership
NextEra Energy Resources, LLC
NM Affordable Reliable Energy Alliance
NM Economic Development Department
NM RETA
NMPRC
PNE-AG
Renewable Energy Industries of NM
Sandia National Labs
Sandia Pueblo
Sandoval County Economic Development Department
Sandoval Economic Alliance
Sierra Club
Single Space Strategies
Solariant Capital, LLC
Sovereign Energy
SWEEP
Third Act NM
Village of Los Lunas, Economic Development Division
Walmart
Western Environmental Law Center
WRA

GRIDWORKS

PNM's 2026 Integrated Resource Plan
PNM System, Challenges, and Opportunities
Workshop #2 - Hybrid
January 14, 2026

WORKSHOP SUMMARY

Representatives from 59 stakeholder organizations attended this workshop to learn about or get updates on PNM's current resources, opportunities, challenges, constraints, and planning landscape. Over 96 individual stakeholders attended: 31 in person and 65 virtually. The list of participating organizations (excluding PNM, its consultants, and facilitators) is attached.

MATERIALS

- **Gridworks slide deck**
- **PNM slide deck**
- **Workshop recording (note that ZOOM "station discussions" are included, in-person "station discussions" are not):** https://youtu.be/mw3xEaPLYvM
- **Discussion Guides**
  - **Demand Forecast**
  - **Supply Resources**
  - **Behind the Meter Resources**
  - **Transmission and Market-Enabled Resources**
- **Materials shared during the day:**
  - **PNM 20-Year Transmission Outlook**
  - **DOE Pathways Report Next Generation Geothermal**
  - **Potential economic development sites sites.partnerwithPNM.com**

WELCOME AND INTRODUCTION

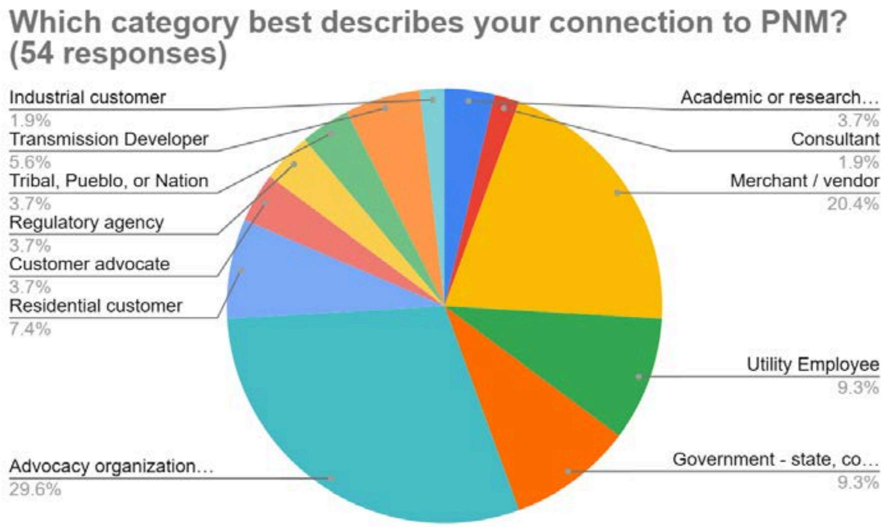
This orientation workshop, facilitated by the NM PRC-appointed facilitator, Gridworks, had the following objectives:

1. Build a foundation of shared knowledge about the PNM system, opportunities, and challenges.
2. Facilitate discussions among participants and PNM subject-matter experts on key topics.
3. Introduce a framework to orient stakeholders and introduce them to the in-depth work ahead.
4. Gather baseline information to measure the process's success.
5. Build relationships and connections, and offer appreciation for stakeholders.

All participants had the opportunity to introduce themselves and complete a survey on their knowledge of electric utility planning, primary interests, and their desire for materials in advance of future workshops. Over 50% of respondents requested materials three business days prior to future workshops. Respondents also offered suggestions of groups that should be invited to participate in this process.

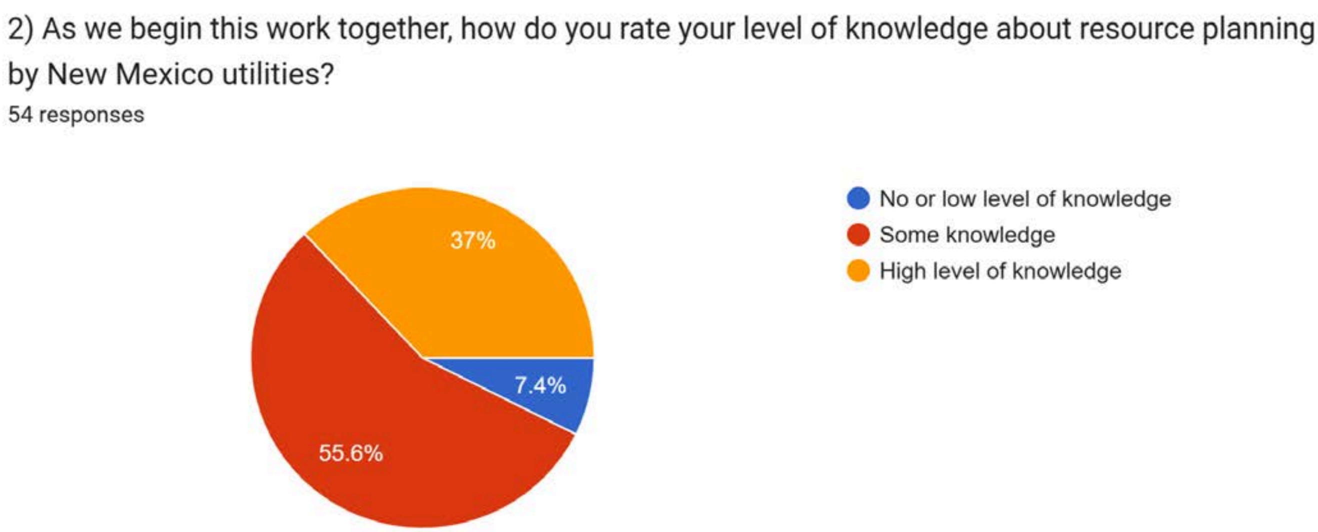
Participants were asked about their connection to PNM:

GRIDWORKS

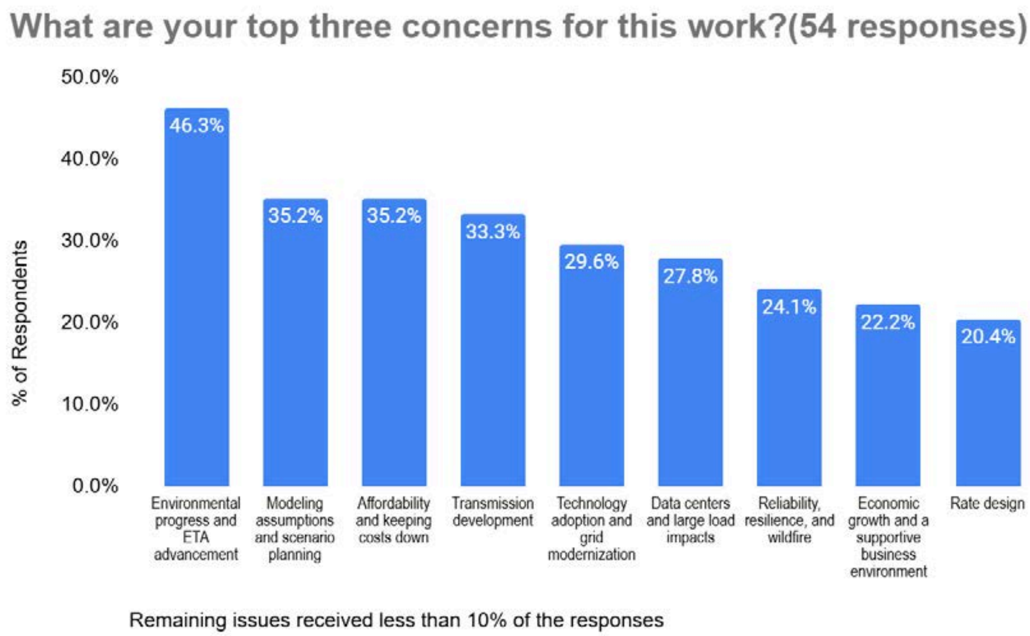


*Utility employees include 2 gas and 2 electric utility respondents.

Their level of knowledge about the resource planning process:



And their top three concerns:



IRP PURPOSE AND PNM SYSTEM OVERVIEW, REQUIREMENTS, AND MODELING FRAMEWORK

PNM staff presented information about the purpose, components, considerations, and objectives of the IRP. PNM's resource mix, pending activities, affordability drivers, planning requirements, and planning landscape were described. The PNM team presented a high-level overview of the 2026 IRP modeling framework, including envisioned futures, scenarios, and sensitivities to be analyzed. A summary of 2023 IRP stakeholder comments was included in the PNM slide deck and, due to time constraints during the day, participants are encouraged to review these slides (32-37) at their convenience. Participants' questions were offered both verbally and in writing. Questions that were not addressed during workshop #2 will guide future workshops and utility comments.

KNOWLEDGE FOUNDATION IN SUPPORT OF THE CENTRAL QUESTION

The afternoon activity included small-group discussions with PNM's subject-matter experts in four areas: demand forecasting, supply-side resources, distribution and behind-the-meter resources, and transmission- and market-enabled resources. **These topics are key to the central question for the stakeholder process: "What is PNM's resource need to meet expected demand?"** Two-page discussion guides served as the starting point for discussions, and all attendees had the opportunity to discuss all four areas. The group then reflected on the discussions and offered additional questions or topics that needed further discussion.

Discussion themes from each of the four stations are summarized below:

Demand Forecasting

- **Resources or load modifiers?:** What are the forecasted quantities of energy efficiency, customer-sited solar, batteries (including electric vehicles), and demand response projects and how do they compare with current actual values? Are these being considered as load modifiers or resources?
- **Elements of demand**: What are the contributions from electric vehicles, building electrification, energy efficiency, and demand response compared with data center growth?
- **Characteristics of demand**: ramp schedules, customer type, and impacts of severe weather are of interest to stakeholders.
- **Data center loads**: Stakeholders were interested in the quantity of data center loads included in the projected demand curve, the maturity phases of data center projects, and the threshold size of economic development projects. Alternative approaches to the High Economic Development scenario, such as Public Service Company of Colorado's incremental need pool concept or a reduced ramp rate for new loads due to "supply chain" constraints, were offered by stakeholders.

Supply-side Resources

- **Sources for cost data and affordability interests:** What information is used to inform costs for supply-side resources? Are the costs regionally specific? How are resources with high fixed costs but low/no fuel costs compared to resources with relatively lower capital costs but exposure to market fuel prices?
- **Geothermal and small modular reactor resources cost data:** Stakeholders encourage a closer look.
- **IRP and RFP connections:** How are RFP results modeled, and how are they connected to IRP model results?
- **Gas volatility and infrastructure availability:** There is interest in the upcoming gas volatility study and also in the capacity of the gas delivery infrastructure.
- **Modeling a "no ETA" scenario:** Stakeholders sought a better understanding of the purpose of such a scenario and the information it provides regarding the cost of compliance.

Distribution and Behind-the-Meter Resources

- **Resources or load modifiers?:** What are the forecasted quantities of the behind-the-meter resources, and how do they compare with current actual values? Are these being considered as load modifiers or resources?
- **Time-of-Use (TOU) assumptions:** What are the TOU assumptions and impacts on load forecasts?
- **Advanced Metering Infrastructure (AMI):** Participants are curious about data privacy and customer choice options associated with smart meters.
- **Demand response and data centers:** Will data centers join demand response programs?

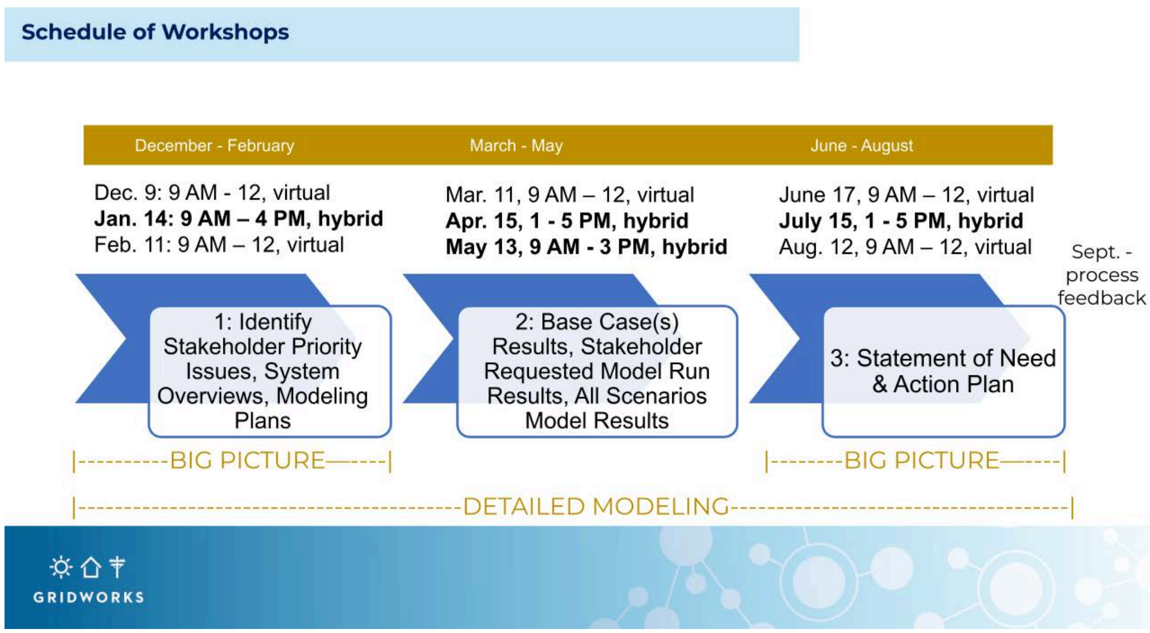
- **Load terminology:** Understanding the differences between flexible and variable loads.
- **Engaging the public:** Some stakeholders are interested in educational efforts to bring others along and explain how they can be constructive participants in the energy transition journey.

Transmission and Market-Enabled Resources

- **Retail load vs. transmission service:** PNM's transmission service ("rights" to move electricity across PNM's transmission system) is almost double its retail customer load. This creates a complexity for planning; need to account for flow-throughs and PNM's transmission service business.
- **Market developments:** PNM will enter the Extended Day Ahead Market in Oct. 2027, giving it access to a broader array of low-cost resources and sharing opportunities, as well as opportunities to sell excess solar. This will change how the transmission system is used and how it should be modeled. Not yet clear how or to what extent this can inform resource planning and the modeling of transmission as a resource.
- **Transmission in modeling:** interest in an iterative process from the nodal analysis, production cost modeling, and back to the capacity expansion analysis. Desire to see zonal transmission cost adders like in the 2023 IRP. PNM plans four transmission sensitivities (RioSol, SunZia, Blackwater DC tie, Four Corners). Also studying transmission expansion for interconnection needs.
- **Regional transmission scenario:** participants expressed strong interest in developing a regional transmission scenario for consideration in this resource plan.
- **PNM's 20yr Transmission Outlook:** takes a statewide, zonal approach to resource development and the transmission needed to enable those resources. Will inform IRP modeling.
- **Transmission to support economic development:** PNM is studying a cluster approach and developing a master plan of potential development sites for exploratory customers. See sites.partnerwithPNM.com.

STAKEHOLDER ENGAGEMENT SCHEDULE AND OPTIONS FOR PARTICIPATION

The schedule of future workshops was presented, see below. A three-phase process offers opportunities for participating in "big picture, or" detailed modeling" discussions or both. Stakeholders requested more details regarding topics for each workshop, which will be provided.



NEXT STEPS

A summary of this workshop is available at [Gridworks Website - PNM IRP](https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/)
(https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/)

Workshop #3 will be held on February 11, 2026, from 9 AM to 12 PM via ZOOM.

The focus will be on preparing for modeling. A short session will be included to address many "big picture" questions posed during workshop #2. Modeling topics will include inputs, assumptions, futures, sensitivities, nodal analysis, and model runs currently planned by PNM.

Stakeholders are asked to be prepared to discuss their specific modeling information requests using the discussion guides from workshop #2 as a starting point. The information sharing mechanism will be described during this workshop. **Stakeholder requested modeling runs will be discussed at workshop #4 on March 11.**

Questions, concerns, and suggestions are welcome via info@gridworks.org or by contacting Margie Tatro at mtatro@gridworks.org or 505-205-0838.

GRIDWORKS

WORKSHOP #2 PARTICIPATING ORGANIZATIONS (Excluding PNM, its consultants, and facilitators)

In-person Attendees

350 NM
Ameren - Lucky Corridor
AzCPA
City of Albuquerque
Customers (3)
Exus Renewables
Gould Law Firm
New Mexico Gas Company
NextEra
NM Affordable Reliable Energy Alliance
NM RETA
NM PRC
Pacific Fusion
Renewable Energy Industries of NM
Sandia National Labs
Sandia Pueblo
Southwestern Power Group
SWEEP
Third Act NM
Walmart
WRA

ZOOM Attendees

Advanced Energy United
AES Clean Energy
Allum Renewable Energy
Bernalillo County Economic Development
Boehm, Kurtz & Lowry Law
City of Albuquerque
California Independent System Operator
CDG Engineers
Clean Energy Buyers Association
City of Lordsburg Economic Development
Clean Energy Coalition for Santa Fe County
Clenera
Coalition for Clean Affordable Energy
Coalition for Community Solar Access
Customer
Energy Futures Group
esVolta
Exus Renewables
Form Energy
Grid United
Gridlab
Interwest Energy Alliance
Invenergy
Mescalero Apache Telecom, Inc.
MMR Group
New Mexico Gas Company
NM Affordable Reliable Energy Alliance
NM DOJ
NM Economic Development Department
NM RETA
NM PRC
NM State Land Office
Onward Energy
Ormat
Pattern Energy
Renewable Energy Industries of NM
Sandia National Labs
Santa Fe County Economic Development Division
Solariant Capital, LLC
Southwestern Power Group
Sovereign Energy
Tesuque Pueblo
Walmart
Western Environmental Law Center
WRA
Unknown (2)

GRIDWORKS

PNM's 2026 Integrated Resource Plan
Modeling Foundation, Workshop #3 - Virtual
February 11, 2026

WORKSHOP SUMMARY

Representatives from 48 stakeholder organizations attended this workshop to explore the modeling framework, inputs, assumptions, and plans for the PNM-initiated modeling work. PNM shared load and resource information, energy and demand forecasts, and the framework it intends to use for its resource modeling. PNM also described the process for requesting access to modeling information. Gridworks presented the themes and dates for future workshops. Over 66 individual stakeholders attended. The list of participating organizations (excluding PNM, its consultants, and facilitators) is included at the end of this document.

MATERIALS

- **Gridworks' Deck Link:** Modeling Foundation WORKSHOP #3.pptx
- **PNM Deck Link:** PNM-IRP-2026-Workshop-3-February.pdf
- **Workshop recording:** https://youtu.be/Q1ntNCX8e0w
- **Materials shared during the day:**
    - PNM-2025-Potential-Study-Report_2025-11-03-5.pdf
    - **Instructions for** Accessing-IRP-Modeling-Data.pdf
    - Stakeholder-Information-Sharing-Request-Form-2.pdf
    - PNM Confidentiality Agreement 2023 IRP Stakeholder Facilitated Process Final

WELCOME AND INTRODUCTION

This modeling foundation workshop had the following objectives:

- Share topics and timing for upcoming stakeholder conversations
- Share information on modeling inputs and assumptions, plans for running base case(s), and the process for stakeholder access to modeling information
- Prepare stakeholders to understand the results of base case model runs to be presented during workshop #4
- Begin detailed modeling conversations

ENGAGEMENT OPTIONS

After a review of the results of the participant poll from Workshop #2, and a summary of themes for future workshops, participants had the opportunity to indicate whether they wished to engage in detailed modeling discussions or take a step back during modeling, then re-engage in the June-August timeframe for work on the statement of need and action plan.

Future Workshops Topics

March - May	June - August
Mar. 11, 9 AM – 12, virtual	**June 17, 9 AM – 3 PM, hybrid**
Apr. 15, 1 - 5 PM, hybrid	**July 15, 1 - 5 PM, hybrid**
May 13, 9 AM - 12, virtual	Aug. 12, 9 AM – 12, virtual

- March 11, WK#4: Base case model results and initial discussion regarding stakeholder-requested model runs
- April 15, WK#5: PNM scenarios model results. Agreement on stakeholder-requested modeling runs.
- May 13, WK#6: Utility shares results of stakeholder requested runs
- June 17, WK#7: Utility decision on the most cost-effective resource portfolio and PNM presentation of draft statement of need and action plan
- July 15, WK#8: Complete statement of need and action plan
- August 12, WK#9: Review key IRP elements, including any unresolved issues

MODELING FOUNDATION: INPUTS, ASSUMPTIONS, AND MODELING FRAMEWORK

PNM staff presented information about the loads and resources tables, demand forecasts for both energy and capacity, the modeling framework, including planned model runs, and a summary of energy efficiency and demand response options. Main themes of discussions are listed below:

PNM's resource position

- PNM's system is generally adequate through 2035, although the margin varies depending on whether economic growth is high or low.
- RPS compliance: 40%, increasing to 50% by 2030.
- Energy long, causing curtailments of renewable generation. Capacity short.
- Any new gas CTs will include the cost of hydrogen burn conversion.
- Behind-the-meter solar is treated as a load modifier.

Action plan and planning period

- Action plan: 2026-2029
- Planning period: 2026-2045
- This IRP is to develop the resources for 2032 and beyond. An action plan for a 3-yr period is not enough runway to account for supply chain difficulties, permitting issues, and the lead time needed to bring new large-scale resources online.

Three potential futures PNM will use to frame modeling

- Current Trends and Policies (CTP)
- Low economic growth (LEG)

- High economic growth (HEG)

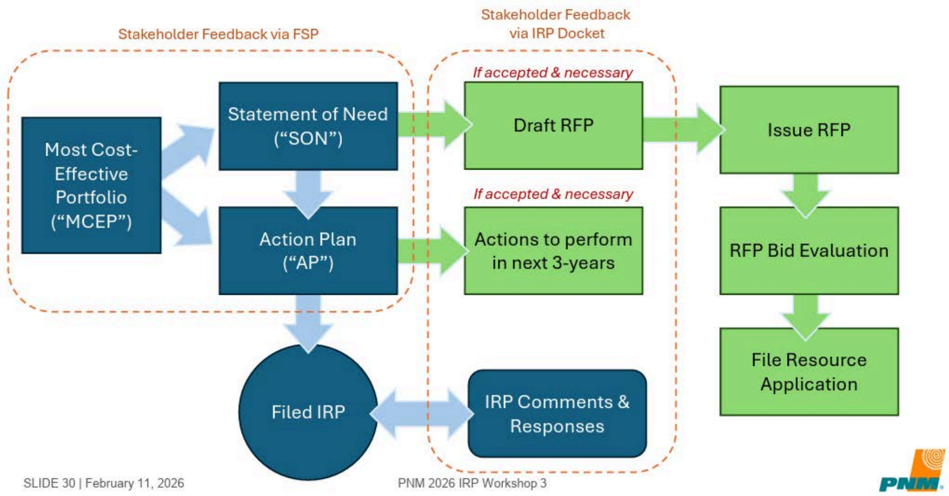
Supplemental RFP for firm dispatchable generation, expected in the next few weeks

- NM PRC Case #23-00409-UT
- Material event filed in January 2026.

Smart meter rollout (AMI) and Time-of-Day (TOD) rate

- Small pilot in the field now. Full rollout expected by 2028; first year of data by 2029.
- Concerns about privacy issues; communication to the general public about time-of-use. rates and behavioral change. Add this as input to the action plan?
- PNM is working on a TOD rate structure; a future filing will be made at the PRC.

Interaction between this resource plan (IRP) and a future solicitation (RFP)



Renewable Portfolio Standard / Energy Transition Act / Carbon-free corporate goal

- PNM is working to balance carbon-free requirements with its corporate 2040 goal while addressing affordability concerns. High curtailment rates for renewable energy and concerns about additional capital expenditures.
- No ETA scenario is in response to requests from consumer advocates and affordability concerns.

MODELING INFORMATION

The PNM team described the process for requesting access to modeling information and presented a list of information to be posted on the shared site, VENUE. Instructions for accessing modeling information are provided in the following document: **Accessing-IRP-Modeling-Data.pdf**. Individuals are invited to complete the forms and email them to IRP@PNM.com:

- **Stakeholder-Information-Sharing-Request-Form-2.pdf**
- **PNM Confidentiality Agreement 2023 IRP Stakeholder Facilitated Process Final**

Questions about information or the access process can be sent to IRP@PNM.com. The files on Venue will be available to all who request access from PNM, subject to confidentiality restrictions.

NEXT STEPS

Stakeholders requested the following information:

- Provide ELCC data by resource type
- Input and output files from SERVM, access to virtual software?
- Provide the load profile data from PNM's EV charging program
- Energy and capacity projections, 2025-2046, stacked bar chart by components
- Share the work papers for the EE bundles
- Provide the probabilistic model for new loads
- Discussion about enhanced geothermal cost assumptions

A summary of this workshop is available at [Gridworks Website - PNM IRP](https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/) (https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/)

Workshop #4 will be held on March 11, 2026, from 9 AM to 12 PM Mountain Time via Webex. Results from the base case model and initial discussion of stakeholder-requested model runs will be presented.

Questions, concerns, and suggestions are welcome via info@gridworks.org or by contacting Margie Tatro at mtatro@gridworks.org or 505-205-0838.

WORKSHOP #3 PARTICIPATING ORGANIZATIONS (Excluding PNM, its consultants, and facilitators)

Advanced Energy United
Black Forest Partners
CDG Engineers
CEBA
Citizens for Alternatives to Radioactive Dumping
Clean Energy Coalition of Santa Fe County
Clenera
Coalition for Clean Affordable Energy
Customers (3)
El Paso Electric
Energy Futures Group
Exus Renewables
Form Energy
Geothermal Scientist
Goschke Energy Advisors
Gould Law Firm
Grid United
GridLab
Hecate Energy
Senator Heinrich's Office
IEEE
Interwest Energy Alliance

Invenergy
Jupiter Power
Kinetic Power, LLC
New Mexico Gas Co
NextEra Energy Resources, LLC
NM Affordable Reliable Energy Alliance
NM Economic Development Department
NM EMNRD
NM PRC
NM RETA
NM State Land Office
OE Solar
Pacific Fusion
Sandia National Labs
Sandia Pueblo
Santa Ana Pueblo
Single Space Strategies
Sovereign Energy
SWEEP
Third Act NM
Walmart
Western Resource Advocates
US Department of Energy
Unidentified (1)

GRIDWORKS

PNM's 2026 Integrated Resource Plan
Modeling Foundation, Workshop #4 - Virtual
March 11, 2026

WORKSHOP SUMMARY

Representatives from 40 stakeholder organizations attended this workshop to receive an update on modeling activities and begin sharing stakeholders' interests in model runs to supplement PNM's runs. Base-case model results were not available due to some modeling issues; Gridworks will notify the stakeholders when they are posted on the shared file site (Venue). PNM updated participants on the list of available modeling information on the VENUE site. PNM discussed the framework for requesting additional modeling, and stakeholders suggested six initial topics of modeling interest.

Fifty-three individual stakeholders attended. The list of participating organizations (excluding PNM, its consultants, and facilitators) is included at the end of this document.

MATERIALS

- **Gridworks' Deck:** **Gridworks Slide Deck**
- **PNM Slide Deck:** **PNM Slide Deck**
- **Workshop recording:** **https://youtu.be/j9hNUTVdr6w**

WELCOME AND INTRODUCTION

This workshop had the following objectives:

- Update participants on activities since Workshop #3
- Inform participants about the status of modeling activities
- Share stakeholders' model run interests
- Understand the process for proposing stakeholder ideas for additional model runs

ACTIVITIES SINCE WORKSHOP #3

Three "office hour" sessions were held over the past month. Session summaries and key outcomes are shown below. Recordings of each are available at
https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/

Transmission Office Hour Feb. 17, 2026	47 attendees	• Transmission questions answered • GETs white paper and PNM 20-Yr Transmission Outlook shared
Geothermal Office Hour March 4, 2026	50 attendees	• Add hydrothermal as a resource option • Geothermal cost and timing sensitivity • Identification of best locations
Follow Up Office Hours March 11, 2026	30 attendees	• Discussion of written responses to 25 questions, also posted • Dialogue to reach clarity on outstanding questions

During the March 4 Geothermal Office Hour, stakeholders proposed consideration of RFP bid language to accommodate enhanced geothermal resources. PNM directs interested stakeholders to the RFP process that will follow this IRP to further that work.

Next, PNM responded to previous questions and allowed time for additional stakeholder questions and clarifications. PNM provided the following guidance about modeling software access and data files:

EnCompass can be made available with some limitations:

- Organizations will need to select a single individual for access.
- PNM computer access agreement and procedures will need to be completed and followed.
- Ability to use the software or work with the data structure requires experience. PNM will not be providing training or support.
- Parties requesting access will need to contact PNM at irp@pnm.com along with a phone number for PNM to discuss.

EnCompass and SERVM data files can be made available on Venue site.

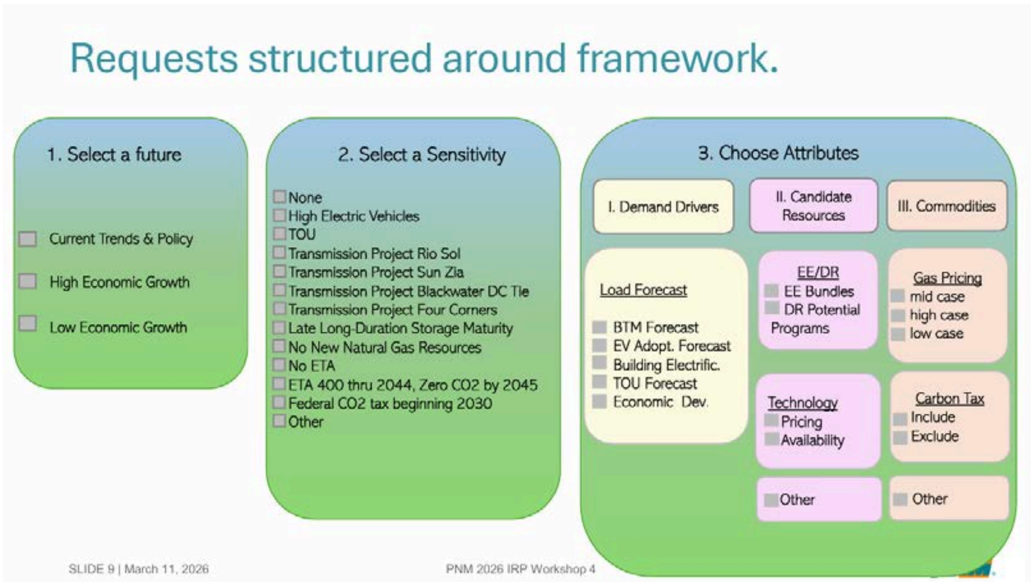
- EnCompass database and output summaries in Excel format will be placed on the confidential VENUE site.
- SERVM data files can be made available in csv format. An executable version can be obtained from PowerGem if a stakeholder licenses SERVM.

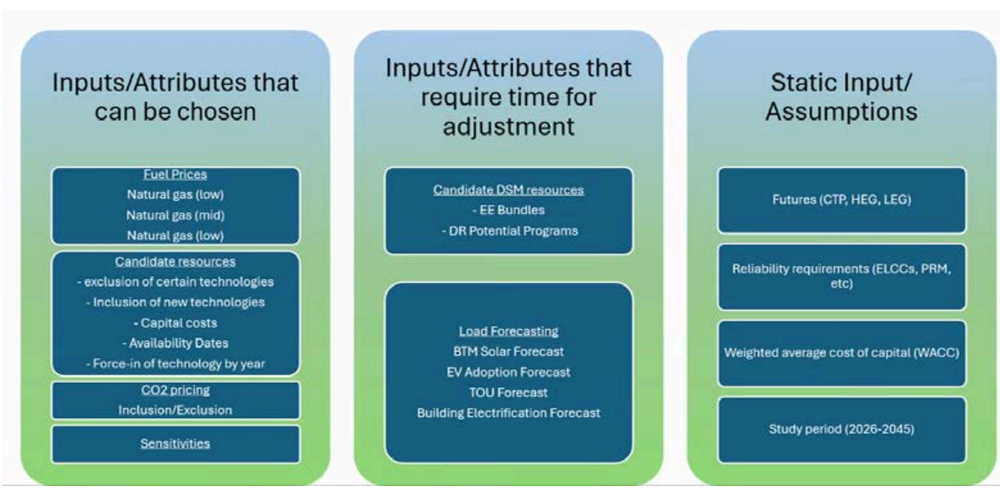
New questions during this workshop centered around the following themes:

- **Hydrogen:** cost assumptions, conversion cost, green fuel availability, and changes in federal funding. PNM agreed to add hydrothermal as a resource option.
- **Modeling inputs:** load growth projections, natural gas price forecast, import tariff and resource costs, and resource adequacy assumptions
- **Policy alignment and the Energy Transition Act:** PNM's 100% carbon-free goal by 2045, state requirements under the ETA, and the no ETA sensitivity
- **Data centers and large loads:** infrastructure needs, stranded costs, and PNM's large load tariff expected later this year
- **Process and timeline:** date for base case results and deadline for stakeholder requests on modeling runs

PNM informed the group that base-case model results are not ready due to modeling issues, but will be shared with stakeholders as soon as they are available via the VENUE site and during Workshop #5 (April 15).

PNM reviewed the framework for stakeholder model run requests and provided the guidance below:





STAKEHOLDER MODELING RUN INTERESTS

PNM consultant Ben Elsey (E3) led a discussion on stakeholder ideas for additional modeling runs. Discussions centered on two key questions:

1. What is at the core of stakeholders' modeling run interests?
2. Which runs will yield new insights to inform the statement of need?

See below for a summary of the discussion, including the names of stakeholders interested in further definition and the objectives of each topic. Stakeholders with an interest in the listed topics are invited to email mtatro@gridworks.org to be added to the informal "working groups" for each topic. Gridworks will contact these working groups to encourage conversations in advance of the April 15 workshop.

Residential DER

- Higher DER penetration - accelerated timing, higher quantity
- Higher battery attachment rates (50%)
- Higher solar growth (40% BTM addition)
- EV adoption rates, V2G, managed charging program
- Building electrification
- Included as a candidate resource in modeling - selected when economic
- Model a range of capacity amounts (supply curve)
- Cost assumptions-see Venue files
- TOU rates
- C&I DER target

Brian Turner, Glenn Wikle, Brad Heusinkveld, Ramon Alatorre, Alex Eubanks, Anna Sommer, Jaime McGovern, Randy Coleman, Barbara Chatterjee

Energy Transition Act 2045 Achievement

- 100% carbon free, 2045
- 10-20% clean firm (geothermal) + 80-90% mix of wind, solar, battery backup
- No new nuclear; some imports from Palo Verde
- Reasonable proxy: no new natural gas + carbon tax?
- No hydrogen, no carbon capture
- FT rates for future gas units

Tom Solomon, Anna Sommer, AnnaLinden Weller, Jaime McGovern

Geothermal

- Model resource expansion as a generic resource?
- Reduced capex costs, both hydrothermal and geothermal
- Long duration storage-pumped storage
- Replace some of the six existing PNM gas combustion plants with geothermal plants of the same or larger capacity at the same location using the existing grid connection.

Tom Solomon, Glenn Wikle, Daren Zigich, Anna Sommer, Jaime McGovern

Transmission Connectivity

- PNM plans: 4 line scenarios
- Lightning Dock line upgrade?
- Southline expansion
- Regional transmission scenario: multiple lines

AnnaLinden Weller, Tom Solomon, Jacob Richardson, Remy Franklin, Kelly Gould, Anna Sommer, Jaime McGovern

Large Loads/Long Duration Storage

- Large load customer subsidizes capex for long duration storage or other tech (lower resource cost in the modeling)
- How does an LDES resource impact capacity expansion?

Daren Zigich, Cara Lynch, AnnaLinden Weller, Brian Andrews, Glenn Wikle, Patrick Goschke, Anna Sommer, Jaime McGovern, Kelly Gould, Brad Heusinkveld, Randy Coleman

Gas Availability

- No gas availability in winter - SERVM resource adequacy

Anna Sommer, Jaime McGovern

GRIDWORKS

NEXT STEPS

- **If stakeholders have additional questions:** submit by email to IRP@pnm.com and info@gridworks.org by this Fri., 3/13, 5 PM. Written responses will be posted on the Gridworks website by Fri., 3/20, 9 AM. Gridworks will also notify stakeholders of this posting via email.
- **For further dialogue,** the team will be hosting an additional office hour on Wednesday, Mar. 25, 1:30-2:30 pm MDT via WebEx. The discussion will begin with written questions submitted by 3/13.
- **Next workshop:** Wed., April 15, 9 am-3 pm MDT, CNM Workforce Training Center, Albuquerque (5600 Eagle Rock Ave NE, Albuquerque, NM 87113). In-person attendance is strongly recommended, though a Webex link will also be available. This is a time change from the previously announced schedule. The morning session will focus on model results, and the afternoon will aim to reach agreement on stakeholder-requested modeling runs.
- **Follow-up items for PNM:**
    - Touch base with PowerGem to release SERVM files
    - Check with consultants regarding hydrogen cost assumptions. Does it account for federal changes to hydrogen funding?
    - Large load treatment in SERVM, subject to weather risk assumptions?
    - Notify Gridworks when base case results are loaded in Venue so that stakeholders can be informed
    - Clarify the Siemens gas price volatility study vis-à-vis the commodity costs in the shared files
    - Elaborate on the criteria PNM will use to evaluate portfolios: most cost-effective, risk, and reliability tradeoffs
    - Future model iterations combining scenarios to explore synergies

Questions, concerns, and suggestions are welcome via info@gridworks.org or by contacting Margie Tatro at mtatro@gridworks.org or 505-205-0838.

GRIDWORKS

WORKSHOP #4 PARTICIPATING ORGANIZATIONS (Excluding PNM, its consultants, and facilitators)

350 New Mexico
Advanced Energy United
AES Clean Energy
Black Forest Partners
CDG Engineers
Clean Energy Buyers Association (CEBA)
Clean Energy Coalition of Santa Fe County
Coalition for Clean Affordable Energy
Customers (2)
Deutsch Domestic Water Company, Inc
EDD
Energy Futures Group
esVolta
Geothermal Scientist/h4ngi Energy
Goschke Energy Advisors
Grid United
Gridlab
Hecate Energy
Senator Heinrich's Office
Invenergy
Jupiter Power
Kinetic Power, LLC
New Mexico Gas Co.
NM Affordable Reliable Energy Alliance
NM PRC
NM RETA
Pacific Fusion
Pattern Energy
Sandia National Labs
Sandoval Economic Alliance
Senate Energy and Natural Resources Committee
Single Space Strategies
SWEEP
Third Act NM
Tierra Adentro Growth Capital (TAGC)
Vote Solar
Walmart
WRA
Xcel Energy

GRIDWORKS

PNM's 2026 Integrated Resource Plan
Base Case Results and Refining Stakeholder-Requested Model Runs
Workshop #5 – Albuquerque and Webex
April 15, 2026

WORKSHOP SUMMARY

Representatives from 36 stakeholder organizations attended this workshop to discuss results from PNM's base case modeling efforts and to develop stakeholder modeling run requests. The PNM IRP team presented model results for three futures – Current Trends and Policies (CTP), Low Economic Growth (LEG), and High Economic Growth (HEG)- and a variety of sensitivities for each future. Participants offered ideas for additional model runs, and several stakeholders volunteered to develop specific requests.

Over 61 individual stakeholders attended, with 24 in person. The list of participating organizations (excluding PNM, its consultants, and facilitators) is included at the end of this document.

MATERIALS

- **Gridworks' Deck Link:** Gridworks slide deck
- **PNM Slide Deck:** PNM slide deck
- **PNM Data on TOU, EVs, and TOU:** Supplemental Data: Economic Growth, EV and TOU
- **Workshop recording:** https://youtu.be/MuYniHCaGa8
- **GridLab report:** https://gridlab.org/datacenter_flex/
- **Geothermal siting presentation:** Geothermal Sites for IRP v1 14-Apr-26 (1)
- 2026 Integrated Resource Plan Stakeholder Scenario Request Form – Fill out form

WELCOME AND INTRODUCTION

This workshop had the following objectives:

- Understand base case model results
- Identify, develop, and refine stakeholders' model run requests that complement utility modeling efforts
- Gather suggested improvements to the stakeholder engagement process (mid-point feedback)

The stakeholder engagement process has included 5 workshops and 5 additional office hour sessions to date. Four workshops remain. Stakeholders were invited to reply to a 3-question mid-process feedback survey. The survey is available via the QR code at the right or https://forms.gle/acRG2Em1HCEUojGV9.

Activities since Workshop #4 included the opportunity for written questions (3/13/2026), the March 25 Office Hour to address questions arising after workshop #4, the formation of 6 modeling request working groups, and the posting of model results in presentation format (PNM slide deck) and on VENUE (4/8/2026).

BASE CASE MODEL RESULTS
The PNM IRP team presented model results for three futures – Current Trends and Policies (CTP), Low Economic Growth (LEG), and High Economic Growth (HEG) – and a variety of sensitivities for each future. Themes of stakeholder questions regarding the model results included the following:

- Achieving the Energy Transition Act (ETA) requirements, particularly for 2040 and 2045
- Relationship between the current RFP activity and IRP modeling
- Clarification of the action plan period versus the modeling focus period
- Understanding assumptions of the High Economic Growth future and review of the EV and TOU components in the demand forecasts (see supplemental data posted following the workshop: Supplemental Data: Economic Growth, EV and TOU)
- TOU rates, relationships with rooftop solar resources, and communication with the public
- Long-duration storage and geothermal resource potential (see information provided regarding Geothermal Sites for IRP v1 14-Apr-26 (1))
- Transmission implications for new generation resources

Understanding of model results is key to the formulation of stakeholder modeling run requests. The afternoon session of the workshop focused on these requests.

STAKEHOLDER MODELING RUN INTERESTS
The PNM team explained the model run request form using an example of modifying the HEG future parameters to include greater customer-sited PV penetration.

Attendees discussed five model run request topics identified as a priority during Workshop #4, plus a new idea on fusion as a candidate resource. (The topic of transmission connectivity will be discussed during the April 20 Office Hour, scheduled for 2:30-3:30 PM MDT via Webex.) Representatives from working groups, formed after Workshop #4, provided updates and shared their objectives for each request, and individuals offered to lead the development of the requests. PNM and its consultant, Ben Elsey, are available to assist stakeholders with refining these requests.

The six model run ideas discussed, along with the names of individual stakeholders who offered to submit the model run request form for each, are listed below:

- **Flexible large load interconnection**. Nikhil Kumar (lead), Gwen Farnsworth, Orland Whitney
    - Requirements for large loads to curtail during peak hours; impact on resource needs.
- **Decarbonization**. AnnaLinden Weller (lead)
    - Interim steps to meet 2040 and 2045 ETA requirements, to demonstrate continuous improvement toward ETA endpoints
- **Distributed Energy Resources (DER), Demand Response (DR), Time-of-Use rates (TOU)**. Alex Eubanks (lead), Ramon Alatorre, Brian Turner
    - 3 scenarios plus perhaps a combination scenario: 1) Virtual power plant as a resource, 2) rooftop top solar + managed EV charging + high battery adoption + 44 MW demand

response continued through the planning period, 3) higher behind-the-meter solar adoption in the high growth scenario
- **Geothermal** - lower cost assumptions, full valuation of geothermal benefits. Tom Solomon (lead)
- **ETA without hydrogen or carbon capture sequestration**. Nikhil Kumar and possibly Anna Sommer (leads), Gwen Farnsworth/AnnaLinden Weller, Tom Solomon
    - Either: 1) fully loaded costs added to new gas assets: costs for hydrogen conversion + hydrogen infrastructure + stranded asset risk OR 2) no hydrogen or carbon capture sequestration option in the capacity expansion model
    - Alternative scenario: no new gas allowed in the model for any of the years, including the near-term years of 2029-2032.
- **Fusion** - cost estimates and timing assumptions. Doug Perkins (lead)

SUMMARY AND NEXT STEPS

This summary, the recording, and all other workshop materials are available at the [Gridworks Website - PNM IRP](https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/) (https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/).

Model Run Requests, even if not fully completed, are due by April 24 at 5 PM MDT via the following form: 2026 Integrated Resource Plan Stakeholder Scenario Request Form – Fill out form. The PNM team will review all ideas submitted by April 24 and will contact requestors between April 24 and May 6 if clarifications or refinements are needed. Stakeholders who would like assistance in filling out the form are encouraged to contact IRP@PNM.com as soon as possible.

Upcoming Workshops and topics are shown below.

Workshop #6, May 13, 9 AM - 12 PM MDT, via Webex PNM will share the list of stakeholder-requested model runs and present any model results to date.
Workshop #7, June 17, 9 AM - 3 PM MDT, as a **hybrid workshop**. In-person attendance is highly recommended, as virtual attendees may have difficulty fully participating. The PNM team will discuss decisions regarding the most cost-effective resource portfolio. All participants will begin conversations regarding the statement of need and action plan.
Workshop #8, July 15, 1 - 5 PM MDT, as a **hybrid workshop**. In-person attendance is highly recommended, as virtual attendees may have difficulty fully participating. Obtain final input from stakeholders regarding the statement of need and action plan.
Workshop #9, August 12, 9 AM - 12 PM MDT, via Webex. Attendees will review final IRP elements, including any unresolved issues.

GRIDWORKS

WORKSHOP #5 PARTICIPATING ORGANIZATIONS (Excluding PNM, its consultants, and facilitators)

350 New Mexico
Advanced Energy United
AES Clean Energy
Ameren – Lucky Corridor
Clean Energy Buyers Association
Clean Energy Coalition of Santa Fe County
Clenera
Coalition for Clean Affordable Energy
Customer (3)
EMNRD
esVolta
Exus Renewables
Form Energy
Gould Law Firm
GridLab
Interwest
New Mexico Gas Co.
NM Affordable Reliable Energy Alliance
NM PRC
NM RETA
Onward Energy
Pacific Fusion
Pattern Energy
Rio Rancho Chamber of Commerce
Sandia National Labs
Senate Energy and Natural Resources Committee
Single Space Strategies
SWEEP
Third Act NM
Tierra Adentro Growth Capital (TAGC)
Vote Solar
Western Environmental Law Center
WRA
Xcel Energy

GRIDWORKS

PNM's 2026 Integrated Resource Plan
Model Results and Implications
Workshop #6 Summary (Corrected 5/19/2026)
May 13, 2026

WORKSHOP SUMMARY

Representatives from 31 stakeholder organizations attended this workshop to discuss PNM's updated base-case modeling efforts and the results of stakeholder-requested model runs. The PNM IRP team presented updated model results, including some modifications to the assumptions presented at the prior workshop.

Over 42 individual stakeholders attended the workshop. The list of participating organizations (excluding PNM, its consultants, and facilitators) is included at the end of this document.

MATERIALS

- **Gridworks' Deck Link:** Gridworks Slide Deck
- **PNM Slide Deck:** PNM-IRP-2026-Workshop-6-2.pdf
- **Background Reading:** Background Reading, SoN and AP
- **Workshop recording:** https://youtu.be/o8w2B2hBTZw

WELCOME AND INTRODUCTION

This workshop had the following objectives:

- Present model results since the prior workshop and discuss possible implications
- Review stakeholder model run requests and results to date
- Prepare stakeholders for Statement of Need and Action Plan conversations

UPDATED BASE CASE MODEL RESULTS

The PNM IRP team presented model results reflecting updates to assumptions since the prior workshop. Updates to the modeling framework and operating parameters included:

- Incorporated transmission cost adders in zonal analysis based on the discussion during the April 20 office hour session.
- Applied end of study period (years 2041-2044) thermal fleet firm-capacity decline to Afton, Luna, Rio Bravo, and Reeves facilities
- Increased the generic solar PV annual capacity factor from 27% to 32% and applied capacity degradation to approved resources for a data center customer
- Revised book life and updated outage rate for pumped hydro, 4hr storage, 8hr storage, and compressed air storage resources
- Corrected extension of existing gas unit operation in "No ETA" scenarios

These updates resulted in no changes to the key trends presented during the prior workshop.
The PNM IRP team also presented results of two sensitivities in the Current Trends and Policies Future. The sensitivities were a low-high gas sensitivity and an extremely high economic development sensitivity.

Both stakeholders and the utility team commented on the productive nature of the dialogue and constructive suggestions offered during the modeling efforts to date.

STAKEHOLDER MODELING RUN REQUESTS - RESULTS TO DATE

The PNM IRP team summarized the stakeholder-requested model run requests. See below.

The PNM team presented the results from 10 stakeholder-requested model runs and described the remaining 4 requests, which are still being finalized.

Stakeholders requested information on these topics:

- Updated model results posted to the Venue site. Note: this was completed on May 13 via the confidential Venue folders.
- ~~PNM's report to the NM PRC regarding the Time of Day (TOD) pilot program. See Heidi Pitt's testimony and attachments PNM Grid Modernization Filing (TOD Pilot) in PNM's Second Annual Grid Modernization Filing, docket number 26-0000069 (pp. 291-426). Exhibit HMP-2 summarizes the Customer Satisfaction Survey report, and Exhibit HMP-4 details the load shifting impact report.~~
- PNM's report to the NM PRC regarding the Time-of-Day (TOD) pilot rates. In PNM's Second Annual Grid Modernization Review Filing, PNM Grid Modernization Filing (TOD Pilot), the current state of the TOD pilot is provided in the Direct Testimony of Heidi Pitts. Topics discussed include customer enrollment, bill guarantee results, energy usage reports and dashboard, and the Roadmap to Default TOD rates. Exhibit HMP-4 is the 2025 load shifting impact report.
- Capacity factor assumptions used for the geothermal-related stakeholder model runs: available via the Venue files, "2026 Facilitated Stakeholder Process >> 1 - Public Modeling data >> 1.1 Generic Resources. Note: PNM is modeling 69% capacity factor for hydrothermal (based on Lightning Dock) and 86% capacity factor for enhanced geothermal (based on a developer's estimates).

The following analyses are pending and will be presented as results become available, either in an office hour session before Workshop #7 or during the next workshop. Pending analyses:

1. Reliability analysis (LOLE of CTP, HEG, others)
2. Remaining stakeholder scenarios
3. Customer impacts for CTP, HEG, LEG
4. Qualitative analysis
5. Determination of Most Cost-Effective Portfolio (MCEP)
6. Draft Statement of Need (SON)
7. Draft Action Plan (AP)

Gridworks described the statement of need and action plan. Further details and links to recent examples from the three NM investor-owned utilities are available here: Background Reading, SoN and AP

STAKEHOLDER QUESTIONS

Gridworks facilitated stakeholder questions at appropriate points throughout PNM's presentations. Most questions focused on clarifying results and improving understanding of key takeaways. Importantly, PNM emphasized that the modeling remains conceptual and is based on generic assumptions. PNM reiterated that the competitive procurement process is the critical phase where decisions regarding specific technologies and projects will ultimately be made.

One outstanding issue for further discussion is how PNM will determine the **most cost-effective portfolio**. Stakeholders asked how this evaluation would be conducted, and PNM acknowledged that defining this approach is a next step in its analysis.

SUMMARY AND NEXT STEPS

This summary, the recording, and all other workshop materials are available at the Gridworks Website - PNM IRP (https://gridworks.org/initiatives/pnm-2026-integrated-resource-plan/).

Upcoming workshops and topics are shown below.

Workshop #7 June 17, 9 AM-3 PM hybrid*	Utility decisions based on modeling results; outline of statement of need and action plan. **LOCATION: CNM Montoya Campus (4700 Morris St. NE, Montgomery and Juan Tabo)**
Workshop #8 July 15, 1-5 PM hybrid*	Complete statement of need and action plan
Workshop #9 Aug. 12, 9 AM-12 virtual	Review key IRP elements, including any unresolved issues

Feedback on Stakeholder Process September	Survey and opportunity for direct feedback are forthcoming. Your input is critical to Gridworks and the NM PRC

*Hybrid Workshop: in-person attendance is strongly advised. Webex links will be available, but may not provide the same participation options as provided to in-person participants.

WORKSHOP #6 PARTICIPATING ORGANIZATIONS (Excluding PNM, its consultants, and facilitators)

350 New Mexico
AES Clean Energy
Bernalillo County Economic Development
Clean Energy Coalition of Santa Fe County
Clenera
Coalition for Clean Affordable Energy
Customer
Deutsch Domestic Water Company, Inc
Energy Futures Group
esVolta
Exus Renewables
Form Energy
Gridlab
Hecate Energy
Interwest Energy Alliance
Jupiter Power
Linea Energy
Navajo Transitional Energy Company (NTEC)
New Mexico Gas Co.
NM Affordable Reliable Energy Alliance
NM EMNRD
NM PRC
NM RETA
Pacific Fusion
Pattern Energy
Sandia National Labs
Single Space Strategies
SWEEP
Third Act NM
Vote Solar
WRA

GRIDWORKS

PNM's 2026 Integrated Resource Plan
Utility Decisions, Statement of Need, and Action Plan
Workshop #7 Summary

WORKSHOP SUMMARY

Representatives from 34 stakeholder organizations attended this workshop to review all modeling efforts completed to date and provide input to PNM on the draft Statement of Need and Action Plan. Over 48 individual stakeholders attended the workshop, 14 of whom attended in person. The list of participating organizations (excluding PNM, its consultants, and facilitators) is included at the end of this document.

MATERIALS

- Gridworks Slide Deck
- PNM Slide Deck
- 2026 PNM IRP Reliability Results - Powergem
- Key Takeaways (E3 Slide Deck)
- PNM Slide Deck - Draft SoN and Action Plan
- 2026 IRP Draft Action Plan
- 2026 IRP Draft Statement of Need
- **Workshop recording:** httpshttps://gridworks.org/wp-content/uploads/2026/06/2026-IRP-Draft-Action-Plan-V1-3.docx://youtu.be/HQS2AlDH334

WELCOME AND INTRODUCTION

This workshop had the following objectives:

- Return to "BIG PICTURE" discussions;
- Present a recap of modeling activities and present SERVM reliability analyses;
- Discuss key takeaways, portfolio direction based on future outcomes, and implications for the statement of need; and
- Review the draft Statement of Need and Action Plan, gather stakeholder feedback, and announce the process for submitting redline edits.

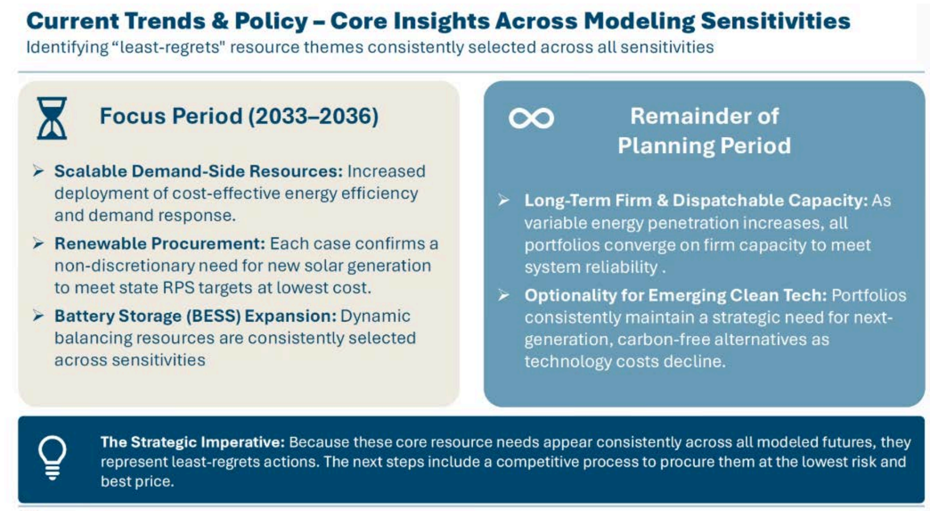
RECAP OF MODELING ACTIVITIES

The PNM team provided a review of all workshops, office hours, and modeling results to date. A gas volatility study is underway. A resiliency report on the Current Trends and Policies (CTP) and High Economic Growth (HEG) futures, as well as for the stakeholder modeling request #12 (described in the PNM Slide Deck from the June 10th Office Hour), is expected soon. Results of these analyses will be made available to stakeholders.

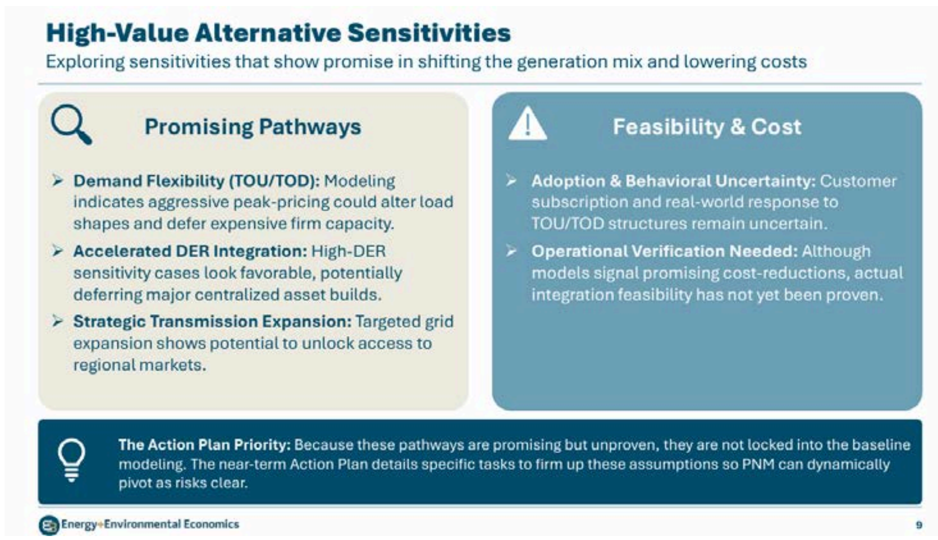
PNM's consultant, PowerGem, reviewed the SERVM-based reliability analyses performed on the CTP and HEG futures for study years 2036, 2040, and 2045. PowerGem concluded that both futures meet reliability requirements.

MODEL RESULTS - KEY TAKEAWAYS

PNM's consultant, E3, described the rationale for presenting a "least regrets" framework of model results as contrasted with a single preferred portfolio for long-term planning. Insights across sensitivities for the Current Trends and Policies Futures are shown below:



Modeling a variety of sensitivities revealed three promising pathways, identified below:



STATEMENT OF NEED AND ACTION PLAN

PNM presented key elements of the draft statement of need and action plan. Stakeholders worked in small groups to generate feedback for the utility on these two important sections of the IRP report. A summary of stakeholder comments is attached. Stakeholders expressed frustration that they received the draft materials on short notice and requested additional time to review the information and consult with colleagues before offering detailed feedback.

NEXT STEPS

- Stakeholder comments on the draft Statement of Need and Action Plan are due to IRP@PNM.com and dshields@gridworks.org by **5 PM MDT on Wednesday, July 1**. Redline edits and narrative comments are welcome. Links to the two documents can be found here: 2026 IRP Draft Action Plan and 2026 IRP Draft Statement of Need.

- PNM to share gas volatility study
- PNM to share resiliency report, including analyses of CTP, HEG, and stakeholder run request #12
- PNM to share results from customer impact analyses

Upcoming workshops and topics are shown below.

Workshop #8 July 15, 1-5 PM hybrid*	Complete statement of need and action plan
Workshop #9 Aug. 12, 9 AM-12 virtual	Review key IRP elements, including any unresolved issues
Feedback on Stakeholder Process September	A survey and opportunity for direct feedback are forthcoming. Your input is critical to Gridworks and the NM PRC

*Hybrid Workshop: in-person attendance is strongly advised. Webex links will be available, but may not offer the same participation options as those for in-person participants.

GRIDWORKS

WORKSHOP #7 PARTICIPATING ORGANIZATIONS (Excluding PNM, its consultants, and facilitators)

Advanced Energy United
Bernalillo County Economic Development
CABQ
Clenera
Coalition for Clean Affordable Energy
Customers (2)
Deutsch Domestic Water Company, Inc
Energy Futures Group
Energy Futures Group
esVolta
Form Energy
Goschke Energy Advisors
Gould Law Firm
GridLab
Interwest Energy Alliance
Jupiter Power
Kinetic Power, LLC
Linea Energy
New Mexico Gas Co.
NM Affordable Reliable Energy Alliance
NM PRC
Pacific Fusion
Plus Power
Sandia National Labs
Sandia Pueblo
Single Space Strategies
SWEEP
350 New Mexico
Third Act NM
Village of Los Lunas, Economic Development Division
Vote Solar
Walmart
WRA
Zanskar Geothermal & Minerals

GRIDWORKS

PNM 2026 IRP, Workshop #7, June 17, 2026

Initial Stakeholder Feedback on Draft Statement of Need and Action Plan

Statement of Need

- Provide energy amounts (MWh) in addition to capacity position (MW) (tables 1 and 2)
- Identify the time periods for the action plan, focus period, and planning horizon. How is PNM thinking about steps for long-lead resources? Include a timeline that illustrates when new resources are expected to come online
- Clearly describe what is in the baseline and the relationship to current procurement activities
- Break down expected load growth into segments (data centers, large loads, residential electrification, etc.)
- More information on affordability and customer impacts of each scenario
- Define the extreme economic growth scenario and reconsider how it is weighted in the analysis (should not be on equal footing as CTP and HEG)
- Define short-duration storage, 4hr versus 8hr discharge rates, and applications
- Reconcile IRP gas capacity amounts with recent filings (resource application and supplemental RFP); explain why PNM believes a 2029 gas resource acquisition is realistic, given current supply chain conditions and PNM's contingency plans if gas doesn't come online by 2029
- Explain how PNM is thinking about hydrogen conversion, infrastructure costs, and deliverability uncertainty
- Provide examples of emerging resources
- Explain where/how stakeholder input and requested modeling runs are reflected in PNM's analysis, and how stakeholder input impacted PNM's identified need
- Explain how demand-side management is included in an all-source solicitation

Action Plan

- Commit to a large load tariff that includes financial assurances and protections for existing customers
- #3 – Work with developers and the Commission to consider alternative RFP structures (tiered or phased)
- #4 – add "public and private" partnerships and accelerate work on this to take advantage of the next legislative session
- #7 – Need specific targets, programs, and metrics for energy efficiency and demand-side management
- #8 – Identify specific goals for smart meter implementation, data-informed program development, and customer communication plans
- Commit to RFP criteria that prioritize technologies with tax credits
- Add specific time frames for action plan items

Format and Structure

- Bullet points, key takeaways, graphics, and summary conclusions are preferred over lengthy text
- A non-technical audience should be able to understand the key points
- Be more specific in targets and actions; clearly defined boundaries so it is evident if/when a material event is triggered
- Add a section describing the impact of stakeholder input

GRIDWORKS

PNM's 2026 Integrated Resource Plan
Statement of Need and Action Plan Review
Workshop #8 Summary

WORKSHOP SUMMARY

Representatives from 27 stakeholder organizations attended this July 15, 2026, workshop to review all modeling efforts completed to date and provide input to PNM on the draft Statement of Need and Action Plan. Over 37 individual stakeholders attended the workshop, 7 of whom attended in person. The list of participating organizations (excluding PNM, its consultants, and facilitators) is included at the end of this document.

MATERIALS

- Gridworks Slide Deck
- PNM Modeling Update Slide Deck
- PNM Statement of Need & Action Plan Slide Deck
- Revised PNM Statement of Need
- Revised PNM Action Plan
- Gas Volatility Analysis
- PNM SoN and Action Plan Feedback Tracker
- Workshop recording: https://youtu.be/s9iWSjAG-GM

WELCOME AND INTRODUCTION

The workshop objectives were to review the Statement of Need and Action Plan, hear how stakeholder input was considered, and assess the level of agreement with these two elements of the IRP.

UPDATE ON MODELING ACTIVITIES

The PNM team shared the results of the reliability analysis for stakeholder-requested scenario #12 and the revised results for the High and Extreme Economic Growth scenarios. The gas volatility study is complete and available here: Gas Volatility Analysis. Key takeaways from the revised High Economic Growth reliability analysis, which increased the accredited capacity for energy-limited resources, indicated a need for fewer firm-dispatchable and carbon-free resources compared to the results presented in May. The analysis indicated a need for more dynamic balancing resources in the Extreme Economic Growth situation.

STATEMENT OF NEED AND ACTION PLAN

The PNM team summarized the revised Statement of Need (SoN) and Action Plan (AP), which were sent to stakeholders and posted on the Gridworks website on July 9. Stakeholder comments from Workshop #7 and seven sets of written comments submitted by July 2 were considered by the utility team while developing these revised documents. Disposition of all comments is shown in the PNM SoN and Action Plan Feedback Tracker.

PNM discussed Action Plan item #4, a proposed emerging technology working group, as critical to developing emerging clean energy resources in New Mexico. PNM proposed to form a working group to evaluate strategic public and private partnerships, policies, and funding mechanisms or tax credits, including new state and federal incentives, to support the deployment of emerging clean energy resource developments. Several stakeholders offered connections and possible allies in this endeavor.

STAKEHOLDER FEEDBACK ON REVISED STATEMENT OF NEED AND ACTION PLAN

Stakeholders were invited to respond to the questions below regarding the Statement of Need (SoN). (Results of the polling are included with each question. There were 10 responses.)

- Do you agree with the **amount and types of resources** PNM needs to reliably meet customer demand and state policies during 2026-2045? Results: 60% YES, 40% NO.
- Do you agree that the SoN includes the **technical characteristics** of any proposed new resources to be procured, **expressed in terms of energy or capacity**? Results: 60% YES, 40% NO.
- Do you feel that the SoN takes a **broad view** of the evolving needs of the system? Results: 80% YES, 20% NO.

Concerns mentioned by individual respondents include:

- ➢ A desire for more definition on customer outreach and communications efforts related to the smart meter rollout and the transition to time-of-day rates.
- ➢ Skepticism about the durability of data center load growth. Request for a breakdown of the load forecasts by sector.
- ➢ Opposition to including nuclear as a resource option.
- ➢ Opposition to including gas as a resource; need to avoid stranded assets.
- ➢ Accessibility of the SoN to non-technical audiences.
- ➢ Request for an overview/appendix/summary table of emerging technology resource options.
- ➢ Inclusion of a description of a large load tariff and implications for resource planning.
- ➢ Correction to a statement related to fusion technology.

The team noted that some information requested by stakeholders during the SoN discussion will be included in other chapters of the IRP report.

Stakeholders were also invited to respond to the questions below regarding the Action Plan: (Results of the polling are included with each question. There were 6 responses.)

- Do you agree that the Action Plan includes specific steps over the next 3 years to implement the resource plan? Results: 67% YES, 33% NO.
- Do you agree that the Action Plan details specific actions to develop any resource solicitation or contracting activities to fulfill the statement of need? Results: 83% YES, 17% NO.
- Does the plan include the issuance of a status report of actions contained in the 2023 IRP Action Plan? Results: 83% YES, 17% NO.

Issues voiced by respondents include:

- ➢ Lack of assurance that all IRP participants will receive regular updates on the Action Plan.
- ➢ Lack of a commitment to a distributed energy resources roadmap or enabling of Community Solar, customer-sited generation and storage, microgrids, and virtual power plants (VPPs).
- ➢ Lack of a commitment to developing an open-access Grid Services Tariff.

NEXT STEPS
PNM will develop the full IRP report and intends to share a draft with stakeholders for informational purposes prior to Workshop #9.

Across the full body of stakeholder feedback received to date, two remain as open items:

- Evaluation of affordability, customer impacts, and revenue requirements for each tier of resources
- Evaluation of transmission options: WestTEC corridors that affect PNM, flow-based operations

Workshop #9 is scheduled for **Aug. 12 from 9 AM - 12 NOON MDT** via WebEx. (Gridworks apologizes for the error in the workshop time that was announced during Workshop #8.) This workshop will focus on the IRP content and include an invitation to provide feedback on the stakeholder engagement process.

WORKSHOP #8 PARTICIPATING ORGANIZATIONS (Excluding PNM, its consultants, and facilitators)

350 New Mexico
Advanced Energy United
City of Albuquerque
Clean Energy Coalition of Santa Fe County
Coalition for Community Solar Access
Customers (2)
Energy Futures Group
Exus Renewables
Form Energy
Gridlab
Gould Law Firm
Interwest Energy Alliance
Invenergy
Kinetic Power, LLC
New Mexico Gas Co.
NM Affordable Reliable Energy Alliance
NM PRC
NM RETA
Pacific Fusion
Pattern Energy
SWEEP
Third Act NM
Tierra Adentro Growth Capital
TransAlta
WRA
Xcel Energy

GRIDWORKS

PNM's 2026 Integrated Resource Plan
IRP Review and Process Feedback
Workshop #9 Summary

WORKSHOP SUMMARY

Representatives from 24 stakeholder organizations attended this August 12, 2026, workshop to receive an update on the PNM IRP Report and learn about changes made to the Statement of Need since the prior workshop. 31 stakeholders attended the virtual workshop. The list of participating organizations (excluding PNM, its consultants, and facilitators) is included at the end of this document.

MATERIALS

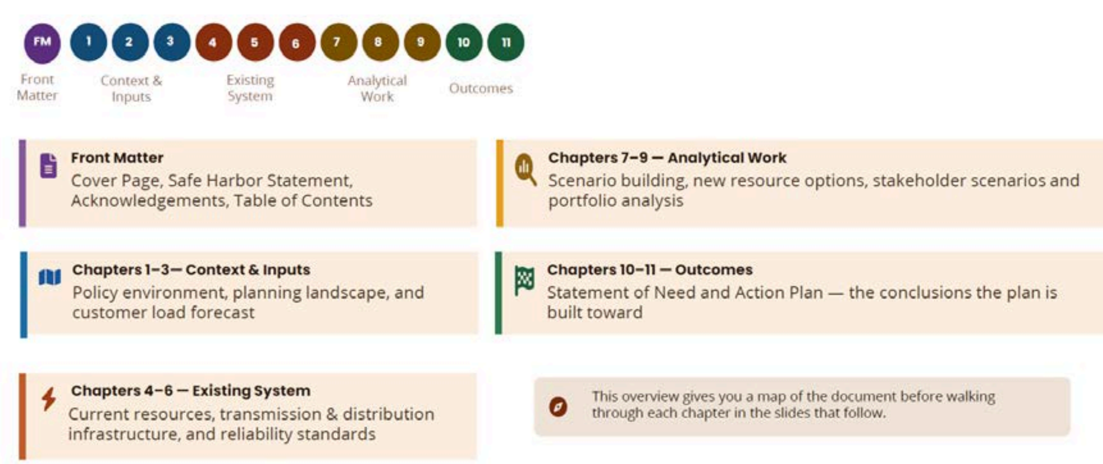
- **Gridworks Slide Deck**
- **PNM Slide Deck**
- **Updated SoN, Chapter 10**
- **Preliminary PNM 2026 IRP Draft Report**
- **Workshop recording:** https://youtu.be/ai_mOV7k9JY

WELCOME AND INTRODUCTION

The workshop objectives were to understand key elements of the IRP report, review updates to the Statement of Need since the last workshop, review the main themes that surfaced during the 9-month stakeholder engagement process, and invite feedback on this process as input for the facilitator's report to the NM Public Regulation Commission. Gridworks expressed appreciation to all stakeholders who participated in this process, noting that 44 individuals attended 6 of the 16 stakeholder gatherings to date.

IRP REPORT CONTENT

The PNM team shared the organization of the IRP report and identified sections that were influenced by stakeholder engagement. A copy of the draft report was distributed to stakeholders on Aug. 6: Preliminary PNM 2026 IRP Draft Report. The report structure is as follows:



GRIDWORKS

The PNM team shared an analysis of possible customer cost impacts across the three analyzed scenarios (Current Trends and Policies, High Economic Growth, and Low Economic Growth).

Stakeholder questions focused on the load forecast under record-heat conditions, planned resource additions (including transmission assets), assumptions about hydrogen costs, flexible data center interconnections, rate impacts, overlap with the distribution system planning process, and the relationship between current and planned resource acquisition activities.

UPDATED STATEMENT OF NEED

The PNM team presented updated ranges of resources needed for the CTG, stakeholder-defined, LEG, and HEG scenarios. These updates were made to align with results of the modeling runs and were shared with stakeholders in an updated Statement of Need document, distributed on Aug. 10, [Updated SoN, Chapter 10](). Changes between the July and August versions for the CTG scenario are illustrated below.

Incremental to 2029 Baseline

Table 4 – Incremental Installed Capacity Resource Needs Based on CTP Future and Sensitivities

Resource Category	Through 2036		Through 2045	
	Low	High	Low	High
Carbon-Free Energy (Supply-Side)	~~196~~ 360	~~374~~ 598	~~657~~ 1,144	~~1,533~~ 1,409
Carbon-Free Energy (Demand-Side)	~~103~~ 196	~~103~~ 196	~~327~~ 420	~~327~~ 420
Dynamic Balancing (Supply-Side)	0	~~80~~ 0	517	~~883~~ 768
Dynamic Balancing (Demand-Side)	~~6~~ 15	~~6~~ 45	~~10~~ 19	~~12~~ 52
Firm Dispatchable (Supply-Side)	0	200	~~584~~ 863	~~2,208~~ 1,602

IRP KEY TAKEAWAYS

The Statement of Need and Action Plan contain key results from the modeling efforts and stakeholder discussions. In addition, the following takeaways were noted:

- There are limited resource needs through 2036, depending on the load
- For the next IRP, expand potential modeling sensitivities for the late 30's and beyond to provide better insight into options and challenges to complete the path to a zero-carbon portfolio
- Continue work advancing Integrated System Planning concepts
- Enhance information on demand-side program possibilities and potential

ACTION ITEMS FOR PNM

- Share resource adequacy/weather resiliency study (by PowerGem)
- Incorporate results of stakeholder scenarios #10-13 into IRP report
- Add transmission addition (2029-2032 resource filing) to IRP report

NEXT STEPS

The IRP Resource Adequacy Analysis will be included as an appendix to the IRP Report. The final version of the IRP Report will also be made available to stakeholders through Gridworks' communications.

Public comments on the IRP Report are allowed up to 30 days after the Sept. 1 filing date via NM PRC's docket number 25-00022-UT. PNM has 60 days after filing to respond to public comments, and then the NM PRC staff and commission will conduct their review and acceptance process.

Stakeholders are invited to provide feedback to Gridworks on the stakeholder engagement process by Sept. 4. This feedback is critical to the facilitator's report to the NM PRC and vital to improving New Mexico's electric utilities' planning process. Feedback is welcome via a survey (see the QR code and link below), and/or via a direct conversation with the Gridworks team.

https://forms.gle/pr9x2uQZ6c31VGk77

GRIDWORKS

WORKSHOP #9 PARTICIPATING ORGANIZATIONS (Excluding PNM, its consultants, and facilitators)

Advanced Energy United
AES Clean Energy
Black Forest Partners
City of Albuquerque
CDG Engineers
Clean Energy Coalition of Santa Fe County
Clenera
Coalition for Community Solar Access
Customer
Gould Law Firm
Gridlab
Interwest Energy Alliance
Invenergy
Linea Energy
New Mexico Gas Co.
NM Affordable Reliable Energy Alliance
NM PRC
NM RETA
Pacific Fusion
Sandia Pueblo
Vote Solar
Western Resource Advocates
Zanskar Geothermal & Minerals

Appendix D: 2023 IRP FSP and 2026 IRP FSP Feedback

1 2023 IRP Filed Comments

Appendix D provides the disposition of material issues raised during the facilitated stakeholder process and identifies whether each issue was adopted, adopted in part, not adopted, deferred, or remains unresolved, together with PNM's rationale and the resulting effect, if any, on the Statement of Need or Action Plan.

In keeping with the transparency aspect of the new IRP Rule, a series of comments were filed in public in Docket No. 23-00409-UT regarding the filed 2023 IRP report. Although none of the comments PNM agreed to adopt required an amendment of the 2023 IRP, many of the responses improved the overall process and clarity for stakeholders. These comments were adopted to help improve the IRP process, augment stakeholder transparency, and increase stakeholder understanding of how PNM determines the Statement of Need, the Action Plan and ultimately the IRP report. The table below summarizes all stakeholder feedback that PNM agreed to from the 2023 IRP filed comments. Responses to these comments as well as information was provided throughout the 2026 IRP FSP process in various workshops, office hours or directly in the 2026 IRP report. A summary of these comments as well as PNM's response are provided below.

Table D-1. 2023 Filed IRP Comments/Feedback

#	Topic	Comment/Feedback	Response	2026 IRP Status
1	IRP Process	Provide a better understanding of how TOU rates implementation/customers' electricity usage behaviors impacts	Adopted	Completed, arranged for SME's to discuss with interested stakeholders in breakout session in Workshop #7; also provided multiple PNM filings regarding these programs to all stakeholders via the Venue site. PNM's website (pnm.com) also provides substantial information on TOU/TOD rates for customers
2	IRP Process	Provide a better understanding concerning "Behind the meter" data collection	Adopted	Completed, arranged for SME's to discuss with interested stakeholders in breakout session in Workshop #7; also provided multiple PNM filings regarding these programs to all stakeholders via the Venue site
3	IRP Process	Provide analysis of impact of distributed generation with local storage backup	Adopted	Provided analysis in stakeholder scenarios #5, 6, 7, 11 and 12 from Workshop #6, additional write up in IRP report stakeholder scenario section
4	IRP Process	Develop and include an overview/table of generating resources	Adopted	Completed; Provided in Workshop #2 and 2026 IRP report

#	Topic	Comment/Feedback	Response	2026 IRP Status
5	RFP Process	Present a clear process for the RFP	Adopted	Completed; Provided an overview in Workshop #8 on how the SoN is used to provide direction in RFP requests. Provided procurement timeframes in Appendix P
6	Modeling	Provide more clarity from the beginning for the process about what scenarios and sensitivities PNM plants to model	Adopted	Completed; Overview in Workshop #3 on February 11, 2026. PNM followed up in Workshop #4 in March 2026 and Workshop #5 in April 2026.
7	Modeling	Perform an ELCC study for thermal generation	Adopted	Completed; Presented study scope to solicit stakeholder input in February 2026. Receiving none, PNM proceeded with the scope as presented. Results were uploaded on Venue on 3/19/26 and PNM provided update in Workshop #3.
8	Modeling	Include a detailed study of gas price volatility	Adopted	Completed; Presented study scope to solicit stakeholder input in February 2026. Receiving none, PNM proceeded with the scope as presented. Study was uploaded on Venue on 7/7/26. Result summary provided in Workshop #8 and summarized in the 2026 IRP report, Section 8.9.
9	Transmission	Provided detailed information regarding regional transmission planning	Adopted	Summarized in the 2026 IRP report, Section 2.4
10	Transmission	Provide potential expansions of transmission connectivity to other utilities and analysis	Adopted	Completed, PNM explicitly analyzed four transmission alternatives for the 2026 IRP report, Section 5.8
11	Modeling	Analyze information regarding advanced transmission technologies and grid-enhancing technologies	Adopted	PNM provided additional GETs information, uploaded to the Venue site on March 5, 2026 and a full write up is in the 2026 IRP report, Section 5.1
12	Modeling	Alignment of EE bundles and PNM EE programs	Adopted	Completed; Included a description of updated methodology in Section 3.4 and Section 8.1 of the 2026 IRP Report
13	IRP Report	Clearly articulate how federal rebates and tax credits reduce costs of different resources	Adopted	Completed; Included how federal incentives if applied were used to reduce costs of technologies in Section 8 of the 2026 IRP report
14	Modeling	Expand modeling sensitivities regarding electrification	Adopted	PNM performed sensitivities that expanded the modeling for electrification though high electric vehicle adoption. Sensitivity results provided during the FSP in Workshops #5 and #6 and in the 2026 IRP Report in Section 9

#	Topic	Comment/Feedback	Response	2026 IRP Status
15	IRP Report	Specifically Identify all Resources Chosen in the MCEP	Adopted	Provided in the 2026 IRP report in Appendix N

2 2026 IRP FSP Frequent Themes

The 2026 IRP FSP spanned over nine months solicitating stakeholder feedback on many aspects of PNM's triennial IRP planning process. Over the course of the facilitated process, there were a series of topics that were frequently raised by participants and discussed multiple times. Some of these matters could impact future IRPs and therefore do not have immediate solutions. Other comments point to areas PNM could improve upon in future IRP cycles. Although these themes were discussed over multiple workshops with multiple stakeholders; no specific conclusion could be agreed upon. These topics also warrant more time to satisfactorily address and understand all the implications than the few months of time allotted for the FSP to investigate a solution. Other topics while not directly impacting PNM's SoN or the AP for this IRP were either addressed or resolved during the workshops or office hour meetings. These topics, listed in no particular order are discussed below.

2.1 Data Center Load Growth, Forecasting, & Customer Protections

Early in the process, stakeholders expressed concern over the scale, timing, and uncertainty of economic development load growth projections. Stakeholders cited project timing, infrastructure demands, and the risk that existing retail customers could bear stranded costs for speculative loads. Requests for load breakdown, the evaluation process to determine if loads were tangible were continually vocalized. To assuage the concern associated with this type of load growth, PNM provided supplemental forecast details multiple times and had SMEs on hand during multiple meetings to respond to any questions. In addition, PNM modeled multiple load forecasts as well as stakeholder-requested model runs were performed. Finally, PNM committed to filing a formal large-load tariff to provide financial assurances and ratepayer protections and Gridworks directed stakeholder interest to the NMPRC forum which began during this process to discuss utility options for large load tariffs and its implications. Although the current 2026 IRP process cannot fully address this topic during the FSP, PNM is actively participating in this regulatory process and will provide follow-up information in its action plan status updates.

2.2 Energy Transition Act (ETA) Compliance vs. New Natural Gas Generation

During the FSP, some stakeholders questioned PNM's reliance on new natural gas combustion turbines (CTs) as a future candidate resource, raising concerns about alignment with ETA mandates (100% carbon-free by 2045). Doubts centered on gas price volatility, pipeline infrastructure, stranded asset risk, and the technical and economic viability of green hydrogen conversion given shifting federal funding. Participants also strongly objected to PNM's 2029-2032 System Resources filing which included requested approval of one small gas facility to PNM's portfolio.

Prudent planning requires PNM to be technology agnostic and to ensure all feasible technologies are evaluated on a level playing field. To that end, PNM incorporated hydrogen conversion costs, completed a natural gas volatility study, modeled a no-ETA comparison sensitivity, and executed stakeholder runs evaluating decarbonization without hydrogen, carbon capture, or new gas. For modeling purposes, PNM assumed all new natural gas resource candidates included the cost of conversion equipment needed to burn hydrogen beginning in 2045. Further, for hydrogen fuel pricing there was no use of federal funding or incentives used to reduce overall costs and only renewable resources would be used to provide the energy needed for a hydrogen production processing facility. In essence, PNM fully burdened this candidate resource type with substantial capital and operating costs when competing with all other candidate technologies. PNM contracted with Siemens to perform a natural gas volatility study to understand the implications of natural gas price spikes. PNM approached hydrogen conversion without a bias relying heavily on industry experts to provide guidance on the feasibility of conversion and the infrastructure needed to have a clean burning fuel. This same approach was undertaken in the 2029-32 Resource Plan for gas resources.

2.3 Nuclear as a Candidate Resource

In long-term capacity expansion modeling, the model consistently selected new nuclear resources late in the planning period in order to meet firm dispatchable resource needs and to support 100% carbon free mandated energy production by 2045. Reaction to these results incited strong opposition and vocalizing safety/waste concerns. Stakeholder opposition to nuclear as an acceptable candidate resource was discussed and repeated,

PNM clarified that nuclear was included purely as a generic proxy resource for firm capacity in the long-term expansion model and would require significant screening and evaluation before it had the ability to become a selection. Additionally, PNM emphasized that resource procurement is not a function of the IRP facilitated stakeholder process. Specifically, the IRP identifies three areas of need: carbon free resources, dynamic balancing resources and firm generating resources. To model in IRP, PNM uses generic feasible technologies to serve as proxies. Specific technology identification to meet the needs as shown in the Statement of Need is determined though market solicitations and analyses. Although the IRP and resource procurement through an RFP are inextricably linked, the IRP does not prescribe exact technologies but serves to provide direction and magnitude while fully expecting specific technology types would be vetted through a subsequent procurement process. Additionally, the timing of nuclear resource additions in PNM's 2026 IRP modeling were in the 2040's, which on the early side, is 14 years into the future. PNM plans to monitor long lead-time technologies such as nuclear, in addition to emerging technology maturity to determine if, and when, such technologies could assist PNM meeting customer requirements while considering reliability, affordability and environmental impacts.

2.4 Distributed Energy Resources (DERs), Virtual Power Plants (VPPs), & Demand Response

Some stakeholders asked that PNM consider expanding its options for customer-sited resources (rooftop solar, batteries, electric vehicles, demand response) and treat such options as dispatchable resources. Stakeholders pressed for PNM to commit to a more explicit DER roadmap, community solar enablement, microgrids, and an open-access Grid Services Tariff.

Consistent with recognition from Gridworks to this topic, PNM modeled stakeholder-requested DER sensitivities, including a VPP scenario which was a combined simulation featuring high rooftop solar, high Time-of-Use rate adoption, behind-the-meter batteries, and additional demand response. However, during final Action Plan reviews, stakeholders expressed that the plan still lacked explicit commitments or policy targets for a DER roadmap. PNM did not agree with specific stakeholder commitments as PNM has already implemented or plans to implement some of these programs/projects, such as VPP, whole house EV pilot program and Commission-approved distribution sited BESS.

2.5 Costing & Integration of Emerging Clean Energy Technologies (Geothermal, LDES, & Fusion)

A dominant topic in the 2026 IRP FSP was a greater inclusion of emerging clean technologies, specifically enhanced geothermal, long-duration energy storage (LDES), and nuclear fusion, arguing that initial generic cost and performance assumptions undervalued their potential as firm clean power compared to fossil resources. For geothermal specifically, stakeholders questioned generic capital cost estimates, questioned capacity factor assumptions, and requested tailored RFP bid language to accommodate the longer development lead times of enhanced geothermal systems.

To address this concern, PNM held dedicated office hours (including a March 4 session on geothermal costs), updated capacity factor assumptions, and executed stakeholder-requested model runs across multiple price points for geothermal and nuclear fusion. While specific RFP bid language and contracting terms were deferred to the post-IRP competitive procurement process, PNM committed to creating an Emerging Technology Working Group in Action Plan Item #4 to evaluate public-private partnerships, federal/state tax incentives, and deployment opportunities that would support this technology. The focus of the working group will include identifying potential solutions to challenges of seeking emerging and long-lead technologies under the current RFP processes outlined in the IRP rule.

2.6 Reliability & Resource Adequacy Modeling

Although there were not any specific issues that arose in the FSP workshops regarding PNM's reliability and resource adequacy planning, stakeholders sought assurance that proposed candidate portfolios would maintain system reliability under high load growth and severe weather, particularly with increased reliance on energy-limited renewables and storage.

PNM through its consultant (PowerGEM) completed SERVM probabilistic reliability modeling across Current Trends and Policies (CTP) and High Economic Growth (HEG) futures. SERVM analyses confirmed that the CTP and HEG portfolios met reliability standards, with some accredited capacity adjustments iterated for the HEG portfolio to align with PNM's 1-day-in-10-years planning standard. While evaluated portfolio reliability was not debated, stakeholders continued to express concerns regarding the specific resource mix used to achieve it. Additionally, PNM performed a resiliency study to evaluate how CTP and HEG portfolios perform under extreme summer and winter weather events, both under standard interconnected operations and an islanded sensitivity. System resiliency was also evaluated to determine daily risk by season, the impact of firm dispatchable capacity on resiliency and performance of different technology types under extreme conditions.

2.7 Transmission Constraints & Market Opportunities

Stakeholders highlighted the complexity of PNM's system. PNM’s wholesale transmission business exceeds the amount of PNM’s utilization of transmission for retail customers planned for in the IRP. As a result, PNM’s transmission utilization is more than double the amount of PNM’s peak retail load. The wholesale transmission business must be considered in the ability of the transmission system to deliver resources identified in the IRP to PNM’s retail load. Stakeholders urged PNM to capture the benefits of joining the Extended Day Ahead Market (EDAM) in 2027 and regional transmission expansion. Previous work and stakeholder comments from the 2023 IRP encouraged PNM to expand modeling of the transmission system in its IRP. In response to stakeholder comments, PNM expanded its IRP modeling to include transmission project analysis of four transmission path sensitivities derived from its 20-Year Transmission plan with the intent to explore whether market related benefits could be obtained from these potential transmission related interconnections. While this work is still ongoing, PNM recognizes there is still work to be performed in this area and plans to perform additional analysis regarding these potential projects prior to or as part of the 2029 IRP. Evaluating broader regional transmission options (such as WestTEC corridors and flow-based operations) as requested in the FSP was cited as potential options for improving the work PNM has accomplished in PNM’s next IRP.

2.8 Customer Bill Impacts, Affordability, & Revenue Requirements

Stakeholders requested transparent data showing how candidate resource portfolios and economic growth futures would translate into customer rate impacts, overall revenue requirements, and energy affordability.

PNM identified an MCEP as the CTP baseline case, as well as resource plans under varying key supply- and demand-side assumptions. System average rate impacts for CTP, HEG, and LEG futures were presented to stakeholders in PNM’s August Workshop #9. Average rate impacts for the last year (2036) of the 2026 IRP focus period reflected cost impacts for each portfolio, providing the estimated incremental revenue requirements and energy requirements above a baseline set by PNM’s 2029-2032 Resource filing illustrative rates.

2.9 Relationship Among IRP, Current Procurements, & Future RFPs

Stakeholders expressed confusion regarding overlapping proceedings (such as PNM's 2029-2032 resource filing, the supplemental RFP and future resource filing), how existing baseline procurements were treated, and whether a 3-year Action Plan provided sufficient lead time for large-scale or emerging clean energy additions. PNM clarified that portfolios identified by capacity expansion tools used generic, conceptual resources, whereas specific projects and commercial technologies were chosen later through a competitive procurement process. Stakeholders were also concerned about timing of RFP needs, noting that emphasis should be adjusted to accommodate long-lead time resources. To satisfy stakeholders, the Statement of Need and Action Plan were explicitly revised to account for better transparency and document the timeframes for each period and show how all PNM procurements (current and future) are aligned.

PNM agreed with stakeholders on long-lead times for RFP's and resource procurements, thus why PNM's 2026 IRP is focusing on resources needed to serve system needs for the forward looking 7-10 years.

2.10 Behind the meter (BTM) & Time-of-Day (TOD) Rates

A single stakeholder raised questions regarding customer data privacy, rate choice, and the need for public education and communication plans to support the transition to default TOD rates following full smart meter deployment by 2028–2029. For this IRP, PNM shared many updates and filings that PNM has made regarding its grid modernization plan, including TOD pilot customer satisfaction reports and load-shifting data. In addition, PNM provided opportunities for stakeholders to have access to PNM's SMEs multiple times in various meetings in the effort to increase customer understanding of these programs, designs and future plans. Although many of these programs are still in their infancy and plans are not completely established, it was requested that the final Action Plan include more concrete customer outreach strategies, metrics, and implementation goals. PNM provides substantial information on its website (pnm.com) on TOD rates and customer choice options and believes this is a standard way for customer communications with today's audiences. PNM implements the latest and best practices in customer privacy protection in the systems implemented for AMI and Grid Modernization data collection. PNM considers its website an important element of customer communication and will evaluate additional communication channels as program design and deployment milestones are established.

2.11 Modeling Access, Transparency, & Stakeholder Process

Early in the FSP, some stakeholders experienced frustration regarding delayed access to model inputs, software licenses, workpapers, and raw data files. To address this concern, PNM established a centralized site for modeling data and other information on the VENUE platform. PNM held more than five dedicated office hours for Q&A, extended review periods, and collaborated with stakeholders to execute and present results for 12 stakeholder-requested model runs.

PNM made all software database inputs and outputs available to stakeholders once data was ready for sharing. A modeling access form was provided to stakeholders early in the process. For those that were interested, the form was to be completed and emailed to PNM. PNM then validated the request and provided access to PNM's VENUE platform for access to inputs and outputs for all modeling performed by PNM. Most modeling input data, modeling framework, load forecast data and zonal output data such as resource information and simulation results were provided to any stakeholders requesting access. For stakeholders that requested detailed software modeling inputs, a confidentiality form was also provided to any stakeholder that requested this type of access. This allowed those stakeholders to perform their own modeling using the same database of information PNM used in the 2026 IRP. For the 2026 IRP, PNM noted that the nodal model inputs contained proprietary data and included NERC CIP protected data which required stakeholders to demonstrate the ability to meet FERC requirements to access such data.

3 2026 IRP FSP Statement of Need/Action Plan Feedback

As part of the 2026 IRP FSP process PNM presented a draft SoN and AP to solicit feedback from participants. Over the course of two workshops, PNM gathered over 70 comments, suggestions and redlines for both documents. Table D-2 summarizes all comments PNM received via workshop, through Gridworks or via email. PNM's response to each is also found in the table.

Table D-2 - 2026 IRP FSP Statement of Need/Action Plan Comments

Issue Number	Status	Description	Category	Date Reported	Respondent	Comments
1	Closed	Provide energy amounts (MWh) in addition to capacity position (MW) (tables 1 and 2)	SON	6/17/2026	June Meeting	Addressed in the revised draft SoN
2	Closed	Explain how PNM is thinking about hydrogen conversion, infrastructure costs, and deliverability uncertainty	SON	6/17/2026	June Meeting	Will be discussed in 2026 IRP report
3	Closed	Break down expected load growth into segments (data centers, large loads, residential electrification, etc.)	SON	6/17/2026	June Meeting	Will be addressed in 2026 IRP report
4	Closed	Reconcile IRP gas capacity amounts with recent filings (resource application and supplemental RFP); explain why PNM believes a 2029 gas resource acquisition is realistic, given current supply chain conditions and PNM's contingency plans if gas doesn't come online by 2029	SON	6/17/2026	June Meeting	Addressed in the revised draft SoN.
5	Closed	Define short-duration storage, 4hr versus 8hr discharge rates, and applications	SON	6/17/2026	June Meeting	Will be addressed in the IRP report
6	Closed	Clearly describe what is in the baseline and the relationship to current procurement activities	SON	6/17/2026	June Meeting	Addressed in the revised draft SoN.
7	Closed	Explain where/how stakeholder input and requested modeling runs are reflected in PNM's analysis, and how stakeholder input impacted PNM's identified need	SON	6/17/2026	June Meeting	Addressed in the revised draft SoN.
8	Closed	Identify the time periods for the action plan, focus period, and planning horizon. How is PNM thinking about steps for long-lead resources? Include a timeline that illustrates when new resources are expected to come online	SON	6/17/2026	June Meeting	Addressed in the revised draft SoN.
9	Closed	Define the extreme economic growth scenario and reconsider how it is weighted in the analysis (should not be on equal footing as CTP and HEG)	SON	6/17/2026	June Meeting	Addressed in revised statement of need. Scenario has been defined in Stakeholder meetings and data postings and will be discussed in the IRP report.
10	Closed	Provide examples of emerging resources	SON	6/17/2026	June Meeting	Emerging resources that PNM evaluated will be addressed in 2026 IRP report.
11	Closed	Explain where/how stakeholder input and requested modeling runs are reflected in PNM's analysis, and how stakeholder input impacted PNM's identified need	SON	6/17/2026	June Meeting	Addressed in the revised draft SON
12	Closed	Explain how demand-side management is included in an all-source solicitation	SON	6/17/2026	June Meeting	Not applicable to SON. PNM will define the resource types eligible to its next RFP. Stakeholders are encouraged to provide comments during the RFP commentary period.
13	Closed	Specific targets, pilot programs, reporting metrics, etc. for EE and DSM (Items #7 and #8)	Action Plan	6/17/2026	June Meeting	Updates on the EE triennial plan, TOD pilot program, and the EV managed charging program are publicaly coordinated in other forums.

Table D-2 - 2026 IRP FSP Statement of Need/Action Plan Comments

Issue Number	Status	Description	Category	Date Reported	Respondent	Comments
14	Closed	Commit to a large load tariff that includes financial assurances and protections for existing customers	Action Plan	6/17/2026	June Meeting	Addressed in the revised draft AP
15	Closed	#3 – Work with developers and the Commission to consider alternative RFP structures (tiered or phased)	Action Plan	6/17/2026	June Meeting	Addressed in the revised draft AP
16	Closed	#8 – Identify specific goals for smart meter implementation, data-informed program development, and customer communication plans	Action Plan	6/17/2026	June Meeting	Being worked out through Grid Moderization Plan which is publically available along with status updates.
17	Closed	Commit to RFP criteria that prioritize technologies with tax credits	Action Plan	6/17/2026	June Meeting	PNM is technology agnostic so it can select the best plan for ratepayers
18	Closed	Add specific time frames for action plan items	Action Plan	6/17/2026	June Meeting	Added more specificity in revised draft AP
19	Open	More information on affordability and customer impacts of each scenario	SON	6/17/2026	June Meeting	In progress
20	Closed	#8, Default to TOD Rates. Bolster communication efforts on DSM implementation plans. Seek more media outlets and expert researchers venues; draw lessons learned from wildfire and public safety power cutoff campaigns.	SON	7/1/2026	Independent	While it does not specifically tie to the Action Plan it has been internally shared with the AMI team
21	Closed	Resources Categories, p. 3. Under firm dispatchable resources, define the list of technologies; specify “100-hour+ storage”.	SON	7/1/2026	Linea Energy	Please see revised draft SoN
22	Closed	Range of Resource Needs by Future, p. 4. Which trajectory is PNM pursuing: baseline? CTP? HEG? Considering that the 2033-2036 RFP is meant to follow quickly after the 2029-2032 Supplement RFP, can PNM provide an indication of when/how the trajectory PNM is pursuing will be determined?	SON	7/1/2026	Linea Energy	Addressed in the revised draft SON
23	Closed	Current Trends and Policy Future, p. 5. “Steady load growth” – provide a breakdown of the drivers of load growth, including the percent driven by large loads. Provide as much transparency as possible regarding the load forecast	SON	7/1/2026	Linea Energy	Load Forecast will be a section in the IRP and the Working papers are on the Venue file exchange site
24	Closed	Stakeholder scenarios, p. 5. Specifically, these sensitivities expand the near-term variance for Carbon-Free resources, accelerate the overall demand for Dynamic Balancing flexibility, [insert] demonstrate the feasibility of portfolios without the gas resource assumed to be selected from the 2029-2032 Supplemental RFP…	SON	7/1/2026	Linea Energy	This was not a conclusion of the Stakeholder scenarios.
25	Closed	High Economic Growth Future, p. 6. provide some detail on what the high economic growth assumes relative to CTP in terms of load.	SON	7/1/2026	Linea Energy	Load Forecast will be a section in the IRP and the Working papers are on the Venue file exchange site
26	Closed	Stakeholder scenarios, p. 5. Under dynamic balancing resources, p. 6. Add: In addition, increasing selection of demand side resources (including TOU rates and increased behind-the-meter solar) results in a reduction of gas build by up to 80 MW and decreased the NPV by up to $282 million compared to the CTP scenario.	SON	7/1/2026	Advanced Energy United	Rewritten in the revised draft SoN

Table D-2 - 2026 IRP FSP Statement of Need/Action Plan Comments

Issue Number	Status	Description	Category	Date Reported	Respondent	Comments
27	Closed	Background, p. 1. Under reliability, add: Due to growth in high load-factor (24-7) loads, weather variability, and fuel supply limitations, resource acquisitions with various capabilities may be required to ensure reliability in other hours.	SON	7/1/2026	WRA	Removed in the revised draft SoN
28	Closed	Resource categories, p. 3. Under firm dispatchable resources, either delete or clarify hydrogen, if commercially viable. Any scenario that includes hydrogen should include rigorous cost assumptions for hydrogen, including the cost of electrolyzers, storage, pipelines, and renewable energy to produce the fuel as utility costs.	SON	7/1/2026	WRA	PNM's H2 conversion already includes cost of electrolyzers, pipelines, and renewable energy to produce hydrogen. PNM's experts fully believe that hydrogen will be viable by the time PNM requires it.
29	Closed	Bridging the capacity need gap, p. 3. In opening paragraph, add: The model was permitted to only allow for alternative resource selections after 2032, and resources included in all PNM selected portfolios prior to 2033 were selected and locked into all model runs by PNM.	SON	7/1/2026	WRA	This is not true for the modeling analysis. The model was permitted to allow any viable candidate resources beginning in 2029. PNM also revised the draft SoN to clarify the selections that were locked into model runs.
30	Closed	Bridging the capacity need gap, p. 3. Under 2029-20232 System Resources, revise language to: These fixed inputs are PNM-owned and purchased projects that are proposed for near-term system reliability, pending final Commission regulatory approval, and which PNM has elected to lock into all modeling scenarios. These projects are fully embedded across all modeling cases, including the low forecast.	SON	7/1/2026	WRA	Addressed in the revised draft SoN
31	Closed	Bridging the capacity need gap, p. 4. Under 2029-2032 Supplemental Procurements, add: Regardless, the model selections here do not provide insight into resource options that may be alternatives to this gas generation, as these gas generation resources are fixed inputs in this IRP modeling.	SON	7/1/2026	WRA	Addressed in the revised draft SoN
32	Closed	Bridging the capacity need gap, p. 4. Under Generic Long-Term Resources, add: These are the only resources presented in PNM's portfolio modeling that are permitted to vary in the scenario and sensitivity analyses.	SON	7/1/2026	WRA	Addressed in the revised draft SoN
33	Closed	Range of Resource Needs, p. 4. Clarify definition of baseline: existing plus the 2 categories of incremental proposed acquisitions, penning PRC approval. Additional word edits suggested.	SON	7/1/2026	WRA	Addressed in the revised draft SoN
34	Closed	Current Trends and Policy Future, p. 5. Does "baseline" mean the same thing here? Is this perhaps a "benchmark" portfolio? Are you using "baseline" to refer to a set of generation resources as an input to the modeling, or a specific scenario or portfolio result?	SON	7/1/2026	WRA	Addressed in the revised draft SoN

Table D-2 - 2026 IRP FSP Statement of Need/Action Plan Comments

Issue Number	Status	Description	Category	Date Reported	Respondent	Comments
35	Closed	Stakeholder Scenarios, p. 6. Under firm dispatchable resources, add: This shows that the proposed near-term dispatchable resource additions proposed this year exclude the opportunity to evaluate alternative and more incremental alternatives to serve capacity needs through 2036.	SON	7/1/2026	WRA	The model was permitted to allow any viable candidate resources beginning in 2029. PNM also revised the draft SoN to clarify the selections that were locked into model runs.
36	Closed	High Economic Growth Future, p. 7. Clarify timelines for Focus Period, 2033 through 2036, and Planning Period, 2033 through 2045.	SON	7/1/2026	WRA	Addressed in the revised draft SON
37	Closed	Conclusion, p. 8. Add to opening paragraph: However, the modeling conducted only provides insight into alternative resource options after 2032.	SON	7/1/2026	WRA	The model was permitted to allow any viable candidate resources beginning in 2029;
38	Closed	Conclusion, p. 8. Clarify upcoming cycles, starting in 2033. Additional wordsmithing edits suggested.	SON	7/1/2026	WRA	Addressed in the revised draft SoN
39	Closed	Affordability and “least-regrets” framework, pp. 1-2. Implies that PNM is not serious about finding long-term, cost effective solutions to the ETA problem. Shifts the problem to the market and if the market does not supply a solution then???	SON	7/1/2026	NMPRC Staff	Addressed in the revised draft SoN. "least regrets" intent was to not unreasonable preclude options, including long-term, with an overly restrictive SoN.
40	Closed	Resource categories, p. 3. Recommend dropping the dynamic balancing resources. The ELCC for these resources is making their cost/benefit not attractive. Lump LDES into firm dispatchable resources, can be used for dynamic balancing or energy arbitrage along with being firm and dispatchable.	SON	7/1/2026	NMPRC Staff	PNM disagrees with that concept. These resources get selected because the cost/benefits contribute to defining a least-cost portfolio.
41	Closed	Range of Resource Needs by Future, p. 4. The resources needed are those that can supply 24/7 reliable power while meeting the ETA requirements by 2045 at a cost that is affordable. If PNM cannot demonstrate that that is possible then the SON should identify that the ETA or other laws must be amended or that exceptions to the rules may be needed by 2044.	SON	7/1/2026	NMPRC Staff	PNM categorizes long duration storage as a firm dispatchable resource. The SoN was revised to note that some technologies have characteristics that fit in more than one operational category.
42	Closed	Table 2, Generic Resource Attributes, p. 4. PNM should state in the SON exactly what they believe to be the end resource position in 2045, with and without a fueled resource; demonstrate how much storage (GWhs) capacity is necessary to sustain the system	SON	7/1/2026	NMPRC Staff	SoN revised to clarify technologies and approximate amounts that are selected over the planning period ending in 2045.
43	Closed	Resource categories, p. 3. PNM should identify the specific resource types selected in the modeling. Reporting need solely by functional category, without the underlying resource composition that the modeling already contains, obscures that the Focus Period need is weighted toward renewables, energy efficiency, and storage and includes no new gas or nuclear.	SON	7/1/2026	NMAREA	Addressed in the revised draft SON. Please see Figure 6 - Range of Resource Needs Based on CTP Sensitivities through 2036

Table D-2 - 2026 IRP FSP Statement of Need/Action Plan Comments

Issue Number	Status	Description	Category	Date Reported	Respondent	Comments
44	Closed	Range of Resource Needs by Future, p. 4. should also be presented on an accredited (firm) capacity basis and an energy (GWh) basis. Presenting need in nameplate MW while measuring adequacy in accredited capacity is internally inconsistent and obscures what the resources actually contribute to reliability and to serving load.	SON	7/1/2026	NMAREA	IRP report will included accredited capacity and energy role of technologies. All details are not needed for the SoN.
45	Closed	Table 2, Generic Resource Attributes, p. 5. include the LEG (Low Economic Growth); omits the low case, which presents an unbalanced view of the range PNM modeled. The LEG result, that baseline resources and active procurements are sufficient through the Focus Period and beyond, is directly relevant to the amount of near-term procurement that is actually required and belongs in the same table as the upside cases.	SON	7/1/2026	NMAREA	LEG table has been added.
46	Closed	High Economic Growth Future, Focus Period, p. 8. This is introduced as "above the CTP," but appears to be the range above the baseline. (The above-CTP range is presented as 604-817 in Table 2 and the HEG summary in the conclusion)	SON	7/1/2026	NMAREA	Addressed in the revised draft SON
47	Closed	High Economic Growth Future, Planning Period, p. 8. 181 MW, This number appears to be incorrect. See the CTP section in Table 2, where the number is 536. Same 536 appears at the very top of page 7 in the CTP description	SON	7/1/2026	NMAREA	Addressed in the revised draft SON
48	Closed	Conclusion, p. 9. Procurement beyond the committed 2029-2032 resources should be triggered by demonstrated and committed load growth rather than by the upper bounds of the High Economic Growth or Extreme Economic Development sensitivities.	SON	7/1/2026	NMAREA	Addressed in the revised draft SON
49	Closed	#3, next all-source RFP. RFP that allows for a longer term online target date for geothermal or other clean firm bids? Limited to a 3-year window only?	Action Plan	7/1/2026	WRA	Action plan RFP covers 4 years period starting 2033. It will be up to bidders to determine if viable projects are available in this time-frame. The IRP and RFP cycles follow the requirements of the IRP rule which provides for stakeholders to provide input on the RFP.
50	Closed	#3, next all-source RFP. Highlight the importance of prioritizing capturing tax credit-eligible storage projects. Add: ...prioritizing renewable projects facing tax credit deadlines to maximize ratepayer benefits.	Action Plan	7/1/2026	Linea Energy	PNM is technology agnostic so it can select the best plan for ratepayers

Table D-2 - 2026 IRP FSP Statement of Need/Action Plan Comments

Issue Number	Status	Description	Category	Date Reported	Respondent	Comments
51	Closed	#4, partnerships for emerging resource development. Add: PNM will study the feasibility and assumptions associated with gas to hydrogen conversion.	Action Plan	7/1/2026	Linea Energy	Assumptions are based on best available data and come from industry experts. As technologies develop this information is updated and will be revisited in future IRP's. Item 4 is included to help focus on solutions to challenges of advancing emerging technologies.
52	Closed	#9, annual reporting. Also include reporting on annual compliance with ETA mandates.	Action Plan	7/1/2026	Linea Energy	Docket 26-0000039-UT demonstrates PNM's CO2 compliance. Duplication in the action plan is unneccasry.
53	Closed	RFP will identify the demand-side resource types eligible to respond and describe how PNM will evaluate those resources. Prior to issuing this RFP, PNM will publish its proposed accreditation methodology for demand-side resources for stakeholder comment	Action Plan	7/1/2026	SWEEP	Expanded on Action Plan item 3.
54	Closed	#7, demand side initiatives. With stakeholders, PNM will develop a demand-side and DER implementation roadmap addressing energy efficiency, demand response, managed EV charging, customer-sited storage, VPP/DER aggregation, and other flexible load resources (potential programs, tariffs, or pilots). Will evaluate whether a grid services tariff, VPP pilot, or other compensation mechanism will enable DERs/DSM.	Action Plan	7/1/2026	SWEEP	More specifics have been added to Action Plan on demand-side management efforts. With substantial efforts already in progress on Grid Moderinzation including AMI implementation, additional DR programs and energy efficiency initiatives, expanding on these is not warrented.
55	Closed	New item, demand-side resources capacity accreditation. PNM will publish for stakeholder comment, its capacity accreditation method for demand-side resources. Too address both summer and winter seasons, comparable in rigor and transparency to PNM's ELCC-based accreditation approach for supply-side storage resources, will explain how seasonal reliability-hour availability is quantified. Publish its methodology at least 90 days before issuing the 2033-2036 All-Source RFP.	Action Plan	7/1/2026	SWEEP	PNM does not beleive a separate action item is warrented. The IRP report includes information on ELCC methodology and calculations used for resource planning purposes which will be availabe more than 90-days before an RFP is issued. For the 2026 IRP, PNM has provided accredited capacity for DSM options. PNM has not calculated accredited capacity for sub categories for RFP purposes. PNM provides accredited capacity information in the instructions to bidders for its next RFP solicitation subsequent to acceptance of the SON and AP for the 2026 IRP. Stakeholders are encourage to provide comments during the RFP commentary period.

Table D-2 - 2026 IRP FSP Statement of Need/Action Plan Comments

Issue Number	Status	Description	Category	Date Reported	Respondent	Comments
56	Closed	#8, Default to TOD Rates. Add to Pricing Advisory Committee scope: customer protections, customer education and outreach. Include opt-out rates, load shifting, bill impacts, and peak reduction in metrics.	Action Plan	7/1/2026	SWEEP	Addressed in the revised draft AP
57	Closed	#9, annual reporting. Annual reports include progress on demand-side and DER implementation, including EE savings, DR enrolled MW and accredited capacity where applicable, TOD participation and opt-out rates, managed charging participation, customer-sited storage and VPP/DER aggregation participation, non-confidential RFP participation by demand-side resource.	Action Plan	7/1/2026	SWEEP	Annual updates on PNM's demand side efforts are publically available through other required filings. Including in IRP Action Plan is duplicative.
58	Closed	Add to #1 - 1.PNM will continue to pursue the necessary regulatory approvals and advance construction efforts to support the timely commercial operation of resources included in the Application for 2029-2032 System Resources and Abandonment of Four Corners Power Plant.	Action Plan	7/1/2026	WRA	Accepted
59	Closed	#4, partnerships for emerging resource development. Edits to working group scope: ...to support the deployment of emerging zero carbon resources including fusion and enhanced geothermal and transmission expansion in New Mexico.	Action Plan	7/1/2026	Pacific Fusion	Edits included with item 4. Due to its ambiguity "longer term planning principles" is not defined. PNM requires more specificity in order to determine if this is warranted
60	Closed	#7, demand side initiatives. Editing changes: best efforts, programs that are achievable and available to PNM...	Action Plan	7/1/2026	WRA	PNM slightly reworded this idea into the Action Plan under the DR and EE items. PNM felt its approach is consistent with NMPRC's current rules.
61	Closed	#3, next all-source RFP. Should add: "or to procure resources that will start construction in the 2033-2036 timeframe to meet system needs in 2045 and beyond."	Action Plan	7/1/2026	NMPRC Staff	Expanded action plan item #4.
62	Closed	#6, EDAM participation, resource adequacy proposal. This is a slippery slope if the EDAM starts mandating PRMs (like SPP imposes on SPS). Also, ELCC control may be relegated which can also limit the value of high quality NM resources.	Action Plan	7/1/2026	NMPRC Staff	No action required.
63	Closed	#8, opt out TOD rates. Not sure if this is an IRP action. TOD may have very little impact on overall resource needs.	Action Plan	7/1/2026	NMPRC Staff	No action required.
64	Closed	#3, next all-source RFP. scope and timing of resources procured under this RFP should be scaled to demonstrated and committed load growth, rather than to the upper bounds of the high economic growth or extreme economic development sensitivities,	Action Plan	7/1/2026	NMAREA	This was reflected in the revised draft SoN
65	Closed	#3, next all-source RFP. provide an estimate of the revenue requirement and customer rate impact of the resources identified to meet 2033–2036 focus-period needs, evaluated on a full revenue-requirement basis	Action Plan	7/1/2026	NMAREA	Addressed in the revised draft SoN.

Table D-2 - 2026 IRP FSP Statement of Need/Action Plan Comments

Issue Number	Status	Description	Category	Date Reported	Respondent	Comments
66	Closed	#5, transmission alternatives. including how each transmission alternative affects portfolio costs and whether, and to what extent, building new transmission eliminates or reduces other resource needs	Action Plan	7/1/2026	NMAREA	PNM will provide appropriate information justifying the basis for any facilities sought under a regulatory filing.
67	Closed	#6, EDAM participation, resource adequacy proposal. PNM will evaluate the impact of the regional resource adequacy program on its planning reserve margin and long-term reliability planning metrics, and will report that evaluation to stakeholders for incorporation into its next IRP.	Action Plan	7/1/2026	NMAREA	Accepted, but reworded.
68	Closed	#9, annual reporting. include the actual revenue requirement and customer rate impact of resources as they are acquired.	Action Plan	7/1/2026	NMAREA	These reports are more appropriate for the application of the resource filing rather than IRP Action Plan status updates.
69	Closed	#4, partnerships for emerging resource development. Add "longer term planning principles" to working group scope and support emerging clean energy resource development.	Action Plan	7/1/2026	WRA	Edits included with item 4. Due to its ambiguity "longer term planning principles" is not defined. PNM requires more specificity in order to determine if this is warranted
70	Closed	#4, partnerships for emerging resource development. Add "public and private" partnerships"	Action Plan	7/1/2026	NMPRC Staff	Added to Acton Plan Item 4
71	Closed	Bridging the Capacity Need Gap, p. 4. Statement of Need contains no cost information. PNM should disclose the estimated revenue requirement and customer rate impact of each tier of resources, including the filed 2029-2032 System Resources, the 2029-2032 Supplement, and the Focus Period generic resources, shown against PNM's currently approved revenue requirement, so that stakeholders and the Commission can evaluate the affordability of the plan PNM is recommending.	SON	7/1/2026	NMAREA	This has been incorporated into the IRP report.
72	Closed	New item, transmission planning and operations. For purposes of its next integrated resource planning and transmission planning processes, PNM will: (a) evaluate any recommendations for transmission upgrades or new transmission corridors relevant to PNM's system that are identified in the WestTEC 10-year and 20-year expansion plans; and (b) assess adoption of a "flow-based" approach to transmission planning, utilization and congestion assessment.	Action Plan	7/1/2026	WRA	Action plan modified to incorporate WestTEC and flow-based assessment.

Appendix E: Additional Details on PNM's Existing Generation

In accordance with the IRP Rule, this appendix provides detailed characteristics of our existing generation resources.

- Table E-1 Provides information on current PVNGS ownership shares
- Table E-2 Provides information on current FCPP ownership shares
- Table E-3 Highlights thermal resource operational characteristics
- Table E-4 Reviews the ongoing costs associated with existing resources
- Table E-5 Shows a ten-year historical look at PNM wind performance
- Table E-6 Summarizes solar resources within PNM's portfolio
- Figure E-1 Shows solar capacity growth
- Table E-7 Provides a general characteristic of storage resources within PNM's portfolio
- Figure E-2 Shows storage resources over time
- Table E-8 Summarizes PPA and ESA annual costs
- Table E-9. General characteristics of Peak Saver and Power Saver
- Table E-10. General characteristics of PNM's Triennial filing energy efficiency programs

NUCLEAR

Palo Verde Nuclear Generating Station (PVNGS)

The Palo Verde Nuclear Generating Station (PVNGS) is PNM's only nuclear generating resource and provides 288 MW of carbon-free capacity to the Company's generation portfolio. Located approximately 50 miles west of Phoenix, Arizona, the three-unit facility is operated by Arizona Public Service Company (APS) on behalf of the plant's seven co-owners. Commercial operation began between 1986 and 1988, and the units are licensed by the U.S. Nuclear Regulatory Commission to operate through 2045 (Unit 1), 2046 (Unit 2), and 2047 (Unit 3).

PNM's ownership interest is distributed across all three generating units and currently consists of 30 MW in Unit 1, 124 MW in Unit 2, and 134 MW in Unit 3. The ownership interests of all participating utilities are summarized in Table E-1.

TABLE E-1. CURRENT PVNGS OWNERSHIP SHARES (NET DEPENDABLE SUMMER CAPACITY)

Owner	Unit 1 (MW)	Unit 2 (MW)	Unit 3 (MW)	Percentage
Arizona Public Service	382	382	382	29.1%
Salt River Project	333	240	230	20.4%
El Paso Electric	207	208	207	15.8%
Southern California Edison	207	208	207	15.8%
Public Service Co of New Mexico	**30**	**124**	**134**	**7.3%**
So. Cal. Public Power Assoc.	77	78	77	5.9%
Los Angeles Dept. of Water & Power	75	75	75	5.7%
Total	**1,311**	**1,314**	**1,312**	**100.0%**

PNM's current ownership reflects the completion of a multi-year transition associated with historical lease arrangements. Portions of Units 1 and 2 were previously subject to sale/leaseback financing agreements, under which PNM reacquired 154 MW of owned capacity while allowing the remaining leased interests to expire in 2023 and 2024. As a result, PNM's ownership interest decreased from 402 MW, as reported in the 2023 IRP, to the current 288 MW. The remaining ownership interests are expected to remain available through the expiration of each unit's operating license.

APS is responsible for nuclear fuel procurement on behalf of the owners. Fuel supply is secured through long-term agreements covering uranium concentrate, conversion, enrichment, and fuel fabrication services with multiple qualified suppliers, providing diversity in the fuel supply chain and reducing procurement risk.

Energy from PVNGS is delivered to PNM's service territory using jointly owned transmission facilities together with contracted transmission rights. PNM expects these transmission arrangements, along with existing fuel procurement practices, to continue supporting reliable operation of the facility throughout the planning horizon.

COAL

Four Corners Power Plant (FCPP)

The Four Corners Power Plant (FCPP) is a two-unit, coal-fired generating facility located on the Navajo Nation near Fruitland, New Mexico. Units 4 and 5 are operated by Arizona Public Service Company (APS) on behalf of the plant's owners. Coal for the facility is supplied from the adjacent Navajo Mine, which is owned by Navajo Transitional Energy Company (NTEC). The current coal supply agreement extends through 2031.

PNM has owned an interest in FCPP since acquiring a 13% share of Units 4 and 5 in 1969 and 1970. PNM's ownership totals 200 MW of net dependable summer capacity. Current ownership shares for the facility are summarized in Table E-2.

TABLE E-2. CURRENT FCPP OWNERSHIP SHARES (SUMMER NET DEPENDABLE CAPACITY)

Owner	Unit 4 (MW)	Unit 5 (MW)	Total (MW)	Percentage
Arizona Public Service	485	485	970	63%
Public Service Co of New Mexico	**100**	**100**	**200**	**13%**
Salt River Project	77	77	154	10%
Tucson Electric Power	54	54	108	7%
Navajo Transitional Energy Company	54	54	108	7%
Total	**770**	**770**	**1,540**	**100%**

Power generated by FCPP is delivered to PNM's service territory through the Company's transmission system. In addition to providing dispatchable generation, the facility has historically contributed to resource adequacy and operational flexibility during periods of high customer demand.

Following the retirement of the San Juan Generating Station in 2022, FCPP became PNM's only remaining coal-fired generating resource and the largest source of direct carbon emissions within the Company's generation portfolio. Under the Energy Transition Act, electric utilities must comply with increasingly stringent emissions limitations beginning in 2032. Based on the evaluation following the 2023 IRP, the abandonment of its ownership interest in FCPP following expiration of the existing coal supply agreement (July 2031) is currently pending before the NM PRC (Docket No. 26-0000114).

Although PNM plans to exit ownership of the generating units in 2031, the Company expects to retain certain transmission-related facilities associated with the site that are necessary to maintain reliable operation of the transmission system. These retained facilities are not part of the proposed abandonment of the generating assets.

The Four Corners facility is governed through a series of agreements among the co-owners, including co-tenancy, operating, coal supply, and lease agreements. The coal supply agreement expires in 2031, while the underlying land leases extend beyond plant operations to provide for decommissioning activities. Under the existing agreements, PNM's responsibility for mine reclamation is limited to its proportionate share of the required reclamation funding established under the coal supply agreement.

NATURAL GAS

Afton Generating Station

The Afton Generating Station (Afton) is a 235 MW natural gas-fired combined-cycle generating facility located near La Mesa, New Mexico. The plant entered commercial operation in 2007 and consists of a General Electric (GE) Frame 7 combustion turbine, a heat recovery steam generator, and a steam turbine. Afton can operate in either simple-cycle or combined-cycle mode, providing operational flexibility to support a range of system conditions. Afton is assumed to be available with PNM's portfolio through its planned retirement year, 2042. For modeling purposes, PNM assumed that Afton would be capable of prolonging its planned retirement by a couple of years to reach the end of 2044. This assumption will be re-evaluated in the following IRP (2029).

Located within PNM's southern service territory, Afton serves both local and system-wide reliability needs. The facility can deliver energy to customers in southern New Mexico and, through existing transmission arrangements, to load centers in northern New Mexico. Natural gas is supplied via the El Paso Natural Gas Company's southern mainline, providing access to regional fuel supplies.

La Luz Energy Center

The La Luz Energy Center (La Luz) is a 41 MW natural gas-fired simple-cycle generating facility located in Valencia County near PNM's Belen Substation, west of Albuquerque. Placed in service in 2016, it is the newest thermal generating resource in PNM's portfolio and consists of a single GE LM6000 aeroderivative combustion turbine. La Luz is assumed to be available in PNM's portfolio through its planned retirement year, 2055 and is expected to be converted to burn hydrogen fuel by 2045.

La Luz is strategically located within the Albuquerque load pocket, where it provides fast-start generation and operating reserves to support system reliability. The facility is capable of reaching full output in approximately 10 minutes, enabling it to respond quickly to changing system conditions, fluctuations in customer demand, and variability in renewable generation. The unit is equipped with selective catalytic reduction and carbon oxidation systems to reduce air emissions during operation.

Natural gas is supplied to the facility through the Transwestern pipeline system, with additional access to the nearby El Paso Natural Gas interstate pipeline network. The aeroderivative turbine technology also provides operational flexibility that may support the use of lower-carbon fuels such as hydrogen.

Lordsburg Generating Station

The Lordsburg Generating Station (Lordsburg) is an 86 MW natural gas-fired simple-cycle peaking facility located near Lordsburg, New Mexico. The plant entered commercial operation in 2002 and consists of two GE LM6000 aeroderivative combustion turbines that provide fast-start, dispatchable generation to support system reliability. For modeling purposes, PNM assumed that Lordsburg units would be capable of prolonging its planned retirement by a couple of years to reach the end of 2044 and are expected to be converted to burn hydrogen fuel by 2045.

Located within PNM's southern service territory, Lordsburg provides peaking capacity, operating reserves, and load-following capability during periods of high demand and changing system conditions. Energy generated at the facility can serve customer load in southern New Mexico or be delivered to northern New Mexico through existing transmission arrangements. Natural gas is supplied via the El Paso Natural Gas Company's southern mainline, and the aeroderivative turbine technology provides operational flexibility that may support the future use of lower-carbon fuels as those technologies become commercially viable.

Luna Energy Facility

The Luna Energy Facility (Luna) is a 190 MW natural gas-fired combined-cycle generating resource located near Deming, New Mexico. Commissioned in 2006, the facility consists of two GE 7FA combustion turbines, each paired with a heat recovery steam generator, and is jointly owned by PNM, Tucson Electric Power, and Samchully Power & Utilities 1, LLC, with each owner holding a one-third interest. PNM assumes that Luna will be available through its planned retirement year, 2042. Luna operates exclusively in combined-cycle mode, providing efficient, dispatchable generation to support system reliability. For modeling purposes, PNM assumed that Luna would be capable of prolonging its planned retirement by a couple of years to reach the end of 2044. This assumption will be re-evaluated in the following IRP (2029).

Energy produced from PNM's ownership share can be delivered directly to customers in southern New Mexico or, through existing transmission arrangements, to load centers in northern New Mexico. Natural gas is supplied via the El Paso Natural Gas Company's southern mainline, with each co-owner responsible for procuring its own fuel supply.

Reeves Generating Station

The Reeves Generating Station (Reeves) is a 146 MW natural gas-fired steam generating facility located in central Albuquerque. The plant consists of three steam turbine units, Units 1, 2, and 3, that are 42, 41, and 63 MW, respectively. The units entered commercial operation between 1960 and 1962 and Units 1 and 2 were upgraded in 2010 and 2011. Natural gas is supplied by the New Mexico Gas Company.

Reeves plays an important role in maintaining reliable electric service within the Albuquerque load pocket by providing dispatchable generation, voltage support, and operational flexibility while helping to alleviate local transmission constraints. As one of the few generating resources located within the metropolitan area, the facility continues to provide essential reliability services that support operation of the transmission system. As discussed in Section 4.1.3 of the 2026 IRP report, the findings from the Reeves analysis supported the decision to incorporate the Reeves extension as a resource until 2044 in PNM's 2026 IRP.

Rio Bravo Generating Station

The Rio Bravo Generating Station (Rio Bravo) is a 149 MW natural gas-fired simple-cycle generating facility located in south Albuquerque. The plant consists of a GE 7FA combustion turbine that entered commercial operation in 2000 and was acquired by PNM in 2013 following approval by the NMPRC.

Located within the Albuquerque load pocket, Rio Bravo provides dispatchable generation that supports local reliability by helping relieve transmission constraints, maintain system operating criteria, and provide voltage support. The facility is designed for dual-fuel operation, using natural gas supplied by the New Mexico Gas Company as its primary fuel and fuel oil stored on-site as a backup fuel source when needed. As a load-side generating resource, Rio Bravo continues to play an important role in supporting reliable operation of PNM's transmission system and serving customer demand. Rio Bravo's operational term extends through November 2040. For modeling purposes, PNM assumed that Rio Bravo would be capable of prolonging its planned retirement by some years to reach the end of 2044. This assumption will be re-evaluated in the following IRP (2029).

Valencia Energy Facility

The Valencia Energy Facility (Valencia) is a natural gas-fired simple-cycle generating facility located south of Belen, New Mexico, within PNM's northern load pocket. The facility consists of a GE 7FA combustion turbine that entered commercial operation in 2008. PNM purchases the plant's output under a long-term power purchase agreement (PPA) with Onward Energy. In 2025, the NMPRC approved an extension of the PPA from 2028, the expiration in the original PPA, through 2039. The NMPRC also approved an increase in PNM's contracted capacity from 155 MW to 167 MW starting in June 2028. Valencia provides dispatchable peaking capacity and operational flexibility to support reliability in the Albuquerque load area, while natural gas is supplied through a dedicated pipeline interconnection with Transwestern's interstate pipeline system. Table E-3 and E-4 show the thermal resources operating characteristics and costs.

Table E-3 Thermal Resources Operational Characteristics

Thermal Resources	Heat Rate at Max Output (Btu/kWh)	Forced Outage Rate (%)	Accredited Capacity (%)	CO2 Rate (lbs/MWh)	SO2 Rate (lbs/MWh)	NOx Rate (lbs/MWh)	Water Usage (gal/MWh)	Coal Ash Rate (lbs/MWh)	Nameplate Capacity (MW)
COAL									
Four Corners Unit 4	9,650	20	72	1,963	.505	.655	584	253	100
Four Corners Unit 5	9,650	20	72	2,029	.505	.655	584	253	100
NUCLEAR									
Palo Verde Unit 1	10,300	2	94	-	-	-	19	-	30
Palo Verde Unit 2	10,300	2	94	-	-	-	19	-	124
Palo Verde Unit 3	10,300	2	94	-	-	-	19	-	134
NATURAL GAS									
Afton Generating Station	7,680	2	92	926	.005	.18	92	-	235
La Luz Gas Turbine	9,747	8.7	98	1,121	.007	.25	44.5	-	41
Lordsburg Generating Station Unit 1	9,885	4.3	98	1,117	.008	1.07	250.6	-	43
Lordsburg Generating Station Unit 2	9,890	4.8	98	1,180	.005	.80	250.6	-	43
Luna Energy Facility	7,621	3	92	817	.002	.04	184	-	190
Reeves Generating Station Unit 1	12,057	3.3	92	1,452	.009	3.39	897	-	42
Reeves Generating Station Unit 2	11,851	3.3	92	1,495	.007	2.89	897	-	41
Reeves Generating Station Unit 3	11,583	3.3	92	1,424	.007	2.89	897	-	63
Rio Bravo Gas Turbine	10,619	5.4	98	1,367	.008	.44	7.8	-	149
Valencia Energy Facility	10,234	3.3	98	1,410	.010	.40	22.4	-	155

Table E-4. Ongoing Costs Associated with Existing Resources ($Millions)

Fuel Costs ($ millions)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Palo Verde	18.5	17.4	19.2	20.2	21.3	22.7	23.5	22.9	24.5	25.6	25.4	27.0	28.1	27.4	29.1	30.7	30.4	32.3	33.5	30.7
Four Corners	39.0	39.6	42.4	45.0	47.9	16.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M Costs ($ millions)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Palo Verde	51.4	54.8	54.3	55.3	59.3	58.6	55.9	57.4	58.8	60.1	61.5	63.0	64.6	66.1	67.7	69.4	71.1	72.9	74.7	76.5
Four Corners	20.9	21.4	23.5	21.8	21.3	11.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Afton	12.7	12.5	23.1	12.6	12.8	15.0	15.4	15.7	16.0	16.4	16.8	17.3	17.7	18.2	18.7	19.9	20.4	20.9	21.5	22.0
La Luz	1.6	1.7	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.1	2.1	2.1	2.2	2.2
Lordsburg	3.1	3.4	3.6	3.6	3.7	3.5	3.6	3.6	3.7	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.3	4.4	4.5
Luna	10.1	9.8	10.2	10.0	10.1	9.9	10.0	10.2	10.4	10.6	10.7	10.9	11.1	11.3	11.6	12.6	12.9	13.2	13.6	13.9
Reeves	7.9	8.2	8.4	8.6	8.9	9.1	9.2	9.5	9.7	10.0	10.2	10.5	10.8	11.1	11.4	11.7	12.0	12.3	12.6	0.1
Rio Bravo	3.0	2.4	2.8	2.9	5.5	3.2	3.3	3.4	3.5	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5
Valencia	23.7	24.0	20.8	18.4	18.6	18.8	19.0	19.2	19.4	19.6	19.8	20.0	20.2	20.4	-	-	-	-	-	-
PNM-Owned Solar	4.4	4.5	5.0	5.3	5.4	5.6	5.7	5.9	6.1	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8	8.0	8.3
Annual Revenue Requirement ($ millions)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Palo Verde	56.4	57.2	58.1	59.0	59.9	61.5	62.8	64.1	65.5	72.8	73.9	74.9	76.0	76.9	90.2	89.9	89.7	89.4	88.9	141.2
Four Corners	22.1	22.4	22.6	22.7	23.3	18.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Investment Recovery	-	-	-	-	-	-	11.2	11.5	11.7	11.9	12.1	12.3	12.5	12.7	12.9	13.1	13.3	13.5	13.7	13.9
Afton	21.9	21.4	22.0	22.3	20.8	20.3	20.0	19.8	19.5	20.2	19.8	19.5	19.1	18.7	21.3	20.6	20.5	19.9	18.8	28.8
La Luz	5.9	6.0	5.8	5.6	5.1	5.1	5.1	5.1	5.0	5.3	5.2	5.1	5.0	4.9	4.8	5.4	5.3	5.1	4.8	2.5
Lordsburg	5.3	5.8	6.0	5.8	5.5	5.4	5.6	5.7	5.8	6.7	6.8	6.9	7.0	7.0	7.2	9.4	9.4	9.4	9.1	7.8
Luna	9.9	9.9	9.7	10.3	11.2	11.3	11.6	11.9	12.2	13.8	14.0	14.3	14.6	14.8	15.0	19.0	19.1	19.1	18.5	22.4
Reeves	11.2	10.9	10.5	11.5	8.8	11.5	12.9	12.6	13.0	18.7	19.3	18.5	17.6	16.5	18.2	17.3	16.1	15.0	13.8	0.4
Rio Bravo	6.8	7.0	7.2	7.0	7.1	8.1	8.6	9.0	9.4	11.7	12.0	12.2	12.5	12.7	16.1	16.2	16.3	16.4	15.9	15.6

Geothermal

Dale Burgett Geothermal Plant

The Dale Burgett Geothermal Plant is an 11 MW geothermal generating resource located in the Animas Valley of Hidalgo County, approximately 20 miles southwest of Lordsburg, New Mexico. PNM purchases the facility's energy and associated RECs under a long-term PPA with Zanskar Geothermal & Minerals. The facility reached its full 11 MW capacity in 2018. The current PPA is set to expire in March 2042.

The plant uses a closed-loop binary-cycle process that transfers heat from geothermal groundwater to a secondary working fluid to generate electricity before reinjecting the geothermal fluid back into the underground reservoir. This process enables continuous generation while minimizing emissions and conserving the geothermal resource through reinjection of the produced fluids.

Wind

New Mexico Wind Energy Center (NMWEC)

The New Mexico Wind Energy Center (NMWEC) is PNM's longest-serving wind resource and has supplied renewable energy to the Company's portfolio since 2003. PNM purchases the energy and associated RECs generated by the 200 MW facility from NextEra Energy, Inc. NMWEC is located near House, New Mexico and interconnects with PNM's transmission system at the Taiban Mesa Substation on the Blackwater–Clines Corners 345-kV line. In 2019, the project was repowered with upgraded turbine technology, increasing annual energy production, and PNM extended its PPA through 2043.

Red Mesa Wind Energy Center

Red Mesa Wind Energy Center (Red Mesa) provides 102 MW under a long-term PPA with NextEra Energy, Inc. PNM began purchasing energy and associated RECs in 2015 and the 20-year PPA is scheduled to expire at the end of 2034. Red Mesa is located in Cibola County, New Mexico and is interconnected to PNM's 115-kV transmission system at the Red Mesa Substation.

Casa Mesa Wind Project

The Casa Mesa Wind Project (Casa Mesa) added 50 MW of wind generation to PNM's portfolio in 2018 under a long-term PPA with NextEra Energy, Inc. The 25-year PPA is scheduled to expire in 2043. Located in eastern New Mexico in De Baca and Quay Counties, the project shares a transmission interconnection with the adjacent NMWEC. Because both facilities utilize the same point of interconnection, their combined output is limited to 200 MW.

La Joya Wind Projects

PNM has two separate long-term PPAs for the projects with Avangrid Renewables that expire in 2041. The La Joya 1 and La Joya 2 Wind Projects (La Joya Wind Projects) represent the newest operating wind resources in PNM's existing portfolio. The projects are 166 MW and 140 MW, respectively, totaling 306 MW. The projects are both located in Torrance County, New

Mexico. While both facilities contribute carbon-free energy to PNM’s portfolio, the output and RECs from La Joya 1 support voluntary customer renewable energy programs and therefore do not count as an RPS-eligible resource for compliance with the ETA. La Joya 2 supplies retail customers and provides RECS that contribute to PNM’s ETA compliance.

Historical operating data provides additional insight into the long-term performance of PNM’s wind portfolio. Historic performance has varied due to a number of factors, including prevailing weather conditions, the 2019 repowering of the New Mexico Wind Energy Center (NMWEC), and the advent of newer projects such as Casa Mesa and La Joya with advanced turbine technologies.

Palomas

To be located within San Miguel and Torrance County. Palomas is an 800 MW wind generation facility that is currently pending NMPRC approval in PNM’s 2029-2032 system resource application and therefore is not considered an existing resource within PNM's portfolio until 2029. If approved, the project would expand PNM's carbon-free energy portfolio and further diversify the company's renewable resource mix throughout the planning horizon.

Table E-5 below shows a ten-year summary of energy generation and capacity factors for each of PNM’s wind resources.

TABLE E-5. TEN-YEAR HISTORY OF PNM'S WIND RESOURCE PERFORMANCE

Energy (GWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Casa Mesa	-	-	-	187,441	187,442	191,070	163,498	177,759	182,195	180,605
La Joya 1	-	-	-	-	-	560,453	555,817	611,121	550,144	494,483
La Joya 2	-	-	-	-	-	384,857	446,022	464,478	439,440	402,901
NMWEC*	492,427	496,778	485,108	610,138	573,382	611,353	577,112	582,838	546,202	504,921
Red Mesa	214,030	215,606	212,754	220,073	230,275	196,105	197,568	199,437	160,464	163,215
Total	**706,457**	**712,384**	**697,862**	**1,017,652**	**991,099**	**1,943,838**	**1,940,017**	**2,035,633**	**1,878,445**	**1,746,125**
Capacity Factor (%)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Casa Mesa	-	-	-	43%	43%	44%	37%	41%	42%	41%
La Joya 1	-	-	-	-	-	39%	38%	42%	38%	34%
La Joya 2	-	-	-	-	-	31%	35%	38%	36%	33%
NMWEC[1]	28%	28%	28%	35%	33%	35%	33%	33%	31%	29%
Red Mesa	24%	24%	24%	25%	26%	22%	22%	22%	18%	18%
Average	**27%**	**23%**	**23%**	**33%**	**32%**	**34%**	**33%**	**35%**	**33%**	**30%**

Notes
1. Increased output from NMWEC in 2019 due to repowering

SOLAR

The expansion of PNM’s solar portfolio has occurred through a series of Commission-approved resource procurements and competitive solicitations, resulting in the addition of utility-scale solar facilities across New Mexico. Table E-6 highlights the general characteristics of solar resources within PNM’s portfolio, and Figure E-1 summarizes the growth in installed and committed solar PV capacity over time and illustrates the increasing role of solar generation within PNM's resource portfolio.

TABLE E-6. GENERAL CHARACTERISTICS OF PNM'S SOLAR RESOURCES (EXISTING, APPROVED, PENDING)

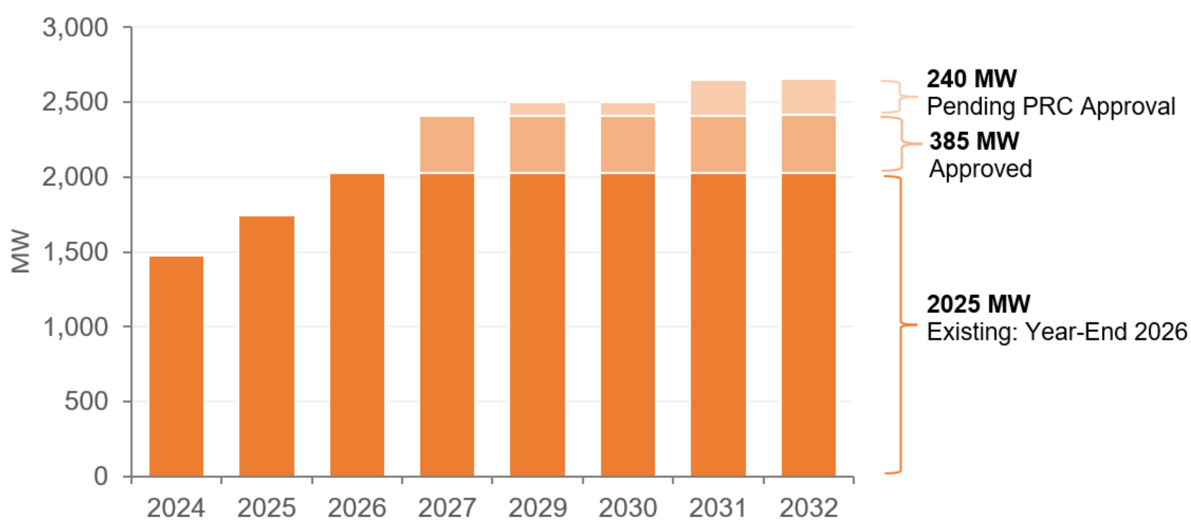
Solar Resources	Status	County	State	First Year	Last Year	Nameplate Capacity (MW)
			OWNED			
Alamogordo Solar	Existing	Otero	NM	2011	2041	5
Albuquerque Solar Energy Center (Reeves)	Existing	Bernalillo	NM	2011	2041	2
Cibola Solar	Existing	Cibola	NM	2015	2035	8
Deming Solar	Existing	Luna	NM	2011	2041	9
Las Vegas Solar	Existing	San Miguel	NM	2011	2041	5
Los Lunas Solar	Existing	Valencia	NM	2011	2041	7
Manzano Solar	Existing	Valencia	NM	2013	2043	8
Meadow Lake Solar	Existing	Valencia	NM	2014	2045	9
Otero Solar	Existing	Otero	NM	2013	2043	8
Prosperity Solar	Existing	Bernalillo	NM	2011	2041	1
Rio Communities Solar	Existing	Valencia	NM	2015	2045	10
Rio Del Oro Solar	Existing	Valencia	NM	2019	2049	10
Rio Rancho Solar	Existing	Bernalillo	NM	2019	2049	10
San Miguel 1 Solar	Existing	San Miguel	NM	2019	2049	10
San Miguel 2 Solar	Existing	San Miguel	NM	2019	2049	10
Sandoval Solar	Existing	Sandoval	NM	2014	2044	6
Santa Fe Solar	Existing	Santa Fe	NM	2015	2045	9
Santolina Solar	Existing	Bernalillo	NM	2015	2045	11
South Valley Solar	Existing	Bernalillo	NM	2015	2045	10
Sunbelt Solar	Approved	San Juan	NM	2027	2047	100
Vista Solar	Existing	Valencia	NM	2019	2049	10
			PPA			
Arroyo Solar	Existing	McKinley	NM	2024	2044	300
Atrisco Solar	Existing	Bernalillo	NM	2024	2044	300
Britton Solar	Existing	Torrance	NM	2019	2044	50
Cat Hills Solar	Pending	Valencia	NM	2030	2050	150
Community Solar Phase 1	Existing	Various	NM	2026	2046	117
Community Solar Phase 2	Approved	Various	NM	2027	2049	185
Encino North Solar	Existing	Sandoval	NM	2023	2043	50
Encino Solar	Existing	Sandoval	NM	2020	2045	50
Facebook 1 Solar	Existing	Valencia	NM	2017	2042	10
Facebook 2 Solar	Existing	Bernalillo	NM	2018	2043	10
Facebook 3 Solar	Existing	Bernalillo	NM	2018	2043	10
Four Mile Solar	Approved	San Juan	NM	2027	2047	100
Jicarilla Solar 1	Existing	Rio Arriba	NM	2023	2043	50
Jicarilla Solar 2	Existing	Rio Arriba	NM	2022	2037	50

Solar Resources	Status	County	State	First Year	Last Year	Nameplate Capacity (MW)
Quail Ranch Solar	Existing	Bernalillo	NM	2025	2045	100
Route 66 Solar	Existing	Cibola	NM	2022	2047	50
San Juan Solar	Existing	San Juan	NM	2024	2044	200
Sky Ranch Solar	Existing	Valencia	NM	2024	2044	190
Star Light Solar	Existing	Valencia	NM	2026	2046	100
TAG Solar I	Existing	Sandoval	NM	2025	2045	140
Wild Cat Solar	Pending	McKinley	NM	2029	2049	90
Windy Lane Solar	Existing	De Baca	NM	2026	2046	90
					Subtotal, Solar (Existing)	**2,025**
					Subtotal, Solar (Approved)	**385**
					Subtotal, Solar (Pending)	**240**
					Total, Solar (Existing, Approved, Pending)	**2,650**

Notes

1. Community Solar: Comprises multiple solar facilities, including both operational and planned projects. A total of 117 MW is expected to be operational by year-end 2026. Phase 1 is expected to reach 125 MW, while Phase 2 is anticipated to begin commercial operation in 2027 and expand to 185 MW by year-end 2029.
2. Windy Lane and Starlight are classified as existing resources due to their expected commercial operation by the end of 2026.

FIGURE E -1. SOLAR CAPACITY GROWTH



ENERGY STORAGE

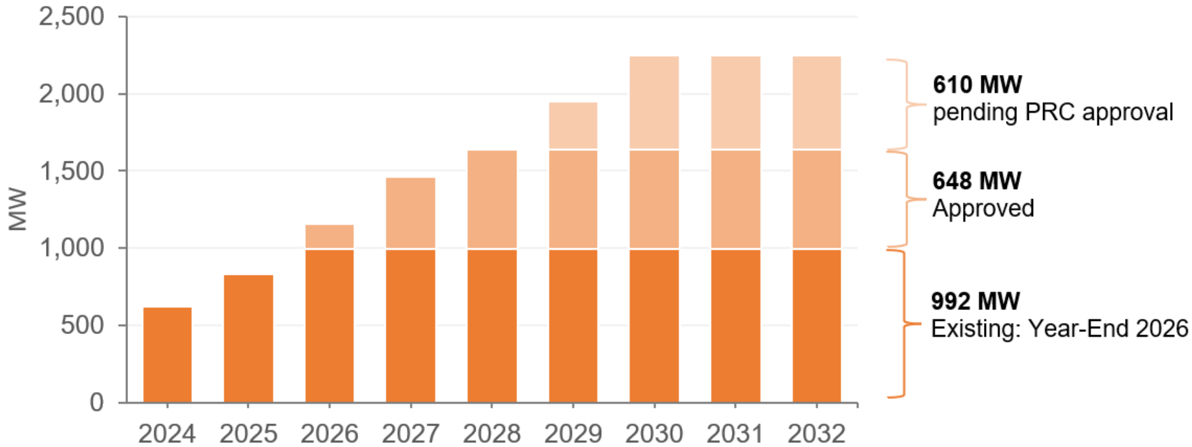
Large utility-scale battery energy storage was first added to PNM's portfolio in 2023 with the commercial operation of the Arroyo Battery Energy Storage System (150 MW) and the Jicarilla I Battery Energy Storage System (20 MW). These projects demonstrated the operational benefits of pairing battery storage with large-scale solar generation by enabling renewable energy to be stored and dispatched to better align with customer demand.

Since bringing these first two projects online, PNM has significantly expanded its battery energy storage portfolio through a series of Commission-approved resource procurements and competitive solicitations. New standalone and co-located battery storage facilities have been developed to support renewable integration, improve system flexibility, and maintain reliability as the Company's generation portfolio transitions toward carbon-free resources. Table E-7 summarizes the existing and future development of individual storage projects, while Figure E-2 illustrates the growth of battery energy storage capacity within PNM's portfolio over time.

TABLE E-7. GENERAL CHARACTERISTICS OF PNM'S STORAGE RESOURCES (EXISTING, APPROVED, PENDING)

Energy Storage Resources	Status	County	State	First Year	Last Year	Nameplate Capacity (MW)
OWNED						
Distribution Storage	Existing	Various	NM	2024	2044	12
Distribution Storage	Approved	Various	NM	2027	2047	30
Sandia Storage	Existing	Bernalillo	NM	2026	2046	60
Sunbelt BESS	Approved	San Juan	NM	2027	2047	50
PPA						
Arroyo Storage	Existing	McKinley	NM	2023	2043	150
Atrisco Storage	Existing	Bernalillo	NM	2024	2044	300
Britton BESS	Pending	Torance	NM	2029	2049	60
Cat Hills BESS	Pending	Valencia	NM	2031	2051	150
Corazon Storage	Approved	Bernalillo	NM	2027	2047	150
Encino BESS	Pending	Sandoval	NM	2029	2049	110
Four-Mile Mesa Storage	Approved	San Juan	NM	2027	2047	100
Gila Monster BESS	Pending	Sandoval	NM	2031	2051	150
Jicarilla Storage	Existing	Rio Arriba	NM	2023	2043	20
Quail Ranch Storage	Existing	Bernalillo	NM	2026	2045	100
Route 66 Storage	Existing	Cibola	NM	2025	2047	50
San Juan Storage	Existing	San Juan	NM	2024	2044	100
Sky Ranch II Storage	Existing	Valencia	NM	2025	2044	100
Sky Ranch Storage	Existing	Valencia	NM	2024	2044	50
Star Light Storage	Approved	Valencia	NM	2026	2046	100
Sun Lasso Storage	Approved	Bernalillo	NM	2028	2048	150
TAG I Storage	Existing	Sandoval	NM	2025	2045	50
TAG II BESS	Pending	Sandoval	NM	2029	2049	90
Wildcat BESS	Pending	McKinley	NM	2029	2049	50
Windy Lane Storage	Approved	De Baca	NM	2026	2046	68
Subtotal, Storage (Existing)						**992**
Subtotal, Storage (Approved)						**648**
Subtotal, Storage (Pending)						**610**
Total, Storage (Existing, Approved, Pending)						**2,250**

FIGURE E-2. ENERGY STORAGE IN PORTFOLIO OVER TIME



The following table, Table E-8 presents the annual costs associated with power purchase agreements and energy storage agreements for existing and approved resources. These costs reflect the contractual obligations associated with the resources over the planning period.

TABLE E-8. ANNUAL COSTS OF PPA & ESA RESOURCES

PPA Cost – Wind ($ millions)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Casa Mesa	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	4.2	0.0	0.0
La Joya 1	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	1.3	0.0	0.0	0.0	0.0
La Joya 2	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	4.0	-	-	-	-
Lone Mesa (NMWEC)	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	12.6	-	-
Red Mesa	7.4	7.6	7.7	7.9	8.1	8.2	8.4	8.6	8.7	-	-	-	-	-	-	-	-	-	-	-
Palomas[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PPA Cost – Solar ($ millions)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Arroyo Solar	13.2	13.1	13.0	12.9	12.8	12.7	12.6	12.6	12.5	12.4	12.3	12.2	12.1	12.0	12.0	11.9	11.8	11.7	1.0	-
Atrisco Solar	20.9	20.8	20.6	20.5	20.3	20.2	20.1	19.9	19.8	19.6	19.5	19.4	19.2	19.1	19.0	18.8	18.7	18.6	15.4	-
Britton Solar	4.2	4.2	4.2	4.1	4.1	4.1	4.0	4.0	4.0	4.0	3.9	3.9	3.9	3.8	3.8	3.8	3.7	3.7	3.7	-
Cat Hills Solar[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	--	-	-	-	-	-	-
Encino North Solar	3.4	3.4	3.3	3.3	3.3	3.3	3.3	3.3	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.1	3.1	2.1	-	-
Encino Solar	4.3	4.2	4.2	4.2	4.2	4.1	4.1	4.1	4.0	4.0	4.0	3.9	3.9	3.9	3.9	3.8	3.8	3.8	3.7	1.9
Four-Mile Solar	-	-	11.5	11.5	11.5	11.4	11.4	11.3	11.2	11.1	11.0	11.0	10.9	10.8	10.7	10.7	10.6	10.5	10.4	10.4
Jicarilla Solar 1	2.6	2.6	2.6	2.6	2.6	2.5	2.5	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.3	1.7	-
Jicarilla Solar 2	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.3	2.3	0.8	-	-	-	-	-	-	-	-
NMRD Solar	3.2	3.1	3.1	3.1	3.1	3.1	3.0	3.0	3.0	3.0	2.9	2.9	2.9	2.9	2.9	2.8	2.8	0.9	-	-
Quail Ranch Solar	8.2	8.1	8.1	8.0	8.0	7.9	7.9	7.8	7.8	7.7	7.6	7.6	7.5	7.5	7.4	7.4	7.3	7.3	7.2	5.4
Route 66 Solar	3.6	3.6	3.5	3.5	3.5	3.5	3.4	3.4	3.4	3.4	3.3	3.3	3.3	3.3	3.2	3.2	3.2	3.2	3.1	3.1
San Juan Solar	18.9	18.9	18.8	18.7	18.6	18.5	18.4	18.3	18.2	18.1	18.0	17.9	17.8	17.8	17.7	17.6	17.5	17.4	15.9	-
Sky Ranch Solar	12.2	12.2	12.1	12.0	12.0	11.9	11.9	11.8	11.8	11.7	11.6	11.6	11.5	11.5	11.4	11.3	11.3	11.2	2.8	0.0
Star Light Solar	-	10.4	10.4	10.3	10.3	10.2	10.2	10.1	10.1	10.0	10.0	9.9	9.9	9.8	9.8	9.7	9.7	9.6	9.6	9.6
TAG Solar I	12.2	12.1	12.0	11.9	11.8	11.7	11.6	11.6	11.5	11.4	11.3	11.2	11.1	11.0	11.0	10.9	10.8	10.7	10.6	7.0
Wild Cat Solar[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Windy Lane Solar	-	9.8	9.8	9.8	9.7	9.7	9.6	9.6	9.5	9.5	9.4	9.4	9.3	9.3	9.3	9.2	9.2	9.1	9.1	9.0
PPA Cost - Geothermal ($ millions)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Dale Burgett	7.2	7.4	7.6	7.8	8.0	8.2	8.4	8.6	8.8	9.0	9.2	9.5	9.7	9.9	10.2	10.4	10.7	-	-	-

PPA Cost - Natural Gas ($ millions)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Valencia Energy Facility	23.7	24.0	20.8	18.4	18.6	18.8	19.0	19.2	19.4	19.6	19.8	20.0	20.2	20.4	-	-	-	-	-	-
ESA Cost - Storage ($ millions)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Arroyo Storage	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	-
Atrisco Storage	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3
Britton BESS[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cat Hills BESS[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Corazon Storage	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Encino BESS[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Four-Mile Storage	-	-	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8
Gila Monster BESS[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jicarilla Storage	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	8.0	-	-
Quail Ranch Storage	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
Route 66 Storage	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
San Juan Storage	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	15.4	-
Sky Ranch II Storage	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	-	-
Sky Ranch Storage	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	2.4	-
Star Light Storage	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Sun Lasso Storage	-	-	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3
TAG I Storage	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	4.4
TAG II BESS[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wildcat BESS[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Windy Lane Storage	-	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4

Notes

1. Pending approval at the NMPRC

Demand Side Resources

Tables E-9 and E-10 summarize the general characteristics of the demand response and energy efficiency resources currently included in PNM's portfolio, including key program attributes, availability, and operational considerations. For modeling purposes in IRP, demand response and energy efficiency program impacts were initially based on the Energy Efficiency and Demand Response Potential Study conducted by ICF for 2026 through 2045. Throughout the statutory period, the ICF forecast impacts were adjusted to align with the program savings and participation levels reflected in the pending 2027-2029 EE and LM program plan filing. The operating lives assumed for energy efficiency programs within the statutory planning period were based on ICF's study assumptions and were used consistently throughout the modeling process. The Peak Saver and Power Saver programs were not assumed to continue beyond 2029, as any extension of these programs would require additional approval from the New Mexico Public Regulation Commission. Peak Saver and Power Saver were included as potential program extensions in the model, using the operating lives assumed by ICF.

Table E-9. General Characteristics of Peak and Power Saver

Demand Response Resources	Status	County	State	First Year	Last Year	Seasonality	Accredited Capacity (%)	Nameplate Capacity (MW)
Peak Saver	Existing	Various	NM	2026	2029	Year-Round	63	30
Power Saver	Existing	Various	NM	2026	2029	Summer	63	40
COST								
Year	2026	2027		2028			2029	
Peak Saver ($000)	3,843	3,477		3,558			3,557	
Power Saver ($000)	5,547	7,050		7,393			7,574	

Table E-10. General Characteristics of PNM's Triennial Energy Efficiency Programs

Energy Efficiency Resources	Status	County	State	First Year	Last Year	Accredited Capacity (%)	Nameplate Capacity (MW)
2026 Program	Existing	Various	NM	2026	2039	87	51
2027 Program	Existing	Various	NM	2027	2040	87	50
2028 Program	Existing	Various	NM	2028	2041	87	52
2029 Program	Existing	Various	NM	2029	2042	87	54
ENERGY COST							
	2026 Program	2027 Program		2028 Program		2029 Program	
($/MWh)	22.5	26.9		28.9		30.5	
ENERGY (GWh)							
Year	2026	2027		2028		2029	
2026 Program	103	103		104		103	

2027 Program	-	102	102	102
ENERGY (GWh)				
Year	2026	2027	2028	2029
2028 Program	-	-	103	102
2029 Program	-	-	-	103

Appendix F Transmission and Distribution Facilities

This appendix provides a detailed list of PNM's owned transmission and distribution facilities. Table F-1 provides a list of PNM's existing, planned/under construction, and future transmission substations. Table F-2 provides a list of PNM's existing, planned/under construction, and future distribution substations. Items included on this list are color-coded using the following convention:

- Black – Existing
- **Green – Existing, To Be Replaced**
- **Blue – Future Planned (24+ Months) or Under Construction**

Table F-3 lists existing jointly-owned transmission lines.

TABLE 0-1: EXISTING, PLANNED/UNDER CONSTRUCTION, AND FUTURE TRANSMISSION SUBSTATIONS

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Afton	**345 kV**	**Yes**	**EPE - TOP Owned and Operated by EPE - PNM only owns generation into the substation. Substation will not be evaluated for PNM CIP.**			
Alamogordo	**115 kV**	**No**	**N/A**			
Alamogordo (elements)	-	No	N/A	AR 115 Alamogordo - Amrad	115 kV	Line
Alamogordo (elements)	-	No	N/A	Gary Stephenson - Alamogordo 115 kV line	115 kV	Line
Alamogordo (elements)	-	Yes	PNM - TOP station, Tri-State - TO line	ADA: Dona Ana 115 kV-Alamogordo 115 kV	115 kV	Line
Alamogordo (elements)	-	Yes	PNM - TOP station, Tri-State - TO line	AC 115 Alamogordo - Carrizo	115 kV	Radial Line
Alamogordo (elements)	-	No	EPE owns, PNM Maintains	AH 115 Alamogordo - Holloman	115 kV	Line
Alamogordo (elements)	-	No	N/A	Alamogordo #1 Shunt Capacitors	115 kV	Reactive Resource
Alamogordo (elements)	-	No	N/A	Alamogordo #2 Shunt Capacitors	115 kV	Reactive Resource
Alamogordo (elements)	-	No	N/A	Alamogordo #3 Shunt Capacitors	115 kV	Reactive Resource
Alamogordo North, Mid, & South	**115 kV**	**No**	**N/A**			
Gary Stephenson (elements)	-	No	N/A	Gary Stephenson -Amard 115 kV line	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Gary Stephenson (elements)	–	No	N/A	Alamogordo South-Alamogordo 115 kV line	115 kV	Line
Gary Stephenson (2028)	**115 kV**	**No**	**N/A**			
Alamogordo South 1 & 2 (2028)	**115 kV**	**No**	N/A			
Alcazar	**115 kV**	**No**	**N/A**			
Algodones	**115 kV**	**No**	**N/A**			
Algodones (elements)	–	No	N/A	AL: Algodones 115 kV-Pachman 115 kV	115 kV	Line
Algodones (elements)	–	No	N/A	AW: Algodones 115 kV-Britton 115 kV	115 kV	Line
Algodones (elements)	–	No	N/A	ANZ: Algodones Tap 115 kV-Algodones 115 kV	115 kV	Line
Algodones (elements)	–	Yes	PNM - TOP station, Tri-State - TO line	Algodones 115 kV-La Jara 115 kV	–	Line
Algodones 1 & 2	**115 kV**	**No**	**N/A**			
Alire	**46 kV**	**No**	**N/A**			
Alire (elements)	–	No	N/A	AM: Alire Tap 46kV-Alire Substation	46 kV	Radial Line
Ambrosia 115	**115 kV**	**No**	**N/A**			
Ambrosia 115 (elements)	–	No	N/A	AY: Ambrosia 115 115 kV-Ya-Ta-Hey 115 kV	115 kV	Line
Ambrosia 115 (elements)	–	No	N/A	MA: Ambrosia 115 kV-Red Mesa 115 kV	115 kV	Line
Ambrosia 115 (elements)	–	Yes	TSGT owns, PNM maintains	MB: Ambrosia 115 kV-Bluewater 115 kV	115 kV	Line
Ambrosia 115 (elements)	–	No	N/A	Ambrosia #1 Shunt Capacitors	115 kV	Reactive Resource
Ambrosia 230	**230 kV**	**Yes**	**PNM - TOP**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Ambrosia 230 (elements)	–	Yes	PNM - TOP	WA: Ambrosia 230 kV-West Mesa 230 kV	230 kV	Line
Ambrosia 230 (elements)	–	Yes	TSGT owns, PNM maintains	PSA: Ambrosia - PEGS 230 kV Line	230 kV	Line
Ambrosia 230 (elements)	–	No	N/A	BI: Ambrosia 230 kV-Bisti 230 kV	230 kV	Line
Ambrosia 230 (elements)	–	No	N/A	Ambrosia 230/115 kV Transformer	230 kV	Transformer
Amrad	**115 kV**	**Yes**	**EPE - TOP**			
Amrad (elements)	–	No	N/A	AR 115 Alamogordo - Amrad	115 kV	Line
Amrad (elements) (2028)	–	No	N/A	Gary Stephenson -Amard 115 kV line	115 kV	Line
Amrad 345	**345 kV**	**Yes**	**EPE - TOP**			
Amrad 345 (elements)	–	Yes	EPE - TOP	AA: Amrad-Eddy (Artesia) 345 kV Line	345 kV	Line
Amrad 345 (elements)	–	Yes	EPE - TOP	Amrad-Caliente (Picante) 345 kV Line	345 kV	Line
Amrad 345 (elements)	–	Yes	EPE - TOP	Amrad 345/115 kV Transformer	345 kV	Transformer
Anderson	**115 kV**	**No**	**N/A**			
Arno 1 & 2	**46 kV**	**No**	**N/A**			
Arriba	**115 kV**	**No**	**N/A**			
Arriba (elements)	–	No	N/A	AA: Arriba Tap 115 kV-Arriba Substation	115 kV	Radial Line
Artesia (elements)	–	Yes	EPE - TOP	Amrad-Eddy 345 kV Line	345 kV	Line
Artesia and DC Converter Station	**345 kV**	**Yes**	**EPE - TOP**			
Aspen	**115 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Aspen (elements)	–	No	N/A	ASPN-WSMS1: Aspen-West Mesa	115 kV	Line
Aspen (elements)	–	No	N/A	ASPN-PRGR1: Aspen-Prager	115 kV	Line
Avila	**115 kV**	**No**	**N/A**			
Avila (elements)	–	No	N/A	AV: Avila Tap 115 kV-Avila Substation	115 kV	Line
B-A 115	**115 kV**	**No**	**N/A**			
B-A 115 (elements)	–	No	N/A	AB 115 Reeves-BA (East Circuit)	115 kV	Line
B-A 115 (elements)	–	No	N/A	CB: BA 115 kV-Pachman 115 kV	115 kV	Line
B-A 115 (elements)	–	No	N/A	RB: Reeves 115 kV-BA 115 kV	115 kV	Line
B-A 115 (elements)	–	No	N/A	RL: BA 115 kV-STA 115 kV	115 kV	Line
B-A 115 (elements)	–	No	N/A	RS: BA 115 kV-Zia 115 kV	115 kV	Line
B-A 345	**345 kV**	**No**	**N/A**			
B-A 345 (elements)	–	No	N/A	WN: Rio Puerco 345 kV-BA 345 kV	345 kV	Line
B-A 345 (elements)	–	No	N/A	CJ: Rio Puerco 345 kV-BA 345 kV	345 kV	Line
B-A 345 (elements)	–	No	N/A	BA-DMND1: BA-Diamond Tail #1 345 kV	345 kV	Line
B-A 345 (elements)	–	No	N/A	BA-DMND2: BA-Diamond Tail #2 345 kV	345 kV	Line
B-A 345 (elements)	–	No	N/A	BA 345/115 kV Transformer	345 kV	Transformer
B-A 345 (elements)	–	No	N/A	BA (CJ -formerly WW)- Line Reactor	345 kV	Reactive Resource
Ball Park	**46 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Ball Park (elements)	–	No	N/A	PK: Ball Park Tap 46 kV-Ball Park Substation	46 kV	Radial Line
Beckner Road	**115 kV**	**No**	**N/A**			
Bel Air	**115 kV**	**No**	**N/A**			
Bel Air (elements)	–	No	N/A	BA: Bel Air Tap 115 kV-Bel Air Substation	115 kV	Radial Line
Belen	**115 kV**	**No**	**N/A**			
Belen (elements)	–	No	N/A	SOC: Belen 115 kV-Socorro 115 kV	115 kV	Line
Belen (elements)	–	No	N/A	Phase shifting transformer on Belen-Socorro 115 kV line	115 kV	PST
Belen (elements)	–	No	N/A	WL: Belen - Willard 115 kV	115 kV	Line
Belen (elements)	–	No	N/A	PJ: Belen - Tome 115 kV	115 kV	Line
Belen (elements)	–	No	N/A	LZ: Belen-La Luz	115 kV	Gen Tie Line
Belen (elements)	–	No	N/A	Belen Series Reactor #1	115 kV	Reactive Resource
Belen (elements)	–	No	N/A	Belen Series Reactor #2	115 kV	Reactive Resource
Belen (elements)	–	No	N/A	BELN-SURA1: Sun Ranch-Belen 115 kV	115 kV	Line
Beverly Wood	**115 kV**	**No**	**N/A**			
Bisti	**230 kV**	**No**	**N/A**			
Bisti (elements)	–	No	N/A	BI: Bisti-Ambrosia 230 kV Line	230 kV	Line
Bisti (elements)	–	No	N/A	BP: Bisti-Pillar 230 kV Line	230 kV	Line
Bisti (elements)	–	No	N/A	BX 230 kV Line (radial)	230 kV	Radial Line
Black Ranch	**115 kV**	**No**	**N/A**			
Blackwater	**345 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Blackwater (elements)	-	No	N/A	TB: Blackwater-Taiban 345 kV Line	345 kV	Line
Blackwater (elements)	-	No	N/A	BWF - Generation interconnection	345 kV	Gen Tie Line
Blackwater (elements)	-	No	N/A	DC Converter	345 kV	DC Converter
Blackwater (elements)	-	No	N/A	Synchronous Condenser	345 kV	Reactive Resource
Blackwater (elements)	-	No	N/A	Blackwater Shunt Capacitor	230 kV	Reactive Resource
Bluewater	**115 kV**	**No**	**TSGT - TOP. Removed Low IRC since PNM does not own or maintain any devices in this station-Bluewater is a TSGT station. PNM owns 2 lines in and out of Bluewater but does not own any devices including protection for these lines in the station.**			
Bluewater (elements)	-	No	N/A	BLEW-CIBL1: Bluewater-Cibola 115 kV	115 kV	Line
Bluewater (elements)	-	No	N/A	MB: Ambrosia 115 kV-Bluewater 115 kV	115 kV	Line
Bosque Farms	**46 kV**	**No**	**N/A**			
Bosque Farms (elements)	-	No	N/A	BF: Bosque Farm Tap 115kV	115 kV	Radial Line
Bosque Farms (elements)	-	No	N/A	BF: Bosque Farm Tap 46kV	46 kV	Radial Line
Britton	**115 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Britton (elements)	–	No	N/A	TW: Britton 115 kV-Willard 115 kV	115 kV	Line
Britton (elements)	–	No	N/A	AW: Algodones 115 kV-Britton 115 kV	115 kV	Line
Britton (elements)	–	No	N/A	Britton Shunt Capacitor #1	115 kV	Reactive Resource
Britton (elements)	–	No	N/A	Britton Shunt Capacitor #2	115 kV	Reactive Resource
Buckman	**115 kV**	**No**	**N/A**			
Burro Mountain	**69 kV**	**No**	**N/A**			
Cabezon	**345 kV**	**No**	**N/A**			
Cabezon (elements)	345 kV	No	N/A	WW: San Juan-Cabezon 345 kV Line	345 kV	Line
Cabezon (elements)	345 kV	No	N/A	CZ: Cabezon-Rio Puerco	345 kV	Line
Cabezon (elements)	345 kV	Yes	TSGT - TO/TOP	Transformer 345/115 kV	345 kV	Transformer
Caja Del Rio	**115 kV**	**No**	**N/A**			
Camel Tracks	**46 kV**	**No**	**N/A**			
Capitol	**46 kV**	**No**	**N/A**			
Capitol (elements)	–	No	N/A	HT: Capitol Tap 46kV-Capitol Substation	46 kV	Radial Line
Central	**115 kV**	**No**	**N/A**			
Church Rock	**115 kV**	**No**	**N/A**			
Church Rock (elements)	–	No	N/A	CM: Church Rock Tap 115 kV-Church Rock Substation	115 kV	Line
Cibola	**115 kV**	**No**	**N/A**			
Cibola (Elements)	–	No	N/A	CIBL-PTRO1 Cibola to Petroglyph	115kV	Line
Cibola (Elements)	–	No	N/A	BLEW-CIBL1 Cibola to Bluewater	115kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Cibola (Elements)	–	No	N/A	Route 66 Solar	115kV	Gen Tie Line
Claremont	**115 kV**	**No**	**N/A**			
Claremont (elements)	–	No	N/A	CL: ClaremontTap 115kV-Claremont Substation	115 kV	Radial Line
Clines Corners	**345 kV**	**No**	**N/A**			**Station**
Clines Corners (elements)	–	No	N/A	CLCR-DMND1: Clines Corners-Diamond Tail #1 345 kV line	345 kV	Line
Clines Corners (elements)	–	No	N/A	CLCR-DMND2: Clines Corners-Diamond Tail #2 345 kV line	345 kV	Line
Clines Corners (elements)	–	No	N/A	CLCR-WESP1: Clines Corners-Western Spirit	345 kV	Line
Clines Corners (elements)	–	No	N/A	CP: Clines Corners to Guadalupe 345kV	345 kV	Line
Clines Corners (elements)	–	No	N/A	Clines Corners-Western Spirit Line Shunt Reactor	345 kV	Reactive Resource
Clines Corners (elements)	–	No	N/A	Wind Farm Generation interconnection	–	Gen Tie Line
Coal	**115 kV**	**No**	**N/A**			
Coal (elements)	–	No	N/A	CQ: Coal 115 kV-Coal Tap 115 kV	115 kV	Line
Cochiti	**46 kV**	**No**	**N/A**			
Cochiti (elements)	–	No	N/A	CR: Cochiti Tap 46kV-Cochiti Substation	46 kV	Radial Line
Colinas	**115 kV**	**No**	**N/A**			
College	**115 kV**	**No**	**N/A**			
College	**115 kV**	**No**	**N/A**			
College (elements)	–	No	N/A	CK: Tome-College 115 kV	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
College (elements)	–	No	N/A	College Sectionalizing Breaker		Sectionalizing Breaker
College (elements)	–	No	N/A	TC: College - El Cerro 115 kV	115 kV	Line
Cornell	**115 kV**	**No**	**N/A**			
Cornell (elements)	–	No	N/A	CN: Cornell Tap 115 kV-Cornell Substation	115 kV	Radial Line
Corrales Bluffs	**115 kV**	**No**	**N/A**			
Corrales Bluffs (Q2 2023)	**115 kV**	**No**	**N/A**			
Corrales Bluffs (elements)	–	No	N/A	RR: Corrales Bluffs 115 kV-Veranda 115 kV	115 kV	Line
Corrales Bluffs (elements)	–	No	N/A	CY: Corrales Bluffs 115 kV-Pachman 115 kV	115 kV	Line
Corrales Bluffs (elements)	–	No	N/A	IC: Corrales Bluffs - Irving 115 kV	115 kV	Line
Corrales Bluffs (elements)	–	No	N/A	CS: Corrales Bluffs 115 kV-Sara 115 kV	115 kV	Radial Line
Corrales Bluffs (elements)	–	No	N/A	CT: Corrales Bluffs 115 kV-Sara 115 kV	115 kV	Radial Line
Cottonwood 1 & 2	**115 kV**	**No**	**N/A**			
Cottonwood 1 & 2 (elements)	–	No	N/A	CW: Cottonwood 115 kV Tap-Cottonwood Substation	115 kV	Radial Line
Cuchilla	**115 kV**	**No**	**N/A**			
Cuchilla (elements)	115 kV	No	N/A	RC: Cuchilla 115kV Tap-Cuchilla Substation	115 kV	Line
Deming East & West	**115 kV**	**No**	**N/A**			
Deming East & West (elements) (2031)	–	No	N/A	DM: Mimbres 115 kV-Deming 115 kV	115 kV	Radial Line
Diamond Tail	**345 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Diamond Tail (elements)	–	No	N/A	BA-DMND1: Diamond Tail-BA #1 345 kV	345 kV	Line
Diamond Tail (elements)	–	No	N/A	BA-DMND2: Diamond Tail-BA #2 345 kV	345 kV	Line
Diamond Tail (elements)	–	No	N/A	CLCR-DMND1: Diamond Tail-Clines Corners #1 345 kV	345 kV	Line
Diamond Tail (elements)	–	No	N/A	CLCR-DMND2: Diamond Tail-Clines Corners #2 345 kV	345 kV	Line
Diamond Tail (elements)	–	No	N/A	DMND-NRTN1: Diamond Tail-Norton 345 kV	345 kV	Line
Eastridge	**115 kV**	**No**	**N/A**			
Eastridge (elements)	–	No	N/A	ET: Eastridge 115 kV Tap-Eastridge Substation	115 kV	Radial Line
El Cerro	**115 kV**	**No**	**N/A**			
El Cerro	**115 kV**	**No**	**N/A**			
El Cerro (elements)	–	No	N/A	El Cerro Sectionalizing Breaker		Sectionalizing Breaker
El Cerro (elements)	–	No	N/A	TC: El Cerro - College 115 kV	115 kV	Line
El Cerro (elements)	–	No	N/A	AT: El Cerro - Person 115 kV	115 kV	Line
El Dorado	**115 kV**	**No**	**N/A**			
El Dorado (elements)	–	No	N/A	ES: El Dorado Tap-El Dorado Substation	115 kV	Line
Embudo	**115 kV**	**No**	**N/A**			
Embudo	**115 kV**	**No**	**N/A**			
Embudo (elements)	–	No	N/A	EJ: Embudo 115 kV-Juan Tabo 115 kV	115 kV	Radial Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Embudo (elements)	–	No	N/A	ER: Embudo 115 kV-Reeves 115 kV	115 kV	Line
Embudo (elements) (2028)	–	No	N/A	RE: Embudo 115 kV-Reeves 115 kV	115 kV	Line
Embudo (elements)	–	No	N/A	EMDU-PALO1 Palomas - Embudo 115 kV	115 kV	Line
Embudo (elements)		No	N/A	EMBU-MORR1: Morris-Embudo	115 kV	Line
Embudo (elements)	–	No	N/A	SE: Embudo 115 kV-Sandia 115 kV	115 kV	Line
Embudo (elements)	–	No	N/A	EB-TL: Embudo 115 kV-North (TL Tap)	115 kV	Line
Enchanted Hills	**115 kV**	**No**	**N/A**			
ETA	**115 kV**	**Yes**	**NNSA- Los Alamos Laboratory (LA Cty) TO/TOP**			
ETA (element)	–	No	N/A	NL: Norton 115 kV-ETA (LAC) 115 kV	115 kV	Line
First Street	**115 kV**	**No**	**N/A**			
Fort Marcy	**46 kV**	**No**	**N/A**			
Four Corners	**500 / 345 / 230 kV**	**Yes**	**APS - TO/TOP**			
Four Corners (elements)	–	No	N/A	Four Corners - 500/345 kV Transformer 1AA	500 kV	Transformer
Four Corners (elements)	–	No	N/A	FC: Four Corners-San Juan 345 kV Line	345 kV	Line
Four Corners (elements)	–	No	N/A	Four Corners-Shiprock 345 kV Line	345 kV	Line
Four Corners (elements)	–	No	N/A	FRCR-PINT1: Four Corners-Pintado ISD Q1 2022	345 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Four Corners (elements)	–	No	N/A	Four Corners - Cholla 345 kV 1	345 kV	Line
Four Corners (elements)	–	No	N/A	Four Corners - Cholla 345 kV 2	345 kV	Line
Four Corners (elements)	–	No	N/A	AF: Four Corners 230 kV-Pillar 230 kV	230 kV	Line
Four Corners (elements)	–	No	N/A	Four Corners 345/230 kV XFMR #4	345 kV	Transformer
Four Corners (elements)	–	No	N/A	Four Corners 345/230 kV XFMR #8	345 kV	Transformer
Four Corners (elements)	–	No	N/A	Four Corners - 230/69 kV XFMR #2	230 kV	Transformer
Four Corners (elements)	–	No	N/A	Four Corners - Pintado Line Reactor	345 kV	Reactive Resource
Four Hills	**115 kV**	**No**	**N/A**			
Gallegos 115	**115 kV**	**No**	**N/A**			
Gallegos 115 (elements)	–	No	N/A	Gallegos-230/115 kV Transformer	230 kV	Transformer
Gallegos 115 (elements)	–	No	N/A	GU 115 kV line	115 kV	Line
Gallegos 115 (elements)	–	No	N/A	GK 115 kV line	116 kV	Line
Gallegos 230	**230 kV**	**No**	**N/A**			
Gallegos 230 (elements)	–	No	N/A	Gallegos-Pillar 230 kV Line (GC)	230 kV	Line
Gallinas	**115 kV**	**No**	**N/A**			
Gavilan 1 & 2	**115 kV**	**No**	**N/A**			
Girard	**115 kV**	**No**	**N/A**			
Gold St. 1 & 2	**115 kV**	**No**	**N/A**			
Greenlee	**345 kV**	**Yes**	**TEP - TOP**			
Greenlee (elements)	–	No	N/A	Greenlee-APE COOP 345 kV	345 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Greenlee (elements)	–	No	N/A	GH: Greenlee-Hidalgo 345 kV	345 kV	Line
Greenlee (elements)	–	No	N/A	Greenlee-Copper Verde 345 kV	345 kV	Line
Greenlee (elements)	–	No	N/A	Greenlee-Winchester 345 kV	345 kV	Line
Greenlee (elements)	–	No	N/A	Greenlee-Springerville 345 kV	345 kV	Line
Guadalupe	**345 kV**	**No**	**N/A**			
Guadalupe (elements)	–	No	N/A	TG: Taiban Mesa-Guadalupe 345 kV	345 kV	Line
Guadalupe (elements)	–	No	N/A	CP: Clines Corners to Guadalupe 345kV	345 kV	Line
Guadalupe (elements)	–	No	N/A	Wind Farm Interconnection Tie	345 kV	Gen Tie Line
Guadalupe (elements)	–	No	N/A	GUAD #2 Reactor	345 kV	Reactive Resource
Guadalupe (elements)	–	No	N/A	GUAD #1 Reactor	345 kV	Reactive Resource
Guadalupe (elements)	–	No	N/A	Guadalupe SVC	345 kV	Reactive Resource
Halona	**46 kV**	**No**	**N/A**			
Halona (elements)	–	No	N/A	HT: Halona 46kV Tap-Halona Substation	46 kV	Radial Line
Hamilton 1 & 2	**115 kV**	**No**	**N/A**			
Hassayampa	**500 kV**	**Yes**	**SRP - TOP**			
Hawkins 1 & 2	**115 kV**	**No**	**N/A**			
Hazeldine	**46 kV**	**No**	**N/A**			
Hazeldine (elements)	–	No	N/A	HS: Hazeldine 46kV Tap-Hazeldine Substation	46 kV	Radial Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Hermanas	**115 kV**	**No**	**N/A**			
Hernandez	**115 kV**	**No**	**TSGT - TOP Sub Operated by Tri-State - PNM owns line and 2 relays in station**			
Hernandez (elements)	–	No		HO: Hernandez 115 kV-Ojo 115 kV	115 kV	Line
Hernandez (elements)	–	No		NH: Norton 115 kV-Hernandez 115 kV	115 kV	Line
Hickox	**46 kV**	**No**	**N/A**			
Hickox (elements)	–	No	N/A	HT: Hickox 46kV Tap-Hickox Substation	46 kV	Radial Line
Hidalgo 115	**115 kV**	**No**	**N/A**			
Hidalgo 115 (elements)	–	No	N/A	LB: Hidalgo 115 kV-Lordsburg 115 kV	115 kV	Line
Hidalgo 115 (elements)	–	Yes	TSGT owns, PNM maintains	PYR1: Hidalgo 115 kV-Pyramid 115 kV	115 kV	Line
Hidalgo 115 (elements)	–	Yes	TSGT owns, PNM maintains	PYR2: Hidalgo 115 kV-Pyramid 115 kV	115 kV	Line
Hidalgo 115 (elements)	–	No	N/A	HR: Hidalgo 115 kV-Turquoise 115 kV	115 kV	Line
Hidalgo 345	**345 kV**	**Yes**	**EPE - TOP**			
Hidalgo 345 (elements)	–	No	N/A	GH: Hidalgo-Greenlee 345 kV Line	345 kV	Line
Hidalgo 345 (elements)	–	No	N/A	HL: Hidalgo-Luna 345 kV Line	345 kV	Line
Hidalgo 345 (elements)	–	No	N/A	345/115 kV Transformer T1	345 kV	Transformer
Hidalgo 345 (elements)	–	No	N/A	345/115 kV Transformer T2	345 kV	Transformer
Hidden Mountain (elements) (2028)		No	N/A	HIMO-RTSN1: Rattlesnake-Hidden Mountain #1	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Hidden Mountain (elements)		No	N/A	HIMO-RTSN1: Rattlesnake-Hidden Mountain #2	115 kV	Line
Hidden Mountain (elements)		No	N/A	HIMO-RTSN1: Rattlesnake-Hidden Mountain #3	115 kV	Line
Hidden Mountain (elements)		No	N/A	HIMO-PAJA1: Hidden Mountain-Pajarito 345kV line	345 kV	Line
Hidden Mountain (elements)		No	N/A	HIMO-WESP1: Hidden Mountain-Western Spirit 345 kV line	345 kV	Line
Hidden Mountain (elements)		No	N/A	HIMO 345 kv/115 kV transformer 1	345 kV	Transformer
Hidden Mountain (elements)		No	N/A	HIMO 345 kv/115 kV transformer 2	345 kV	Transformer
Hidden Mountain (elements)		No	N/A	HIMO 345 kv/115 kV transformer 3	345 kV	Transformer
Hidden Mountain 115	**115 kV**	**No**	**N/A**			
Hidden Mountain 345	**345 kV**	**No**	**N/A**			
Hogback	**230 kV**	**Yes**	**CoF - TO/TOP**			
Holloman	**115 kv**	**Yes**	**EPE - TOP**			
Holloman (elements)	–	No	EPE owns, PNM Maintains	AH 115 Alamogordo - Holloman	115 kV	Line
Hollywood (elements)	–	No	N/A	HG: Hollywood 115 kV-Gavilan 115 kV	115 kV	Radial Line
Hollywood (elements)	–	No	N/A	Hollywood - Carrizo Canyon 115 kV	115 kV	Radial Line
Hollywood (Ruidoso) 1 & 2	**115 kV**	**No**	**N/A**			
Hondale	**115 kV**	**No**	**N/A**			
Huning Ranch	**115 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Huning Ranch (elements)	–	No	N/A	HM: Huning Ranch - Los Morros 115 kV Line	115 kV	Line
Huning Ranch (elements)	–	No	N/A	HU: Huning Ranch - West Mesa Bus #1 115 kV Line	115 kV	Line
Huning Ranch (elements)	–	No	N/A	WD: Huning Ranch - West Mesa Bus #3 115 kV Line	115 kV	Line
Huning Ranch (elements)	–	No	N/A	Huning Ranch Shunt Capacitor #1	115 kV	Reactive Resource
Huning Ranch (elements)	–	No	N/A	Huning Ranch Shunt Capacitor #2	115 kV	Reactive Resource
Huning Ranch (elements)	–	No	N/A	HNRN-RTSN1: Huning Ranch - Rattlesnake #1 115 kV line	115kV	Radial Line
Huning Ranch (elements)	–	No	N/A	HNRN - RTSN2: Huning Ranch to Rattlesnake #2 115 kV line	115kV	Radial Line
Hurley Tap	**115 kV**	**No**	**N/A**			
Indian Hospital	**115 kV**	**No**	**N/A**			
Inez	**115 kV**	**No**	**N/A**			
Inez (elements)	–	No	N/A	MT: Inez 115 kV Tap-Inez Substation	115 kV	Radial Line
Innovation	**115 kV**	**No**	**N/A**			
Iris	**115 kV**	**No**	**N/A**			
Iron Street 1 & 2	**46 kV**	**No**	**N/A**			
Iron Street 1 & 2 (elements)	–	No	N/A	PI: Iron Street-Prager	46 kV	Line
Iron Street 1 & 2 (elements)	–	No	N/A	HI: Iron Street-Person	46 kV	Line
Irving	**115 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Irving (elements)	–	No	N/A	IC: Irving 115 kV-Corrales 115 kV	115 kV	Line
Irving (elements)	–	No	N/A	IR: Irving 115 kV-Reeves 115 kV	115 kV	Line
Irving (elements)	–	No	N/A	WR: West Mesa 115 kV-Irving 115 kV	115 kV	Line
Isleta	**46 kV**	**No**	**N/A**			
Isleta (elements)	–	No	N/A	IS: Isleta 46kV Tap-Isleta Substation	46 kV	Radial Line
Jarales	**115 kV**	**No**	**N/A**			
Jarales (elements)	–	No	N/A	JA: Jarales 115 kV Tap-Jarales Substation	115 kV	Radial Line
Jefferson	**115 kV**	**No**	**N/A**			
Jefferson (elements)	–	No	N/A	JT: Jefferson 115 kV Tap-Jefferson Substation	115 kV	Radial Line
Jicarilla	**345 kV**	**No**	**N/A**			
Jicarilla (elements)	–	No	N/A	OC: San Juan-Jicarilla 345 kV line	345 kV	Line
Jicarilla (elements)	–	No	N/A	OJ: Jicarilla 345 kV-Ojo 345 kV	345 kV	Line
Jicarilla (elements)	–	No	N/A	Jicarilla 345/115 kV Transformer	345 kV	Transformer
Jicarilla (elements)	–	No	N/A	Jicarilla Solar 1 and 2	345kV	Gen Tie Line
Jicarilla (elements)	–	No	N/A	Jicarilla-JANPA bus tie		Bus Tie
Jicarilla (elements)	–	No	N/A	Jicarilla Shunt Reactor	345 kV	Reactive Resource

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Jojoba	**500 kV**	**Yes**	SRP - TOP Operated by APS/SRP-PNM does not operate any equipment at this site-Jointly Owned Lines Operated by Other Utilities. It is covered by the ANPP agreement and is therefore being evaluated by SRP.			
Jojoba (elements)	–	No	N/A	Hassayampa 500 kV-Jojoba	500 kV	Line
Jojoba (elements)	–	No	N/A	345 kV-Kyrene 345 kV	345 kV	Line
Juan Tabo	**115 kV**	**No**	**N/A**			
Juan Tabo (element)	–	No		EJ: Juan Tabo Tap 115 kV Tap-Juan Tabo Substation	115 kV	Radial Line
Kaiser	**46 kV**	**No**	**N/A**			
Kaiser (element)	–	No		RT: KaiserTap 46 kV Tap-Kaiser Substation	46 kV	Radial Line
Keleher	**46 kV**	**No**	**N/A**			
Keleher (element)	–	No		KL: Keleher 46 kV Tap-Keleher Substation	46 kV	Radial Line
Kermac	**115 kV**	**No**	**N/A**			
Kewa	**115 kV**	**No**	**N/A**			
Kirtland	**115 kV**	**No**	**N/A**			
Kirtland (elements)	–	No	N/A	KB: Kirtland 115 kV-Sandia Lab 115 kV	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Kirtland (elements)	–	No	N/A	KS: Sandia 115 kV-Kirtland 115 kV	115 kV	Line
Kirtland (elements)	–	No	N/A	PS: Person 115 kV-Kirtland 115 kV	115 kV	Line
Kirtland (elements)	–	No	N/A	PROS-KIRT1 Kirtland-Prosperity 115 kV	115 kV	Line
Kirtland (elements)	–	No	N/A	KD: Kirtland 115 kV-Sandia Lab 115 kV	115 kV	Line
Kirtland (elements)	–	No	N/A	KA: Kirtland 115 kV-USAF 115 kV	115 kV	Line
Kyrene	**500 kV**	**No**	SRP - TOP			
La Bajada	**46 kV**	**No**	**N/A**			
La Morada	**115 kV**	**No**	**N/A**			
Lawrence	**115 kV**	**No**	**N/A**			
Lawrence (elements)	–	No	N/A	LW: Lawrence Tap 115 kV-Lawrence Substation	115 kV	Radial Line
Lenkurt	**115 kV**	**No**	**N/A**			
Lenkurt (elements)	–	No	N/A	LU: Lenkurt Tap 115 kV-Lenkurt Substation	115 kV	Radial Line
Leyendecker	**115 kV**	**No**	**N/A**			
Leyendecker (elements)	–	No	N/A	LT: Leyendecker Tap 115 kV-Leyendecker Substation	115 kV	Radial Line
Lomas	**115 kV**	**No**	**N/A**			
Lomas (elements)	–	No	N/A	PL: Prager Tap 115 kV-Lomas 115 kV	115 kV	Radial Line
Lordsburg	**115 kV**	**No**	**N/A**			
Lordsburg (elements)	–	No	N/A	LB: Hidalgo 115 kV-Lordsburg 115 kV	115 kV	Line
Lordsburg (elements)	–	No	N/A	Lordsburg Gen Tie	115 kV	Gen Tie Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Lordsburg (elements)	–	No	N/A	Lordsburg Transformer 115/69 kV	115 kV	Transformer
Lordsburg 69 kV	**68 kV**	**No**	**N/A**			
Lordsburg 69 kV	**69 kV**	**No**	**N/A**			
Lordsburg 69 kV (elements)	–	No	N/A	Lordsburg-MD 69 kV Line	69 kV	Radial Line
Lordsburg 69 kV (elements)	–	No	N/A	Lordsburg 115/69 kV Transformer	69 kV	Radial Line
Lordsburg 69 kV (elements)	–	No	N/A	Lordsburg-Burro Mountain 69 kV Line	69 kV	Radial Line
Los Angeles	**115 kV**	**No**	**N/A**			
Los Chavez	**46 kV**	**No**	**N/A**			
Los Chavez (elements)	–	No	N/A	Los Chavez Shunt Capacitor #1	46 kV	Reactive Resource
Los Chavez (elements)	–	No	N/A	Los Chavez Shunt Capacitor #1	46 kV	Reactive Resource
Los Lunas	**46 kV**	**No**	**N/A**			
Los Morros	**115 kV**	**No**	**N/A**			
Los Morros (elements)	–	No	N/A	Los Morros Sectionalizing Breaker	115 kV	Sectionalizing Breaker
Los Morros (elements)	–	No	N/A	WB: Belen - Los Morros 115 kV	115 kV	Line
Los Morros (elements)	–	No	N/A	Los Morros-Huning Ranch 115kV	115 kV	Line
Los Morros (elements)	–	No	N/A	LOMO-STCE1 Los Morros-St. Cecilia	115 kV	Line
Los Morros 1 & 2	**115 kV**	**No**	**N/A**			
Lost Horizon	**115 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Lost Horizon (elements)	–	No	N/A	LO: Lost Horizon Tap 115 kV-Lost Horizon Substation	115 kV	Line
Louden Hill (Q2 2024)	**46 kV**	**No**	**N/A**			
Louden Hill (element)	46 kV	No	N/A	LH: Louden Hill Tap 46kV	46 kV	Radial Line
Luna 115	**115 kV**	**No**	**PNM - TO/TOP**			
Luna 115 (elements)	–	No	N/A	LK: Luna 115 kV-MD-1 115 kV	115 kV	Line
Luna 115 (elements)	–	No	N/A	ML: Luna 115 kV-Mimbres 115 kV	115 kV	Line
Luna 115 (elements) (2031)	–	No	N/A	Luna 115 kV - Perrin 115 kV	115 kV	Line
Luna 345	**345 kV**	**No**	**EPE - TO/TOP**			
Luna 345 (elements)	–	No	N/A	HL:Luna-Hidalgo 345 kV Line	345 kV	Line
Luna 345 (elements)	–	No	N/A	VL: Luna-Springerville 345 kV Line	345 kV	Line
Luna 345 (elements)	–	No	N/A	LN: Luna-Afton 345 kV Line	345 kV	Line
Luna 345 (elements)	–	No	N/A	LD: Luna-Diablo 345 kV Line	345 kV	Line
Luna 345 (elements)	–	No	PNM - TO/TOP	LL: Luna-LEF 345 kV Tie	345 kV	Gen Tie Line
Luna 345 (elements)	–	No	PNM - TO/TOP	Luna 345/115 kV Transformer	345 kV	Transformer
Manhattan	**46 kV**	**No**	**N/A**			
Manzanita (Q4 2023)	**46 kV**	**No**	N/A			
Manzano	**115 kV**	**No**	**N/A**			
Mariposa	**115 kV**	**No**	**N/A**			
Marquez	**115 kV**	**No**	**N/A**			
Marquez (elements)	–	No	N/A	KC: Marquez 115 kV-Marquez Tap 115 kV	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
McKinley	**345 kV**	**Yes**	**TEP - TOP**			
McKinley (elements)	–	No	N/A	McKinley - San Juan 345 kV Line 1 (TS1)	345 kV	Line
McKinley (elements)	–	No	N/A	McKinley - San Juan 345 kV Line 2 (TS2)	345 kV	Line
McKinley (elements)	–	No	N/A	McKinley-Springerville 345 kV Line	345 kV	Line
McKinley (elements)	–	Yes	PNM TOP	Yah-ta-hey Transformer 345/ 115 kV #1	345 kV	Transformer
McKinley (elements)	–	Yes	PNM TOP	Yah-ta-hey Transformer 345/ 115 kV #2	345 kV	Transformer
MD-1	**115 kV**	**No**	**N/A**			
MD-1 (elements)	–	No	N/A	MH: MD-1 115 kV-Ivanhoe (PD) 115 kV	115 kV	Radial Line
MD-1 (elements)	–	No	N/A	LK: Luna 115 kV-MD-1 115 kV	115 kV	Line
MD-1 (elements)	–	No	N/A	MR: MD-1 115 kV-Turquoise 115 kV	115 kV	Line
MD-1 (elements)	–	No	N/A	MD-1 Shunt Capacitors	115 kV	Reactive Resource
MD-1 (elements) (2031)	–	No	N/A	MD-1 115 kv - Perrin 115 kv	115 kV	Line
MD-1 69 kV	**69 kV**	**No**	**N/A**			
MD-1 69 kV	**69 kV**	**No**	**N/A**			
MD-1 69 kV (elements)	–	No	N/A	MD 115/69 kV Transformer	115 kV	Transformer
MD-1 69 kV (elements)	–	No	N/A	MD 69 kV shunt Capacitor	69 kV	Reactive Resource
MD-1 69 kV (elements)	–	No	N/A	MD-Lordsburg 69 kV Line	69 kV	Radial Line
MD-1 69 kV (elements)	–	No	N/A	MD-Silver City 69 kV Line	69 kV	Radial Line
MD-1 69 kV (elements)	–	No	N/A	MD-Cobre Mine 69 kV Line	69 kV	Radial Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Mejia	**115 kV**	**No**	**N/A**			
Mejia (elements)	–	No	N/A	ZN: MejiaTap 115 kV-Mejia Substation	115 kV	Line
Menaul	**115 kV**	**No**	**N/A**			
Menaul (elements)	–	No	N/A	MT: Menaul Tap 115 kV-Menaul Substation	115 kV	Radial Line
Miguel Lujan	**115 kV**	**No**	**N/A**			
Miguel Lujan (elements)	–	No	N/A	MI: Miguel Lujan 115 kV Tap-Miguel Lujan Substation	115 kV	Radial Line
Mimbres	**115 kV**	**No**	**N/A**			
Mimbres (elements)	–	Yes	PNM owns/operates Mimbres station, Tri-State owns the line	MEB: Mimbres 115 kV-Caballo (TSGT) 115 kV	115 kV	Line
Mimbres (elements)	–	No	N/A	ML: Luna 115 kV-Mimbres 115 kV	115 kV	Line
Mimbres (elements)	–	No	N/A	DM: Mimbres 115 kV-Deming 115 kV	115 kV	Radial Line
Mimbres (elements)	–	No	N/A	MW: Mimbres 115 kV-Hermanas-Hondale 115 kV	115 kV	Radial Line
Mimbres (elements)	–	No	N/A	DL: Mimbres 115 kV-Picacho 115 kV	115 kV	Line
Mimbres (elements)	–	No	N/A	Mimbres #1 Shunt Capacitors	115 kV	Reactive Resource
Mimbres (elements)	–	No	N/A	Mimbres #2 Shunt Capacitors	115 kV	Reactive Resource
Mimbres (elements)	–	No	N/A	Mimbres #3 Shunt Capacitors	115 kV	Reactive Resource
Mission	**115 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Mission (elements)	–	No	N/A	MN: Mission 115 kV-North 115 kV	115 kV	Line
Mission (elements)	–	No	N/A	NR: Reeves 115 kV-Mission 115 kV	115 kV	Line
Mission (elements)	–	No	N/A	Mission Sectionalizing Breaker	115 kV	Sectionalizing Breaker
Mission 1 & 2	**115 kV**	**No**	**N/A**			
Montano	**115 kV**	**No**	**N/A**			
Montano (elements)	–	No	N/A	MP: Montano Tap 115 kV-Montano Substation	115 kV	Radial Line
Montgomery Plaza	**115 kV**	**No**	**N/A**			
Montgomery Plaza (elements)	–	No	N/A	MG: Montgomery Plaza Tap 115 kV-Montgomery Plaza Substation	115 kV	Radial Line
Morris (2031)	**115 kV**	**No**	**N/A**			
Morris (elements)	–	No	N/A	MORR-NRTH1: Morris-North	115 kV	Line
Morris (elements)	–	No	N/A	EMBU-MORR1: Morris-Embudo	115 kV	Line
Morris (elements)	–	No	N/A	Sectionalizing breaker	115 kV	Sectionalizing Breaker
Morris (elements)	–	No	N/A	Sectionalizing breaker	115 kV	Sectionalizing Breaker
Morris 1 & 2	**115 kV**	**No**	**N/A**			
Newell	**46 kV**	**No**	**N/A**			
Newell (elements)	–	No	N/A	WT: Newell Tap 46kV-Newell Substation	46 kV	Radial Line
North	**115 kV**	**No**	**N/A**			
North (elements)	–	No	N/A	EB-TL: Embudo 115 kV-North (TL Tap)	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
North (elements)	–	No	N/A	PN: Richmond-North	115 kV	Line
North (elements)	–	No	N/A	MN: Mission 115 kV-North 115 kV	115 kV	Line
North (elements)	–	No	N/A	RN: Reeves 115 kV-North 115 kV	115 kV	Line
North (elements) (2031)	–	No	N/A	MORR-NRTH1: Morris-North	115 kV	Line
North (elements)	–	No	N/A	North #1 Shunt Capacitors	115 kV	Reactive Resource
North (elements)	–	No	N/A	North #2 Shunt Capacitors	115 kV	Reactive Resource
North 1 and 2	**115 kV**	**No**	**N/A**			
North Bernalillo	**115 kV**	**No**	**N/A**			
North Bernalillo (elements)	–	No	N/A	BR: North BernalilloTap 115kV-North Bernalillo Substation	115 kV	Radial Line
North Silver	**69 kV**	**No**	**N/A**			
Norton 115	**115 kV**	**No**	**N/A**			
Norton 115 (elements)	–	No	N/A	NL: Norton 115 kV-ETA (LAC) 115 kV	115 kV	Line
Norton 115 (elements)	–	No	N/A	ANZ: Norton Tap 115 kV-Norton 115 kV	115 kV	Line
Norton 115 (elements)	–	No	N/A	NH: Norton 115 kV-Hernandez 115 kV	115 kV	Line
Norton 115 (elements)	–	No	N/A	NS: Norton 115 kV-Zia 115 kV	115 kV	Line
Norton 115 (elements)	–	No	N/A	Norton Series Reactors	115 kV	Reactive Resource
Norton 115 (elements)	–	No	N/A	Norton Shunt Capacitors	115 kV	Reactive Resource

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Norton 345	**345 kV**	**No**	**N/A**			
Norton 345 (elements)	–	No	N/A	DMND-NRTN1: Diamond Tail-Norton 345 kV	345 kV	Line
Norton 345 (elements)	–	No	N/A	Norton 345/115 kV Transformer	345 kV	Transformer
Ojo 115	**115 kV**	**No**	**N/A**			
Ojo 115 (elements)	–	No	N/A	HO: Hernandez 115 kV-Ojo 115 kV	115 kV	Line
Ojo 345	**345 kV**	**Yes**	**PNM - TOP**			
Ojo 345 (elements)	–	No	N/A	OJ: Jicarilla 345 kV-Ojo 345 kV	345 kV	Line
Ojo 345 (elements)	–	Yes	TSGT Owns and Operates	OT: Ojo-Taos 345 kV Line	345 kV	Line
Ojo 345 (elements)	–	No	N/A	Ojo 345/115 kV Transformer	345 kV	Transformer
Ojo 345 (elements)	–	No	N/A	OJO #1 OJ Line Reactor	345 kV	Reactive Resource
Ojo 345 (elements)	–	No	N/A	OJO #2 OJ Line Reactor	345 kV	Reactive Resource
Ortiz	**115 kV**	**No**	**N/A**			
Pachmann	**115 kV**	**No**	**N/A**			
Pachmann (Q3 2023)	**115 kV**	**No**	**N/A**			
Pachmann (elements)	–	No	N/A	PR: Pachmann 115 kV-Rio Puerco 115 kV	115 kV	Line
Pachmann (elements)	–	No	N/A	CE: Pachmann 115 kV-Scenic 115 kV	115 kV	Line
Pachmann (elements)	–	No	N/A	CY: Corrales Bluffs 115 kV-Pachmann 115 kV	115 kV	Line
Pachmann (elements)	–	No	N/A	CB: BA 115 kV-Pachmann 115 kV	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Pachmann (elements)	–	No	N/A	AL: Algodones 115 kV-Pachmann 115 kV	115 kV	Line
Pajarito	**345 kV**	**No**	**N/A**			
Pajarito (elements)	–	No	N/A	Pajarito-Western Spirit Line Shunt Reactor	345 kV	Reactive Resource
Pajarito (elements)	–	No	N/A	PAJA-WSMS1: West Mesa 345 kV to Pajarito 345 kV	345kV	Line
Pajarito (elements)	–	No	N/A	PAJA-SAND1: Pajarito 345 kV to Sandia 345 kV	345kV	Line
Pajarito (elements) (2029)	–	No	N/A	Pajarito - Prosperity 345 kV	345 kV	Line
Pajarito (elements)	–	No	N/A	HIMO-PAJA: Hidden Mnt 345 kV to Pajarito 345 kV	345kV	Line
Palace	**115 kV**	**No**	**N/A**			
Palm	**115 kV**	**No**	**N/A**			
Palo Verde	**500 kV**	**Yes**	**SRP - TOP Switchyard is operated by SRP. Covered by delegation in the ANPP High Voltage Switchyard Operating Agent agreement.**			
Palo Verde (elements)	–	No	N/A	PV-WW: Palo Verde 500 kV-Westwing 500 kV	500 kV	Line
Palo Verde (elements)	–	No	N/A	PV-WW: Palo Verde 500 kV-Westwing 500 kV	500 kV	Line
Palomas (2028)	**115 kV**	**No**	**N/A**			
Palomas (elements)	–	No	N/A	EMDU-PALO1 Palomas - Embudo 115 kV	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Palomas (elements)	–	No	N/A	PALO-REEV1 Palomas - Reeves 1 115 kV	115 kV	Line
Palomas 1 & 2 (2028)	**115 kV**	**No**	N / A			
Panorama	**115 kV**	**No**	**N/A**			
Paradise Hills	**115 kV**	**No**	**N/A**			
Pecos	**46 kV**	**No**	**N/A**			
Peralta	**46 kV**	**No**	**N/A**			
Perrin (2031)	**115 kV**	**No**	**N/A**			
Perrin (element)	–	No	N/A	Perrin - MD1 115 kV Line	115 kV	Line
Perrin (element)	–	No	N/A	Perrin - Luna 115 kV	115 kV	Line
Perrin (element)	–	No	N/A	Sectionalizing Breaker	115 kV	Sectionalizing Breaker
Perrin 1 & 2	**115 kV**	**No**	N / A			
Person	**115 kV**	**No**	**N/A**			
Person (elements)	–	No	N/A	PS: Person 115 kV-Kirtland 115 kV	115 kV	Line
Person (elements)	–	No	N/A	SP: Person 115 kV-Normally Open Switch SP-83 and HW-43	115 kV	Radial Line
Person (elements)	–	No	N/A	AT: Person 115 kV-El Cerro 115 kV	115 kV	Line
Person (elements)	–	No	N/A	Person Transformer 115/46 kV	115 kV	Transformer
Person (elements)	–	No	N/A	PM: Person 115 kV-West Mesa 115 kV	115 kV	Line
Person (elements)	–	No	N/A	PW: Person - Snow Vista	115 kV	Line
Person (elements)	–	No	N/A	Rio Bravo Gen Tie	115 kV	Gen Tie Line
Person (elements)	–	No	N/A	PERS-SAGE1: Person-Sagebrush	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Person (elements)	–	No	N/A	PB: Person - Tome 115 kV	115 kV	Line
Person 46kV	**46 kV**	**No**	**N/A**			
Person 46kV (elements)	–	No	N/A	EL: Person radial (Arno)	46 kV	Radial Line
Person 46kV (elements)	–	No	N/A	BN: Person-Tome	46 kV	Line
Person 46kV (elements)	–	No	N/A	PB: Person-Tome	46 kV	Line
Person 46kV (elements)	–	No	N/A	PC: Person radial (KAFB West)	46 kV	Radial Line
Person 46kV (elements)	–	No	N/A	PH: Person-Iron Street	46 kV	Radial Line
Person 46kV (elements)	–	No	N/A	115/46 kV Transformer	46 kV	Transformer
Petroglyph	**115 kV**	**No**	**N/A**			
Petroglyph	**115 kV**	**No**	**N/A**			
Petroglyph (elements)	–	No	N/A	PTRO-WSMS1 West Mesa to Petroglyph	115kV	Line
Petroglyph (elements)	–	No	N/A	CIBL-PTRO1: Petroglyph-Cibola	115kV	Line
Picacho	**115 kV**	**Yes**	**EPE - TOP PNM owns station, EPE operates Picacho station,**			
Picacho (elements)	–	Yes	TSGT owns, PNM maintains	PDA: Picacho 115 kV-Dona Ana (TSGT) 115 kV	115 kV	Line
Picacho (elements)	–	No	N/A	DL: Mimbres 115 kV-Picacho 115 kV	115 kV	Line
Picacho (elements)	–	Yes	EPE - TOP	FNT: Picacho 115 kV-Frontier 115 kV	115 kV	Line
Pillar	**230 kV**	**No**	**N/A**			
Pillar (Elements)	–	No	N/A	BP: Pillar 230 kV-Bisti 230 kV	230 kV	Line
Pillar (Elements)	–	No	N/A	AF: Pillar-Four Corners 230 kV Line	230 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Pillar (Elements)	–	No	N/A	GC: Pillar 230 kV-Gallegos 230 kV	230 kV	Line
Pintado	**345 kV**	**No**	**N/A**			
Pintado (Elements)	–	No	N/A	FRCR-PINT1: Pintado-Four Corners 345 kV	345 kV	Line
Pintado (Elements)	–	No	N/A	PINT-RIPU1: Pintado-Rio Puerco 345 kV	345 kV	Line
Pintado (Elements)	–	No	N/A	ARSO-PNT1: Arroyo Solar gen tie	345 kV	Gen Tie Line
Pittsburgh-Midway	**115 kV**	**No**	**N/A**			
Pittsburgh-Midway (elements)	–	No	N/A	YP: Pitt/Midway Tap 115 kV-Pitt/Midway Substation	115 kV	Radial Line
Power Plant	**46 kV**	**No**	**N/A**			
Power Plant (elements)	–	No	N/A	ZS: Power Plant-Zia	46 kV	Line
Power Plant (elements)	–	No	N/A	ZM: Power Plant-Zia	46 kV	Line
Power Plant (elements)	–	No	N/A	MS: Power Plant-Zia	46 kV	Line
Prager	**115 kV**	**No**	**N/A**			
Prager	**115 kV**	**No**	**N/A**			
Prager (elements)	–	No	N/A	PL: Prager 115 kV-Lomas 115 kV	115 kV	Radial Line
Prager (elements)	–	No	N/A	WP: West Mesa 115 kV-Prager 115 kV	115 kV	Line
Prager (elements)	–	No	N/A	Transformer 115/46 kV	115 kV	Transformer
Prager (elements)	–	No	N/A	RP: Prager 115 kV-Richmond 115 kV	115 kV	Line
Prager (elements)	–	No	N/A	Prager Shunt Capacitors	115 kV	Reactive Resource
Prager (elements) (2031)	–	No	N/A	ASPN-PRGR1: Aspen-Prager	115 kV	Line
Prager 46kV	**46 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Prager 46kV (element)	–	No	N/A	PI: Prager-Iron Street	46 kV	Line
Prager 46kV (element)	–	No	N/A	PY: Person-Prager	46 kV	Line
Prager 46kV (element)	–	No	N/A	115/46 kV Transformer	46 kV	Transformer
Princess Jeanne	**115 kV**	**No**	**N/A**			
Progress	**115 kV**	**No**	**N/A**			
Prosperity 115 (Q2 2024)	**115 kV**	**No**	**N/A**			
Prosperity (Q2 2024)	**115 kV**	**No**	**N/A**			
Prosperity 345 (Q2 2029)	**345 kV**	**No**	**N/A**			
Prosperity (elements)	–	No	N/A	PERS-PROS1 Prosperity-Person 115 kV line	115 kV	Line
Prosperity (elements)	–	No	N/A	PRSO-KIRT1 Prosperity-Kirtland 115 kV line	115 kV	Line
Prosperity (elements)	–	No	N/A	PROS-STUD1 Prosperity-Studio 115 kV line	115 kV	Line
Prosperity (elements) (2029)	–	No	N/A	Prosperity-Pajarito 345 kV line 1	345 kV	Line
				Prosperity-Pajarito 345 kV line 2	345 kV	Line
Prosperity (elements)	–	No	N/A	345/115 kV Transformer	345 kV	Transformer
Quail Ranch (Q1 2024)	**345 kV**	**No**	N/A			
Quail Ranch (elements)	–	No	N/A	QLRA-WSMS1 Quail Ranch-West Mesa 345 kV Line	345 kV	Line
Quail Ranch (elements)	–	No	N/A	QLRA-RIPU1 Quail Ranch-Rio Puerco 345 kV line	345 kV	Line
Quail Ranch (elements)	–	No	N/A	Atrisco Solar - QR: Atrisco Solar Gen Tie	345 kV	Gen Tie Line
Randolph	**115 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Rattlesnake (2028)	**115 kV**	**No**	**N/A**			
Rattlesnake (elements)	–	No	N/A	HNRN-RTSN1: Rattlesnake to Huning Ranch #1 115 kV Line	115kV	Radial Line
Rattlesnake (elements)	–	No	N/A	HNRN-RTSN2: Rattlesnake to Huning Ranch #2 115 kV Line	115kV	Radial Line
Rattlesnake (elements)		No	N/A	HIMO-RTSN1: Rattlesnake-Hidden Mountain #1	115 kV	Line
Rattlesnake (elements)		No	N/A	HIMO-RTSN1: Rattlesnake-Hidden Mountain #2	115 kV	Line
Rattlesnake (elements)		No	N/A	HIMO-RTSN1: Rattlesnake-Hidden Mountain #3	115 kV	Line
Rattlesnake (elements)	–	No	N/A	RTSN-SURA1: Sun Ranch-Rattlesnake 115 kV	115kV	Line
Red Mesa	**115 kV**	**No**	**N/A**			
Red Mesa (elements)	–	No	N/A	KM: West Mesa - Red Mesa 115 kV	115 kV	Line
Red Mesa (elements)	–	No	N/A	MA: Ambrosia 115 kV-Red Mesa 115 kV	115 kV	Line
Red Mesa (elements)	–	N/A	PNM does not own or operate this line.	Red Mesa Wind Farm Tie 115 kV	115 kV	Gen Tie Line
Reeves	**115 kV**	**No**	**N/A**			
Reeves	**115 kV**	**No**	**N/A**			
Reeves (elements)	–	No	N/A	AB: Reeves 115 kV-BA 115 kV	115 kV	Line
Reeves (elements)	–	No	N/A	RB: Reeves 115 kV-BA 115 kV	115 kV	Line
Reeves (elements)	–	No	N/A	NR: Reeves 115 kV-Mission 115 kV	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Reeves (elements)	–	No	N/A	RN: Reeves 115 kV-North 115 kV	115 kV	Line
Reeves (elements)	–	No	N/A	IR: Irving 115 kV-Reeves 115 kV	115 kV	Line
Reeves (elements)	–	No	N/A	ER: Embudo 115 kV-Reeves 115 kV	115 kV	Line
Reeves (elements)	–	No	N/A	RE: Embudo 115 kV-Reeves 115 kV	115 kV	Line
Reeves (elements) (2028)	–	No	N/A	PALO-REEV1 Palomas - Reeves 1 115 kV	115 kV	Line
Reeves (elements)	–	No	N/A	NW: Reeves 115 kV-West Mesa 115 kV	115 kV	Line
Reeves (elements)	–	N/A	N/A	Reeves Unit 1 gen tie	116 kV	Gen Tie Line
Reeves (elements)	–	N/A	N/A	Reeves Unit 2 gen tie	117 kV	Gen Tie Line
Reeves (elements)	–	N/A	N/A	Reeves Unit 3 gen tie	118 kV	Gen Tie Line
Reeves (elements)	–	No	N/A	Reeves Shunt Capacitors	115 kV	Reactive Resource
Richmond (2027)	**115 kV**	**No**	**N/A**			
Richmond	**115 kV**	**No**	**N/A**			
Richmond (element)	–	No	N/A	RP: Richmond - Prager 115 kV	115 kV	Line
Richmond (element)	–	No	N/A	CG: Richmond - Sandia 115 kV	115 kV	Line
Richmond (element)	–	No	N/A	PN: Richmond - North 115 kV	115 kV	Line
Rio Hondo	**115 kV**	**No**	**N/A**			
Rio Puerco 115	**115 kV**	**No**	**N/A**			
Rio Puerco 115 (elements)	–	No	N/A	PV: Rio Puerco 115 kV-Veranda 115 kV	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Rio Puerco 115 (elements)	-	No	N/A	PR: Pachmann 115 kV-Rio Puerco 115 kV	115 kV	Line
Rio Puerco 115 (elements)	-	No	N/A	Encino/Encino N 115 kv Gen Tie	115 kV	Gen Tie Line
Rio Puerco 115 (elements)	-	No	N/A	Tag Solar 115 kv Gen Tie	115 kV	Gen Tie Line
Rio Puerco 345	**345 kV**	**No**	**N/A**			
Rio Puerco 345 (elements)	-	No	N/A	BJ: West Mesa-Rio Puerco 345 kV Line 1	345 kV	Line
Rio Puerco 345 (elements)	-	No	N/A	AJ: West Mesa-Rio Puerco 345 kV Line 2	345 kV	Line
Rio Puerco 345 (elements)	-	No	N/A	WN: BA - Rio Puerco 345 kV Line 1	345 kV	Line
Rio Puerco 345 (elements)	-	No	N/A	CJ: BA - Rio Puerco 345 kV Line 2	345 kV	Line
Rio Puerco 345 (elements)	-	No	N/A	CZ: Cabezon-Rio Puerco	345 kV	Line
Rio Puerco 345 (elements)	-	No	N/A	PINT-RIPU1: Rio Puerco-Pintado 345 kV	346 kV	Line
Rio Puerco 345 (elements)	-	No	N/A	Rio Puerco 345 kV/115 kV Transformer	345 kV	Transformer
Rio Puerco 345 (elements)	-	No	N/A	Rio Puerco - Pintado 345 kV (series capacitors)	345 kV	Line
Rio Puerco 345 (elements)	-	No	N/A	Rio Puerco -Cabezon 345 CZ (series capacitors)	345 kV	Line
Rio Puerco 345 (elements)	-	No	N/A	QLRA-RIPU1 Quail Ranch-Rio Puerco 345 kV line	345 kV	Line
Rio Puerco 345 (elements)	-	No	N/A	FW #1 Line Shunt Reactor	345 kV	Reactive Resource
Rio Puerco 345 (elements)	-	No	N/A	WW #2 Line Shunt Reactor	345 kV	Reactive Resource

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Rio Puerco 345 (elements)	-	No	N/A	Rio Puerco SVC	345 kV	Reactive Resource
Rita	**115 kV**	**No**	**N/A**			
Rodeo	**115 kV**	**No**	**N/A**			
Roy	**115 kV**	**No**	**N/A**			
Sagebrush (Q2 2024)	**115 kV**	**No**	**N/A**			
Sagebrush (elements)	-	No	N/A	PERS-SAGE1: Person-Sagebrush	115 kV	Line
Sagebrush (elements)	-	No	N/A	SAGE-SAND1: Sagebrush-Normally Open Switch SP-83 and HW-43	115 kV	Line
Sagebrush 1 & 2 (Q2 2028)	**115 kV**	**No**	**N/A**			
Saint Cecilia	**46 kV**	**No**	**N/A**			
Saint Cecilia (Q2 2024)	**115 kV**	**No**	**N/A**			
Saint Cecilia (elements)	-	No	N/A	LOMO-STCE1 St. Cecilia-Los Morros 115 kV Line	115kV	Line
Saint Cecilia (elements)	-	No	N/A	STCE-SURA1: Sun Ranch-St. Cecilia 115kV	115kV	Line
San Antonio (elements)	-	No	N/A	TA: San Antonio Tap 46 kV-San Antonio Substation	46 kV	Radial Line
San Antonito 1 & 2	**46 kV**	**No**	**N/A**			
San Juan 230	**345/230/69/12.47**	**Yes**	**TEP partial owner**			
San Juan 230 (elements)	-	No	N/A	230/12.47 kV Transformer	230/12.47	Transformer
San Juan 230 (elements)	-	No	N/A	230/69 kV Transformer (to radial CC line)	230/69kv	Transformer
San Juan 230 (elements)	-	No	N/A	345/69 kV Transformers (to radial CO line)	345/69kv	Transformer

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
San Juan 230 (elements)	–	No	N/A	SF: San Juan-Hogback 230 kV Line	230 kV	Line
San Juan 345	**345 kV**	**Yes**	**PNM & TEP - TOP, 5 Tos**			
San Juan 345 (elements)	–	No	N/A	345/230 kV Transformer	345/230kv	Transformer
San Juan 345 (elements)	–	No	N/A	WW: San Juan-Cabezon	345 kV	Line
San Juan 345 (elements)	–	No	N/A	FC: San Juan 345 kV-Four Corners 345 kV	345 kV	Line
San Juan 345 (elements)	–	No	N/A	SJ-MC-1: McKinley 345 kV-San Juan 345 kV	345 kV	Line
San Juan 345 (elements)	–	No	N/A	SJ-MC-2: McKinley 345 kV-San Juan 345 kV	345 kV	Line
San Juan 345 (elements)	–	No	N/A	SH: San Juan-Waterflow 345 kV Line	345 kV	Line
San Juan 345 (elements)	–	No	N/A	OC: San Juan 345 kV-Jicarilla 345 kV	345 kV	Line
San Juan 345 (elements)	–	No	N/A	SR: San Juan 345 kV-Shiprock 345 kV	345 kV	Line
San Juan 345 (elements)	–	No	N/A	San Juan 345 kV - San Juan North 345 kV	345 kV	Line
San Juan North (Q1 2024)	**345 kV**	**No**	N/A		**345 kV**	
San Juan North (elements)	–	No	N/A	San Juan North 345 kV - San Juan 345 kV -	345 kV	Line
San Juan North (elements)	–	No	N/A	San Juan Solar gen tie	345 kV	Gen Tie Line
San Lucas	**115 kV**	**No**	**N/A**			
San Lucas (elements)	–	No	N/A	LS: San Lucas Tap 115 kV-San Lucas Substation	115 kV	Line
San Pedro	**115 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
San Pedro (elements)	–	No	N/A	ST: San Pedro Tap 115kv-San Pedro Substation	115 kV	Line
Sandia	**46 kV**	**No**	**N/A**			
Sandia (elements)	–	No	N/A	ID: radial line	46 kV	Radial Line
Sandia (elements)	–	No	N/A	Sandia-Kirtland AFB East 2	46 kV	Line
Sandia (elements)	–	No	N/A	Sandia-Kirtland AFB East 3	46 kV	Line
Sandia (elements)	–	No	N/A	Sandia-Kirtland AFB East 4	46 kV	Line
Sandia (elements)	–	No	N/A	115/46 kV Transformer	46 kV	Transformer
Sandia (elements)	–	No	N/A	115/46 kV Transformer	46 kV	Transformer
Sandia (elements)	–	No	N/A	Sandia 1-2 Bus tie	46 kV	Bus Tie
Sandia (elements)	–	No	N/A	Sandia 46 kV Shunt Capacitor #1	46 kV	Reactive Resource
Sandia (elements)	–	No	N/A	Sandia 46 kV Shunt Capacitor #2	46 kV	Reactive Resource
Sandia (elements)	–	No	N/A	Sandia 46 kV Shunt Capacitor #3	46 kV	Reactive Resource
Sandia (elements)	–	No	N/A	Sandia 46 kV Shunt Capacitor #4	46 kV	Reactive Resource
Sandia 115	**115 kV**	**No**	**N/A**			
Sandia 115 (elements)	–	No	N/A	SE: Sandia 115 kV-Embudo 115 kV	115 kV	Line
Sandia 115 (elements)	–	No	N/A	KS: Sandia 115 kV-Kirtland 115 kV	115 kV	Line
Sandia 115 (elements)	–	No	N/A	Sandia 115/46 kV Transformer #1	115 kV	Transformer
Sandia 115 (elements)	–	No	N/A	Sandia 115/46 kV Transformer #2	115 kV	Transformer
Sandia 115 (elements)	–	No	N/A	CG: Sandia-Richmond 115 kV Line	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Sandia 115 (elements)	–	No	N/A	SP: Sandia 115 kV-Normally Open Switch SP-83	115 kV	Radial Line
Sandia 115 (elements)	–	No	N/A	KS: Sandia 115 kV-SNL	115 kV	Line
Sandia 115 (elements)	–	No	N/A	SAGE-SAND1: Sagebrush-Normally Open Switch SP-83 and HW-43	115 kV	Line
Sandia 115 (elements)	–	No	N/A	Sandia #1 Shunt Capacitors	115 kV	Reactive Resource
Sandia 115 (elements)	–	No	N/A	Sandia #2 Shunt Capacitors	115 kV	Reactive Resource
Sandia 345	**345 kV**	**No**	**N/A**			
Sandia 345 (elements)	–	No	N/A	Sandia 345/115 kV Transformer T1	345 kV	Transformer
Sandia 345 (elements)	–	No	N/A	Sandia 345/115 kV Transformer Out of Service Spare	345 kV	Transformer
Sandia 345 (elements)	–	No	N/A	PAJA-SAND1: Sandia 345 kV to Pajarito 345 kV	345 kV	Line
Santa Fe Plant	**46 kV**	**No**	**N/A**			
Sara 1 & 2	**115 kV**	**No**	**N/A**			
Sara 1 & 2 (elements)	–	No	N/A	CS: Sara 1&2 Tap 115 kV-Sara 1&2 Substation	115 kV	Line
Sara 3 & 4	**115 kV**	**No**	**N/A**			
Sara 3 & 4 (elements)	–	No	N/A	CT: Sara 3&4 Tap 115 kV-Sara 3&4 Substation	115 kV	Line
Sara 5	**115 kV**	**No**	**N/A**			
Sara 6 & 7	**115 kV**	**No**	**N/A**			
Sara 8	**115 kV**	**No**	**N/A**			
Scenic	**115 kV**	**No**	**N/A**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Scenic	**115 kV**	**No**	**N/A**			
Scenic (elements)	–	No	N/A	SK: Scenic - West Mesa 115 kV	115 kV	Line
Scenic (elements)	–	No	N/A	CE: Scenic - Pachmann 115 kV	115 kV	Line
Scenic (elements)	–	No	N/A	Scenic Sectionalizing Breaker	115 kV	Sectionalizing Breaker
Sewer Plant	**115 kV**	**No**	**N/A**			
Shiprock	**345 kV**	**Yes**	**WAPA - TOP**			
Shiprock (elements)	–	No	N/A	SR: San Juan 345 kV-Shiprock 345 kV	345 kV	Line
Shiprock (elements)	–	No	N/A	Shiprock - Four Corners 345 kV Line	345 kV	Line
Shiprock (elements)	–	No	N/A	Shiprock - Lost Canyon 230 kV line	345 kV	Line
Shiprock (elements)	–	No	N/A	Shiprock - Kayenta	345 kV	Line
Shiprock (elements)	–	No	N/A	Shiprock 345/230 kV Transformers	345 kV	Transformer
Signetics (elements)	–	No	N/A	SG: Signetics Tap-Signetics Substation	115 kV	Line
Signetics 1 & 2	**115 kV**	**No**	**N/A**			
Silver City	**69 kV**	**No**	**N/A**			
Silver City	**69 kV**	**No**	**N/A**			
Silver City (elements)	–	No	N/A	Silver City-Turquoise 69 kV Line	69 kV	Line
Silver City (elements)	–	No	N/A	Silver City-MD 69 kV Line	69 kV	Line
Silver City (elements)	–	No	N/A	Silver City Capacitor	69 kV	Reactive Resource

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Silver City (elements)	–	No	N/A	Silver City-North Silver 69 kV	69 kV	Line
Snow Vista	**115 kV**	**No**	**N/A**			
Snow Vista	**115 kV**	**No**	**N/A**			
Snow Vista (elements)	–	No	N/A	Sectionalizing Breaker		Sectionalizing Breaker
Snow Vista (elements)	115 kV	No	N/A	WJ: West Mesa - Snow Vista	115 kV	Line
Snow Vista (elements)	115 kV	No	N/A	PW: Person - Snow Vista 115 kV	115 kV	Line
Sol (Q2 2025)	**115 kV**	**No**	**N/A**			
Sol (elements)	–	No	N/A	Sol-Studio 115 kV line	115 kV	Line
Sol (elements)	–	No	N/A	Sandia-Sol 115 kV line	116 kV	Line
South Coors	**115 kV**	**No**	**N/A**			
South Pacheco (elements)	–	No	N/A	ZF: South PachecoTap 115 kV-South Pacheco Substation	115 kV	Line
South Pacheco 1 & 2	**115 kV**	**No**	**N/A**			
Springerville	**345 kV**	**Yes**	**TEP - TOP**			
Springerville (elements)	–	No	N/A	Springerville-McKinley 345 kV Line (MC-SP-1)	345 kV	Line
Springerville (elements)	–	No	N/A	Springerville-McKinley 345 kV Line (MC-SP-2)	345 kV	Line
Springerville (elements)	–	No	N/A	Springerville-Coronado 345 kV Line (SP-CO-1)	345 kV	Line
Springerville (elements)	–	No	N/A	GH: Springerville-Greenlee 345 kV Line (SP-GL-1)	345 kV	Line
Springerville (elements)	–	No	N/A	Springerville-Winchester 345 kV Line (SP-VL-1)	345 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Springerville (elements)	–	No	N/A	Macho Springs - 345 kV (El Paso)	345 kV	Line
St. Joseph	**115 kV**	**No**	**N/A**			
STA	**115 kV**	**No**	**LANL**			
STA (elements	–	No	N/A	RL: BA 115 kV-STA 115 kV	115 kV	Line
State Pen	**115 kV**	**No**	**N/A**			
Storrie Lake	**115 kV**	**No**	**TGST - TOP**			
Storrie Lake (elements)	–	No	N/A	VS: Valencia 115 kV-Storrie Lake 115 kV	115 kV	Line
Studio	**115 kV**	**No**	**N/A**			
Studio (Q4 2026)	**115 kV**	**No**	**N/A**			
Studio (elements)	–	No	N/A	PA: Studio Tap 115 kV-Studio Substation	115 kV	Line
Studio (elements)	–	No	N/A	PROS-STUD1 Prosperity-Studio 115	116 kV	Line
Studio (elements)	–	No	N/A	Sol-Studio 115 kV	115 kV	Line
Studio (elements)	–	No	N/A	Sectionalizing Breaker	115 kV	Sectionalizing Breaker
Sun Ranch (Q4 2023)	**115 kV**	**No**	N/A			
Sun Ranch (elements)	–	No	N/A	RTSN-SURA1: Sun Ranch-Rattlesnake 115 kV	115 kV	Line
Sun Ranch (elements)	–	No	N/A	BELN-SURA1 Sun Ranch-Belen 115 kV	115 kV	Line
Sun Ranch (elements)	–	No	N/A	STCE-SURA1: Sun Ranch-St. Cecilia 115 kV	115 kV	Line
Sun Ranch (elements)	–	No	N/A	STCE-SURA1: Sun Ranch to Los Morros 115 kV	115 kV	Line
Sun Ranch (elements)	–	No	N/A	SKRA-SURA1: Sun Ranch-Sky Ranch 115 kV (Gen Tie)	115 kV	Gen Tie Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Sun Ranch (elements)	–	No	N/A	Sun Ranch – Star Light 115 kV (Gen Tie)	115 kV	Gen Tie Line
Taiban Mesa	**345 kV**	**No**	**N/A**			
Taiban Mesa (elements)	–	No	N/A	TG: Taiban Mesa-Guadalupe 345 kV	345 kV	Line
Taiban Mesa (elements)	–	No	N/A	TB: Blackwater-Taiban 345 kV Line	345 kV	Line
Taiban Mesa (elements)	–	No	N/A	Taiban Mesa 345 kV-Lone Mesa 345 kV	345 kV	Gen Tie Line
Tijeras	**46 kV**	**No**	**N/A**			
Tome	**115 kV**	**No**	**N/A**			
Tome	**115 kV**	**No**	**N/A**			
Tome (elements)	–	No	N/A	TJ: Tome 115 kV-Belen 115 kV	115 kV	Line
Tome (elements)	–	No	N/A	TV: Tome 115 kV-VEF 115 kV	115 kV	Gen Tie Line
Tome (elements)	–	No	N/A	CK: College - Tome 115 kV	115 kV	Line
Tome (elements)	–	No	N/A	Tome 115/46 kV Transformer	115 kV	Transformer
Tome (elements)	–	No	N/A	PB: Person - Tome 115 kV	115 kV	Line
Tome 46	**46 kV**	**No**	**N/A**			
Tome 46 (elements)	–	No	N/A	BN: Tome-Person	46 kV	Line
Tome 46 (elements)	–	No	N/A	PB: Tome-Person	46 kV	Line
Tome 46 (elements)	–	No	N/A	115/46 kV Transformer	46 kV	Transformer
Tramway	**115 kV**	**No**	**N/A**			
Truman	**115 kV**	**No**	**N/A**			
Truman (elements)	–	No	N/A	TR: Truman Tap 115 kV-Truman Substation	115 kV	Radial Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Tularosa	**115 kV**	**No**	**N/A**			
Turquoise	**69 kV**	**No**	**N/A**			
Turquoise	**115 kV**	**No**	**N/A**			
Turquoise (elements)	–	No	N/A	Turquoise-Silver City 69 kV Line	69 kV	Line
Turquoise (elements)	–	No	N/A	Turquoise 115/69 kV Transformer	115 kV	Transformer
Turquoise (elements)	–	No	N/A	Turquoise-Burro Mountain 69 kV Line	69 kV	Line
Turquoise (elements)	–	No	N/A	TY: Turquoise 115 kV-Tyrone 115 kV	115 kV	Line
Turquoise (elements)	–	No	N/A	Tyrone 115/69 kV Transformer	115 kV	Transformer
Turquoise (elements)	–	No	N/A	MR: MD-1 115 kV-Turquoise 115 kV	115 kV	Line
Turquoise (elements)	–	No	N/A	HR: Hidalgo 115 kV-Turquoise 115 kV	115 kV	Line
Tyrone 69	**69 kV**	**No**	**N/A**			
United	**115 kV**	**No**	**N/A**			
UNM North Campus (elements)	–	No	N/A	UT: UNM North Campus Tap 115 kV-UNM North Campus Substation	115 kV	Radial Line
UNM North Campus Sub	**115 kV**	**No**	**N/A**			
UNM Unit Sub 1, 2 and 3	**115 kV**	**No**	**N/A**			
Unser	**115 kV**	**No**	**N/A**			
Valencia (2027)	**115kV**	**No**	N/A			
Valencia	**115 kV**	**No**	**N/A**			
Valencia (elements)	–	No	N/A	VS: Valencia 115 kV-Storrie Lake 115 kV	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Valencia (elements)	-	No	N/A	SL: Zia 115 kV-Valencia 115 kV	115 kV	Line
Valencia (elements)	-	No	N/A	Valencia Transformer 115/46 kV	115 kV	Transformer
Valencia (elements)	-	No	N/A	Valencia Shunt Capacitors	115 kV	Reactive Resource
Van Buren T1 & T4	**69 kV**	**No**	**N/A**			
Veranda	**115 kV**	**No**	**N/A**			
Veranda (elements)	-	No	N/A	RR: Veranda 115 kV-Corrales Bluff 115 kV	115 kV	Line
Veranda (elements)	-	No	N/A	PV: Rio Puerco 115 kV-Veranda 115 kV	115 kV	Line
Veranda (elements)	-	No	N/A	Dist - Veranda (Sectionalizing Breaker system)		Sectionalizing Breaker
Veranda 1 & 2	**115 kV**	**No**	**N/A**			
Volcano 1 & 2	**115 kV**	**No**	**N/A**			
Warner	**46 kV**	**No**	**N/A**			
Wayne	**115 kV**	**No**	**N/A**			
Wesmeco	**115 kV**	**No**	**N/A**			
Wesmeco (elements)	-	No	N/A	WC: Wesmeco Tap 115 kV-Wesmeco Tap Substation	115 kV	Radial Line
West Mesa 115/ 230 (elements)	-	No	N/A	WD: West Mesa 115 kV - Huning Ranch 115 kV	115 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	SK: Scenic - West Mesa 115 kV	115 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	PTRO-WSMS1 West Mesa to Petroglyph	115 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	WJ: West Mesa - Snow Vista	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
West Mesa 115/ 230 (elements)	-	No	N/A	WR: West Mesa 115 kV-Irving 115 kV	115 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	NW: Reeves 115 kV-West Mesa 115 kV	115 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	WP: West Mesa 115 kV-Prager 115 kV	115 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	KM: West Mesa 115 kV-Red Mesa 115 kV	115 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	WV-PM: West Mesa 115 kV-Person (Volcano) 115 kV	115 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	230/115 kV Transformer #1	230 kV	Transformer
West Mesa 115/ 230 (elements)	-	No	N/A	230/115 kV Transformer #2	230 kV	Transformer
West Mesa 115/ 230 (elements)	-	No	N/A	HU: West Mesa 115 kV - Huning Ranch 115 kV	115 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	WA: West Mesa-Ambrosia 230 kV Line	230 kV	Line
West Mesa 115/ 230 (elements)	-	No	N/A	West Mesa #1 Shunt Capacitors	115 kV	Reactive Resource
West Mesa 115/ 230 (elements)	-	No	N/A	West Mesa #2 Shunt Capacitors	115 kV	Reactive Resource
West Mesa 115/ 230 (elements) (2031)	-	No	N/A	ASPN-WSMS1: Aspen-West Mesa	115 kV	Line
West Mesa 115/230	**115/230**	**No**	**N/A**			
West Mesa 345	**345 kV**	**No**	**N/A**			
West Mesa 345 (elements)	-	No	N/A	EP: West Mesa 345 kV-Arroyo 345 kV	345 kV	Line
West Mesa 345 (elements)	-	No	N/A	BJ: West Mesa-Rio Puerco 345 kV Line 1	345 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
West Mesa 345 (elements)	-	No	N/A	AJ: West Mesa-Rio Puerco 345 kV Line 2	345 kV	Line
West Mesa 345 (elements)	-	No	N/A	PAJA-WSMS1: West Mesa 345 kV - Pajarito 345kV	345 kV	Line
West Mesa 345 (elements)	-	No	N/A	345/115 kV Transformer #1	345 kV	Transformer
West Mesa 345 (elements)	-	No	N/A	345/115 kV Transformer #2	345 kV	Transformer
West Mesa 345 (elements)	-	No	N/A	West Mesa - EP Line Reactor	345 kV	Reactive Resource
West Mesa 345 (elements)	-	No	N/A	West Mesa AJ Reactor	345 kV	Reactive Resource
West Mesa 345 (elements)	-	No	N/A	QLRA-WSMS1 Quail Ranch-West Mesa 345 kV Line	345 kV	Line
Western Spirit	**345 kV**	**No**	**N/A**			
Western Spirit (elements)	-	No	N/A	CLCR-WESP1 Clines Corners to Western Spirit	345kV	Line
Western Spirit (elements)	-	No	N/A	HIMO-WESP 345 kV line	345 kV	Line
Western Spirit (elements)	-	No	N/A	CCWF-WESP1 Tie to Third Party Wind Farm	345kV	Gen Tie Line
Western Spirit (elements)	-	No	N/A	DMWF-WESP1 Tie to Third Party Wind Farm	345kV	Gen Tie Line
Western Spirit (elements)	-	No	N/A	Western Spirit-Hidden Mountain Line Shunt Reactor	345 kV	Reactive Resource
Western Spirit (elements)	-	No	N/A	Western Spirit - Hidden Mountain series Capacitor	345 kV	Line
Westwing	**500 kV**	**Yes**	**APS - TOP**			
Willard	**115 kV**	**No**	**TSGT - TO & TOP**			

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Willard (elements)	–	No	N/A	WL: Willard 115 kV-Belen 115 kV	115 kV	Line
Willard (elements)	–	No	N/A	TW: Britton 115 kV-Willard 115 kV	115 kV	Line
Winrock	**115 kV**	**No**	**N/A**			
Wyoming	**115 kV**	**No**	**N/A**			
Yah-ta-hey	**115/345**	**No**	**N/A**			
Yah-ta-hey (elements)	–	No	N/A	YN: Ya-Ta-Hey 115 kV-Coalmine 115 kV	115 kV	Radial Line
Yah-ta-hey (elements)	–	No	N/A	YP: Ya-Ta-Hey 115 kV-Pitt Midway Substation	115 kV	Radial Line
Yah-ta-hey (elements)	–	Yes	TSGT owns, PNM maintains	GYTH: Ya-Ta-Hey - PEGS 115 kV	115 kV	Line
Yah-ta-hey (elements)	–	No	N/A	AY: Ambrosia 115 115 kV-Ya-Ta-Hey 115 kV	115 kV	Line
Yah-ta-hey (elements)	–	No	N/A	Yah-ta-hey Transformer 345/ 115 kV	345 kV	Transformer
Yah-ta-hey (elements)	–	No	N/A	Yah-ta-hey Transformer 345/ 115 kV	345 kV	Transformer
Yah-ta-hey (elements)	–	No	N/A	Yah-Ta-Hey #1 Shunt Capacitors	115 kV	Reactive Resource
Yah-ta-hey (elements)	–	No	N/A	Yah-Ta-Hey #2 Shunt Capacitors	115 kV	Reactive Resource
Zafarano	**115 kV**	**No**	**N/A**			
Zamora	**46 kV**	**No**	**N/A**			
Zamora (elements)	–	No	N/A	TZ: Zamora Tap 46kV-Zamora Tap Substation	46 kV	Radial Line
Zia	**115 kV**	**No**	**N/A**			
Zia (elements)	–	No	N/A	ZIA: Zia 115 kV-Norton 115 kV/Algodones 115 kV	115 kV	Line

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Zia (elements)	–	No	N/A	ZF: Zia 115 kV-South Pacheco Substation	115 kV	Radial Line
Zia (elements)	–	No	N/A	SL: Zia 115 kV-Valencia 115 kV	115 kV	Line
Zia (elements)	–	No	N/A	RS: BA 115 kV-Zia 115 kV	115 kV	Line
Zia (elements)	–	No	N/A	3- 115/46 kV Zia Transformers	115 kV	Transformer
Zia (elements)	–	No	N/A	NS: Norton 115 kV-Zia 115 kV	115 kV	Line
Zia (elements)	–	No	N/A	Zia #1 Shunt Capacitors	115 kV	Reactive Resource
Zia (elements)	–	No	N/A	Zia #2 Shunt Capacitors	115 kV	Reactive Resource
Zia (elements)	–	No	N/A	Zia #3 Shunt Capacitors	115 kV	Reactive Resource
Zia (elements)	–	No	N/A	Zia #4 Shunt Capacitors	115 kV	Reactive Resource
Zia 46	**46 kV**	**No**	**N/A**			
Zia 46 (elements)	–	No	N/A	ZS: Zia-Power Plant	46 kV	Line
Zia 46 (elements)	–	No	N/A	ZM: Zia-Power Plant	46 kV	Line
Zia 46 (elements)	–	No	N/A	MS: Zia-Power Plant	46 kV	Line
Zia 46 (elements)	–	No	N/A	ZB: Zia radial (Santa Domingo)	46 kV	Radial Line
Zia 46 (elements)	–	No	N/A	Zia 1-2 bus tie	46 kV	Line
Zia 46 (elements)	–	No	N/A	115/46 kV Transformer	46 kV	Transformer
Zia 46 (elements)	–	No	N/A	115/46 kV Transformer	46 kV	Transformer
Zia 46 (elements)	–	No	N/A	115/46 kV Transformer	46 kV	Transformer
Zia 46 (elements)	–	No	N/A	Zia 46 kV Shunt Capacitor #1	46 kV	Reactive Resource

Station Name	Station Voltage Level(s)	Jointly Owned / Operated? Yes	Jointly Owned / Operated Details	Element Name (Lines, transformers, Reactive Resources)	Element Voltage (High side for transformers)	Element Type
Zia 46 (elements)	–	No	N/A	Zia 46 kV Shunt Capacitor #2	46 kV	Reactive Resource

TABLE F-2: EXISTING, PLANNED/UNDER CONSTRUCTION, AND FUTURE DISTRIBUTION SUBTATIONS

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
Alamogordo 1	**115 kV**			
	–	**Alamogordo North 115/12.47 lV Transformer**	**115 kV**	**Transformer**
	–	**A10010**	**115 kV**	**Line**
	–	**A10011**	**115 kV**	**Line**
	–	**A10012**	**115 kV**	**Line**
	–	**Alamogordo Middle 115/12.47 lV Transformer**	**115 kV**	**Transformer**
	–	**A10001**	**115 kV**	**Line**
	–	**A10002**	**115 kV**	**Line**
	–	**A10003**	**115 kV**	**Line**
	–	**Alamogordo South 115/12.47 lV Transformer**	**115 kV**	**Transformer**
	–	**A10083**	**115 kV**	**Line**
	–	**A10089**	**115 kV**	**Line**
	–	**A10097**	**115 kV**	**Line**
Alcazar	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Alcazar 115/12.47kV Transformer	115 kV	Transformer
	–	Alcazar 11	12.47 kV	Line
	–	Alcazar 12	12.47 kV	Line
	–	Alcazar 13	12.47 kV	Line
	–	Alcazar 14	12.47 kV	Line
Algodones	**115 kV**			
	–	Algodones 115/12.47kV Transformer	115 kV	Transformer
	–	Algodones 11	12.47 kV	Line
	–	Algodones 12	12.47 kV	Line
	–	Algodones 13	12.47 kV	Line
	–	Algodones 2 115/12.47kV Transformer	115 kV	Transformer
	–	Algodones 21	12.47 kV	Line
Alire	**46 kV**			
	–	Alire 46/12.47 kV Transformer	46 kV	Transformer
	–	Alire 11	12.47 kV	Line
	–	Alire 12	12.47 kV	Line
Anderson	**115 kV**			
	–	Anderson 115/12.47kV Transformer	115 kV	Transformer
	–	Anderson 11	12.47 kV	Line
	–	Anderson 12	12.47 kV	Line
	–	Anderson 13	12.47 kV	Line
Arno	**46 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Arno 46/12.47 kV Transformer	46 kV	Transformer
	–	Arno 11	12.47 kV	Line
	–	Arno 12	12.47 kV	Line
	–	Arno 13	12.47 kV	Line
	–	Arno 46/12.47 kV Transformer	46 kV	Transformer
	–	Arno 24	12.47 kV	Line
	–	Arno 25	12.47 kV	Line
	–	Arno 26	12.47 kV	Line
Arriba	**115 kV**			
	–	Arriba 115/12.47kV Transformer	115 kV	Transformer
	–	Arriba 11	12.47 kV	Line
	–	Arriba 12	12.47 kV	Line
	–	Arriba 13	12.47 kV	Line
	–	Arriba 14	12.47 kV	Line
Aspen	**115 kV**			
	–	Aspen 115/12.47kV Transformer	115 kV	Transformer
	–	Aspen 11	12.47 kV	Line
	–	Aspen 12	12.47 kV	Line
	–	Aspen 13	12.47 kV	Line
	–	Aspen 14	12.47 kV	Line
Avila	**115 kV**			
	–	Avila 115/12.47kV Transformer	115 kV	Transformer

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Avila 11	12.47 kV	Line
	–	Avila 12	12.47 kV	Line
	–	Avila 13	12.47 kV	Line
Baca	**46 kV**			
	–	Baca 46/12.47 kV Transformer	46 kV	Transformer
	–	Baca 11	12.47 kV	Line
	–	Baca 12	12.47 kV	Line
Ball Park	**46 kV**			
	–	Ball Park 46/4.16 kV Transformer	46 kV	Transformer
	–	Ball Park 11	4.16 kV	Line
	–	Ball Park 12	4.16 kV	Line
	–	Ball Park 13	4.16 kV	Line
	–	Ball Park 14	4.16 kV	Line
Beckner	**115 kV**			
	–	Beckner 1 115/12.47kV Transformer	115 kV	Transformer
	–	Beckner 11	12.47 kV	Line
	–	Beckner 12	12.47 kV	Line
	–	Beckner 13	12.47 kV	Line
	–	Beckner 14	12.47 kV	Line
	–	Beckner 2 115/12.47kV Transformer	115 kV	Transformer
	–	Beckner 21	12.47 kV	Line
	–	Beckner 22	12.47 kV	Line
	–	Beckner 23	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Beckner 24	12.47 kV	Line
Bel Air	**115 kV**			
	–	Bel Air 115/12.47kV Transformer	115 kV	Transformer
	–	Bel Air 11	12.47 kV	Line
	–	Bel Air 12	12.47 kV	Line
	–	Bel Air 13	12.47 kV	Line
	–	Bel Air 14	12.47 kV	Line
Beverly Wood	**115 kV**			
	–	Beverly Wood 115/12.47kV Transformer	115 kV	Transformer
	–	Beverly Wood 11	12.47 kV	Line
	–	Beverly Wood 12	12.47 kV	Line
	–	Beverly Wood 13	12.47 kV	Line
Black Ranch	**115 kV**			
	–	Black Ranch 115/12.47kV Transformer	115 kV	Transformer
	–	Black Ranch 11	12.47 kV	Line
	–	Black Ranch 12	12.47 kV	Line
	–	Black Ranch 13	12.47 kV	Line
	–	Black Ranch 14	12.47 kV	Line
	–	Black Ranch 2 115/12.47kV Transformer	115 kV	Transformer
	–	Black Ranch 21	12.47 kV	Line
	–	Black Ranch 22	12.47 kV	Line
	–	Black Ranch 23	12.47 kV	Line
	–	Black Ranch 24	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
Bosque Farms	**115 kV**			
	–	Bosque Farms 1 115/12.47kV Transformer	115 kV	Transformer
	–	Bosque Farms 11	12.47 kV	Line
	–	Bosque Farms 12	12.47 kV	Line
Buckman	**115 kV**			
	–	Buckman 1 115/12.47kV Transformer	115 kV	Transformer
	–	Buckman 11	12.47 kV	Line
	–	Buckman 12	12.47 kV	Line
	–	Buckman 2 115/12.47kV Transformer	115 kV	Transformer
	–	Buckman 21	12.47 kV	Line
	–	Buckman 22	12.47 kV	Line
	–	Buckman 23	12.47 kV	Line
Burro Mountain	**69 kV**			
	–	Burro Mountain 69/12.47 kV Transformer	69 kV	Transformer
	–	Burro Mountain 7-160	12.47 kV	Line
	–	Burro Mountain 7-387	12.47 kV	Line
Caja Del Rio	**115 kV**			
	–	Caja Del Rio 115/12.47kV Transformer	115 kV	Transformer
	–	Caja Del Rio 11	12.47 kV	Line
	–	Caja Del Rio 12	12.47 kV	Line
	–	Caja Del Rio 13	12.47 kV	Line
	–	Caja Del Rio 14	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
Camel Tracks	**46 kV**			
	–	Camel Tracks 46/12.47 kV Transformer	46 kV	Transformer
	–	Camel Tracks 11	12.47 kV	Line
	–	Camel Tracks 12	12.47 kV	Line
	–	Camel Tracks 13	12.47 kV	Line
Capitol	**46 kV**			
	–	Capitol 46/4.16 kV Transformer	46 kV	Transformer
	–	Capitol 11	4.16 kV	Line
	–	Capitol 12	4.16 kV	Line
Central	**115 kV**			
	–	Central 115/12.47kV Transformer	115 kV	Transformer
	–	Central 11	12.47 kV	Line
	–	Central 12	12.47 kV	Line
	–	Central 13	12.47 kV	Line
	–	Central 14	12.47 kV	Line
Church Rock	**115 kV**			
	–	Church Rock 115/12.47kV Transformer	115 kV	Transformer
Claremont	**115 kV**			
	–	Claremont 1 115/12.47kV Transformer	115 kV	Transformer
	–	Claremont 11	12.47 kV	Line
	–	Claremont 12	12.47 kV	Line
	–	Claremont 13	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Claremont 14	12.47 kV	Line
	–	Claremont 2 115/12.47kV Transformer	115 kV	Transformer
	–	Claremont 21	12.47 kV	Line
	–	Claremont 22	12.47 kV	Line
	–	Claremont 23	12.47 kV	Line
	–	Claremont 24	12.47 kV	Line
Coal	**115 kV**			
	–	Coal 115/12.47kV Transformer	115 kV	Transformer
	–	Coal 11	12.47 kV	Line
	–	Coal 12	12.47 kV	Line
	–	Coal 13	12.47 kV	Line
	–	Coal 14	12.47 kV	Line
Cochiti	**46 kV**			
	–	Cochiti 46/12.47 kV Transformer	46 kV	Transformer
	–	Cochiti 11	12.47 kV	Line
	–	Cochiti 12	12.47 kV	Line
Colinas	**115 kV**			
	–	Colinas 115/12.47kV Transformer	115 kV	Transformer
	–	Colinas 11	12.47 kV	Line
	–	Colinas 12	12.47 kV	Line
	–	Colinas 13	12.47 kV	Line
College	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	College 115/12.47kV Transformer	115 kV	Transformer
	–	College 11	12.47 kV	Line
	–	College 12	12.47 kV	Line
	–	College 13	12.47 kV	Line
	–	College 14	12.47 kV	Line
Cornell	**115 kV**			
	–	Cornell 115/12.47kV Transformer	115 kV	Transformer
	–	Cornell 11	12.47 kV	Line
	–	Cornell 12	12.47 kV	Line
	–	Cornell 13	12.47 kV	Line
	–	Cornell 14	12.47 kV	Line
Corrales Bluffs	**115 kV**			
	–	Corrales Bluff 115/12.47kV Transformer	115 kV	Transformer
	–	Corrales Bluff 11	12.47 kV	Line
	–	Corrales Bluff 12	12.47 kV	Line
	–	Corrales Bluff 13	12.47 kV	Line
	–	Corrales Bluff 14	12.47 kV	Line
Cottonwood	**115 kV**			
	–	Cottonwood 1 115/12.47kV Transformer	115 kV	Transformer
	–	Cottonwood 11	12.47 kV	Line
	–	Cottonwood 12	12.47 kV	Line
	–	Cottonwood 13	12.47 kV	Line
	–	Cottonwood 14	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Cottonwood 2 115/12.47kV Transformer	115 kV	Transformer
	–	Cottonwood 21	12.47 kV	Line
	–	Cottonwood 22	12.47 kV	Line
	–	Cottonwood 23	12.47 kV	Line
	–	Cottonwood 24	12.47 kV	Line
Cuchilla	**115 kV**			
	–	Cuchilla 115/12.47kV Transformer	115 kV	Transformer
	–	Cuchilla 11	12.47 kV	Line
	–	Cuchilla 12	12.47 kV	Line
Deming East & West	**115 kV**			
	–	Deming East 115/13.8kV Transformer	115 kV	Transformer
	–	Deming East 11	13.8 kV	Line
	–	Deming East 12	13.8 kV	Line
	–	Deming East 13	13.8 kV	Line
	–	Deming West 115/13.8kV Transformer	115 kV	Transformer
	–	Deming West 11	13.8 kV	Line
	–	Deming West 12	13.8 kV	Line
	–	Deming West 13	13.8 kV	Line
Eastridge	**115 kV**			
	–	Eastridge 115/12.47kV Transformer	115 kV	Transformer
	–	Eastridge 11	12.47 kV	Line
	–	Eastridge 12	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Eastridge 13	12.47 kV	Line
	–	Eastridge 14	12.47 kV	Line
El Cerro	**115 kV**			
	–	El Cerro 115/12.47kV Transformer	115 kV	Transformer
	–	El Cerro 11	12.47 kV	Line
	–	El Cerro 12	12.47 kV	Line
	–	El Cerro 13	12.47 kV	Line
El Dorado	**115 kV**			
	–	El Dorado 115/12.47kV Transformer	115 kV	Transformer
	–	El Dorado 11	12.47 kV	Line
	–	El Dorado 12	12.47 kV	Line
Embudo	**115 kV**			
	–	Embudo 115/12.47kV Transformer	115 kV	Transformer
	–	Embudo 11	12.47 kV	Line
	–	Embudo 12	12.47 kV	Line
	–	Embudo 13	12.47 kV	Line
	–	Embudo 14	12.47 kV	Line
Enchanted Hills	**115 kV**			
	–	Enchanted Hills 115/12.47kV Transformer	115 kV	Transformer
	–	Enchanted Hills 11	12.47 kV	Line
	–	Enchanted Hills 12	12.47 kV	Line
	–	Enchanted Hills 13	12.47 kV	Line
	–	Enchanted Hills 14	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
First Street	**115 kV**			
	–	First Street 115/12.47kV Transformer	115 kV	Transformer
	–	First Street 11	12.47 kV	Line
	–	First Street 12	12.47 kV	Line
	–	First Street 13	12.47 kV	Line
	–	First Street 14	12.47 kV	Line
Fort Marcy	**46 kV**			
	–	Fort Marcy 46/12.47 kV Transformer	46 kV	Transformer
	–	Fort Marcy 11	12.47 kV	Line
	–	Fort Marcy 12	12.47 kV	Line
	–	Fort Marcy 13	12.47 kV	Line
	–	Fort Marcy 14	12.47 kV	Line
Four Hills	**115 kV**			
	–	Four Hills 115/12.47kV Transformer	115 kV	Transformer
	–	Four Hills 11	12.47 kV	Line
	–	Four Hills 12	12.47 kV	Line
	–	Four Hills 13	12.47 kV	Line
	–	Four Hills 14	12.47 kV	Line
Gallinas	**115 kV**			
	–	Gallinas North 115/12.47kV Transformer	115 kV	Transformer
	–	Gallinas 11	12.47 kV	Line
	–	Gallinas 12	12.47 kV	Line
	–	Gallinas 14	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
Gary Stephenson (2028)	**115 kV**			
Gary Stephenson 1 (2028)	**115 kV**			
	–	Gary Stephenson 11	12.47 kV	Line
	–	Gary Stephenson 12	12.47 kV	Line
	–	Gary Stephenson 13	12.47 kV	Line
	–	Gary Stephenson 14	12.47 kV	Line
Gary Stephenson 2 (2028)	**115 kV**			
	–	Gary Stephenson 21	12.47 kV	Line
	–	Gary Stephenson 22	12.47 kV	Line
	–	Gary Stephenson 23	12.47 kV	Line
	–	Gary Stephenson 24	12.47 kV	Line
Gavilan	**115 kV**			
	–	Gavilan North 115/12.47kV Transformer	115 kV	Transformer
	–	Gavilan 12-10	12.47 kV	Line
	–	Gavilan 12-30	12.47 kV	Line
	–	Gavilan South 115/12.47kV Transformer	115 kV	Transformer
	–	Gavilan 12-00	12.47 kV	Line
Girard	**115 kV**			
	–	Girard 115/12.47kV Transformer	115 kV	Transformer
	–	Girard 11	12.47 kV	Line
	–	Girard 12	12.47 kV	Line
	–	Girard 13	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Girard 14	12.47 kV	Line
Gold	**115 kV**			
	–	Gold 115/13.8kV Transformer	115 kV	Transformer
	–	Gold 11	13.8 kV	Line
	–	Gold 12	13.8 kV	Line
	–	Gold 13	13.8 kV	Line
Halona	**46 kV**			
	–	Halona 46/4.16 kV Transformer	46 kV	Transformer
	–	Halona 11	4.16 kV	Line
	–	Halona 12	4.16 kV	Line
	–	Halona 14	4.16 kV	Line
Hamilton	**115 kV**			
	–	Hamilton 1 115/12.47kV Transformer	115 kV	Transformer
	–	Hamilton 11	12.47 kV	Line
	–	Hamilton 12	12.47 kV	Line
	–	Hamilton 13	12.47 kV	Line
	–	Hamilton 14	12.47 kV	Line
	–	Hamilton 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Hamilton 21	12.47 kV	Line
	–	Hamilton 22	12.47 kV	Line
	–	Hamilton 23	12.47 kV	Line
	–	Hamilton 24	12.47 kV	Line
Hawkins	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Hawkins 1 115/12.47kV Transformer	115 kV	Transformer
	–	Hawkins 11	12.47 kV	Line
	–	Hawkins 12	12.47 kV	Line
	–	Hawkins 13	12.47 kV	Line
	–	Hawkins 14	12.47 kV	Line
	–	Hawkins 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Hawkins 21	12.47 kV	Line
	–	Hawkins 22	12.47 kV	Line
	–	Hawkins 23	12.47 kV	Line
	–	Hawkins 24	12.47 kV	Line
Hazeldine	**46 kV**			
	–	Hazeldine 2 46/4.16 kV Transformer	46 kV	Transformer
	–	Hazeldine 11	4.16 kV	Line
	–	Hazeldine 12	4.16 kV	Line
Hermanas	**115 kV**			
	–	Hermanas 115/13.8 kV Transformer	115 kV	Transformer
	–	Hermanas 11	13.8 kV	Line
	–	Hermanas 12	13.8 kV	Line
	–	Hermanas 13	13.8 kV	Line
	–	Hermanas 14	13.8 kV	Line
Hickox	**46 kV**			
	–	Hickox 2 46/4.16 kV Transformer	46 kV	Transformer

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Hickox 11	4.16 kV	Line
	–	Hickox 12	4.16 kV	Line
Hollywood (Ruidoso)	**115 kV**			
	–	Hollywood North 115/12.47kV Transformer	115 kV	Transformer
	–	Hollywood 12-123	12.47 kV	Line
	–	Hollywood South 115/12.47kV Transformer	115 kV	Transformer
	–	Hollywood 12-126	12.47 kV	Line
Hondale	**115 kV**			
	–	Hondale 115/13.8 kV Transformer	115 kV	Transformer
	–	Hondale 11	13.8 kV	Line
	–	Hondale 12	13.8 kV	Line
Indian Hospital	**115 kV**			
	–	Indian Hospital 115/12.47kV Transformer	115 kV	Transformer
	–	Indian Hospital 11	12.47 kV	Line
	–	Indian Hospital 12	12.47 kV	Line
	–	Indian Hospital 13	12.47 kV	Line
	–	Indian Hospital 14	12.47 kV	Line
Inez	**115 kV**			
	–	Inez 115/12.47kV Transformer	115 kV	Transformer
	–	Inez 11	12.47 kV	Line
	–	Inez 12	12.47 kV	Line
Innovation	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Innovation 115/12.47kV Transformer	115 kV	Transformer
	–	Innovation 11	12.47 kV	Line
	–	Innovation 12	12.47 kV	Line
	–	Innovation 13	12.47 kV	Line
	–	Innovation 14	12.47 kV	Line
Iris	**115 kV**			
	–	Iris 115/12.47kV Transformer	115 kV	Transformer
	–	Iris 11	12.47 kV	Line
	–	Iris 12	12.47 kV	Line
	–	Iris 13	12.47 kV	Line
	–	Iris 14	12.47 kV	Line
Iron Street	**46 kV**			
	–	Iron Street 1 46/12.47 kV Transformer	46 kV	Transformer
	–	Iron Street 2 46/12.47 kV Transformer	46 kV	Transformer
	–	Iron Street 11	12.47 kV	Line
	–	Iron Street 12	12.47 kV	Line
	–	Iron Street 13	12.47 kV	Line
	–	Iron Street 14	12.47 kV	Line
	–	Iron Street21	12.47 kV	Line
	–	Iron Street 22	12.47 kV	Line
	–	Iron Street 23	12.47 kV	Line
	–	Iron Street 24	12.47 kV	Line
Isleta	**46 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Isleta 46/12.47 kV Transformer	46 kV	Transformer
	–	Isleta 11	12.47 kV	Line
	–	Isleta 12	12.47 kV	Line
Jarales	**115 kV**			
	–	Jarales 115/12.47kV Transformer	115 kV	Transformer
	–	Jarales 11	12.47 kV	Line
	–	Jarales 12	12.47 kV	Line
	–	Jarales 13	12.47 kV	Line
	–	Jarales 14	12.47 kV	Line
Jefferson	**115 kV**			
	–	Jefferson 115/12.47kV Transformer	115 kV	Transformer
	–	Jefferson 11	12.47 kV	Line
Juan Tabo	**115 kV**			
	–	Juan Tabo 115/12.47kV Transformer	115 kV	Transformer
	–	Juan Tabo 11	12.47 kV	Line
	–	Juan Tabo 12	12.47 kV	Line
	–	Juan Tabo 13	12.47 kV	Line
	–	Juan Tabo 14	12.47 kV	Line
Kaiser	**46 kV**			
	–	Kaiser 46/4.16 kV Transformer	46 kV	Transformer
	–	Kaiser 11	4.16 kV	Line
Keleher	**46 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Keleher 46/4.16 kV Transformer	46 kV	Transformer
	–	Keleher 11	4.16 kV	Line
	–	Keleher 12	4.16 kV	Line
	–	Keleher 13	4.16 kV	Line
Kewa	**115 kV**			
	–	Kewa 115/12.47kV Transformer	115 kV	Transformer
	–	Kewa 11	12.47 kV	Line
	–	Kewa 12	12.47 kV	Line
	–	Kewa 13	12.47 kV	Line
La Bajada	**46 kV**			
	–	La Bajada 46/12.47kV Transformer	46 kV	Transformer
	–	La Bajada 11	12.47 kV	Line
La Morada	**115 kV**			
	–	La Morada 115/12.47kV Transformer	115 kV	Transformer
	–	La Morada 11	12.47 kV	Line
	–	La Morada 12	12.47 kV	Line
	–	La Morada 13	12.47 kV	Line
	–	La Morada 14	12.47 kV	Line
Lawrence	**115 kV**			
	–	Lawrence 115/12.47kV Transformer	115 kV	Transformer
	–	Lawrence 11	12.47 kV	Line
	–	Lawrence 12	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Lawrence 13	12.47 kV	Line
	–	Lawrence 14	12.47 kV	Line
Lenkurt	**115 kV**			
	–	Lenkurt 115/12.47kV Transformer	115 kV	Transformer
	–	Lenkurt 11	12.47 kV	Line
	–	Lenkurt 12	12.47 kV	Line
	–	Lenkurt 13	12.47 kV	Line
	–	Lenkurt 14	12.47 kV	Line
Leyendecker	**115 kV**			
	–	Leyendecker 115/12.47kV Transformer	115 kV	Transformer
	–	Leyendecker 11	12.47 kV	Line
	–	Leyendecker 12	12.47 kV	Line
	–	Leyendecker 13	12.47 kV	Line
	–	Leyendecker 14	12.47 kV	Line
Lomas	**115 kV**			
	–	Lomas 115/12.47kV Transformer	115 kV	Transformer
	–	Lomas 11	12.47 kV	Line
	–	Lomas 12	12.47 kV	Line
	–	Lomas 13	12.47 kV	Line
	–	Lomas 14	12.47 kV	Line
	–	Lomas 15	12.47 kV	Line
	–	Lomas 16	12.47 kV	Line
Lordsburg	**69 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Lordsburg T1 69/12.47kV Transformer	69 kV	Transformer
	–	Lordsburg 1000	12.47 kV	Line
	–	Lordsburg T2 69/12.47kV Transformer	69 kV	Transformer
	–	Lordsburg 318	12.47 kV	Line
Los Angeles	**115 kV**			
	–	Los Angeles 115/12.47kV Transformer	115 kV	Transformer
	–	Los Angeles 11	12.47 kV	Line
	–	Los Angeles 12	12.47 kV	Line
	–	Los Angeles 13	12.47 kV	Line
Los Chavez	**46 kV**			
	–	Los Chavez 46/12.47kV Transformer	46 kV	Transformer
	–	Los Chavez 11	12.47 kV	Line
	–	Los Chavez 12	12.47 kV	Line
Los Lunas	**46 kV**			
	–	Los Lunas 46/12.47kV Transformer	46 kV	Transformer
	–	Los Lunas 11	12.47 kV	Line
	–	Los Lunas 12	12.47 kV	Line
Los Morros	**115 kV**			
	–	Los Morros 1 115/12.47kV Transformer	115 kV	Transformer
	–	Los Morros 11	12.47 kV	Line
	–	Los Morros 12	12.47 kV	Line
	–	Los Morros 13	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Los Morros 14	12.47 kV	Line
	–	Los Morros 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Los Morros 21	12.47 kV	Line
	–	Los Morros 22	12.47 kV	Line
	–	Los Morros 23	12.47 kV	Line
	–	Los Morros 24	12.47 kV	Line
Lost Horizon	**115 kV**			
	–	Lost Horizon 115/12.47kV Transformer	115 kV	Transformer
	–	Lost Horizon 11	12.47 kV	Line
	–	Lost Horizon 12	12.47 kV	Line
	–	Lost Horizon 13	12.47 kV	Line
	–	Lost Horizon 14	12.47 kV	Line
Louden Hills	**115 kV**			
	–	Louden Hills 115/12.47kV Transformer	115 kV	Transformer
	–	Louden Hills 11	12.47 kV	Line
	–	Louden Hills 12	12.47 kV	Line
Manhattan	**46 kV**			
	–	Manhattan 46/12.47kV Transformer	46 kV	Transformer
	–	Manhattan 11	12.47 kV	Line
	–	Manhattan 12	12.47 kV	Line
Manzanita	**46 kV**			
	–	Manzanita 1 46/12.47kV Transformer	46 kV	Transformer

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Manzanita 11	12.47 kV	Line
	–	Manzanita 12	12.47 kV	Line
	–	Manzanita 2 115/12.47kV Transformer	115 kV	Transformer
	–	Manzanita 21	12.47 kV	Line
	–	Manzanita 22	12.47 kV	Line
Manzano	**115 kV**			
	–	Manzano 115/12.47kV Transformer	115 kV	Transformer
	–	Manzano 11	12.47 kV	Line
	–	Manzano 12	12.47 kV	Line
	–	Manzano 13	12.47 kV	Line
Mariposa	**115 kV**			
	–	Mariposa 115/12.47kV Transformer	115 kV	Transformer
	–	Mariposa 11	12.47 kV	Line
	–	Mariposa 12	12.47 kV	Line
	–	Mariposa 13	12.47 kV	Line
	–	Mariposa 14	12.47 kV	Line
Marquez	**115 kV**			
	–	Marquez 115/12.47 kV Transformer	115 kV	Transformer
	–	Marquez 11	12.47 kV	Line
	–	Marquez 12	12.47 kV	Line
MD-1	**69 kV**			
	–	MD-11 69/23.5 kV Transformer	69 kV	Transformer

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	MD-1 11	23.5 kV	Line
	–	MD-1 12	23.5 kV	Line
	–	MD-1 13	23.5 kV	Line
	–	MD-1 14	23.5 kV	Line
	–	MD-1 T1 North 69/23.5 kV Transformer	69 kV	Transformer
	–	MD-1 T2 South 69/23.5 kV Transformer	69 kV	Transformer
Mejia	**115 kV**			
	–	Mejia 115/12.47kV Transformer	115 kV	Transformer
	–	Mejia 11	12.47 kV	Line
	–	Mejia 12	12.47 kV	Line
	–	Mejia 13	12.47 kV	Line
	–	Mejia 14	12.47 kV	Line
Menaul	**115 kV**			
	–	Menaul 115/12.47kV Transformer	115 kV	Transformer
	–	Menaul 11	12.47 kV	Line
	–	Menaul 12	12.47 kV	Line
	–	Menaul 13	12.47 kV	Line
	–	Menaul 14	12.47 kV	Line
	–	Menaul 15	12.47 kV	Line
	–	Menaul 16	12.47 kV	Line
Miguel Lujan	**115 kV**			
	–	Miguel Lujan 115/12.47kV Transformer	115 kV	Transformer

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Miguel Lujan 11	12.47 kV	Line
	–	Miguel Lujan 12	12.47 kV	Line
	–	Miguel Lujan 13	12.47 kV	Line
	–	Miguel Lujan 14	12.47 kV	Line
Mission	**115 kV**			
	–	Mission 1 115/12.47kV Transformer	115 kV	Transformer
	–	Mission 11	12.47 kV	Line
	–	Mission 12	12.47 kV	Line
	–	Mission 13	12.47 kV	Line
	–	Mission 14	12.47 kV	Line
	–	Mission 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Mission 21	12.47 kV	Line
	–	Mission 22	12.47 kV	Line
	–	Mission 23	12.47 kV	Line
	–	Mission 24	12.47 kV	Line
Montano	**115 kV**			
	–	Montano 115/12.47kV Transformer	115 kV	Transformer
	–	Montano 11	12.47 kV	Line
	–	Montano 12	12.47 kV	Line
	–	Montano 13	12.47 kV	Line
	–	Montano 14	12.47 kV	Line
Montgomery Plaza	**115 kV**			
	–	Montgomery Plaza 115/12.47kV Transformer	115 kV	Transformer

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Montgomery Plaza 11	12.47 kV	Line
	–	Montgomery Plaza 12	12.47 kV	Line
	–	Montgomery Plaza 13	12.47 kV	Line
	–	Montgomery Plaza 14	12.47 kV	Line
Morris	**115 kV**			
	–	Morris 115/12.47kV Transformer	115 kV	Transformer
	–	Morris 11	12.47 kV	Line
	–	Morris 12	12.47 kV	Line
	–	Morris 13	12.47 kV	Line
	–	Morris 14	12.47 kV	Line
	–	Morris 15	12.47 kV	Line
	–	Morris 16	12.47 kV	Line
North	**115 kV**			
	–	North 1 115/12.47kV Transformer	115 kV	Transformer
	–	North 11	12.47 kV	Line
	–	North 12	12.47 kV	Line
	–	North 13	12.47 kV	Line
	–	North 14	12.47 kV	Line
	–	North 2 115/12.47 kV Transformer	115 kV	Transformer
	–	North 21	12.47 kV	Line
	–	North 22	12.47 kV	Line
	–	North 23	12.47 kV	Line
	–	North 24	12.47 kV	Line
North Bernalillo	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	North Bernalillo 115/12.47kV Transformer	115 kV	Transformer
	–	North Bernalillo 11	12.47 kV	Line
	–	North Bernalillo 12	12.47 kV	Line
	–	North Bernalillo 13	12.47 kV	Line
	–	North Bernalillo 14	12.47 kV	Line
North Silver	**69 kV**			
	–	North Silver 69/12.47 kV Transformer	69 kV	Transformer
	–	North Silver 12-1061	12.47 kV	Line
	–	North Silver 12-1065	12.47 kV	Line
Ortiz	**115 kV**			
	–	Ortiz 115/12.47kV Transformer	115 kV	Transformer
	–	Ortiz 11	12.47 kV	Line
	–	Ortiz 12	12.47 kV	Line
	–	Ortiz 13	12.47 kV	Line
	–	Ortiz 14	12.47 kV	Line
Pachmann	**115 kV**			
	–	Pachmann 115/12.47kV Transformer	115 kV	Transformer
	–	Pachmann 11	12.47 kV	Line
	–	Pachmann 12	12.47 kV	Line
	–	Pachmann 13	12.47 kV	Line
	–	Pachmann 14	12.47 kV	Line
Palace	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Palace 115/12.47kV Transformer	115 kV	Transformer
	–	Palace 11	12.47 kV	Line
	–	Palace 12	12.47 kV	Line
	–	Palace 13	12.47 kV	Line
Palm	**115 kV**			
	–	Palm 115/12.47kV Transformer	115 kV	Transformer
	–	Palm 11	12.47 kV	Line
	–	Palm 12	12.47 kV	Line
	–	Palm 13	12.47 kV	Line
	–	Palm 14	12.47 kV	Line
Palomas (2028)	**115 kV**			
	–	Palomas 1 115/12.47kV Transformer	115 kV	Transformer
	–	Palomas 11	12.47 kV	Line
	–	Palomas 12	12.47 kV	Line
	–	Palomas 13	12.47 kV	Line
	–	Palomas 14	12.47 kV	Line
	–	Palomas 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Palomas 21	12.47 kV	Line
	–	Palomas 22	12.47 kV	Line
	–	Palomas 23	12.47 kV	Line
	–	Palomas 24	12.47 kV	Line
Panorama	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Panorama 115/12.47kV Transformer	115 kV	Transformer
	–	Panorama 11	12.47 kV	Line
	–	Panorama 12	12.47 kV	Line
	–	Panorama 13	12.47 kV	Line
Paradise Hills	**115 kV**			
	–	Paradise Hills 1 115/12.47kV Transformer	115 kV	Transformer
	–	Paradise Hills 11	12.47 kV	Line
	–	Paradise Hills 12	12.47 kV	Line
	–	Paradise Hills 13	12.47 kV	Line
	–	Paradise Hills 14	12.47 kV	Line
	–	Paradise Hills 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Paradise Hills 21	12.47 kV	Line
	–	Paradise Hills 22	12.47 kV	Line
	–	Paradise Hills 23	12.47 kV	Line
	–	Paradise Hills 24	12.47 kV	Line
Pecos	**46 kV**			
	–	Pecos 46/12.47kV Transformer	46 kV	Transformer
	–	Pecos 11	12.47 kV	Line
	–	Pecos 12	12.47 kV	Line
Peralta	**46 kV**			
	–	Peralta 46/12.47kV Transformer	46 kV	Transformer
	–	Peralta 11	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Peralta 12	12.47 kV	Line
Perrin (2031)	**115 kV**			
	–	Perrin 1 115/23.5 kV Transformer	115 kV	Transformer
	–	Perrin 2 115/23.5 kV Transformer	115 kV	Transformer
	–	Perrin 11	23.5 kV	Line
	–	Perrin 12	23.5 kV	Line
	–	Perrin 13	23.5 kV	Line
Petroglyph	**115 kV**			
	–	Petroglyph 115/12.47kV Transformer	115 kV	Transformer
	–	Petroglyph 11	12.47 kV	Line
	–	Petroglyph 12	12.47 kV	Line
	–	Petroglyph 13	12.47 kV	Line
	–	Petroglyph 14	12.47 kV	Line
Power Plant	**46 kV**			
	–	Power Plant 46/4.16kV Transformer	46 kV	Transformer
	–	Power Plant 11	4.16 kV	Line
	–	Power Plant 12	4.16 kV	Line
	–	Power Plant 13	4.16 kV	Line
Prager	**115 kV**			
	–	Prager 115/12.47kV Transformer	115 kV	Transformer
	–	Prager 11	12.47 kV	Line
	–	Prager 12	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Prager 13	12.47 kV	Line
	–	Prager 14	12.47 kV	Line
Princess Jeanne	**115 kV**			
	–	Princess Jeanne 115/12.47kV Transformer	115 kV	Transformer
	–	Princess Jeanne 11	12.47 kV	Line
	–	Princess Jeanne 12	12.47 kV	Line
	–	Princess Jeanne 13	12.47 kV	Line
	–	Princess Jeanne 14	12.47 kV	Line
Progress	**115 kV**			
	–	Progress 1 115/12.47kV Transformer	115 kV	Transformer
	–	Progress 11	12.47 kV	Line
	–	Progress 12	12.47 kV	Line
	–	Progress 13	12.47 kV	Line
	–	Progress 14	12.47 kV	Line
	–	Progress 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Progress 21	12.47 kV	Line
Prosperity	**115 kV**			
	–	Prosperity 115/12.47kV Transformer	115 kV	Transformer
	–	Prosperity 11	12.47 kV	Line
	–	Prosperity 12	12.47 kV	Line
	–	Prosperity 13	12.47 kV	Line
	–	Prosperity 14	12.47 kV	Line
Randolph	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Randolph 115/12.47kV Transformer	115 kV	Transformer
	–	Randolph 11	12.47 kV	Line
	–	Randolph 12	12.47 kV	Line
	–	Randolph 13	12.47 kV	Line
	–	Randolph 14	12.47 kV	Line
	–	Randolph 15	12.47 kV	Line
	–	Randolph 16	12.47 kV	Line
Rattlesnake (2028)	**115 kV**			
	–	Rattlesnake 115/12.47kV Transformer	115 kV	Transformer
	–	Rattlesnake 11	12.47 kV	Line
	–	Rattlesnake 12	12.47 kV	Line
Reeves	**115 kV**			
	–	Reeves 115/12.47kV Transformer	115 kV	Transformer
	–	Reeves 11	12.47 kV	Line
	–	Reeves 12	12.47 kV	Line
	–	Reeves 13	12.47 kV	Line
	–	Reeves 14	12.47 kV	Line
Rio Hondo	**115 kV**			
	–	Rio Hondo 115/12.47kV Transformer	115 kV	Transformer
	–	Rio Hondo 11	12.47 kV	Line
	–	Rio Hondo 12	12.47 kV	Line
	–	Rio Hondo 13	12.47 kV	Line
	–	Rio Hondo 14	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
Rita	**115 kV**			
	–	Rita 115/12.47kV Transformer	115 kV	Transformer
	–	Rita 11	12.47 kV	Line
	–	Rita 12	12.47 kV	Line
Rodeo	**115 kV**			
	–	Rodeo 115/12.47kV Transformer	115 kV	Transformer
	–	Rodeo 11	12.47 kV	Line
	–	Rodeo 12	12.47 kV	Line
	–	Rodeo 13	12.47 kV	Line
	–	Rodeo 14	12.47 kV	Line
Roy	**115 kV**			
	–	Roy 115/12.47kV Transformer	115 kV	Transformer
	–	Roy 11	12.47 kV	Line
	–	Roy 12	12.47 kV	Line
	–	Roy 13	12.47 kV	Line
Sagebrush	**115 kV**			
	–	Sagebrush 1 115/12.47kV Transformer	115 kV	Transformer
	–	Sagebrush 11	12.47 kV	Line
	–	Sagebrush 12	12.47 kV	Line
	–	Sagebrush 13	12.47 kV	Line
	–	Sagebrush 14	12.47 kV	Line
	–	Sagebrush 2 115/12.47 kV Transformer	115 kV	Transformer

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Sagebrush 21	12.47 kV	Line
	–	Sagebrush 22	12.47 kV	Line
	–	Sagebrush 23	12.47 kV	Line
	–	Sagebrush 24	12.47 kV	Line
San Antonito	**46 kV**			
	–	San Antonito 1 46/12.47 kV Transformer	46 kV	Transformer
	–	San Antonito 2 46/12.47 kV Transformer	46 kV	Transformer
	–	San Antonito 11	12.47 kV	Line
	–	San Antonito 12	12.47 kV	Line
	–	San Antonito 21	12.47 kV	Line
	–	San Antonito 22	12.47 kV	Line
San Pedro	**115 kV**			
	–	San Pedro 115/12.47 kV Transformer	115 kV	Transformer
	–	San Pedro 11	12.47 kV	Line
	–	San Pedro 12	12.47 kV	Line
	–	San Pedro 13	12.47 kV	Line
	–	San Pedro 14	12.47 kV	Line
Santo Domingo	**46 kV**			
	–	Santo Domingo 46/12.47 kV Transformer	46 kV	Transformer
Sara	**115 kV**			
	–	Sara 1 115/12.47 kV Transformer	115 kV	Transformer
	–	Sara 2 115/12.47 kV Transformer	115 kV	Transformer

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Sara 3 115/12.47 kV Transformer	115 kV	Transformer
	–	Sara 4 115/12.47 kV Transformer	115 kV	Transformer
	–	Sara 5 115/12.47 kV Transformer	115 kV	Transformer
	–	Sara 6 115/12.47 kV Transformer	115 kV	Transformer
	–	Sara 7 115/12.47 kV Transformer	115 kV	Transformer
	–	Sara 8 115/12.47 kV Transformer	115 kV	Transformer
Scenic	**115 kV**			
	–	Scenic 115/12.47 kV Transformer	115 kV	Transformer
	–	Scenic 11	12.47 kV	Line
	–	Scenic 12	12.47 kV	Line
	–	Scenic 13	12.47 kV	Line
	–	Scenic 14	12.47 kV	Line
	–	Scenic 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Scenic 21	12.47 kV	Line
	–	Scenic 22	12.47 kV	Line
	–	Scenic 23	12.47 kV	Line
	–	Scenic 24	12.47 kV	Line
Sewer Plant	**115 kV**			
	–	Sewer Plant 115/12.47 kV Transformer	115 kV	Transformer
	–	Sewer Plant 11	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Sewer Plant 12	12.47 kV	Line
	–	Sewer Plant 13	12.47 kV	Line
	–	Sewer Plant 14	12.47 kV	Line
Signetics	**115 kV**			
	–	Signetics 1 115/12.47 kV Transformer	115 kV	Transformer
	–	Signetics 11	12.47 kV	Line
	–	Signetics 12	12.47 kV	Line
	–	Signetics 13	12.47 kV	Line
	–	Signetics 14	12.47 kV	Line
	–	Signetics 16	12.47 kV	Line
	–	Signetics 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Signetics 21	12.47 kV	Line
	–	Signetics 22	12.47 kV	Line
	–	Signetics 23	12.47 kV	Line
	–	Signetics 24	12.47 kV	Line
	–	Signetics 26	12.47 kV	Line
Silver City	**69 kV**			
	–	Silver City North 69/12.47 kV Transformer	69 kV	Transformer
	–	Silver City South 69/12.47 kV Transformer	69 kV	Transformer
	–	Silver City 12-10	12.47 kV	Line
	–	Silver City 12-16	12.47 kV	Line
	–	Silver City 11-17	12.47 kV	Line
	–	Silver City 11-18	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
Snow Vista	**115 kV**			
	–	Snow Vista 1 115/12.47 kV Transformer	115 kV	Transformer
	–	Snow Vista 11	12.47 kV	Line
	–	Snow Vista 12	12.47 kV	Line
	–	Snow Vista 13	12.47 kV	Line
	–	Snow Vista 14	12.47 kV	Line
	–	Snow Vista 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Snow Vista 21	12.47 kV	Line
	–	Snow Vista 22	12.47 kV	Line
	–	Snow Vista 23	12.47 kV	Line
	–	Snow Vista 24	12.47 kV	Line
South Coors	**115 kV**			
	–	South Coors 115/12.47 kV Transformer	115 kV	Transformer
	–	South Coors 11	12.47 kV	Line
	–	South Coors 12	12.47 kV	Line
	–	South Coors 13	12.47 kV	Line
	–	South Coors 14	12.47 kV	Line
South Pacheco	**115 kV**			
	–	South Pacheco 1 115/12.47kV Transformer	115 kV	Transformer
	–	South Pacheco 11	12.47 kV	Line
	–	South Pacheco 12	12.47 kV	Line
	–	South Pacheco 13	12.47 kV	Line
	–	South Pacheco 14	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	South Pacheco 2 115/12.47 kV Transformer	115 kV	Transformer
	–	South Pacheco 25	12.47 kV	Line
	–	South Pacheco 26	12.47 kV	Line
	–	South Pacheco 27	12.47 kV	Line
	–	South Pacheco 28	12.47 kV	Line
St. Cecilia	**115 kV**			
	–	St. Cecilia 115/12.47 kV Transformer	115 kV	Transformer
	–	St. Cecilia 11	12.47 kV	Line
	–	St. Cecilia 12	12.47 kV	Line
	–	St. Cecilia 13	12.47 kV	Line
St. Joseph	**115 kV**			
	–	St. Joseph 115/12.47 kV Transformer	115 kV	Transformer
	–	St. Joseph 11	12.47 kV	Line
	–	St. Joseph 12	12.47 kV	Line
	–	St. Joseph 13	12.47 kV	Line
	–	St. Joseph 14	12.47 kV	Line
State Pen	**115 kV**			
	–	State Pen 1 115/12.47 kV Transformer	115 kV	Transformer
	–	State Pen 11	12.47 kV	Line
	–	State Pen 12	12.47 kV	Line
	–	State Pen 13	12.47 kV	Line
Studio	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Studio 1 115/12.47 kV Transformer	115 kV	Transformer
	–	Studio 11	12.47 kV	Line
	–	Studio 12	12.47 kV	Line
	–	Studio 13	12.47 kV	Line
	–	Studio 14	12.47 kV	Line
	–	Studio 2 115/12.47 kV Transformer	115 kV	Transformer
Thomas	**115 kV**			
	–	Thomas 115/12.47 kV Transformer	115 kV	Transformer
	–	Thomas 11	12.47 kV	Line
	–	Thomas 12	12.47 kV	Line
	–	Thomas 13	12.47 kV	Line
	–	Thomas 14	12.47 kV	Line
Tijeras	**46 kV**			
	–	Tijeras 46/12.47 kV Transformer	46 kV	Transformer
	–	Tijeras 11	12.47 kV	Line
	–	Tijeras 12	12.47 kV	Line
	–	Tijeras 13	12.47 kV	Line
Tome	**115 kV**			
	–	Tome 115/12.47 kV Transformer	115 kV	Transformer
	–	Tome 11	12.47 kV	Line
	–	Tome 12	12.47 kV	Line
	–	Tome 13	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
Tramway	**115 kV**			
	–	Tramway 115/12.47kV Transformer	115 kV	Transformer
	–	Tramway 11	12.47 kV	Line
	–	Tramway 12	12.47 kV	Line
	–	Tramway 13	12.47 kV	Line
	–	Tramway 14	12.47 kV	Line
Truman	**115 kV**			
	–	Truman 115/12.47kV Transformer	115 kV	Transformer
	–	Truman 11	12.47 kV	Line
	–	Truman 12	12.47 kV	Line
	–	Truman 13	12.47 kV	Line
	–	Truman 14	12.47 kV	Line
Tularosa	**115 kV**			
	–	Tularosa 115/12.47kV Transformer	115 kV	Transformer
	–	Tularosa 11	12.47 kV	Line
	–	Tularosa 12	12.47 kV	Line
	–	Tularosa 13	12.47 kV	Line
	–	Tularosa 14	12.47 kV	Line
Tyrone	**69 kV**			
	–	Tyrone 69/12.47 kV Transformer	69 kV	Transformer
	–	Tyrone 12-395	12.47 kV	Line
	–	Tyrone 12-517	12.47 kV	Line
Unser	**115 kV**			

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Unser 115/12.47kV Transformer	115 kV	Transformer
	–	Unser 11	12.47 kV	Line
	–	Unser 12	12.47 kV	Line
	–	Unser 13	12.47 kV	Line
	–	Unser 14	12.47 kV	Line
Valencia (2027)	**115 kV**			
	–	Valencia Transformer 115/12.47 kV	115 kV	Transformer
	–	Valencia 11	12.47 kV	Line
	–	Valencia 12	12.47 kV	Line
	–	Valencia 13	12.47 kV	Line
Van Buren	**69 kV**			
	–	Van Buren T1 69/12.47 kV Transformer	69 kV	Transformer
	–	Van Buren 11	12.47 kV	Line
	–	Van Buren 12	12.47 kV	Line
	–	Van Buren 13	12.47 kV	Line
	–	Van Buren T2 12.47/4.16kV Transformer	12.47 kV	Transformer
	–	Van Buren T4 69/4.16 kV Transformer	69 kV	Transformer
	–	Van Buren 41	4.16 kV	Line
	–	Van Buren 42	4.16 kV	Line
	–	Van Buren 43	4.16 kV	Line
Veranda	**115 kV**			
	–	Veranda 1 115/12.47kV Transformer	115 kV	Transformer

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Veranda 11	12.47 kV	Line
	–	Veranda 12	12.47 kV	Line
	–	Veranda 13	12.47 kV	Line
	–	Veranda 14	12.47 kV	Line
	–	Veranda 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Veranda 21	12.47 kV	Line
	–	Veranda 22	12.47 kV	Line
	–	Veranda 23	12.47 kV	Line
	–	Veranda 24	12.47 kV	Line
Volcano	**115 kV**			
	–	Volcano 1 115/12.47kV Transformer	115 kV	Transformer
	–	Volcano 11	12.47 kV	Line
	–	Volcano 12	12.47 kV	Line
	–	Volcano 13	12.47 kV	Line
	–	Volcano 14	12.47 kV	Line
	–	Volcano 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Volcano 21	12.47 kV	Line
	–	Volcano 22	12.47 kV	Line
	–	Volcano 23	12.47 kV	Line
	–	Volcano 24	12.47 kV	Line
Warner	**46 kV**			
	–	Warner 46/12.47 kV Transformer	46 kV	Transformer
	–	Warner 11	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
	–	Warner 12	12.47 kV	Line
	–	Warner 13	12.47 kV	Line
Wayne	**115 kV**			
	–	Wayne 1 115/12.47 kV Transformer	115 kV	Transformer
	–	Wayne 11	12.47 kV	Line
	–	Wayne 12	12.47 kV	Line
	–	Wayne 13	12.47 kV	Line
	–	Wayne 14	12.47 kV	Line
	–	Wayne 2 115/12.47 kV Transformer	115 kV	Transformer
	–	Wayne 21	12.47 kV	Line
	–	Wayne 22	12.47 kV	Line
	–	Wayne 23	12.47 kV	Line
	–	Wayne 24	12.47 kV	Line
Wesmeco	**115 kV**			
	–	Wesmeco 115/12.47 kV Transformer	115 kV	Transformer
	–	Wesmeco 11	12.47 kV	Line
	–	Wesmeco 12	12.47 kV	Line
	–	Wesmeco 13	12.47 kV	Line
	–	Wesmeco 14	12.47 kV	Line
Westpointe 40 (2027)	**115 kV**			
	–	Westpointe 40 115/12.47 kV Transformer	115 kV	Transformer
	–	Westpointe 11	12.47 kV	Line
	–	Westpointe 12	12.47 kV	Line

Station Name	Station Voltage Level(s)	Element Name (Lines, transformers)	Element Voltage (High side for transformers)	Element Type
Winrock	**115 kV**			
	–	Winrock 115/12.47 kV Transformer	115 kV	Transformer
	–	Winrock 11	12.47 kV	Line
	–	Winrock 12	12.47 kV	Line
	–	Winrock 13	12.47 kV	Line
	–	Winrock 14	12.47 kV	Line
	–	Winrock 15	12.47 kV	Line
Wyoming	**115 kV**			
	–	Wyoming 115/12.47 kV Transformer	115 kV	Transformer
	–	Wyoming 11	12.47 kV	Line
	–	Wyoming 12	12.47 kV	Line
	–	Wyoming 13	12.47 kV	Line
	–	Wyoming 14	12.47 kV	Line
Zafarano	**115 kV**			
	–	Zafarano 115/12.47 kV Transformer	115 kV	Transformer
	–	Zafarano 11	12.47 kV	Line
	–	Zafarano 12	12.47 kV	Line
	–	Zafarano 13	12.47 kV	Line
	–	Zafarano 14	12.47 kV	Line
Zamora	**46 kV**			
	–	Zamora 46/12.47 kV Transformer	46 kV	Transformer
	–	Zamora 11	12.47 kV	Line
	–	Zamora 12	12.47 kV	Line

TABLE F-3: EXISTING JOINT-OWNED TRANSMISSION LINES

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

APPENDIX G: RULES AND REGULATORY

TRANSMISSION SYSTEM

Over the last 20 years, U.S. electric transmission service has undergone major regulatory changes in the way transmission services are offered and provided and how transmission system planning is conducted.

FERC Order No. 888

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

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

Energy Policy Act of 2005

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

FERC Order No. 890

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

FERC Order No. 1000

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

FERC Order No. 881

FERC Order 881 issued on December 16, 2021, requires transmission providers to move away from seasonal and static lines ratings, which are generally conservative. In their place, the rule requires ambient adjusted ratings (AAR) , which use near-term forecast ambient air temperatures. All requirements in this rule must be implemented by July 12, 2025. PNM is in the process of implementing AAR by the effective date.

FERC Order 897

FERC Order 897 was issued on June 15, 2023 and directed transmission providers to file one-time informational reports (due October 25, 2023) that describe their policies and processes for conducting extreme weather vulnerability assessments of transmission assets and operations. The order further directed NERC to develop a new or modified reliability standard to require transmission system planning for extreme heat and cold weather conditions over wide geographical areas. NERC's process is on-going.

FERC Order 2023

FERC Order reforms procedures and agreements that electric transmission providers use to integrate new generating facilities into the existing transmission system. FERC adopted these reforms to reduce backlogs for projects seeking to connect to the transmission system, improve certainty in the interconnection processes managed by the dozens of transmission providers around the country, and ensure access to the transmission system for new technologies. PNM is in the process of drafting and filing a revised Open Access Transmission Tariff pursuant to this rule issue in July 2023.

WECC and NERC Criteria

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

PNM must comply with NERC operating standards, which, in part, might dictate the use of certain resources to meet the requirements. These include Control Performance Standards[1] (CPS), which measure a control area operator's ability to control system frequency and balance its load

1 See https://www.nerc.com/pa/Stand/Pages/default.aspx (BAL-001-0_1a)

and generation at all times. They also include Disturbance Control Standards[2], which measure the control area's ability to respond to generator or load loss.

PNM must also comply with NERC standards that relate to transmission planning and operations. These include Transmission Planning Standards[3] (TPL), which measure the sufficiency of the transmission system to meet present and future needs. TPL standards state that, "The interconnected power system shall be operated at all times so that general system instability, uncontrolled separation, cascading outages or voltage collapse will not occur as a result of any single contingency or multiple contingencies of sufficiently high likelihood."

Power Supply Assessment (PSA)

NERC requires WECC to annually evaluate future resource adequacy of the western region based upon annual resource plans submitted by member utilities. The PSA is a regional and subregional determination of resource adequacy, rather than an individual utility evaluation of resource adequacy. The purpose, is to project whether enough physical resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths[4]. PNM, balancing area coordinator (BAC) in New Mexico, participates in the PSA study process and collects historical and future load and resource information from load-serving entities (LSEs) within New Mexico. This assessment is important because, if the PSA were to identify a resource adequacy issue in the region or subregion where PNM operates, PNM would be obligated to participate in finding a solution to the resource deficiency.

Reserve Sharing Agreements

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

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

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

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2 See https://www.nerc.com/pa/Stand/Pages/default.aspx (BAL-002-1 and BAL-002-WECC-1)

3 See https://www.nerc.com/pa/Stand/Pages/default.aspx (TPL-001-0.1 through TPL-004-0)

4 See https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (Reliability Assessment Guidebook)

the necessary reserves itself, the requirement would equal its single largest operating unit, which is the utility's largest risk.

PNM's SRSG allocation is partly determined by the size of the units that are included in PNM's operating portfolio. Currently, PNM's single largest potential risk is SJGS Unit 4 (392 megawatts), if it is operating, or Afton (230 megawatts), if Afton is operating and SJGS Unit 4 is not. Looking forward, and for purposes of this IRP, PNM must determine how new resource additions might change the level of reserves required for SRSG purposes or otherwise result in additional costs to meet reliability standards. Generally, PNM's planning criterion is to limit the size of new generation to that of the current largest unit.

Other System Reliability Standards

Although states have played the primary role in setting reserve margin requirements, federal agencies (Federal Energy Regulatory Commission [FERC] and NERC) have taken on increased responsibility. Numerous states (including Maryland, New Jersey, Pennsylvania, Ohio, Indiana, Wyoming, Delaware, and the District of Columbia, in addition to portions of Michigan, Wisconsin, Illinois, Kentucky, Tennessee, and Virginia) have received approval from FERC to utilize one-day-in-10-years resource planning criteria. Implementation of this criterion would result in planning for sufficient resources so that no more than 48 load hours would be lossed in a 20-year planning period. This is a more stringent criterion than PNM's existing reserve planning criteria, but could be a consideration for future planning.

New Mexico IRP Rule

This section shows the IRP Rule and where in the IRP to find content associated with its various requirements.

17.7.3.8 NMAC: Integrated Resource Plans for electric utilities. B. The IRP submitted to the commission by an electric utility shall contain the utility's New Mexico jurisdictional information as follows:

(1) description of existing resources;	**Section 3; Section 4; Appendix E**
(2) current load forecast;	**Section 3; Appendix H**
(3) load and resources table;	**Section 6.4; Appendix O**
(4) new load and facilities arising from special service agreements, economic development projects, and affiliate transactions;	**Section 1.5.6; Appendix H**
(5) identification of resource options;	**Section 8; Appendix K**
(6) statement of need;	**Section 10**
(7) determination of the resource portfolio; and	**Section 9**
(8) action plan	**Section 11**

Description of existing resources.

A. The mandate of the energy transition act to incorporate 80% renewable energy onto the grid by 2040 requires utilities operating in New Mexico to develop flexible management of grid resources. Utilities may categorize resources into the following four functional groups to reflect their role in serving this need:	
(1) load modifying resources – includes but not limited to energy efficiency, distributed generation, and time of use tariffs;	**Section 3.2; Section 3.3; Appendix E**
(2) renewable load serving resources – includes both utility scale solar and wind technologies;	**Section 4.1; Appendix E**
(3) conventional load serving resources – includes coal, nuclear, and gas technologies; and	**Section 4.1; Appendix E**
(4) grid balancing resources – includes demand response, storage technologies, natural gas combustion engines, and reciprocating engines.	**Section 3.2.2; Section 4.1; Appendix E**
B. The utility's description of its existing resources used to serve its jurisdiction load shall include:	
(1) name(s) and location(s) of utility-owned generation facilities;	**Section 4.1; Appendix E**
(2) rated capacity of utility-owned generation facilities;	**Section 4.1; Appendix E**
(3) fuel type, heat rates, annual capacity factors, and availability factors projected for utility-owned generation facilities over the planning period;	**Section 4.1; Appendix E**

(4) cost information, including capital costs, fixed and variable operating and maintenance costs, fuel costs, and purchased power costs;	**Appendix E**
(5) existing generation facilities' expected retirement dates;	**Section 4.1; Appendix E**
(6) amount of capacity obtained or to-be-obtained through existing purchased power contracts or agreements relied upon by the utility, including the fuel type, if known, and contract duration;	**Section 4.1; Appendix E**
(7) estimated in-service dates for utility-owned generation facilities for which certificates of public convenience and necessity (CCN) have been granted but which are not in-service;	**Section 4.2; Appendix E**
(8) amount of capacity and, if applicable, energy purchased via the utility's participation in regional energy markets;	**Section 2.4.1; Appendix O**
(9) description of existing demand-side resources, including:	
(a) demand-side resources deployed at the time the IRP is filed; and	**Section 3.2**
(b) demand-side resources approved by the commission, but not yet deployed at the time the IRP is filed;	**N/A**
(i) information provided concerning existing demand-side resources shall include, at a minimum, the expected remaining useful life of each demand-side resource and the energy savings and reductions in peak demand, as appropriate, made by the demand-side resource;	**Section 3.2; Appendix E**
(10) description of each existing energy storage resource, including energy storage resources approved but not yet deployed at the time the IRP is filed, and at a minimum, the expected remaining useful life of the resource, its maximum capacity, dispatch characteristics, and operating costs;	**Section 4.1.7; Section 4.2; Appendix E**
(11) reserve margin and reserve reliability requirements with which the utility must comply, and the methodology used to calculate its reserve margin;	**Section 6; Appendix M;**
(12) existing transmission capabilities:	**Section 5; Appendix F**
(a) the utility shall report its existing and under-construction transmission facilities of 115 kV and above, including associated switching stations and terminal facilities;	**Section 5; Appendix F**
(b) the utility shall specifically identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of supply-side resources; and	**Section 5**
(c) the utility shall describe all transmission planning or coordination groups to which it is a party, including state and regional transmission groups,	**Section 2.4; Section 5**

transmission companies, and coordinating councils with which the utility may be associated;	
(13) existing distribution capabilities:	
(a) the utility shall report its existing distribution facilities, under-construction distribution facilities, or distribution facilities approved but not-yet-deployed at the time the IRP is filed, including all substations, switching stations, power lines and other equipment, below 115 kV, including associated transformers and feeder lines;	**Section 5; Appendix F**
(b) the utility shall specifically identify the location and extent of capability limitations on its distribution network that may affect the future siting of distributed energy resources; and	**Section 5**
(c) the utility shall describe all distribution planning or coordination groups to which it is a party;	**Section 5**
(14) details of any planned or anticipated transmission and distribution network upgrades;	**Section 5; Appendix F**
(15) environmental impacts of existing supply-side resources:	
(a) the utility shall provide the percentage of megawatt-hours generated by each fuel used by the utility on its existing system for the latest year for which such information is available;	**Section 4.1**
(b) to the extent feasible, for each existing supply-side resource on its system, the utility shall present emission rates (expressed in pounds emitted per megawatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury; and	**Section 4.1; Appendix E**
(c) to the extent feasible, for each existing supply-side resource on its system, the utility shall present the water consumption rate;	**Section 4.1; Appendix E**
(16) a summary of back-up fuel capabilities and options; and	**Section 4; Appendix E**
(17) an assessment of the critical facilities susceptible to supply-source disruptions, extreme weather events, or other failures.	**Section 5; Section 6; Appendix L; Appendix M**

Current load forecast.

A. The IRP shall contain a load forecast for each year of the planning period.	**Section 3.4; Appendix H**
B. The load forecast shall incorporate the following information and projections:	
(1) annual sales of energy, net load, and reliability reserves on a system-wide basis, by customer class, and disaggregated among commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states;	**Section 3.1; Section 6.1; Appendix H**

(2) weather normalization adjustments;	**Appendix H**
(3) assumptions for economic and demographic factors relied on in load forecasting;	**Section 3.4; Appendix H**
(4) expected capacity and energy impacts of existing and proposed demand-side resources; and	**Section 3.2; Section 8.1; Appendix H; Appendix K**
(5) typical historic day and week load patterns on a system-wide basis for each major customer class.	**Appendix H**
C. The utility shall develop an expected growth forecast, a high-growth forecast, and a low-growth forecast, or an alternative forecast that provides an assessment of uncertainty (e.g., probabilistic techniques).	**Section 3.4; Appendix H**
D. Required detail.	
(1) The utility shall explain how the utility's load forecasts account for the demand-side savings attributable to actions other than the utility-sponsored demand-side resources for each major customer class, as well as the effect of those utility-sponsored demand-side resources for each major customer class on the load forecasts.	**Section 3.4.2; Appendix H**
(2) The utility shall compare the annual forecast in its most recently filed resource plan to the annual forecast in the current resource plan.	**Section 3.4; Appendix H**
(a) In its initial IRP filing, the utility shall provide information demonstrating how well its forecasts predicted demand (during the preceding four years.)	**N/A**
(3) The utility shall explain and document the assumptions, methodologies, and any other inputs upon which it relied to develop its load forecast.	**Section 3; Appendix H**

Load and resources table.

A. The IRP shall contain a table of the utility's existing loads and resources at the time of filing.	**Section 6.4; Appendix O**
B. The load and resources table, to the extent practical, shall contain the appropriate components from the load forecast.	**Appendix O**
C. Resources shall include:	
(1) utility-owned generation;	**Appendix O**
(2) energy storage resources;	**Appendix O**
(3) existing and future contracted-for purchased power, including qualifying facility purchases;	**Appendix O**
(4) purchases through net metering programs, as appropriate;	**Appendix O**
(5) demand-side resources, as appropriate; and	**Appendix O**

(6) other resources relied upon by the utility, such as pooling, wheeling, or coordination agreements effective at the time the IRP is filed.	**Appendix O**

Identification of resource options.

A. The utility shall identify additional resource options in its IRP that it evaluated for selection as part of the utility's portfolio.	**Section 8; Appendix K**
B. In identifying additional resource options, the utility should consider all supply-side, energy storage, and demand-side resources.	**Section 8; Appendix K**
C. The utility shall describe the assumptions and methodologies used in evaluating its resource options, including, as applicable:	
(1) life expectancy;	**Section 8; Appendix K**
(2) whether the resource is replacing or adding capacity or energy;	**Section 1.5.5; Section 4.1.3; Section 8; Section 9; Appendix K; Appendix O**
(3) dispatchability;	**Section 8; Appendix K**
(4) lead-time requirements;	**Section 8; Appendix P**
(5) flexibility, including black start capability;	**Appendix K**
(6) load-modifying or grid-balancing capabilities;	**Section 8.1; Section 8.3**
(7) efficiency; and	**Section 8; Appendix K**
(8) ability to most effectively provide reasonable and consistent progress toward satisfaction of the renewable portfolio standard.	**Section 2.2; Section 8.2**
D. For supply-side resource options, the utility shall identify the assumptions actually used for capital costs, fixed and variable operating and maintenance costs, fuel costs forecast by year, and purchased power demand and energy charges forecast by year, fuel type, heat rates, annual capacity factors, availability factors and, emission rates (expressed in pounds emitted per kilowatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury.	**Appendix I; Appendix J; Appendix K**
E. The utility shall describe its existing rates and tariffs that incorporate load management or load modifying concepts. The utility shall also describe how changes in rate design might assist in meeting, delaying or avoiding the need for new capacity.	**Section 3.2; Section 3.3; Appendix H**
F. In identifying resource options, the utility shall include a description of the projected emissions of carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan;	**Section 9.2.5; Appendix K; Appendix N**

17.7.3.10 Statement of need.

A. The statement of need is a description and explanation of the amount and the types of new resources, including the technical characteristics of any proposed new resources, to be procured, expressed in terms of energy or capacity, necessary to reliably meet an identified level of electricity demand in the planning horizon and to effect state policies.	**Section 10**
B. The statement of need shall not solely be based on projections of peak load. The need may be attributed to, but not limited by, incremental load growth, renewable energy customer programs, or replacement of existing resources, and may be defined in terms of meeting net capacity, providing reliability reserves, securing flexible resources, securing demand-side resources, securing renewable energy, expanding or modifying transmission or distribution grids, or securing energy storage as required to comply with resource requirements established by statute or commission decisions.	**Section 10**

Determination of the resource portfolio.

A. To identify the most cost-effective resource portfolio, utilities shall evaluate all supply-side resources, energy storage, and demand-side resource options on a consistent and comparable basis, taking into consideration risk and uncertainty, including but not limited to financial, competitive, operational, fuel supply, price volatility, downstream impacts on transmission and distribution investments, extreme-weather events, and anticipated environmental regulation costs.	**Section 7; Section 9; Appendix N**
B. The utility shall evaluate the cost of each resource through its projected life with a life-cycle or similar analysis.	**Section 8; Appendix E; Appendix K**
C. The utility shall consider and describe ways to mitigate ratepayer risk.	**Section 7.2; Section 9**
D. Each electric utility shall provide a summary of how the following factors were considered in, or affected, the development of resource portfolios:	
(1) load management or modification and energy efficiency requirements;	**Section 3.2; Section 8.1; Section 9; Appendix E; Appendix K**
(2) renewable energy portfolio requirements;	**Section 2.2; Section 8.2; Section 9**
(3) existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions;	**Section 2.2; Section 8.8.3; Section 9.2.5; Appendix I**
(4) fuel diversity;	**Section 8; Section 9; Appendix I**

(5) susceptibility to fuel interdependencies;	**Section 4; Section 8.8; Section 9; Appendix I; Appendix J**
(6) transmission or distribution constraints; and	**Section 5; Section 8.5; Section 9.3; Appendix F**
(7) system reliability and planning reserve margin requirements.	**Section 6; Section 6.4; Section 7.3.4; Section 10; Appendix L; Appendix M**
E. Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop alternative portfolios by altering risk assumptions and other parameters developed by the utility.	**Section 7; Section 9; Appendix N; Appendix O**

17.7.3.11 NMAC: Action plan. The utility's action plan shall:

(1) detail the specific actions the utility shall take to implement the IRP spanning a three year period following the filing of the utility's IRP;	**Section 11**
(2) detail the specific actions the utility shall take to develop any resource solicitations or contracting activities to fulfill the statement of need as accepted by the commission; and	**Section 11; Appendix P**
(3) include a status report of the specific actions contained in the previous action plan.	**Section 1.4.1**

17.7.3.9 NMAC: Facilitated stakeholder process; IRP process. A. At least six months prior to the filing of its IRP, the utility shall notify the commission, members of the public, the New Mexico attorney general, and all parties to its most recent base rate case and most recent IRP case of its intent to file an IRP.

(1) The utility shall provide commission utility division staff and stakeholders who have signed a confidentiality agreement reasonable access to the same modeling software used by the utility on equal footing as the utility, and shall perform a reasonable number of modeling runs per staff or a stakeholder, if requested by staff or a stakeholder, in accordance with commission precedent, and the utility shall share all modeling information.	**Section 1.2; Appendix C; Appendix D**

APPENDIX H: LOAD FORECAST DETAILS

This appendix provides details surrounding the assumptions and development of our load forecast. Tables H-1 and H-2 show the peak demand forecast and annual energy demand across the CTP, LEG, HEG, and XEG scenarios considered in the IRP. Figures H-1 and H-2 component of annual peak demand forecast and component of annual energy demand forecast under CTP. The subsequent sections provide details behind the load forecasting approach (including data required by the IRP Rule).

Table H-1. Annual peak demand forecast under various futures (MW)

Peak Demand – prior EE adjustment (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Current Trends & Policy	2,250	2,448	2,641	3,082	3,124	3,136	3,152	3,188	3,218	3,238	3,254	3,278	3,312	3,360	3,391	3,420	3,461	3,500	3,562	3,604
Low Economic Growth	2,026	2,078	2,130	2,523	2,565	2,616	2,624	2,640	2,648	2,652	2,653	2,662	2,678	2,700	2,707	2,718	2,739	2,758	2,794	2,816
High Economic Growth	2,414	2,639	2,844	3,331	3,405	3,447	3,491	3,558	3,619	3,671	3,719	3,778	3,850	3,932	3,994	4,056	4,135	4,212	4,318	4,398
Extreme Economic Development	2,414	2,639	2,879	3,422	4,076	4,585	4,764	4,881	4,994	5,099	5,199	5,312	5,439	5,578	5,694	5,807	5,937	6,066	6,233	6,367

Table H-2. Annual energy demand under various futures (GWh)

Annual Energy - prior EE adjustment (GWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Current Trends & Policy	11,379	12,910	14,176	17,704	18,120	18,187	18,289	18,345	18,441	18,534	18,646	18,721	18,818	18,940	19,088	19,202	19,343	19,485	19,667	19,778
Low Economic Growth	10,267	10,718	11,038	14,039	14,606	14,992	15,073	15,061	15,069	15,062	15,059	15,022	15,019	15,027	15,061	15,052	15,074	15,098	15,153	15,158
High Economic Growth	11,869	13,597	14,921	18,772	19,377	19,596	19,837	20,033	20,278	20,523	20,797	21,033	21,303	21,602	21,939	22,234	22,561	22,891	23,266	23,556
Extreme Economic Development	11,869	13,597	15,381	19,828	25,248	29,800	31,272	31,912	32,616	33,328	34,108	34,763	35,512	36,280	37,139	37,850	38,645	39,441	40,332	41,044

FIGURE H-1. ANNUAL PEAK DEMAND FORECAST COMPONENT (CTP)

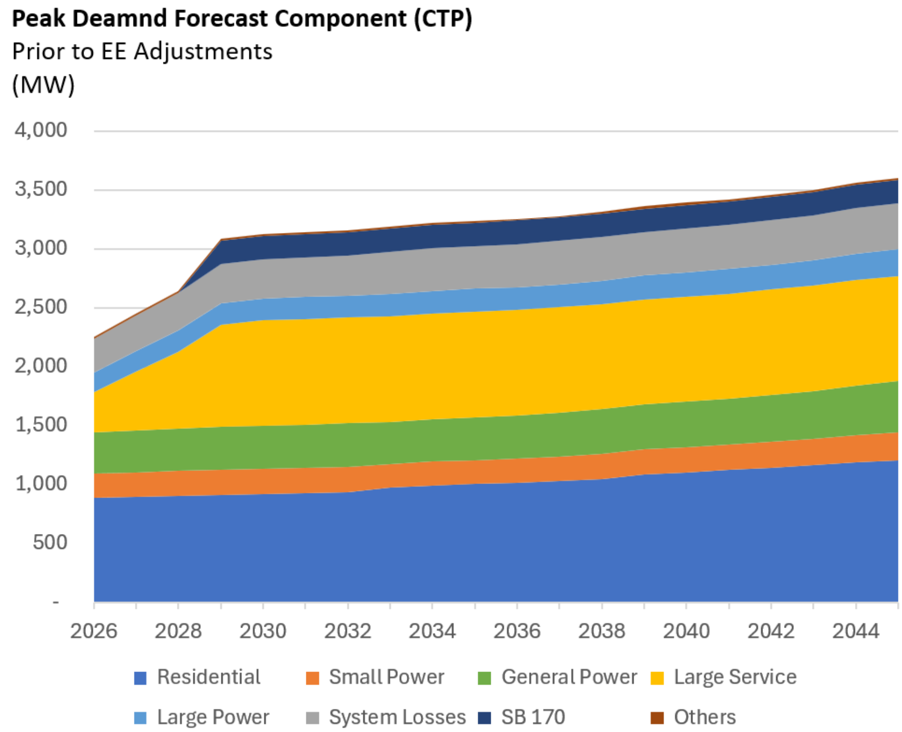
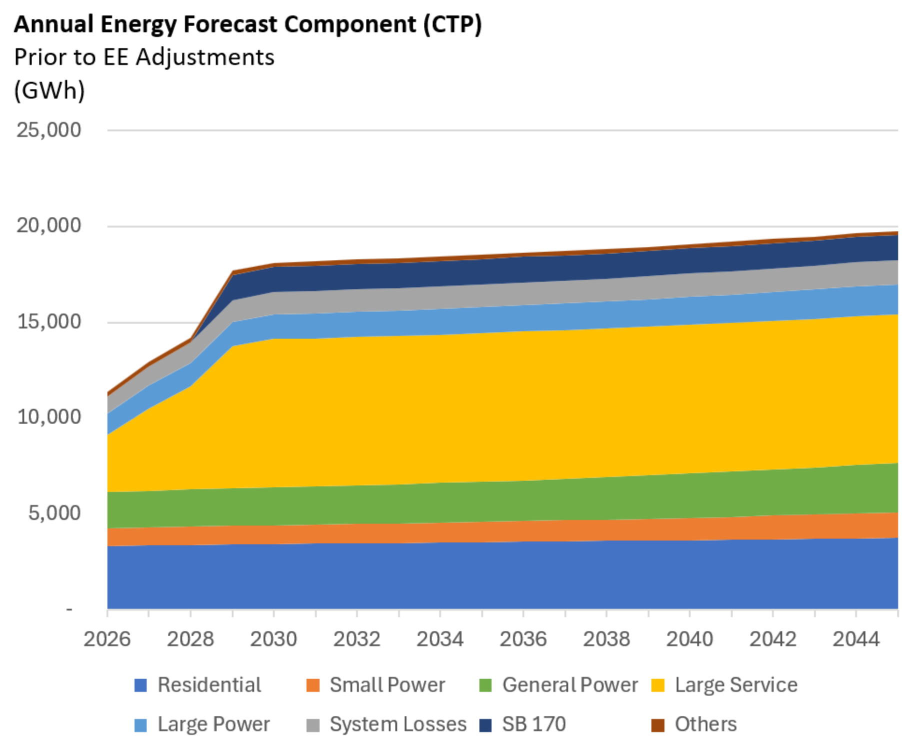


FIGURE H-2. ANNUAL ENERGY DEMAND FORECAST COMPONENT (CTP)



LOAD FORECAST METHODOLOGY

This document presents the load forecasting methodology, data inputs, modeling framework, and scenario results developed for PNM's Integrated Resource Plan (IRP).

CONTENTS

1. Executive Summary

This document presents the load forecasting methodology, data inputs, modeling framework, and scenario results developed for PNM's Integrated Resource Plan (IRP). The forecast covers the planning horizon from 2026 through 2045 and provides the foundation for resource planning decisions.

The forecast is developed using a bottom-up methodology that combines econometric modeling, end-use analysis, and hourly load simulation. Key components include:

- Economic growth projections from Woods and Poole for PNM service territory counties
- Weather normalization using a 10-year normal period (2015-2024) with extreme weather scenarios
- Behind-the-meter (BTM) solar photovoltaic capacity and generation forecasts
- Electric vehicle (EV) adoption forecasts based on EPRI studies for light duty, fleet, and medium/heavy duty vehicles
- Building electrification impacts including heat pump adoption and new construction requirements
- Residential time-of-use (TOD) rate impacts on load shapes
- Statistically Adjusted End-Use (SAE) models for residential and commercial customer classes
- Hourly load models calibrated to load research data for peak demand forecasting

The forecast is presented through multiple scenarios that capture a range of outcomes from strong growth to weak growth conditions. Complex scenarios combine multiple input variables to represent plausible planning futures for resource adequacy assessment.

2. Economic Data and Forecasts

Economic data are collected on a county level for New Mexico. These county level forecasts are analyzed based on the counties PNM serves. One of the main drivers for the forecast is economic variable. The following paragraph describes how PNM analyzed economic variable forecasts.

2.1 Data Sources and Coverage

Economic data and forecasts are provided by Woods and Poole, a nationally recognized provider of regional economic projections. The dataset includes:

- Annual historical data from 1950 to 2024
- Annual forecasts extending to 2050
- State and county level detail

Data is compiled for counties within PNM's service territory, organized into two geographic regions:

Table 2.1: PNM Service Territory Counties

Region	County	Primary Economic Characteristics
North	Bernalillo	Major metro area (Albuquerque); dominant share of population and employment
North	San Miguel	Rural; smaller population base
North	Sandoval	Suburban growth corridor; Rio Rancho area
North	Santa Fe	State capital; government employment, tourism
North	Union	Rural; agriculture-based economy
North	Valencia	Suburban/rural; growing residential base
South	Grant	Mining and natural resources
South	Hidalgo	Rural; border region
South	Luna	Border community (Deming); agriculture

Region	County	Primary Economic Characteristics
South	Otero	Military (Holloman AFB); tourism (Alamogordo)

Annual data are converted to monthly frequency using centered moving averages to provide the temporal resolution required for monthly energy forecasting models.

2.2 Economic Scenarios

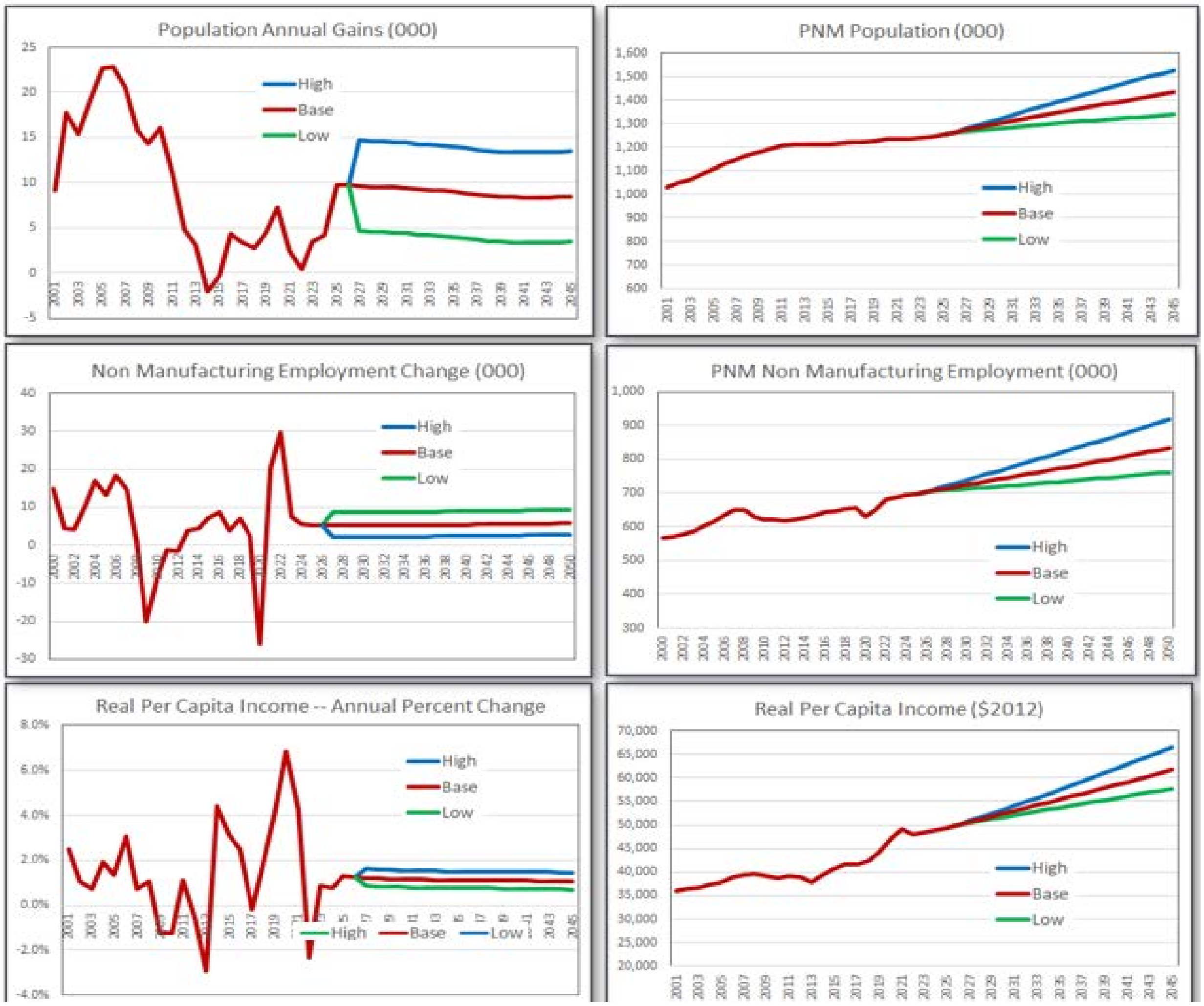
Three economic growth scenarios are developed to capture the range of plausible economic outcomes over the forecast horizon. All statistics represent averages over the 2026 to 2045 forecast period.

Table 2.2: Economic Scenario Summary (2026-2045 Averages)

Economic Indicator	High Case	Base Case	Low Case
Population Annual Gains	13,700	8,900	4,200
Non-Mfg. Employment Annual Gains	8,700	5,300	2,500
Real Per Capita Income Growth	1.5%	1.1%	0.8%

Figure 2.1 shows economic scenarios for population annual growth in different scenarios.

Figure 2.1: Economic Scenario Comparison



2.3 Comparison to Prior IRP

The primary drivers of residential and commercial customer growth are population and nonmanufacturing employment. Compared to the prior IRP:

- Population forecasts are slightly weaker. The 2045 population is approximately 27,000 lower (-1.9%) than the prior IRP forecast, though annual gains beyond 2025 are approximately the same.
- Employment forecasts are largely consistent with the prior IRP. Employment in 2050 is approximately 2,000 higher (-0.3%) than previously projected.

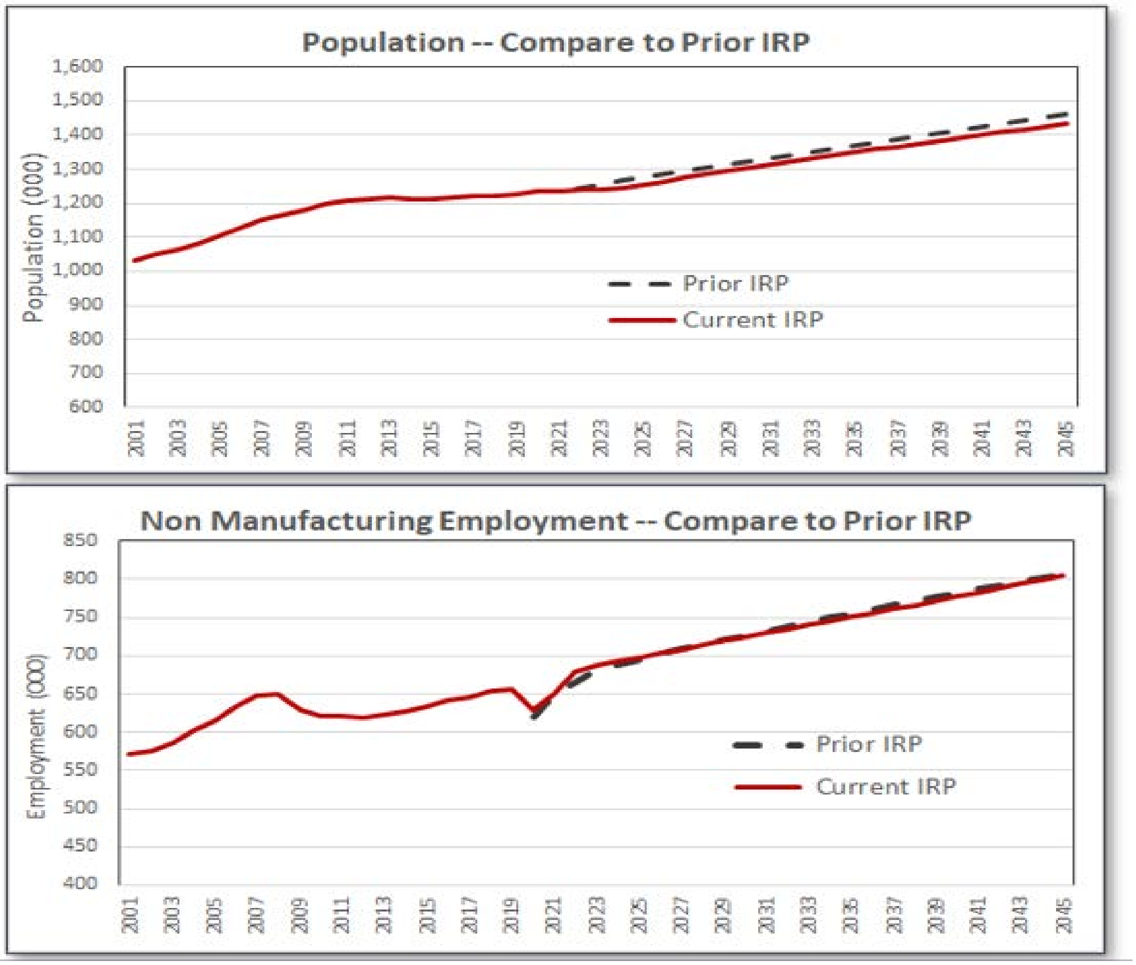
Table 2.3: Economic Forecast Comparison to Prior IRP

Metric	Current IRP	Prior IRP	Difference	% Change
Population in 2045	~1,390,000	~1,417,000	-27,000	-1.9%
Employment in 2050	Comparable	Comparable	+2,000	+0.3%
Post-2025 Annual Pop. Gains	~8,900	~8,900	Minimal	~0%

Figure 2.2 shows population and non-manufacturing employment growth compared to prior Integrated Resource Planning (IRP). Population growth has declined from the previous IRP which impacts this forecast slightly down. On the other hand, non-manufacturing employment is very similar to the last IRP. It did not change much from what was in the last IRP.

Population growth is very significant for the residential class forecast for customers in future. Non-manufacturing employment plays a role in residential customers. More employment in non-manufacturing means more residential customers in the future. Both variables are very stable and did not change much from last IRP.

Figure 2.2: Economic Forecast — Current vs. Prior IRP



3. Weather Data, Normal and Extreme Weather

Weather data are collected through AccuWeather services on an hourly basis. PNM composed weather data for four weather stations. The following describes the process in detail.

3.1 Weather Data Sources

Hourly weather data are obtained from AccuWeather for four weather stations across PNM's service territory. Table 3.1 shows the weather stations and their locations.

Table 3.1: Weather Station Details

Station Name	ID	Region	Latitude	Longitude	Elevation (ft)
Albuquerque International Sunport	KABQ	North	35.04°N	106.62°W	5,355
Santa Fe Municipal Airport	KSAF	North	35.62°N	106.09°W	6,348
Deming Municipal Airport	KDMN	South	32.26°N	107.72°W	4,314
Alamogordo-White Sands Regional	KALM	South	32.84°N	105.99°W	4,197

Key weather variables collected include:

- Temperature: Used to compute heating degree days (HDD) and cooling degree days (CDD) at multiple base temperatures
- Global Horizontal Irradiation (GHI): Used for solar generation modeling

3.2 Station Weighting

Station weights for composite weather variables are based on monthly billed sales by geographic area. Figure 3.1 shows the map of different weather stations and their location.

Figure 3.1: Weather stations with locations

Table 3.2: Weather stations with heating, cooling degree days with solar GHI

Station	Heating Degrees	Cooling Degrees	Solar GHI
KABQ	75.0%	77.8%	76.3%
KALM	3.0%	3.2%	3.1%
KDMN	9.0%	8.4%	8.9%
KSAF	13.0%	10.5%	11.7%

Hourly weather data from AccuWeather

- Temperature – Used to compute Degree Days
- Global horizontal irradiation (GHI) – Used for solar generation

4 Stations

- North: Albuquerque (KABQ), Santa Fe (KSAF)
- South: Deming (KDMN), Alamogordo (KALM)

Station weights are created based on billed sales on a seasonal basis for winter and summer. Table 3.3 shows the methodology used for creating the weights that are presented above in table 3.2.

Table 3.3: Station Weighting Methodology

Weight Type	Basis	Season/Period	Application
Heating Degree Day Weights	Billed sales by station area	Winter season	Composite HDD for energy models
Cooling Degree Day Weights	Billed sales by station area	Summer season	Composite CDD for energy models
Solar GHI Weights	Billed sales by station area	Annual	Composite GHI for PV generation models

3.3 Normal and Extreme Weather

Normal weather is defined using a 10-year averaging period from 2015 to 2024. Extreme weather represents a 1-in-20-year event.

Figure 3.2: Normal vs. Extreme Weather Temperatures

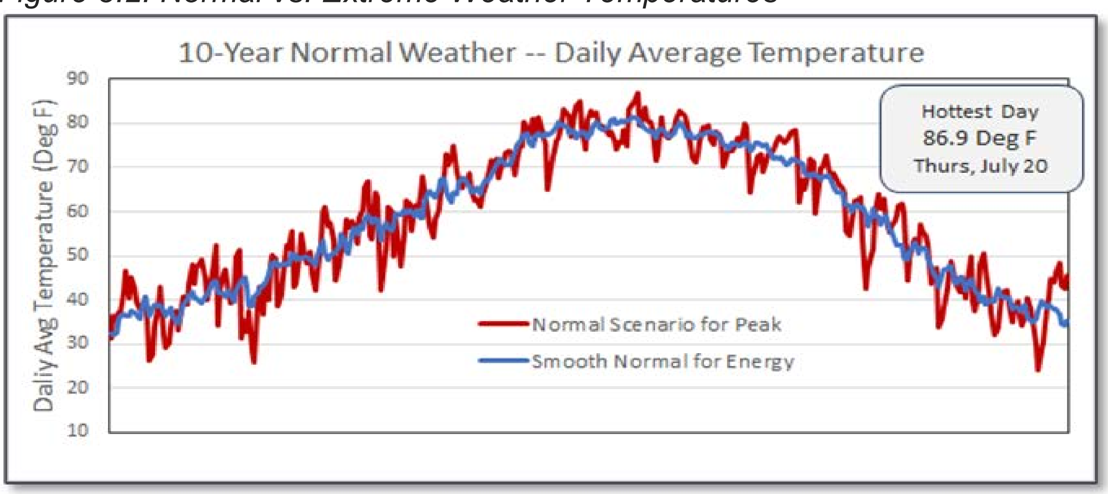


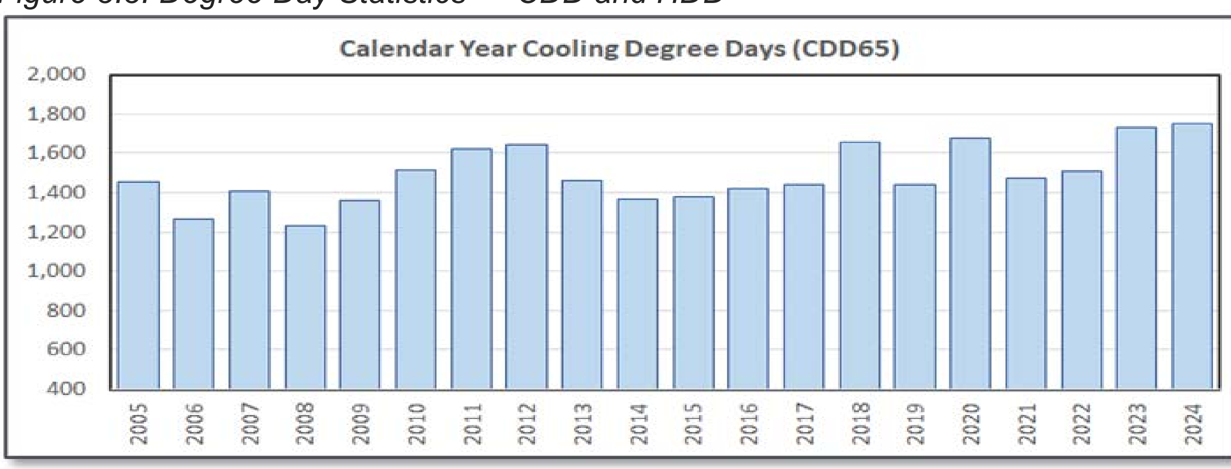
Table 3.4 shows the definition for weather metric with different values and the normal weather period that are used in the forecast.

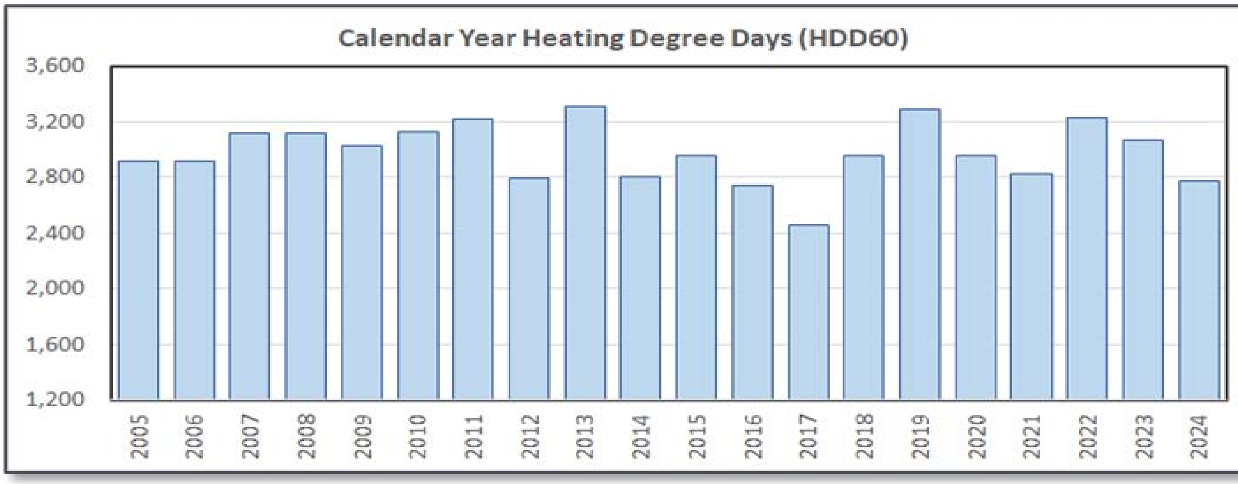
Table 3.4: Normal Weather Statistics

Weather Metric	Normal Value	Extreme Value	Period
Typical Hottest Day Temperature	86.9°F	89.4°F (Extreme Hot)	10-year normal (2015-2024)
Typical Coldest Day Temperature	21.8°F	3.5°F (Extreme Cold)	10-year normal (2015-2024)
Annual CDD (10-year avg)	1,549	1,751 (2024)	2015-2024
Annual HDD (10-year avg)	2,953	3,289 (2019)	2015-2024

Figure 3.3 below shows calendar year cooling degree days and calendar year heating degree days for different years from 2005 to 2024. It is noticeable how weather fluctuates year by year.

Figure 3.3: Degree Day Statistics — CDD and HDD





Degree Day Base Temperatures are defined in the table below. This degree day base temperature is used in the forecast to assess the different weather responses for the load.

Table 3.5: Degree Day Base Temperatures

Degree Day Type	Base Temperatures Used
Cooling Degree Days (CDD)	55°F, 60°F, 65°F, 70°F, 75°F
Heating Degree Days (HDD)	45°F, 50°F, 55°F, 60°F

4. Weather Response Modeling

4.1 Load Research Data

Load research data provide hourly and daily energy use estimates for a statistical sample of customers by rate class. These data form the foundation for understanding the relationship between weather and electricity consumption.

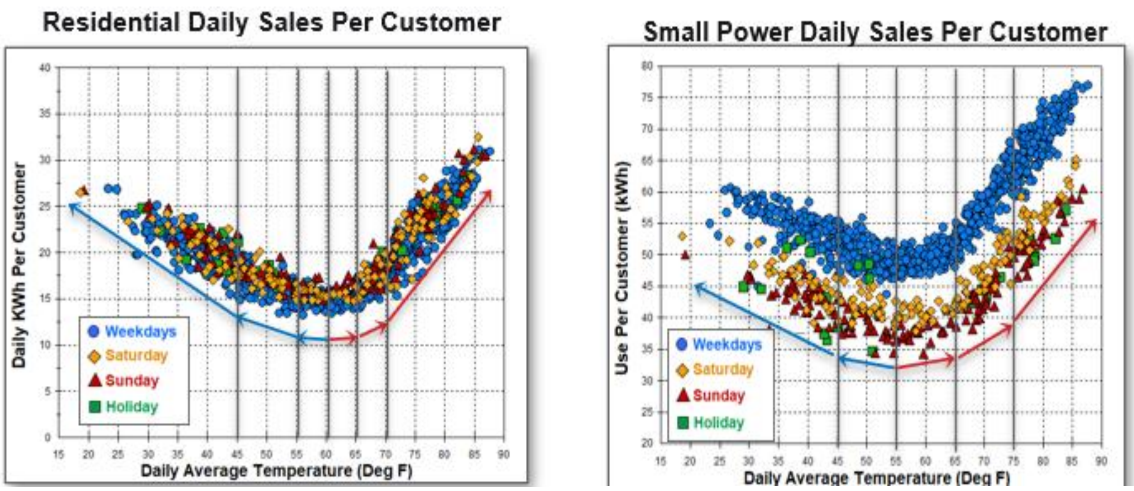
4.2 Weather Response Characteristics

Analysis of daily sales per customer reveals several important characteristics: following page describes in bullet points the weather response with Figure 4.1.

- Daily energy use shows a strong response to daily weather conditions

- The response of load to weather is nonlinear, with increasing sensitivity at temperature extremes
- Weather response patterns differ across customer classes (Residential, Small Power, General Power)

Figure 4.1: Residential and Small Power daily sales for different days



4.3 Degree Day Weighting

Load research data are used to calculate optimal heating degree day (HD) and cooling degree day (CD) weights through daily regression models:

- The dependent variable (Y) is daily sales per customer
- Independent variables (X) are daily CD and HD values at multiple base temperatures
- Regression results determine the optimal weights for low, medium, and high-powered degree day variables
- Separate weight sets are computed for Residential, Small Power, and General Power customer classes

Table 4.1: HDD and CDD weights for different classes

Residential Weights

Spline	Wgt
HD60	0.285
HD55	0.422
HD45	0.293
CD60	0.188
CD65	0.286
CD70	0.526

Small Power Weights

Spline	Wgt
HD55	0.572
HD45	0.428
CD55	0.237
CD65	0.629
CD75	0.134

General Power Weights

Spline	Wgt
HD55	0.307
HD45	0.693
CD55	0.448
CD65	0.552

5. Behind the Meter Solar Data and Forecasts

The detailed behind-the-meter solar data and forecast can be found in the study in Appendix H2: BTM Solar Forecasting Methodology.

6. Electric Vehicle Forecast

Electric vehicle (EV) saturation is growing in PNM service territory based on the history. PNM used EPRI EV forecast to build energy use for charging electric vehicles. Scenarios are created using EPRI data.

6.1 Adoption Forecast Methodology

Electric vehicle adoption forecasts are based on the EPRI study and cover three vehicle segments:

- Light duty vehicles: Charging at home and away from home
- Fleet vehicles: Commercial charging
- Medium/heavy duty vehicles: Commercial charging

6.2 Light Duty Vehicle Forecast

The light duty vehicle forecast uses a 50/50 weighting of EPRI Low and Medium adoption scenarios. Figure 6.1 shows Light Duty Vehicle (LDV) and Medium/Heavy Vehicle (MDV) forecasts with high, low scenarios. Table 6.1 lays out numbers of LDV and MDV.

Figure 6.1: Electric Vehicle Adoption Scenarios

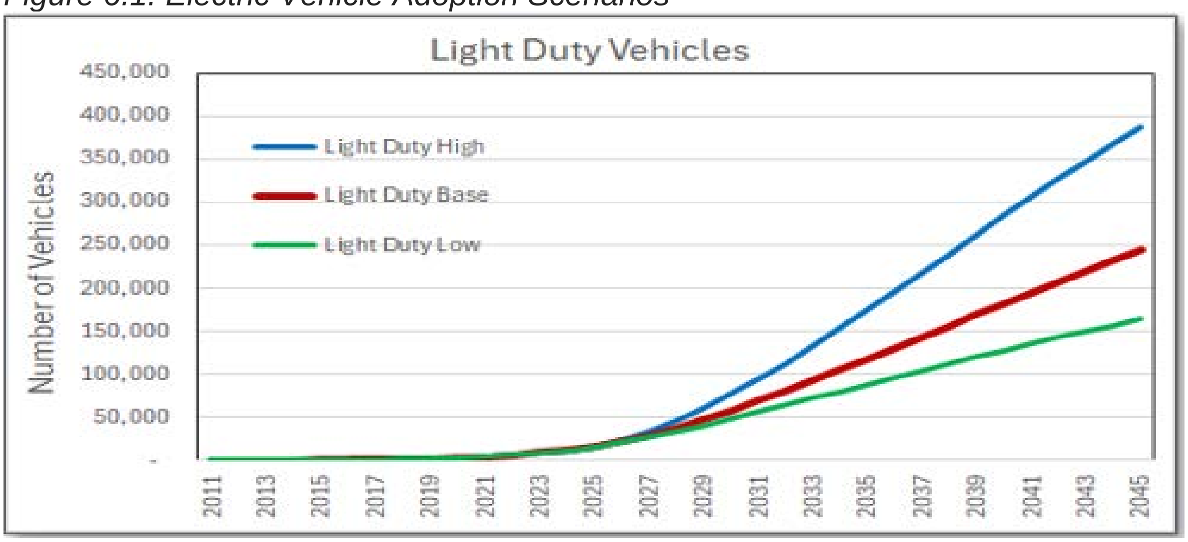


Figure 6.2: Fleet and Medium/Heavy duty vehicle forecast

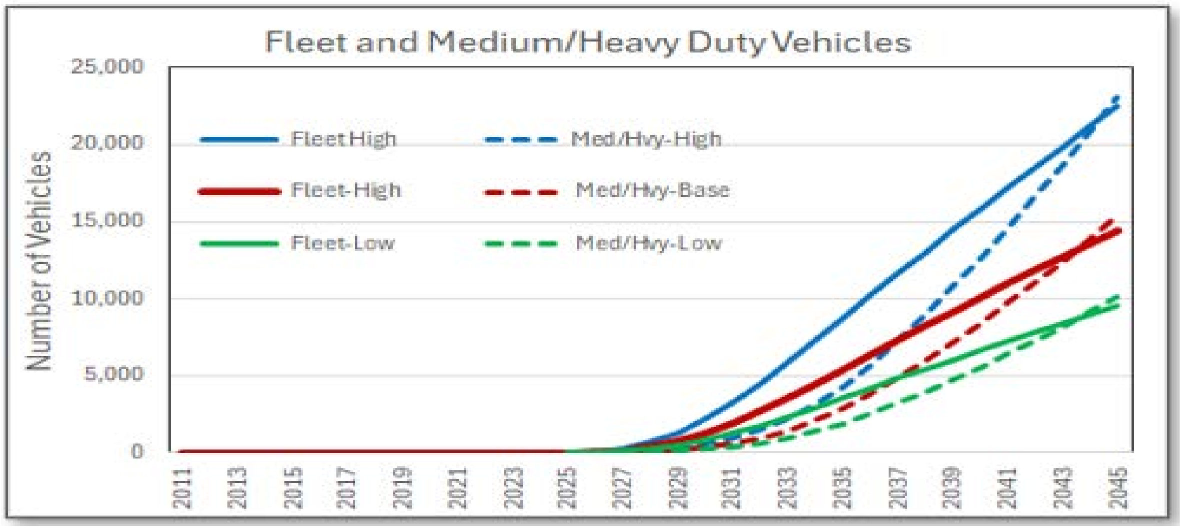


Table 6.1: EV Adoption Scenarios — Light Duty Vehicles

Metric	High EV	Base EV	Low EV
New Vehicle Sales by 2045 (annual)	18,900	12,000	6,900
Total EV Count in 2045	387,000	245,000	164,000
EPRI Scenario Weighting	50/50 Low/Medium + Uplift	50/50 Low/Medium	50/50 Low/Medium - Reduction

Figure 6.2 details Fleet and Medium/Heavy duty vehicle forecast, adjustments with comparing what was done in the previous IRP forecasts. This is helpful to understand as electrification in PNM system is changing and is dynamic in nature.

6.3 Fleet and Medium/Heavy Duty Vehicle Forecast

Table 6.2 describes weighing and adjustments in the Medium/Heavy duty vehicles in the forecast.

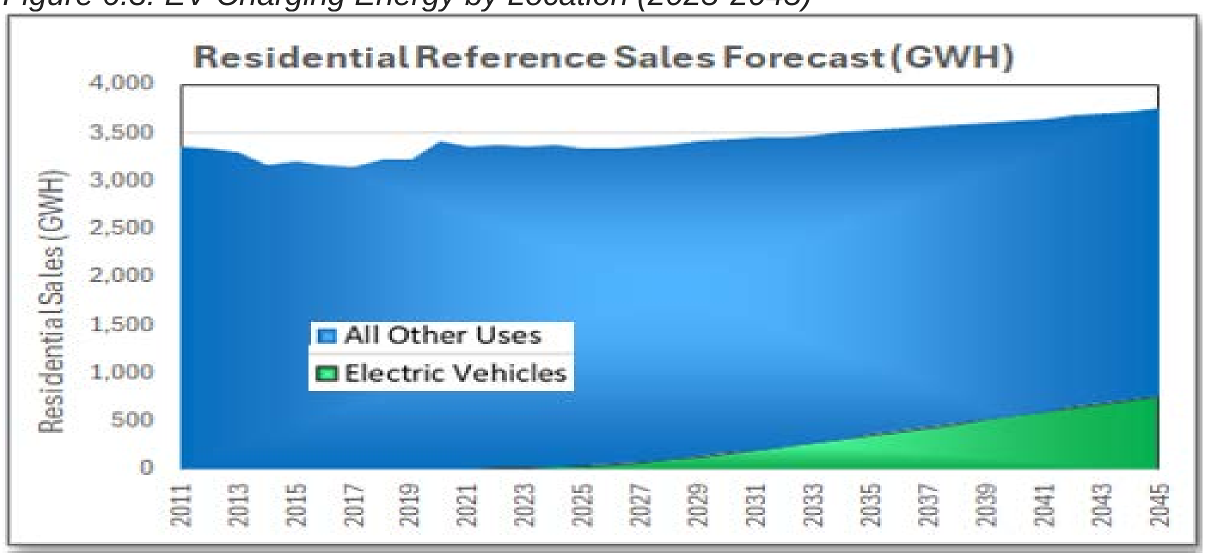
Table 6.2: Fleet and Medium/Heavy Duty Vehicle Forecast

Vehicle Segment	EPRI Weighting	Additional Adjustment	Acceleration Year	Prior IRP
Fleet (Light Commercial)	50/50 Low/Medium	Reduced by 50%	2030	Not modeled
Medium Duty	50/50 Low/Medium	Reduced by 50%	2035	Not modeled
Heavy Duty	50/50 Low/Medium	Reduced by 50%	2035	Not modeled

6.4 EV Charging Energy

Figure 6.3 depicts EV charging energy based on location based on the uses and EV charging.

Figure 6.3: EV Charging Energy by Location (2025-2045)



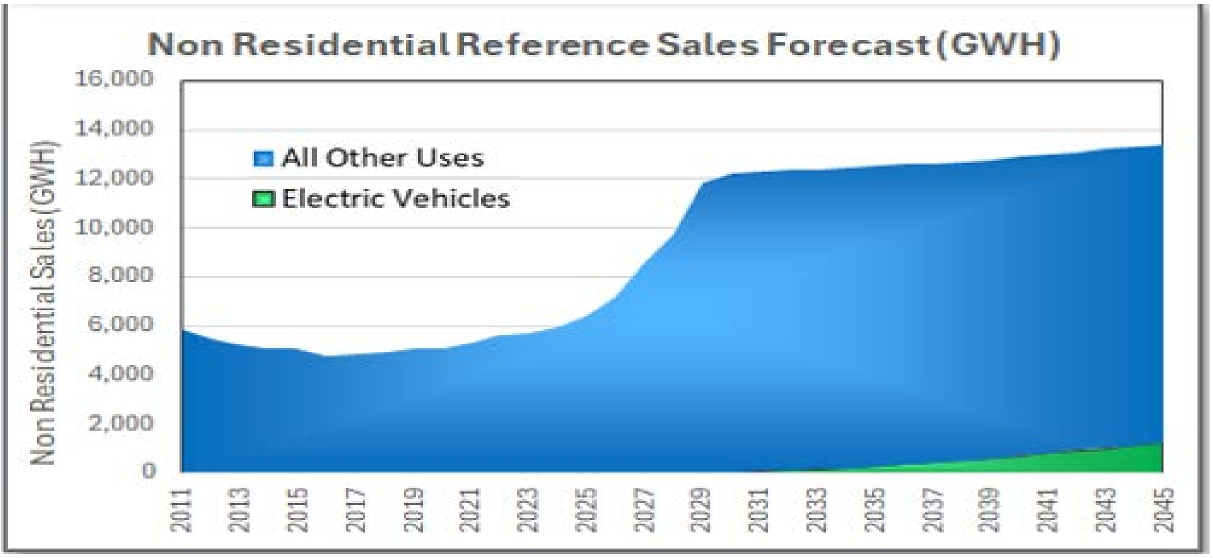


Table 6.3 elaborates on the EV segments and charging locations and key metrics in the forecast horizon.

Table 6.3: EV Charging Energy by Segment

Segment	Charging Location	Share of LDV Charging	Key Metric (2025-2045)
Residential (LDV at home)	Home	80%	Sales gain: 419 GWh; EV energy: 722 GWh
Nonresidential (LDV away)	Workplace/Public	20%	Growing; part of nonres total
Fleet	Commercial	100% nonresidential	Accelerates from 2030
Medium/Heavy Duty	Commercial	100% nonresidential	Accelerates from 2035

Segment	Charging Location	Share of LDV Charging	Key Metric (2025-2045)
Total Nonres by 2045	All commercial	~60% of total	Driven by fleet and M/HD

6.5 EV Charging Profiles

Table 6.4 shows the vehicle types and profiles used for forecasting for EVs.

Table 6.4: EV Charging Profile Sources

Vehicle Type	Location	Profile Source	Strategies Modeled
Light Duty — Home	Residential	NREL EV-Pro	Immediate; Start at time; Charge by time
Light Duty — Away	Workplace/Public	Idaho National Labs	Observed patterns
Fleet	Commercial	California study	By vehicle type
Med/Heavy Duty	Commercial	California study	Bus, refuse, drayage, tractor-trailer, etc.

7. Other Scenario Inputs

PNM considers electrification an essential part of load forecasting. Building electrification was analyzed to describe the impact on energy and demand forecast in this section.

7.1 Building Electrification

The building electrification scenario models the transition from natural gas and propane to electric alternatives. Table 7.1 depicts the construction methodology and 7.1.1 shows existing home conversion from gas to electric.

Table 7.1: New Construction Electrification Assumptions (Starting 2030)

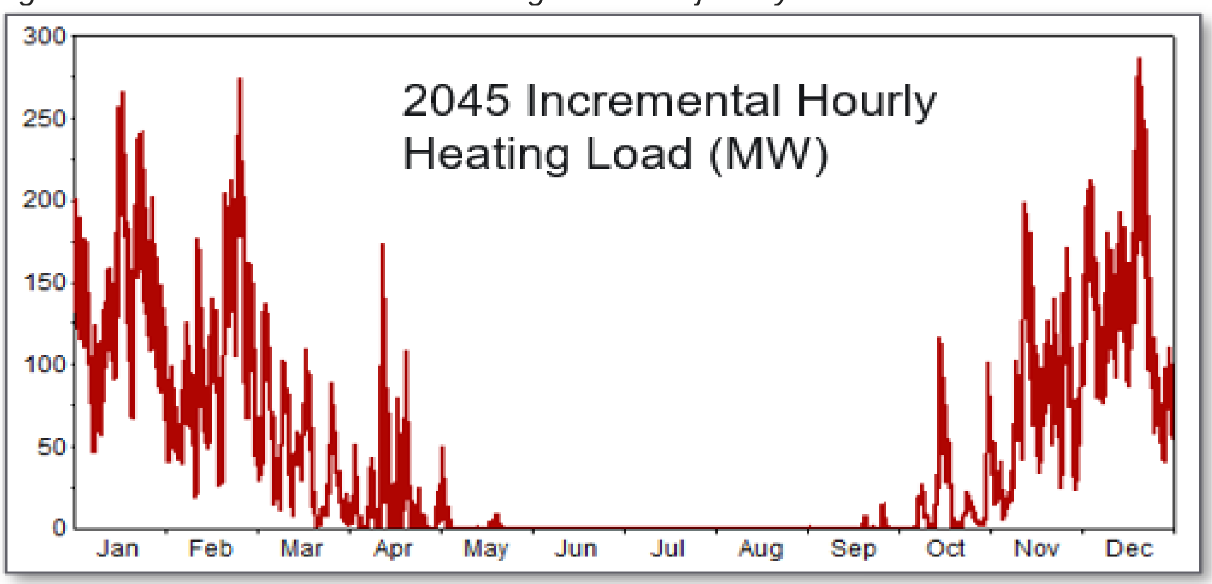
Parameter	**Current Baseline**	**Electrification Scenario**
Natural Gas/Propane Permitted	Yes	No (banned in new construction from 2030)
Electric Heat Share	15%	75%
Heat Pump Share of Increase	—	80%
Evaporative Cooling	Prevalent	Reduced; replaced by central AC
Electric Water/Cooking/Dryer	Baseline	Increased

Figure 7.1 shows the incremental heating load because of electrification in the system-based assumption described in Table 7.1. Winter months are very noticeable because it is adding heating load to the system.

Table 7.1.1: Existing Home Conversion Assumptions

Parameter	Value
Annual Conversion Rate	~2% of existing homes (~7,000 homes/year)
Evaporative Cooling Displacement	30% of converted homes
Incremental Cooling UEC	~1,500 kWh/year
Heat Pump Heating UEC	~2,500 kWh/year (average)

Figure 7.1: Residential Electric Heating Share Trajectory



7.2 Residential Time-of-Use Rates

The TOU/TOD scenario introduces residential time-of-use rate structures beginning with pilots through 2029, followed by a full opt-out program in 2030. In this scenario, it is assumed 80% will opt in and 20% will opt out. Based on these parameters, Table 7.2 shows impact on the system in the morning, evening, price ratio and on peak reduction. Table 7.2.1 shows the participation assumed based on impact study basis from ACEEE

50 pricing basis. Figure 7.2 and Table 7.2.2 show residential hourly load with or without TOU/TOD.

Table 7.2: TOU/TOD Rate Structure

Parameter	Summer	Winter
On-Peak Period (Evening)	5:00-8:00 PM	5:00-8:00 PM
On-Peak Period (Morning)	None	5:00-8:00 AM
Price Ratio (On/Off Peak)	4.0	2.5
On-Peak Reduction (Non-EV)	10.5%	Proportional

Table 7.2.1: TOU/TOD Participation Assumptions

Customer Segment	Assumption
Non-EV Homes Opt-Out Rate	20%
EV Owners on WHEV Rate	80%
WHEV Off-Peak Window	10:00 PM - 5:00 AM
Impact Study Basis	ACEEE summary of 50 pricing pilots

Figure 7.2: System Load Profile — TOU/TOD Impact on Peak Demand

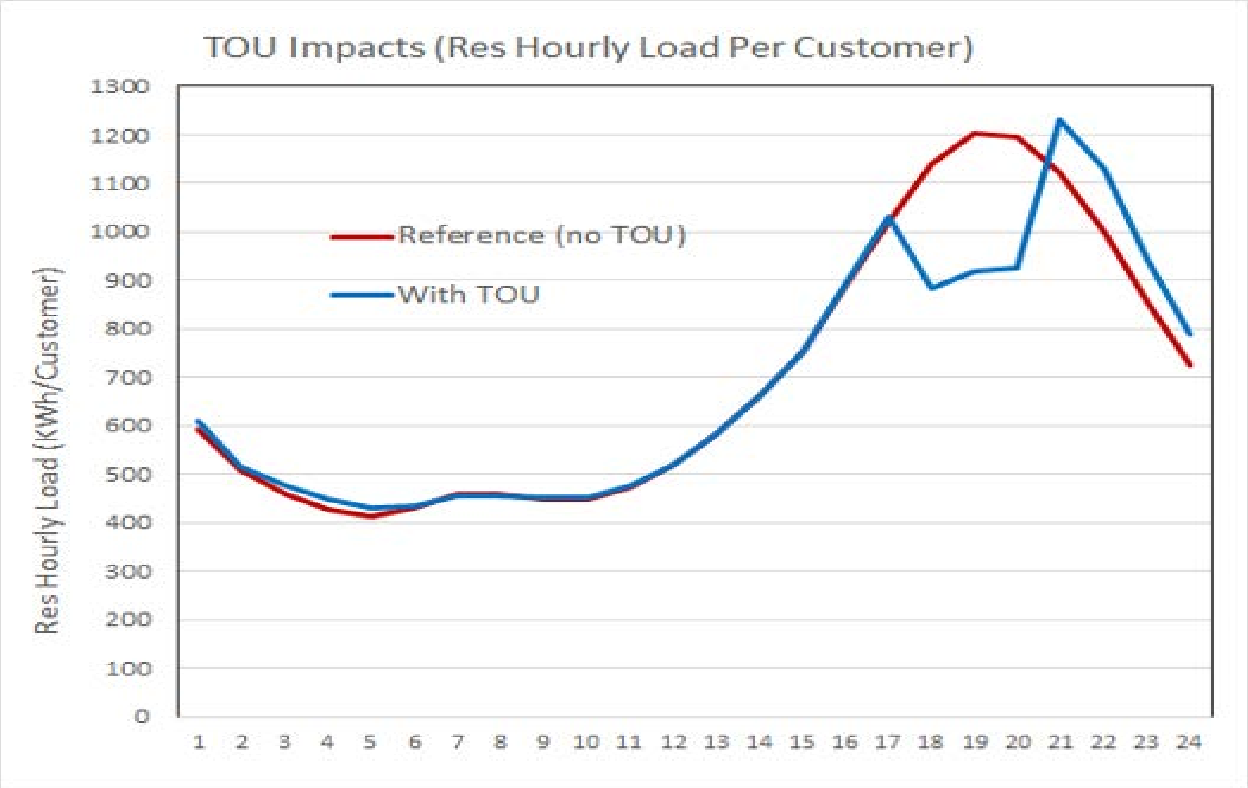


Table 7.2.2: TOU/TOD Peak Shift Impact

Condition	**System Peak Hour**
Without TOU	Hour Ending 19 (6:00-7:00 PM)
With TOU (incl. WHEV bounce-back)	Hour Ending 21 (8:00-9:00 PM)

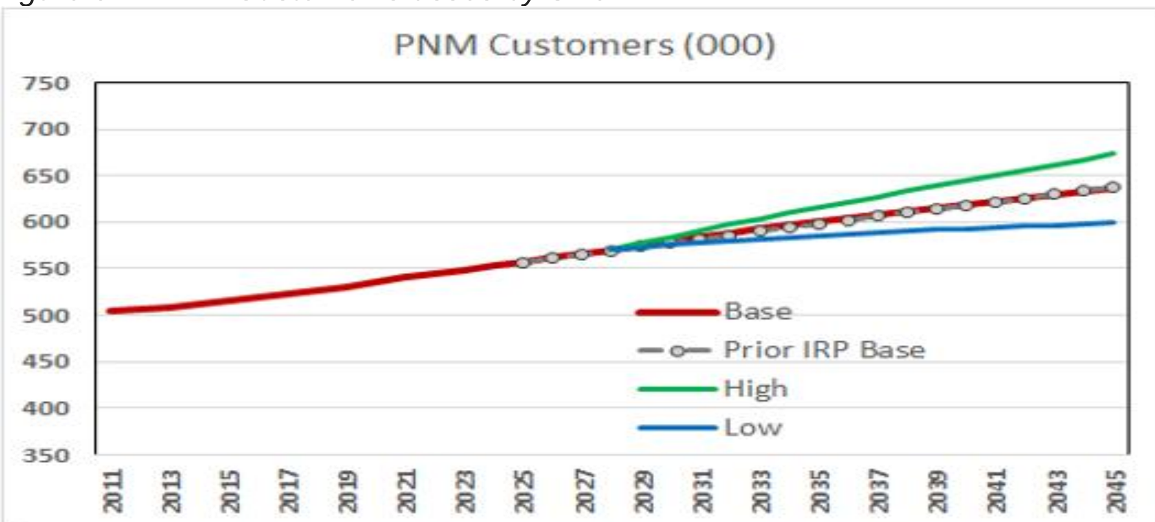
8. Energy Modeling and Forecasts

Energy models are based on customers and use per customer forecast models. Customer and use per customer are multiplied to get energy sales. The following describes the process.

8.1 Customer Forecast

Customer forecast is created based on economic variable that is described in the economic variable forecast earlier. Figure 8.1 shows PNM customer forecast and scenarios with prior IRP, followed by average annual customer gain in the forecast.

Figure 8.1: PNM Customer Classes by Size



Range	Res	SP	GP	LP	Total
	Average Annual Customer Gain				
2015-2025	3,921.1	240.6	4.5	-6.6	4,181.2
2025-2035	4,055.8	322.0	15.6	0.2	4,394.7
2035-2045	3,262.4	320.6	13.9	0.3	3,597.2
	Average Annual Growth Rate				
Range	Res	SP	GP	LP	Total
2015-2025	0.83%	0.45%	0.10%	-3.49%	0.78%
2025-2035	0.79%	0.58%	0.36%	0.10%	0.76%
2035-2045	0.59%	0.54%	0.31%	0.19%	0.58%

*Total includes LS, Water, Irrigation, and Lighting classes

Table 8.1 shows customer models by class and the variables used to produce the forecast.

Table 8.1: Customer Forecast Models by Class

Customer Class	**Short-Term (Through 2028)**	**Long-Term (After 2028)**	**Key Drivers**
Residential (Res)	Trend model	Population elasticity	Population growth

Customer Class	Short-Term (Through 2028)	Long-Term (After 2028)	Key Drivers
Small Power (SP)	Trend model	Pop./Employment elasticity	Population and employment
General Power (GP)	Regression	Regression	Pop. and non-mfg. employment
Large Power (LP4)	Elasticity	Elasticity	Non-mfg. employment
Industrial	Direct input	Direct input	Known expansion plans

8.2 Energy Use and Sales Framework

The modeling process follows a two-step approach:

- Step 1: Forecast energy use per customer using regression models with end-use drivers and weather variables
- Step 2: Compute sales as Energy Use minus PV Generation

8.3 Statistically Adjusted End-Use (SAE) Framework

Residential and commercial energy models employ the SAE methodology, which accounts for appliance saturation, equipment efficiency, and thermal efficiency of buildings.

Table 8.2: SAE Model Data Sources

Data Source	Application	Coverage
EIA (2025 data, Mountain Region)	Initialize efficiency/saturation trends	National/regional benchmarks
PNM Efficiency Potential Study	Base-year intensities and saturations	PNM-specific calibration
PNM Load Research Data	Hourly/daily use estimates by class	Statistical sample, 2015-June 2022

SAE framework in Figure 8.3 and Table 8.3.1 shows the components of SAE framework. Table 8.3.1 describes subcomponents and drivers that impact those variables.

Figure 8.3: Residential SAE Model Framework

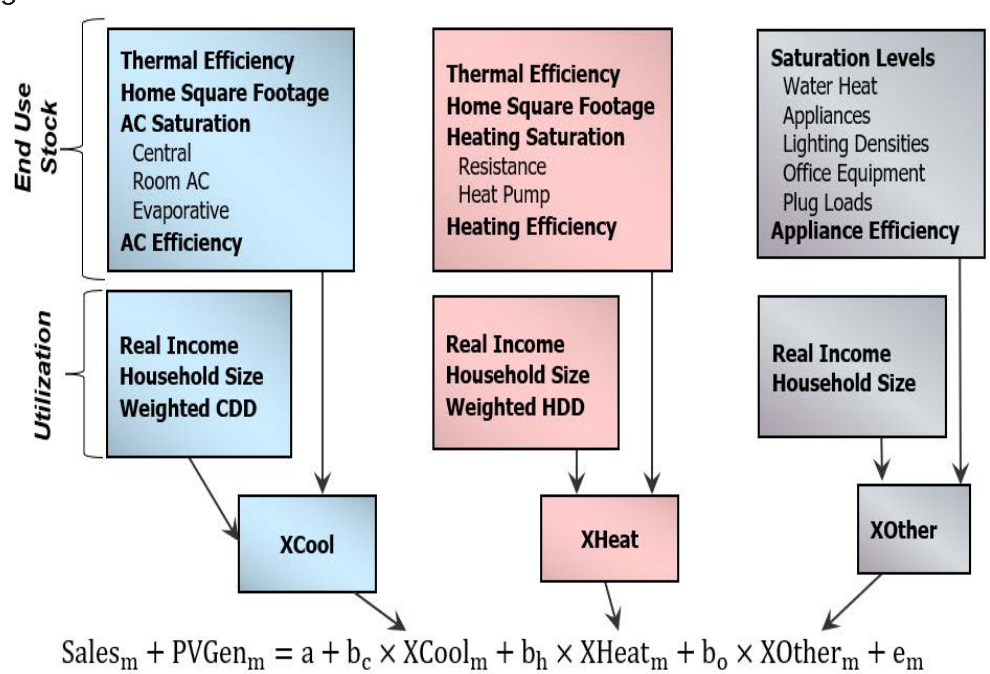


Table 8.3.1: Residential SAE End-Use Components

End-Use Component	Sub-Components	Utilization Drivers
Heating (XHeat)	Thermal eff., home sq.ft., heat saturation, heat efficiency	Income, household size, weighted HDD
Cooling (XCool)	Thermal eff., home sq.ft., AC saturation, AC efficiency	Income, household size, weighted CDD
Other (XOther)	Water heat, appliances, lighting, plug loads, efficiency	Income, household size

Table 8.3.2: SAE Framework Applicability by Customer Class

Customer Class	SAE Used	Notes
Residential	Yes	Full end-use decomposition
Small Power	Yes	Commercial SAE framework
General Power	Yes	Commercial SAE framework
Large Power (LP4)	Yes	Commercial SAE framework
Industrial	No	Direct customer input

9. Hourly Load and Peak Demand Forecasts

Hourly load and peak demand forecasts are created on multiple steps from creating models on a class basis to build monthly energy. The monthly energy forecasts are then calibrated with class level hourly load profile from load research. Electric vehicles (EV) and Photovoltaic (PV) were added to the forecasts along with industrial and economic development projects for future. Table 9.1 shows the bottom-up approach for the system hourly load forecast and it's step by step process from energy to demand.

9.1 Bottom-Up Methodology

The hourly system load forecast is constructed using a bottom-up approach:

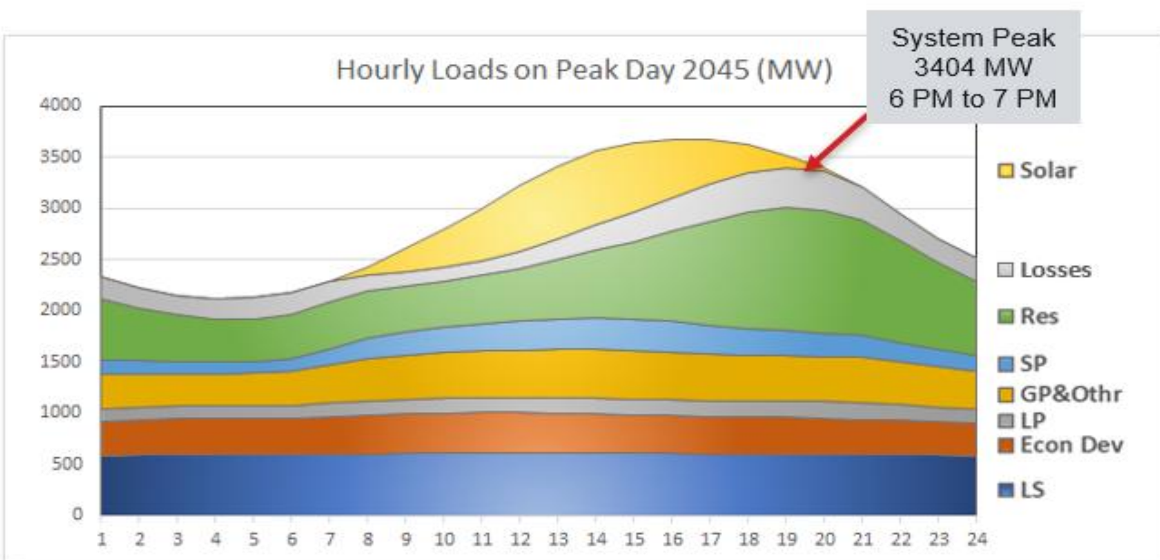
Table 9.1: Bottom-Up Hourly Load Construction Steps

Step	Process	Input	Output
1	Monthly sales forecast by class (excl. EV/PV)	Energy models	Calendar month class sales
2	Calibrate hourly profiles to monthly energy	Load research models	Hourly class profiles
3	Add incremental EV charging	EV profiles × energy	Hourly loads with EV
4	Subtract incremental PV generation	PV profiles × generation	Hourly net loads
5	Apply loss factors by voltage level	Loss factors	Loads with losses

Step	Process	Input	Output
6	Add industrial/econ development	Customer data	System load (pre-UFE)
7	Sum across all classes	—	Bottom-up system load
8	Apply UFE adjustment factors	Historical UFE	Final system load

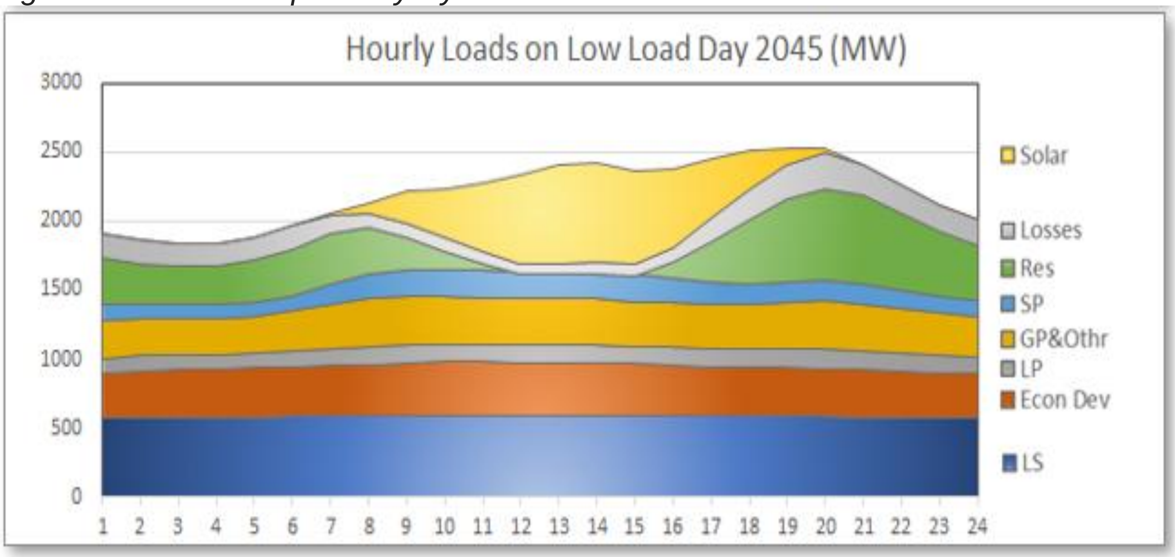
Figure 9.1 shows the 2045 peak day and Figure 9.2 shows the 2045 low load day. One with the peak day shows 2045 peak day decomposition for different classes and the peak time of that day. This helps to show the shares of each class with losses along with solar.

Figure 9.1. Hourly loads on Peak Day 2045 (MW)



The other figure shows a low day in 2045 with same decomposition of classes, losses and solar in it. This is very critical to know as this is change from current composition of load that exists in the system today. Integration of renewables and EVs in future changes the load profile for different classes. The system profile look different from present day.

Figure 9.2: Bottom-Up Hourly System Load Construction



9.2 System Peak Demand

System peak demand under different conditions allows PNM system to analyze peak demand in CTP (Reference case) in MW and shows the peak demand amount 3404 MW with peak time with and without PV in the system. TOU/TOU analyses were done to see the impact on the peak and the peak time. Table 9.2 shows the system peak under different conditions.

Table 9.2: System Peak Summary

Metric	Value
Reference Case System Peak	3,404 MW
Peak Hour (with PV)	Hour Ending 19 (6:00-7:00 PM)
Peak Hour (without PV)	Hour Ending 17 (4:00-5:00 PM)

Metric	Value
Peak Hour (with TOU)	Hour Ending 21 (8:00-9:00 PM)

10. Forecast Scenarios and Results

10.1 Forecast scenarios

Forecast scenarios were created based on several drivers such as economic, weather, model uncertainty, BTM (Behind the Meter generation) and so. These scenarios are stitched with the reference scenario (Current Trends and Polices) on top of each case to create a probabilistic outcome for future for both energy and demand (Peak). Table 10.1 shows the buildup of scenarios.

The idea is to show each of the components' impact on CTP to test the system energy and demand. This helps to create band with CTP and to show how the system will change in forecast so we can plan better. In the CTP case, which is the base case, population and economic growth play a vital role to determine the future energy and demand. This is used as the plan to create a probable future that is likely to happen in the service territory. Table 10.1 shows different components of the forecast.

Table 10.1: Individual Component Cases

Component	High/Strong Case	Base/Reference	Low/Weak Case
Economics	High pop., employment, income	Base case	Low pop., employment, income
Weather	Hot summer, cold winter	10-yr normal	Mild summer, mild winter

Component	High/Strong Case	Base/Reference	Low/Weak Case
Model Uncertainty	+2%	0%	-2%
BTM PV	Low PV (675 MW)	Base PV (835 MW)	High PV (1,033 MW)
Electric Vehicles	High EV (387K)	Base EV (245K)	Low EV (164K)
Econ. Development	Ref. + 65 MW	Ref. (11 cust., ~400 MW)	Ref. - 110 MW
Industrial Growth	Planned expansion	Planned expansion	Smaller/slower
Electrification	Included	Not included	Not included
TOU	Included (some combos)	Not included	Not included

Note: In the Strong Growth scenario, "weak PV" means less solar offset (higher net load). In the Weak Growth scenario, "strong PV" means more solar offset (lower net load).

10.2 Economic Growth Cases

CTP (Reference Case) is created with base economic assumptions with normal weather. High Economic Growth (HEG) is based on high population growth, employment, income, hot/cold weather. Low Economic Growth (LEG) is with low population growth, employment, income, and mild weather.

10.3 Weather Scenario and Short-Term Uncertainty

Weather scenario forecast is based on the 20 years hottest for summer and coldest in 20 years. This is based on 1 in 20 extreme cases. Normal weather conditions are 10-year average for both summer and winter. 2015 to 2024 is the basis for normal weather conditions. Low weather conditions are the mildest for both summer and winter with 1 in 20 mild cases. Table 10.2 shows the composition.

Table 10.2: Weather Uncertainty Bands

Scenario	Summer Condition	Winter Condition	Basis
High Weather	Hottest in 20 years	Coldest in 20 years	1-in-20 extreme
Normal	10-year average	10-year average	2015-2024 normal
Low Weather	Mildest in 20 years	Mildest in 20 years	1-in-20 mild

Table 10.3 shows the uncertainty band from the model.

Table 10.3: Model Uncertainty Band

Parameter	Value	Basis
Uncertainty Range	±2% of forecast	Typical year-ahead error
Interpretation	2-sigma confidence band	~95% confidence interval

10.4 EV and PV Scenarios

EV and PV are very important for forecast in PNM service territory. As these are integrated with the forecast, PNM investigated different scenarios for Light Duty Vehicle (LDV) and Photovoltaic (PV). Table 10.4 shows the scenarios.

Table 10.4: EV and PV Scenario Summary

Scenario	LDV Count 2045	PV Capacity 2045 (MW)	Prior IRP PV Base (MW)
High	387,000	1,017	1,054
Base	245,000	822	1,054
Low	164,000	668	1,054

10.5 Industrial Growth and Economic Development

Industrial growth and economic development is a lion share of load growth in the forecast. Table 10.5 shows the customer additions and timeline for these growths. PNM internally keeps the economic development data and updates frequently based on customer inputs.

Table 10.5: Economic Development Scenarios

Scenario	New Customers	Total New Load (MW)	Timeline
Reference Case	11	~400	By mid-2033
High Case	11+	~465 (+65)	By mid-2033
Low Case	11-	~290 (-110)	By mid-2033

11. Complex Scenarios

Load forecasts are not based on just one deterministic forecast. PNM investigated multiple scenarios based on different categories and followed a waterfall methodology. Next section explains this.

11.1 Waterfall Methodology

Complex scenarios are constructed using a waterfall approach that sequentially adds the impacts of individual component cases to the reference forecast.

Figure 11.1: Strong Growth Scenario — Waterfall Build-Up

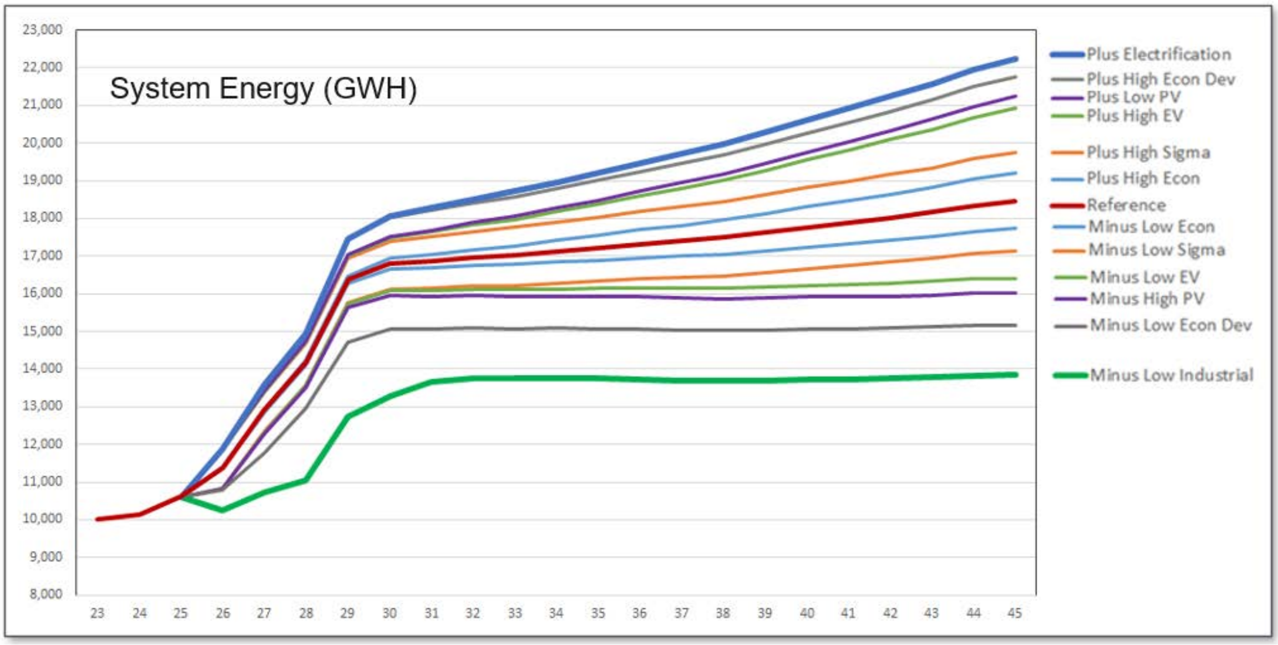


Figure 11.1 shows complex scenarios build up and Table 11.1 and Table 11.2 shows strong grown and weak growth scenarios compositions.

Table 11.1: Strong Growth Scenario Composition

Component	Case Used	Impact Direction
Economic Growth	High	Increases load
Weather	Strong (hot/cold)	Increases load

Component	Case Used	Impact Direction
Model Uncertainty	Positive (+2%)	Increases load
BTM PV	Weak (low adoption)	Less offset → higher net load
Electric Vehicles	Strong (high adoption)	Increases load
Economic Development	Strong	Increases load
Electrification	Included	Increases load

Table 11.2: Weak Growth Scenario Composition

Component	Case Used	Impact Direction
Economic Growth	Low	Decreases load
Weather	Weak (mild)	Decreases load
Model Uncertainty	Negative (-2%)	Decreases load
BTM PV	Strong (high adoption)	More offset → lower net load

Component	Case Used	Impact Direction
Electric Vehicles	Weak (low adoption)	Decreases load growth
Economic Development	Weak	Decreases load
Industrial Expansion	Weak	Decreases load

12. Energy Forecast Summary

The energy sales forecast reflects the combined effects of customer growth, appliance efficiency trends, BTM solar generation, EV adoption, building electrification, and TOU/TOD rate impacts. Key observations:

- Customer growth is driven primarily by population and employment trends
- BTM PV continues to offset load growth, though adoption has moderated vs. prior IRP
- EV charging is the most significant new load growth driver, with nonresidential charging dominant by 2045
- Building electrification shifts heating loads to electricity with significant winter peak impacts
- TOU rates shift peak timing but have modest total energy impact

Energy sales forecasts are provided by customer class:

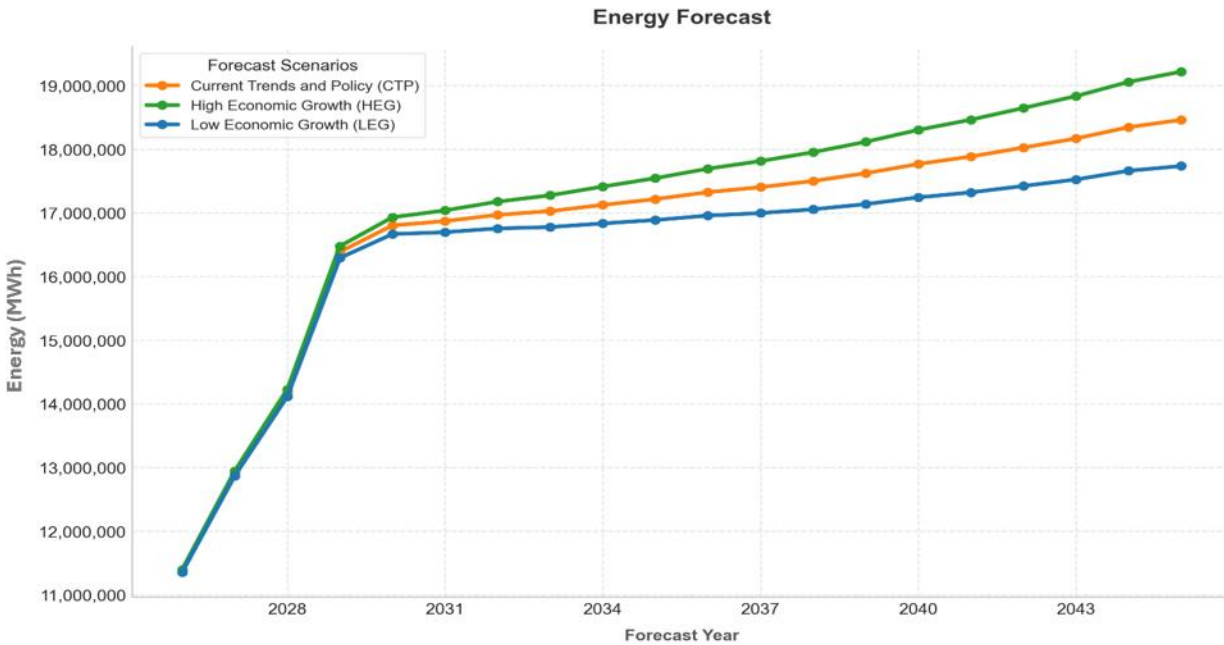
- Residential
- Commercial (Small Power + General Power + Large Power)
- Industrial (Large Service: Rates 5, 15, 30, 33, 35)
- Economic Development (not assigned to a specific rate class)
- Other (Irrigation, Water, and Lighting)

Below are the energy and demand forecasts that show the energy (GWh) forecasts for the whole system. Demand (MW). These forecasts are based on the best estimates that were described above with all the economic and weather forecasts.

12.1 Energy (GWh) forecasts

Energy (GWh) is expected to grow at 2.9% on average for the forecast horizon (2026 - 2045). Earlier in the forecast period energy grows faster than later due to industrial and economic development growth. This is the best estimate with CTP (Current Trends and Policies). Figure 12.1 shows CTP with HEG and LEG.

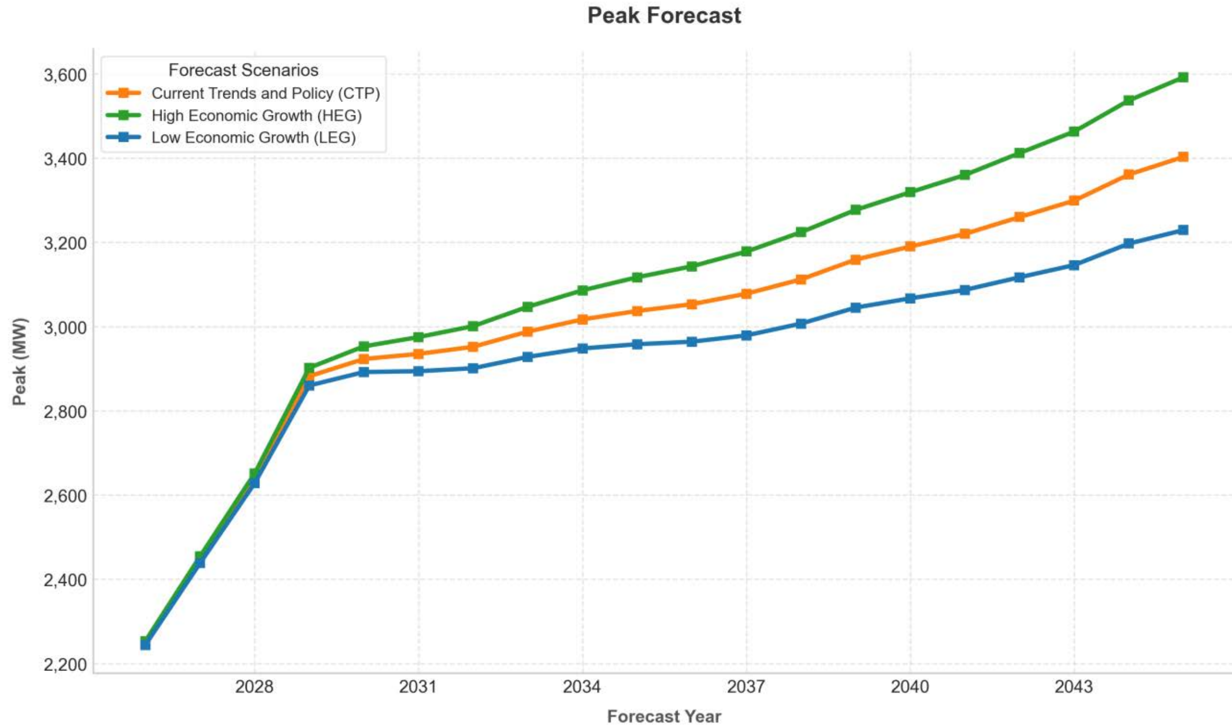
Figure 12.1: Energy Forecast (MWh)



12.2 Demand (MW) forecast

PNM's peak demand, which is approximately 2,117 MW in 2025, is expected to grow at an average rate of 2.24% per year over the 20-year IRP horizon. This forecast reflects current expectations for economic and demographic changes, economic development projects, behind-the-meter solar adoption, and electric vehicle adoption.

Figure 12.2: Demand (MW) forecast



APPENDIX H1: GLOSSARY OF TERMS AND ABBREVIATIONS

Term	Definition
AC	Alternating Current (solar: rated AC output)
ACEEE	American Council for an Energy-Efficient Economy
BTM	Behind the Meter — generation at customer premises
CDD	Cooling Degree Days
EPRI	Electric Power Research Institute
EV	Electric Vehicle
GHI	Global Horizontal Irradiation
GWh	Gigawatt-hours (1,000,000 kWh)
HDD	Heating Degree Days
IRP	Integrated Resource Plan

Term	Definition
kW / kWh	Kilowatt / Kilowatt-hour
LDV	Light Duty Vehicle
MW	Megawatt (1,000 kW)
NLR	National Laboratory of the Rockies
PNM	Public Service Company of New Mexico
PV	Photovoltaic (solar panels)
SAE	Statistically Adjusted End-use

Community Solar

The Community Solar Act, enacted by New Mexico's legislature in April 2021, requires PNM to interconnect 125 MW, plus tribal projects, of solar facilities to the distribution system across the utility serve area in Phase I of the program. Developers of community solar, known as Subscriber Organizations, are selected by the NMPRC program administrator and may sell subscriptions to utility customers anywhere in the utility's service area. The NMPRC has also set the Phase II capacity for PNM of an additional 185 MW, bringing the total for PNM to 310 MW. Phase II capacity selection will likely begin after the Rule 573 rulemaking process, scheduled to be completed by July 1, 2026.

Customers who subscribe to a community solar facility benefit from a credit on their electric bill from the utility. The utility receives the energy generated from the facility as well as the Renewable Energy Certificates (RECs). Per statute, at least 30% of community solar capacity is allocated to income-qualified subscribers or service organizations. PNM estimates that approximately 75,000 customers may eventually subscribe to community solar within the allocated Phase I and Phase II capacity.

Appendix H2: BTM Solar Forecasting Methodology

Technical Description

Integrated Resource Plan 2026

Load Forecasting — Distributed Energy Resources

June 2026

1. Overview

This document describes the methodology used to estimate behind-the-meter (BTM) solar photovoltaic (PV) capacity and generation, and its integration into the load forecasting framework for the IRP 2026. The approach combines scenario-based capacity projections, irradiance-driven production modeling, and load adjustment techniques to quantify the impact of distributed solar on utility sales.

The methodology consists of three primary components:

- Capacity Forecasting — scenario-based projections of annual BTM solar additions
- Solar Generation Modeling — irradiance-driven production functions with temporal allocation
- Integration with Load Forecasting — use vs. sales framework distinguishing end-use demand from utility-observed load

Together, these components provide a comprehensive, auditable framework for estimating the impact of distributed solar across the forecast horizon through 2045.

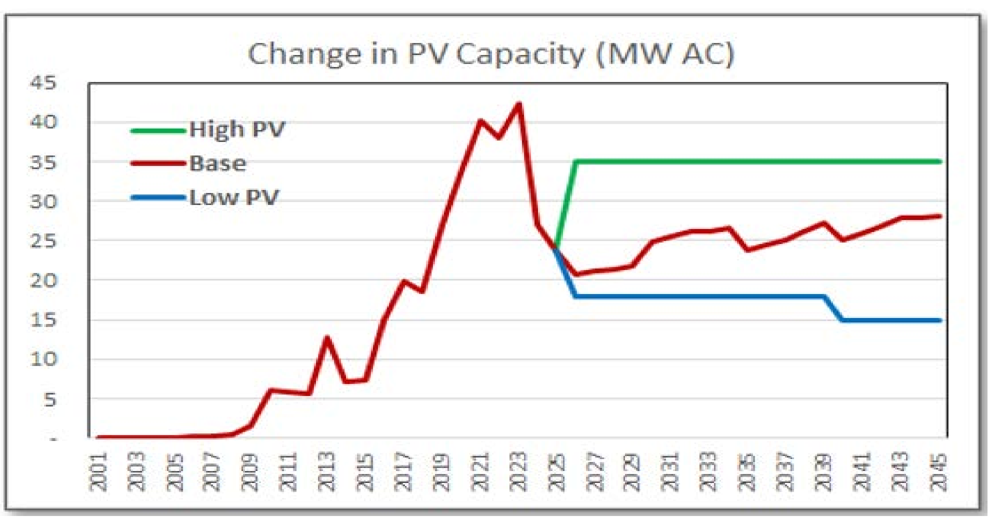
2. PV Capacity Forecast

2.1 Annual Capacity Additions

BTM PV adoption is modeled using three scenarios — High, Base, and Low — representing different assumptions regarding policy conditions, market adoption rates, and customer participation incentives.

The progression of annual capacity additions is illustrated in Figure 1 below.

Figure 1. Change in PV Capacity — Annual Additions by Scenario (MW AC)



As shown in Figure 1, historical additions exhibit considerable variability in the period prior to 2025, reflecting fluctuations in incentive structures and market conditions. Following the 2025 inflection point, annual additions stabilize into distinct scenario-defined trajectories:

- High Scenario: approximately 35 MW per year
- Base Scenario: approximately 25–30 MW per year
- Low Scenario: approximately 15–18 MW per year

The divergence across scenarios reflects uncertainty in long-term adoption drivers, including the anticipated policy changes beginning in 2025 and evolving customer economics for distributed generation.

2.2 Total Installed Capacity

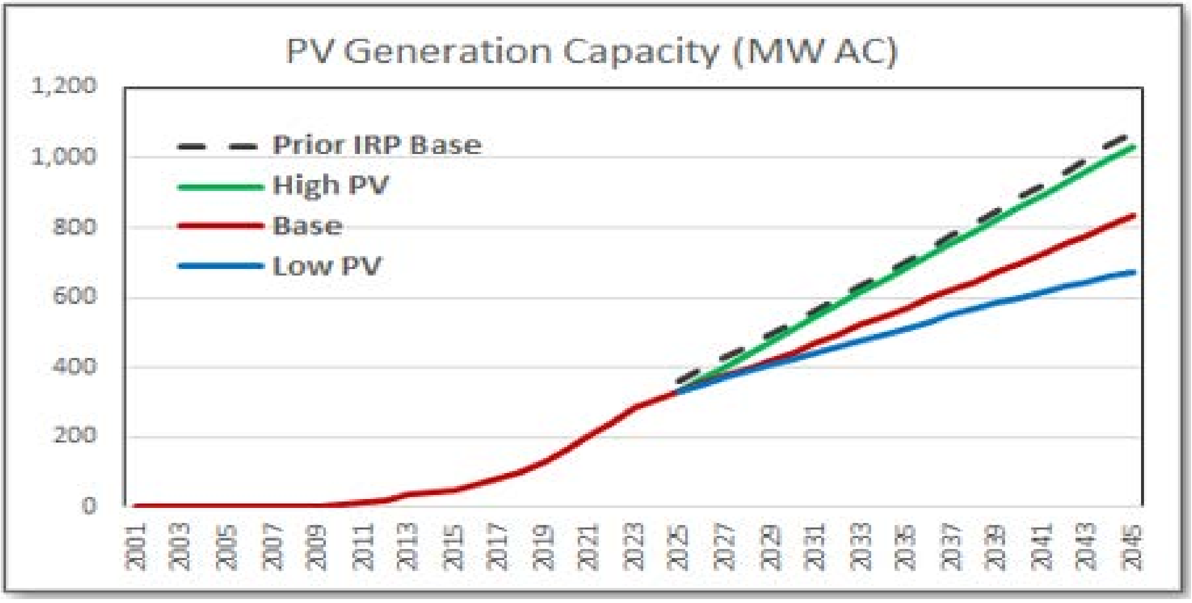
The base PV forecast has been reduced from the prior IRP, reflecting a slowdown in installations during 2025 and subsequent policy changes. PNM created high and low scenarios of the BTM capacity forecast based on real data in the system along with the National trend.

Table 1. BTM Solar Capacity Scenarios

Year	Base PV (MW)	High PV (MW)	Low PV (MW)
2025	332	332	332
2030	457	507	417
2035	582	682	502
2040	707	857	587
2045	835	1,033	675

Cumulative BTM PV capacity is derived by applying annual additions over the historical and forecast periods. The resulting trajectories are presented in Figure 2 below.

Figure 2. Total PV Generation Capacity by Scenario with Prior IRP Comparison (MW AC)



As illustrated in Figure 2, total BTM PV capacity increases materially through 2045 under all modeled scenarios. Key observations include:

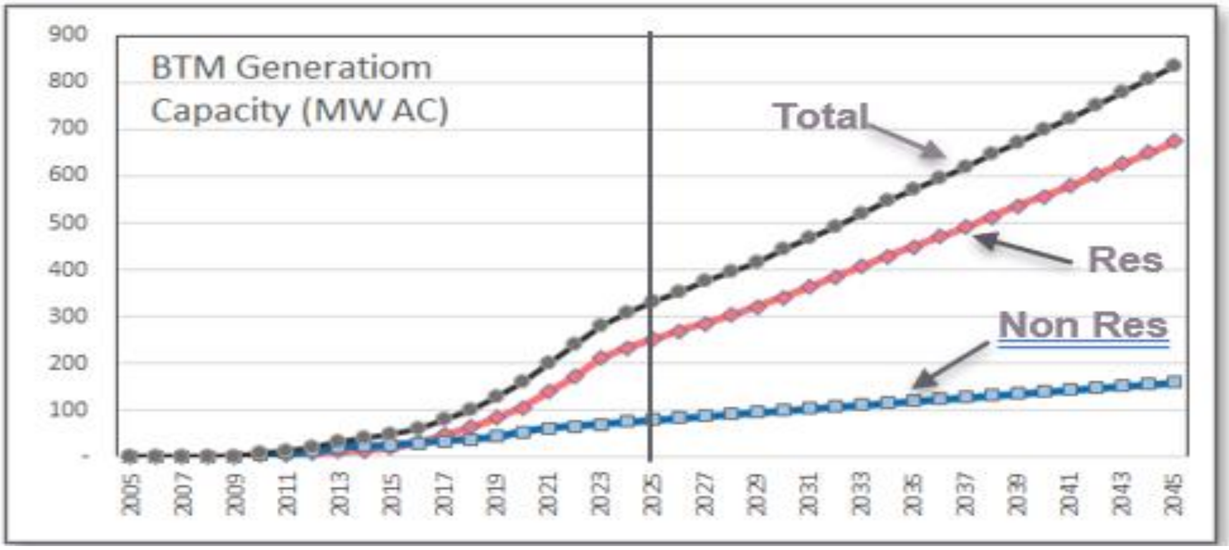
- The High scenario approaches the trajectory established by the prior IRP base case
- The updated Base scenario reflects a downward adjustment relative to prior planning expectations, attributable to expected near-term policy changes and market slowdown
- The Low scenario results in substantially lower long-term penetration relative to both the High scenario and prior IRP assumptions

This comparison to the prior IRP base case, shown as a dashed reference line in Figure 2, is important for explaining the directional change in forecast assumptions to IRP reviewers.

2.3 Customer Class Allocation

BTM PV capacity is disaggregated into residential and non-residential customer classes. The distribution of installed capacity by class is presented in Figure 3 below.

Figure 3. BTM Solar Capacity by Customer Class — Residential and Non-Residential (MW AC)



As shown in Figure 3, residential installations account for the substantial majority of total BTM capacity throughout the forecast period. Non-residential capacity grows more gradually and represents a comparatively modest share of the total installed base. This composition has important implications for load forecasting, as residential BTM solar contributes disproportionately to load masking during daytime hours.

3. PV Generation Modeling

3.1 Production Function

BTM solar generation is estimated using a normalized production function that relates daily output per unit of installed capacity to solar irradiance inputs:

$$Y = f(X)$$

Where:

- Y = Daily average generation (kWh per kW of installed capacity)
- X = Daily Global Horizontal Irradiation (GHI, kWh/m²/day)

Total energy generation is computed by scaling the normalized output by total installed capacity:

$$\text{Generation (GWh)} = \text{Capacity (kW)} \times \text{kWh/kW} \div 1{,}000{,}000$$

This production function is calibrated using historical generation data from metered BTM systems and corresponding GHI observations. The relationship captures the primary weather-driven driver of PV output while maintaining a simplified, interpretable structure appropriate for long-range planning.

Figure 4 shows 2018 daily GHI as an example. The hourly GHI information on a typical clear day and on a cloudy day is shown in Figure 5.

Figure 4. 2018 Daily GHI Sum

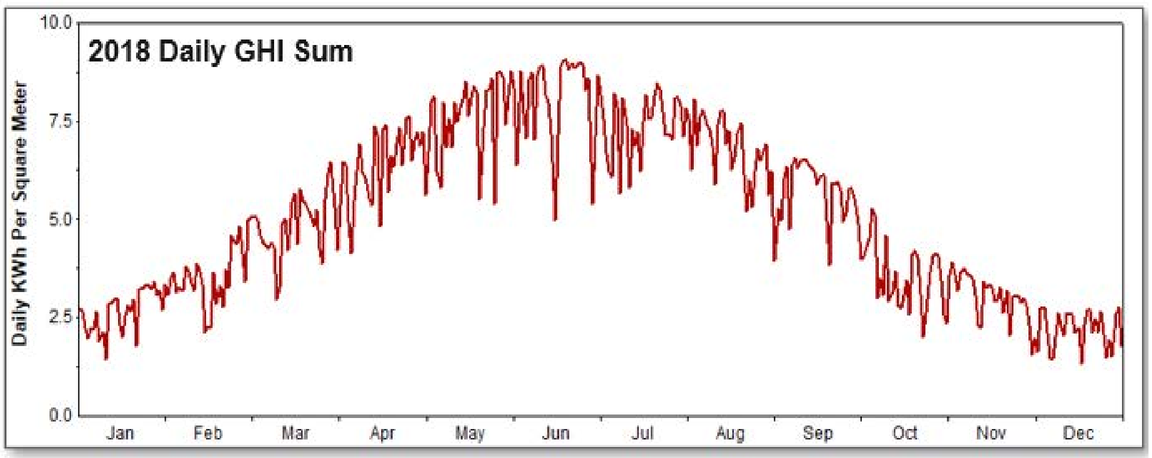
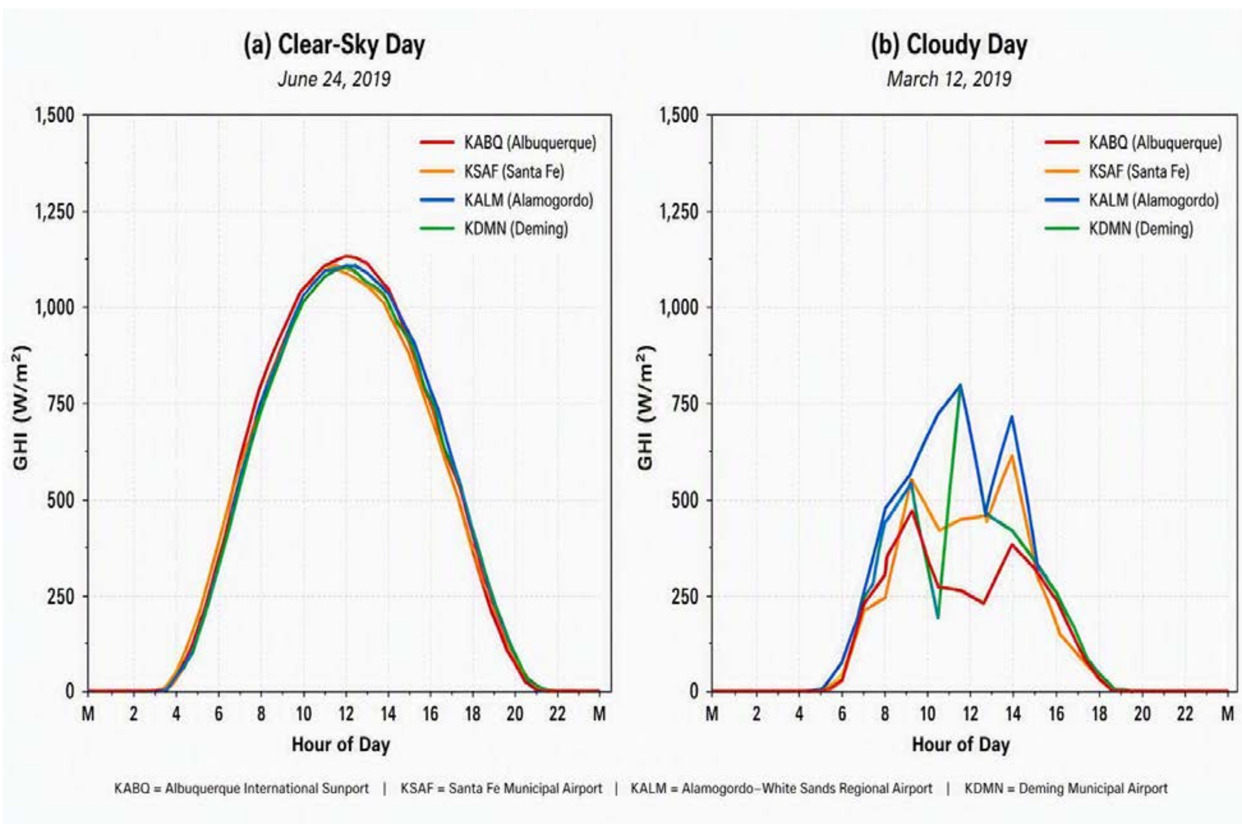


Figure 5. Hourly GHI on a clear day and cloudy day for different weather stations



3.2 Temporal Allocation

Daily generation estimates are allocated to hourly values using representative hourly irradiance profiles, derived from the AccuWeather solar resource dataset. This disaggregation ensures:

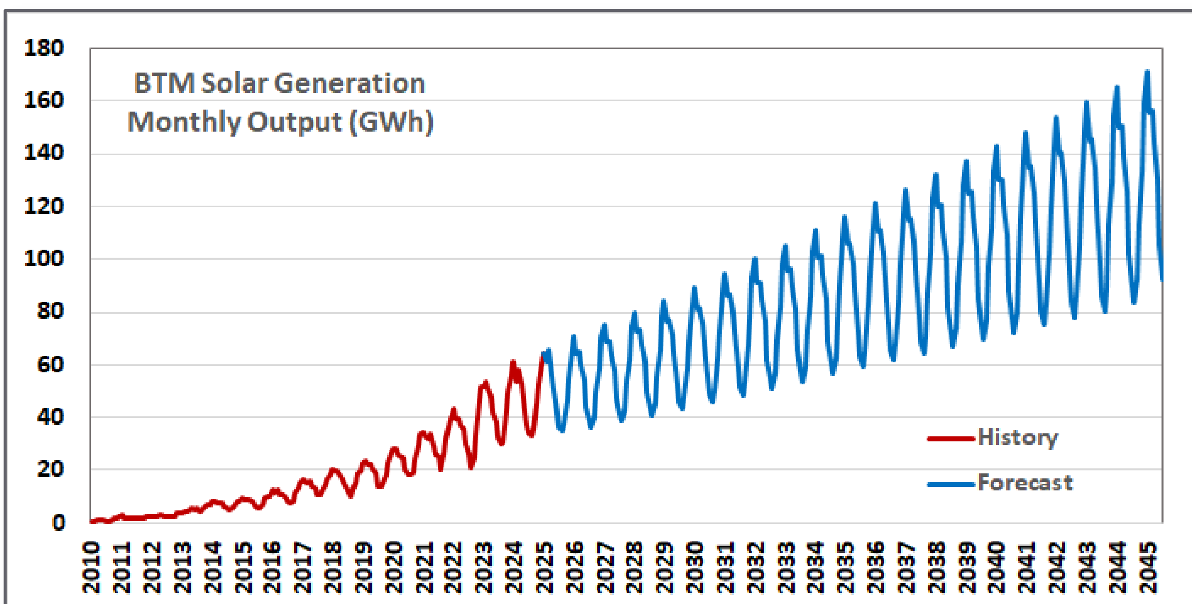
- Alignment with hourly load shapes used in the broader load forecasting model
- Realistic intraday solar production patterns consistent with observed PV system behavior
- Proper representation of morning ramp-up and evening ramp-down in net load profiles

The temporal allocation step is critical for accurately characterizing the peak-offset effect of BTM solar on utility-supplied load, particularly during afternoon demand periods.

3.3 Seasonal Generation Patterns

The resulting generation forecasts exhibit strong seasonal variability, driven by both solar irradiance availability and installed capacity growth. Monthly BTM solar generation — both historical and forecast — is presented in Figure 6 below.

Figure 6. BTM Solar Monthly Generation — Historical and Forecast with Seasonal Variability (GWh)



As shown in Figure 6, monthly generation follows a recurring seasonal cycle throughout the full time series. The figure illustrates:

- A clear transition from observed historical generation to modeled forecast values, with the breakpoint at approximately 2025

- Consistent peak production during high-irradiance periods and reduced output during winter months
- Increasing amplitude of seasonal variation over time, reflecting growth in installed capacity as shown in

This seasonal structure is consistent with expected solar generation profiles for the service territory and reinforces the importance of irradiance-based shaping within the production model. The interaction of capacity growth and seasonal irradiance patterns drives increasing load masking during summer months over the forecast horizon.

4. Integration with Load Forecasting

4.1 Use vs. Sales Framework

The BTM solar methodology is integrated into the load forecasting process through a use-versus-sales construct. Under this framework, total customer energy requirements (end-use load) are estimated independently of distributed generation, and utility sales are derived by netting out BTM solar generation:

> *Utility Sales = End-Use Load − BTM PV Generation*

This separation ensures that the forecast accurately represents the distinction between true customer demand and the portion of that demand served by utility-supplied energy. It also facilitates transparent scenario analysis, as changes in the PV adoption scenario flow directly and traceably into changes in projected utility sales.

4.2 Impact of BTM Solar

BTM solar reduces utility-supplied load through a load masking effect, where customer self-generation offsets a portion of observable system load. This effect has both temporal and magnitude dimensions:

- Temporal: load masking is concentrated during daytime hours and peaks during summer months, consistent with the seasonal patterns shown in Figure 6
- Magnitude: the cumulative impact grows substantially over the forecast horizon as total installed capacity increases
- Customer class: because residential installations represent the dominant share of total BTM capacity, the masking effect is most pronounced in the residential segment of the load forecast

The combined effect of rising capacity and seasonal generation patterns means that utility-observable load increasingly diverges from true end-use demand over time. Properly accounting for this divergence is essential for accurate resource adequacy planning and for avoiding the systematic underestimation of peak demand that can result from relying solely on observed load data.

Figure 7 shows monthly residential energy sources with PNM sales and BTM generation, and Figure 8 and Figure 9 show a typical low day and peak day with BTM and PNM sales.

Figure 7. Monthly residential energy sources with PNM sales and BTM generation

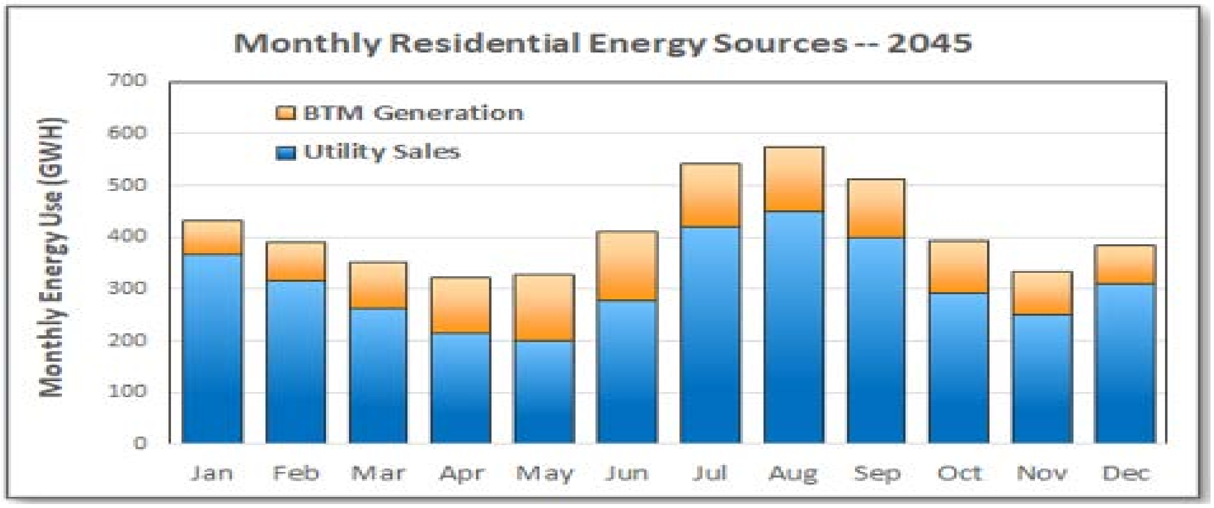


Figure 8. Residential energy sources in the low load day (2045)

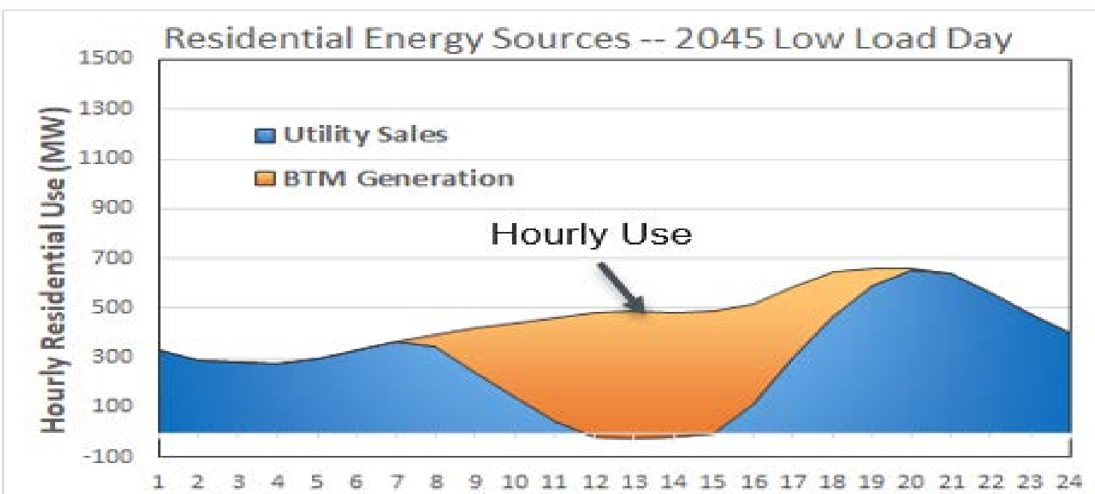
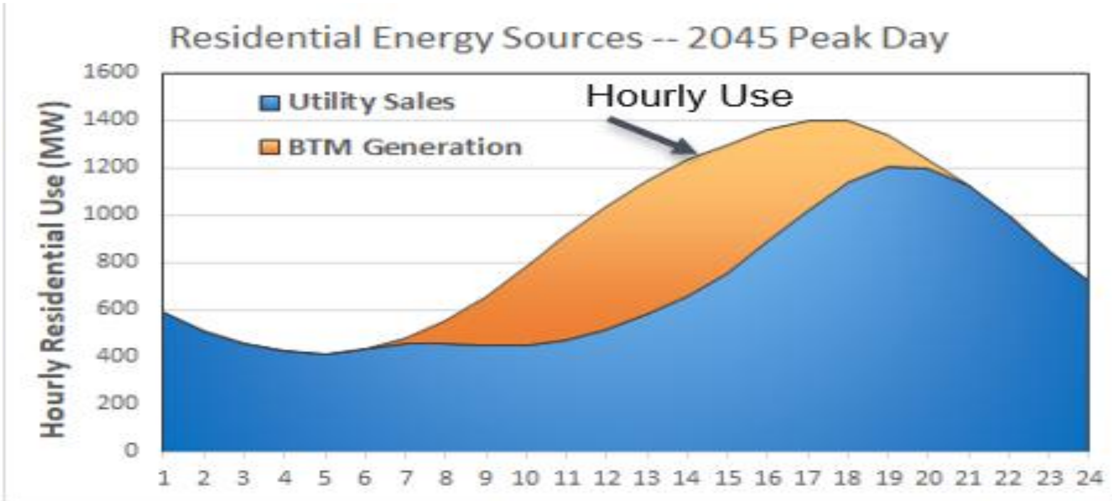


Figure 9. Residential energy sources in the peak day (2045)



5. Key Observations

The following summary observations are drawn from the methodology and supporting figures:

Observation	Detail
Scenario Sensitivity	Capacity outcomes vary significantly across adoption. The spread between High and Low scenarios is material to resource planning outcomes.
Residential Dominance	Residential PV drives the majority of BTM growth and associated load masking impacts. Non-residential contribution is comparatively modest throughout the forecast period.
Seasonality	Solar generation exhibits strong and increasing seasonal behavior over the forecast horizon. Summer peak periods experience the greatest load offset from BTM generation.
Sales Impact	BTM generation materially reduces utility sales relative to end-use load, with the gap widening over time. This underscores the importance of the use-versus-sales separation in the load forecast.
Policy Sensitivity	The 2025 inflection point is prominent in both Figures 1 and 2, reflecting the anticipated policy change. Scenario design explicitly captures uncertainty in the post-2025 policy environment.

Appendix H3: Comparison Between ICF's EE savings and Itron's EE savings

Executive Summary

This document outlines key methodological and goal differences between the Energy Efficiency (EE) Plan Forecast (Program Potential) and Itron's EE Forecast embedded in the load forecast that is used for the Integrated Resource Plan (IRP). The EE Plan Forecast focuses solely on utility program impacts, while the Itron's EE Forecast (Load Forecast) incorporates broader efficiency gains from appliance standards and technological improvements. Utilities use load forecast for the long-term resource planning while the EE plan forecast is used to encourage the customers to save energy beyond codes and standards that are upcoming. PNM understands the EE importance in the resource plan because it may enable utilities such as PNM to avoid major capital investments for new power plants and transmission upgrades.

Overview

The EE Plan forecast does not align with the numbers for EE that are in the load forecast for IRP. The EE in load forecast are savings due to appliance standards and ongoing technology improvements. It estimates how Codes & Standards (C&S), technology and utility programs impact energy use by specific types of equipment (known as end-uses). The EE plan forecast, on the other hand, specifically target for more savings going forward by implementing specific EE programs. This is achieved by encouraging customers to replace an older appliance for a newer one that could be beyond C&S that are mandated by federal and state policy.

EE plan forecast may yield higher efficiency gain for a specific end-use because there might be more incentive doing so for a customer. This happens when a customer chooses to replace an appliance or equipment that is beyond the standard C&S already in place for that specific appliance or equipment.

EE plan forecast Methodology

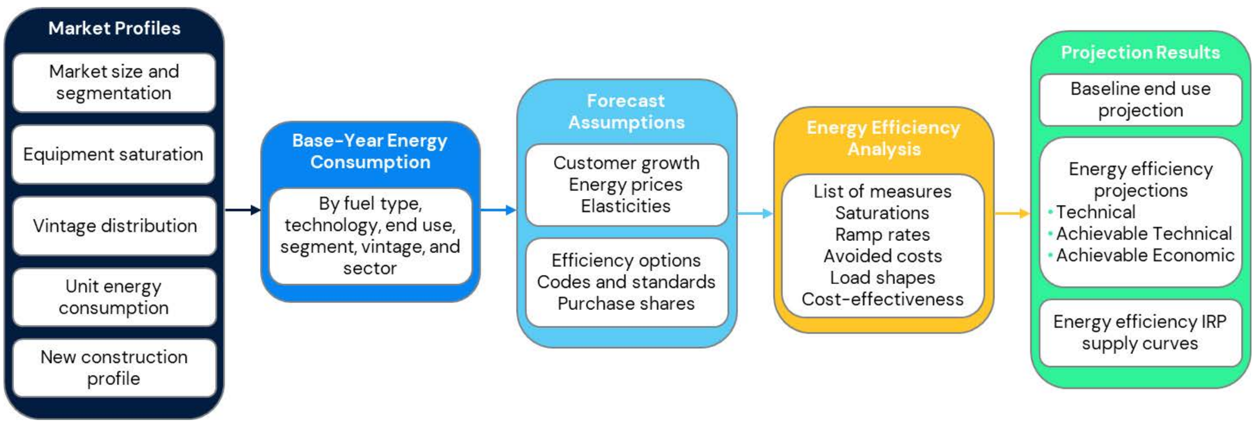
EE plan forecast is put together by a potential study which is done by estimating three levels of potential. They are –

- **Technical potential:** Maximum possible savings if all current equipment were replaced with the most efficient technology available, regardless of cost.
- **Economic potential:** A subset of technical potential that is cost-effective from a specific perspective (e.g., utility, societal, or customer).
- **Achievable potential (Or program potential):** A subset of economic potential that is a realistic estimate of what can be attained through actual program implementation, considering market barriers and customer adoption rates.

The purpose of this EE plan forecast might be to identify and quantify EE as a viable, cost-effective resource option that can offset the need for new power plants or transmission infrastructure in conjunction to saving energy.

PNM's EE plan was developed by using the help of ICF, a consulting company that specializes potential study. ICF used their tool called "VISIONLoadMAP" that analyzes market profiles, base year energy consumption, forecast assumptions, energy efficiency analysis to provide projections results. These projection results are then utilized to plan for PNM's EE plan forecast. Figure 1-1 shows a visual of the tool,

Figure 1-1: VisionLoadMAP Analysis Framework



Baseline Projection

ICF developed the baseline projection of annual electricity use for 2025 through 2045 by customer segment and end use without new utility conservation programs. The baseline projection is the foundation for the analysis of savings in future conservation cases and scenarios as well as the metric that potential is measured against. ICF developed the reference baseline in alignment with PNM's long-term demand forecast, but with some modifications to account for known future conditions.

Inputs to the baseline projection include:

- Customer growth projections
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards

It should also be noted that this reference baseline does not include the following:

- Future DSM program impacts
- Climate change projections – to remain consistent with PNM's official load forecast, these projections assume normal weather conditions

- Does not include the explicit electrification of fossil fuels

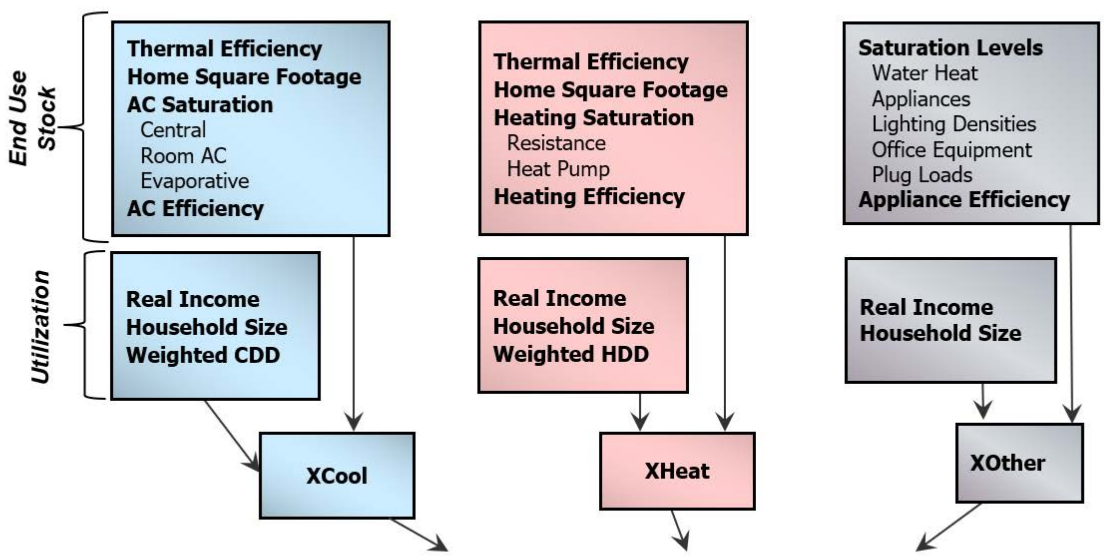
EE in load forecast Methodology

PNM’s load forecast is a projection of future electricity consumption and peak demand. It inherently accounts for “naturally occurring” EE improvements (Federal appliance efficiency standards that are already market practice). Naturally occurring EE are embedded in historical consumption trends used for the load forecast.

Load forecast is used to estimate the amount of energy supply required to meet future demand, assuming current market and regulatory conditions continue.

Itron’s SAE (Statistically Adjusted End-Use) model accounts for the efficiency gain based on the mandates. PNM uses Energy Information (EIA) data to incorporate the future C&S that will be implemented in the market. Figure 1-2 shows the SAE framework. “End-Use stock” in the figure below shows the efficiency gains that are considered in the framework to account for EE.

Figure 1-2: Statistically Adjusted End-Use (SAE) Framework



$$\mathrm{Sales}_m + \mathrm{PVGen}_m = a + b_c \times \mathrm{XCool}_m + b_h \times \mathrm{XHeat}_m + b_o \times \mathrm{XOther}_m + e_m$$

PNM’s load forecast captures the EE projection based on this SAE framework for residential and commercial customers. PNM construct customer load by adding the Distributed Energy Resources (DER) back to the sales for each sector to build true load for each sector.

EIA produces projections for different appliances and equipment for efficiencies, saturations, stock turnovers for these sectors every year. These data are available publicly and used for the load forecast that PNM develops. PNM constructs energy forecast by forecasting customer growth for each sector (Residential, Commercial, Industrial) and by forecasting average energy use per customer for each sector. Customer growth projection is then multiplied by the average use per customer projection to get each sector's energy consumption. This consumption is then reduced by the Distributed Energy Resources (DER) projection to forecast the energy need for that sector.

This energy forecast is then used with the load research data to develop peak demand forecast. Peak demand forecast is also adjusted by the DER or any future loads such as emerging technologies (EV, data center etc.).

The Key Distinction

The key distinction between an EE plan forecast and EE in load forecast lies in the baseline.

- PNM's load forecast represents a future where only existing market-driven EE occurs with continued utility programs. These are the EE that are going to happen based on federal and state mandates and customer adoption depending on their choices. Utility programs in the forecast captured by taking the historical trends and assumed every program has a sunset. Econometric model captures this trend due to the use of historical data. This historical trend continues with the regression by the driver variable (Independent variable).
- The EE plan forecast provides future achievable EE in energy consumption which is yielded by being innovative and by implementing programs with the new technology and utility incentives.
- EE program plan is updated every year by assessing program effectiveness and annual savings. This is an impact driven model which is forward-looking and is designed for any potential extra savings.

It is worthy to mention here that baseline determination is very critical to estimate EE plan forecast from the potential study. Essentially the baseline freezes the C&S impacts for future and start the EE plan impact without the C&S which is naturally occurring savings. On the next page on Table 1 shows the EE savings from the load forecast Vs EE plan forecast in MWh from 2026 - 2045

Table 1: Total EE Incremental Forecast (Itron) vs EE Program Potential (ICF Potential Study) MWh (2026–2045)

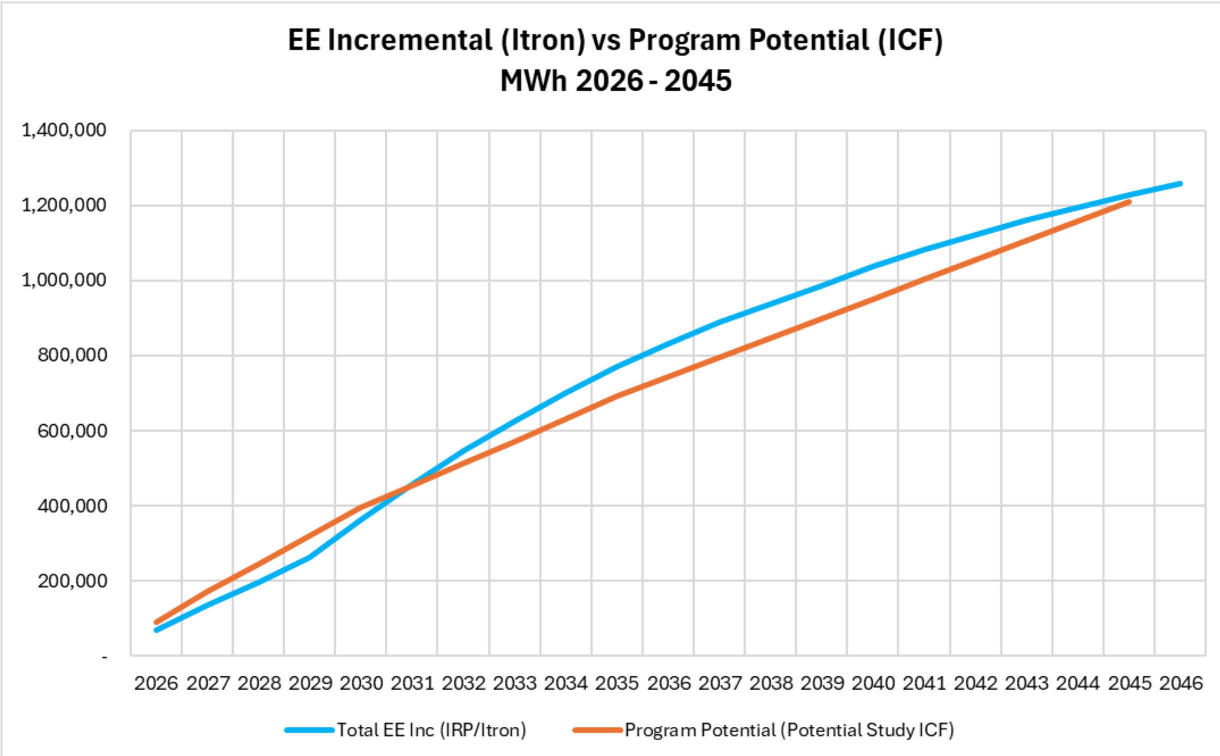
Year	Total EE Incremental (Itron)	Program Potential (ICF)
2026	69,426	89,000
2027	135,270	171,000

2028	196,982	245,333
2029	260,783	319,667
2030	360,660	394,000
2031	456,708	453,400
2032	547,501	512,800
2033	626,261	572,200
2034	700,968	631,600
2035	769,494	691,000
2036	831,806	743,000
2037	887,602	795,000
2038	938,835	847,000
2039	985,545	899,000
2040	1,036,276	951,000
2041	1,081,674	1,003,000
2042	1,123,108	1,055,000
2043	1,160,562	1,107,000
2044	1,195,342	1,159,000
2045	1,227,325	1,211,000

Figure 1-3 shows the graphical representation of Itron load forecast and EE plan forecast. It is noticeable that PNM’s load forecast shows more EE savings in the long run than EE plan forecast overall. Load forecasts start off with slower savings but catches up and grows faster. This is because the EE plan forecast is aggressive at the start and slows down later due each program life span.

In essence, this is better for planning for resources because PNM is capturing most of the savings through the load forecast which enables PNM to plan for future resources better.

Figure 1-3: EE incremental (Itron Load Forecast) Vs Program Potential (EE plan forecast)



Summary

Energy efficiency (EE) is one of the fundamental aspects that PNM takes into considerations when planning for future resources. In the integrated resource plan (IRP) EE is, even though, considered from the load forecast, EE plan forecast is taken into equation. If EE plan forecast yields greater savings from a specific program, the savings impact our resource plan. This is done by comparing the underlying EE numbers from the load forecasts and the specific program savings that may not be captured in the load forecasts due to the nature of forecasting framework, such as building shell improvement for better heating or cooling efficiency. This scenario is rare but can happen.

APPENDIX H4: ECONOMIC DEVELOPMENT SCENARIO SUMMARY

The economic development scenario combines industrial growth and new large customer additions to define load growth uncertainty in the IRP. In the reference case, approximately 11 new customers are added, resulting in about 400 MW of incremental load, with additions completed by mid-2033. The chart shows a distinct upward step-change in energy consumption around the late 2020s and early 2030s, reflecting the timing of these additions. The high case tracks above the reference with additional growth of approximately +65 MW, while the low case remains below the reference with a reduction of approximately -110 MW. Overall, the chart highlights that economic development drives discrete increases in load, creating divergence across scenarios and directly influencing resource planning, capacity needs, and timing of future investments.

Figure 1. Economic Development Scenario

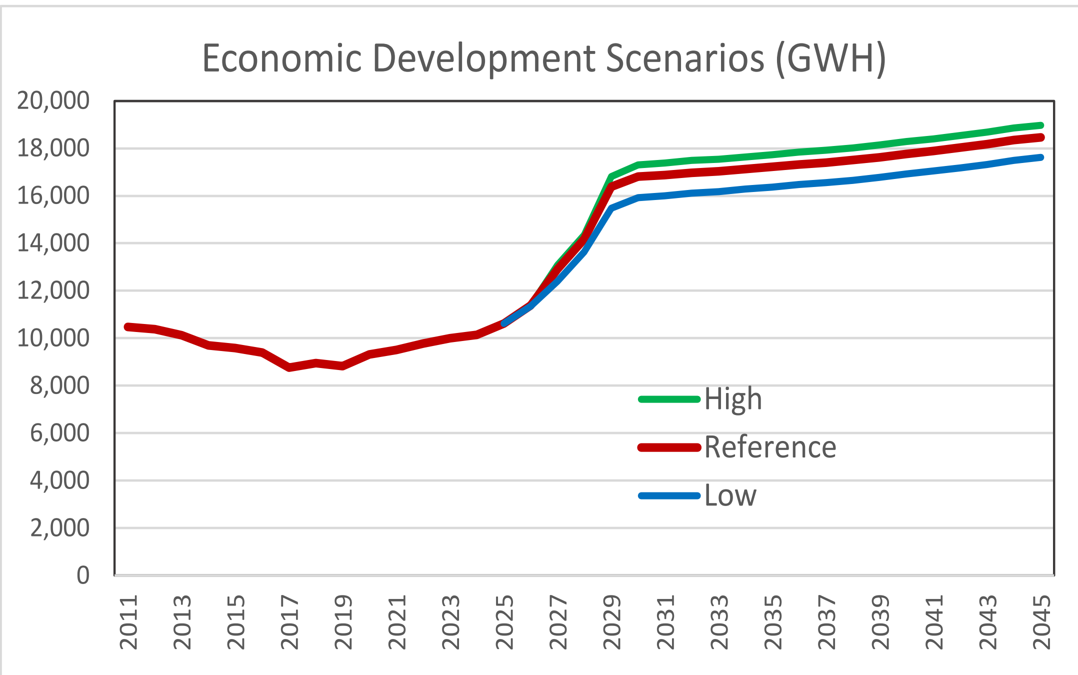


Table 1. Economic Development Scenario

Year	Annual System Energy (GWh)				Annual Peak (MW)			
	Base	Low Indust	High Econ Dev	Low Econ Dev	Base	Low Indust	High Econ Dev	Low Econ Dev
2025	10,615	10,554	10,615	10,612	2,130	2,127	2,130	2,130
2030	16,803	15,017	17,297	15,922	2,924	2,720	2,981	2,812
2035	17,217	15,885	17,732	16,373	3,038	2,885	3,098	2,936
2040	17,768	16,444	18,285	16,922	3,191	3,038	3,250	3,090
2045	18,461	17,130	18,977	17,618	3,404	3,251	3,463	3,303

APPENDIX I: GAS, CO_2, MARKET PRICE FORECAST

The commodity price forecasts for natural gas, carbon, and wholesale electricity markets used in the IRP were developed by Siemens. Forecasts for carbon, natural gas, and wholesale electricity prices are summarized in the tables below.

Table I-1. Forecast trajectories for natural gas, carbon, and wholesale market prices assumed in IRP

Natural Gas Price (Nominal $/MMBtu)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Henry Hub - Low	$3.20	$2.95	$2.26	$2.07	$2.15	$2.00	$2.19	$2.49	$2.52	$2.89	$2.93	$3.31	$3.55	$3.88	$4.17	$4.64	$5.07	$5.51	$5.47	$5.84
Henry Hub - Base	$4.32	$4.13	$4.07	$4.07	$4.11	$4.22	$4.33	$4.60	$4.94	$5.22	$5.62	$5.94	$6.33	$6.74	$7.31	$7.91	$8.62	$9.31	$9.90	$10.57
Henry Hub - High	$4.65	$5.74	$5.82	$5.60	$5.80	$5.83	$5.97	$6.64	$7.20	$7.64	$8.15	$8.66	$9.36	$10.06	$10.79	$11.76	$12.79	$13.73	$14.59	$15.52
San Juan - Low	$2.56	$2.55	$2.06	$1.82	$1.87	$1.69	$1.89	$2.20	$2.19	$2.60	$2.63	$3.02	$3.26	$3.56	$3.84	$4.29	$4.70	$5.11	$5.04	$5.40
San Juan - Base	$3.62	$3.77	$3.78	$3.84	$3.88	$3.98	$4.07	$4.33	$4.65	$4.92	$5.29	$5.59	$5.95	$6.35	$6.87	$7.43	$8.09	$8.75	$9.31	$9.93
San Juan - High	$3.88	$5.34	$5.44	$5.35	$5.61	$5.63	$5.75	$6.40	$6.94	$7.34	$7.80	$8.25	$8.90	$9.57	$10.27	$11.15	$12.10	$13.03	$13.79	$14.64
Permian - Low	$1.50	$1.93	$1.45	$1.33	$1.35	$1.17	$1.32	$1.55	$1.52	$1.85	$1.84	$2.16	$2.34	$2.57	$2.77	$3.13	$3.45	$3.77	$3.60	$3.86
Permian - Base	$2.28	$3.11	$2.99	$3.14	$3.17	$3.26	$3.33	$3.55	$3.81	$4.02	$4.33	$4.58	$4.87	$5.20	$5.63	$6.09	$6.63	$7.17	$7.62	$8.13
Permian - High	$2.45	$4.65	$4.46	$4.51	$4.74	$4.76	$4.88	$5.47	$5.94	$6.29	$6.68	$7.08	$7.65	$8.23	$8.81	$9.58	$10.38	$11.14	$11.86	$12.59

Natural gas prices reported reflect annual average of monthly basin projections. Monthly delivered prices are modeled in EnCompass.

Hydrogen Price (Nominal $/MMBtu)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21.36

CO2 Price (Nominal $/short ton)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Base	-	-	-	-	$12.82	$14.22	$15.78	$17.50	$19.41	$21.53	$23.89	$26.50	$29.40	$32.61	$36.17	$40.13	$44.51	$49.38	$54.78	$60.77
High	$106.5	$111.2	$116.15	$121.26	$126.57	$132.09	$137.82	$143.79	$149.98	$156.42	$163.68	$171.23	$179.09	$187.27	$195.77	$203.96	$212.46	$221.29	$230.46	$239.98
Low	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Wholesale Market Price (Nominal $/MWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Four Corners - Low	$67.12	$62.08	$53.48	$52.05	$56.04	$59.85	$58.43	$62.70	$66.82	$66.06	$61.38	$59.46	$59.22	$62.03	$59.79	$57.16	$52.51	$54.81	$57.35	$59.84
Four Corners - Base	$64.79	$63.78	$70.20	$72.48	$77.81	$88.06	$87.78	$91.43	$94.03	$94.61	$93.91	$94.41	$93.35	$93.79	$86.30	$80.94	$81.89	$84.28	$85.81	$88.89
Four Corners - High	$117.5	$110.9	$106.05	$104.20	$107.93	$114.80	$115.67	$110.51	$114.22	$114.26	$118.07	$117.41	$119.08	$114.27	$111.67	$100.33	$88.66	$80.88	$84.00	$83.73
Palo Verde - Low	$66.16	$64.71	$61.20	$61.36	$69.69	$77.19	$77.45	$81.95	$86.45	$87.05	$82.57	$80.08	$77.26	$79.71	$76.73	$74.53	$67.76	$69.36	$71.11	$74.96
Palo Verde - Base	$63.28	$65.70	$72.71	$76.45	$86.32	$99.50	$98.48	$101.48	$104.17	$107.04	$106.41	$106.78	$105.70	$108.22	$104.01	$99.30	$100.24	$103.31	$104.49	$111.46
Palo Verde - High	$109.48	$108.5	$104.07	$105.20	$114.06	$124.82	$128.43	$129.05	$136.82	$139.16	$143.64	$144.30	$141.48	$137.31	$134.92	$120.31	$108.45	$102.62	$108.14	$111.55
SPP South - Low	$28.23	$30.02	$31.25	$33.75	$36.56	$36.96	$35.58	$34.10	$34.56	$35.53	$35.27	$35.69	$35.26	$36.67	$36.92	$39.25	$41.10	$45.22	$48.44	$51.57
SPP South - Base	$27.59	$30.65	$35.88	$39.93	$44.75	$47.11	$47.60	$46.10	$50.04	$53.05	$53.94	$55.95	$55.62	$57.96	$58.84	$62.27	$65.83	$69.96	$74.33	$80.36
SPP South - High	$92.15	$97.83	$107.84	$118.60	$128.98	$135.05	$138.52	$140.91	$148.87	$156.20	$162.64	$166.89	$169.64	$175.30	$182.82	$187.24	$193.88	$204.40	$213.88	$227.29

Wholesale market prices reported reflect annual average projections. Hourly electricity prices are modeled in EnCompass.

Appendix J: PNM Natural Gas Volatility Study

This appendix provides the PNM Natural Gas Volatility Study.

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Public Service of New Mexico **CONFIDENTIAL**

Natural Gas Price Volatility Study

July 2nd, 2026

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Executive Summary

Fuel price volatility analysis and its impact on the cost to produce electricity is a critical component of an integrated resource plan. Price volatility stems from a real or perceived supply – demand imbalance caused by disruptions to the delivery network, extreme weather events, geopolitical issues and other factors. Rather than relying on a single forward curve to model future fuel prices it is critical to evaluate a variety of scenarios such that potential price changes are factored into the resource plan creating a more robust analysis.

Siemens used a two-part approach consisting of a qualitative assessment of factors that could influence the regional gas market and a quantitative assessment of the impact of price volatility on PNM’s gas requirements. The qualitative analysis was completed to assess the potential for fundamental shifts in energy price behavior due to changes in the underlying market structure. The study considered the potential commodity and basis pricing impacts from the following factors:

- Gas production and supply
- Pipeline capacity and infrastructure changes
- Liquified Natural Gas (LNG) exports
- Weather
- Inflation

The quantitative assessment was split into a long-term market simulation to create a series of future potential price paths. Those price paths were then tested against the forecasted gas supply requirement to estimate the potential variance in annual gas expense. Due to the long-dated nature of the simulation, the impact of short duration price spikes is muted. To account for this, Siemens used a historical price analysis that identified the magnitude, duration, frequency and financial impact of short-term basis price disruptions and the associated impact on gas load.

Energy markets are dynamic and constantly evolving with the shifting and conflicting priorities of low cost, reliability, and sustainability. Our analysis found that while there will be many changes in the desert Southwest gas markets in the next 20 years, we do not believe the net impact will significantly alter the regional market structure and therefore historical prices can be used to simulate future prices. Basis price spikes will continue to occur; however, they will be short duration, and tools exist to mitigate the impact. Lastly, long-dated market simulation indicates that price volatility will continue to exhibit similar patterns with annual cost variances in the $0.14 to $1.09/MMBtu range. This is a meaningful number however, similar to basis risk, the impact of long dated volatility on a rolling 2 – 5-year horizon can be effectively, and cost efficiently reduced to a tolerable level thereby reducing impacts to rate payers.

Fundamental considerations

Background and analysis inputs

PNM, formally known as Public Service Company of New Mexico, is the largest electric utility in the state of New Mexico, serving approximately 540,000 customers across a service territory that includes Albuquerque, Santa Fe, and surrounding communities in central and northern New Mexico. Founded in 1917, PNM has been a cornerstone of the state's energy infrastructure for over a century. The utility operates as a regulated investor-owned utility under the jurisdiction of the New Mexico Public Regulation Commission and is a subsidiary of PNM Resources, which also owns Texas-based utility Texas-New Mexico Power (TNMP).

PNM's generation portfolio has historically included a mix of coal, natural gas, nuclear, and renewable resources. The utility was a significant participant in the San Juan Generating Station, a large coal-fired power plant near Farmington, New Mexico, which was retired in 2022 as part of the state's broader energy transition efforts driven by the Energy Transition Act of 2019. PNM has been actively replacing retired coal capacity with solar, wind, and battery storage projects to meet the ETA targets. PNM continues to navigate the challenges of grid modernization, integrating distributed energy resources, managing wildfire risk, and maintaining reliability while transitioning to a cleaner energy portfolio in one of the sunniest and most wind-rich states in the country.

PNM’s 2026 IRP will be filed in September 2026 and as part of that process PNM agreed to perform a natural gas volatility study from the comments provided in the 2023 IRP process. For this 2026 IRP, PNM examined three planning cases, High Economic Growth (HEG), Low Economic Growth and the Current Trends and Policy (CTP) reference case.

PNM provided forecasted gas load data that was extracted from the CTP reference case. Graphical representation of that data is found in Figure One on page 7.

For the purpose of this analysis, Siemens evaluated the cost variability stemming from the generation profile and associated gas load as shown in the charts below.

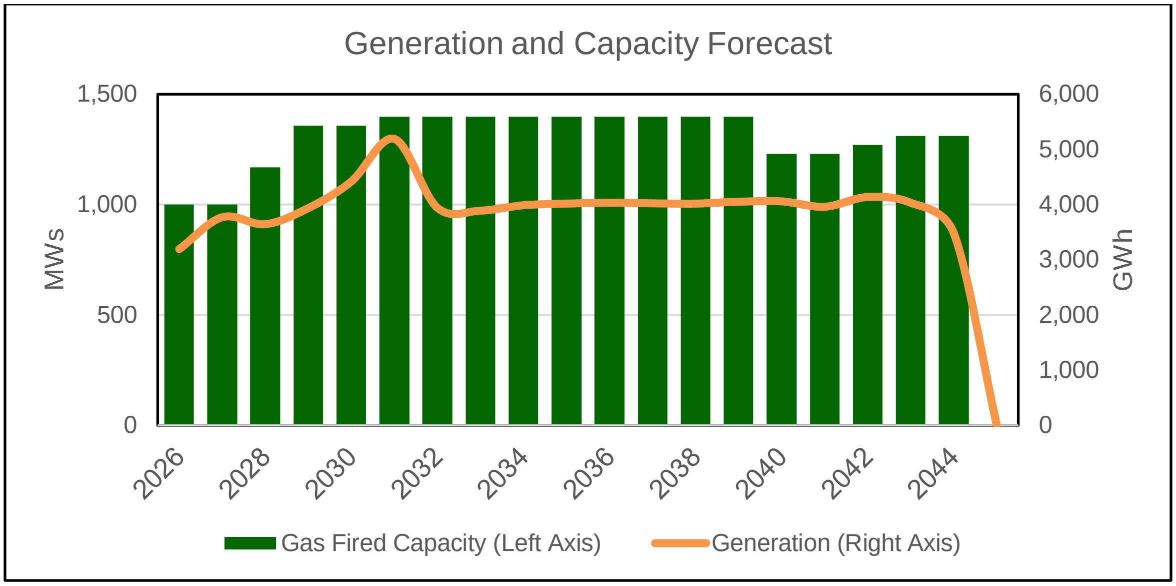

Figure 1 Generation and Capacity Forecast

(Capacity is reported in MWs, annual generation is in GWh)

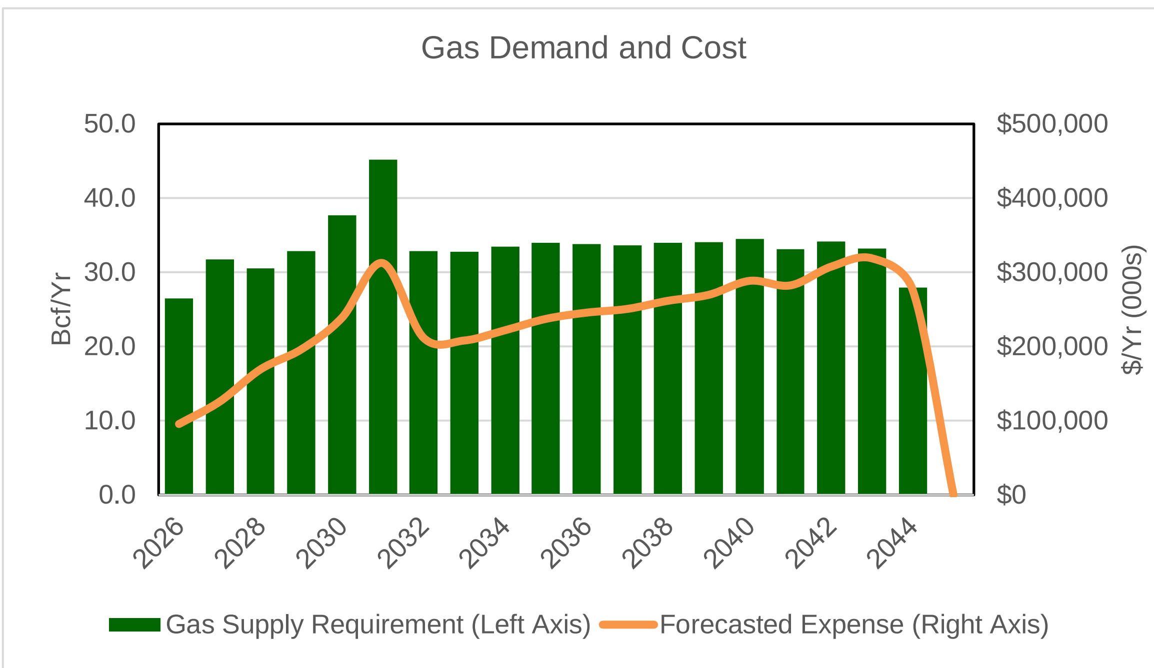

Figure 2 Gas Demand and Cost

The above volumes and associated costs were tested for sensitivity to market volatility using 3 years of historical data and then bifurcating NYMEX Henry Hub risk from basis risk into four different basis locations. PNM purchases the majority of its gas based on the El Paso San Juan or Keystone Pool indices however, for the sake of thoroughness Siemens evaluated several adjacent markets and then tested for correlation to confirm the impact of basis price spikes in adjacent markets on prices for PNM. Those results are presented in the conclusions section of the quantitative analysis results.

The US natural gas market is very dynamic and rapidly evolving. The impacts of fracking, changes to the IRA, new pipeline builds, increased LNG, data center growth and numerous other factors will move the market in different directions as those competing factors try to reach equilibrium. Many of the assumptions used in this analysis are based on years of experience in the market and represent the best estimate of the future direction of price and volatility.

Domestic supply and production analysis

Natural gas production in the western United States is expected to continue growing over the next several years, driven by both legacy Rockies output and strong gains in associated gas from oil plays such as the Permian in west Texas and southeast New Mexico. Federal forecasts indicate U.S. marketed gas will reach new record highs in 2026–2027, with a disproportionate share of incremental volumes coming from western basins and the Gulf Coast corridor. In the broader North American context, tight gas plays in the Rockies and gas focused activity in parts of the Permian and Mid Continent are expected to mature but still contribute to net growth into the 2030s.

Within the Permian Basin itself, natural gas output is forecasted to rise steadily as oil directed drilling continues and gas oil ratios climb in maturing fields. EIA's latest outlook shows Permian marketed gas reaching roughly 25.8 Bcf/d in 2026, after adding about 1.9 Bcf/d in 2024 and another 1.0 Bcf/d in 2025, making the basin a major driver of U.S. supply growth. Recent revisions to Permian shale play mapping also lift estimated 2026 shale gas output by about 0.8 Bcf/d, underscoring how new zones and productivity gains are reshaping the basin's gas profile.

Longer term Permian forecasts suggest continued expansion in both associated and non-associated gas as drilling technology improves, and more gas focused development becomes economic relative to other basins. Some private forecasts see Permian gas focused production growing from around 4 Bcf/d in the early 2020s to roughly 5 Bcf/d by the early 2030s and to more than 9 Bcf/d by 2040, supported by rising initial well productivity and gradual increases in well count. At the same time, pipeline expansions out of the basin, including new late decade projects, are expected to alleviate constraints and allow higher flows to Gulf Coast LNG terminals and western demand centers.

As reflected in the chart below, US natural gas production is forecasted to continue to rise through 2045 in all but the low case scenario where production is seen to decline.

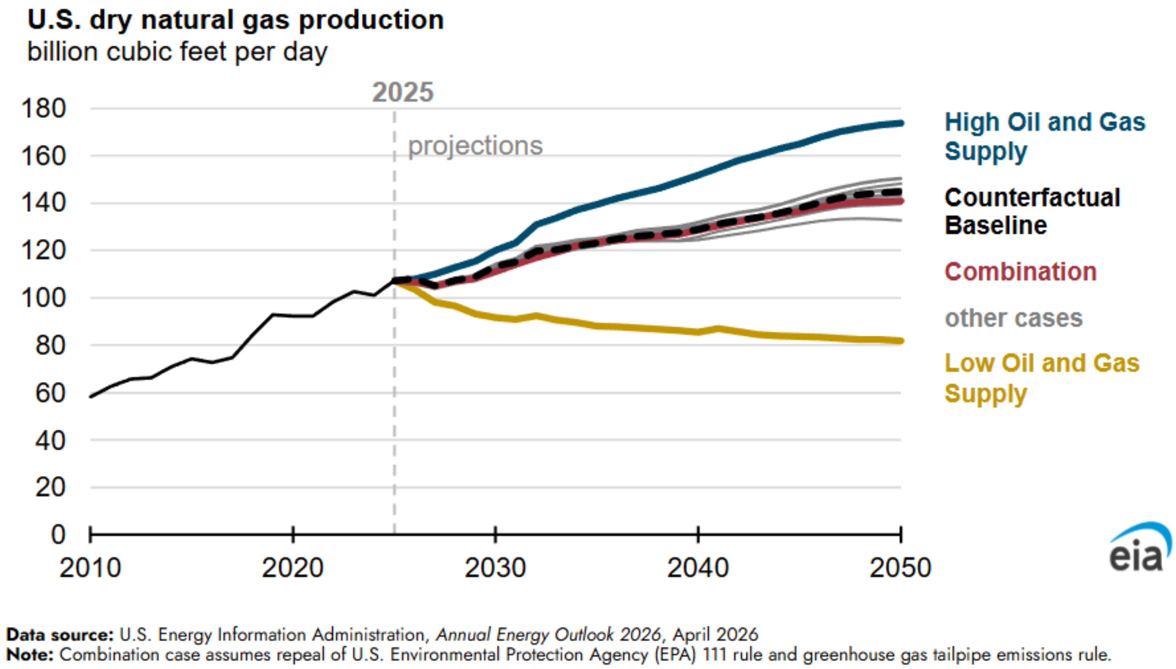

Figure 3 US Natural Gas Production

For western U.S. markets, these production trends imply increasing reliance on Permian and other western basin supplies to meet growing power burn, industrial demand, and export linked calls on gas. As more Permian gas moves east and south toward LNG and petrochemical hubs, western states will need to balance in region Rockies output, imports from Canada, and competition for Permian molecules, with infrastructure build out and price spreads determining how much of the new supply actually clears into West Coast and desert Southwest hubs. From a trading and risk perspective, the interaction between Permian associated gas growth, periodic capacity bottlenecks, and seasonal western demand will remain a central factor in basis behavior and volatility across western U.S. hubs.

Specifically in the case of PNM, rising Permian and New Mexico gas production generally improves physical supply security but does not eliminate exposure to regional basis and price shocks. New Mexico is now the third largest U.S. gas producer with about 8% of national output and Permian side growth in the state, plus Texas, provides ample molecules that can flow toward the Four Corners/San Juan interfaces and into the desert Southwest. That backdrop lowers long run scarcity risk but increases dependence on how well pipeline projects and interconnections keep up with supply and demand shifts across the West.

In the near term, congestion at Waha and along key westbound and northbound routes means PNM remains moderately exposed to volatility in regional gas prices even if the basin is in a long physical supply position. Episodes of negative or very weak Waha pricing contrast sharply with potential spikes at downstream Southwest and Rockies hubs when weather, outages, or maintenance bind capacity, creating sizable basis moves that can flow through to PNM's delivered gas cost for generation. Future projects like the proposed Transwestern Desert Southwest expansion (Texas–New Mexico–Arizona) aim to add about 1.5 Bcf/d of capacity by around 2029 which would improve PNM adjacent routing options but also tighten the link between PNM's region and Permian dynamics. In conclusion, natural gas supply is adequate and will not be a major diver of price volatility over the long term.

Weather analysis

Weather can impact natural gas price volatility in the U.S. Southwest primarily by driving power sector demand. Extended hot spells across Texas, New Mexico, Arizona, and Southern California push cooling loads higher and force gas fired generators to ramp, especially when solar output fades in late afternoon and evening peaks. In recent years, summer power burn has reached record levels over 50–60 Bcf/d nationally, and the Southwest tends to experience heat waves earlier in the cooling season often extending into the post summer shoulder season, so early or extreme heat waves can quickly tighten regional balances and lift hub prices and basis. Conversely, milder than expected shoulder season weather depresses power burn and keeps more gas in storage, softening prices relative to pre-season expectations.

Cold outbreaks also create volatility by increasing demand and disrupting production in adjacent regions across the Southwest. Arctic blasts and winter storms have at times cut Permian and other Lower 48 production by several Bcf/d, with events like Winter Storm Uri and subsequent cold snaps knocking 5–10+ Bcf/d offline at times as un winterized wells, gathering systems, and plants froze. When those storms extend into West Texas and the Four Corners region, the Southwest can see both reduced inflows and elevated heating and power demand, impacting basis prices at regional hubs and driving short duration intraday price spikes.

Hydrology and renewables further modulate weather driven volatility in the Southwest. Strong hydro years and high solar output in the broader Western Interconnect can displace some gas fired generation during mild periods, capping prices, whereas drought conditions or cloudy, low wind situations create increased reliance on gas just as temperatures deviate from normal. As renewable penetration grows, the system becomes more sensitive to extreme temperature days when wind or solar underperform, making weather shocks translate more directly into swings in Southwest gas burn, storage trajectories, and spot price volatility.

These weather factors were evaluated in the analysis completed based on Platt's *Gas Daily* Daily (GDD) price history that was used to complete the modelling and calculate volatility. Additionally, we evaluated the price history to identify the frequency, duration and cost impact of short duration basis market disruptions. Extreme weather events will continue to occur and may increase in frequency and intensity; however, we do not believe they create a material long term risk and can be mitigated cost effectively.

Inflation analysis

During one of the PNM facilitated stakeholder conference calls, Third Act asked if inflation impacts would be addressed during the study. This is an entirely valid inquiry given the recent volatility in the monthly Producer Price Index (PPI) and Consumer Price Index (CPI) values as reported by the BLS history. The question was initially addressed during the Siemens presentation outlining the analytical approach that would be used to complete the gas volatility study. The initial response based on anecdotal price history was that gas prices and inflation are not correlated. Siemens also confirmed that inflation would be evaluated using a rigorous analytical approach and the results of that analysis would be included as part of the volatility analysis report.

To assess whether Henry Hub natural gas prices move with the general CPI price level, Siemens performed an Ordinary Least Squares (OLS) regression analysis using monthly Henry Hub spot prices and headline CPI data from January 1997 onward. OLS regression is a statistical method used to model the relationship between a continuous dependent variable and one or more independent variables. It determines the "line of best fit" (red line) by minimizing the sum of the squared differences (residuals) between the actual observed values and those predicted by the linear equation. In basic terms, the OLS regression looks for a mathematical relationship between an independent value (inflation) and a dependent value (natural gas prices). This mathematical relationship is reflected by the red line in the sample graph below. If the data point plots (blue dots) are tightly grouped around the redline, it indicates a strong correlation.

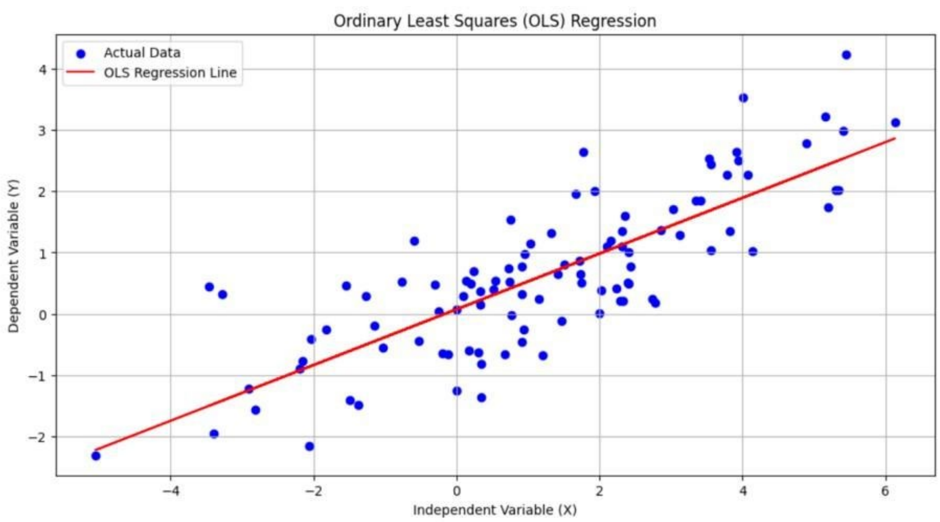

Figure 4 OLS Output Example

To conduct the analysis both variables (CPI and natural gas prices) were transformed into natural logs. The first regression tested whether log gas prices showed a long-term time trend. The time-trend model produced a small but statistically significant relevant output, suggesting a slight downward trend over the sample period. However, the model had a very low R^2, indicating although we do see a slight relationship between time and price; time explains only a small portion of the variation in gas prices.

The second step in the analysis was testing whether log gas prices moved in tandem with CPI. That analysis with log CPI produced a statistically significant but negative coefficient that can be interpreted as elasticity; a 1% increase in CPI was associated with an estimated 0.28% decrease in Henry Hub prices over the sample. However, the model fit (distance between blue data dots and the red line) was even weaker, indicating that CPI explains very little of the movement in gas prices. Overall, the results suggest that Henry Hub prices do not behave like a stable inflation-linked commodity and are likely driven more by market-specific factors such as weather, storage levels, supply-demand conditions, and energy market shocks.

Infrastructure analysis

Several gas pipeline projects are proposed or advancing in New Mexico, ranging from large interstate expansions out of the Permian Basin to short laterals for specific loads within New Mexico. While the laterals will have a limited impact on price volatility other than creating additional load, the interstate projects will increase capacity to bring Permian gas into the PNM service territory helping to reduce price volatility. Given that pipelines are subject to multiple regulatory agencies at the Federal and State level, construction is always subject to delay.

The following is a list of major projects planned for the New Mexico market

- Energy Transfer is developing the Desert Southwest pipeline, an addition to and expansion of the Transwestern pipeline system. The new system will consist of approximately 516 miles of 42-inch pipe plus nine compressor stations across Texas, New Mexico, and Arizona. Design capacity around 1.5 Bcf/d to move Permian gas to growing Southwest demand (utilities, data centers, high-tech load), with in-service targeted for Q4 2029. Positioned as a $5.3 billion project leveraging the existing Transwestern system. The proposed pipeline pathway will pass through the southern portions of PNM's service territory in the Cliff Silver City region with delivery locations planned for Doña Ana County and Luna counties. The project sold all 1.5 Bcf/d of the initial capacity under 25-year contracts with investment-grade counterparties. Since the initial open season, Energy Transfer has received considerable interest above planned capacity and is considering expansion options.

- Western States and Tribal Nations (WSTN) have developed a proposed Southwest Pathway concept to bring Rockies gas down into New Mexico to serve growing regional demand as well as move gas to LNG facilities in Mexico creating greater access to Asian markets with requiring transit of the Panama Canal reducing shipping times by 50%. Unlike the Desert Southwest pipeline, this project is conceptual at this point and likely will be several years in development prior to construction; however, it shifts the supply source from the Permian basin to the Rocky Mountains potentially offsetting some degree of basis risk.

  New Mexico is part of a multistate roadmap (with Wyoming, Utah, tribal partners) proposing routes to move Rockies gas to western U.S. markets and Asian export paths. Options include building new pipe paralleling Transwestern and Public

Service of New Mexico ROWs, potentially tying into expansions like Desert Southwest and other proposed lines toward Phoenix and El Paso.

Energy Transfer has proposed developing a 17-mile gas pipeline (Green Chile) in southern New Mexico to serve “Project Jupiter,” a controversial data center load near Las Cruces. Filed with FERC in Feb 2026; the project is currently in the approvals queue having been denied an easement by NM Land Commission forcing a re-route of the pipeline. Sierra Club Rio Grande and other environmental groups filed a formal protest at FERC demanding a full environmental review of both the pipeline and the powerplant. The original start date of April 16th has slipped and there is no new in-service date until the FERC issues are resolved. While laterals are generally not major contributors to price volatility, this project is designed for up to ~400,000 Dth/d, mostly across BLM and private land, but is facing opposition from some state legislators and environmental groups concerned about air quality and permitting speed. Put in perspective, 400,000 Dth/d is enough natural gas to fuel four (4) 500 mw combined cycle plants dispatching as base load units. At issue is the speed at which permitting is proceeding as a precedent for additional mid volume interconnects for additional data center generation load.

These New Mexico-linked projects sit alongside a broader wave of Permian takeaway additions (e.g., other pipelines into Texas and to Mexico), which the EIA notes could add significant capacity between 2025–2029. The net effect is more optionality to move Permian gas westward and into regional power and data-center loads, with associated siting and environmental risk around projects like Green Chile. Our conclusion is that new pipeline builds will increase operation flexibility to bring gas into the PNM service territory and decrease spot gas price volatility

LNG Exports

U.S. LNG exports have grown rapidly over the past decade, turning the country into one of the world’s largest LNG suppliers. Growth has been driven by abundant shale gas (especially from the Permian, Haynesville, and Marcellus), relatively low domestic prices, and heavy investment in Gulf Coast liquefaction capacity. Export volumes are concentrated at a handful of large terminals, with most cargoes destined for Europe and Asia under a mix of long-term contracts and spot sales. Policy decisions, permitting timelines, and global demand cycles now play a major role in shaping forward U.S. gas balances.

The expansion of U.S. LNG exports has significant implications for domestic gas prices and regional basis. As more liquefaction capacity comes online, Gulf Coast and associated upstream hubs (Henry Hub, Houston Ship Channel, Waha, Haynesville-linked points) become increasingly tied to global LNG netbacks. In tight global markets, strong LNG demand can pull U.S. prices higher; in oversupplied conditions, U.S. liquefaction plants may run at lower utilization, easing pressure on domestic prices. This linkage also raises the importance of pipeline infrastructure connecting producing basins to export terminals.

LNG exports also carry geopolitical and energy-security implications. For allies in Europe and parts of Asia, U.S. cargoes provide diversification away from more politically exposed pipeline supplies and single-supplier LNG dependence. At the same time, U.S. export policy, environmental scrutiny over new projects, and community impacts along the Gulf Coast have become more prominent in permitting debates. Over the medium term, the balance between adding new LNG trains and meeting domestic decarbonization and affordability goals will shape both the scale and pattern of U.S. LNG exports.

Exports averaged on the order of 14–15 Bcf/d in 2025 and are projected to climb further as new Gulf Coast capacity ramps through 2026–2027. Government and industry estimates put operating U.S. LNG export capacity near 18 Bcf/d in mid-2026, with another roughly 15 Bcf/d under construction, implying a potential doubling of effective capacity over the next several years as projects like Plaquemines, Golden Pass, Port Arthur, and Corpus Christi Stage 3 move toward full service. Forward analyses suggest that incremental LNG feedgas demand in 2026 alone could add roughly 6–8 Bcf/d of call on U.S. gas versus today as this next wave comes online and ramps up. With 2027 export volume estimated to be 18.1 Bcf/d.

For U.S. gas markets, this LNG growth wave tightens the link between Henry Hub and global LNG netbacks and puts a premium on Gulf Coast and feedgas-adjacent basis. As new trains ramp, feedgas demand can rise by mid-single-digit Bcf/d chunks, absorbing surplus production from basins like the Permian and Haynesville and potentially flattening or lifting domestic price curves, especially in winter or during global disruptions such as outages in competing export regions. At the same time, pipeline delays or bottlenecks into liquefaction sites remain a risk factor, with EIA flagging that most new liquefaction capacity is Gulf-centric and contingent on synchronized midstream build-out.

Key upcoming LNG projects after 2026 are dominated by U.S. Gulf Coast expansions plus a handful of floating and modular concepts that could add a sizeable new wave of liquefaction capacity late in the decade. Many are already approved by FERC but not yet built, while others (like certain Plaquemines and Port Arthur phases) are in various stages between pre-FID and early construction. Together, these projects could add well over 10 Bcf/d of additional U.S. capacity post-2026 if they all proceed, with timing and volume governed by global demand, contract coverage, and financing conditions.

Beyond individual terminals, the post-2026 period is characterized by a broader “second wave” of LNG capacity globally, including Qatar’s additional North Field East/West trains, projects in Canada, Africa, and Russia, and Asia-Pacific expansions. Analyses of this wave highlight that while 2026–2027 are pivotal startup years for currently-under-construction U.S. plants, much of the incremental capacity that truly reshapes balances will arrive closer to 2028–2032 as these new U.S. phases and competing global projects ramp. This timing matters for U.S. gas markets because it affects when the next “step change” in LNG feedgas demand hits basins like Permian and Haynesville after the mid-decade build-out.

From a risk and strategy angle, these post-2026 projects set the stage for a possible second tightening in U.S. balances late in the decade, following the initial 2026–2027 ramp. If most of the listed U.S. expansions reach final investment decision (FID) and execute on time, U.S. LNG capacity by early-2030s could be more than double mid-2020s levels, deepening the linkage between Henry Hub and global LNG netbacks and keeping Gulf Coast basis structurally supported, but also increasing sensitivity to global overbuild and cyclical LNG price swings. This may put upward pressure on prices in the PNM service territory but should not impact price volatility in a meaningful way.

Data center/ load growth; impact on gas price volatility

The New Mexico Consumer Protection Alliance inquired about the impact of data center load growth and the resulting impact on natural gas price volatility. This is a valid concern as data center development in New Mexico has accelerated over the past few years, transforming the state from a secondary market into an emerging hub for hyperscale and AI-focused infrastructure. Meta's multibillion-dollar campus in Los Lunas, now expanding with dedicated AI and machine-learning buildings, exemplifies this trend and has helped anchor a broader ecosystem of facilities around Albuquerque and central New Mexico. New projects such as large campuses planned by New Era Energy, Zenith Volts, and others could, if built, make New Mexico one of the most significant data center geographies in North America by total capacity.

This growth is driven by several structural advantages and policy signals. New Mexico offers abundant, relatively affordable land, access to high-capacity transmission corridors, and proximity to major renewable energy developments such as the SunZia Wind project, which is adding thousands of megawatts of new capacity in the region. The state's Energy Transition Act aligns well with hyperscale operators' decarbonization commitments and supports long-term renewable procurement strategies for data center loads.

Longer-run, the impact on PNM's supply mix and rate trajectory depends heavily on how projects are structured. If big campuses act as "anchor customers" that sign long-term renewable PPAs, pay green premiums, and co-fund transmission and storage, they can help de-risk new carbon-free build-out and spread fixed grid costs over more kilowatt-hours, moderating or even offsetting bill impacts for other customers. Policy debates now underway in New Mexico regarding regulating data-center microgrids, setting fair cost-allocation rules, and shaping PNM's 2026 IRP will be critical in determining the impact of data-center growth. Given the data center developers preference for renewably sourced power, regulatory constraints on grid interconnections and prudent resource planning; data center load growth may drive an increased demand for gas fired generation but due to the 24/7 baseload nature of data center load, that demand will likely be served under long term gas purchase agreements backed with transportation capacity that will not create a significant demand for incremental spot priced gas thereby negating the daily gas price volatility risk.

Fundamental analysis conclusions

PNM plans to meet future electric demand by transitioning to a carbon-free portfolio built around large additions of renewable energy, storage, and flexible thermal resources that can ultimately burn clean fuels like hydrogen. Under the 2023 Integrated Resource Plan and subsequent planning updates, coal exits entirely by 2032, nuclear from Palo Verde remains a key carbon-free baseload component, and new solar, wind, and battery storage provide most incremental energy and capacity. To maintain reliability as renewable penetration rises, PNM's "All Technologies" planning scenario includes new combustion turbine-type units that start on natural gas but are designed to convert to hydrogen as PNM progresses to a carbon free portfolio.

While this increase in thermal generation is significant, fundamental analysis indicates that short term basis disruptions will continue to occur however the market will be able to supply this generation with minimal long term volatility impact.

Quantitative Analysis

Translating volatility into IRP scenarios and metrics

For an integrated resource plan, the statistical volatility model is a means to an end: it supplies a distribution of future gas prices used to stress test resource portfolios, not an end in itself. A common approach is to use forward curves as a baseline expectation and then layer on stochastic shocks calibrated from a Monte Carlo simulation model to generate multiple fuel price paths that preserve observed volatility and mean reversion. These paths can then be fed into gas supply forecasts to evaluate how the proposed portfolio will perform in terms of expected cost, cost variance, and downside risk (e.g., high price percentile metrics).

Volatility characteristics and modeling framework

Natural gas prices exhibit volatility clustering, heavy tails, and strong seasonality, with winter and extreme weather events driving many of the largest moves. Empirical studies and EIA analysis show that annualized volatility for Henry Hub can range from roughly 20–30 percent in benign periods to 70–80 percent or more during stress episodes, and that gas volatility is typically higher and more erratic than oil volatility. Volatility also varies by tenor: front month futures display higher conditional variance than longer dated contracts, which is relevant when IRPs use different horizons for near term dispatch versus long term planning.

Quantitative analytical framework

For the quantitative analysis of the natural gas exposure, a model was created which simulates gas markets and quantifies the possible gas exposure of PNM to the unpredictable nature of Henry Hub and the basis markets. The methodology consists of a stochastic simulation for gas prices with Monte Carlo integration to create confidence intervals of gas prices starting with the prompt month through the end of 2045.

To estimate the impact of natural gas spot price volatility Siemens used a 6-step approach as outlined below:

1. Analyze historical spot pricing data to calculate volatility including short duration market disruptions that create pricing anomalies
2. Apply this volatility to the forward curve via Monte Carlo simulation
3. Generate thousands of potential price paths
4. Organize these paths into standard deviation bands around the forward curve
5. Apply these paths to forecasted monthly gas consumption (from IRP dispatch) to quantify cost exposure
6. Estimate the variance between expected and unfavorable outcomes to assess risk potentially passed on to ratepayers

To create the price paths, Siemens used 3.5 years of historical market prices for both Henry Hub as well as the local basis markets. The three-and-a-half-year period was selected to provide a reasonable amount of history to be statistically valid without capturing history that predates infrastructure and structural market changes that impact price.

Prices were simulated considering historical volatility, correlation between hubs and mean reverting prices. The prices listed in the table below were used as the starting point for simulations. These prices represent the range of expected prices over the future starting with a low price in the 5th percentile indicating all but 5% of prices will be above that price increasing to the 95th percentile which indicates a price point at which 95% of prices will be at or below that level. These prices are used to bound the simulations. Using a blend of the potential range of prices Siemens conducted a market simulation to estimate the future cost of natural gas and its impact on PNM's annual gas expense based on the expected volume requirement provided by PNM.

Percentile	Platts Waha	Platts Houston Ship Channel	El Paso Permian	El Paso San Juan	Platts Henry Hub
95%	$ 2.21	$ 3.34	$ 2.28	$ 4.04	$ 3.82
75%	$ 2.13	$ 3.31	$ 2.19	$ 3.90	$ 3.77
50%	$ 2.06	$ 3.28	$ 2.12	$ 3.81	$ 3.74
25%	$ 2.01	$ 3.25	$ 2.07	$ 3.71	$ 3.71
5%	$ 1.93	$ 3.21	$ 1.99	$ 3.52	$ 3.66

Table 1 Basis market simulation constraints

The following table utilizes the price distributions shown above to quantify the potential impact of forward-looking price over the planning horizon. The expected cost is based on the P50 scenario while the unfavorable case is based on the P95 price scenario. The P50 case is the expected case or 50% probability of occurrence event. P95 is the high market case, or the unfavorable event. The difference between the two cases is the “at risk” number; the difference between expected and unfavorable case, assuming no hedging.

Year	Volume (millions)	Unit Cost P50 ($)	Total Cost P50 ($ millions)	Unit Cost P95 ($)	Total Cost P95 ($ millions)	At risk spread ($ millions)
2026	26.5	2.93	77.6	3.43	91.0	13.3
2027	31.8	3.85	122.1	4.74	150.6	28.5
2028	30.6	3.87	118.4	4.86	148.4	30.0
2029	32.9	3.77	124.0	4.71	154.9	30.9
2030	37.7	3.83	144.6	4.67	175.9	31.4
2031	45.2	3.78	170.7	4.62	209.0	38.3
2032	32.8	3.87	127.2	4.70	154.4	27.1
2033	32.8	3.79	124.2	4.74	155.4	31.2
2034	33.4	3.91	130.7	4.69	156.7	26.0
2035	34.0	3.87	131.4	4.99	169.3	37.9
2036	33.8	3.82	129.3	5.02	170.0	40.7
2037	33.7	3.85	129.8	5.13	172.7	42.9
2038	34.0	3.83	130.3	4.91	166.9	36.7
2039	34.0	3.76	127.9	4.70	160.1	32.2
2040	34.5	4.03	139.0	4.94	170.3	31.3
2041	33.1	3.87	128.1	4.77	157.9	29.8
2042	34.2	3.73	127.6	5.07	173.3	45.7
2043	33.2	3.84	127.5	4.70	156.1	28.7
2044	27.9	3.82	106.6	4.78	133.5	26.8
2045	2.6	3.64	9.5	4.37	11.4	1.9

Table 2 Annual gas cost variances

Short term basis analysis

As mentioned in the fundamental analysis section, short-term disruptions will continue to occur due to four primary factors:

- Pipeline constraints or outages that prevent gas from moving from a surplus region to a demand center (capacity limits, maintenance, explosions, force majeure).
- Extreme weather that simultaneously spikes local demand and disrupts production or transportation (polar vortex, hurricanes, deep freeze-offs).
- Low regional storage levels or loss of storage flexibility, which tighten local balances and amplify price response to any shock.
- Sudden shifts in regional supply–demand from structural changes or global/geopolitical events that change flows and competition for gas supply.

As reflected in the graph below, El Paso San Juan experiences some short duration basis events that could cause significant increases in natural gas expense if not appropriately mitigated.

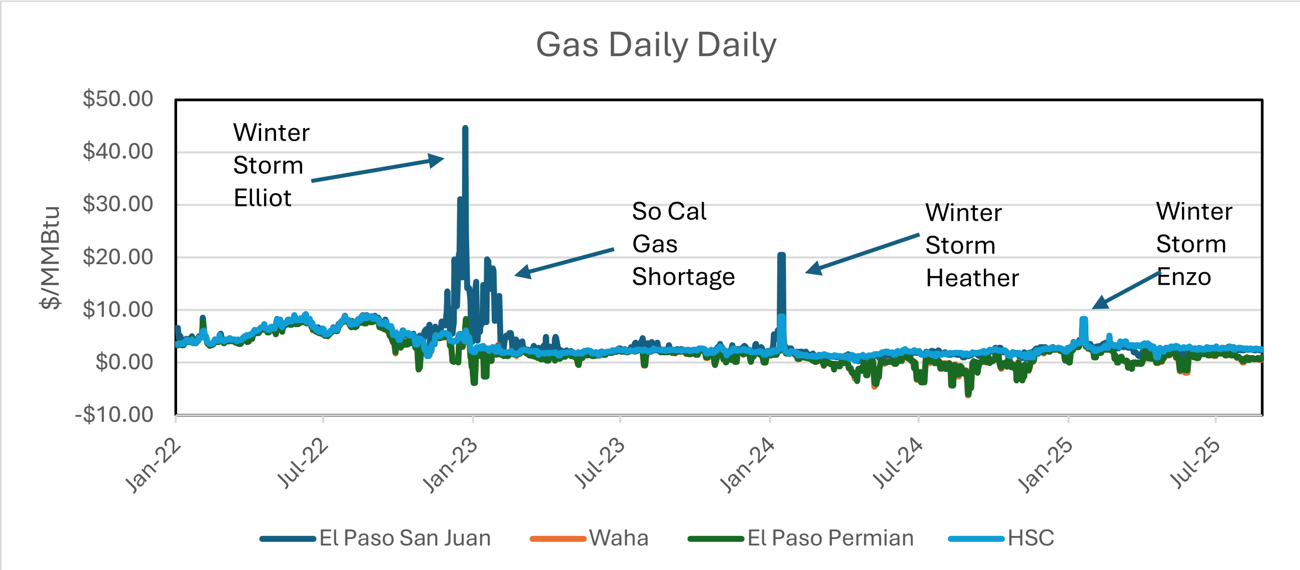

Figure 5 Natural gas spot price history

To quantify the potential impact of these basis market anomalies Siemens considered three and a half years of spot price history and identified 6 events, totaling 47 days, ranging from 1 day in duration to 20 days in December of 2022. The events selected were based on days when gas basis differentials were two standard deviations above the mean. Siemens assumed that the average daily volume during an event increased by 20% over forecast and then applied the historical basis differential that occurred during the event to the increased volume to quantify the financial impact.

Over the 3 ½ year analysis time frame, the cost implication was slightly under $10.4 mm with the majority concentrated in the December and January period in 2022/2023. Assuming the pattern were to repeat, on an average annual load of 30 Bcf the potential impact would be $0.30 to $0.33/MMBtu, assuming no basis hedging is in place. The vast majority of that risk occurs in the near term current and prompt month markets where the PNM risk management program allows for up to an 85% hedge ratio. An 85% hedge ratio would reduce the $10.5 mm exposure to $1.6 mm or approximately 2%-4% of the expected p50 annual gas cost. When evaluating basis risk in the Western US markets it is critical to remember that basis can swing in both directions and there may be situations where due to pipeline constraints PNM could experience negative basis and be paid to take gas.

Risk Mitigation

Natural gas price volatility does create risk for PNM ratepayers. Markets in the Southwest, particularly the Permian and San Juan basins can be volatile as discussed earlier in this report. Using risk management tools readily available in the physical and financial energy markets can reduce those risks to an acceptable level. PNM has a functional commodity price risk management program in place that was approved for hedging through 2028 by the New Mexico Public Regulation Commission under Docket No. 24-00238-UT. The plan, as approved, authorizes PNM to hedge forward energy requirements using physical and financial instruments. It is important to note that volatility in the basis markets can be both favorable and unfavorable therefore PNM limits the volumes for gas hedging to a reasonable level except during the current and prompt month when PNM is most exposed to unfavorable price swings. The guidelines apply to the amount of energy required to meet jurisdictional loads projected for the forward planning period, subject to the condition that PNM will hedge no more than 30% of projected annual gas supply required to fuel the gas fired generation fleet, with the exception of the prompt month, where up to 85% of the projected month's energy requirement may be hedged. The plan further allows the current year energy requirement to be hedged to 70%, 1st calendar year out to be hedged to 60%, and the 2nd calendar year to be hedged to 40%. These longer-term energy hedges reduce volumetric exposure on gas fired generation. When coupled with the near-term natural gas hedges will substantially reduce PNM's exposure to both short- and long-term natural gas prices spikes.

In addition to the risk reduction achieved through fuel hedging, PNM's targeted timeline for compliance with the ETA will, by default, reduce exposure to fuel price swings by structurally shifting the supply mix away from fuel-dependent generation toward renewables and other carbon free resources. As PNM moves toward meeting the ETA's renewable and carbon free standards, the goal is to develop a carbon free portfolio as soon as possible. Accordingly, as PNM adjusts its resource base to accomplish these objectives, its marginal energy needs will increasingly come from wind, solar, and other resources with no commodity fuel cost, rather than increasing reliance on gas-fired units whose dispatch costs are directly tied to natural gas prices. This transition means a growing share of PNM's cost of service is driven by fixed-capital and contracted capacity costs instead of pass-through fuel costs, dampening the impact of short-term gas price spikes on retail rates. In practical terms, each incremental megawatt-hour served from long-lived renewable assets under ETA compliance displaces prospective gas-fired generation, narrowing PNM's "open" natural gas requirement and thereby reducing the volume of gas that must be procured at floating market prices, which in turn lowers the utility's cash-flow and revenue requirement sensitivity to natural gas price shocks over time.

Conclusions

The quantitative and fundamental analyses presented in this study indicate that fuel cost variability associated with natural gas price volatility, while non-trivial, is bounded and can be prudently managed within the context of PNM's long-term resource planning framework. Long-horizon simulations calibrated to observed market behavior suggest that annual average gas cost outcomes are expected to remain within an approximate range of $0.14 to $1.09 per MMBtu around the forward curve, even after explicitly incorporating stochastic shocks and basis dynamics into the modeling construct. This per unit variance equated to a $26-to-$46 million-dollar annual variance as reflected in

Figure 6 spread across 5000+ GWh of generation. Coupled with basis risk in the $10.8 million dollar range, this is not an insignificant amount of exposure. It is important to remember; these risk numbers do not include the impact of the risk reduction of the hedging program discussed previously. When viewed against total portfolio fuel costs and the broader IRP time frame, this level of variance is material for planning and risk-allocation purposes but does not rise to the level of a structural threat to overall rate stability, provided that it is explicitly recognized and addressed through ongoing risk management practices.

At the same time, the historical basis assessment confirms that short-duration, high-magnitude disruptions—such as the six identified events totaling 47 days over the observed period—can create concentrated cost impacts if left unmanaged; in PNM's case, the back-cast estimate of roughly $0.30 to $0.33 per MMBtu on an annual load of 30 Bcf illustrates the potential rate effect of unhedged exposure to such episodes. However, these disruptions are episodic rather than chronic and occur within a broader market context characterized by robust domestic supply growth, ongoing interstate pipeline expansions, and increasing routing optionality into the desert Southwest. When combined with the established commodity risk-management program, structured procurement, and storage and capacity rights, these market fundamentals support the conclusion that both long-dated volatility and short-term basis risk can be reduced to levels consistent with a reasonable balance of affordability, reliability, and prudence for retail customers.

Accordingly, the conclusions developed in this analysis support a finding that PNM's treatment of gas price risk within its Integrated Resource Plan is reasonable and consistent with sound utility practice, in that it relies on empirically grounded stochastic methods, incorporates both qualitative and quantitative assessments of key drivers, and translates resulting cost distributions into actionable planning metrics. The Company's strategy—anchored in portfolio diversification, flexible thermal resources capable of transitioning to lower-carbon fuels, and the selective use of financial and physical hedging instruments—provides a credible path to maintaining cost variability within tolerable bounds over the 20-year horizon while continuing to meet statutory decarbonization and reliability objectives. On this basis, it is reasonable to conclude that fuel price risk to ratepayers is bounded and mitigated to align with Commission's expectations for prudent risk management. No additional modifications to the Company's gas price volatility assumptions or risk management practices are warranted at this time.

Appendix K: Cost and Performance Data for New Resource Options

Toward the end of 2025, PNM contracted the Electric Power Research Institute (EPRI) to develop cost and performance assumptions for supply-side candidate resources. These assumptions included capital costs (2026$/kW), fixed O&M costs (2026$/kW-yr), variable O&M costs (2026$/MWh), forced outage rates (%), heat rates (Btu/kWh), CO_2 emission rates (lb/MWh), and water usage rates (lb/MWh), among other resource characteristics. Future cost projections were developed by applying technology-specific cost trajectories informed by NREL's 2024 Annual Technology Baseline (ATB) and consultant-provided information. This approach preserves the relative cost trends reflected in the ATB while anchoring future projections to EPRI-developed base-year assumptions. This appendix summarizes the assumptions used to characterize the new supply-side resource options evaluated in the IRP. Contents include:

- Characteristics of New Candidate Supply-Side and Demand-Side Resources (Table K-1);
- Capital Cost Assumptions for Candidate Resources by Year (Table K-2);
- Fixed O&M Cost Assumptions for Candidate Resources by Year (Table K-3);
- Variable O&M Cost Assumptions for Candidate Resources by Year (Table K-4);
- Characteristics of the energy efficiency bundles considered in the IRP (Table K-5);
- Costs of the demand response potential programs considered in the IRP (Table K-6);
- Summer Capacity of the Demand Response Potential Programs Considered in the IRP (Table K-7); and
- Summer Capacity of the Demand Response Potential Programs Considered in the IRP (Table K-8)

Table K-1 Characteristics of New Candidate Supply-side and Demand-side Resources

Technology	First Year Available	Modeled Capacity (MW)	Life (Years)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/kW-yr)	Storage Duration (Hrs)	Heat Rate (Btu/kWh)	Round Trip Efficiency (%)	Forced Outage Rate (%)	Firm Capacity (%)	CO_2 Rate (lbs/MWh)	Water Usage (lb/MWh)
Generating/Storage Technology Resources													
Solar Photovoltaic[3]	2029	10	30	1,532	16	0	-	-	-	1	6.6	-	-
Wind[3]	2033	151	25	2,615	57	0	-	-	-	3	20.1	-	-
Battery Storage (4 hr)[3]	2029	10	20	1,724	15	0	4	-	87	8	96	-	-
Battery Storage (8 hr)[3]	2029	10	20	2,476	93	0	8	-	88.5	8	96	-	-
CAES[3]	2035	100	40	5,740	37	11	10	-	59.9	8	99.5	-	92
CT (heavy frame)[2,3]	2030	179	30	2,403	16	9	-	10,236	-	2	98	1,195.5	8
CT (aero)[2,3]	2030	40	30	3,563	37	7	-	9,449	-	2	98	1,103.5	44
Combined Cycle[2,3]	2031	582	30	2,924	20	5	-	6,762	-	2.5	92	6,762	535.4
Combined Cycle with CCS[2,3]	2031	499	30	5,978	36	6	-	7,765	-	2.5	92	43.7	535.4
Linear Generator[2,3]	2030	40	30	3,746	8	8	-	7,582	-	2	98	888.5	-
Geothermal[3]	2033	30	30	8,007	227	2	-	-	-	1.5	76	-	1,462
Enhanced	2033	30	30	10,329	227	2	-	-	-	1.5	76	-	1,462
Iron Air Energy	2029	100	30	4,144	22	0	100	-	38	4	92	-	37
Pumped Hydro[3]	2034	100	50	4,220	40	0	24	-	80	5	95	-	2,755
SMR[3]	2035	146	30	8,263	140	12	-	10,900	-	1.4	98.6	-	19.1
Demand Side Management Candidate Resources													
Energy Efficiency	2031	5-26	13-18	-	-	25-284	-	-	-	-	50	-	-
Peak Saver Extension	2030	30	15	-	387	0	-	-	-	-	63	-	-
Power Saver	2030	40	15	-	563	0	-	-	-	-	63	-	-
Grid Interactive WH[4]	2030	0.006	10	-	1	0	-	-	-	-	63	-	-
Water Heater DLC[4]	2030	1.12	10	-	183	0	-	-	-	-	63	-	-
Battery Storage DLC[4]	2030	0.1	15	-	4	0	-	-	-	-	63	-	-
Electric Vehicle DCM[4]	2030	0.76	10	-	75	0	-	-	-	-	63	-	-
Time-of-Day Rate	2030	1.19	10	-	64	0	-	-	-	-	63	-	-
EV Time-of-Day Rate[4]	2030	0.56	10	-	24	0	-	-	-	-	63	-	-
Behavioral	2030	2	10	-	41	0	-	-	-	-	63	-	-

Notes

1. Vampiric losses (storage loss rate) of .03%/Hour was applied to the iron air energy storage candidate resource
2. Emissions rates shown for new thermal generators correspond to operations using natural gas; no emissions attributed to plant output when operated using hydrogen fuel starting in 2045
3. First-year availability was based on information provided by EPRI, and includes the time required for construction, RFP evaluation, contract negotiations, and other regulatory processes
4. WH = Water Heater; DLC = Direct Load Control; DCM = Direct Charge Management; EV = Electric Vehicle

TABLE K-2 CAPITAL COST ASSUMPTIONS FOR CANDIDATE RESOURCES BY YEAR (NOMINAL, $/KW)

Technology[1]	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
	$/kW																			
Solar - Photovoltaic	1,477	1,495	1,514	1,532	1,551	1,571	1,590	1,610	1,630	1,650	1,671	1,692	1,713	1,734	1,755	1,777	1,799	1,822	1,844	1,867
Wind	2,306	2,348	2,391	2,434	2,478	2,523	2,569	2,615	2,663	2,711	2,760	2,810	2,861	2,913	2,966	3,020	3,075	3,131	3,187	3,245
Battery Storage (4 hr)	1,661	1,682	1,702	1,724	1,745	1,767	1,789	1,811	1,834	1,856	1,879	1,903	1,926	1,950	1,975	1,999	2,024	2,049	2,075	2,101
Battery Storage (8 hr)	2,386	2,416	2,446	2,476	2,507	2,538	2,570	2,602	2,634	2,667	2,700	2,734	2,768	2,802	2,837	2,872	2,908	2,944	2,981	3,018
CAES	4,056	4,536	4,513	4,879	5,070	5,264	5,379	5,497	5,618	5,740	5,865	5,992	6,122	6,254	6,388	6,524	6,663	6,805	6,949	7,096
CT (heavy frame)	1,922	2,150	2,139	2,312	2,403	2,494	2,549	2,605	2,662	2,720	2,779	2,840	2,901	2,963	3,027	3,092	3,158	3,225	3,293	3,363
CT (aero)	2,850	3,188	3,172	3,429	3,563	3,699	3,780	3,863	3,948	4,034	4,122	4,211	4,302	4,395	4,489	4,585	4,683	4,782	4,883	4,987
Combined Cycle	2,451	2,649	2,433	2,570	2,762	2,924	3,004	3,085	3,139	3,193	3,249	3,306	3,364	3,423	3,482	3,543	3,605	3,668	3,733	3,798
Combined Cycle with CCS	5,011	5,416	4,973	5,254	5,647	5,978	6,141	6,307	6,417	6,529	6,642	6,759	6,877	6,997	7,119	7,244	7,371	7,500	7,631	7,765
Linear Generator	2,996	3,351	3,334	3,604	3,746	3,889	3,974	4,061	4,150	4,241	4,333	4,427	4,523	4,620	4,719	4,820	4,923	5,027	5,134	5,243
Geothermal	7,959	7,943	7,936	7,937	7,945	7,960	7,981	8,007	8,038	8,074	8,276	8,482	8,694	8,911	9,133	9,361	9,595	9,835	10,080	10,332
Enhanced Geothermal	13,407	12,649	12,048	11,563	11,165	10,835	10,560	10,329	10,133	9,969	10,217	10,472	10,734	11,002	11,276	11,557	11,846	12,142	12,445	12,755
Iron Air Energy Storage	3,993	4,043	4,093	4,144	4,196	4,248	4,301	4,354	4,408	4,463	4,519	4,575	4,632	4,689	4,748	4,807	4,866	4,927	4,988	5,050
Pumped Hydro	3,331	3,431	3,534	3,640	3,749	3,862	3,978	4,097	4,220	4,346	4,477	4,611	4,749	4,892	5,039	5,190	5,345	5,506	5,671	5,841
SMR[2]	-	-	-	-	-	-	-	-	-	8,263	8,130	7,981	7,816	7,634	7,434	7,510	7,584	7,655	7,724	7,790

Notes

1. Candidate technologies have different first-year availability assumptions in EnCompass. EnCompass model uses the cost of a resource in the year it is selected, which must be on or after the resource's first year of availability
2. The SMR candidate resource includes no data from 2026 through 2034 based on NREL's 2024 ATB, therefore no cost curve was able to be determined throughout that period.

Table K-3 Fixed O&M Cost Assumptions for Candidate Resources by Year (Nominal, $/kW-yr)

Fixed O&M	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Solar - Photovoltaic	15	15	16	16	17	17	18	18	19	20	20	21	21	22	23	23	24	25	25	26
Wind	47	48	49	51	52	54	56	57	59	61	63	64	66	68	71	73	75	77	79	82
Battery Storage (4 hr.)	13	14	14	15	15	16	16	17	17	18	18	19	19	20	20	21	22	22	23	24
Battery Storage (8 hr.)	85	87	90	93	96	98	101	104	107	111	114	117	121	125	128	132	136	140	144	149
CAES	29	29	30	31	32	33	34	35	36	37	38	39	41	42	43	44	46	47	49	50
CT (heavy frame)	14	14	15	15	16	16	17	17	18	18	19	19	20	20	21	22	22	23	24	24
CT (aero)	33	34	35	36	37	38	39	40	41	43	44	45	47	48	49	51	52	54	56	57
Combined Cycle	18	18	19	19	20	20	21	22	22	23	24	24	25	26	26	27	28	29	30	31
Combined Cycle with CCS	31	33	34	35	36	37	38	39	40	41	43	44	45	47	48	49	51	52	54	56
Linear Generator	7	7	8	8	8	8	9	9	9	9	10	10	10	11	11	11	12	12	12	13
Geothermal	185	190	196	202	208	214	221	227	234	241	248	256	264	272	280	288	297	306	315	324
Enhanced Geothermal	184	190	196	201	208	214	220	227	234	241	248	255	263	271	279	287	296	305	314	323
Iron Air Energy Storage	20	21	21	22	23	23	24	25	25	26	27	28	29	29	30	31	32	33	34	35
Pumped Hydro	31	32	33	34	35	36	37	38	40	41	42	43	45	46	47	49	50	52	53	55
SMR	107	111	114	117	121	124	128	132	136	140	144	149	153	158	162	167	172	177	183	188

TABLE K-4 VARIABLE O&M COST ASSUMPTIONS FOR CANDIDATE RESOURCES BY YEAR (NOMINAL, $/KW-YR)

Variable O&M	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Solar - Photovoltaic	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery Storage (4 hr.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery Storage (8 hr.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAES	8.3	8.6	8.8	9.1	9.4	9.7	9.9	10.2	10.6	10.9	11.2	11.5	11.9	12.2	12.6	13.0	13.4	13.8	14.2	14.6
CT (heavy frame)	7.6	7.9	8.1	8.3	8.6	8.8	9.1	9.4	9.7	10.0	10.3	10.6	10.9	11.2	11.5	11.9	12.2	12.6	13.0	13.4
CT (aero)	6.3	6.5	6.7	6.9	7.1	7.3	7.5	7.7	8.0	8.2	8.5	8.7	9.0	9.3	9.5	9.8	10.1	10.4	10.7	11.1
Combined Cycle	4.1	4.2	4.3	4.4	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3	6.5	6.7	6.9	7.1
Combined Cycle with CCS	5.0	5.1	5.3	5.4	5.6	5.8	5.9	6.1	6.3	6.5	6.7	6.9	7.1	7.3	7.5	7.7	8.0	8.2	8.5	8.7
Linear Generator	7.3	7.5	7.7	7.9	8.2	8.4	8.7	8.9	9.2	9.5	9.8	10.0	10.4	10.7	11.0	11.3	11.7	12.0	12.4	12.7
Geothermal	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.5	2.6
Enhanced Geothermal	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.5	2.6
Iron Air Energy Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SMR	9.1	9.4	9.7	10.0	10.3	10.6	10.9	11.2	11.5	11.9	12.2	12.6	13.0	13.4	13.8	14.2	14.6	15.1	15.5	16.0

Table K-5 Characteristics of the Energy Efficiency Bundles Considered in the IRP

Annual Energy Savings (GWh)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Up to $50	0.6	0.6	0.5	0.5	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Over $50	19	19	18	17	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Up to $75	-	-	-	-	-	50	52	52	52	51	52	51	51	51	52	42	42	42	43	43
$75 to $125	-	-	-	-	-	8	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Over $125	-	-	-	-	-	26	26	26	26	27	27	27	27	27	27	27	26	27	23	22
Peak Reduction (MW)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Up to $50	0.1	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Over $50	6	6	6	6	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Up to $75	-	-	-	-	-	20	20	21	21	20	19	19	19	20	20	18	17	18	19	19
$75 to $125	-	-	-	-	-	5	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Over $125	-	-	-	-	-	23	23	23	23	24	24	25	25	26	26	26	25	25	21	21
Levelized Cost ($/MWh)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Up to $50	41	41	43	43	43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Over $50	211	212	209	258	276	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Up to $75	-	-	-	-	-	27	26	26	26	26	26	26	26	25	25	29	29	29	29	28
$75 to $125	-	-	-	-	-	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108
Over $125	-	-	-	-	-	284	284	284	284	282	280	278	276	272	271	269	242	239	250	249
Average Life (Years)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Up to $50	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Over $50	15	15	15	15	15		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Up to $75	-	-	-	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
$75 to $125	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Over $125	-	-	-	-	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13

TABLE K-6 COSTS OF THE DEMAND RESPONSE POTENTIAL PROGRAMS CONSIDERED IN THE IRP

Total Program Cost ($000)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Battery Energy Storage DLC	-	-	-	-	55	96	185	172	169	150	157	164	173	183	192	197	208	219	231	239
Behavioral	-	-	-	-	378	585	737	755	777	800	824	848	873	898	924	951	979	1,008	1,037	1,068
Domestic Hot Water Heater DLC	-	-	-	-	1,691	2,429	3,521	2,603	2,196	2,192	2,270	2,343	2,413	2,484	2,556	2,627	2,692	2,762	2,862	2,921
Electric Vehicle Direct Charge Management	-	-	-	-	692	1,985	5,199	6,443	7,693	8,185	9,293	10,313	11,443	12,564	13,763	14,786	15,936	17,033	18,219	19,158
Electric Vehicle TOD Rate	-	-	-	-	223	554	1,212	816	594	334	305	255	224	187	156	116	92	70	69	62
Grid Interactive Water Heater	-	-	-	-	13	21	32	42	58	74	91	101	113	128	114	104	94	137	95	86
Peak Saver	3,843	3,477	3,558	3,557	5,376	5,442	5,514	5,591	5,677	5,771	5,877	5,988	6,109	6,244	6,396	6,556	6,730	6,920	7,128	7,345
Power Saver	6,787	7,050	7,393	7,574	7,815	8,119	8,433	8,760	9,100	9,452	9,818	10,198	10,591	10,998	11,416	11,841	12,288	12,719	13,178	13,662
Time of Day Rate	-	-	-	-	594	672	697	415	266	165	167	171	175	179	187	194	198	201	216	217

TABLE K-7 SUMMER CAPACITY OF THE DEMAND RESPONSE POTENTIAL PROGRAMS CONSIDERED IN THE IRP

Summer Potential (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Battery Energy Storage DLC	-	-	-	-	0.1	0.3	0.8	1.1	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8
Behavioral	-	-	-	-	2.1	3.4	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.3	4.3
Domestic Hot Water Heater DLC	-	-	-	-	1.1	2.2	3.3	3.8	3.9	3.8	3.7	3.6	3.5	3.4	3.3	3.3	3.2	3.1	3.1	3.0
Electric Vehicle Direct Charge Management	-	-	-	-	0.8	2.8	7.7	11.4	14.5	16.3	18.0	19.6	21.2	22.7	24.2	25.4	26.6	27.7	28.8	29.6
Electric Vehicle TOD Rate	-	-	-	-	0.6	1.9	4.9	6.8	8.0	8.6	9.1	9.5	9.8	10.0	10.2	10.2	10.2	10.2	10.2	10.1
Grid Interactive Water Heater	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Peak Saver[1]	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Power Saver[1]	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Time of Day Rate	-	-	-	-	1.2	2.7	4.5	5.4	5.8	5.7	5.6	5.5	5.5	5.4	5.4	5.3	5.3	5.3	5.3	5.3

Notes

1. The Peak Saver and Power Saver demand response programs are assumed to remain at their current maximum potential, as defined in the 2027 Energy Efficiency and Load Management Triennial Plan, throughout the 2026 IRP study period. Because any changes to these programs require NMPRC approval through future energy efficiency triennial filings, no additional program expansion is assumed.

TABLE K-8 WINTER CAPACITY OF THE DEMAND RESPONSE POTENTIAL PROGRAMS CONSIDERED IN THE IRP

Winter Potential (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Battery Energy Storage DLC	-	-	-	-	0.1	0.3	0.8	1.1	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.7	1.7	1.8	1.8	1.9
Behavioral	-	-	-	-	1.5	2.3	2.8	2.8	2.7	2.7	2.7	2.6	2.6	2.6	2.6	2.5	2.5	2.5	2.5	2.4
Domestic Hot Water Heater DLC	-	-	-	-	1.5	2.8	4.2	4.8	5.0	4.9	4.8	4.7	4.7	4.6	4.5	4.5	4.4	4.4	4.3	4.2
Electric Vehicle Direct Charge Management	-	-	-	-	0.8	2.8	7.8	11.6	14.8	16.6	18.5	20.2	21.8	23.4	25.0	26.3	27.6	28.8	29.9	30.7
Electric Vehicle TOD Rate	-	-	-	-	0.6	2.0	5.0	6.9	8.2	8.8	9.4	9.8	10.1	10.4	10.5	10.6	10.7	10.7	10.7	10.6
Grid Interactive Water Heater	-	-	-	-	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Peak Saver[1]	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Power Saver	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Time of Day Rate	-	-	-	-	0.4	0.9	1.6	1.9	2.0	1.9	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.7	1.7	1.7

Notes

1. The Peak Saver demand response program is assumed to remain at their current maximum potential, as defined in the 2027 Energy Efficiency and Load Management Triennial Plan, throughout the 2026 IRP study period. Because any changes to this program requires NMPRC approval through future energy efficiency triennial filings, no additional program expansion is assumed.

APPENDIX L: 2025 RESOURCE ADEQUACY ASSESSMENT: DESERT SOUTHWEST

This appendix provides the 2025 Resource Adequacy Assessment: Desert Southwest Final Report – May 2026.

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2025 Resource Adequacy Assessment: Desert Southwest

Final Report

May 2026

Energy+Environmental Economics

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Acknowledgements & Disclaimer

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Arizona Public Service Company (APS)
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Salt River Project (SRP)
Tucson Electric Power Company (TEP)

Technical Advisory Group

Over the course of this study, E3 convened a Technical Advisory Group comprising individuals with expertise and interests in resource adequacy. These individuals graciously shared their time through several meetings, providing their feedback on the project's scope, technical analysis, and key findings. The Technical Advisory Group included the following individuals:

Genevieve de Mijolla, Electric Power Research Institute
Bethany Frew, National Renewable Energy Laboratory
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Branden Sudduth, Western Electricity Coordinating Council
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Gord Stephen, National Renewable Energy Laboratory
Gary Dirks, Arizona State University
Ryan Roy, Western Power Pool
Rebecca Sexton, Western Power Pool
Derek Stenclik, Telos Energy

E3 would like to thank the Technical Advisory Group for their valuable contributions over the course of the study. Participation in the Technical Advisory Group does not indicate endorsement of the report's findings.

Disclaimer

The study sponsors retained E3 to provide an independent assessment of the resource adequacy situation in the Desert Southwest region. The sponsors provided technical information and informed the development of study scenarios. E3 utilized data from the study sponsors and other sources to develop a Southwest resource adequacy model. E3 retained full editorial control over the report and is solely responsible for all contents.

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Acronym Definitions

Acronym	Definition
ACC	Arizona Corporation Commission
AEPCO	Arizona Electric Power Cooperative
APS	Arizona Public Service Company
BAA	Balancing Authority area
CAISO	California Independent System Operator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CRSP	Colorado River Storage Project
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
EPE	El Paso Electric Company
ESIG	Energy Systems Integration Group
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
HILF	High Impact Low Frequency
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool
PNM	Public Service Company of New Mexico
RECAP	Renewable Energy Capacity Planning Model
SRP	Salt River Project
TEP	Tucson Electric Power
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WRAP	Western Resource Adequacy Program

1. Executive Summary

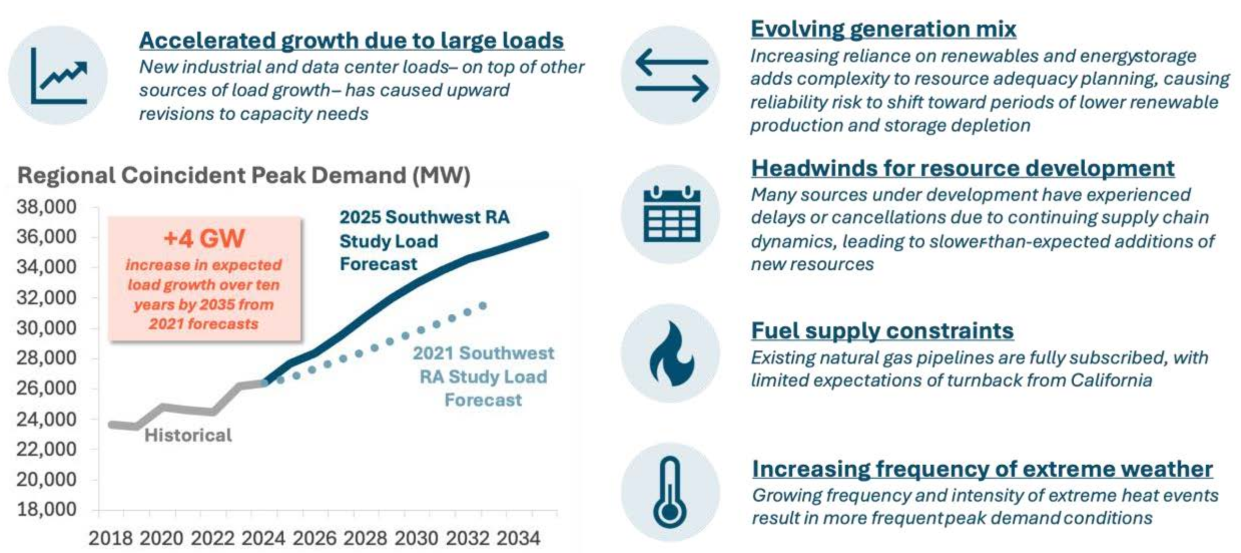
In 2022, E3 published ***Resource Adequacy in the Desert Southwest***, a comprehensive resource adequacy outlook for the U.S. Southwest region. Conducted shortly after high-profile reliability events in California (2020) and Texas (2021), the 2021 study quantified the resources needed to maintain regional reliability and evaluated whether utilities' plans would be sufficient to meet those needs using industry-leading loss-of-load-probability modeling. The study highlighted three key findings:

1. Load growth and aging plant retirements are creating a significant need for new capacity (13+ GW of effective capacity across the region by 2033) – but utilities' current resource plans have identified resources sufficient to meet those needs
2. A large share of the region's needs will be met with solar, storage, and other "non-firm" resources – but firm resources will remain essential for reliability
3. The scale of new resource additions needed requires unprecedented levels of development, necessitating immediate and sustained action over the next decade

These conclusions, as well as the study's thorough description of resource adequacy best practices, have since helped shape the regional discourse on resource adequacy.

Looking forward, the region's utilities face an increasingly complex set of challenges in planning a reliable electricity system. Transformational changes with direct implications upon the electricity system – some anticipated and some unforeseen – are underway, creating an environment of elevated complexity, uncertainty, and risk. These key developments are shown in Figure 1-1.

Figure 1-1. Key trends in the Southwest with direct implications for resource adequacy



Despite these developments, this assessment reaffirms the conclusions reached by the 2021 study, underscoring a pressing need for new resources and the importance of successful implementation of plans to ensure regional resource adequacy. In addition to reaffirming the prior study's near-term conclusions, this study extends the analysis to include a longer-term resource adequacy outlook beyond 2035.

1.1. Study Scope and Purpose

In light of these developments, the six utilities that sponsored *Resource Adequacy in the Desert Southwest* commissioned this follow-up study to provide an updated outlook of resource adequacy for the region. This study's scope is more expansive than the previous assessment, including both near-term and long-term evaluations of regional resource adequacy. The two assessments focus on different questions and rely on different modeling approaches:

- The **"Near-Term Assessment,"** which provides an updated projection of the region's resource adequacy position over the next decade based on utility plans, reprises the analytical methods used in the previous study using updated input data and considers the current progress and challenges towards implementing resource plans.
- The **"Long-Term Assessment"** extends beyond the scope of the prior study to evaluate the region's resource adequacy needs over a twenty-year period, exploring the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs. It does so by constructing and analyzing multiple hypothetical portfolios across a range of load forecasts and clean energy penetrations.[1] These portfolios are not projections or regional forecasts, but instead collectively show a range of potential long-term outcomes.

These two analyses complement to one another: the near-term analyses focus on the specific question of whether utilities' plans will be sufficient to maintain resource adequacy in the coming decade, while the long-term analysis explores a broader range of potential long-term portfolios, providing context for how near-term plans align with long-term needs. The scope and design of these two complementary efforts are contrasted in Table 1-1.

[1] The different clean energy penetrations are a key study design element and does not reflect the region nor any individual utility's goals. Changing the clean energy penetrations allows the study to explore common and uncommon patterns across a broader range of possible future portfolios and energy mixes.

Table 1-1. Contrasting scopes for the near-term and long-term assessments of resource adequacy

Study Element	Near-Term Assessment	Long-Term Assessment
Time Horizon	**Ten years** *(2025-2035)*	**Twenty years** *(through 2045)*
Modeling Tools	**RECAP** *(loss-of-load-probability)*	**PLEXOS & RECAP** *(long-term capacity expansion & loss-of-load-probability)*
Load Forecast	**Single load forecast** *provided as inputs by utilities and aggregated by E3*	**Three load forecasts** *developed by E3 to reflect a range of long-term growth outcomes*
Resource Portfolios	**Single portfolio** *provided as an **input** by utilities*	**Twenty-three portfolios** *created as **outputs** using LTCE*
Principal Study Question	***Are utilities' resource plans sufficient to meet near-term resource adequacy needs of the region?***	***What are the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs?***

Both phases of analysis in this study focus on evaluation of resource adequacy at a regional scale, and do not account for certain details or constraints that may impact the specific decisions made by each utility to meet its resource adequacy needs while balancing other planning objectives. Examples of utility-specific considerations that are not captured directly in this analysis include: (1) transmission deliverability, (2) constraints on fuel supply, (3) utility-specific portfolio considerations, and (4) regional resource adequacy programs (e.g. Western Resource Adequacy Program). As such, while the analysis provides useful indicative and directional results to present a picture of resource adequacy needs at a regional level, the analysis presented herein should not be viewed as a substitute for or alternative to each individual's planning processes.

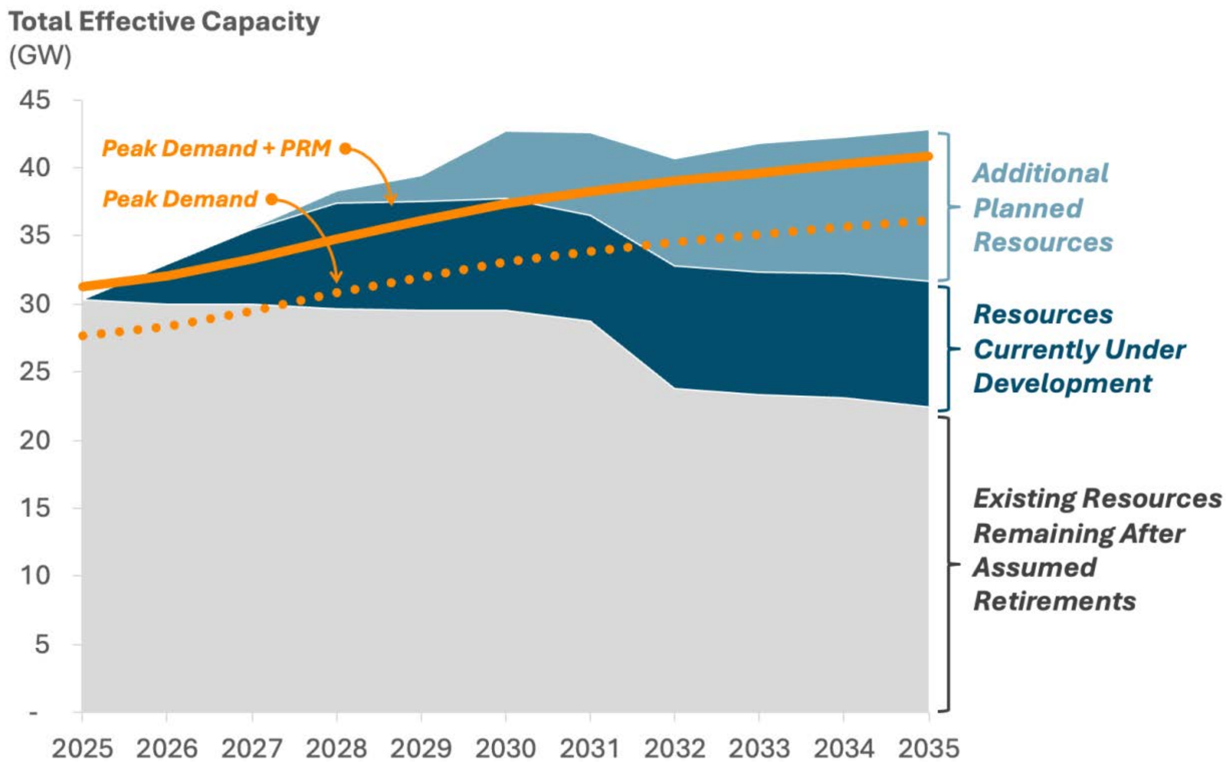
1.2. Near-Term Assessment Highlights

The near-term reliability outlook presented here uses load forecasts and resource portfolios provided by utilities in early 2025. Since that time, utilities have continued to update load forecasts and adjust resource plans in response to continuously changing conditions. For this reason, these results do not reflect the most current outlook for loads and resources within the region, but nonetheless serve as a useful directional indication of the relative scale of resource needs and provides validation that utility planning processes continue to identify resource portfolios capable of meeting regional reliability needs.

The near-term assessment provides a focused analysis on the adequacy of utilities' resource plans to maintain a level of reliability corresponding to a regional LOLE of 0.1 days per year or better. This analysis is conducted based on demand forecasts and portfolios provided directly by the utilities, which are analyzed using E3's RECAP model for LOLP modeling. Based on this analysis, Figure 1-2 shows the projected load-resource balance for the region under the assumptions used in this study, including both change in regional capacity need with growing loads and the effective capacity provided by existing resources, resources under development, and generic resources included in utility plans.

- Over the next decade, the aggregated demand forecasts identified across utility plans increase by 30%, or a total of over 8,000 MW. Incorporating a planning reserve margin of 13%, load growth increases the regional need for effective capacity by nearly 10,000 MW.
- At the same time, the retirements and expiring contracts of coal and natural gas plants assumed in this study result in the loss of approximately 8,000 MW of effective capacity.
- In conjunction, these two factors create a need for 18,000 MW of new effective capacity over the course of the next decade to maintain regional resource adequacy.
- Resources currently under development are poised to meet a portion of those needs, providing just over 9,000 MW of effective capacity and positioning the region to maintain load resource balance over the next several years.
- The additional generic resources included in utility plans are sufficient to close the remaining gap, creating some headroom in advance of planned resource retirements and satisfying the need for new capacity over the coming decade.

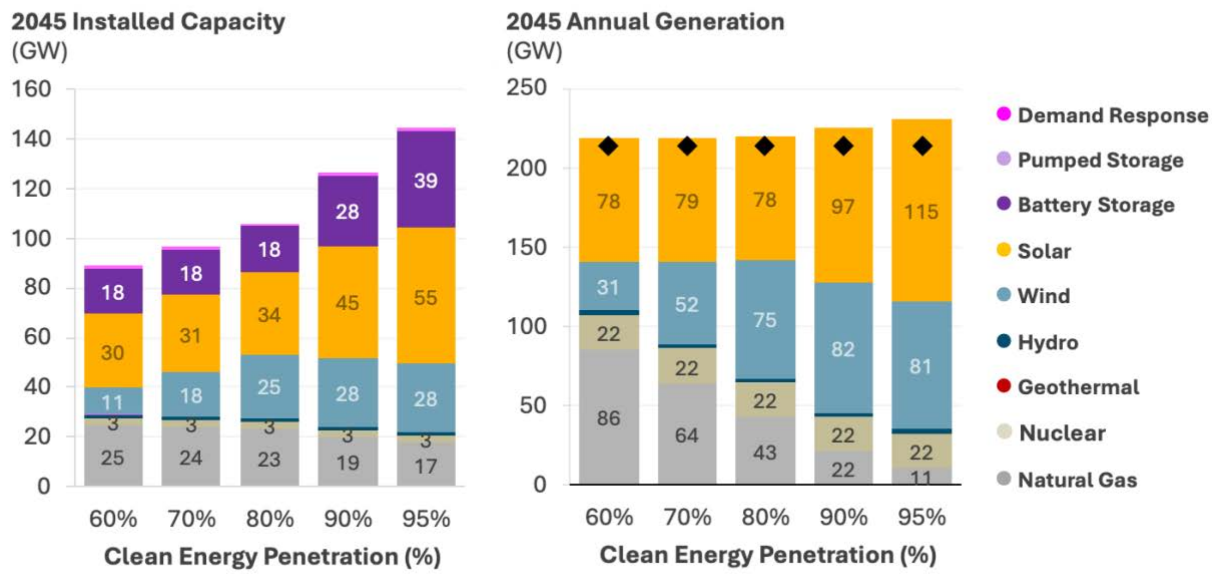
Figure 1-2. Projected regional load-resource balance according to utility plans current as of Q1 2025



1.3. Long-Term Assessment Highlights

The installed capacity and annual generation by resource type for five portfolios spanning clean energy penetrations from 60 to 95% under the Reference load forecast are shown in Figure 5-5. This collection of portfolios, each designed to meet a regional resource adequacy target of 0.1 days per year, show a range of plausible pathways to meet long-term energy and resource adequacy needs in the Southwest region.

Figure 1-3. Installed capacity and annual generation mix at different clean energy penetrations, Reference load forecast



Several observations are self-evident in these portfolios:

- While the specific quantities vary, all portfolios meet regional resource adequacy needs with a diverse mix of firm (gas and nuclear), renewable (wind and solar), and energy-limited (storage, DR, and hydro) resources.
- The differences in capacity among portfolios provides a measure of the relative effectiveness of firm, variable, and energy-limited resources in contributing to resource adequacy needs: from 60 to 95%, the total quantity of incremental renewables (+42 GW) and storage (+21 GW) is nearly eight times greater than the quantity of natural gas resources displaced (-8 GW).
- While the share of the energy mix served by natural gas decreases in inverse proportion to the penetration of clean energy resources, the amount of installed capacity needed to maintain reliability does not exhibit the same decline. Even in a 95% clean energy portfolio where natural gas accounts for only 5% of annual energy, the installed capacity of natural gas resources necessary to ensure reliability (17 GW) is roughly 40% of the system peak demand.

Additional sensitivities examine alternative load forecasts and the availability of emerging technologies, and while the composition of the portfolios adjust according to the specific assumptions made, the general observations described above hold true across all scenarios modeled.

1.4. Key Findings

The near-term and long-term assessments inform six key findings from this assessment. The first three focus primarily upon the results of the near-term assessment, and the second three build upon these based on the results of the long-term assessment.

1. Need for New Resources is Urgent

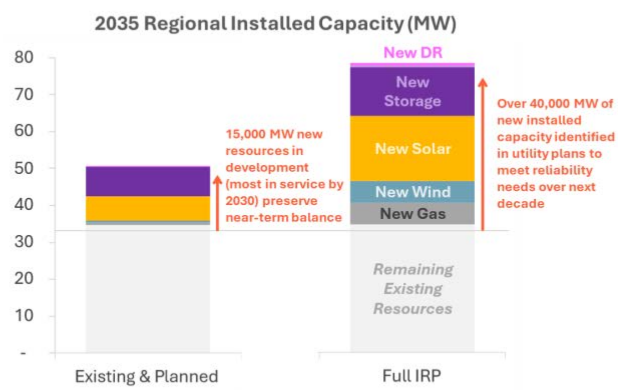
Large increases in regional demand, coupled with anticipated retirements, continue to drive a significant need for new resources across the region to maintain reliability

Over the next decade, the anticipated demand based on utility inputs to this study shows regional coincident peak demand increasing from roughly 27,500 MW to over 36,000 MW. At the same time, assumed retirements and expiring contracts with existing resources result in the loss of nearly 8,000 MW of effective capacity from the 2025 existing portfolio. For a system at or near load-resource balance today, the compound effect of these two changes is a total need for new *effective* capacity of roughly 18,000 MW over the next decade.

2. Utility Plans Demonstrate Adequacy

Over the next decade, utilities' resource plans include new natural gas, renewables, and storage sufficient to maintain regional resource adequacy

Collectively, the utilities' resource plans provided as inputs for this assessment include over 40,000 MW of new installed capacity by 2035. If these resources are successfully brought in service according to prescribed schedules – which will require a rate of new resource additions far greater than recent historical trends – this study shows that the region will maintain sufficient generating capacity to ensure a level of resource adequacy consistent of LOLE of 0.1 days per year or better.



Notably, the *nameplate* capacity of the resource additions included in utility plans (40,000 MW) far exceeds the amount of *effective* capacity they provide to the system to ensure reliability due to the inherent limitations of variable and energy-limited resources.[2]

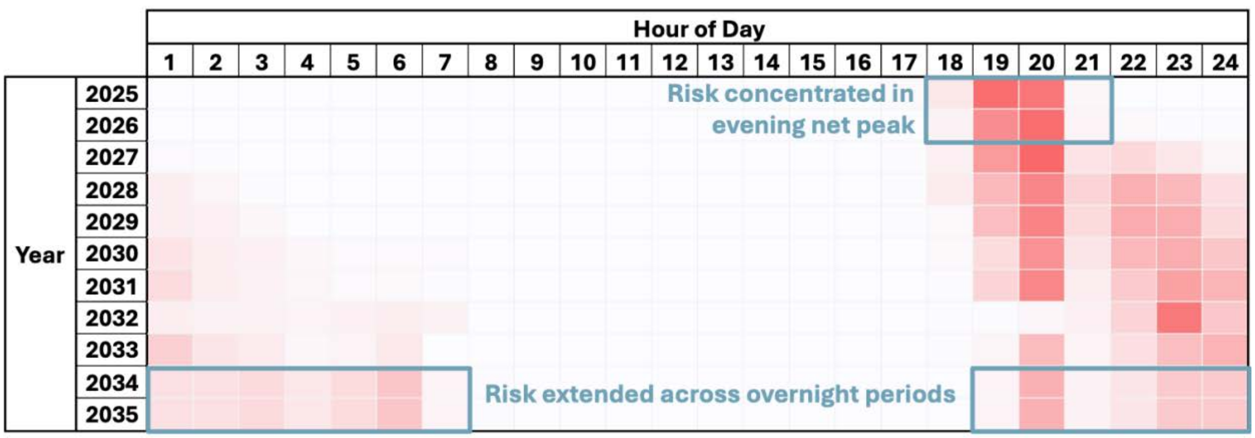
[2] Effective capacity (or perfect capacity) measures a resource's contribution to resource adequacy, typically measured against a "perfect resource" or a resource that is available at all times.

3. Reliability Risks are Shifting Rapidly

Reliability risk has already shifted from afternoon peak to the evening "net peak," and will extend deeper into overnight periods as resource mix evolves

The Southwest utilities are planning to meet a growing share of future resource adequacy needs with renewable and energy storage resources; by 2035, these resources are projected to account for roughly half of the total effective capacity in the region. These portfolio changes directly impact the timing of reliability risks, which shift away from the traditional peak period as penetrations of variable resources rise. This effect is already present in today's system, as the growth of solar has caused risk to shift into the evening. Over the next decade, increasing levels of energy-limited resources will continue to shift and extend the periods when the system is at the edge of reliability (see Figure 1-4). Based on utility plans, higher risks in the late evening and overnight periods could begin to emerge as soon as 2027.

Figure 1-4. Relative loss-of-load risk by time of day based on utility plans, 2025-2035



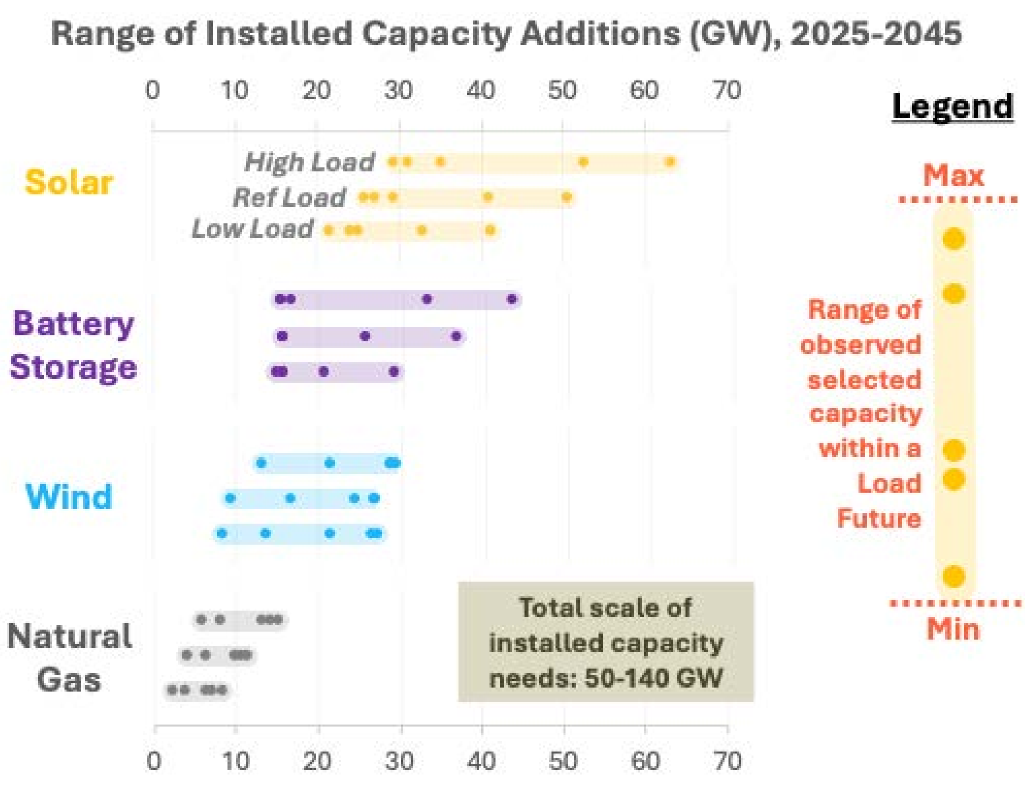
These effects are caused by evolving portfolio identified across all utilities to meet their needs, and in turn, directly impact the contributions that additional resources can make to resource adequacy in multiple ways. With existing solar penetration shifting risk to late evenings, marginal solar additions provided limited reliability value (marginal solar provides between 5 to 7%). Beyond 2027, the extension of risk into the overnight periods contributes to the observed declines in the marginal capacity value of short-duration storage resources (4-hr storage decreases from 90% in 2025 to 38% in 2035), which in turn increases the relative value of resources that can provide longer duration services to the grid and firm resources capable of generating over sustained periods without limits on their use.

4. Diversity is a Robust Long-Term Strategy

Meeting growth with a combination of new gas, renewables, and storage resources is a robust strategy across a wide range of longer-term future conditions

Beyond 2035, maintaining resource adequacy, as loads continue to grow and existing resources retire, will require substantial investments in new resources. This study demonstrates that regional resource adequacy can be met with a wide range of resource mixes, showing reliable resource portfolios that span from 60 to 95% clean energy; across all portfolios studied, the total amount of new installed capacity added between 2025 and 2045 ranges from 50 to 140 GW. In all cases where the availability of commercially available technologies is not explicitly restricted, long-term needs are met by a diverse mix of new renewables, storage and natural gas resources; the range of new resource additions by technology across the twenty-year period are shown in Figure 1-5. To the extent emerging technologies mature, they may also contribute to regional resource adequacy needs (as evidenced by the selection of new nuclear in several portfolios) but do not appear to diminish the importance of resource diversity. All portfolios also include continued expansion of energy efficiency and demand response; beyond these levels, additional demand-side resources (including behind-the-meter generation, virtual power plants, and incremental energy efficiency and demand response) could also contribute to meeting regional needs if they provide capabilities aligned with the future needs of the electricity system.

Figure 1-5. New installed capacity additions from 2025 to 2045 across portfolios in the long-term assessment

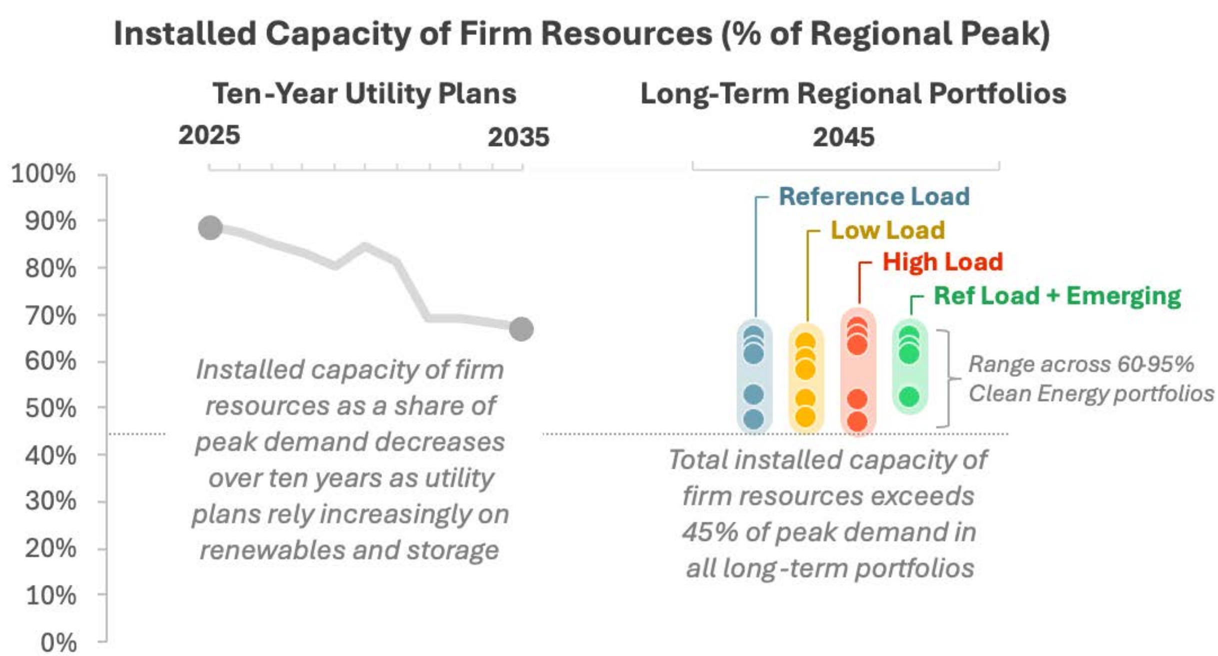


5. Firm Resources are Critical to Reliability

Firm generation resources remain essential to ensuring long-term resource adequacy and mitigating risks of large energy deficiencies, particularly during periods when renewable output is low

While the contributions of variable and energy-limited resources to resource adequacy are substantial across all portfolios analyzed, both categories of resources are subject to significant declines in their marginal capacity value at higher penetration. In practice, this means that even if portfolios include renewables and storage capable of serving most annual energy needs, ensuring resource adequacy also requires “firm” resources capable of producing energy across sustained periods when renewables and energy storage may be unavailable. Across all portfolios analyzed in the long-term assessment where new firm resource options are unconstrained, their total installed capacity ranges between 45-70% of system peak demand (Figure 1-6). In all long-term portfolios, nuclear and natural gas resources play a critical role in ensuring reliability when electric demand is high, renewable availability is low, and energy storage resources have been depleted (for instance, during cloudy winter weeks). Under such conditions, resources with the capability to generate on demand for as long as necessary allow the system to maintain reliability.

Figure 1-6. Summary of firm resource contributions across near-term and long-term assessments

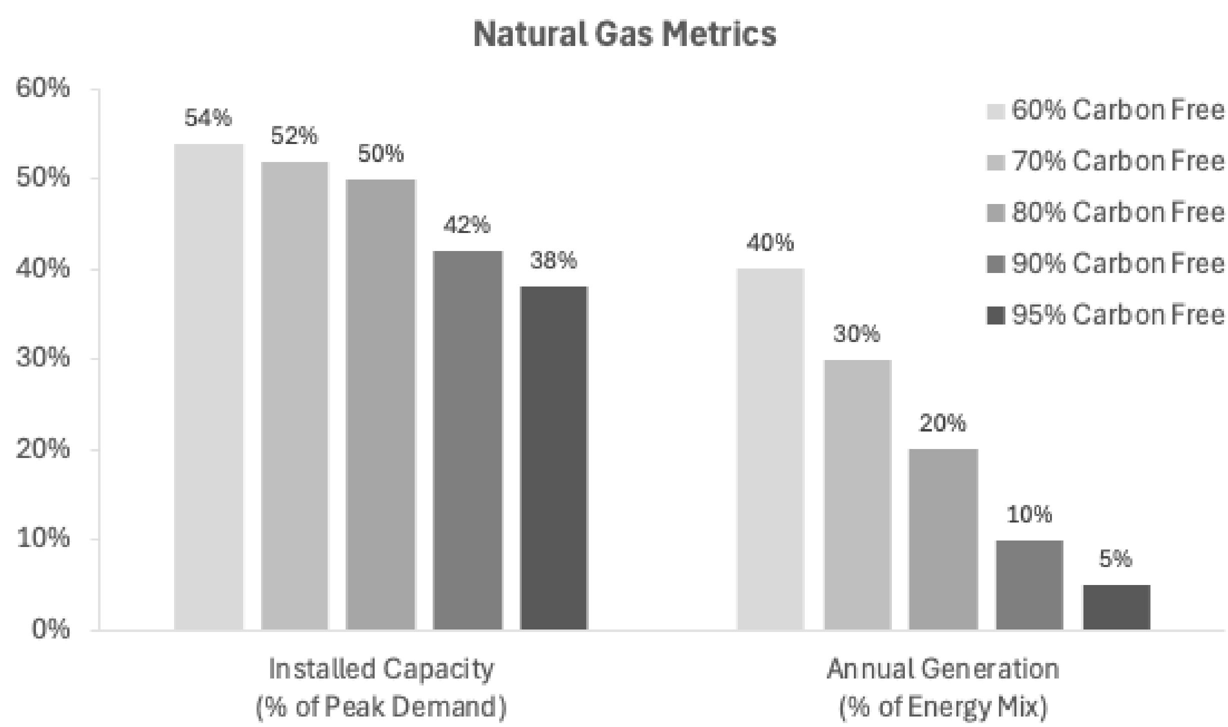


6. Natural Gas Remains the Primary Firm Option

Across all portfolios, natural gas fulfills the majority of the region's long-term need for firm resources, even under the highest clean energy penetrations studied.

The range of portfolios in the long-term assessment yields useful insights into the future adequacy of natural gas, captured through three metrics, shown in Figure 1-7: (1) **installed capacity,** the total gas capacity needed to ensure reliability and (2) **annual generation,** the share of regional energy produced by gas-fired resources. Across the portfolios, as clean energy penetration rises from 60 to 95%, annual gas generation falls sharply (from 40% to 5% of total energy) while installed capacity declines only modestly, from 54 to 38% of peak demand. This contrast is the key finding: increasing clean energy primarily reduces how often gas resources must run, not how much capacity is required. Even at 95% clean energy, a large amount of natural gas capacity (nearly 40% of peak demand) plays a critical reliability role, where it serves as a rarely-used backstop option during periods of low renewable output.

Figure 1-7. Key metrics for natural gas fleet in long-term adequacy assessment



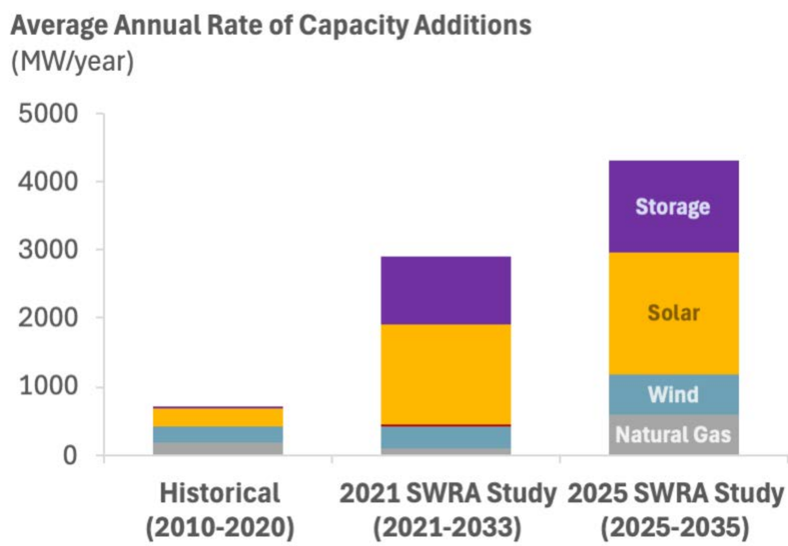
These results further underscore the finding that additions of new natural gas resources to the region are part of a robust strategy to meet near- and long-term resource adequacy needs, capable of supporting grid reliability across a wide range of future clean energy penetrations and load levels.

1.5. Study Implications

Both the 2021 and 2025 assessments indicate that, despite increasing portfolio complexity and evolving resource adequacy risks, the utilities' collective planning practices are effective in their identification of resource portfolios with the technical ability to maintain regional resource adequacy. Notably, the two assessments reached this conclusion while evaluating different load forecasts and resource portfolios. The consistency of this technical result provides strong evidence that utilities' methods and analytical toolkits provide a sound foundation for resource adequacy planning, and that utilities have used this foundation to adjust plans quickly in response to the changing outlook for future demand.

Having demonstrated that the utilities' plans have the technical capability to meet projected needs, the most immediate challenge for maintaining regional resource adequacy lies in successful implementation. Meeting the needs forecasted in this study would require that utilities add over 4,000 MW of new installed capacity to the system each year over the next decade – a quantity that exceeds the necessary rate of additions previously identified in the 2021 study and eclipses the long-term historical average by a factor of four (see Figure 6-5).

Figure 1-8. Comparison of annual average capacity additions



In an environment marked by heightened uncertainty and rapid change, translating these plans into reliable real-world outcomes presents a more multifaceted set of challenges than the planning itself. Successful implementation will require coordinated orchestration across a range of processes, systems, and institutions involving a wide range of regional stakeholders. The region's utilities will naturally play a central role in each step of implementation, but the ultimate outcomes will reflect the collective performance of actors and systems that no single entity controls. Given the rapid pace of change and potential for unanticipated shifts in the energy landscape, even well-formulated plans will likely require frequent reevaluation and revision; the ability to monitor emerging conditions, identify gaps early, and adapt accordingly will be as important as the plans themselves. The risk factors in Table 1-2 represent the most significant aspects of implementation required to ensure resource adequacy.

Delays or unexpected obstacles caused by any one of these factors – or further increases in regional demand not anticipated at the time of this study – could jeopardize utilities' ability to add resources to the system at the pace needed to meet regional growth projections reliably. To mitigate these risks and support successful implementation, utilities and regional stakeholders can focus on several near-term actions.

While these actions cannot fully eliminate implementation risk, sustained focus in these areas will improve the likelihood that planned resources are delivered on time and that regional reliability is maintained under increasingly uncertain conditions.

Table 1-2. Summary of implementation considerations and potential strategies to limit risk

Implementation Consideration	Description of Potential Risks	Potential Solutions
Load Forecast Uncertainty	Large customer growth continues to be highly uncertainty, making reliability planning a moving target	• Strengthen interconnection and service agreements • Design rates or tariffs that better align large customer development with system planning needs
Procurement Risk & Supply Chain	Supply chain constraints have led to increasing project costs, longer lead times for equipment, and project delays and cancellations	• Initiate procurements earlier in advance of resource need • Maintain diversified pipeline of projects • Incorporate flexibility to account for delays or cancellations • Leverage cost-effective demand-side programs to limit bulk system needs
Transmission Interconnection & Deliverability	Large scale of resource development will also require coordinated buildout of transmission system, which can include longer study processes and long lead times	• Pursue parallel development of generation and transmission through Integrated System Planning • Prioritize transmission upgrades that unlock multiple resources • Repurpose existing infrastructure made available as legacy plants retire
Permitting & Regulatory Approval Processes	New projects require permits and regulatory approvals from a variety of bodies (e.g. local governments, regulatory agencies and boards, and federal bodies) – each of which poses potential to delay development	• Engage early with permitting agencies and local communities • Explore potential to streamline local permitting with model ordinances • Repurpose brownfield power plant sites
Operations & Market Integration	Increasingly penetrations of variable and energy-limited resources add complexity to grid operations, requiring accurate forecasting and sophisticated dispatch algorithms to maximize storage value	• Invest in advanced forecasting, grid visibility tools, and optimized dispatch strategies • Coordinate with market operators to ensure market rules enable maximum storage value
Fuel Supply	Plans to right-size fuel transportation rights for a growing gas fleet depend in part on development of a new interstate pipeline, a large multijurisdictional infrastructure project that could experience delays for a variety of reasons	• Secure fuel transportation capacity • Identify short-term risk mitigation strategies to ensure adequacy in the event of delay

2. Introduction

In 2022, E3 published ***Resource Adequacy in the Desert Southwest***, a thorough analysis of the resource adequacy outlook for the region over the coming decade. Following shortly after high profile reliability events in California (2020) and Texas (2021), this study sought to quantify the resource needs to ensure reliability and evaluate the adequacy of utilities' plans to meet those needs using industry-leading loss-of-load-probability modeling. Three key findings emerged from the analysis:

1. Load growth and aging plant retirements are creating a significant need for new capacity (13+ GW of effective capacity across the region by 2033) – but utilities' current resource plans have identified resources sufficient to meet those needs
2. A large share of the region's needs will be met with solar, storage, and other "non-firm" resources – but firm resources will remain essential for reliability
3. The scale of new resource additions needed requires unprecedented levels of development, necessitating immediate and sustained action over the next decade

These key findings, as well as the study's thorough description of resource adequacy best practices, have since helped shape the regional discourse on resource adequacy.

2.1. Key Developments Since 2021

Since 2021, observed resource additions in the Southwest have largely aligned with projections from five years ago. While load growth has slightly outpaced prior forecasts, the region has largely maintained a stable balance of loads and resources during this period.

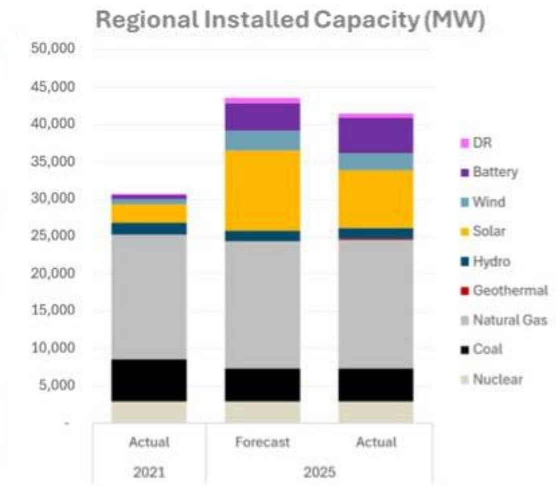
- Regional electricity demand has grown at a slightly faster rate than anticipated, exceeding previous forecasts by roughly 750 MW.
- The capacity of firm resources (nuclear, coal, and gas) has closely aligned with projections, showing a slight reduction since 2021 with retirements at Cholla and San Juan power plants.
- Additions of solar and wind resources have lagged projections by roughly 3,000 MW and 500 MW, respectively; a reflection of development challenges experienced by many of the projects under development in the region;
- Additions of energy storage resources have exceeded previous projections by roughly 1,000 MW, helping preserve load-resource balance despite other headwinds and stressors.

A summary comparison between the 2025 projections from the 2021 study and actual current conditions is provided in Figure 2-1.

Figure 2-1. 2025 system comparison: projections from 2021 study vs. actual

Comparing the Outlook for 2025 vs. Actual Results

Impact on Resource Adequacy : Actual vs. Forecast		
Load Growth	🟡	Load growth slightly higher than forecast: Actual CP (**27,500 MW**) vs. forecast CP (**26,750 MW**)
Coal Retirements	-	Cholla & San Juan retired as planned
Natural Gas Additions	-	Small capacity upgrades, no major new generation projects added through 2025
Renewable Additions	🟡	Fewer new solar resources added than plans
Storage Additions	🟢	More new energy storage resources developed
Overall Regional Position	🟡	**Regional resource adequacy position slightly tighter than anticipated**



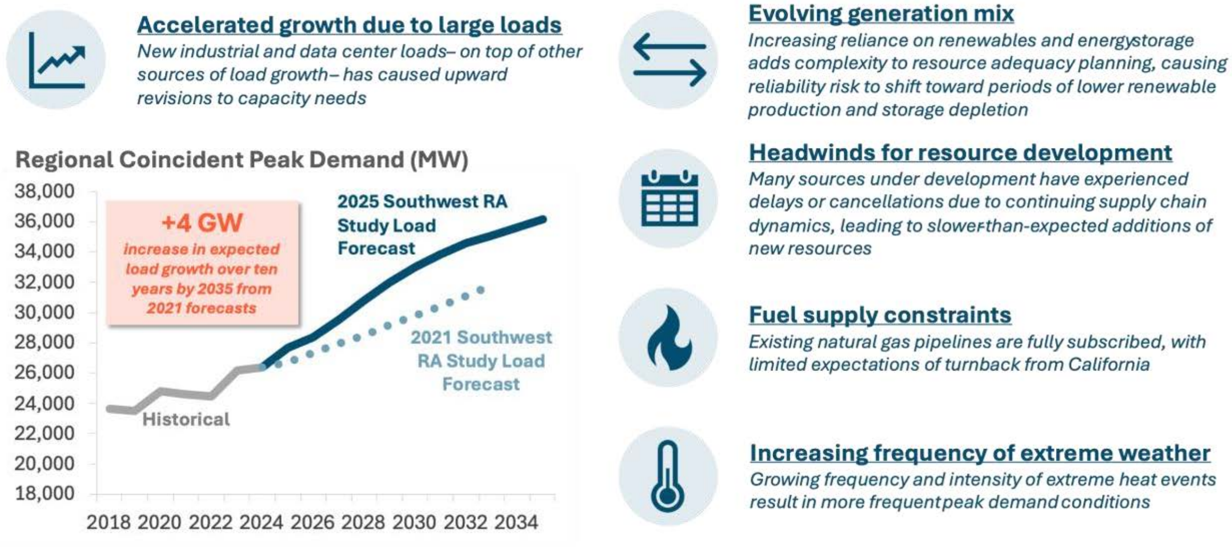
Looking forward, the region's utilities will continue to face an increasingly complex set of challenges in planning a reliable electricity system. Transformational changes with direct implications upon the electricity system – some anticipated and some unforeseen – are underway, creating an environment of elevated complexity, uncertainty, and risk. These include:

- **Accelerating load growth,** due primarily to an increase in the number of data centers and other large manufacturing and industrial customers seeking electric service in the Southwest;
- **Evolving resource mix** and the corresponding task of planning and operating an increasingly complex electricity system that includes a mix of firm, variable, and energy-limited resources.
- **Resource development headwinds,** including delays and cancellations of projects under development, as constraints in global and domestic supply chains have driven unanticipated cost increases and equipment backlogs;[3]
- **Fuel supply constraints,** as the existing interstate pipeline system that delivers natural gas to generation resources within the region is nearly fully subscribed;
- **Increasing frequency of extreme weather,** including record-breaking heat waves in key population centers[4];

These evolving trends and the challenges they pose to utilities are summarized in Figure .

[3] Between 2021 and 2025, increased demand for all resources, but supply chains
[4] See, for example: https://www.nytimes.com/2023/07/31/us/phoenix-heat-july.html

Figure 2-2. Key trends in the Southwest with direct implications for resource adequacy



2.2. Study Scope and Purpose

In light of these developments, the six utilities that originally sponsored *Resource Adequacy in the Desert Southwest* have commissioned this study to provide an updated forward-looking view of resource adequacy across the region. This study's scope is more expansive than the previous assessment, including both near-term and long-term evaluations of regional resource adequacy needs. The two assessments focus on different questions and rely on different modeling approaches to answer them:

- The **"Near-Term Assessment,"** which focuses on the region's position over the next decade based on utility plans, reprises the modeling tools and approach used in the previous study to provide an updated outlook on resource adequacy.
- The **"Long-Term Assessment"** extends beyond the scope of the prior study to evaluate the region's resource adequacy needs over a twenty-year period, exploring the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs. It does so by constructing and analyzing multiple hypothetical portfolios across a range of load forecasts and clean energy penetrations.[5] These portfolios are not projections or regional forecasts, but instead collectively show a range of potential long-term outcomes.

These two analyses complement one another: the near-term analyses focus on the specific question of whether utilities' current plans will be sufficient to maintain resource adequacy in the coming decade, while the long-term analysis widens the aperture to explore a broader range of potential

[5] The exploration of clean energy penetration across different portfolios is a specification enforced for this study's design. With this specification for each portfolio, the study can explore a range of portfolios with different resource mixes, varying in levels of gas, storage, and renewables to meet resource adequacy in the Southwest.

long-term options that provide context for how decisions made in the near-term will impact the region across the next several decades.

The scope and design of these two complementary efforts are contrasted in Table 2-1.

Table 2-1. Contrasting scopes for the near-term and long-term assessments of resource adequacy

Study Element	Near-Term Assessment	Long-Term Assessment
Time Horizon	**Ten years** *(2025-2035)*	**Twenty years** *(through 2045)*
Modeling Tools	**RECAP** *(loss of load probability)*	**PLEXOS & RECAP** *(long-term capacity expansion & LOLP)*
Load Forecast	**Single load forecast** *provided as inputs by utilities and aggregated by E3*	**Three load forecasts** *developed by E3 to reflect a range of long-term growth outcomes*
Resource Portfolios	**Single portfolio** *provided as an **input** by utilities*	**Twenty-three portfolios** *created as **outputs** using LTCE*
Principal Study Question	***Are utilities' resource plans sufficient to meet near-term resource adequacy needs of the region?***	***What are the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs?***

Both phases of analysis in this study focus on evaluation of resource adequacy at a regional scale, and do not account for specific details or constraints that may impact the decisions made by each individual utility to meet its resource adequacy needs while balancing other planning objectives. Examples of utility-specific considerations that are not captured directly in this analysis include: (1) transmission deliverability, (2) constraints on fuel supply, and (3) utility-specific portfolio considerations. As such, while the analysis provides useful indicative and directional results that present a picture of resource adequacy needs at a regional level, the analysis presented herein should not be viewed as a substitute for or alternative to each individual utility's planning processes.

2.3. Report Contents

The remainder of this report is organized as follows:

- **Section 3** provides general background on resource adequacy and discusses key trends impacting resource adequacy planning for Southwest utilities;
- **Section 4** presents the near-term resource adequacy assessment;
- **Section 5** presents the long-term resource adequacy assessment; and
- **Section 6** provides key findings of the two assessments and discusses their implications.

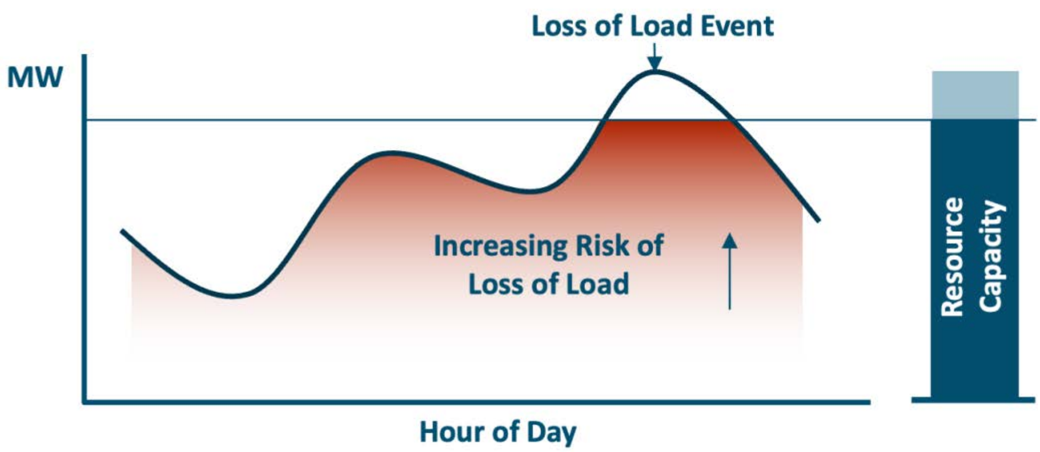
3. Study Background

3.1. Defining Resource Adequacy

> **NERC Definition of Resource Adequacy**
> *"The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."*

Resource adequacy is the ability of an electric power system to produce sufficient generation to meet loads across a broad range of weather and system operating conditions, subject to a long-run reliability target that limits the frequency of shortfalls to very rare instances. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers.

Figure 3-1. Illustration of a loss of load event due to insufficient generation



While there is no single mandatory standard defined for resource adequacy, many utilities – including all sponsors of this study – rely on some interpretation of the "one day in ten years" planning target. While this rule of thumb has been interpreted in a number of different ways, the most common interpretation relies allows for a Loss of Load Expectation (LOLE) of 0.1 days per year. While there is no formal resource adequacy standard currently established for the Southwest region as a whole, the near-ubiquity of the one-day-in-ten-year target makes it useful as a benchmark for this study, and regional resource adequacy is evaluated relative to an LOLE of 0.1 days per year.

3.2. Recent Industry Trends and Developments

3.2.1. Increasing Load Growth

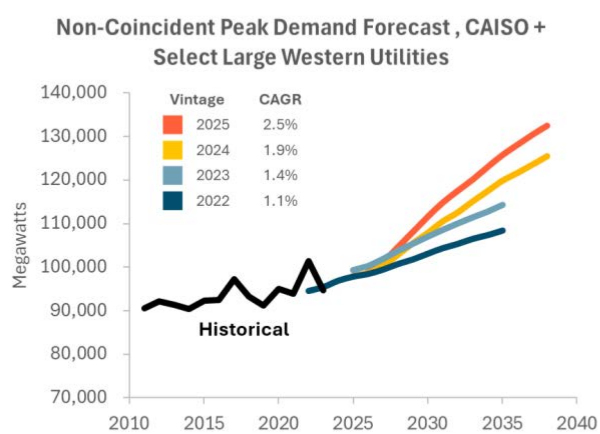
Arguably the most significant development since the 2021 study has been the increase in demand forecasts among utilities in the Southwest. These increases are largely the result of updates to the outlook for data centers and other large technological and industrial customers. The forecasts provided as inputs to this study, in aggregate, reflect a 20% increase in 2035 demand, a change that is almost entirely attributable to large customers.

This trend is not isolated to the Southwest: it is national in scope and scale. Multiple public studies suggest that rapid near-term growth could lead to a two- to three-fold increase in data center loads by the end of the decade:

- In a 2025 Grid Strategies report, the study states "Electricity usage is forecast to grow by an average of 5.7% per year over the next five years" and that "Data centers are the largest driver of demand and energy growth, accounting for about 55% of demand growth in utility load forecasts"
- A 2026 study published by EPRI, the findings reports that "In 2024, total U.S. data center nominal IT capacity is estimated to be 35 to 44 GW… By 2030, EPRI's scenarios for the realization of planned and announced projects result in a range of 56 to 132 GW U.S. total nominal capacity. "[6]

The trend of accelerating load growth is also apparent in recent demand forecasts published by utilities across the Western Interconnection. The effect of progressive increases in utility demand forecasts across the broader western region is illustrated in Figure , which shows the combined non-coincident peak demand forecasts for CAISO and select large western utilities in the West based on their most recent published forecasts at different moments in

Figure 3-2. Evolution of peak demand forecasts for large Western utilities since 2022



Represents sum of non-coincident peak demand for following jurisdictions: APS, CAISO, EPE, NVE, Pacificorp, PGE, PNM, PSCo, PSE, and TEP. Key updates by vintage:

- 2023: APS, CAISO, Pac, PNM, PSE
- 2024: CAISO, NVE, Pac, PNM, PSCo
- 2025: CAISO, EPE, Pac, PSE
- ***2026 (expected): APS, CAISO, NVE, PNM, TEP***

[6] Available at: https://powering-intelligence.epri.com

time.[7] Between 2022 and 2025, the compound annual growth rate among this group increased from just over 1% per year to 2.5% per year, resulting in an additional 10 GW of growth by 2035.

The challenges posed by the rapid growth of large customers are multifaceted:

- **Development Pace:** meeting the rapid pace of load growth requires a correspondingly rapid pace of new resource development, which creates strain upon global supply chains, local permitting processes, and a range of steps in the development process in between.
- **Forecast Uncertainty:** while the current pace of growth is rapid, long-term forecasts are subject to a heightened level of uncertainty; this uncertainty creates a confounding challenge for utilities making long-term investments to meet near-term growth;
- **Load Shape:** data centers and other large customers typically have relatively high "load factors" compared to residential and commercial customers, meaning that their loads are flatter throughout the day and year. As these loads become a growing share of the system, portfolios must be designed to account for round-the-clock needs of large customers.

3.2.2. Evolving Generation Mix

Due to wide-ranging technical, economic, and political forces, the composition of the generation mix is quickly shifting. Throughout the system, aging fossil generation resources are approaching the ends of their useful lives. In turn, the new resources added to the system to meet growing needs comprise a heterogenous mix of technologies, including natural gas, wind, solar, energy storage, and various demand-side resources. The transition of the electricity system to a more diverse mix of resources introduces new complexities to planning for resource adequacy.

For the purposes of describing the effects of different types of generation resources upon resource adequacy, generation resources can be classified into three broad categories:

- **"Firm"**: resources that can produce at or near maximum capacity for sustained periods of time, except when unavailable due to plant outages. Examples include nuclear, coal, and natural gas.
- **"Variable":** resources whose output varies hour by hour, typically as a function of meteorological conditions. Examples include wind and solar.
- **"Energy-limited":** resources with constraints on how long (and sometimes how often) they can generate at full capacity due to constraints that limit the amount of energy they can produce. Examples include hydroelectric generation, energy storage, and demand response.

Historically, most electricity systems have consisted primarily of firm resources, but as the penetrations of variable and energy-limited resources grow, their implications for resource

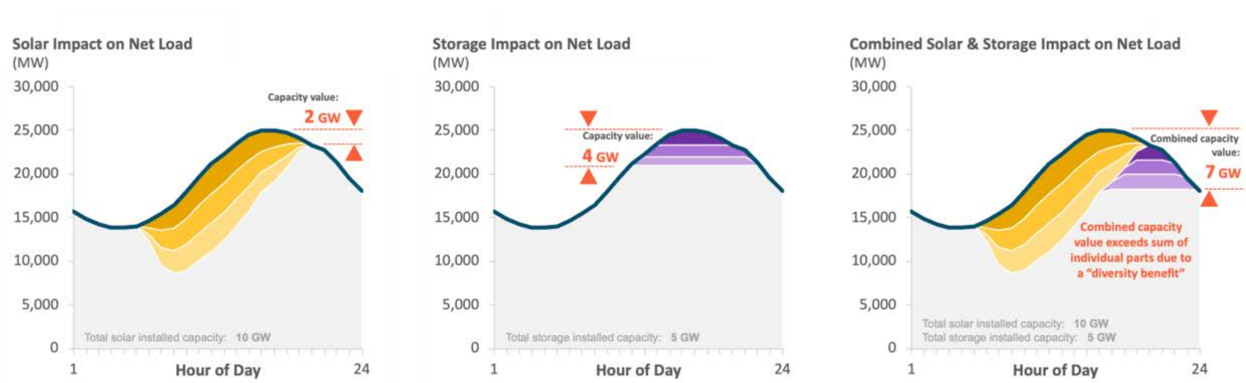
[7] While this graphic provides clear evidence of the trend of accelerating growth, it is also a lagging indicator: because many utilities release official load forecasts with integrated resource plans published on two- or three-year cycles, the forecasts included in the diagram above do not necessarily reflect each utility's most current expectations for load growth.

adequacy become significant. The contributions of variable and energy-limited resources differ from traditional firm resources in three important ways (illustrated in Figure 3-3.):

1. Because variable resource output is often lower than rated capacity during the periods in which supply is most constrained, the contribution of variable resources to resource adequacy is typically lower than their rated capacity. Further, as their penetration increases, the highest "net load" (load minus variable resource production, and a reasonable proxy for reliability risks) shifts away from system peak demand. In turn, this drives a "saturation effect" where the marginal value of variable resources decline with scale.
2. Because energy-limited resources have a finite ability to generate energy (e.g. a four-hour battery operated at full capacity will exhaust state of charge in four hours), they are also subject to saturation: as successive tranches of storage flatten net peak demand, the next tranche of storage must dispatch over a longer period to have the same effect.
3. The declining marginal value of both variable and energy-limited resources may be partially offset by the presence of interactive effects among different resources, often described as a "diversity benefit": a portfolio of complementary resources can provide a contribution to resource adequacy that exceeds the sum of its individual parts. The nature and size of this effect will vary based on the combination of resources (and can even be negative).

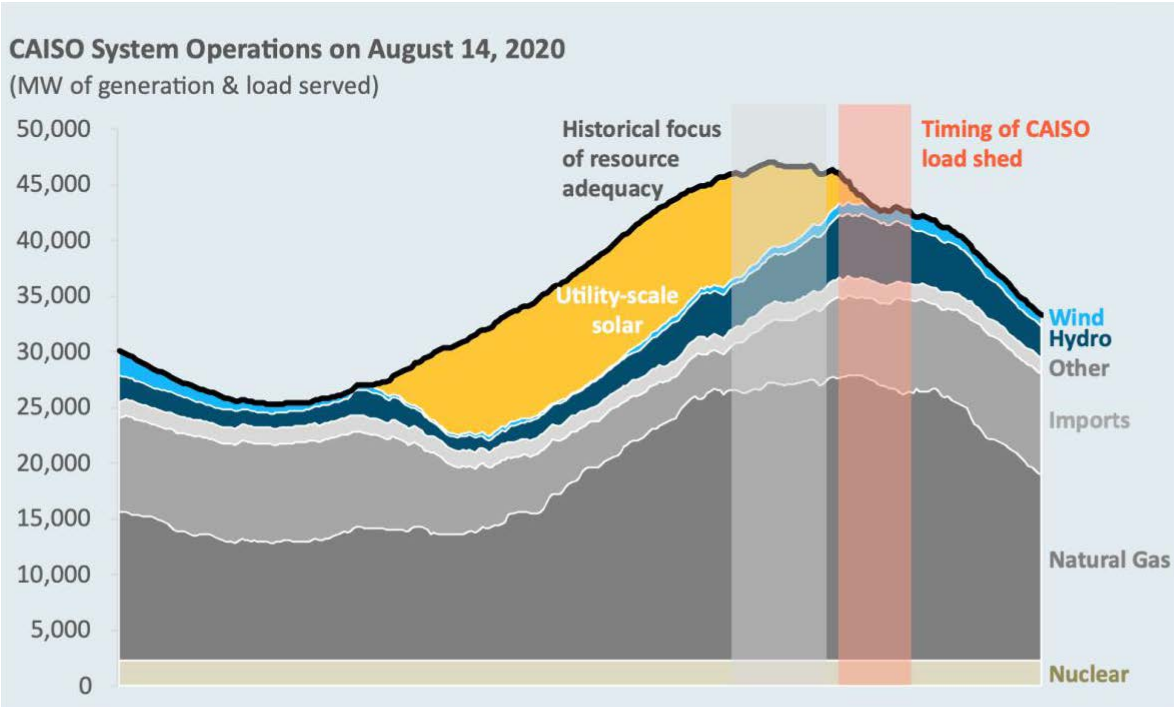
The underlying mechanism at the root of these complex, dynamic effects is the fact that increasing penetrations of both variable and energy-limited resources cause the periods of greatest reliability risk to shift away from the traditional peak period. As risk shifts or extends towards periods where a resource's availability is diminished, its marginal value declines; as risk shifts or extends into periods where a resource's ability is increased, its marginal value increases.

Figure 3-3. Illustrative impacts of solar and energy storage upon net load



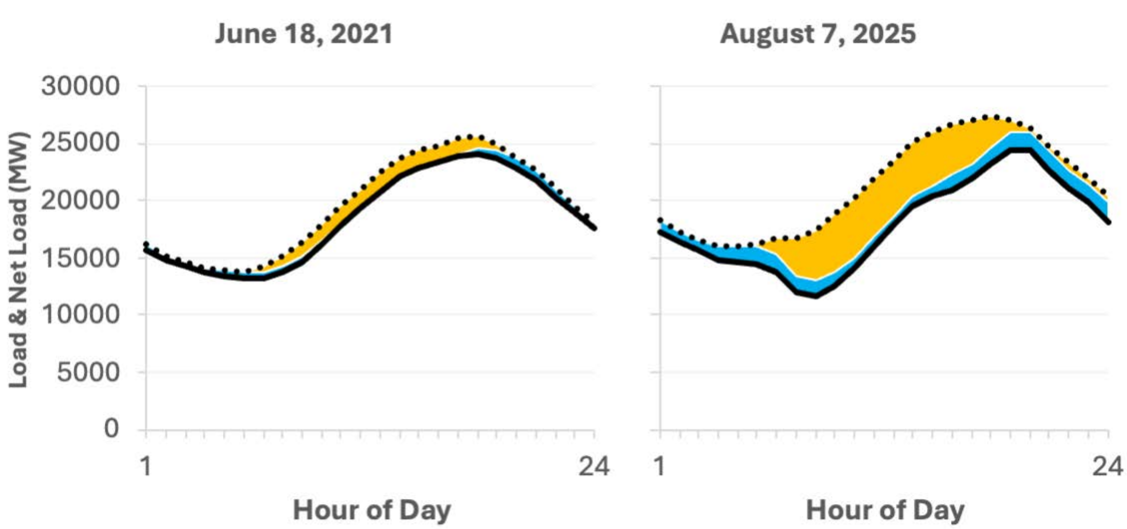
The August 2020 blackouts in California, highlighted in the 2021 study, remain the best real-world illustration of the shifting of reliability risks at higher penetrations of variable resources. Figure , developed from data published by CAISO, highlights the changing nature of resource adequacy risks under increased penetrations of solar; the period of the day during which load shedding was required occurred after the traditional peak period that has historically been the focus of resource adequacy planning.

Figure 3-4. CAISO system operations on August 14, 2020



Due to the large amount of solar generating capacity added in the Southwest region over the last five years, the same evening-peaking net load phenomenon is now also apparent. Figure compares the load and net load curves for the region on the regional peak days in 2021 and 2025, illustrating how the increasing penetration of solar has shifted the net load peak – and, by extension, the region's reliability risk, into the evening.

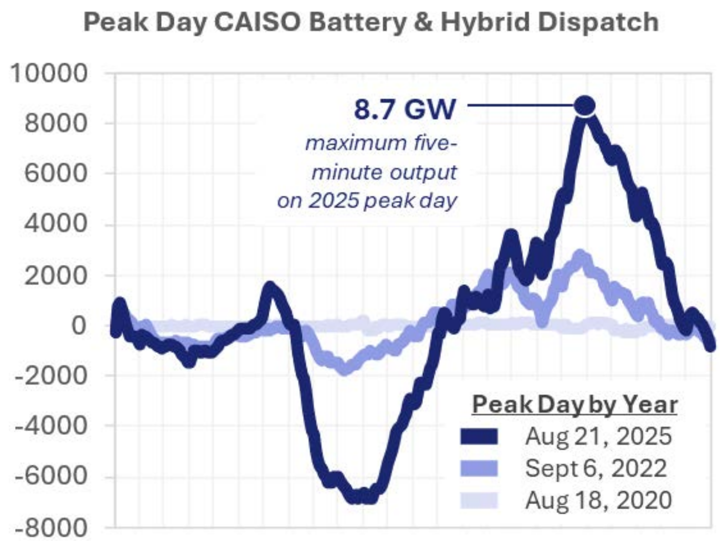
Figure 3-5. Load & net load curves for the Southwest region on regional peak days, 2021 and 2025



The real-world impact of energy storage on electricity systems is also now readily apparent. Since 2021, energy storage has matured from a technology in the early phases of commercial deployment (XX GW installed nationally at the end of 2021) to a proven resource at grid scale (XX GW at the end of 2025). Nowhere is its current impact on grid operations and its contribution to resource adequacy greater than in California, where battery storage resources in CAISO reached a five-minute maximum output of nearly 9 GW during the net peak period and into the evening on the day of the highest electricity demand (see Figure).

While significant amount of storage in the California system is now playing a key role in grid operations, the penetration is quickly approaching levels where the saturation effects described above are expected to emerge in the near future. The most recent analysis published by the California Public Utilities Commission projects that the marginal capacity value of storage will decline from 92% in 2026 to 75% by 2028 and 22% by 2030 as "critical hours spread to late afternoon and later into the night, contributing to storage ELCC declines."[8]

Figure 3-6. Dispatch of CAISO energy storage resources on select peak days



As the penetration of renewables, storage, and other non-firm resources continue to grow, so will the prominence of these complex dynamics. One of the implications that follows from these evolving challenges is that the timing of reliability risks will continue to shift towards periods when non-firm resources are not available – often periods of lower renewable production. During these periods, firm generation is the remaining resource that can dispatch at full capacity for prolonged periods. While the amount of firm resource capacity needed will vary from system to system, the essential role of firm capacity in maintaining resource adequacy – even in electricity systems with very high penetrations of renewables and storage – has been identified by numerous studies, including:

- *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California*, a study completed by E3 in 2019;
- "The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation" (Sepulveda et al.), published by researchers at the Massachusetts Institute of Technology;

[8] Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/reliability-filing-requirements_lses-2024-26_irp-plans_20260210.pdf

- *Net Zero America*, led by researchers at Princeton University to study pathways to meet a "net zero" carbon target for the United States by 2050;
- The *Los Angeles 100% Renewable Energy Study*, completed by the NREL to develop plans that would meet the City of Los Angeles' 100% renewable goals; and
- "Clean Firm Power is the Key to California's Carbon-Free Energy Future," a study co-funded by the Environmental Defense Fund and the Clean Air Task Force.

In many of these studies, the presence of firm resources alongside large penetrations of wind, solar, and storage is essential to the reliability of the system.

3.2.3. Headwinds Facing Resource Development

While resource needs are growing with increasing loads and the generation mix continues to evolve, utilities and project developers are also facing a more challenging environment to bring new resources online. Multiple sources indicate that the rates of project delays and cancellations and the lead times for new project development have increased in the past several years:

- A press release issued by the Energy Information Administration (EIA) at the end of 2025 reported that "[i]n the third quarter of 2025, solar projects representing about 20% of planned capacity reported a delay," a reduction from the highest rate of delay (25% in Q3 2024) but notably higher than the rates observed in 2020 (10-15%).[9]
- Experts at the Electric Power Research Institute (EPRI) reported that as of mid-2025, gas turbine manufacturers were typically quoting delivery lead times of up to five to seven years for new units, a considerable increase over historical norms.[10]
- A 2025 report published by Lawrence Berkeley National Laboratory (LBNL) reports that across a sample of 1,161 projects in service between 2009 and 2024, the length of time between projects securing an interconnection agreement and achieving commercial operations has increased from "…11 months for projects built in 2007, 19 months in 2015, and 35 months for those built in 2024."[11]
- An analysis by Cleanview, a market intelligence platform, reports that "…1,891 power projects with a combined 266 GW of generation capacity have been canceled in 2025—equivalent to roughly one-quarter of America's entire current electricity generation capacity."[12]

These "headwinds" are directly linked to the observed rapid increases in energy demand at a national scale, which has placed additional pressure on many of the processes and necessary steps

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[9] Available at: https://www.eia.gov/todayinenergy/detail.php?id=66604

[10] Available at: https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply

[11] Available at: https://emp.lbl.gov/sites/default/files/2025-12/Queued%20Up%202025%20Edition%20-%2012.15.2025.pdf

[12] Available at: https://cleanview.co/content/canceled-projects-report

to develop new resources. Multiple factors contribute to the protracted timelines for new resource development and the increasing costs for new resources, including:

- **Interconnection study processes,** which have become increasingly complex and time-consuming as the volume of projects in interconnection queues has grown and system impact analyses have become more rigorous.
- **Permitting processes,** which often require coordination across multiple jurisdictions and can introduce multi-year timelines due to environmental review, siting challenges, and stakeholder engagement requirements
- **Supply chain constraints,** which are contributing to both longer backlogs for specialized equipment and rising project costs, particularly for transformers, gas turbines, and other critical grid components.
- **Financing and market conditions,** which have increased the cost of capital relative to historically low levels in 2020 and, in some cases, have contributed to project delays or cancellations as developers reassess project economics.
- **Workforce and labor constraints,** which are limiting the availability of skilled labor necessary for engineering, procurement, and construction, thereby extending project schedules and increasing development risk.

Collectively, these factors contribute to longer and less predictable development timelines, increasing the risk of delays in the development of resources needed to ensure reliability.

3.2.4. Fuel Supply Constraints

In the Southwest region, natural gas power plants represent a large share of the region's total installed capacity today (roughly 17 GW of a total of 30 GW) and play a key role in ensuring reliability within the region. In order to do so, gas power plants rely on pipeline systems for the "just-in-time" delivery of fuel.

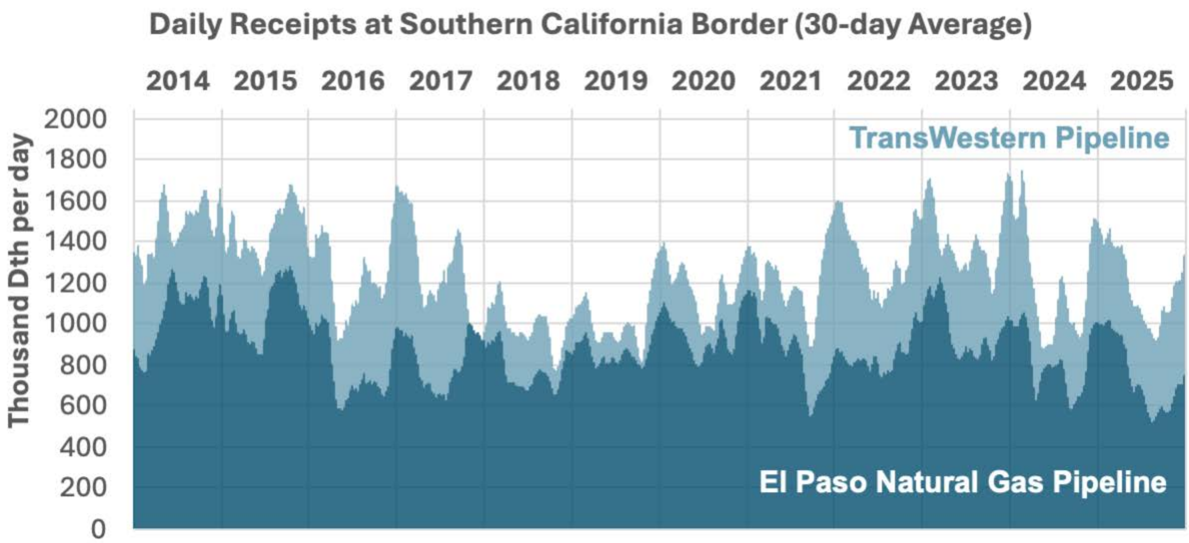
There are two major interstate pipeline systems in the Southwest region: the El Paso Natural Gas and TransWestern pipeline. The two pipeline systems deliver gas from the Permian and San Juan supply basins to end users in Arizona and New Mexico, as well as to the SoCalGas pipeline system at the California border.

To transport gas to natural gas power plants, electric utilities in the Southwest typically contract for "firm service" on the interstate pipeline systems. These contracts provide each utility with priority access to the pipeline to transport a prescribed daily volume of natural gas, typically sized by each utility to ensure it can adequately supply its portfolio of gas-fired resources. These arrangements allow utilities to ensure their natural gas resources can operate when needed for reliability.[13]

[13] In contrast, in regions where natural gas generators are not served under firm service – and rely on "interruptible service" instead – a lack of pipeline capacity and the corresponding inability to deliver natural gas to power plants has been identified as a major driver of reliability risk.

Ensuring resource adequacy in the region will require utilities to right-size their commitments for firm capacity on the pipeline system for their current and future natural gas needs. On today's system, utilities have limited flexibility to adjust their subscriptions: postings to the "Electronic Bulletin Boards" (EBB) on the two pipeline systems indicate that existing pipelines are nearly fully subscribed today. Further, despite its aggressive clean energy policies, the state of California has not observed a notable decline in its demand for natural gas, and the two pipeline systems continue to be utilized to transport high volumes of natural gas to the Southern California border (see Figure).

Figure 3-7. Daily natural gas receipts at the Southern California border from the two interstate pipeline systems in the Southwest



3.2.5. Climate Uncertainty & Extreme Weather

Concurrent with these changes to customer loads and energy supply, climate change is impacting weather system fundamentals, which has implications for electricity demand and resource availability. Scientific consensus, as captured in the Intergovernmental Panel on Climate Change's (IPCC) *Sixth Assessment Report*, concludes that:

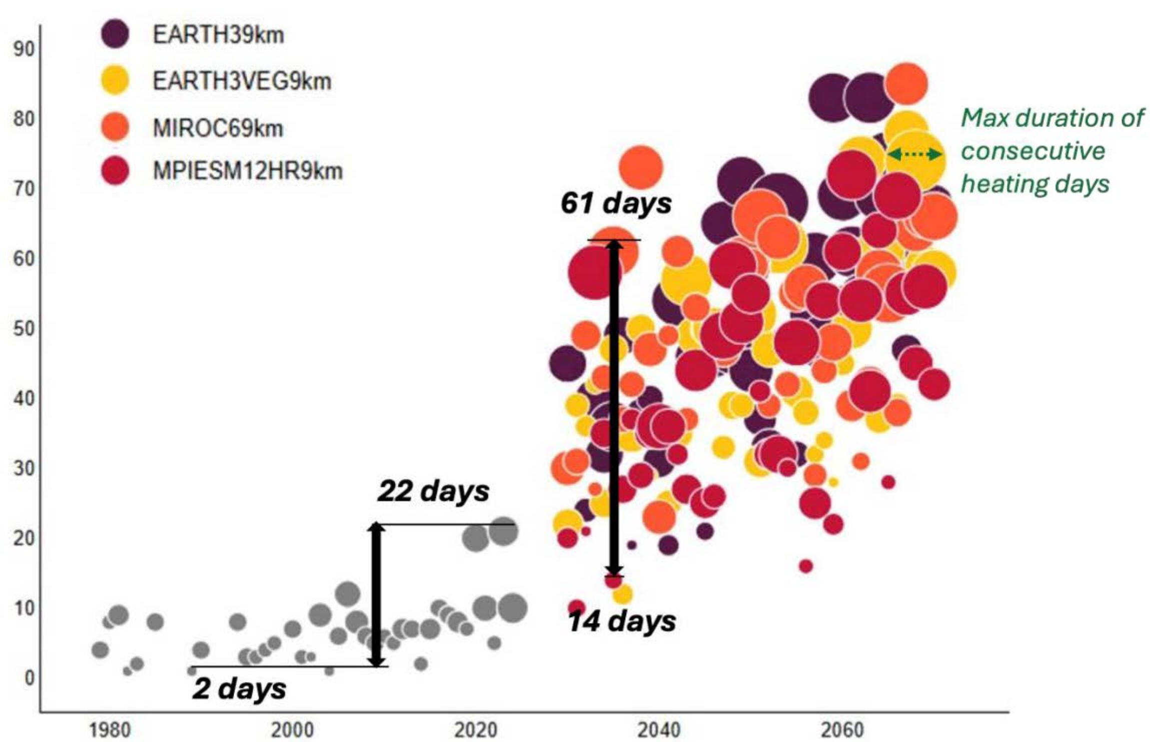
> "[g]lobal surface temperature will continue to increase until at least mid-century under all emissions scenarios considered. Global warming of 1.5°C and 2°C will be exceeded during the 21st century unless deep reductions in CO2 and other greenhouse gas emissions occur in the coming decades."[14]

The impacts of these global trends are far-reaching; the effects are expected to include "increases in the intensity and frequency of hot extremes, including heat waves (*very likely*), and heavy precipitation (*high confidence*), as well as agricultural and ecological droughts in some regions (*high confidence*)." Such increases appear across multiple General Circulation Models (GCM), often coupled with downscaling techniques to produce regional projections of future weather. Figure 3-8

[14] IPCC Sixth Assessment Report

compares the historical observed duration of summer heatwaves in the Southwest (defined as consecutive days reaching a temperature of 110 F or above in Phoenix) with projections of similar events for four GCM models (downscaled to the Southwest region). This comparison indicates both that (a) climate modeling indicates that the length of heatwave effects in the Southwest is expected to increase, while (b) there remains a significant degree of uncertainty – even in the near term – regarding the frequency and duration of temperature extremes.

Figure 3-8. Historical and projected frequencies of consecutive hot summer days (Phoenix temperature above 110F)



3.3. Best Practices for Resource Adequacy Planning

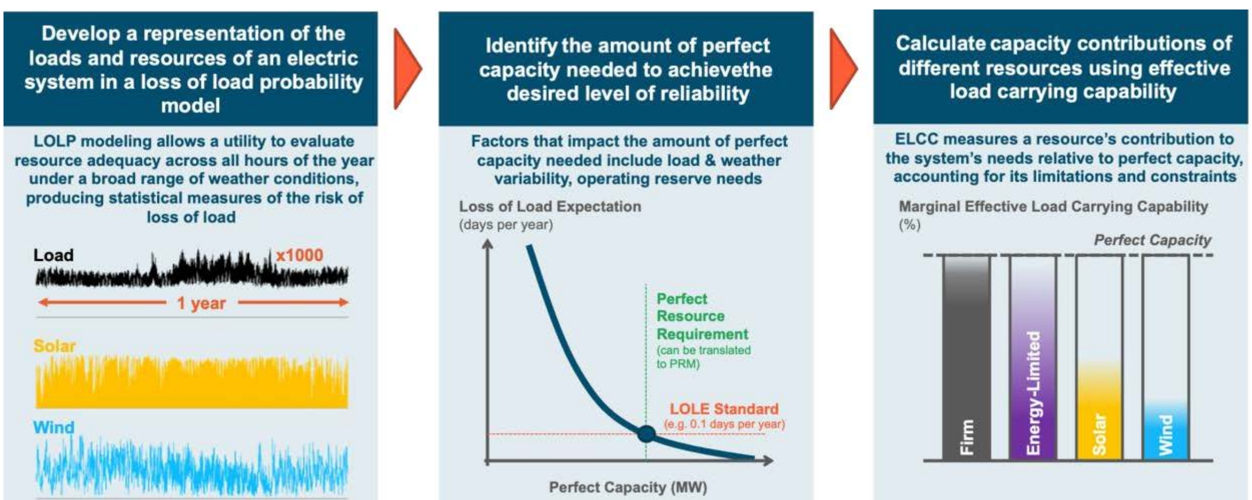
Planning a portfolio capable of serving loads across a wide range of potential conditions – despite the increasing complexity of the system, heightened levels of uncertainty, and the rapid pace of change – requires sophisticated analytical techniques to quantify the needs of the system, the availability of generation resources, and the resulting risks to reliability. The most widely accepted type of model for this type of analysis is **loss-of-load-probability (LOLP) modeling**, which relies on probabilistic and stochastic simulation techniques to evaluate resource adequacy across a broad range of possible conditions. In so doing, LOLP models identify the so-called **“critical periods”** in an electricity system: the conditions under which the system is most likely to experience resource deficiencies that may ultimately lead to the need to curtail firm electric load.

Designing the system to perform during these critical periods has always been the primary challenge of resource adequacy. Historically, those critical periods coincided almost exclusively with peak load, but increasingly, critical periods will occur at different times of day and year due to combinations of high load and low resource availability. The ability to identify such periods is foundational to all aspects of planning an adequate portfolio. At its most foundational level, a robust framework for resource adequacy requires three components:

1. Development of a **loss-of-load-probability model** that can simulate the availability of loads and resources on an hourly basis across a wide variety of weather conditions to identify periods in which an electricity system is vulnerable to reliability risks;
2. Derivation of a **total capacity requirement** that reflects the amount of "perfect capacity" needed to achieve an acceptable level of reliability (this is often subsequently translated into a **"planning reserve margin" requirement**); and
3. Application of an **effective load carrying capability (ELCC)** accounting framework to measure the contribution of each resource (or portfolio of resources) towards the total capacity requirement.

These best practices, summarized in Figure , guide the modeling approach used in both the near-term and long-term assessments to evaluate resource adequacy across the region.

Figure 3-9. Three foundational pillars underpinning a robust approach to resource adequacy



The 2021 study provides a more extensive description of resource adequacy best practices and their application, and most of the concepts and details remain equally useful today. Subsequent E3 publications, as well as a growing body of literature produced by others in the industry, continue to reaffirm the importance of a rigorous time-sequential LOLP modeling approach to evaluate resource adequacy. Key publications include:

- Redefining Resource Adequacy for Modern Power Systems (ESIG, 2021)[15]

[15] Available at: https://www.esig.energy/wp-content/uploads/2022/12/ESIG-Redefining-Resource-Adequacy-2021-b.pdf

- Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches (EPRI, 2022)[16]
- Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation (ESIG, 2023)[17]
- New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements (ESIG, 2024)[18]
- Resource Adequacy for a Decarbonized Future (EPRI, 2024)[19]
- Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets (E3, 2025)[20]

Adoption of these best practices for resource adequacy planning is becoming increasingly common across the industry. In the Southwest, the current methods by the region's major utilities – the sponsors of this study – each have developed LOLP models of their system, have used those tools to derive PRM requirements based on statistical loss-of-load metrics, and have adopted ELCC as the primary method for resource accreditation.

[16] Available at: https://www.epri.com/research/products/000000003002024368
[17] Available at: https://www.esig.energy/wp-content/uploads/2023/02/ESIG-Design-principles-capacity-accreditation-report-2023.pdf
[18] Available at: https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024a.pdf
[19] Available at: https://www.epri.com/research/products/3002027832
[20] Available at: https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf

4. Near-Term Resource Adequacy Assessment

The near-term resource adequacy assessment provides a comprehensive outlook for resource adequacy in the Desert Southwest region across the coming decade by applying the best practices described in Section 3. This section of the report presents the scope, the modeling approach, key inputs and assumptions, and technical results.

4.1. Scope of Analysis

The near-term reliability outlook presented here uses load forecasts and resource portfolios provided by utilities in early 2025. Since that time, utilities have continued to update load forecasts and adjust resource plans in response to continuously changing conditions. For this reason, these results do not reflect the most current outlook for loads and resources within the region, but nonetheless serve as a useful directional indication of the relative scale of resource needs and provides validation that utility planning processes continue to identify resource portfolios capable of meeting regional reliability needs.

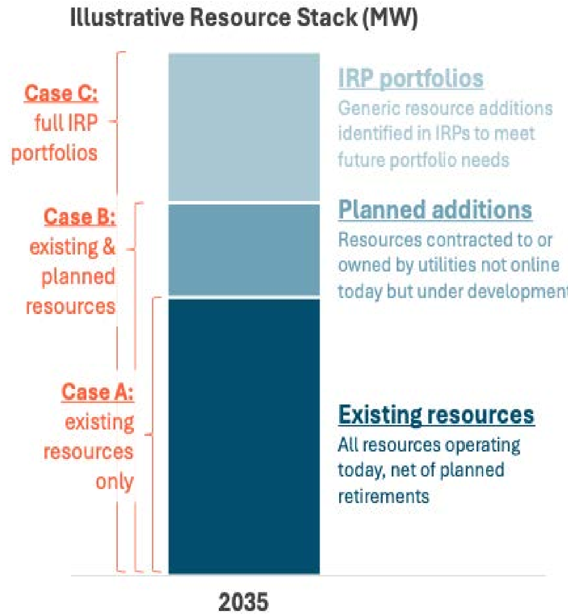
Much like the 2021 study, the scope of the near-term assessment focuses on an evaluation of regional resource adequacy by aggregating load forecasts and resource portfolios provided by individual utilities to the regional level. Using loss-of-load-probability modeling, the analysis uses stochastic chronological simulations of loads and resources across the region. While the primary purpose of the near-term assessment is to evaluate whether utilities' plans will meet regional resource adequacy needs, the supporting analysis provides answers to a range of questions that establish a comprehensive outlook for regional resource adequacy:

1. What is the current and future need for capacity in the Southwest region to maintain reliability across the region with a loss of load expectation of no more than 0.1 days per year ("one day in ten years")?
2. How much new effective capacity will be needed to ensure this level of reliability can be maintained?
3. To what extent will resources that are already under development today satisfy a portion of the need for new resources?
4. To what extent are utilities' resource plans positioned to meet regional resource adequacy needs?
5. How will resource adequacy risks evolve over the coming decade with anticipated changes in loads and resources?
6. How will the contributions of different technologies towards meeting the region's needs during the periods of greatest risk change?

To answer these questions, the near-term resource adequacy assessment includes the following analysis:

- Calculation of reliability statistics for three resource portfolios for each year from 2025-2035: (1) existing resources (net of retirements); (2) existing and in-development resources; and (3) full utility resource plans (see Figure 4-1);
- Close inspection of loss-of-load events observed in the simulations to provide insight into key drivers of reliability risk and the performance of different resources during critical risk periods;
- Evaluation of capacity credits for different technologies across the modeling horizon; and
- Sensitivity analysis on key uncertainties that could impact regional reliability.

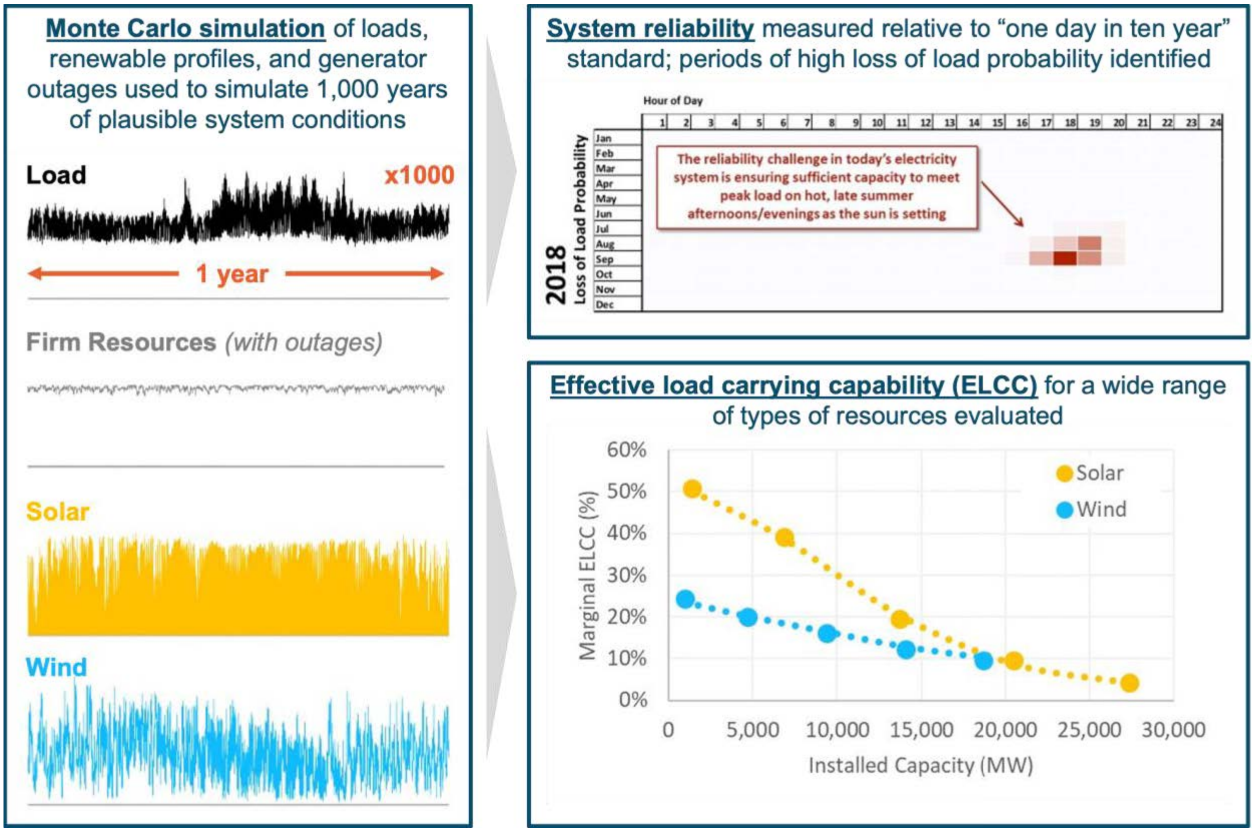
Figure 4-1. Three portfolios evaluated in near-term assessment



4.2. Modeling Approach

This phase of analysis utilizes **Renewable Energy Capacity Planning (RECAP)** model, developed and maintained by E3, to conduct LOLP modeling of the southwest region. RECAP simulates the availability of electric supply to meet demand across a broad range of conditions on a time-sequential basis, accounting for weather-driven variability of electric demand and weather-dependent resources like wind, solar, and hydro; power plant forced outages, and energy limitations and operating constraints for resources like storage and demand response. These simulations determine the likelihood and magnitude of loss of load – energy demand that cannot be served due to an insufficiency of capacity or energy – and provide the basis for calculating the PRM.

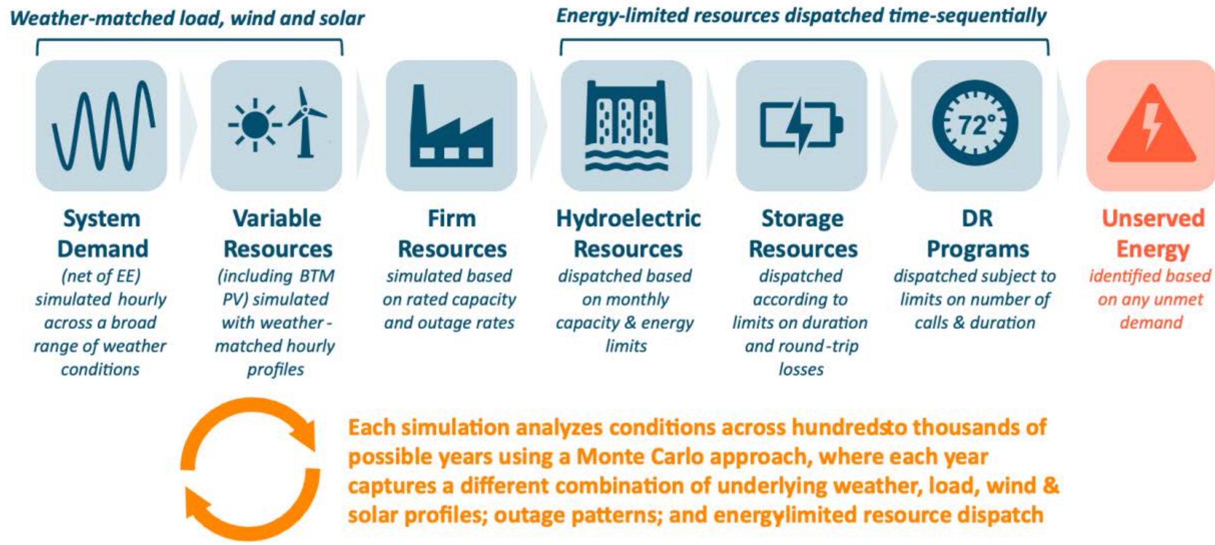
Figure 4-2. Overview of E3's RECAP model



RECAP simulates hundreds of "years" of potential conditions using stochastic techniques to appropriately capture the risk of tail events (e.g., higher load and lower renewable output than expected).[21] RECAP simulates balance between system demand and available generation in each hour of a year and repeats this process hundreds of times with different system conditions (see Figure). This ensures that RECAP captures a wide distribution of potential outcomes, including unlikely tail events that may not occur in a "typical" year. Relevant correlations are preserved within the model to ensure linkage among load, weather, and renewable generation conditions based on historical observations.

[21] In this approach, each "year" represents a different realization of conditions on the Southwest region over the course of a year. Factors that will vary from one "year" to the next include underlying weather patterns – and by extension, load and renewable profiles – power plant outages, and energy-limited resource dispatch.

Figure 4-3. RECAP simulation methodology



Through this simulation process, RECAP calculates the usual suite of statistical metrics produced in LOLP modeling to characterize the frequency, magnitude, and duration of potential reliability events (LOLE, LOLH, EUE, and others). Additionally, RECAP can be used to calculate common "derivative" metrics, including the planning reserve margin and ELCCs for individual resources.

4.3. Key Assumptions

Developing a representation of the Southwest region in an LOLP model requires a broad range of inputs to characterize the range of expected system demands and the capabilities of the available generating resources. The inputs and assumptions needed for this analysis are summarized in Table 4-1.

Table 4-1: Summary of key inputs for RECAP

Module	Inputs Needed
System Demand	• Annual energy demand • Annual 1-in-2 peak demand • Hourly profiles corresponding to a wide range of weather conditions (20+ years) • Minimum operating reserve requirements
Firm Resources *(e.g. nuclear, coal, gas, biomass, geothermal)*	• Seasonal capacity rating by resource • Forced outage rate by resource • Mean time to repair by resource
Variable Resources *(e.g. wind, solar)*	• Installed capacity by resource • Hourly profiles for multiple years, ideally including multiple years of overlap with hourly load profile data
Hydroelectric Resources	• Installed capacity by resource • Monthly/daily energy budgets across a range of plausible hydro conditions • Minimum output levels by month/day • Sustained peaking limitations by month/day
Storage Resources *(e.g. batteries, pumped storage)*	• Installed capacity by resource • Duration by resource • Charging & discharging efficiency by resource • Paired variable resource (for hybrids) • Interconnection configuration & rating (for hybrids)
Demand Response Resources	• Expected load impact by program • Limits on number of program calls (per year or per month) • Duration of calls

4.3.1. Demand Forecast

To produce a regional Southwest demand forecast, this study uses a bottom-up approach that involves three steps (see Figure 4-4): (1) collecting forecasts for annual energy demand from each participating utility and aggregating them to produce a regional forecast; (2) creating and applying hourly profiles for individual components of load to those annual demands in a manner that captures the seasonal and diurnal characteristics; and (3) aggregating the resulting shapes together to derive a total hourly load shape with a regional coincident peak demand. This section describes the demand forecast methodology in detail and the collaboration between E3 and the Southwest utilities.

Figure 4-4. Three-step process to develop hourly load inputs for resource adequacy modeling

Step 1: Develop Regional Energy Demand Forecast

As an input to this study, each sponsoring utility provided a demand forecast based on their outlook at the beginning of 2025. The total energy forecasts provided by utilities are segmented into the following categories:

- Existing end use demands, net of the projected impacts of incremental energy efficiency[22];
- Electric vehicle charging demands;
- New large customer demands; and
- Behind-the-meter solar generation (treated as a decrement to loads).

The total annual demand for electricity is determined by aggregating these utility-provided forecasts together and making an additional adjustment to account for the existing electric demands within the region that are not directly served by these utilities (typically small municipal utilities and cooperatives).

Step 2: Create and Apply Hourly Shapes

The segmentation described above allows the analysis to capture the impacts of these changing elements upon the regional shape of demand for electricity. Hourly shapes for each segment are developed using different approaches, summarized in Table 4-2.

Table 4-2. Description of load shaping approaches used for each segment

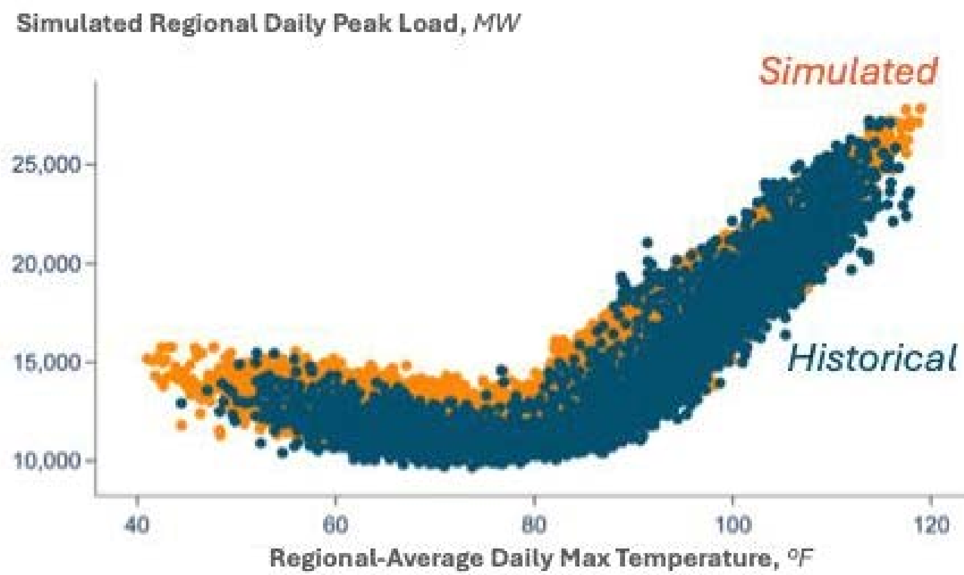
Load Segment	Load Shaping Approach
Existing End Use Demands	Neural network simulation over 45-year history (1970-2024) based on historical temperature (detrended for climate impacts) and electric demand data
Electric Vehicles	Hourly shape for a single year developed using E3's EVGrid modeling toolkit,[23] reflecting a combination of managed and unmanaged charging
New Large Customers	Hourly profile for a single year assuming 90% load factor and a daily shape that coincides with cooling demands (peaks in the day and lowers in the evenings).
Behind-the-Meter Solar PV	Hourly profiles simulated for 1998-2020 using NREL System Advisor Model based on representative locations across six major population centers

Among these four segments, the most important and consequential for the purposes of resource adequacy modeling the shape applied to existing end use demands, both because of their relative magnitude and sensitivity to extreme weather conditions. Robustly capturing the risks associated with extreme weather events that may not occur in a "typical" year requires development of demand shapes across a wide range of weather conditions. To create such a dataset, this study uses neural network regression techniques to simulate present-day electricity demands under an extended

[22] Energy efficiency forecast assumptions are provided by each sponsoring utility and is modeled as energy reduction in each hour across the entire year.
[23] For additional detail, see: https://www.ethree.com/tools/electric-vehicle-grid-impacts-model-2/

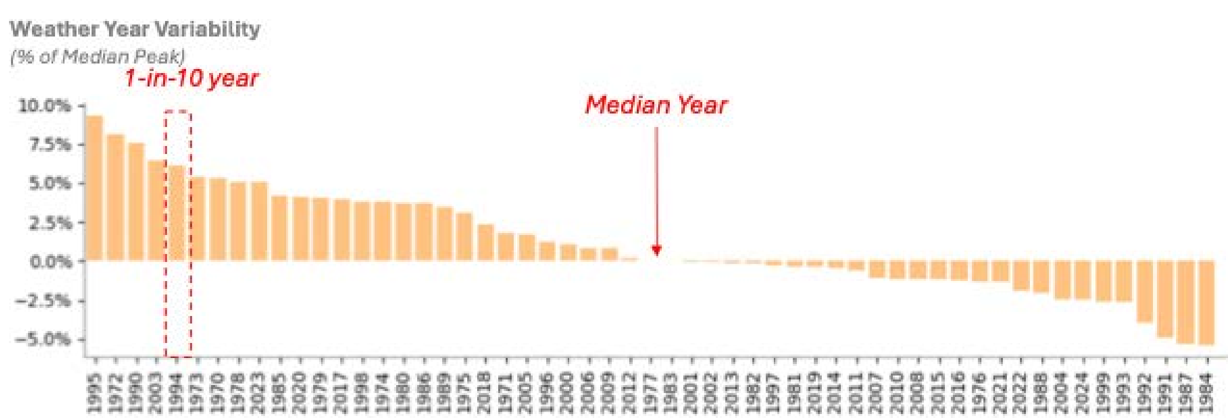
historical weather record.[24] This approach establishes a direct relationship between temperature at key population centers across the region and the corresponding electricity demand. This relationship is illustrated in Figure 4-5, which compares the 2024 actual daily peak and daily maximum temperatures against the simulated outputs from the neural network regression.

Figure 4-5. Historical and simulated weather and load data



Applying this to reanalysis weather data covering the period 1970-2024 produces a 45-year record of hourly demand shapes that reflects a range of typical, mild, and extreme weather conditions. Figure 4-6 represents the peak load variability observed across the 45 years ranked from highest annual peak load observed to the lowest.

Figure 4-6. Peak demand (relative to a "1-in-2" level) for each weather year simulated

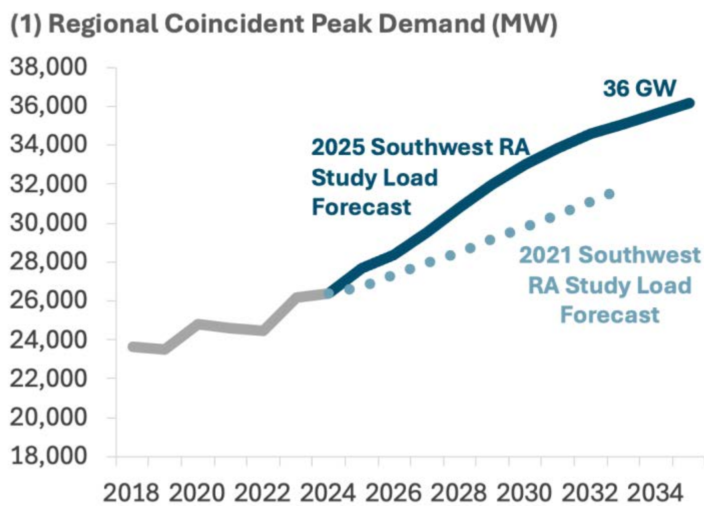


[24] The primary dataset used in this study is ERA5-LAND. As in the previous study, these historical temperature data have been "detrended" to account for the apparent underlying warming trends.

Step 3: Derive Regional Coincident Peak Demand Forecast

All the components described above are combined within RECAP to produce the total load for the Southwest. The resulting hourly profile produces a median peak load forecast for the region and produces a broader range of variability (representing 45 total weather years) needed for a robust assessment of resource adequacy. Figure 4-7 shows the peak load forecast for the full Southwest region present in this study. The figure also compares this study's peak load forecast compared to the 2021 study's peak load forecast. Between the two, the rate of growth is higher (2.7% per year in this study compared to 2.2% per year in the 2021 study).

Figure 4-7. Projected regional coincident peak demand based on utility forecasts



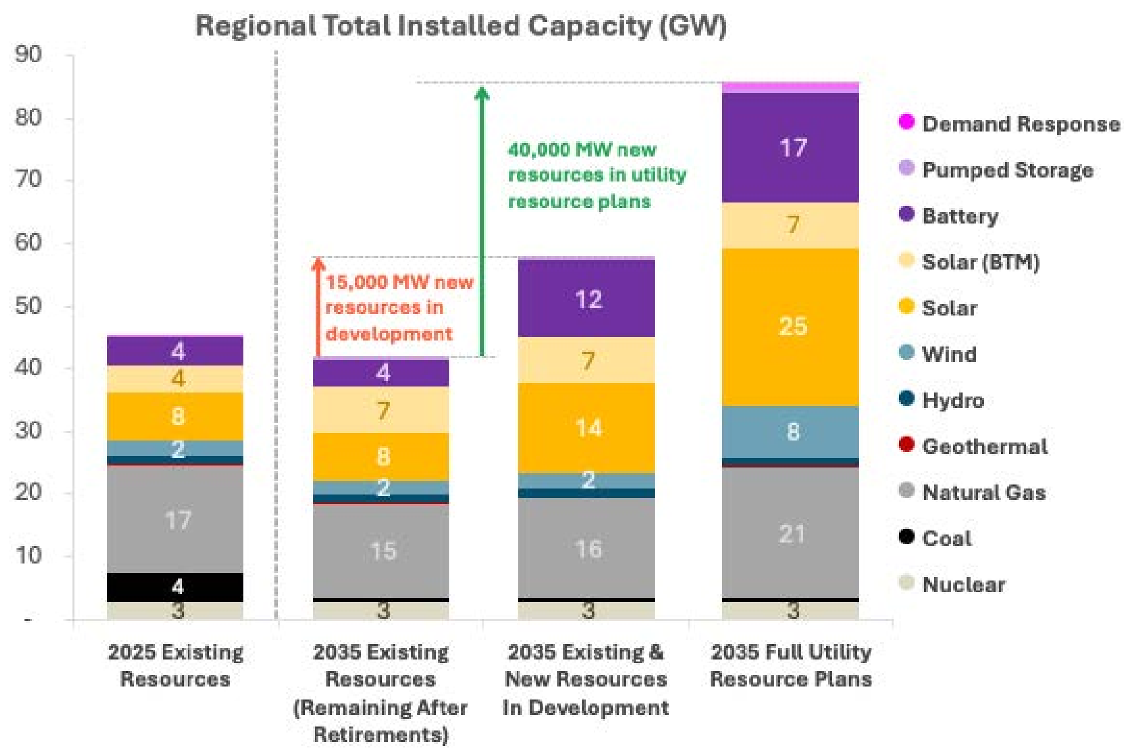
4.3.2. Resource Portfolios

Portfolios of electric generating resources analyzed for the near-term study are created through aggregation of resource data provided directly by the participating utilities. Over the course of the ten-year horizon, three portfolios are evaluated; each evaluation serves a specific purpose:

1. **Existing Resources Only (Remaining After Retirements):** how much additional effective capacity will be needed to meet load growth and replace retiring resources?
2. **Existing & New Resources in Development:** to what extent will resources already under development satisfy need for new capacity?
3. **Full Utility Resource Plans:** to what extent will utilities' resource plans, including generic future resource additions, enable the region to achieve an LOLE of 0.1 days per year or better (if successfully implemented)?

The installed capacity of existing resources in 2025, as well as for the three portfolios analyzed in 2035, are shown in Figure *4-8*.

Figure 4-8: Composition of resource portfolios evaluated in near-term assessment



> *In developing the portfolios for the purposes of this study, the utilities make several important underlying assumptions: first, that the transmission necessary to deliver new resources to loads is also constructed in a timely manner; and second, that the availability of natural gas transportation capability to serve the region's gas generators is not a constraint that limits their use. To the extent either or both of these preconditions are not met, the region may face additional resource adequacy risks not identified by the analysis in the near-term assessment, where these factors are not explicitly modeled.*

The availability of each specific resource included in each portfolio is represented in RECAP's stochastic simulations in a manner that reflects its characteristics and limitations, which generally vary by technology. The key factors that constrain each resource's availability, and the basis for assumptions used in this study, are provided in Table 4-3.

Table 4-3. Overview of data development process and availability representation of different technologies in study

Technology	Data Development and Availability Representation
Nuclear Coal Natural Gas	• Maximum capacity varies seasonally with summer & winter capacity ratings provided by utilities • Random forced outages simulated stochastically based on plant-specific rates provided by utilities
Geothermal	• Maximum capacity specified by plant
Hydro [25]	• Monthly maximum capacity and energy budgets provided by WAPA for five hydro scenarios • Hydro scenarios modeled stochastically based on probabilities provided by WAPA • Hydro resources dispatched to flatten net load, subject to operating constraints
Wind	• Site-specific hourly profiles simulated from meteorological and turbine power data gathered from NREL's WIND Toolkit for the historical period 2007-2012
Solar	• Site-specific hourly profiles simulated using NREL's System Advisor Model (SAM) for the historical period 1998-2022
Battery Storage Pumped Storage	• Dispatched to minimize loss of load, subject to capacity and energy limitations (and interconnection limitations for hybrid facilities) • Random forced outages simulated stochastically using a generic 5% outage assumption
Demand Response	• Maximum capacity varies seasonally with summer & winter capacity ratings provided by utilities

[25] Represents large reservoir projects managed by Western Area Power Administration (WAPA). Pumped Storage Hydro would be considered as Storage.

4.4. Results

4.4.1. Regional Planning Reserve Margin (PRM)

As discussed in Section 3.3, one of the key components in the RA planning framework is to measure the total capacity need needed to achieve a one-day-in-ten-year loss of load expectation (0.1 LOLE) target. Under the load and resource assumptions in this study, maintaining a LOLE of 0.1 days per year in the Southwest requires a 12-13% PRM, expressed as the amount of perfect or effective capacity needed above the median peak load. This result is a direct output of the RECAP model that quantifies the quantity of perfect capacity in MW that is necessary to achieve the reliability target. Dividing this megawatt value by the 1-in-2 peak demand and subtracting one yields the percentage PRM requirement. Table 4-4 illustrates the relationship between the 1-in-2 peak, the total capacity need, and the resulting perfect capacity PRM.

Between 2025 and 2032, the region's 1-in-2 peak grows from 27,666, MW to 31,800 MW; meeting regional needs according to a 0.1 LOLE reliability target in 2032 requires 12-13% reserve margin (31,143 and 38,672 MW of effective capacity for 2025 and 2032 respectively).

While the absolute quantity of capacity needed grows, the relative requirement remains relatively stable and is consistent with the level of planning reserves identified in the 2021 study. The stability of this planning reserve margin throughout the horizon and across studies holds true because the amount of effective capacity needed is independent of the resources in the portfolio: "need" is calculated in a manner that only reflects the nature of electricity demand and operating reserves across all hours of the year.

Table 4-4. Planning reserve margin values for 2025 and 2032

	Peak Load (MW)	Total Capacity Need (MW)	Perfect Capacity PRM (%)
2025	27,666	31,143	13%
2032	34,564	38,672	12%

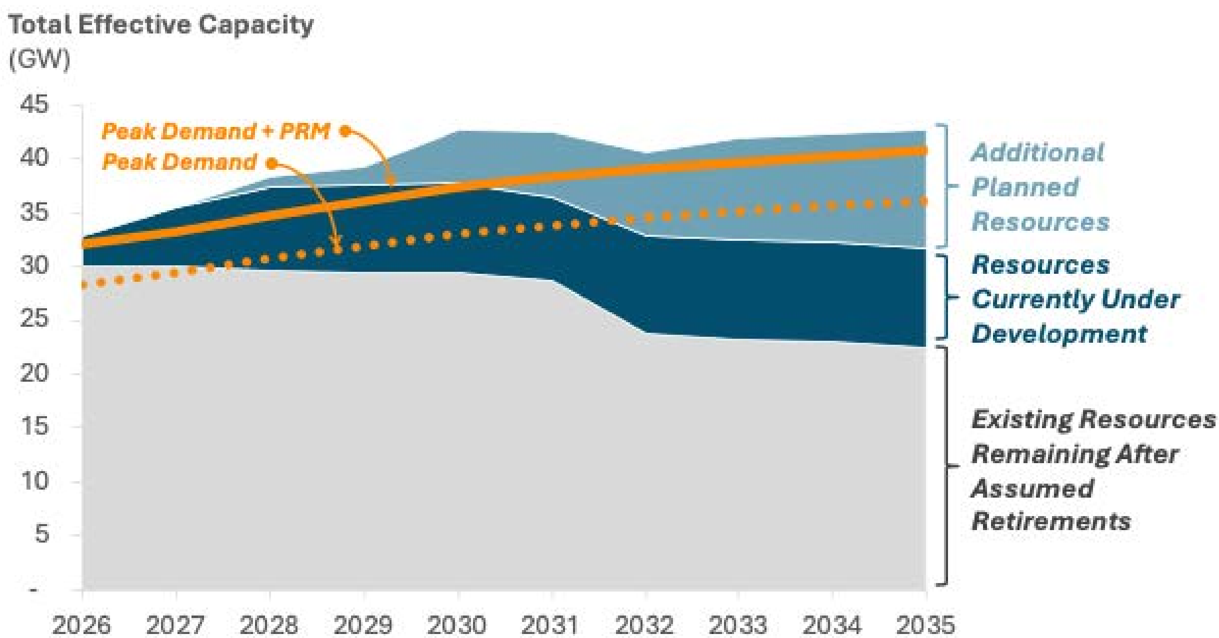
4.4.2. Outlook for Regional Load-Resource Balance

Figure shows the projected load-resource balance for the region based upon the load forecast and resource portfolio assumed used in this study. The figure highlights the increasing regional capacity needs with growing loads and the effective capacity provided by existing resources, resources under development, and generic resources included in utility plans.

- Over the next decade, the aggregated demand forecasts provided by utilities increase by 30%, or a total of over 8,000 MW. Incorporating a planning reserve margin of 13%, load growth increases the regional need for effective capacity by nearly 10,000 MW.

- At the same time, the retirements and expiring contracts of coal and natural gas plants assumed in this study result in the loss of approximately 8,000 MW of effective capacity.
- In conjunction, these two factors create a need for 18,000 MW of new effective capacity over the course of the next decade to maintain regional resource adequacy needs.
- Resources currently under development are poised to meet a portion of those needs, providing just over 9,000 MW of effective capacity and positioning the region to maintain load resource balance over the next several years.
- The additional generic resources included in utility plans are sufficient to close the remaining gap, creating some headroom in advance of planned resource retirements and satisfying the need for new capacity over the coming decade.

Figure 4-9. Projected regional load-resource balance based on utility plans current as of Q1 2025



While the rate of load growth and resource additions have both increased since the publication of the 2021 study, the overall balance of loads and resources ten years into the future remains similar: both the 2021 study and this study show a small margin of capacity above the minimum quantity needed to maintain a regional LOLE of 0.1 days per year. The implication of this consistency is that utilities' updates to their plans in response to accelerating load growth have identified solutions to preserve regional resource adequacy, despite the increasing complexity of the resource mix.

While the presence of a sustained resource deficit would be cause for concern – an indication that the physical limitations of the resources utilities plans would not allow the region to achieve an LOLE of 0.1 days per year – the presence of a margin of surplus does not necessarily indicate that utilities are planning to procure excess capacity due to a variety of factors not explicitly captured in this analysis:

- This analysis treats the region as a "copper sheet" with no internal transmission constraints, allowing resources located anywhere in the region to contribute to meeting all loads. Constraints on the transmission system may limit utilities' ability to utilize resources in this manner.
- This analysis assumes full fuel availability for gas, nuclear, and other fuel-burning resources in the region. Lack of supply in the regional fuel delivery system during critical periods may disrupt utilities' ability to generate power to meet the region's reliability needs.
- The analysis assumes that the dispatch of energy-limited resources (storage, hydro, and demand response) is perfectly orchestrated to maximize their value to regional resource adequacy; in reality, the dispatch of these resources may not align with these patterns due to utility-specific operational choices, market rules and processes, and imperfect information sharing. This, in turn, could result in tighter market conditions than simulated in this study.
- While this analysis adjusts the historical weather record to account for the past warming trends observed, it does not account for potential future load shape changes due to increased warming over the next decade. Increased frequency and severity of extreme heat events could place additional strain on resource adequacy. This risk is explored in several of the sensitivities presented in Section 4.4.5.

Further, while this analysis models resource adequacy at a regional level, the responsibility to ensure resource adequacy remains a utility function, not a regional one. Each individual utility establishes its own reliability target, evaluates the ability of resources to contribute to their own needs, and makes assumptions about the availability of "market support" from neighboring utilities based on their own independent assessment of risk. This approach is inherently unlikely to capture the full value of potential load and resource diversity across the region but remains the de facto method through which resource adequacy is planned and evaluated.

4.4.3. Evolving Drivers of Reliability Risk

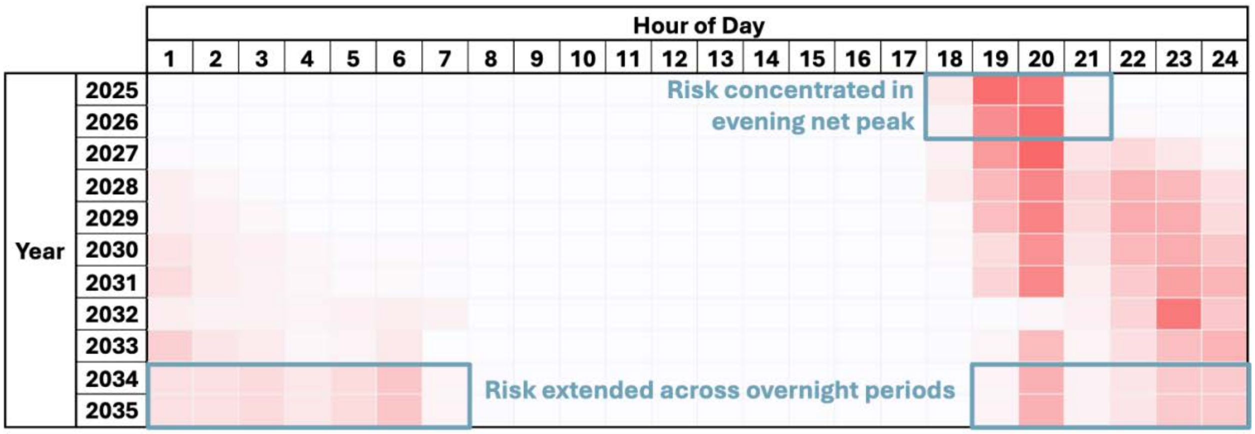
Utilities' plans include significant quantities of renewables and storage resources to help meet regional resource adequacy needs over the next decade: roughly half of the 2035 need for effective capacity is provided by firm resources, while the other half is provided by variable and energy-limited resources. As utilities add increasing quantities of renewables and storage, the periods of highest risk migrate from the afternoon peak periods to other times of the day. This transition is already underway, and will continue over the course of the next decade:

- Historically, the periods of greatest reliability risk occurred during peak demand conditions. In a system of predominantly firm resources, meeting the highest loads of the year – typically on the hottest summer afternoons – required the most generation capacity.
- Today, extreme summer days continue to drive the region's risk, but the timing of risk within the day has shifted due to the higher penetration of solar resources. Since the 2022 Study, the Southwest utility-scale solar fleet has increased from roughly 3 GW to 8 GW. With more solar output during the gross peak load period, today's risk has shifted to evening periods, 6-8pm.

- As the solar and storage additions continue, risk will shift deeper into the evening and nighttime hours. This continued transition is a reflection of the system becoming increasingly "energy constrained," as the greatest reliability risks occur during the periods when storage resources are most likely to be depleted after discharging during the evening.

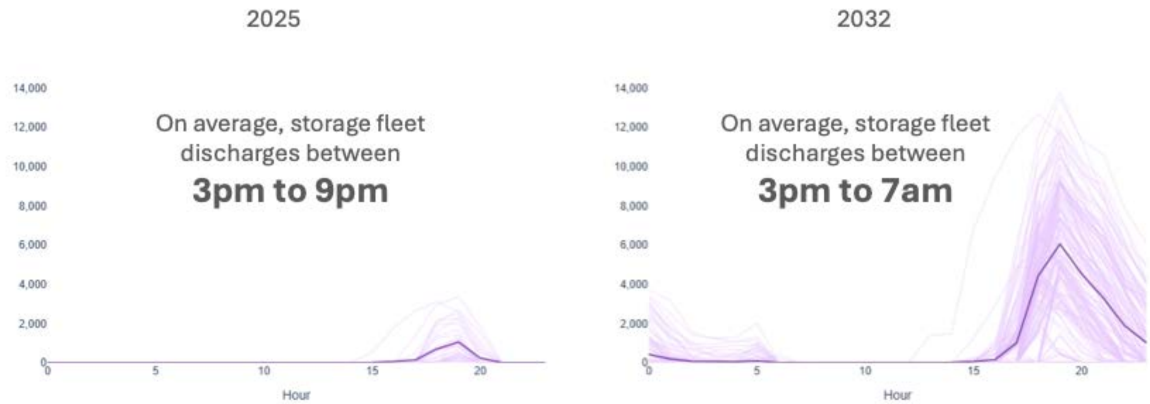
This progressive shift of loss-of-load risk deeper into the overnight period is shown in Figure 4-10 below, which illustrates how the year-by-year changes to loads and resources impact when loss-of-load is most likely to occur. All observed events occur in the summer season.

Figure 4-10. Progression of average loss-of-load risk by hour of the day, 2025 to 2035



The observed shifting of risk from the afternoon into the evening is a direct result of the increasing penetration of solar resources due to the well-documented "net peak." The subsequent extension of risk into overnight periods is a natural result of the increasing penetration of storage resources: at low penetrations, storage resources discharge during finite, short windows during the net peak period, but at higher penetrations, the discharge window for storage resources extends across broader periods as they serve a larger portion of loads. This contrast is shown in Figure 4-11, which contrasts summer discharge patterns for a small portfolio of storage resources in 2025 (roughly 4,000 MW) with a much larger one in 2032 (over 16,000 MW). As the discharge window for storage resources lengthens, the finite amount of energy stored is more likely to be exhausted.

Figure 4-11. Comparison of storage dispatch patterns to maintain reliability in 2025 and 2032

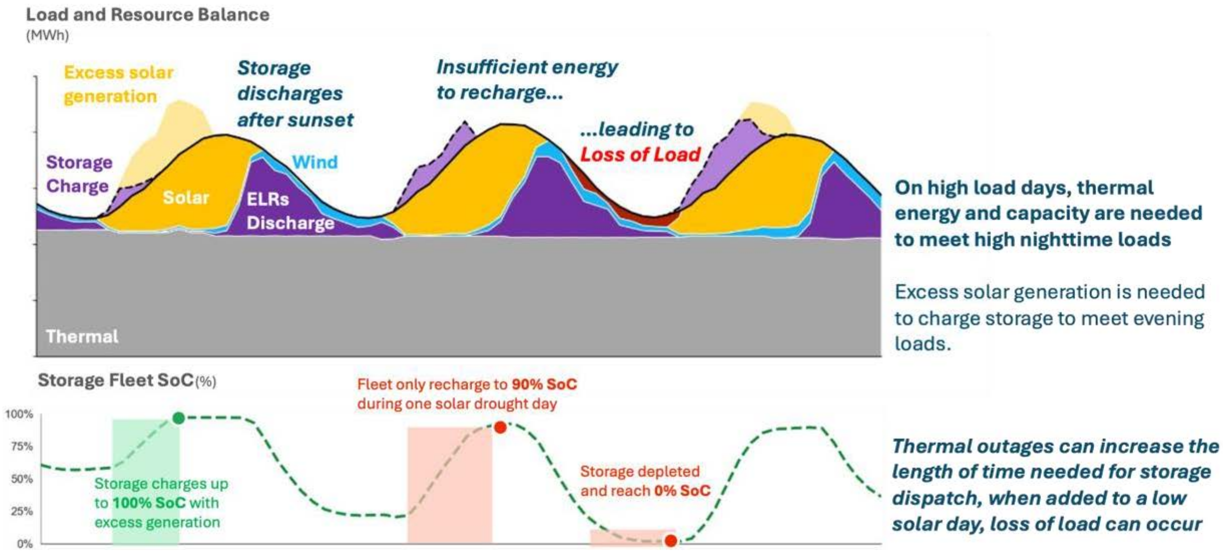


As the nature of loss-of-load risk shifts from periods when the instantaneous generating capacity is insufficient to serve loads to periods following the depletion of energy-limited resources, the system transitions from being "capacity-constrained" to "energy-constrained." Figure 4-12, based on the modeling of 2035 utility plans, provides a specific example of how the depletion of storage state-of-charge across multiple days could eventually culminate in a longer loss of load event during the early morning hours.

- On the first day of the event, storage resources reach full state of charge during daylight hours; during the evening period, they are dispatched during the evening and overnight periods and reach a minimum state of charge of roughly 20%.
- During the subsequent day, the available surplus energy is insufficient for storage resources to fully recharge, and the fleet only reaches 90%.
- As a result, the region's storage resources are fully depleted over the course of the next overnight period, and a loss-of-load event begins in the late evening hours and extends through the full overnight period until the next morning.

This event reflects an energy, rather than a capacity limitation, as the depletion of storage state of charge immediately precedes the realization of loss of load. Importantly, an additional MWh of generation (or a corresponding reduction of load) at any point in time from the late evening of day one to the early morning of day three would have directly reduced the size of this loss of load event.

Figure 4-12. Example of storage depletion in RECAP leading to an "energy-constrained" loss-of-load event



4.4.4. Resource Accreditation

The changing timing of critical periods is intrinsically linked to the capacity value that different types of resources provide to the system. The contribution of each technology to the system, measured using marginal ELCC, provides a direct relative measure of how much each resource contributes to resource adequacy at the margin. Changes to the marginal ELCC from 2025 to 2035, for each technology, are shown in Table 4-5. Technologies are subdivided into three categories (firm, variable, and energy-limited), a schema that groups together resources with similar characteristics and limitations.

- Firm resources (nuclear, coal, natural gas, and geothermal), which can generate electricity at or near maximum capacity for as long as necessary (except when experiencing an outage), exhibit high marginal ELCCs and are not subject to saturation. Differences in their relative ELCCs are primarily a function of outage rates.
- Variable resources (solar, wind), whose output varies from hour to hour as a function of uncontrollable meteorological conditions, exhibit low marginal ELCCs, reflecting the fact that during critical periods, their output is likely to be significantly lower than their full capacity. The marginal capacity value of solar in the Southwest, in particular, is very low (under 10%) due to the fact that critical periods occur during the evening.
- Energy-limited resources (storage, demand response), which have intrinsic finite limitations on the duration of their operations, exhibit high marginal ELCCs at low penetrations (when the system is capacity-constrained) but low marginal ELCCs at higher penetrations (when the system is energy-constrained). These saturation effects are observed across technologies: for instance, the significant increase in storage penetration from 2025 to 2035 drives a reduction in the marginal ELCC of both storage and demand response.

Table 4-5. Marginal ELCCs by technology in 2025 and 2035

Category	Technology	2025	2035	Change
Firm	Nuclear	94%	92%	-2%
	Coal	82%	-	-
	Natural Gas	91%	93%	+2%
	Geothermal	90%	88%	-2%
Variable	Solar	5%	7%	+2%
	Wind	26%	21%	-5%
Energy Limited	Hydro	73%	73%	-
	Battery	93%	36%	-57%
	DR	87%	38%	-49%

4.4.5. Sensitivity Analysis Results

Beyond understanding the reliability risk from the expected future regional portfolios, this study explores a range of potential risks to the region. These sensitivities on the regional resource adequacy risks tests the impact on the capacity position based on changes in resource performance, peak load uncertainty, and changes to the region's thermal portfolio composition.

The sensitivities are designed to capture emerging resource adequacy challenges facing the energy industry. Increasing frequency of extreme weather has led to increased forced outage risk to all resources and increased observed load. In addition, large load additions are accelerating the need for capacity and energy across the industry. Table 4-6 describes each sensitivity tested.

For resources, this study applies increased resource risks to the region's natural gas and storage resource fleet, two resources the region currently and will rely on to meet reliability risk. For storage, additional energy degradation sensitivities are applied. This study also studies the effect of low water availability under drought conditions for the region's hydro resources.

For load, the recent heatwaves in the Southwest 2023 and 2024 resulted in consecutive high load days. This sensitivity captures the increased frequency of extreme weather, testing the region's adequacy under the assumption that the 1-in-5 peak becomes the normal conditions. This study also focuses on the increased risk, but also capacity value, of data centers. This sensitivity looks at the risk associated with an accelerated timeline and the value of load flexibility.

A few themes emerge across the sensitivities:

1. Higher resource forced outage rates increases the risk to the region. By 2032, the natural gas fleet continues to serve as the region's main resource during the critical periods. Doubling the gas forced outage rate reduces the position by 968 effective MW in ELCC. Similar results

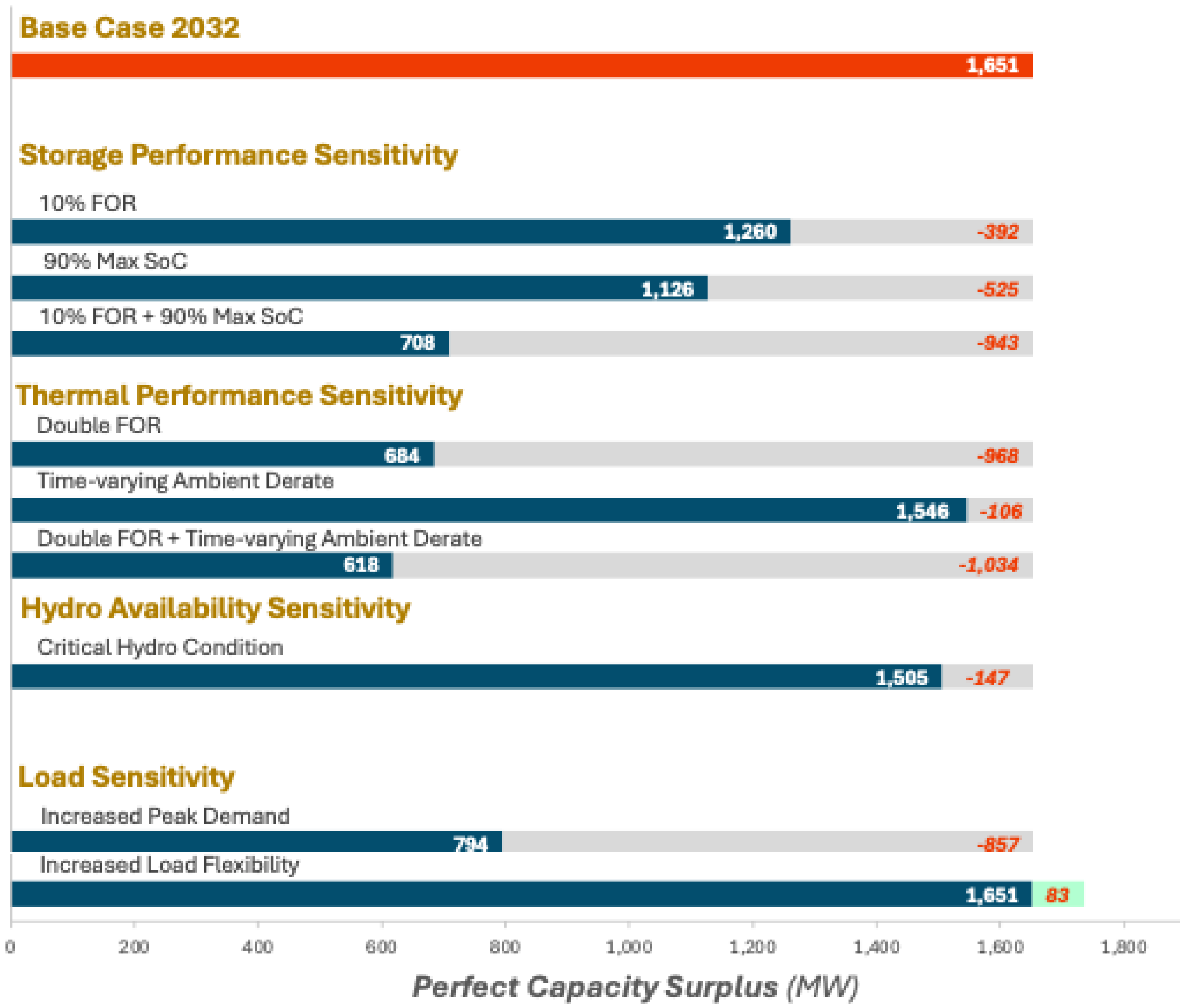
are observed for storage but compounds when the region's fleet increases in outage frequency and has 10% less energy, exacerbating the energy-deficiency problem.

2. Increased frequency of extreme weather (1-in-5 weather conditions) led to an increase in 857 MW higher capacity needs, equivalent to 2.4% of the median peak. Load flexibility can help mitigate some of increased load, but the impacts are lower than the incremental load added to the system.

Table 4-6. Range of 2032 Sensitivities

Category		Sensitivity Case	Description
Thermal Performance	A	Higher Gas Outages Rate	**Double all gas plants FOR** to reflect greater thermal stress from rising summer temperatures and more frequent winter cold weather disruptions
	B	Higher Ambient Derate	**Derate gas fleet summer rating by 5%** to reflect reduced output during long-lasting heat wave conditions
	C	Combine A & B	
Storage Performance	D	Higher Storage Outages	**Increase storage FOR assumptions from 5% to 10%** to account for potential battery performance degradation due to extreme temperatures
	E	Accelerated Battery Degradation	**Reduce storage maximum State-of-Charge from 100% to 90%** to reflect performance degradation due to capacity fading during extended heating events
	F	Combine D & E	
Hydro Availability	G	Critical Hydro Condition	**Assume critical drought conditions** to stress-test hydro energy availability
Load Requirements	H	Increased Median Peak	**Scale weather years so that median peak demand represents a 1-in-5 weather year** to reflect more challenging planning conditions
	I	Increased load flexibility	**Assume load components can achieve higher level of flexibility** during periods of grid stress

Figure 4-13. Achieved 2032 Capacity Position Across Various Sensitivities.



4.5. Discussion

The region faces a substantial and growing need for new capacity in the coming decade, and utilities' resource plans have identified portfolios capable of meeting that need. Regional coincident peak demand is projected to grow by roughly 30% over the next decade while assumed retirements remove nearly 8,000 MW of effective capacity from the existing portfolio. Taken together, the region's total need for new capacity grows to approximately 18,000 MW of new effective capacity by 2035.

Utilities' current plans, which include over 40,000 MW of new nameplate capacity, are projected to close this gap and maintain regional reliability at or better than the 0.1 days per year LOLE target, provided resources are brought online according to planned schedules.

The growing share of non-firm resources in the portfolio, projected to account for roughly half of total effective capacity by 2035, is shifting the timing of reliability risk away from the traditional afternoon peak and into the late evening and overnight hours. This effect is already observable today and is expected to intensify as storage penetration increases, with elevated overnight risk potentially emerging as soon as 2027.

This shift has direct implications for resource accreditation: marginal solar contributes relatively little to reliability at current penetration levels (5 to 7% ELCC), and the capacity value of 4-hour storage is projected to decline from approximately 90% in 2025 to 38% by 2035. These dynamics reinforce the continued importance of firm resources, which can generate on demand across extended periods when renewables and storage may be unavailable or depleted. Today, the viable options are limited and remains largely natural gas and nuclear.

Achieving the scale of development called for in utility plans will require adding over 4,000 MW of new capacity per year. The sensitivity analysis confirms that even modest delays in resource development or further upward load revisions could tighten the regional load-resource balance materially.

While the near-term assessment provides a focused evaluation of whether today's utility plans are sufficient to maintain reliability through 2035, it does not address the longer-term question of what features and characteristics of resource portfolios are able to meet long-term reliability needs. Section 5 builds on this foundation by examining a range of portfolios capable of meeting regional resource adequacy needs through 2045, exploring how the dynamics observed in the near term evolve at higher penetrations of renewables and storage and across a broader range of load, technology scenarios, and energy mixes.

5. Long-Term Resource Adequacy Assessment

5.1. Scope of Analysis

Whereas the near-term assessment focuses on the question of whether utilities' plans will maintain resource adequacy over the next ten years, the long-term assessment explores a broader question: what are the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs? Over a time span that extends beyond some utilities' planning horizon, key uncertainties impacting need are magnified, and the range of possible pathways to meet resource adequacy needs expands. Therefore, rather than focusing on evaluation of a single portfolio, the long-term assessment examines a range of potential portfolios. The long-term assessment utilizes a combination of **long-term capacity expansion (LTCE)** and **LOLP modeling** to design and evaluate twenty-three plausible portfolios that satisfy regional needs by 2045. Each portfolio is created based on a unique combination of the following three variables:

- **Demand Forecast:** three different levels of long-term load growth (Reference, Low, and High);
- **Technology Set:** four different options for the combinations of technologies available to meet incremental needs (Existing Technologies Only, Existing and Emerging Technologies, Existing and No New Gas, and Existing and Emerging, but No New Gas)
- **Clean Energy Penetration:** five different levels of energy mixes, defined using the penetration of clean energy ranging from 60% to 95%, measured based on the percentage of annual energy needs served by carbon free resources.[26]

The twenty-three combinations of these variables that are explored in this assessment are shown in Table 5-1. For each case, LTCE and LOLP models are used together to identify a least-cost portfolio of resources to meet regional resource adequacy needs, subject to specified requirements for the generation mix.

[26] The different clean energy penetrations are a key study design element and does not reflect the region nor any individual utility's goals. Changing the clean energy penetrations allows the study to explore common and uncommon patterns across a broader range of possible future portfolios and energy mixes.

Table 5-1. Twenty-three portfolios created and evaluated in for long-term assessment

Load Forecast	Technology Set	Clean Energy Penetration (% of Energy)				
		60%	70%	80%	90%	95%
Reference	**Existing**	●	●	●	●	●
Low	Existing	●	●	●	●	●
High	Existing	●	●	●	●	●
Reference	Existing & Emerging	●	●	●	●	●
Reference	Existing (No New Gas)					●
High	Existing & Emerging					●
High	Existing (No New Gas)					●

Each combination of these assumptions evaluated in this study is intended to represent a hypothetical long-term portfolio, rather than as a predictive or prescriptive outcome for the region. None of these portfolios are directly representative of current utility plans and no single portfolio developed herein is intended to reflect any sort of preferred or recommended regional resource plan, however all portfolios must achieve a target LOLE of 0.1. By doing so, the twenty-three portfolios studied – together, as a set – establish long-term ranges to bound the needs for specific types of resources; illuminate tradeoffs between different types of resources; and provide a basis for identifying common themes that are applicable across a wide range of potential outcomes.

5.2. Modeling Approach

The long-term assessment relies on a three-step modeling process to generate and evaluate future system portfolios and performance:

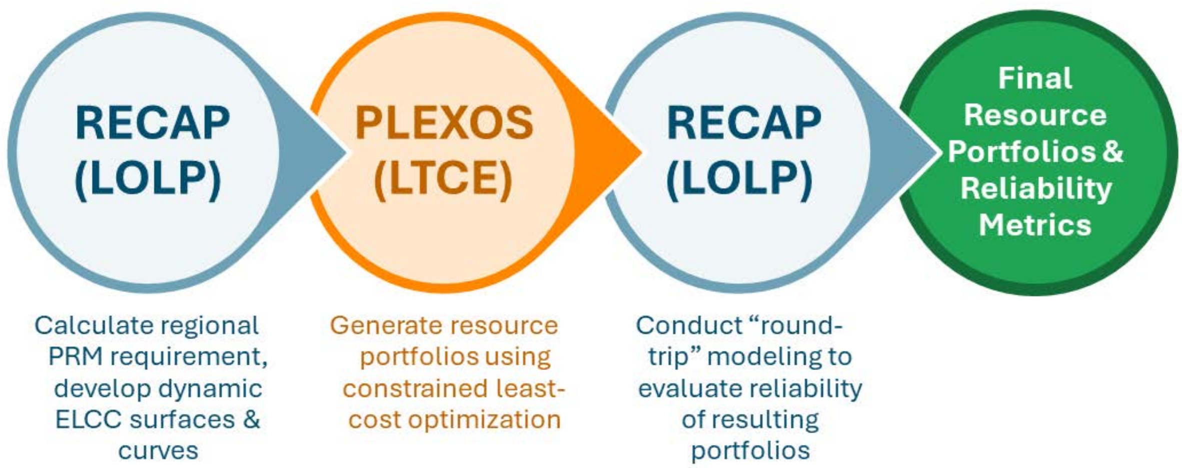
- First, a regional PRM requirement and ELCC curves for new resources are developed using RECAP to conduct LOLP analysis. This analysis builds directly on the datasets generated in the near-term analysis.
- Second, PLEXOS[27] is used to conduct long-term capacity expansion modeling for each of the scenarios defined above. The PRM requirement and ELCC curves derived in the prior step serve as direct inputs into the LTCE modeling, where they are used to define constraints that ensure that sufficient resources are developed to meet regional resource adequacy needs.

[27] More information about the PLEXOS LT model is available on the Energy Exemplar website (https://www.energyexemplar.com/plexos).

- Third, the resulting portfolios are provided back to RECAP, where "round-trip" resource adequacy analysis is conducted to ensure that the level of observed reliability of the portfolio does not deviate substantially from the specified target and to allow for a deeper inspection of the reliability risks present in each one.

This three-step process, illustrated in Figure 5-1, provides the most comprehensive framework through which to evaluate the resource adequacy and drivers of risk present in a portfolio.

Figure 5-1. Three-step modeling process to generate and evaluate portfolios to meet long-term resource adequacy needs

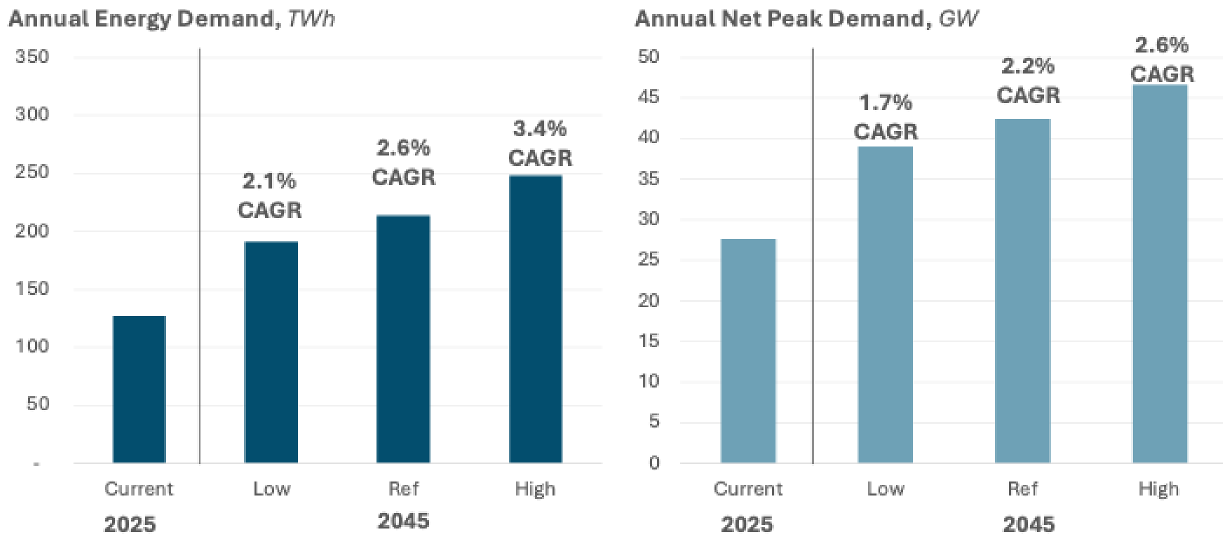


5.3. Key Assumptions

5.3.1. Long-Term Load Forecasts

This study explores the hypothetical portfolios across three load forecasts: Reference, Low, and High. The Reference load forecast represents a continuation of expected growth in the region across all the major load components. For each component, E3 used the 2030-2035 compound annual growth rate from the Phase 1 forecast as the Reference load growth expectation out to 2045. The Low load forecast represents a return to load growth seen earlier in the decade. For baseline and large load customer components, the growth is halved and the adoption of electric vehicles also slows down. The High load forecast represents continued base load growth and accelerated growth of electric vehicles and large loads. Figure 5-2 shows the 2025 annual energy demand and the 2045 coincident peak demand. While both energy and peak demands grow between 2025, the total net energy demand grows at a faster rate relative to net peak demand due to the increase in large loads. These loads are assumed to have a 90% load factor, higher than the existing load factor of around 50%.

Figure 5-2. Southwest 2045 Net Annual Energy (TWh) and Net Coincident Peak (GW)



Across each of the load forecast, continued adoption of energy efficiency and behind-the-meter solar are projected out based on observations from the near-term analysis. For demand response, this study assumes a 5% of peak penetration of demand response is present across each portfolio.

5.3.2. Existing Resource Portfolio

The long-term analysis builds upon the resource portfolio data provided by the utilities for the near-term assessment. The long-term assessment includes the resources identified in the "2035 Existing and New Resources in Development" portfolio, shown in Figure *4-8*, with select modifications:

- Additional planned retirements (roughly 2,000 MW of existing natural gas capacity) between 2035 and 2045 reduce the capacity of the existing natural gas resource portfolio;
- Existing capacity of solar and storage resources are reduced as existing contracts roll off between 2035 and 2045; and
- The Harquahala natural gas plant, currently under utility contract that will soon expire, is assumed to remain in service over the analysis horizon.

These resources are used to populate PLEXOS with an initial regional resource portfolio.

5.3.3. Resource Expansion Options

PLEXOS LT identifies new resources to meet growing loads in two snapshot years: 2035 and 2045. The candidate resources described hereafter represent the menu of new resource options available in PLEXOS. Resource options are classified as either (a) commercially available or (b) emerging technologies; the former are considered as options in all cases (except where expressly prohibited), while the latter are included as options only in 2045 under the "Emerging Technology" sensitivities. The resource options considered are listed in Table 5-2. Resource options available in PLEXOS.

Table 5-2. Resource options available in PLEXOS

Commercially Available (All Cases)	Emerging Technology (Select Cases)
Solar (Arizona & New Mexico options)	Generic Storage (8hr)
Wind (Arizona & New Mexico options)	Generic Storage (12hr)
Natural Gas Combined Cycle	Generic Storage (100hr)
Natural Gas Combustion Turbine	Nuclear Small Modular Reactor (SMR)
Lithium-Ion Battery (4hr)	Enhanced Geothermal System (EGS)

Resource costs were based on the National Renewable Energy Laboratory's Mid Annual Technology Baseline and adjusted to reflect geography and expected market conditions in 2035. Many of the key near-term market trends driving investment decisions in 2026 have a lesser role to play in 2035. Key modeling assumptions include the sunset of current federal tariff impacts by 2030, expiration of solar and wind tax credits before 2030 (in line with the July 2025 budget reconciliation bill), ineligibility of battery storage for investment tax credits due to foreign content-based eligibility restrictions in current federal policy, and short-term gas turbine scarcity premiums that are assumed to normalize by 2035. Emerging technology options are assumed to be available beyond 2040. The following table shows 2045 capital costs and levelized fixed costs (including capital, financing, and fixed O&M costs) for candidate resources.

Table 5-3. Southwest 2045 capital and levelized fixed cost assumption for candidate resources (nominal $)[28]

Technology	Classification	Overnight Capital Costs ($/kW)	Levelized Fixed Cost ($/kW-yr)
Solar	Commercial	$1,776	$140
Wind	Commercial	$2,811	$223
Gas - CT	Commercial	$3,523	$299
Gas - CCGT	Commercial	$4,032	$323
Li-ion Battery (4-hr)	Commercial	$2,506	$233
Nuclear Small Modular Reactor	Emerging	$13,161	$1,271
Enhanced Geothermal System	Emerging	$16,668	$1,739
LDES (8-hr)	Emerging	$4,321	$402
LDES (12-hr)	Emerging	$8,714	$989
LDES (100-hr)	Emerging	$8,506	$965

[28] Resource costs are based on E3's RECOST model and assumptions used specific to the Southwest. For more information on E3's RECOST methodology, please refer to E3 website

New candidate wind and solar generators are subject to additional costs to capture the cost of transmission required to deliver renewable generation to load areas. Wind and solar resources incur two transmission-related costs: a system-level transmission cost representing an increase in transmission headroom required for new generation and an interconnection cost reflecting the cost to connect each individual plant to the bulk electric system.

New gas CT and CCGT resources include both the capital cost for power generation and incremental gas transportation cost adder. The adder reflects the need to secure additional firm fuel deliverability. The adder assumes existing regional gas pipeline capacity is fully subscribed and that new gas resources would need to procure incremental firm transportation rights or equivalent pipeline capacity service. The adder excludes operational fuel costs, which are modeled separately in capacity expansion, and should not double count any transportation, basis, or delivery costs already embedded in fuel price assumptions.

5.3.1. Effective Load Carrying Capability (ELCC) Assumptions

This study uses the planning reserve margin (PRM) and effective load carrying capability (ELCC) methodology to measure the contribution of different types of resources to the total resource adequacy need. Using the RECAP LOLP model developed in the near-term assessment, the long-term assessment incorporates dynamic ELCC curves and surfaces for variable and energy-limited resources to account for their changing contributions as a function of penetration. The ELCC curves used in the long-term assessment reflect resource additions relative to the “Existing & Planned” portfolio and are derived by adapting the model used in the near-term assessment to reflect projected 2045 loads. Examples of the curves produced from this exercise that are input into PLEXOS are shown below, illustrating how:

- The capacity value of incremental wind resources begins at a moderate level (30%) but declines as the proportion of wind in the portfolio increases;
- The capacity value of additional storage resources begins relatively high (80+%) but declines as the system becomes increasingly energy constrained; and
- The rate at which storage capacity value declines depends upon the penetration of additional solar; because solar and storage resources complement one another, higher penetrations of solar slow the declining marginal ELCC of storage.

Figure 5-3: Incremental Wind Capacity Value and Incremental ELCC

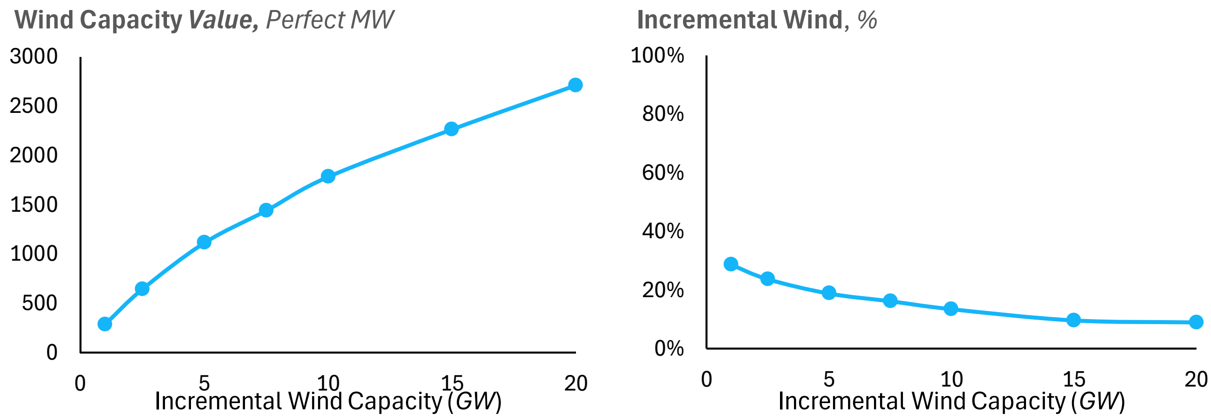
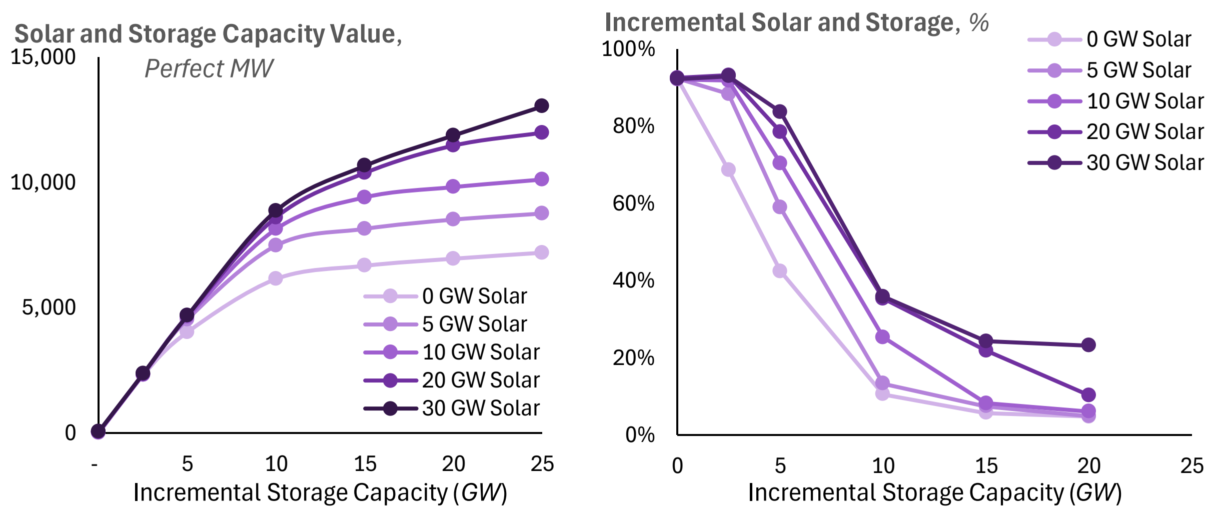


Figure 5-4: Incremental Solar and Storage Capacity Value and Incremental ELCC

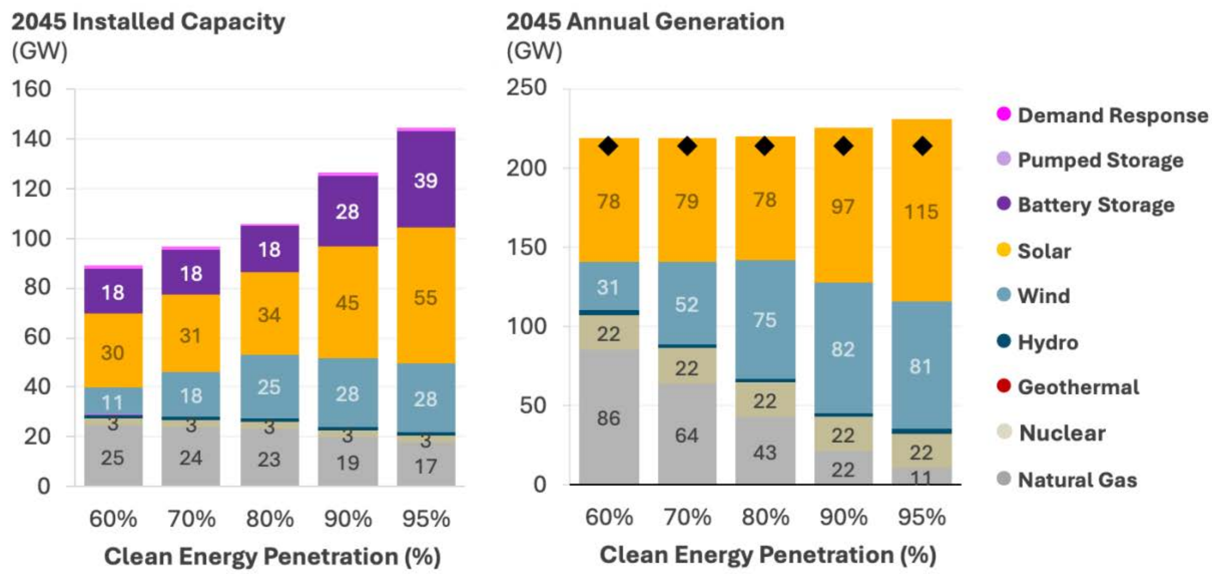


5.4. Results

5.4.1. Resource Portfolios

The installed capacity and annual generation by resource type for five portfolios spanning clean energy penetrations from 60 to 95% under the Reference load forecast are shown in Figure 5-5. This collection of portfolios, each designed to meet a regional resource adequacy target of 0.1 days per year, shows a range of plausible energy mixes while meeting long-term energy and resource adequacy needs in the Southwest region.

Figure 5-5. Installed capacity and annual generation mix at different clean energy penetrations, Reference load forecast



Several observations can be made across these portfolios:

- Of the five portfolios, four (60-90% Clean Energy) produce LOLE results that achieve or are below the 0.1 days per year LOLE target.
- While the specific quantities vary, all portfolios meet regional resource adequacy needs with a diverse mix of firm (gas and nuclear), renewable (wind and solar), and energy-limited (storage, DR, and hydro) resources.
- The differences in capacity among portfolios provides a measure of the relative effectiveness firm, variable, and energy-limited resources in contributing to resource adequacy needs: from 60 to 95%, the total quantity of incremental renewables (+42 GW) and storage (+21 GW) is nearly eight times greater than the quantity of natural gas resources displaced (-8 GW).
- While the share of the energy mix served by natural gas decreases in inverse proportion to the penetration of clean energy resources, the amount of installed capacity needed to maintain reliability does not exhibit the same decline. Even in a 95% clean energy portfolio where natural gas accounts for only 5% of annual energy, the installed capacity of natural gas resources (17 GW) is roughly 40% of the system peak demand.

More detailed reliability statistics for each of these portfolios are reported in Table 5-4.

Table 5-4. Reliability statistics for portfolios spanning 60 to 90% Clean Energy penetration

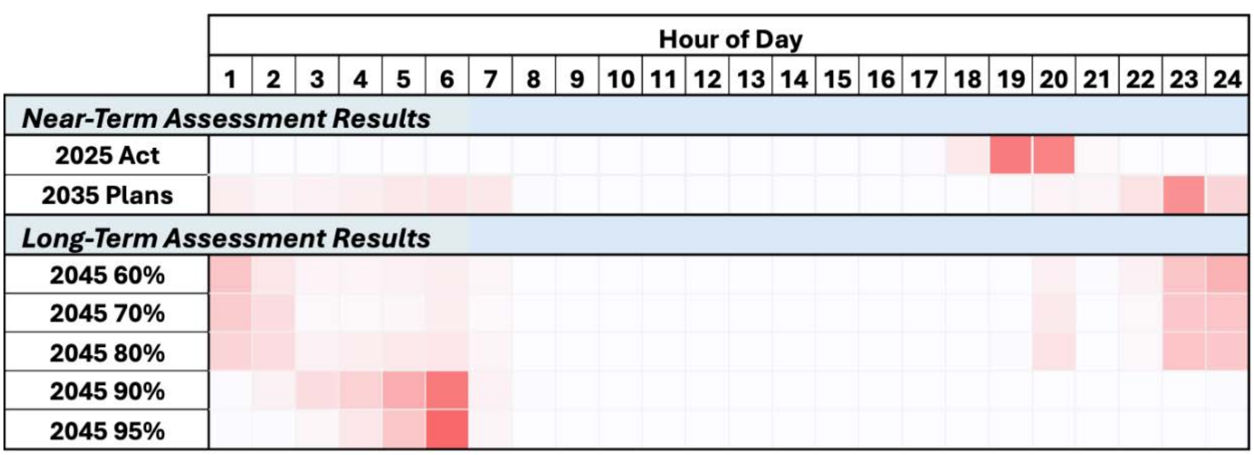
Portfolio	Loss of Load Expectation (days/yr)	Expected Unserved Energy (MWh)	Loss of Load Hours (hrs/yr)
60% Clean Energy	0.11	237	0.21
70% Clean Energy	0.11	220	0.19
80% Clean Energy	0.08	190	0.15
90% Clean Energy	0.07	158	0.15
95% Clean Energy	0.01	21	0.01

5.4.2. Drivers of Reliability Risk

Beyond 2035, the timing and nature of potential reliability risks will continue to evolve as a function of continuing changes to the resource mix. Figure 5-6 shows the timing of loss-of-load risk for each of the five portfolios discussed above (compared against results from the near-term assessment). This figure shows that:

- Because all long-term portfolios include a substantial quantity of solar and storage resources, all five experience loss-of-load risk in the evening and overnight periods.
- The risk profiles for the 60%, 70%, and 80% portfolios are similar in nature to the observed patterns in the utilities' 2035 plans: the periods of highest risk occur around midnight – when load not yet reached its overnight lows and storage resources begin to reach exhaustion – but also stretches into the early morning hours.
- In the 90% and 95% portfolios, the higher penetrations of storage resources cause risk to shift even further into the early morning period, and the timing of greatest risk can occur any time between sundown and sunrise – when load is beginning to increase but storage resources have not yet had a chance to recharge after discharging overnight.

Figure 5-6. Comparison of risk patterns observed in near- and long-term assessments



Across the range of portfolios, this study further investigates what types of factors are most likely to lead to these types of loss-of-load events in each portfolio, focusing on four main potential drivers:

1. High load, extreme summer days,
2. Coincident thermal forced outage conditions
3. Consecutive moderate or below average solar output days,
4. Insufficient stored energy in energy-limited resource fleet.

While all futures experience some form of these drivers, emphasis is different depending on the portfolio composition. Optimized portfolios with higher thermal capacity are more capable of covering high load, non-solar periods, provided expected performance from each power plant. Meeting nighttime reliability will increasingly depend on the availability individual units, something Southwest utilities are acutely aware of today. However, other resources must also perform well during these same periods

While high solar availability and output tend to correlate with high load days, even a few days of average or below-average solar performance ahead of heatwaves results in energy deficiencies in 2045. In all futures observed, solar installed capacity penetration is 75% of peak or higher, effectively meeting midday demand across all futures. However, consecutive days of low solar output reduce the effectiveness of other resources that rely on its energy, namely charging storage and deferring output until nighttime.

By 2045, storage, hydro, and on rare occasions, demand response, is dispatched during nighttime hours, provided it has sufficient energy available. If the preceding hours have ample solar generation, storage and hydro output can be delayed until after sunset. If the preceding hours have below-average solar output, the residual demand increases the pressure for the dispatchable resources to fill the void. During rare days of high load combined with lower-than-normal solar availability, reliability outcomes are primarily driven by lower solar availability.

5.4.3. Relative Portfolio Costs

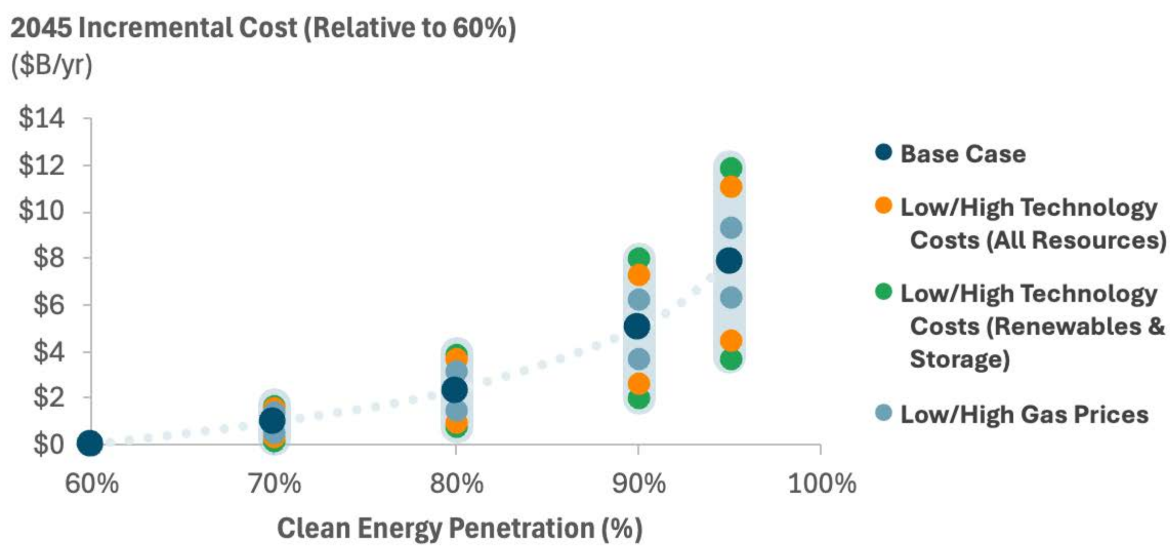
While cost is not a primary focus of this assessment, capacity expansion modeling provides useful directional information on the relative costs of different portfolios since it identifies least-cost resource portfolios subject to the specified constraints. Because the major drivers of scenario costs – the physical costs of the resources, supporting transmission infrastructure, and the fuel costs to operate them – are all highly uncertain across a twenty-year planning horizon, relative costs among the scenarios are shown for five sets of assumptions:

- Using E3's "Base Case" cost trajectories for resource, fuel, and transmission costs, which were the basis of the least-cost optimization in PLEXOS;
- Under alternative "high" and "low" technology cost assumptions (+/-20% relative to mid), applied to all resource and transmission investments;
- Under alternative "high" and "low" technology cost assumptions (+/-20%), applied only to renewable and storage resources; and
- Under alternative "high" and "low" natural gas price forecasts (+/-50%).

The sensitivities on resource, transmission, and fuel costs are inherently generic by design, intended to illustrate the relative relationships among the different contributing factors to portfolio costs. The resulting ranges of portfolio costs, measured relative to the 60% Clean Energy portfolio, are shown in Figure 5-7. These results inform three useful insights:

- Under "Base Case" cost assumptions, portfolios with higher clean energy penetrations have higher costs than portfolios with lower clean energy penetration.
- The costs of increasing clean energy penetration grow at an increasing rate (reflected by the exponential shape of the curves), a reflection of the declining value of renewables and energy storage at higher penetrations.
- Under certain alternative sensitivities (low renewables & storage costs, high natural gas prices), the costs observed in the 70% and 80% Clean Energy portfolios are not materially higher than the 60% Clean Energy portfolio, indicating that economic fundamentals alone may be one factor that could lead utilities to portfolios with higher clean energy penetrations.

Figure 5-7. 2045 incremental system costs, compared to 60% Clean Energy portfolio (nominal $)



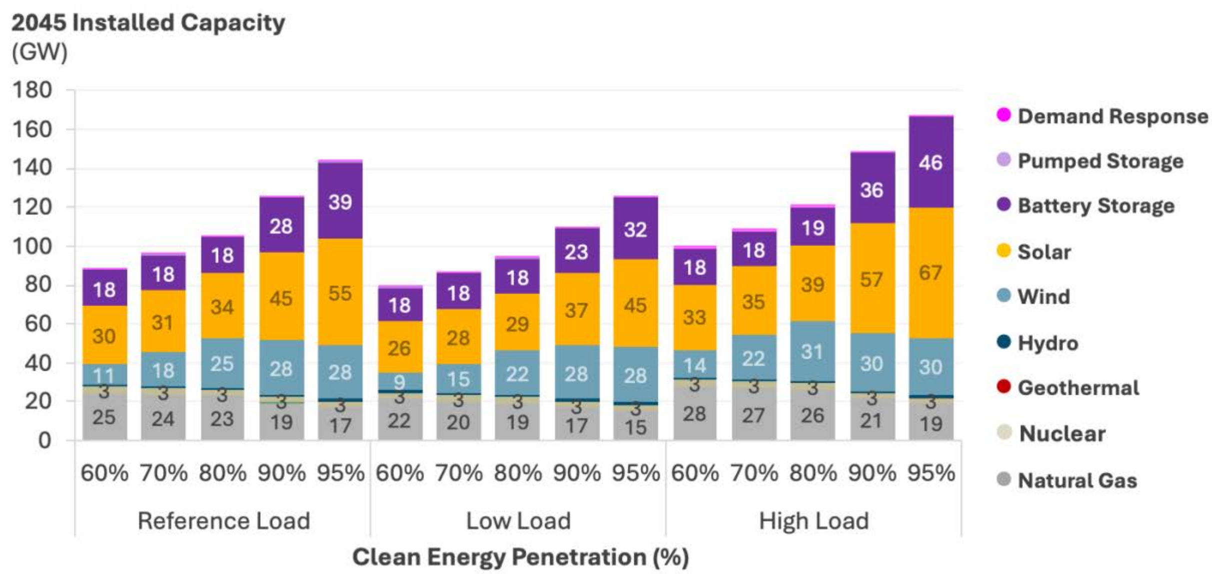
5.4.4. Portfolio Sensitivity Analysis

5.4.4.1. Load Forecast Sensitivities

To explore how load forecast uncertainty impacts the long-term regional resource needs for resource adequacy, additional sets of portfolios are created under alternative Low and High load forecasts. Figure 5-8 compares the resulting ranges of portfolios (which also span clean energy penetrations from 60 to 95%) against the results in the Reference load forecast. While the magnitude of total resource needs to ensure reliability differs across load forecasts, the resulting portfolios are similar in more ways than they are different:

- All portfolios require significant additions of new generation infrastructure relative to today's system. Even the portfolio with the lowest total quantity of resources (60% clean, low load forecast) requires roughly 50 GW of new installed capacity, more than the total capacity of the existing system today.
- All portfolios meet reliability needs with a complementary blend of firm, variable, and energy storage resources.
- All portfolios include new natural gas additions to meet a portion of long-term resource adequacy needs, and fourteen of the fifteen portfolios include gas additions beyond the resources currently under development (the lone exception is the 95% Clean Energy, Low Load portfolio).

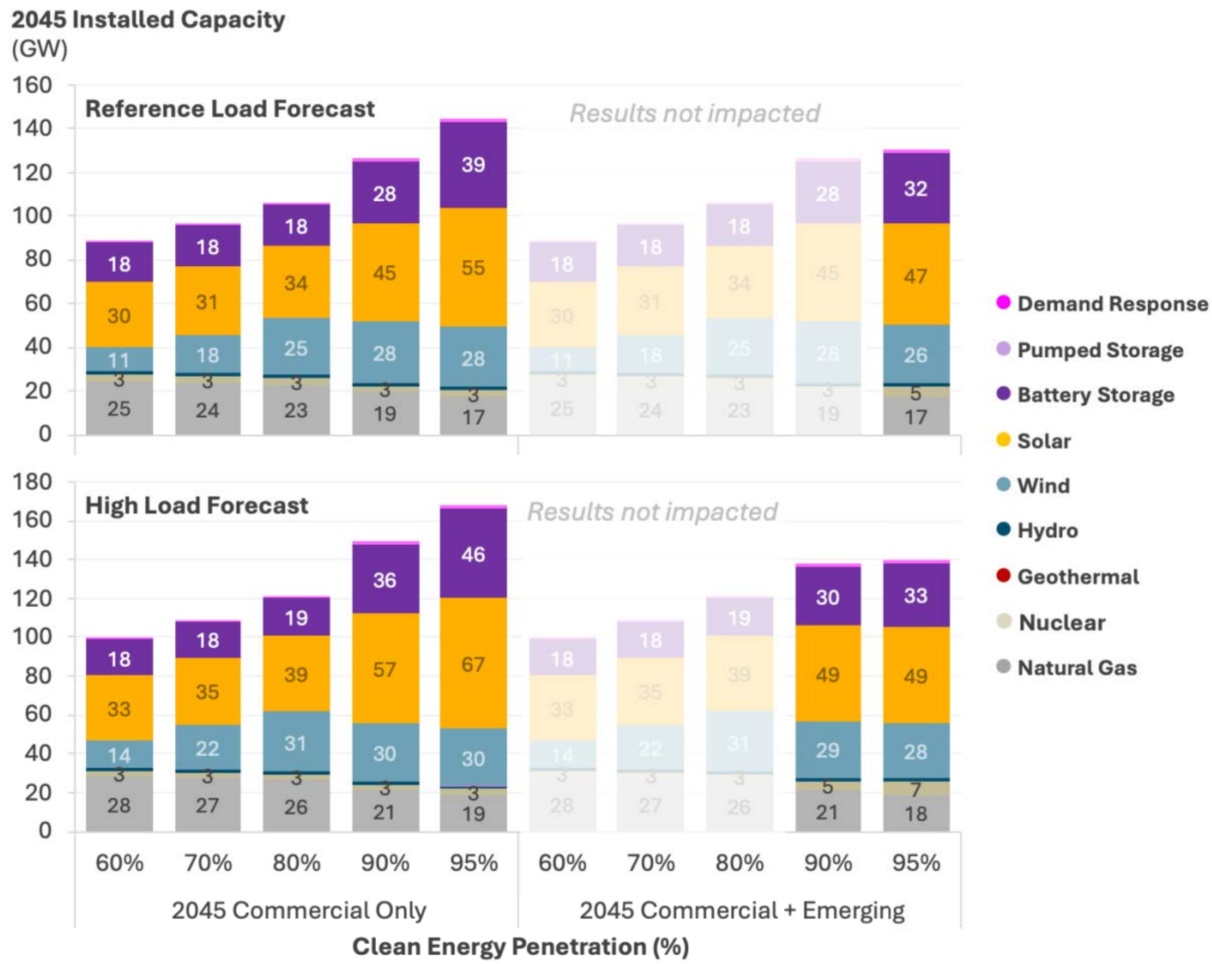
Figure 5-8. Installed capacity by technology under Low, Reference, and High load forecasts



5.4.4.2. *Emerging Technology Sensitivities*

The Reference and High Load cases are modeled with under a sensitivity where emerging technologies described in Section 5.3.3 are available for selection in 2045; these results highlight the potential value of additional resource options. Figure 5-9 compares the installed capacity of portfolios with commercial resources only to their counterparts where emerging technologies are allowed for the Reference Load forecast (top) and High Load forecast (bottom). While no emerging technology options are selected at the lower clean energy penetrations, new nuclear resources are selected at the 90% (High Load only) and 95% (Reference and High Load) levels. Notably, in both cases, the new nuclear resources primarily displace other clean resources (wind, solar, and storage) instead of natural gas.

Figure 5-9. Southwest 2045 Total Installed Capacity (GW) | Reference Emerging Case



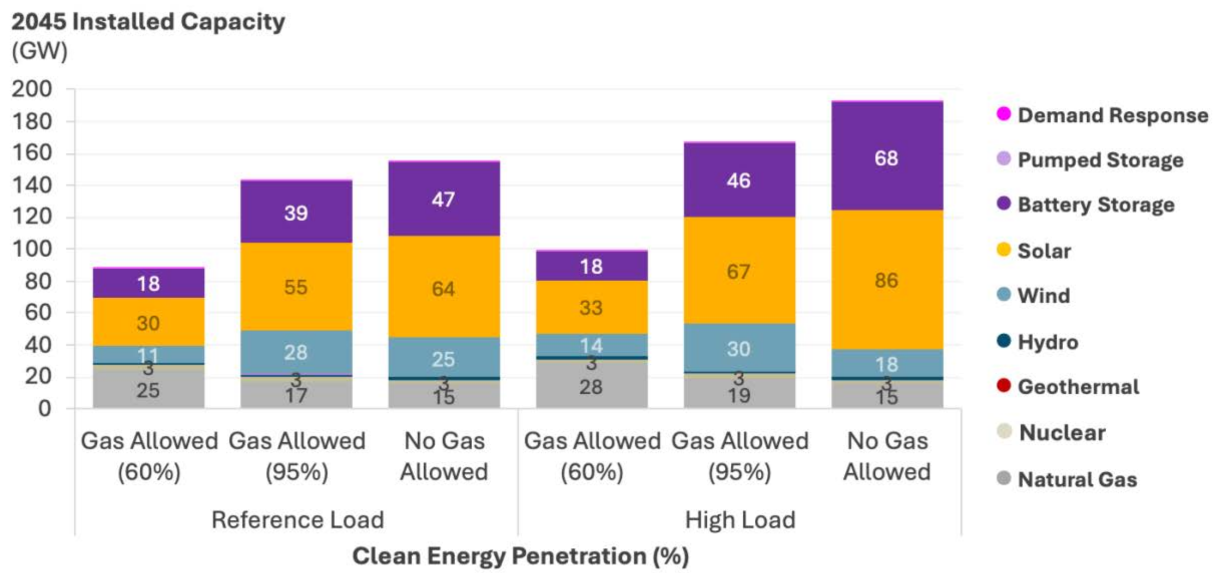
These results depend upon the cost input assumptions used for emerging technologies, and while the cost assumptions used in this study are intended to be reflective of emerging technologies reaching broad market readiness, technological breakthroughs could result in even larger quantities of emerging technologies providing viable options to contribute to regional resource adequacy needs.

5.4.4.3. No New Natural Gas Sensitivity

To further examine the role of firm resources, this study also investigated scenarios in which the new natural gas resources were not included as an option in the LTCE modeling. Figure 5-10 shows total installed capacity in the 95% clean energy portfolios of the reference and high load cases with and without this constraint to new gas builds. The constraint to new gas builds results in a larger system size.

- In the Reference Load case, avoiding the 2 GW of new gas capacity selected in the 95% Clean Energy portfolio requires an additional 8 GW of storage and 6 GW of renewables.
- In the High Load case, avoiding the 4 GW of new gas capacity selected in the 95% Clean Energy portfolio requires an additional 18 GW of storage and 11 GW of renewables.

Figure 5-10. Installed capacity comparison between portfolios with and without new natural gas considered as an option



Under the no new gas allowed cases, loss-of-load events are larger in magnitude as a the result of energy deficiency. These are typically observed during sustained periods of low renewable production that may last multiple days and occur in the summer or the winter. Portfolios that include new gas resources successfully minimize this risk, as the quantity of firm resources capable of generating round the clock is typically sufficient to backfill the energy shortfalls from renewables; portfolios without new gas resources do not have sufficient firm resource capacity to meet system needs during these events, and the resulting effect is that a significant portion of load cannot be served over an extended period of time.

Figure 5-11 and Figure 5-12 provide contrasting examples of how portfolios with and without new gas resources perform under such an event (based on actual winter weather conditions observed from December 1 to 7, 2011). During this week, the Southwest region experienced a winter storm and cloudy conditions, resulting in abnormally low solar output on multiple cloudy days.

- In a portfolio with new natural gas capacity, the quantity of firm resources available (roughly 20 GW) is sufficient, in combination with lower outputs from renewables and storage, to maintain reliability through this event.
- In a portfolio without new natural gas capacity, storage resources are fully depleted on the second day, and because the amount of firm capacity available is much lower, the system experiences a loss of load event that spans from late evening on the fourth day to sunrise the next morning. Also notable about this event is its size: during the period of loss of load, roughly 10 GW – approximately one third of the region's loads – cannot be met by the resources in the portfolio.

Figure 5-11. Hourly Generation 95% High Load Case with Incremental Natural Gas, December 1-7 (GWh)

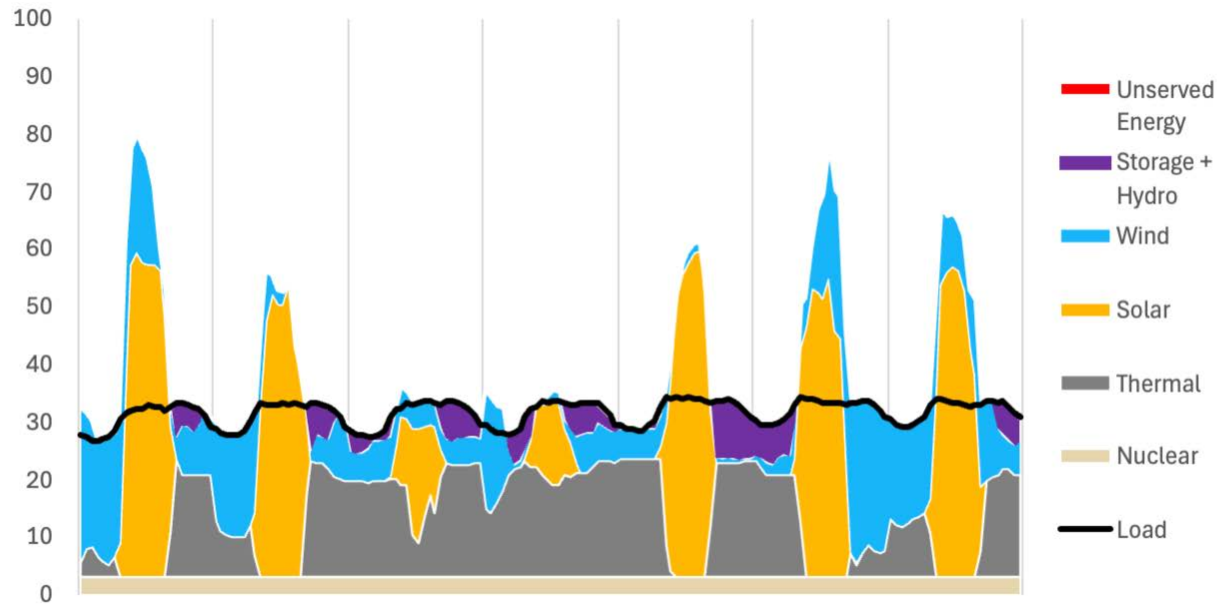
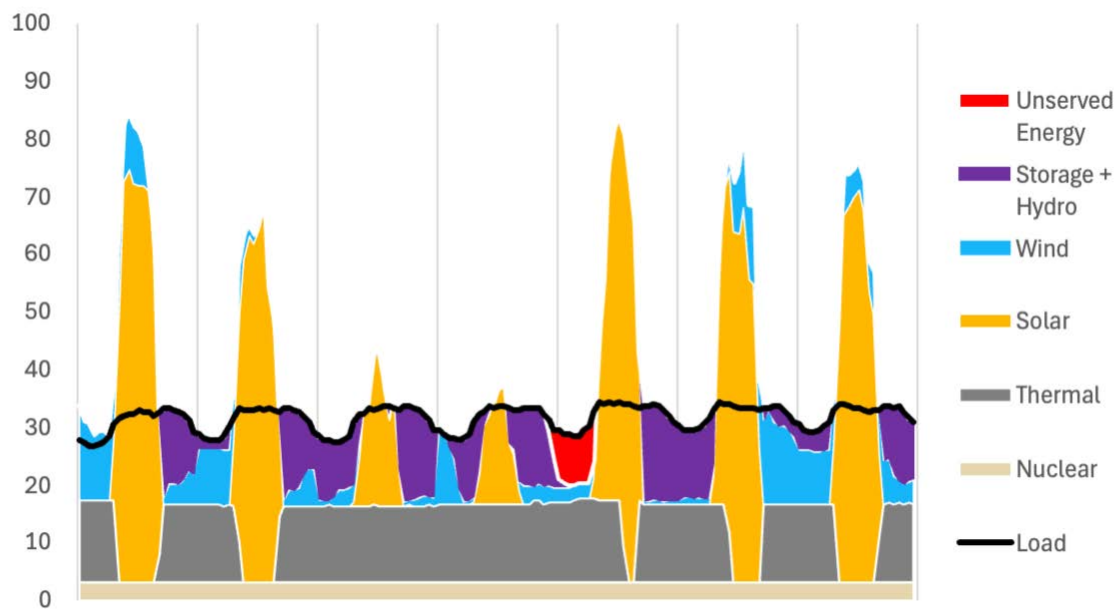
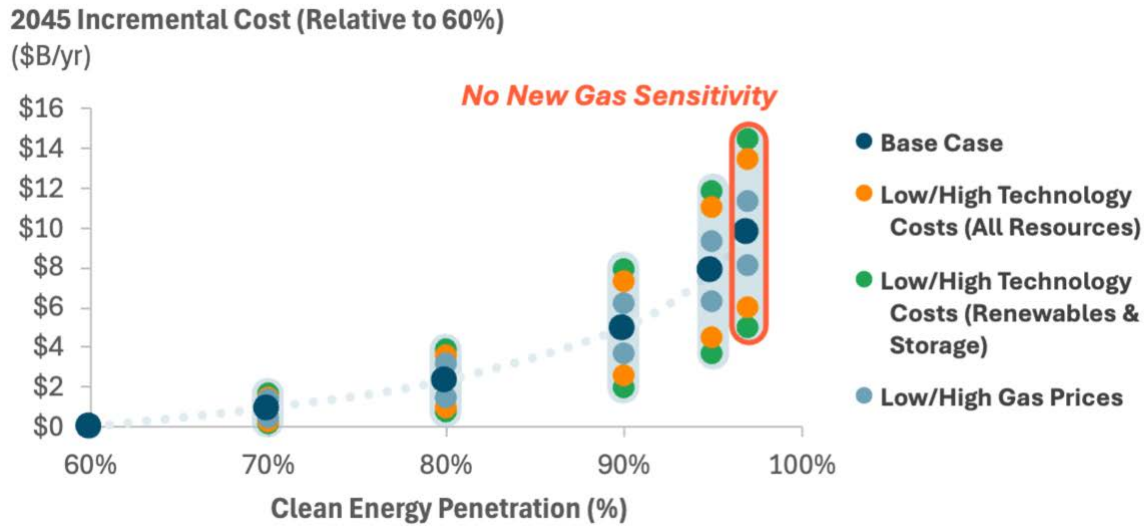


Figure 5-12. Hourly Generation 95% High Load Case Without Incremental Natural Gas, December 1-7 (GWh)



In addition to greater exposure to higher risks of large loss-of-load risks, portfolios that exclude new natural gas resources as an option also exhibit higher costs. Figure 5-13 compares the incremental costs associated with the "No New Gas" sensitivities against the suite of portfolios generated at different levels of clean energy penetration; across all cost assumptions, the sensitivity portfolio without gas shows higher costs than all alternatives, including the 95% Clean Energy portfolio.

Figure 5-13. Portfolio cost comparison including No New Gas sensitivity portfolio



5.5. Discussion

Across all long-term portfolios, maintaining resource adequacy requires a diverse mix of variable, energy-limited, and firm resources. Variable renewables (primarily solar and wind) provide large shares of annual energy, while energy-limited resources (storage, hydro, and demand response) shift energy across hours and help move periods with excess energy to periods with a deficit in energy. However, as penetrations rise, both variable and energy-limited resources experience declining marginal capacity value, reinforcing the need for portfolios that combine complementary resource types rather than relying on any single technology type.

Firm resources are critical to reliability in every portfolio because they can sustain output during multi-hour and multi-day periods when renewable production is low and energy-limited resources are depleted. In practice, this includes conventional firm capacity, such as natural gas (and existing nuclear), which serves as a backstop for critical periods across both summer high load periods and winter low-renewable conditions. The results show that even under higher clean energy penetration, portfolios add new firm capacity for limited periods when the system is capacity- and energy-deficient.

Today, the range of scalable firm options is limited, and natural gas remains the most viable broadly available choice to provide new firm capacity over the planning horizon evaluated in this assessment. Looking forward, if clean firm technologies become commercially available at scale, they can provide the same reliability role as conventional firm resources. In that future, clean firm resources could be dispatched to complement variable and energy-limited resources—providing sustained energy during low-renewable periods and preserving storage energy for the highest-risk hours—alongside any remaining conventional firm capacity.

6. Key Findings & Implications

6.1. Key Findings

The near-term and long-term assessments inform six key findings from this assessment. The first three focus primarily upon the results of the near-term assessment, and the second three build upon these based on the results of the long-term assessment.

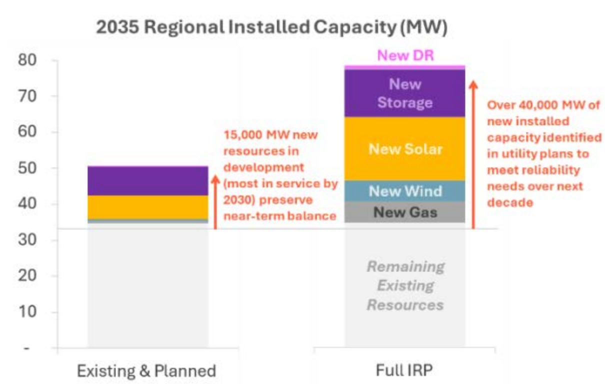
1. Need for New Resources is Urgent

Large increases in regional demand, coupled with anticipated retirements, continue to drive a significant need for new resources across the region to maintain reliability

Over the next decade, the anticipated demand based on utility inputs to this study shows regional coincident peak demand increasing from roughly 27,500 MW to over 36,000 MW. At the same time, assumed retirements and expiring contracts with existing resources result in the loss of nearly 8,000 MW of effective capacity from the 2025 existing portfolio. For a system at or near load-resource balance today, the compound effect of these two changes is a total need for new *effective* capacity of roughly 18,000 MW over the next decade.

2. Utility Plans Demonstrate Adequacy

Over the next decade, utilities' resource plans include new natural gas, renewables, and storage sufficient to maintain regional resource adequacy



Collectively, the utilities' resource plans provided as inputs for this assessment include over 40,000 MW of new installed capacity by 2035. If these resources are successfully brought in service according to prescribed schedules – which will require a rate of new resource additions far greater than recent historical trends – this study shows that the region will maintain sufficient generating capacity to ensure a level of resource adequacy consistent of LOLE of 0.1 days per year or better. Notably, the *nameplate* capacity of the resource additions included in utility plans (40,000 MW) far exceeds the amount of *effective* capacity they provide to the system to ensure reliability due to the inherent limitations of variable and energy-limited resources. [29]

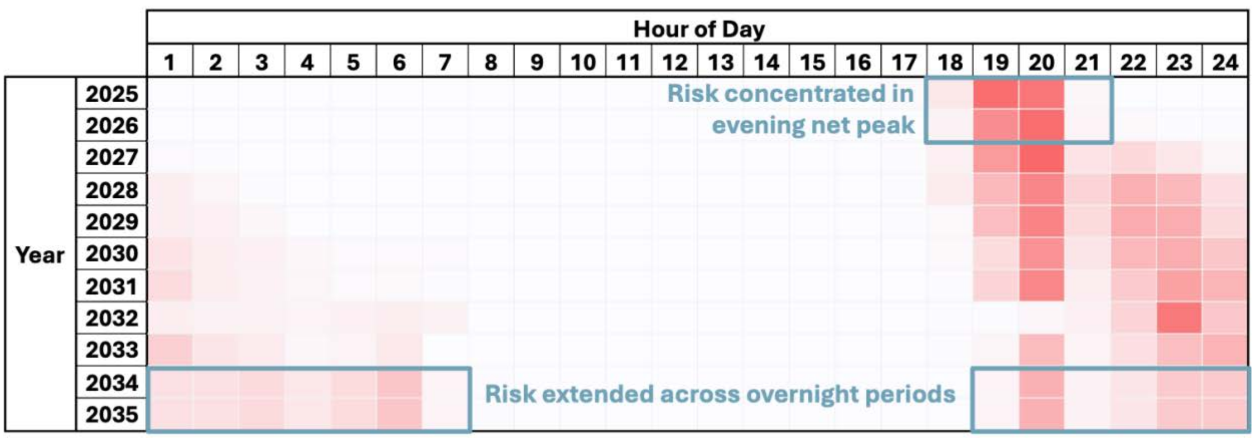
[29] Effective capacity (or perfect capacity) measures a resource's contribution to resource adequacy, typically measured against a "perfect resource" or a resource that is available at all times.

3. Reliability Risks are Shifting Rapidly

Reliability risk has already shifted from afternoon peak to the evening "net peak," and will extend deeper into overnight periods as resource mix evolves

The Southwest utilities are planning to meet a growing share of future resource adequacy needs with renewable and energy storage resources; by 2035, these resources are projected to account for roughly half of the total effective capacity in the region. These portfolio changes directly impact the timing of reliability risks, which shift away from the traditional peak period as penetrations of variable resources rise. This effect is already present in today's system, as the growth of solar has caused risk to shift into the evening. Over the next decade, increasing levels of energy-limited resources will continue to shift and extend the periods when the system is at the edge of reliability (see Figure 6-1). Based on utility plans, higher risks in the late evening and overnight periods could begin to emerge as soon as 2027.

Figure 6-1. Relative loss-of-load risk by time of day based on utility plans, 2025-2035



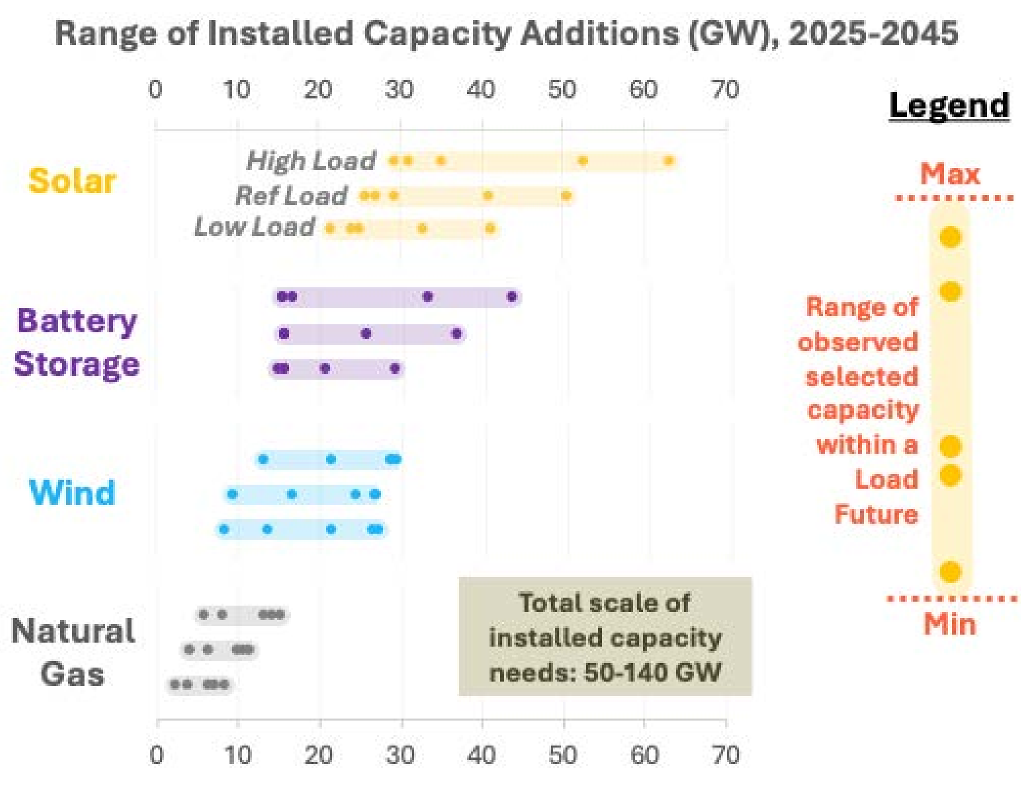
These effects are caused by evolving portfolio identified across all utilities to meet their needs, and in turn, directly impact the contributions that additional resources can make to resource adequacy in multiple ways. With existing solar penetration shifting risk to late evenings, marginal solar additions provided limited reliability value (marginal solar provides between 5 to 7%). Beyond 2027, the extension of risk into the overnight periods contributes to the observed declines in the marginal capacity value of short-duration storage resources (4-hr storage decreases from 90% in 2025 to 38% in 2035), which in turn increases the relative value of resources that can provide longer duration services to the grid and firm resources capable of generating over sustained periods without limits on their use.

4. Diversity is a Robust Long-Term Strategy

Meeting growth with a combination of new gas, renewables, and storage resources is a robust strategy across a wide range of longer-term future conditions

Beyond 2035, maintaining resource adequacy, as loads continue to grow and existing resources retire, will require substantial investments in new resources. This study demonstrates that regional resource adequacy can be met with a wide range of resource mixes, showing reliable resource portfolios that span from 60 to 95% clean energy; across all portfolios studied, the total amount of new installed capacity added between 2025 and 2045 ranges from 50 to 140 GW. In all cases where the availability of commercially available technologies is not explicitly restricted, long-term needs are met by a diverse mix of new renewables, storage and natural gas resources; the range of new resource additions by technology across the twenty-year period are shown in Figure 1-5. To the extent emerging technologies mature, they may also contribute to regional resource adequacy needs (as evidenced by the selection of new nuclear in several portfolios) but do not appear to diminish the importance of resource diversity. All portfolios also include continued expansion of energy efficiency and demand response; beyond these levels, additional demand-side resources (including behind-the-meter generation, virtual power plants, and incremental energy efficiency and demand response) could also contribute to meeting regional needs if they provide capabilities aligned with the future needs of the electricity system.

Figure 6-2. New installed capacity additions from 2025 to 2045 across portfolios in the long-term assessment

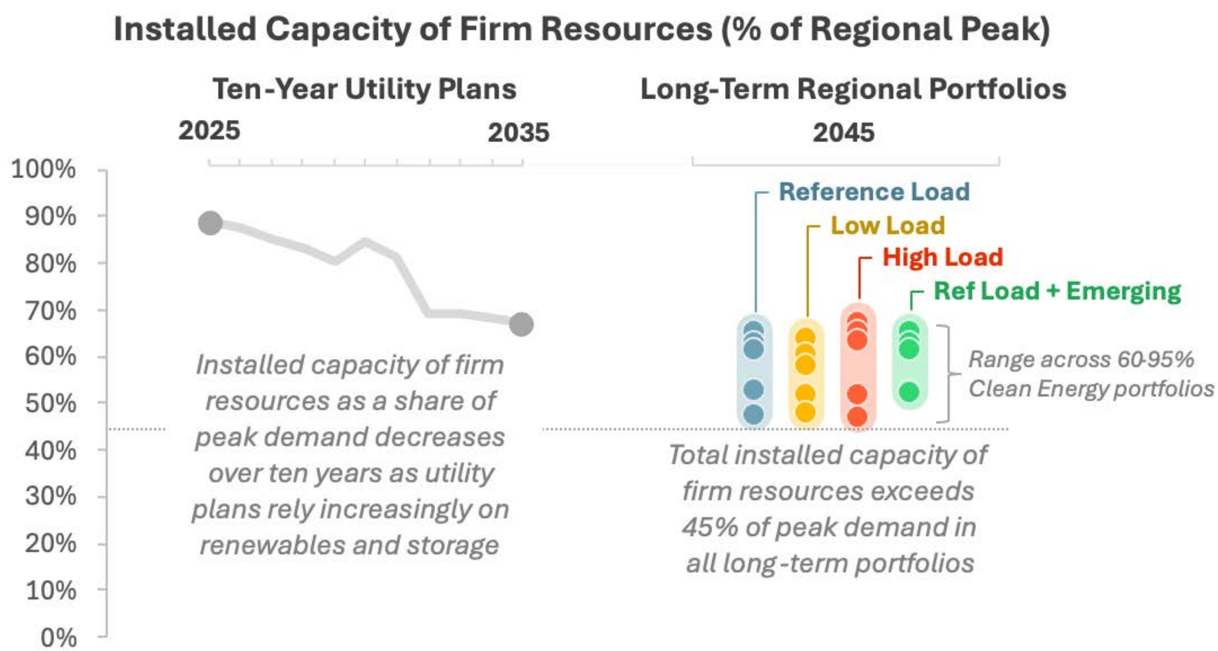


5. Firm Resources are Critical to Reliability

Firm generation resources remain essential to ensuring long-term resource adequacy and mitigating risks of large energy deficiencies, particularly during periods when renewable output is low

While the contributions of variable and energy-limited resources to resource adequacy are substantial across all portfolios analyzed, both categories of resources are subject to significant declines in their marginal capacity value at higher penetration. In practice, this means that even if portfolios include renewables and storage capable of serving most annual energy needs, ensuring resource adequacy also requires “firm” resources capable of producing energy across sustained periods when renewables and energy storage may be unavailable. Across all portfolios analyzed in the long-term assessment where new firm resource options are unconstrained, their total installed capacity ranges between 45-70% of system peak demand (Figure 6-3). In all long-term portfolios, nuclear and natural gas resources play a critical role in ensuring reliability when electric demand is high, renewable availability is low, and energy storage resources have been depleted (for instance, during cloudy winter weeks). Under such conditions, resources with the capability to generate on demand for as long as necessary allow the system to maintain reliability.

Figure 6-3. Summary of firm resource contributions across near-term and long-term assessments

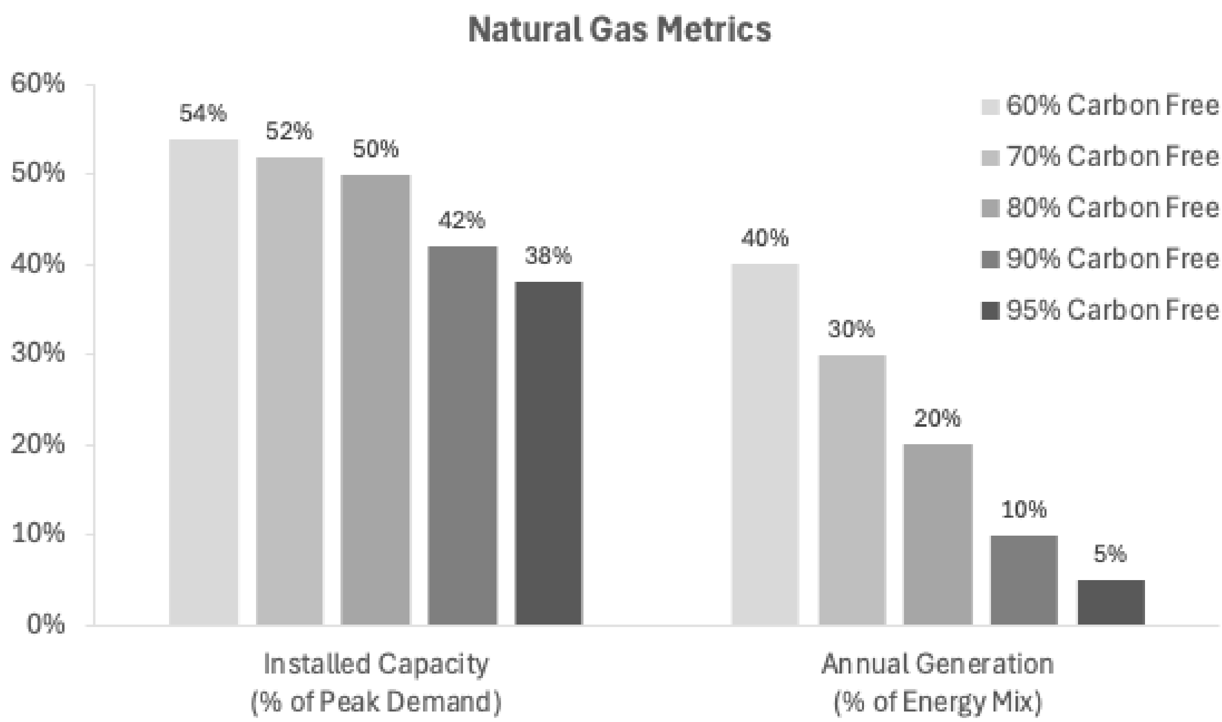


6. Natural Gas Remains the Primary Firm Option

Across all portfolios, natural gas fulfills the majority of the region's long-term need for firm resources, even under the highest clean energy penetrations studied.

The range of portfolios in the long-term assessment yields useful insights into the future adequacy of natural gas, captured through three metrics, shown in Figure 6-4: (1) **installed capacity,** the total gas capacity needed to ensure reliability and (2) **annual generation,** the share of regional energy produced by gas-fired resources. Across the portfolios, as clean energy penetration rises from 60 to 95%, annual gas generation falls sharply (from 40% to 5% of total energy) while installed capacity declines only modestly, from 54 to 38% of peak demand. This contrast is the key finding: increasing clean energy primarily reduces how often gas resources must run, not how much capacity is required. Even at 95% clean energy, a large amount of natural gas capacity (nearly 40% of peak demand) plays a critical reliability role, where it serves as a rarely-used backstop option during periods of low renewable output.

Figure 6-4. Key metrics for natural gas fleet in long-term adequacy assessment



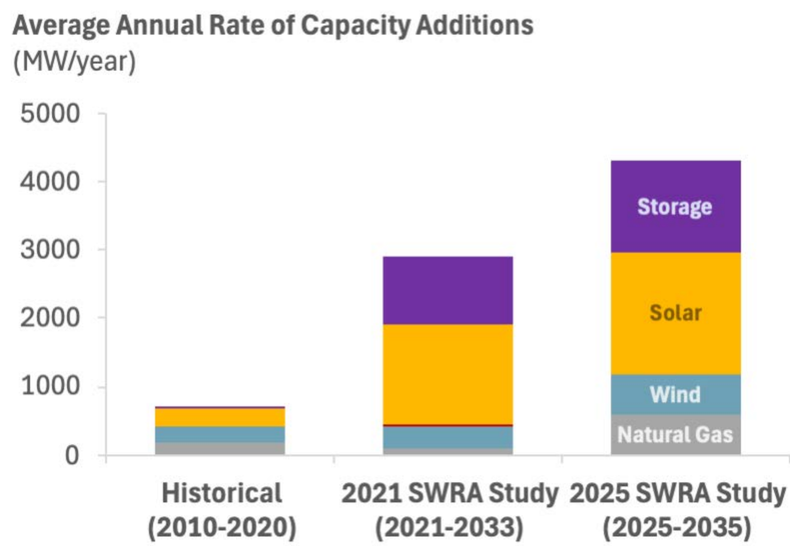
These results further underscore the finding that additions of new natural gas resources to the region are part of a robust strategy to meet near- and long-term resource adequacy needs, capable of supporting grid reliability across a wide range of future clean energy penetrations and load levels.

6.2. Conclusion and Implications

Both the 2021 and 2025 assessments indicate that, despite increasing portfolio complexity and evolving resource adequacy risks, the utilities' collective planning practices are effective in their identification of resource portfolios with the technical ability to maintain regional resource adequacy. Notably, the two assessments reached this conclusion while evaluating different load forecasts and resource portfolios. The consistency of this technical result provides strong evidence that utilities' methods and analytical toolkits provide a sound foundation for resource adequacy planning, and that utilities have used this foundation to adjust plans quickly in response to the changing outlook for future demand.

Having demonstrated that the utilities' plans have the technical capability to meet projected needs, the most immediate challenge for maintaining regional resource adequacy lies in successful implementation. Meeting the needs forecasted in this study would require that utilities add over 4,000 MW of new installed capacity to the system each year over the next decade – a quantity that exceeds the necessary rate of additions previously identified in the 2021 study and eclipses the long-term historical average by a factor of four (see Figure 6-5).

Figure 6-5. Comparison of annual average capacity additions



In an environment marked by heightened uncertainty and rapid change, translating these plans into reliable real-world outcomes presents a more multifaceted set of challenges than the planning itself. Successful implementation will require coordinated orchestration across a range of processes, systems, and institutions involving a wide range of regional stakeholders. The region's utilities will naturally play a central role in each step of implementation, but the ultimate outcomes will reflect the collective performance of actors and systems that no single entity controls. Given the rapid pace of change and potential for unanticipated shifts in the energy landscape, even well-formulated plans will likely require frequent reevaluation and revision; the ability to monitor emerging conditions, identify gaps early, and adapt accordingly will be as important as the plans themselves. The following risk factors represent the most significant aspects of implementation required to ensure resource adequacy:

- **Management of load forecast uncertainty:** since the 2021 study, utilities in the Southwest – and across the country – have experienced large increases in service requests from large customers, but the long-term growth of this new continues to be a major source of uncertainty. Ongoing revisions to load forecasts as the outlook for large customers evolves makes reliability planning a moving target and increases the risk of misalignment between resource development and actual system needs.

- **Procurement & supply chain:** since 2021, global and domestic supply chain constraints have contributed to an increasing trend of increasing project costs and longer lead times for key equipment, highlighting the potential for macroeconomic shocks to create perturbations with far-reaching impacts upon electric utilities. These dynamics are anticipated to persist as demand growth from data centers and other large customers continues at a national scale. This trend has led to an increasing number of project delays and cancellations in recent years and continues to lengthen development timelines for new resources. Longer lead times for new resources and higher risks of potential delays or cancellations will place pressure on utilities to accelerate procurement processes; with many new projects requiring up to five years to complete development, a large portion of the resource procurement to meet 2035 resource requirements will likely occur by 2030.
- **Transmission interconnection & deliverability:** in addition to planning a portfolio of resources capable of supplying load, utilities must also ensure that the transmission system is sized appropriately to allow those resources to be delivered to load when needed. Each new resource requires interconnection studies to identify necessary system upgrades, and large-scale resource development will likely necessitate major transmission expansions. These projects can take a decade or more to plan, permit, and construct. Proactive transmission planning, along with strategies to maximize the use of existing infrastructure as legacy resources retire, can help mitigate these risks.
- **Permitting & regulatory approval processes:** utilities and developers must obtain a variety of permits and regulatory approvals in the process of developing new generation (and associated transmission) from a variety of bodies, which may include local governments, tribal authorities, regulatory agencies and boards, and federal bodies. Higher volumes of applications associated with a faster pace of development may place strain on these processes and could be a contributing factor to delays. Further, in some cases, local ordinances or opposition to project siting may further constrain development opportunities.
- **Operations & market integration:** as the resource mix shifts towards increasing levels of variable and energy-limited resources, grid operations are becoming significantly more complex. Utilities will need more advanced forecasting capabilities (e.g., load, weather, and renewable generation), enhanced real-time visibility, and more sophisticated dispatch strategies to maintain reliability. Effectively integrating storage resources will be especially critical, requiring optimized charging and discharging strategies to capture their full reliability value.
- **Fuel supply:** with the expectation that the region's reliance on natural gas as a capacity resource will increase over the next decade, the region's utilities must also right-size their fuel transportation rights. Several utilities within the region are currently relying upon timely completion of a new interstate pipeline – a project subject to permitting and approval processes in multiple jurisdictions – by the early 2030s to allow for incremental delivery capability to new natural gas power plants.

Delays or unexpected obstacles caused by any one of these factors – or further increases in regional demand not anticipated at the time of this study – could jeopardize utilities' ability to add resources to the system at the pace needed to meet regional growth projections reliably. To mitigate these risks and support successful implementation, utilities and regional stakeholders can focus on several near-term actions:

- **Proactively manage large customer load risks:** strengthen interconnection and service agreements (e.g., financial commitments, phased delivery structures); design rates or tariffs that better align large customer development with system planning needs
- **Accelerate procurement timelines and optionality:** initiate procurements earlier; maintain diversified pipelines of projects to limit systemic risks; incorporate flexibility to account for delays or cancellations; leverage cost-effective demand-side programs to reduce scale of bulk system needs
- **Coordinate transmission and resource planning:** pursue parallel development of generation and transmission through Integrated System Planning; prioritize upgrades that enable access to diverse resource options; repurpose existing infrastructure made available with resource retirements
- **Streamline permitting and stakeholder engagement:** engage early with permitting agencies and local communities to identify and address potential barriers before they delay projects; explore potential to streamline local permitting with model ordinances; repurpose existing brownfield power plant sites
- **Enhance operational capabilities:** invest in advanced forecasting, grid visibility tools, and optimized dispatch strategies, particularly for energy storage and hybrid resources; coordinate with market operators to ensure market rules enable maximum storage value
- **Strengthen fuel and market coordination:** secure fuel transportation capacity needed to support resource plans; identify short-term risk mitigation strategies to ensure adequacy in the event of delay

While these actions cannot fully eliminate implementation risk, sustained focus in these areas will improve the likelihood that planned resources are delivered on time and that regional reliability is maintained under increasingly uncertain conditions.

Appendix M: Reliability and Resource Adequacy Study

This appendix provides the PNM Reliability and Resource Adequacy Study, performed by PowerGem.

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2026 PNM Integrated Resource Plan Supporting Analysis

Reliability and Resource Adequacy Study

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Abbreviations

4HR	Four-hour duration storage
8HR	Eight-hour duration storage
AGC	Automatic Generation Control
BA	Balancing Area
CBO	Congressional Budget Office
CC	Combined cycle generating unit
CT	Combustion turbine
CTP	Current Trends and Policy
DR	Demand response
E3	Energy and Environmental Economics, Inc.
EFOR	Equivalent Forced Outage Rate
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capability
EPE	El Paso Electric
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GWh	Gigawatt-hour
HEG	High Economic Growth
ICAP	Installed (nameplate) capacity
IRP	Integrated Resource Plan
kW	Kilowatt
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
MW	Megawatt
MWh	Megawatt-hour
NMPRC	New Mexico Public Regulation Commission
NMWEC	New Mexico Wind Energy Center
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
PNM	Public Service Company of New Mexico
PRM	Planning Reserve Margin
PSCo	Public Service Company of Colorado
PSH	Pumped storage hydro
PV	Photovoltaic
RFP	Request for Proposals
SAM	System Advisor Model (NREL solar modeling tool)
SERVM	Strategic Energy and Risk Valuation Model

Executive Summary

PowerGEM conducted a suite of resource adequacy and reliability analyses in support of the Public Service Company of New Mexico (PNM) 2026 Integrated Resource Plan (IRP), all performed using the Strategic Energy and Risk Valuation Model (SERVM). Determining the Planning Reserve Margin (PRM) and accrediting resources within a single, synchronized analysis ensures the targeted reserve margin and resource accreditation for PNM's fleet of resources are aligned in the context of resource adequacy. The analysis comprised the determination of the PRM and existing resource accreditation for the 2029 base case, which represents PNM's expected 2029 resource portfolio and load forecast as described in the **SERVM Model Inputs** section of this report, incremental Effective Load Carrying Capability (ELCC) values for new candidate resources, reliability verification of PNM's expansion portfolios, a resiliency analysis under extreme weather, and a transmission import sensitivity.

PowerGEM first analyzed the system to set a baseline of resource adequacy, given PNM's existing fleet of resources and load level. The base case of existing resources was calculated to have a Loss of Load Expectation (LOLE) below the 0.1 target, meaning the modeled portfolio carried more dependable capacity than required for the reliability standard. Economic development load was added to calibrate the system to the 0.1 LOLE target, resulting in a PRM of 14.5%. The existing fleet was accredited entirely on an ELCC basis: wind, solar, battery storage, and demand response (DR) through the Delta Method, and the conventional thermal fleet through a thermal ELCC analysis. The full accreditation by technology and calculated PRM is shown below in **Table 1**.

Table 1: Resource Accreditation and Planning Reserve Margin

Unit Category	ICAP (MW)	ELCC (%)	Accreditation (MW)
Battery	1,950	75%	1,471
Combined Cycle	425	92%	393
Combustion Turbine	786	98%	774
Demand Response	35	59%	21
Geothermal	11	76%	8
Nuclear	288	94%	271
Solar	2,412	19%	458
Steam Turbine Coal	200	72%	143
Steam Turbine Gas	145	92%	133
Wind	1,408	12%	169
Total Accredited Capacity			3,841
Peak Load at 0.1 LOLE			3,354
Planning Reserve Margin			**14.5%**

To properly capture resource accreditation as the penetration of energy-limited technologies changes over time, incremental ELCC values were developed for solar, wind, 4-hour (4HR) storage, 8-hour (8HR) storage, pumped storage hydro (PSH), DR, and energy efficiency and used as inputs for the expansion planning analysis.

A transmission sensitivity was performed in SERVM to evaluate the reliability benefit of increased summer import capability. The analysis showed that doubling the summer peak import capacity from 50 MW to 100 MW produced an approximate 40 MW reliability benefit, corresponding to a reduction of roughly 1.4 percentage points in the targeted PRM, from 14.5% to 13.1%.

After PNM determined its candidate expansion portfolios for the Current Trends and Policy (CTP) and High Economic Growth (HEG) futures, these portfolios were then simulated for study years 2036, 2040, and 2045 to verify their reliability against the 0.1 LOLE target. The incremental 4HR storage adjustment needed to bring each portfolio to the 0.1 LOLE target was calculated. The results are shown in **Table 2** and **Table 3**. A stakeholder-proposed portfolio was also simulated to verify its resulting LOLE and is included in the body of the report.

Table 2: CTP Portfolio Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)	4HR Adjustment for 0.1 LOLE (MW)
2036	0.05	38	18.8%	−170
2040	0.23	221	13.6%	+285
2045	0.08	99	14.2%	−90

Table 3: HEG Portfolio Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)	4HR Adjustment for 0.1 LOLE (MW)
2036	0.05	34	18.6%	−230
2040	0.11	80	15.2%	+20
2045	0.03	19	15.1%	−190

Finally, a resiliency analysis was performed on PNM's CTP and HEG portfolios. This analysis evaluated portfolio performance during an extreme summer weather week and an extreme winter weather week, each simulated with and without market assistance. The results are shown below in **Table 4** and **Table 5**. More discussion on these results is included in the body of the report but it is clear PNM's interconnections provide significant resiliency benefit.

Table 4: Summer Resiliency Weekly EUE (MWh)

Portfolio	Year	Interconnected Weekly EUE (MWh)	Islanded Weekly EUE (MWh)
CTP	2036	6	3,758
CTP	2040	1	4,383
CTP	2045	4	2,509
HEG	2036	33	3,892
HEG	2040	13	3,596
HEG	2045	7	1,152

Table 5: Winter Resiliency Weekly EUE (MWh)

Portfolio	Year	Interconnected Weekly EUE (MWh)	Islanded Weekly EUE (MWh)
CTP	2036	259	9,259
CTP	2040	614	10,237
CTP	2045	76	3,823
HEG	2036	252	17,187
HEG	2040	528	6,061
HEG	2045	54	2,470

A second analysis compared how different resource types contribute to resiliency. Starting from the CTP 2036 portfolio calibrated to 0.1 LOLE, 100 MW of load was added to the portfolio. LM6000 combustion turbine, 4HR storage, DR, and combined solar and storage technologies were each added independently in the amount needed to return the system to the 0.1 LOLE target.

When each resource was sized to meet the same 0.1 LOLE target, annual expected unserved energy (EUE) was lowest for the LM6000, followed by DR, then combined solar and storage, and highest for stand-alone 4HR storage. The difference is largest under sustained winter conditions, where energy-limited resources cannot maintain output across extended extreme weather circumstances. The ordering of the technologies changes under extreme summer conditions, where shortfalls are concentrated in a few evening hours that fall within the discharge duration of storage, and because there is significant capacity added to achieve 0.1 LOLE, DR and the storage-based resources hold EUE below that of the LM6000, with DR clearing the extreme summer week entirely. Again, to achieve a 0.1 LOLE, 580 MW of DR was needed versus 105 MW of the LM6000 resource. The results are summarized below in **Table 6**.

Table 6: 2036 Resiliency Comparison of Different Technologies

Marginal Resource	Marginal MW	Full Study Annual EUE (MWh)	Summer Extreme Week EUE (MWh)	Winter Extreme Week EUE (MWh)
LM6000	105	67	26	145
4HR	345	107	13	603
Demand Response	580	73	0	474
Solar and Storage	580/290	100	<1	463

Study Methodology

Scope of 2026 IRP Analysis

PowerGEM performed a suite of resource adequacy and reliability analyses in support of PNM's 2026 IRP, all conducted using SERVM. The analysis comprised five workstreams:

- **Database Development:** Update the SERVM database with the best available data. The processes involved are detailed in the SERVM Model Inputs section.
- **PRM and Existing ELCCs:** Determination of the PRM and ELCC accreditation of the existing resource fleet for the 2029 base case study year.
    - **Transmission Sensitivity:** Examining the reliability benefit of increased summer import capability.
- **Incremental ELCCs:** ELCC values for incremental resource additions to support expansion planning.
- **Portfolio Reliability Checks:** Verification that PNM's candidate expansion portfolios meet the 0.1 LOLE target.
    - **Stakeholder Proposed Scenario:** Simulate the portfolio in SERVM to verify LOLE.
- **Resiliency Analysis:** Evaluation of portfolio performance under extreme summer and winter weather conditions.
    - **Resiliency Comparison of Different Technologies:** Compare the impact that different resource classes have on resiliency.

The workflow is illustrated in **Figure 1** below and the methodology for each workstream is described in detail in the sections that follow.

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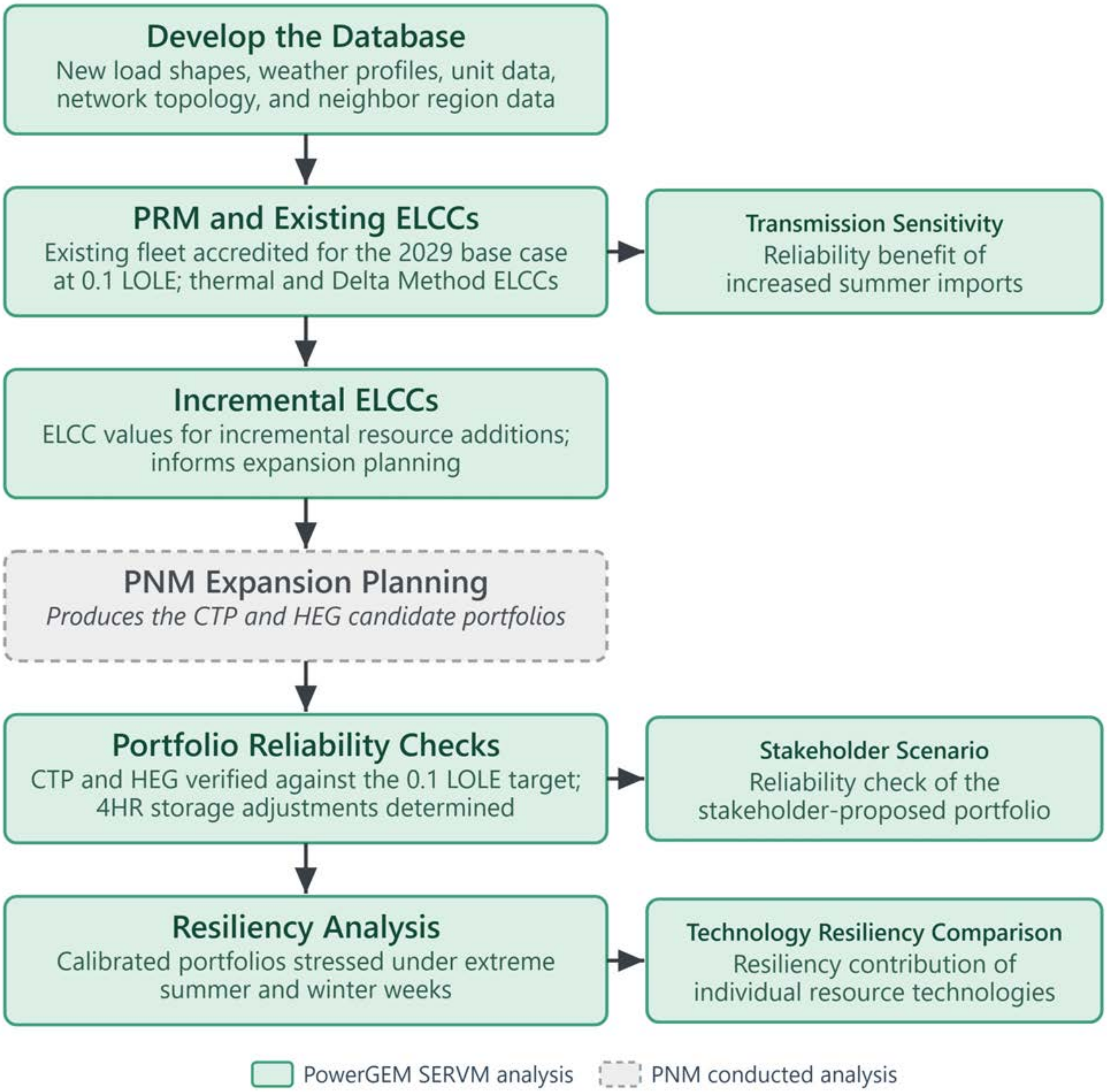
Figure 1: 2026 IRP Resource Adequacy Workflow



Planning Reserve Margin and Existing ELCCs

Planning Reserve Margin

The PRM is the amount of dependable resource capacity a system must carry above its expected peak demand to maintain target reliability metrics. It is expressed as the ratio of accredited capacity in excess of peak load to the peak load itself. Determining the PRM and accrediting resources within a single, synchronized analysis ensures that the capacity a resource is credited with contributing is consistent with the capacity the system relies upon to meet its reliability target.

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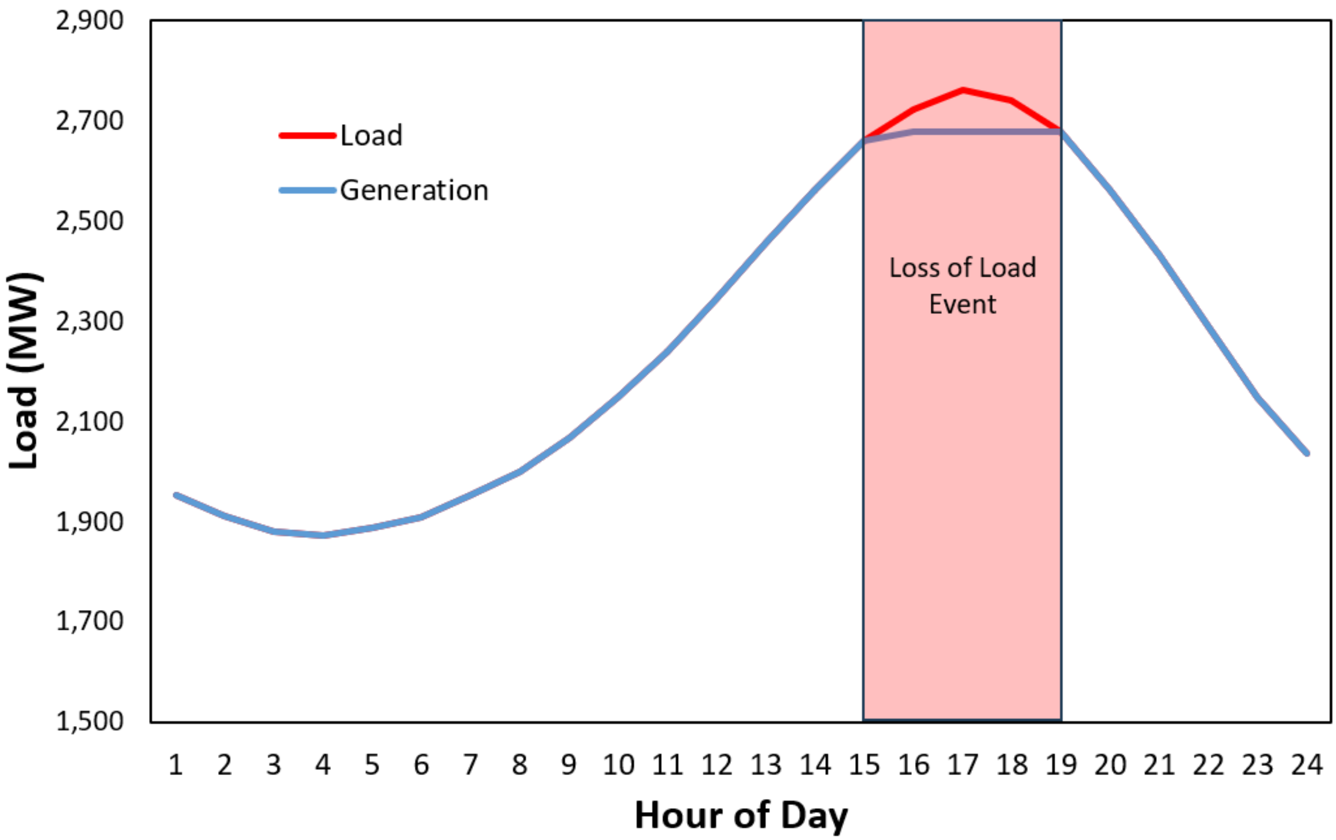
The reliability target used to establish the PRM in this analysis is LOLE, defined as the expected number of days per year on which available capacity is insufficient to serve firm load. Such a capacity shortfall typically occurs across the peak of a day, when demand is highest relative to available supply. **Figure 2: Loss of Load Event Illustration** depicts an example of this type of loss of load event.

Figure 2: Loss of Load Event Illustration



PNM targets the LOLE reliability standard of 0.1 days per year. LOLE is a probabilistic measure of how often available resources are expected to fall short of load, evaluated across thousands of simulated combinations of weather, load, forced outages, and variable generation output. The one-day-in-ten-years criterion is the standard planning basis across North America[1]. RTOs such as the PJM Interconnection[2] and Midwest Independent System Operator (MISO)[3] use the one-day-in-ten-years standard. Utilities such

[1]NERC, Long Term Reliability Assessment. Available at https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf
[2] https://www.pjm.com/-/media/documents/manuals/m20a.ashx, page 8.
[3] https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf, page 2.

as Duke Energy[4] and Arizona Public Service Company[5] also use the same standard to ensure resource adequacy on their respective systems.

A base case was created and used as the foundation for determining the PRM, existing ELCCs, and incremental ELCCs. The base case represents PNM's expected 2029 system: the existing and planned resource portfolio paired with the 2029 CTP load forecast, simulated under the weather, outage, and market assistance assumptions described in the **SERVM Model Inputs** section. It is the starting point against which every other case in this report is measured. This base case was modeled for the 2029 study year with the existing resources shown in **Table 15** and the load forecasts shown in the **Load Forecasts and Load Shapes** section of this report.

The PRM, illustrated in **Figure 3,** is determined as follows. The base case was simulated in SERVM at its forecasted load and was calculated to have an LOLE below the 0.1 target, meaning the modeled portfolio carried more dependable capacity than required for the reliability standard. This initial set of existing resources assumed additional gas resources PNM had identified in its 2029–2032 System Resources application filed with the New Mexico Public Regulation Commission (NMPRC) in mid-2026. PNM utilized generic gas resources to serve as placeholders until it determines actual resources that PNM intends to procure, following evaluation of Request for Proposals (RFP) bids it plans to receive in the second half of 2026. To calibrate the system to the target, economic development load was added until the system reached 0.1 LOLE. This calibrated load level represents the peak demand that the resource portfolio can serve at the reliability standard.

At the calibrated 0.1 LOLE level, each resource is credited by its ELCC rather than its installed capacity (ICAP):

- Firm and conventional thermal resources are accredited using the thermal ELCC values described below.[6]
- Wind, solar, battery storage, and DR resources are accredited using ELCC values developed through the Delta Method described below.

The PRM is then calculated as the ratio of total accredited capacity in excess of the calibrated peak demand to that peak demand. Because all resource types are accredited on an ELCC basis, the resulting PRM reflects the true reliability contribution of each technology in the context of the full portfolio. The PRM established through this process provides the accreditation basis carried forward into the expansion planning and portfolio reliability analyses. Additionally, 12x24 heat maps showing the timing and

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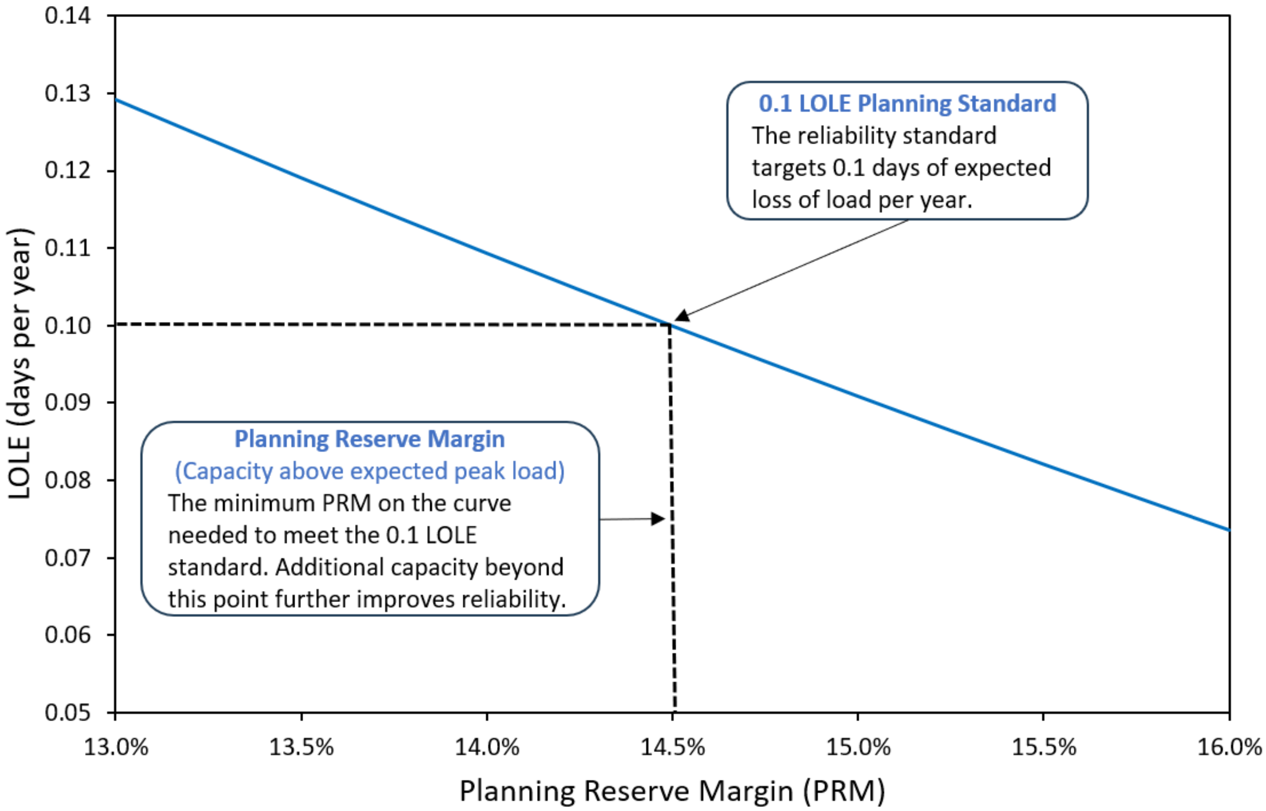
[4] https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/chapter-1-changing-energy-landscape.pdf?rev=88d3584893bc4287be612875fae8bea8, page 7.

[5] https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS_IRP_2023_PUBLIC.pdf?la=en&sc_lang=en&hash=DF34B49033ED43FF0217FC2F93A0BBE6, page 14.

[6] Due to its small nameplate capacity PNM's single geothermal unit was accredited using the UCAP methodology from last IRP of 1-EFOR.

magnitude of loss of load events for the base case calibrated to 0.1 LOLE are provided in the body of the report.

Figure 3: Planning Reserve Margin and 0.1 LOLE Planning Standard



Thermal ELCCs

Conventional thermal resources were accredited using an ELCC methodology applied at the resource category level. The thermal fleet was grouped into five categories: combined cycle (CC), combustion turbine (CT), nuclear, steam coal, and steam gas. The 2029 base case, calibrated to the 0.1 LOLE reliability target, served as the starting point for the analysis.

For each category, the ELCC for these firm dispatchable resources was determined as follows. The entire category was removed from the system, which increased LOLE, and perfect capacity[7] was then added back at several discrete megawatt levels. The resulting LOLE was recorded at each level, and the perfect capacity required to return the system to the base case LOLE was determined by interpolating across these points. The quantity of perfect capacity represents the accredited megawatt contribution of the category, and dividing it by the category's installed capacity yields the raw ELCC value.

To capture the combined contribution of the fleet, the entire thermal portfolio was then removed at once and the same procedure was applied, yielding the total portfolio thermal ELCC. Because of the effect of

[7] Perfect capacity was modeled as a resource with no outages, planned maintenance, or ramping constraints.

planned maintenance scheduling, the sum of the independently calculated category values does not exactly equal the portfolio value determined with all thermal units removed together. To reconcile this, the individual category ELCC megawatts were prorated so that their sum equals the total portfolio ELCC. The resulting category ELCC values were then applied in the PRM calculation to convert installed thermal capacity to accredited capacity.

The Delta Method

To calculate the ELCC of PNM's existing variable energy and energy-limited resources, such as wind, solar, battery storage, and demand-side resources, the Delta Method was used. The Delta Method by Energy and Environmental Economics, Inc. (E3)[8] is a widely used methodology to allocate portfolio ELCC among resource categories. The Delta Method relies on three measured ELCC values:

- **Portfolio ELCC:** total ELCC for a combination of variable energy and energy-limited resources.
- **First-In ELCC:** the marginal ELCC of each individual resource in a portfolio with no other variable energy or energy-limited resources.
- **Last-In ELCC:** the marginal ELCC value of each individual resource when taken in the context of the full portfolio.

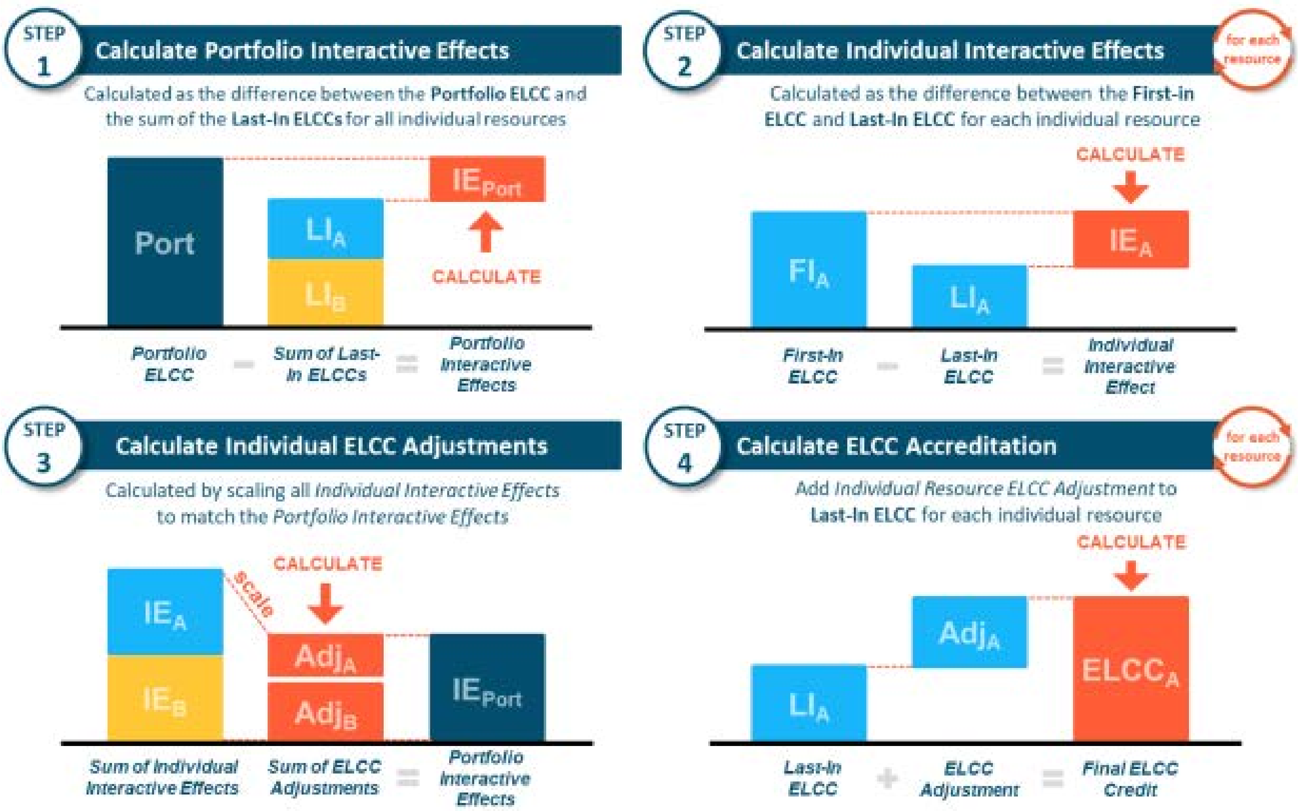
The steps of the Delta Method are as follows:

- **Calculate Portfolio Interactive Effects:** the difference between the portfolio ELCC and the sum of the Last-In ELCCs for all individual resources.
- **Calculate Individual Interactive Effects:** the difference between the First-In ELCC and the Last-In ELCC for each individual resource.
- **Calculate Individual ELCC Adjustments:** calculated by scaling all individual interactive effects to match the portfolio interactive effects.
- **Calculate ELCC Accreditation:** add individual resource ELCC adjustments to the Last-In ELCC for each individual resource to get the final ELCC credit.

Figure 4, sourced from E3's whitepaper, illustrates the four steps of the Delta Method described above, showing how the Portfolio, First-In, and Last-In ELCC values are combined to produce a final ELCC credit for each resource.

[8] E3, Practical Application of ELCC. Available at https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

Figure 4: Delta Method Illustration



Incremental ELCC Methodology

In addition to accrediting the existing fleet, ELCC values were developed for incremental additions of resources to inform the expansion planning process. Incremental ELCCs were calculated for wind, solar, 4HR storage, 8HR storage, pumped storage hydro, DR, and energy efficiency resources.

The incremental ELCC of each resource type was determined using a load addition approach, beginning from the 2029 base case near the 0.1 LOLE reliability target. For each resource type, incremental resource capacity was added to the system, which reduced LOLE below the base case level. Load was then added at several levels, and the resulting LOLE was recorded at each. The amount of load required to return the system to the base case LOLE was determined by interpolating LOLE across the load levels. That quantity of load is the accredited ELCC at that installed capacity level and dividing it by the block's nameplate capacity yields the ELCC percentage.

For solar and the three storage types, this process was repeated at increasing penetration levels, producing results at successive tranches. Solar was evaluated on its own, while each storage type was evaluated with solar co-added at a 2:1 solar-to-storage ratio. At each penetration, two ELCC measures were derived: an average ELCC, representing the cumulative contribution of the entire block up to that penetration, and a tranche ELCC, representing the marginal contribution of each successive increment. A curve was then fit to the tranche ELCC values as a function of incremental capacity for each of these resource types, providing a continuous incremental ELCC curve across the studied penetration range. Wind was evaluated at discrete penetration levels without fitting a continuous curve, and DR and energy efficiency were each evaluated at a single incremental level.

Portfolio Reliability Verification Methodology

As part of the expansion plan modeling process, PNM developed candidate resource portfolios representing its CTP and HEG futures. Each portfolio was simulated in SERVM and results were compared to the 0.1 LOLE reliability target. The CTP and HEG portfolios were each simulated across the 2036, 2040, and 2045 study years.

For each portfolio and study year, the entire fleet of resources was modeled at the corresponding demand and energy requirements and the resulting system LOLE was calculated. Where a portfolio's LOLE deviated from the target of 0.1 LOLE, the amount of 4HR storage required to return the system to 0.1 LOLE was determined. This was done by simulating the portfolio across several 4HR storage adjustment levels, recording the resulting LOLE at each, and interpolating the storage quantity that yields 0.1 LOLE. Storage was added where the portfolio was unreliable, with an LOLE above 0.1, and removed where it was over-reliable, with an LOLE below 0.1. For portfolios and years where 4HR adjustments were identified, such amounts were tabulated; however, the expansion plan portfolios were not adjusted by those amounts of 4HR storage. In addition to the CTP and HEG portfolios, a stakeholder-proposed scenario portfolio was simulated across the same study years to verify its resulting LOLE.

12x24 heat maps showing the timing and magnitude of loss of load events for the CTP and HEG portfolios for all study years calibrated to 0.1 LOLE are provided in this report.

Resiliency Methodology

The resiliency analysis consisted of two parts. The first evaluates how the CTP and HEG expansion portfolios perform under extreme summer and winter weather. The second compares, for the CTP portfolio in 2036, how much resiliency benefit different technologies provide.

Portfolio Resiliency

To evaluate how the expansion portfolios perform under extreme weather conditions, a resiliency analysis was conducted for the CTP and HEG portfolios across 2036, 2040, and 2045 study years. The portfolios analyzed were those calibrated to 0.1 LOLE in the portfolio reliability analysis, including their 4HR storage adjustments.

Rather than simulating the full set of 45 weather years, this analysis isolates the impact of severe weather by simulating a single extreme week for each season. To identify these extreme timeframes, each week across the 45 weather years was characterized by two net load measures, where net load is system load net of wind and solar generation: (1) the maximum net load reached during the week and (2) the average of the daily peak net loads across the week. Weeks were ranked on each measure within their season, and

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the two rankings were combined into an average rank to identify the most severe net load weeks. On this basis, the summer week selected was week 26 of 1994 and the winter week was week 5 of 2011.

Each portfolio, season, and study year combination was simulated under two market conditions: interconnected, in which the PNM system has access to market assistance from neighboring regions, and islanded, in which no market assistance is available. In the islanded cases, Tri-State regions remain included as they are modeled within the PNM Balancing Area (BA) as described in the **Study Topology and Regional Connectivity** section. Comparing the two isolates the reliability contribution of external support during stressed periods. Additionally, the islanded framework allows insight into how the system operates during extreme unserved energy events. One-hundred unit outage iterations were simulated for each case. EUE was the primary metric recorded, reported both weekly over the selected extreme week and on an annual basis, for the interconnected and islanded cases.

Resiliency Comparison of Different Technologies

The second part of the resiliency analysis compares how different resource technologies perform under extreme conditions when each is sized to provide the same reliability, using the CTP portfolio in the 2036 study year.

Starting from the CTP 2036 portfolio at 0.1 LOLE, 100 MW of load was added, raising LOLE above 0.1 days/year. Each of four technologies was then added to the system independently, in the amount required to return the system to 0.1 LOLE:

- LM6000 combustion turbine
- 4-hour storage
- Demand Response
- Solar and storage at a 2:1 solar-to-storage capacity ratio

For each technology, the capacity needed to restore 0.1 LOLE was determined by simulating the portfolio across several capacity levels and interpolating to the amount that returns the system to the target. Because every technology is sized to the same annual reliability, the scenarios differ only in the resource providing it, which isolates how each technology performs under stress.

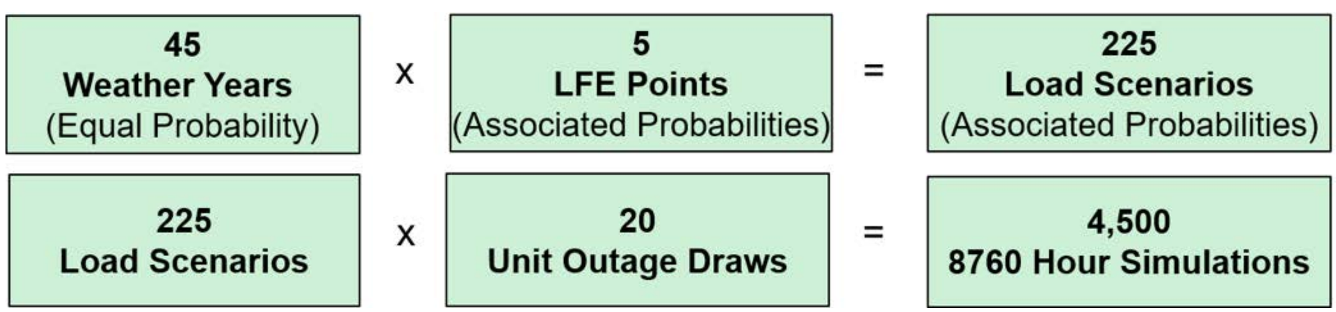
Each scenario was then evaluated two ways. First, EUE was compared across a full simulation of all weather years. Second, EUE and system dispatch were compared during the extreme summer and winter weeks used in the portfolio resiliency analysis.

SERVM Model Inputs

SERVM Framework

Since reliability events are high impact and low probability, many scenarios must be considered to accurately assess the reliability of the PNM system. For this study, SERVM utilized 45 years of historical weather and load shapes spanning 1980 through 2024, 5 points of economic load growth forecast error, and a minimum of 20 Monte Carlo unit outage draw iterations for each scenario to represent a full distribution of realistic scenarios. The number of yearly simulation cases for each scenario is 45 weather years × 5 load forecast errors × 20 unit outage iterations = 4,500 total simulation cases for each scenario studied. Weather years and solar profiles were each given equal probability, while the load forecast error multipliers were given their associated probabilities as reported in the **Load Forecasts and Load Shapes** section.

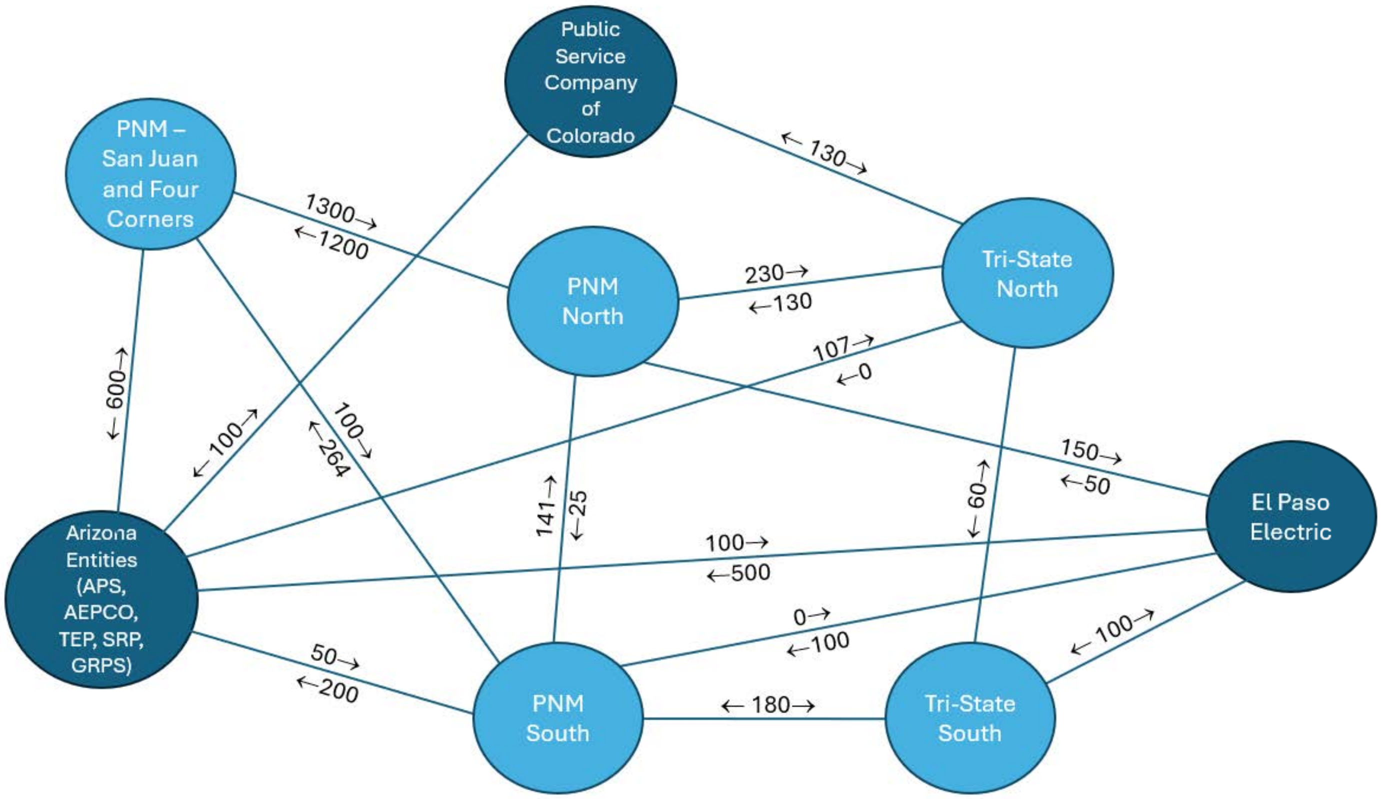
Figure 5: SERVM Uncertainty Framework



Study Topology and Regional Connectivity

The PNM BA and its tier-one neighbors were modeled as separate regions connected by transfer limits, as shown in **Figure 6**. The PNM BA comprises three internal zones — PNM North, PNM South, and PNM San Juan and Four Corners — and was committed and dispatched as a single region along with Tri-State North and Tri-State South. The Data Center and Economic Development loads were modeled in their own independent regions, but with effectively unlimited transmission to the PNM North region. Each tie between regions was modeled with a directional transfer limit in each direction.

Figure 6: Study Topology and Regional Connectivity



*All values in the figure are in MW.

The tier-one neighbors modeled were El Paso Electric (EPE), an aggregate Arizona region, Public Service Company of Colorado (PSCo), and Tri-State North and South. The neighboring regions were modeled in similar fashion to PNM and the loads and resources were all developed based on publicly available data from U.S. Energy Information Administration (EIA) Form 860, Federal Energy Regulatory Commission (FERC) Form 714, and publicly available IRPs. For Tri-State, the load forecast and resource assumptions were provided directly by PNM.

Aggregated Constraints

Aggregated constraints limit the total simultaneous import capability into the PNM BA from all neighbors. This modeling parameter reflects the assumption that PNM has historically experienced lower market assistance during periods when the surrounding region is also stressed. The non-winter aggregated constraints are unchanged from the prior PNM IRP. Winter aggregated constraints were added in this IRP cycle.

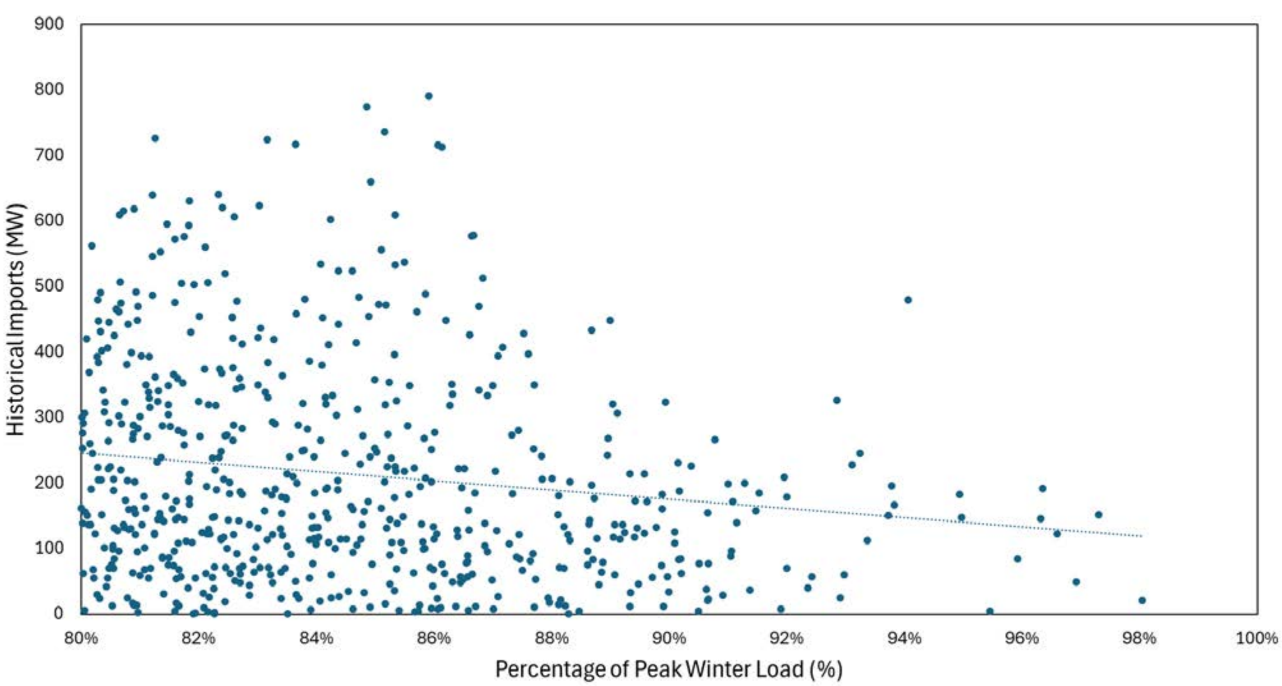
The non-winter aggregated constraints, carried forward from the prior IRP, are summarized in **Table 7**. The base constraint limits aggregate imports from all neighbors during high-load hours, and two additional constraints further restrict imports during the summer super-peak hours. The lower 80% threshold on hours 19 to 22 was applied because those hours have a gross load much less than peak daily load, ensuring the constraint still binds on peak load days.

Table 7: Non-Winter Aggregated Constraints

Constraint	Months	Hours	Gross Load Threshold	Import Limit (MW)
Base	All	All hours	≥ 85% of annual peak	200–300
Summer super-peak	June–August	16–18	≥ 85% of annual peak	100–150
Summer super-peak	June–August	19–22	≥ 80% of annual peak	50

New for the 2026 IRP, a winter aggregated constraint was added to better align modeled winter imports with historical winter import levels. The constraint was developed from historical hourly import data for the 2022 through 2025 winter seasons. **Figure 7** shows the imports observed during winter hours in which PNM was a net purchaser, plotted against the percentage of peak winter load. The observed imports rarely exceeded 800 MW and generally declined as load approached the winter peak. The winter constraint limits were selected to keep modeled winter imports consistent with these historically observed levels.

Figure 7: Historical Winter Imports



The winter constraint applies during December, January, and February, and unlike the summer constraints, which are triggered at high load levels, it varies by time of day rather than by load level, as shown in **Table 8**. Import capability is most restricted during the evening and overnight hours (hours 18 through 7), when the surrounding region is also under winter stress, and least restricted during the midday hours (hours 10 through 15).

Table 8: Winter Aggregated Constraint

Hour of Day	Import Limit (MW)
18–7	250
8	400
9	600
10–15	800
16	600
17	400

Load Forecasts and Load Shapes

There are several loads served by the PNM BA in SERVM: PNM North, PNM South, the Economic Development load, and the Data Center load. The load forecast is presented here on a combined PNM basis, shown as the seasonal peak coincident load and total energy, with the Economic Development and Data Center portions shown separately. The forecasts are shown for the 2029, 2036, 2040, and 2045 study years and are inclusive of the Economic Development and Data Center loads. The 2029 CTP forecast serves as the base case, defined in the **Planning Reserve Margin** section, which is the foundation for the PRM and ELCC analyses.

Table 9: Seasonal Peak Load Forecast (MW)

Scenario	Year	Winter	Spring	Summer	Fall
CTP	2029	2,394	2,361	3,078	2,685
CTP	2036	2,573	2,519	3,254	2,821
CTP	2040	2,732	2,656	3,387	2,963
CTP	2045	2,930	2,843	3,600	3,161
HEG	2029	2,658	2,522	3,327	2,877
HEG	2036	2,997	2,815	3,691	3,165
HEG	2040	3,276	3,064	3,952	3,419
HEG	2045	3,614	3,368	4,338	3,756
Stakeholder	2029	2,393	2,343	3,047	2,661
Stakeholder	2036	2,605	2,445	3,148	2,738
Stakeholder	2040	2,787	2,587	3,257	2,801
Stakeholder	2045	3,007	2,796	3,504	2,992

Table 10: Seasonal Energy Forecast (GWh)

Scenario	Year	Winter	Spring	Summer	Fall
CTP	2029	4,345	4,099	4,918	4,342
CTP	2036	4,616	4,318	5,172	4,490
CTP	2040	4,726	4,406	5,302	4,604
CTP	2045	4,930	4,571	5,500	4,778
HEG	2029	4,600	4,332	5,236	4,605
HEG	2036	5,083	4,753	5,729	4,945
HEG	2040	5,335	4,979	6,024	5,197
HEG	2045	5,731	5,338	6,449	5,556
Stakeholder	2029	4,329	4,071	4,887	4,318
Stakeholder	2036	4,569	4,237	5,085	4,426
Stakeholder	2040	4,667	4,299	5,190	4,521
Stakeholder	2045	4,856	4,436	5,360	4,675

The Economic Development and Data Center load forecasts are modeled on a monthly basis and are identical across the CTP, HEG, and Stakeholder scenarios. The Economic Development load ramps up through 2036 and is then held approximately constant, while the Data Center load is held approximately constant across all study years.

Table 11: Monthly Economic Development Peak Load Forecasts (MW)

Month	2029	2036	2040	2045
1	481	590	590	590
2	496	594	594	594
3	511	600	600	600
4	510	583	585	584
5	520	583	583	584
6	512	562	562	562
7	523	561	562	563
8	553	584	584	585
9	564	585	584	584
10	587	597	597	597
11	585	595	595	595
12	580	589	590	590

Table 12: Monthly Economic Development Energy Forecasts (GWh)

Month	2029	2036	2040	2045
1	300	374	374	374
2	278	338	338	338
3	315	374	374	374
4	312	362	362	362
5	330	374	374	374
6	327	362	362	362
7	345	374	374	374
8	353	374	374	374
9	349	362	362	362
10	368	374	374	374
11	356	362	362	362
12	368	374	374	374

Table 13: Monthly Data Center Forecast

Month	Peak (MW)	Energy (GWh)
1	493	359
2	493	325
3	493	360
4	494	348
5	494	360
6	495	349
7	495	360
8	494	360
9	494	348
10	493	360
11	493	348
12	493	359

The load forecasts presented in this section reflect the expected load for each scenario and study year. As described in the Planning Reserve Margin and Existing ELCCs section, additional economic development load was added to calibrate the 2029 system to the 0.1 LOLE reliability target. The economic development load in the 0.1 LOLE calibrated run is therefore higher than the forecast values shown here.

The Data Center and Economic Development loads are each modeled with their own distinct daily load shape. The following figures show the daily shape of the Economic Development load and the Data Center load.

Figure 8: Average July Data Center Demand

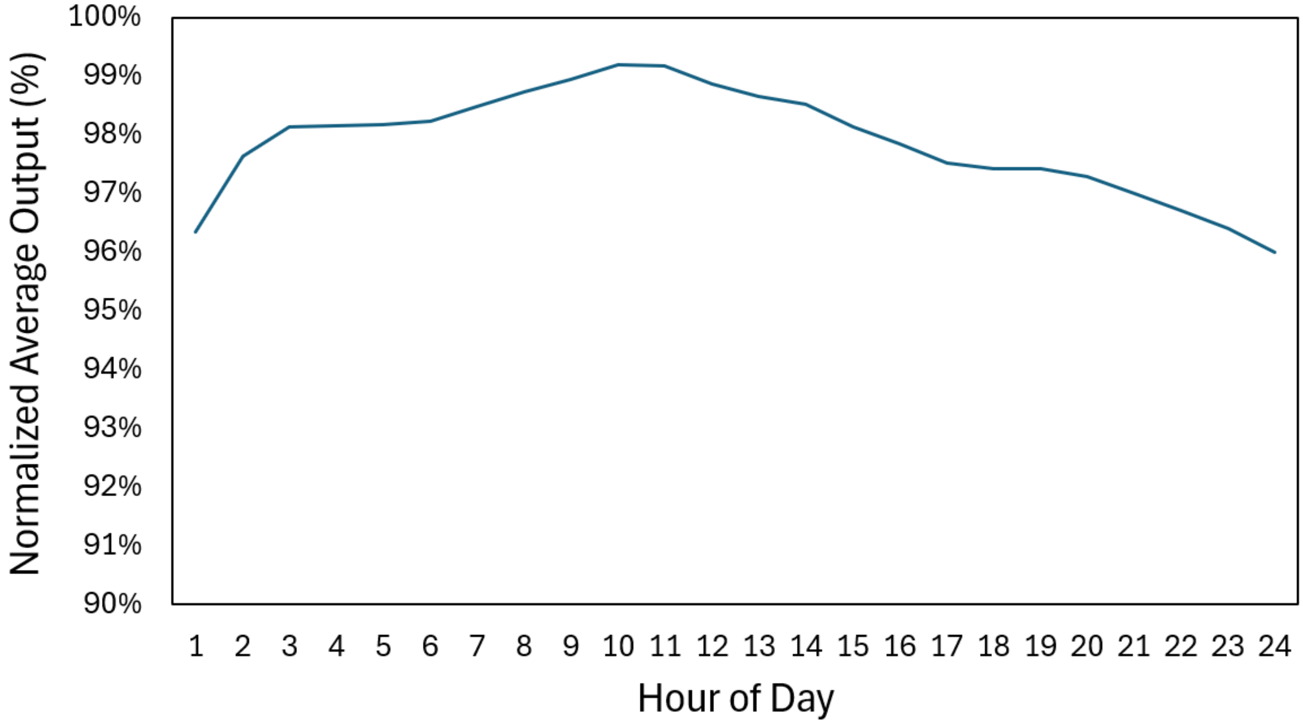
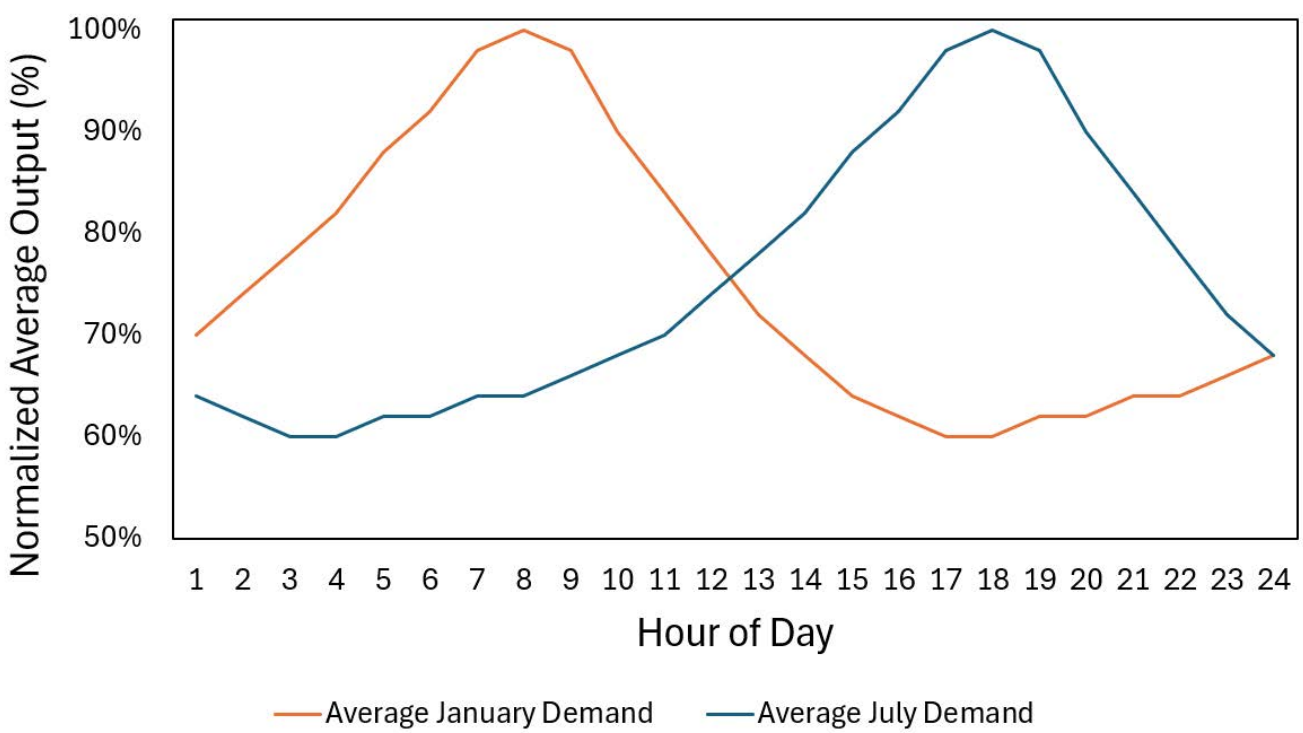


Figure 9: Average Economic Development Demand



To determine the effects of weather uncertainty on PNM’s load, 45 historical years of weather and load, spanning 1980 through 2024, were compiled. Based on this history, a neural network program was used to develop relationships between weather observations and load. For the 2026 IRP, neighboring electric utility historical load data was updated so that the regional data also aligns with PNM’s history. Using the resulting relationships from historical data, synthetic load shapes were created to mimic those relationships when applied to PNM’s load forecasts in its 2026 IRP. By using equal probabilities given to each weather year, and scaling of load shapes such that seasonal peaks align with load forecast projections, these 45 synthetic load shapes were tested and refined to validate that the historical data continues to show a consistent relationship between weather and expected loads.

Figure 10 and **Figure 11** show the results of the synthetic load modeling by displaying the peak load variance for the total PNM load in the winter and summer seasons. The y-axis represents the percentage deviation from the 50/50 load forecast, where zero corresponds to normal weather. The bars represent the variance in projected peak loads based on weather experienced during the historical weather years. The bars are arranged from the largest negative deviation to the largest positive deviation rather than in chronological order, so the figures should be read as the distribution of weather-driven outcomes around the forecast rather than as a trend over time. The tails indicate the most extreme conditions the historical record supports.

Higher variance of the load shapes directly corresponds to higher reserves needed to maintain reliability standards. Planning reserve margin is calculated using the 50/50 load forecast, so weather years that have higher variance over the median cause the system to need more reserves to meet the increased peak load risk in those weather years. These figures offer insight into the magnitude of the effect that weather uncertainty has on the peak load of the PNM system. The 2011 weather year is a significant driver in causing winter LOLE due to an extreme cold weather event occurring in New Mexico.

Figure 10: Summer PNM Load Variance

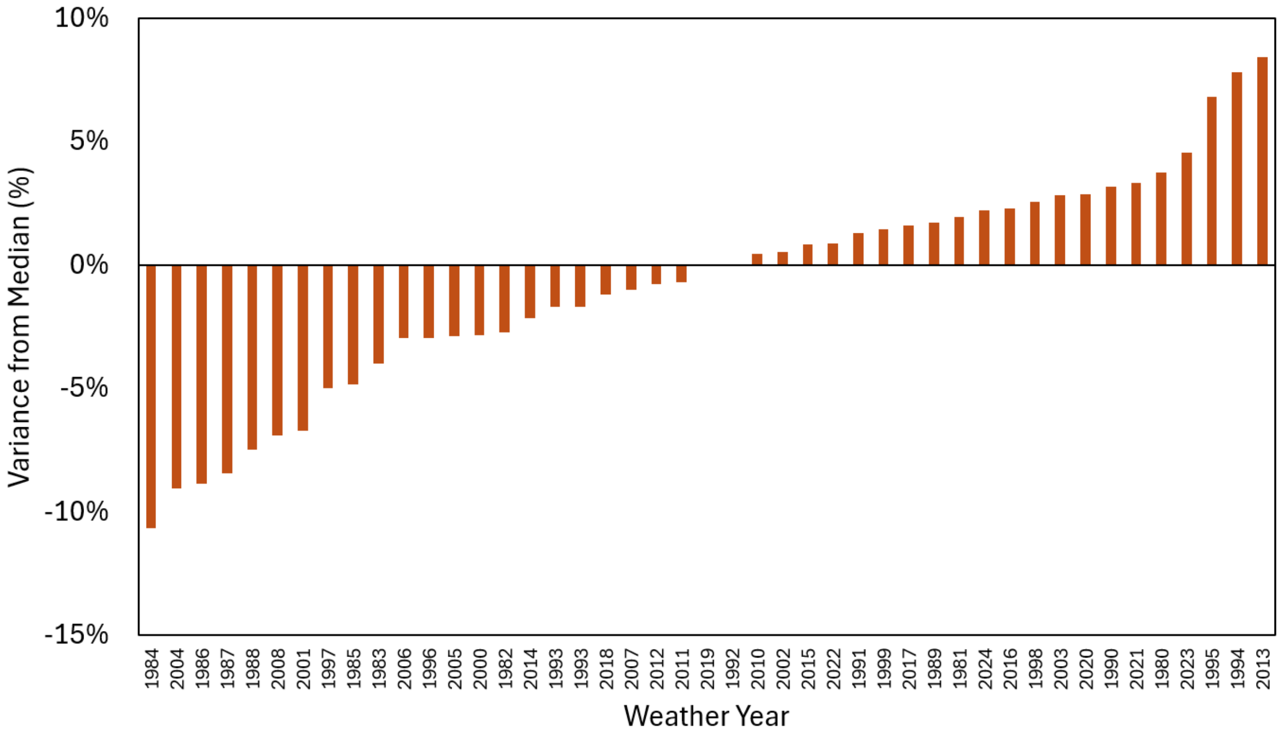
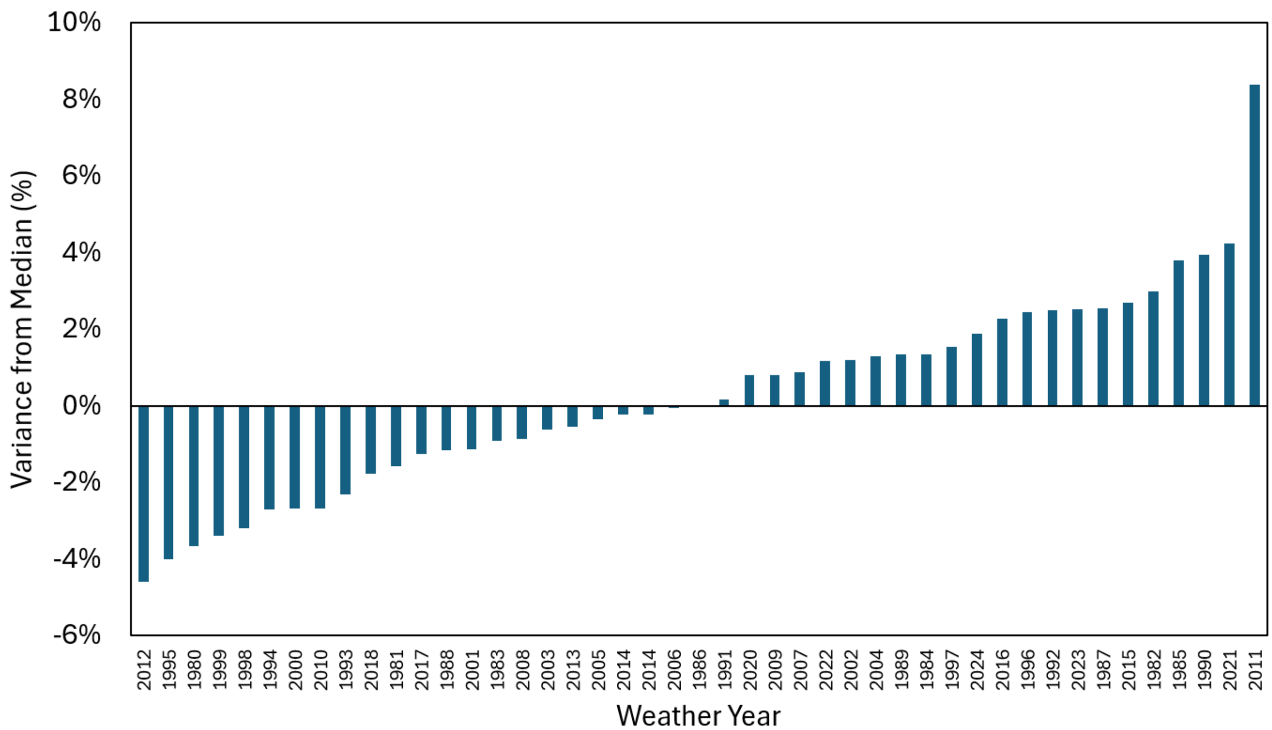


Figure 11: Winter PNM Load Variance



Economic load forecast error multipliers were included to isolate the economic uncertainty that PNM may have in its long-term load forecasts. To estimate economic load forecast error, the difference between Congressional Budget Office (CBO) gross domestic product (GDP) forecasts and actual data was fit to a normal distribution. Using a normal distribution and assuming electric load grows at a slower rate than GDP, a multiplier was applied to the raw CBO forecast error distribution. The resulting multipliers and probabilities are shown in **Table 14**. As an illustration, 11% of the time load is expected to be under-forecasted by 4%. Lastly, each of these five load forecast error points was applied to each of the 45 weather years to create 225 synthetic load shapes.

Table 14: Economic Load Forecast Error

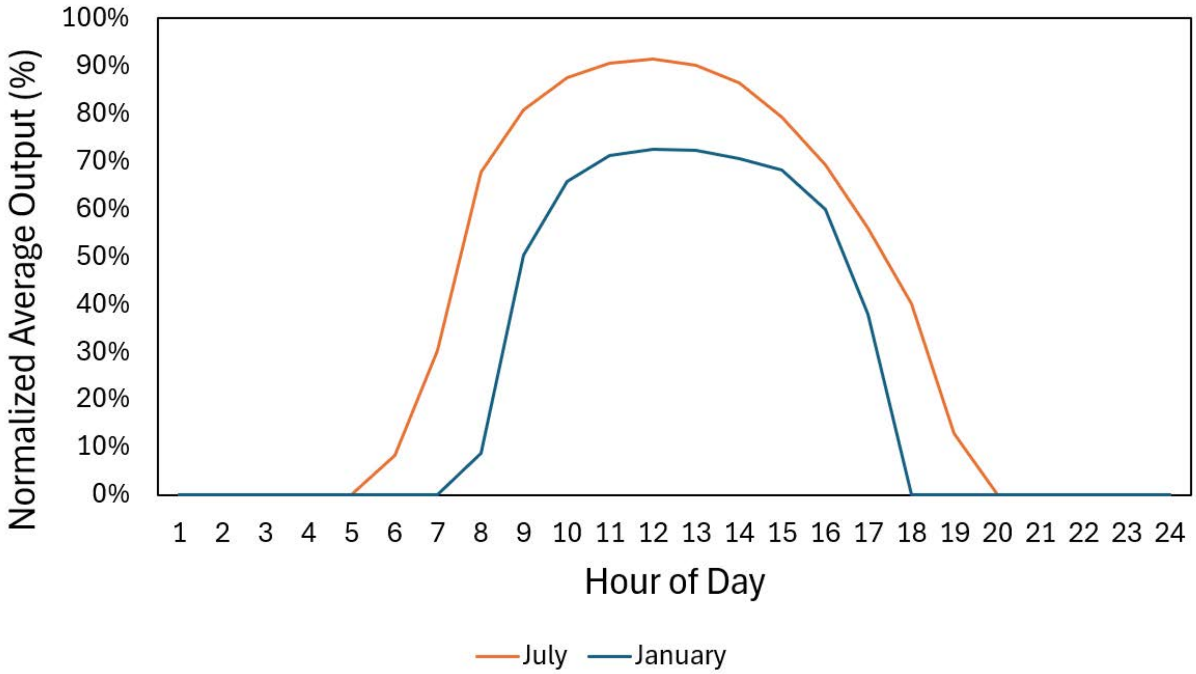
Load Forecast Error Multiplier	Probability (%)
0.96	11%
0.98	23%
1.00	32%
1.02	23%
1.04	11%

Solar Shapes

Solar data was downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) for the latitude and longitude of each of PNM's existing resource locations, for the years 1998 through 2022. Using multiple locations incorporates geographic diversity among the solar projects. The NSRDB data, which includes variables such as air temperature, dew point, global, direct, and diffuse irradiance, wind speed, surface pressure, and surface albedo, was input into NREL's System Advisor Model (SAM) for each year and location to generate hourly solar profiles for both fixed and single-axis tracking photovoltaic (PV) plants. Each solar array was modeled at a 10-degree tilt and a 180-degree (due south) azimuth. The resulting SAM output was normalized to a per-unit profile, which served as the basis for the 1998 through 2022 solar profiles. Solar profiles for the weather years outside this range, 1980 through 1997 and 2023 through 2024, were constructed from the 1998 through 2022 data using load day matching, in which daily load shapes in the years without data were compared to daily load shapes in the years with data and the solar profiles from the closest-matching days were used.

Figure 12 shows the resulting normalized aggregate solar profiles from the 2029 base case, plotted as the average daily output for January and July.

Figure 12: Average PNM Base Case Solar Output



The latitude and longitude of the PNM solar profile locations are listed in **Table 49** in the **Appendix**. The same process was used to create solar profiles for the neighboring regions, whose locations are listed in **Table 50** in the **Appendix**. For future generic solar, a solar profile was created using the normalized final output of the existing tracking solar from the base case.

Wind Shapes

The 1980 through 2024 wind profiles for PNM were developed from historical wind data from the Casa Mesa, La Joya 1, La Joya 2, New Mexico Wind Energy Center (NMWEC), and Red Mesa wind farms, covering the period from April 1, 2021 through December 31, 2024. Synthetic profiles for each weather year were created using a peak load day matching approach: for each day in the weather year being constructed, the day with the closest peak load within five days before or after that calendar day was identified from the April 1, 2021 through December 31, 2024 historical data, and that day's wind profile was used. For example, July 16 in the 1994 profile was matched by examining each July 11 through July 21 day in the historical data, selecting the day with the closest peak load, and using that day's wind output. The resulting daily profiles were smoothed between days, and the final normalized profiles were used in SERVM.

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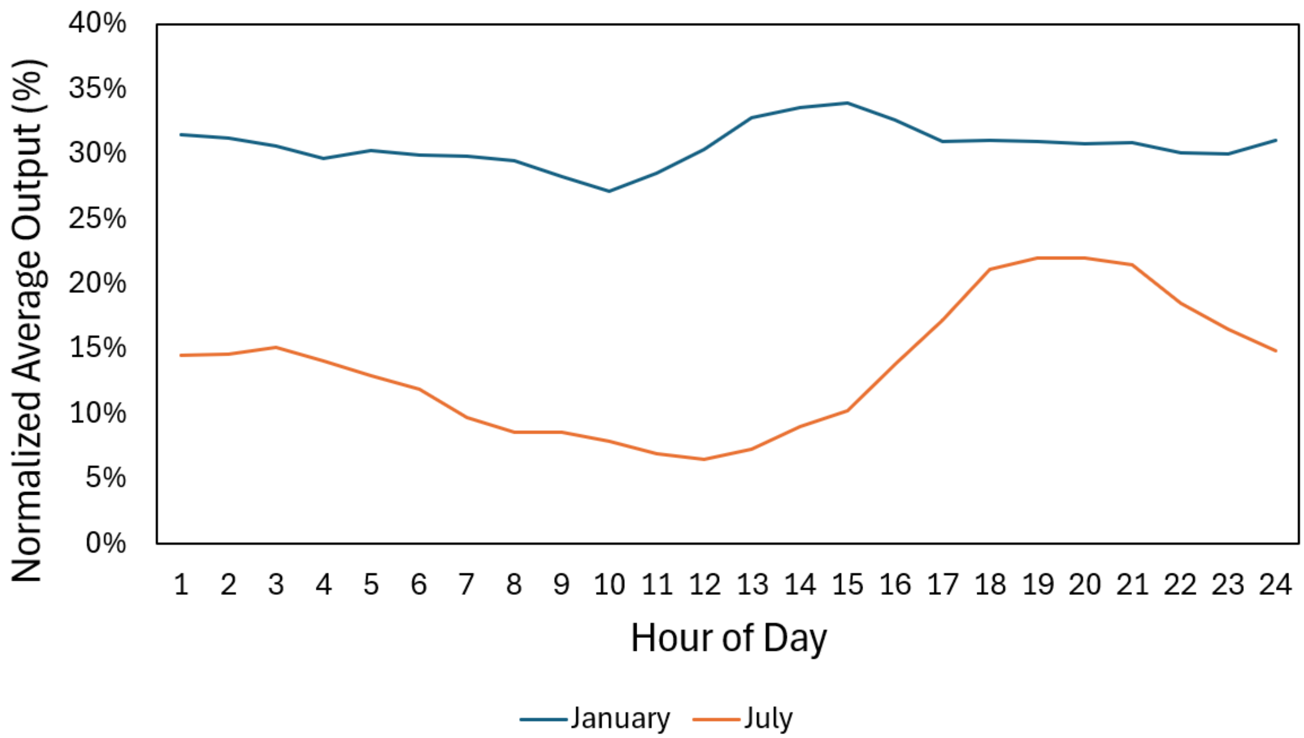
For the NMWEC profile, synthetic profiles were created for both the NMWEC and Casa Mesa sites and then summed, subject to a cap of 200 MW.

The PNM expansion wind profile was developed using the SERVM Wind Diversity Tool. This tool adjusts a region's wind generation profile so that the correlation between the wind output of two regions matches a target correlation, reflecting the diversity of wind resources across areas rather than assuming wind output is fully coincident or fully independent. The tool reaches the target by repeatedly swapping individual days within the same calendar month across years, keeping only those swaps that move the wind correlation closer to the target. The expansion wind profile was created from the La Joya 2 profile and adjusted to a 0.80 correlation with the La Joya 1 profile.

The average daily aggregate PNM wind output for the 2029 base case is shown for January and July in **Figure 13**.

Figure 13: Average PNM Base Case Wind Output



Wind profiles for the neighboring Arizona and PSCo regions were developed from historical hourly wind output for each region over 2019 through 2023. Each year's output was normalized to a 0 to 100 scale relative to that year's maximum hourly generation. Synthetic profiles for the 1980 through 2024 weather

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years were then created through load day matching against the SERVM synthetic load profiles: each synthetic day was paired with the historical days whose load most closely matched, and one of the closest matching days was selected at random to supply that day's normalized wind output. Multiple independent samplings were produced for each region and assigned across that region's wind units, so that units within a region draw on different random selections rather than an identical profile.

Conventional Thermal Resources and Resource Mix

Conventional thermal resources owned by PNM and contracted for via Power Purchase Agreements were modeled for the 2029 study year. These resources are economically committed and dispatched to load on a 5-minute basis respecting all unit constraints including startup times, ramp rates, minimum up times, minimum down times, and shutdown times. All thermal resources are allowed to serve regulation, spinning, and load following reserves assuming the minimum capacity level is less than the maximum capacity. The PNM base case system resource mix and respective Equivalent Forced Outage Rates (EFORs) are provided in **Table 15** below.

Table 15: 2029 Base Case Resource Mix and EFOR

Unit Type	Capacity (MW)	EFOR (%)
Battery	1,950	7.5%
Combined Cycle	425	5.5%
Combustion Turbine	786	2.7%
Demand Response	35	-
Geothermal	11	24.0%
Nuclear	288	2.0%
Solar	2,412	-
Steam Turbine Coal	200	20.0%
Steam Turbine Gas	145	9.1%
Wind[9]	1,408	-
Total	7,660	

EFORs are based on historical performance or expected future performance provided by PNM. Unlike typical production cost models, SERVM does not use an EFOR for each unit as an input. Instead, historical Generating Availability Data System (GADS) data from 2019–2024 are used to create an outage probability

[9] 50MW Casa Mesa wind is modeled within the NWWEC wind unit in SERVM due to real world transmission constraints, so the actual capacity of the system is 1,458MW, but it is modeled at 1,408MW.

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distribution for each unit and SERVM randomly draws from this distribution for each unit to simulate outages. Units without historical data use data from similar units. Outage distributions were scaled to an expected EFOR provided by PNM. Outage distributions are constructed using the following variables.

Full Outage Modeling

- Time-to-Repair Hours
- Time-to-Fail Hours
- Start Probability

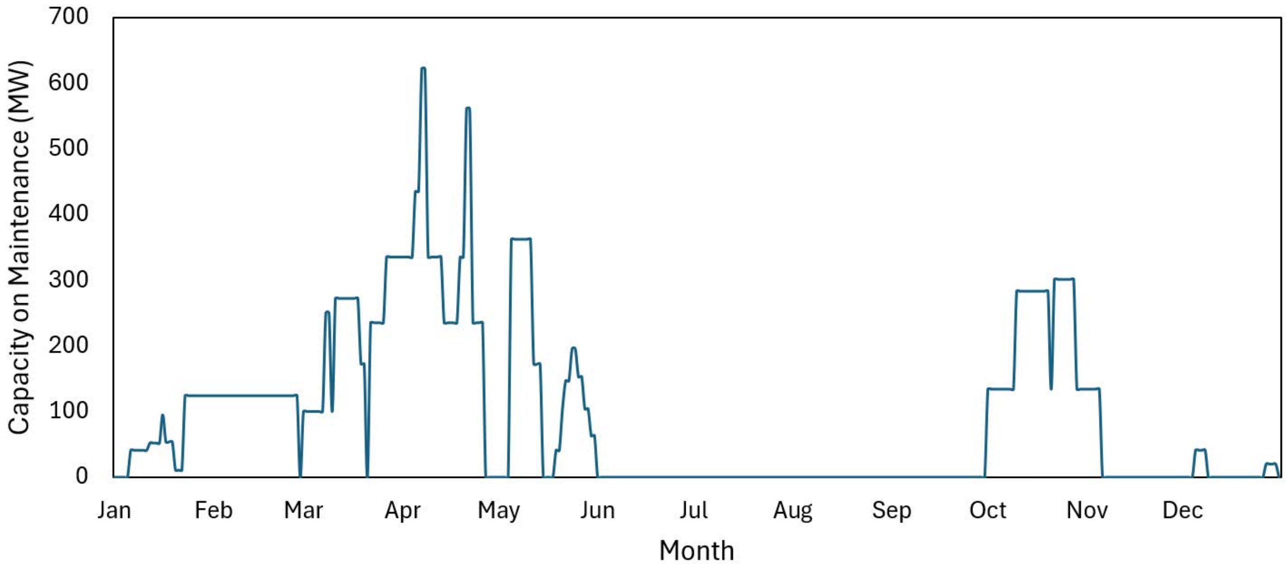
Partial Outage Modeling

- Partial Outage Time-to-Repair Hours
- Partial Outage Derate Percentage
- Partial Outage Time-to-Fail Hours

Planned Maintenance

Planned maintenance outage rates were applied to relevant units. These outage rates were provided by PNM where available and otherwise from publicly available data for the applicable technology. Before the simulation begins, SERVM's maintenance scheduler converts the outage rates into a target number of outage days per year and determines when those days are placed. Candidate windows are ranked by daily system load, by default using the average daily load across the selected net load shapes, and each unit's maintenance is assigned to the lowest load periods available in order to minimize stress on the system during outages. Units are scheduled in descending order of capacity, so that the largest generators, which have the greatest impact on reliability, are placed first into the lowest load windows. The result of this scheduling step is a fixed daily maintenance calendar for every unit. During the Monte Carlo simulation, SERVM enforces these calendars deterministically: each unit is removed from the commitment and dispatch queues on its maintenance start day and returned to service when its window ends. Throughout that period the unit contributes zero capacity with timing that has been deliberately placed in low load periods. The scheduled planned maintenance across the base case is shown in **Figure 14**.

Figure 14: PNM Planned Maintenance Schedule



Battery Modeling

Battery energy storage units were modeled with maximum combined output capacity (if applicable) and round-trip losses consistent with known project information and are economically scheduled and dispatched within SERVM. These resources typically charge during low net demand periods, subject to constraints, and are dispatched during net peak load periods. 4-hour storage units were modeled assuming an EFOR of 7.5%, which is an assumption based on a study conducted by E3[10] on the real-world first-year operation of utility-scale battery energy storage facilities located in California.

Demand Response Modeling

DR programs were modeled as resources in SERVM with specific contract limits. The sections below provide modeling characteristics for each of the modeled programs.

- **Battery Energy Storage Direct Load Control:** This program is modeled as two seasonal resources. PNM sends a dispatch signal that discharges (or curtails charging of) enrolled residential, commercial, and industrial batteries during an event. Events run one per day with a duration of two

[10] https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS-RPAC-Meeting-Presentation-102622.ashx?la=en&hash=9AE20E699D178AFCF8AB30BF9C64FFED

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to four hours. The summer resource is limited to 35 call hours per year and the winter resource to 30 call hours per year.

- **Domestic Hot Water Heater Direct Load Control:** Modeled as two seasonal resources representing residential electric resistance and heat pump water heaters under one-way utility control. Each season allows up to 25 events per year at 4 hours per event, for 100 call hours per year, dispatched once per day. The summer and winter resources use the same event structure; the seasonal difference is in per participant load impact, which is carried in the capacity rather than the event parameters.
- **Peak Saver:** A year-round program for non-residential customers with peak load contributions of at least 150 kW, modeled as two seasonal resources with 4-hour events dispatched once per day. The summer resource is available June through September with up to 100 call hours per year, and the winter resource is available October through May with up to 300 call hours per year.
- **Power Saver:** A summer-only resource for residential and small-to-medium commercial customers, available June through September. It is dispatched once per day in 4-hour events for up to 100 call hours per year.
- **Behavioral:** A residential program modeled as a resource that is called on the roughly 11 highest peak days of the year. Events run 3 to 5 hours within the 1 p.m. to 7 p.m. peak window, one per day, for approximately 40 call hours per year.

Load Modifiers

Some of the units were modeled as Load Modifier (L) units to represent adjustments to the system load profile. In SERVM, Load Modifier units are used to capture expected changes in load composition. Each Load Modifier unit is associated with a weather station and a capacity multiplier table, which uses historical hourly weather data to determine the unit's hourly load shape. For this study, the hourly load shapes for the Load Modifier units were provided by PNM and used to represent the study-specific load adjustments and calibration assumptions. Energy Efficiency and Time of Day resources were modeled as L units in this analysis.

Ancillary Services

SERVM commits resources to meet energy needs plus ancillary service requirements, which are defined as SERVM model inputs. In real-world operation, these ancillary services are needed for uncertain movement in net load or sudden loss of generators during the simulations. Within SERVM, these include regulation up and down, which are served by units with automatic generation control (AGC) capability, spinning reserves, load following reserves, and quick start reserves. **Table 16** shows the definition of each ancillary service for this study. A loss of load event was recorded when there was insufficient generation to serve load plus the regulation up requirement.

Table 16: Ancillary Service Definitions

Ancillary Service	Definition
Regulation Down Requirement	10 Minute Product served by units with AGC capability
Regulation Up Requirement	10 Minute Product served by units with AGC capability
Spinning Reserves Requirement	10 Minute Product served by units that have minimum load less than maximum load
Load Following Down Reserves	10 Minute Product served by units that have minimum load less than maximum load
Load Following Up Reserves	10 Minute Product served by units that have minimum load less than maximum load
Load Following Up Range Adder	Additional upward load-following reserve above the minimum Load Following Up Reserve requirement.
Load Following Min Up Reserves Target	Minimum additional upward load-following reserve maintained above the spinning reserve requirement.
Quick Start Reserves Requirement	Served by units that are offline and have quick start capability
Quick Start Reserves Target	Target amount of quick-start (non-spinning) reserve capacity maintained each hour.

For this study, these ancillary service requirements were applied to the PNM BA, with each requirement specified as a percentage of load. Regulation up and regulation down were each set at 6% of load, and a quick start reserves target of 4% of load was applied.

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Results

Planning Reserve Margin and Existing ELCCs

The existing resource fleet was accredited on an ELCC basis using the methodologies described in the Study Methodology section. The Delta Method was applied to the existing wind, solar, battery storage, and demand-side resources, and a thermal ELCC analysis was used to accredit the conventional thermal fleet as described in the Executive Summary. The resulting ELCC values are shown below.

Table 17: Existing ELCCs

Category	ICAP (MW)	ELCC (%)
Battery	1,950	75%
Solar	2,412	19%
Wind	1,408	12%
Demand Response	35	59%

Table 18: Thermal ELCCs

Category	ICAP (MW)	ELCC (%)
Combined Cycle	425	92%
Combustion Turbine	786	98%
Nuclear	288	94%
Steam Turbine Coal	200	72%
Steam Turbine Gas	145	92%

The full accreditation is shown in **Table 19**.

Table 19: Resource Accreditation (Average ELCC by technology)

Unit Category	ICAP (MW)	ELCC (%)	Accreditation (MW)
Battery	1,950	75%	1,471
Combined Cycle	425	92%	393
Combustion Turbine	786	98%	774
Demand Response	35	59%	21
Geothermal	11	76%	8
Nuclear	288	94%	271
Solar	2,412	19%	458
Steam Turbine Coal	200	72%	143
Steam Turbine Gas	145	92%	133
Wind	1,408	12%	169
Total			**3,841**

The resulting reserve margins are summarized below. At the base case peak load, the system carries an as-is reserve margin of 24.8%. This initial set of existing resources assumed additional gas resources PNM had identified in its 2029–2032 System Resources application filed with the NMPRC in mid-2026. PNM utilized generic gas resources to serve as placeholders until it determines actual resources that PNM intends to procure, following evaluation of RFP bids it plans to receive in the second half of 2026. Economic development load was added to calibrate the system to 0.1 LOLE, and each resource was accredited at its ELCC to determine the PRM. Calibrated to the 0.1 LOLE target, the PRM is 14.5%. This target PRM was then used as the basis for PNM's capacity expansion plans in the 2026 IRP.

Table 20: Reserve Margin Summary

Metric	Value
Total accredited capacity (MW)	3,841
Base case peak load (MW)	3,078
As-is reserve margin	24.8%
0.1 LOLE peak load (MW)	3,354
0.1 LOLE reserve margin	14.5%

The timing of the loss of load events and expected unserved energy from the base case calibrated to 0.1 LOLE are shown in **Table 21** and **Table 22** below. These tables represent the percentage of total loss of load hours (LOLH) and EUE found in the given hour-month combination. A value of 1%, for example, indicates that 1% of the total LOLH or EUE occurred in the given hour within the simulations.

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Table 21: 2029 Base Case LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	-	0.1%	-	-	-	0.5%	0.1%	-	-	-	-	0.1%	0.8%
2	-	0.2%	-	-	-	0.3%	0.1%	-	-	-	-	0.1%	0.6%
3	-	0.2%	-	-	-	0.2%	-	-	-	-	-	0.1%	0.5%
4	-	0.4%	-	-	-	0.0%	-	-	-	-	-	0.2%	0.6%
5	-	0.5%	-	-	-	-	-	-	-	-	-	0.6%	1.1%
6	0.2%	1.6%	-	-	-	-	-	-	-	-	-	1.3%	3.1%
7	0.4%	4.1%	-	-	-	-	-	-	-	-	-	3.4%	7.9%
8	0.5%	5.3%	-	-	-	-	-	-	-	-	-	5.2%	11.0%
9	0.2%	1.9%	-	-	-	-	-	-	-	-	-	2.0%	4.1%
10	-	0.3%	-	-	-	-	-	-	-	-	-	0.5%	0.8%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	0.0%	0.0%	-	-	-	-	0.1%
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	0.0%	0.3%	0.0%	-	-	-	-	0.4%
18	-	-	-	-	-	-	0.7%	0.1%	0.0%	-	-	-	0.8%
19	-	-	-	-	-	8.8%	11.9%	2.2%	-	-	-	0.0%	23.0%
20	-	-	-	-	-	17.3%	16.5%	1.8%	-	-	-	0.0%	35.6%
21	-	0.0%	-	-	-	4.4%	1.9%	0.2%	-	-	-	0.2%	6.7%
22	-	0.0%	-	-	-	0.6%	0.3%	0.0%	-	-	-	0.3%	1.2%
23	-	0.0%	-	-	-	0.2%	0.1%	0.0%	-	-	-	0.3%	0.7%
24	-	0.0%	-	-	-	0.6%	0.1%	0.0%	-	-	-	0.3%	1.1%
Total	**1.3%**	**14.7%**	**-**	**-**	**-**	**33.0%**	**31.9%**	**4.3%**	**0.0%**	**-**	**-**	**14.7%**	**100.0%**

Table 22: 2029 Base Case EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	-	0.1%	-	-	-	0.6%	0.1%	-	-	-	-	0.2%	1.0%
2	-	0.2%	-	-	-	0.1%	0.0%	-	-	-	-	0.4%	0.8%
3	-	0.3%	-	-	-	0.0%	-	-	-	-	-	0.5%	0.8%
4	-	0.7%	-	-	-	0.0%	-	-	-	-	-	0.8%	1.5%
5	-	1.9%	-	-	-	-	-	-	-	-	-	1.8%	3.7%
6	0.2%	4.8%	-	-	-	-	-	-	-	-	-	4.8%	9.8%
7	1.2%	14.6%	-	-	-	-	-	-	-	-	-	12.7%	28.5%
8	1.7%	13.2%	-	-	-	-	-	-	-	-	-	13.1%	28.0%
9	0.2%	1.4%	-	-	-	-	-	-	-	-	-	1.9%	3.5%
10	-	0.0%	-	-	-	-	-	-	-	-	-	0.3%	0.3%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	0.0%	0.0%	-	-	-	-	0.0%
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	0.0%	0.0%	0.0%	-	-	-	-	0.0%
18	-	-	-	-	-	-	0.1%	0.0%	0.0%	-	-	-	0.1%
19	-	-	-	-	-	1.3%	1.9%	0.4%	-	-	-	0.1%	3.7%
20	-	-	-	-	-	6.0%	4.0%	0.5%	-	-	-	0.2%	10.8%
21	-	0.1%	-	-	-	1.3%	0.8%	0.1%	-	-	-	0.5%	2.6%
22	-	0.1%	-	-	-	0.2%	0.1%	0.1%	-	-	-	0.6%	1.1%
23	-	0.1%	-	-	-	0.9%	0.2%	0.0%	-	-	-	0.8%	1.9%
24	-	0.0%	-	-	-	1.4%	0.1%	0.0%	-	-	-	0.2%	1.9%
Total	**3.3%**	**37.5%**	**-**	**-**	**-**	**11.8%**	**7.5%**	**1.1%**	**0.0%**	**-**	**-**	**38.9%**	**100.0%**

As shown in the heat maps, approximately 70% of PNM's LOLH falls in the summer months. These events are concentrated in hours 19 and 20, when net load peaks as solar generation falls offline and load remains high. Conversely, approximately 80% of the EUE falls in the winter months, concentrated in the morning hours 6, 7, and 8. While LOLE is significantly more frequent in summer months, when PNM's load is highest, the most severe events fall in the winter months. PNM's winter events tend to be more severe in magnitude because they are related to PNM's energy limmited resources running out of energy due to prolonged periods of high demand without the ability to charge using solar generation through the night. PNM's summer LOLE is generally related to the lack of capacity to meet higher loads, while winter LOLE is generally related to the lack of energy available to charge storage through low renewable generation.

Transmission Sensitivity

An additional sensitivity was performed to evaluate the reliability benefit of increased summer import capability. In this sensitivity, the import capacity during the summer peak hours was doubled from 50 MW to 100 MW. The additional import allowance produced an approximate 40 MW reliability benefit, which translates to a reduction of roughly 1.4 percentage points in the PRM, from 14.5% to 13.1%.

The benefit is less than the full 50 MW increase in the import allowance. This indicates that during some of the risk hours the binding constraint is the availability of resources in neighboring regions rather than the import limit itself, so the additional import allowance is not always deliverable.

Incremental ELCCs

Incremental ELCC values were developed for solar, wind, 4HR storage, 8HR storage, PSH, DR, and energy efficiency using the methodology described in the Study Methodology section. The incremental ELCC values reflect the marginal accreditation of each technology as penetration increases. Solar and wind results are reported as standalone additions, while the storage results assume a solar buildout at a 2:1 solar-to-storage ratio. DR and energy efficiency were each evaluated at a single incremental level rather than across a range of penetrations. DR was evaluated at an incremental MW level of 50 MW and energy efficiency was evaluated at an incremental MW level of 100 MW.

Table 23: Incremental Solar ELCC

Incremental Solar (MW)	Average ELCC (%)	Tranche ELCC (%)
800	3%	3%
1,600	2%	<1%
2,400	1%	<1%
3,200	1%	<1%
4,000	1%	<1%

Table 24: Incremental Wind ELCC

Incremental Wind (MW)	Average ELCC (%)	Tranche ELCC (%)
500	8%	8%
1,000	5%	2%

Table 25: Incremental Storage Tranche ELCC

Incremental Storage (MW)	4HR	8HR	PSH
400	42%	58%	74%
800	26%	42%	61%
1,200	22%	28%	43%
1,600	—	26%	37%
2,000	—	26%	38%

Table 26: Incremental Demand Response and Energy Efficiency ELCC

Resource	ELCC (%)
Demand Response	63%
Energy Efficiency	50%

Portfolio Reliability Verification

PNM developed candidate expansion portfolios for the CTP and HEG futures across 2036, 2040, and 2045 study years, along with a stakeholder-proposed scenario portfolio. Each portfolio was simulated in SERVM to verify its reliability against the 0.1 LOLE target. The portfolio compositions are presented first, followed by the reliability results.

Table 27: CTP Portfolio

Technology	2036	2040	2045
Solar	2,910	3,053	2,440
Wind	1,356	1,356	800
Short Duration Storage	2,250	2,285	2,248
Long Duration Storage	100	100	100
Combined Cycle	425	425	—
Combustion Turbine	654	487	338
Steam Turbine	146	146	—
Linear Generator	—	120	160
Nuclear	288	288	1,310
Geothermal	11	11	—
Demand Response	45	49	52
Energy Efficiency	403	454	377
Load Forecast	**3,583**	**3,711**	**3,814**

Table 28: HEG Portfolio

Technology	2036	2040	2045
Solar	3,460	3,623	3,049
Wind	1,555	1,555	999
Short Duration Storage	2,406	2,406	2,345
Long Duration Storage	300	300	300
Pumped Storage Hydro	100	100	100
Combined Cycle	425	425	—
Combustion Turbine	654	487	338
Steam Turbine	146	146	—
Linear Generator	—	280	440
Nuclear	288	288	1,310
Geothermal	11	11	—
Demand Response	45	49	52
Energy Efficiency	403	454	377
Load Forecast	**4,048**	**4,326**	**4,609**

Table 29: Stakeholder Proposed Scenario Portfolio

Technology	2036	2040	2045
Solar	2,524	2,425	1,875
Wind	1,356	1,356	1,062
Short Duration Storage	2,273	2,273	1,947
Long Duration Storage	—	—	200
Combined Cycle	425	425	—
Combustion Turbine	482	315	—
Steam Turbine	146	146	—
Nuclear	288	288	1,310
Geothermal	361	361	350
Demand Response	174	258	363
Energy Efficiency	403	454	377
Load Forecast	**3,488**	**3,557**	**3,673**

Each portfolio was simulated across the 2036, 2040, and 2045 study years to determine its LOLE relative to the 0.1 target. For the CTP and HEG portfolios, the incremental 4HR storage adjustment required to bring each portfolio to 0.1 LOLE was also determined. A negative adjustment indicates the portfolio was over-reliable and storage could be removed, and a positive adjustment indicates additional storage was needed.

Table 30: CTP Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)	4HR Adjustment for 0.1 LOLE (MW)
2036	0.05	38	18.8%	−170
2040	0.23	221	13.6%	+285
2045	0.08	99	14.2%	−90

In 2036 the CTP portfolio exceeds the reserve margin target, at 18.8% against the 14.5% target; the portfolio determination in the expansion planning model allows the reserve margin to exceed the PRM where doing so minimizes 20-year net present value. In 2040 the portfolio is underbuilt relative to the target, at 13.6%. In 2045, the estimated reserve margin implies a higher LOLE than the results show. This result indicates a minor disconnect between the ELCCs and the actual reliability contribution of resources. In 2045, as significant nuclear capacity is added and existing wind and solar retire, the average reliability contribution of the remaining renewable and storage resources likely experiences a small increase, leading to the underestimation of the total firm capacity of the portfolio. This effect also occurs in the HEG portfolio for the 2045 study year.

Table 31: HEG Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)	4HR Adjustment for 0.1 LOLE (MW)
2036	0.05	34	18.6%	−230
2040	0.11	80	15.2%	+20
2045	0.03	19	15.1%	−190

The HEG portfolio follows a similar pattern, exceeding the reserve margin target in 2036 at 18.6%, and sitting near the target in 2040 at 15.2% and 2045 at 15.1%.

Heat maps illustrating the timing and severity of each portfolio and study year combination are provided below. In the 2029 base case, LOLH and EUE point in opposite seasonal directions. LOLH is predominantly a summer risk (69% summer, 31% winter), while EUE is already weighted toward winter (20% summer, 80% winter); summer events are frequent but shallow, and winter events are fewer but deeper. The CTP portfolio sees both metrics decisively move into winter with later study years. LOLH inverts from being led by summer to being led by winter by the 2036 study year (24% summer, 76% winter) and becomes almost entirely a winter risk by 2040 (2% summer, 98% winter), holding through 2045. EUE moves from 80% winter in the base case to 94% by 2036 and roughly 99% by 2040, so effectively all unserved energy becomes a winter event.

The HEG portfolio also shifts EUE risk toward winter, but less completely and not monotonically. LOLH is led by winter in 2036 (62% winter) and 2040 (79% winter) but reverses back slightly to summer by 2045 (61% summer, 39% winter). In contrast, EUE stays overwhelmingly winter across all study years (92%, 95%,

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and 88% winter in 2036, 2040, and 2045). The bias of more LOLH summer capacity risk in the HEG portfolio is largely due to the increase in loads which adds more summer peak load compared to winter peak load.

Reliability risk also moves between winter months. In CTP, February and December hold 87% of EUE in 2036. By 2045, January alone holds 84.6% and December falls to 4.8%. HEG moves the same direction: February and December hold 89% in 2036, and January reaches 55.3% by 2045. Net load changes help explain these shifts. As loads increase and the installed capacities of wind and solar resources change, January increases its share of each study year's top 5% of net load energy days in both portfolios — from 10.7% to 20.7% in CTP and 11.3% to 16.7% in HEG. December's share stays flat in CTP but rises in HEG, consistent with December retaining EUE in HEG only.

Table 32: CTP 2036 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.2%	0.4%	-	-	-	0.9%	0.1%	0.1%	-	-	-	0.8%	2.4%
2	0.2%	0.4%	-	-	-	0.8%	0.0%	0.2%	-	-	-	0.3%	2.0%
3	0.2%	1.0%	-	-	-	0.5%	0.1%	0.2%	-	-	-	0.6%	2.6%
4	0.3%	1.4%	-	-	-	0.4%	-	0.2%	-	-	-	0.9%	3.2%
5	0.4%	2.7%	-	-	-	0.4%	-	0.1%	-	-	-	1.3%	5.0%
6	0.4%	5.1%	-	-	-	0.2%	0.0%	0.1%	-	-	-	2.9%	8.8%
7	1.0%	9.3%	-	-	-	-	0.0%	-	-	-	-	6.8%	17.1%
8	1.3%	10.4%	-	-	-	-	-	-	-	-	-	9.8%	21.6%
9	0.3%	3.0%	-	-	-	-	-	-	-	-	-	2.7%	6.0%
10	-	0.3%	-	-	-	-	-	-	-	-	-	0.5%	0.8%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
18	0.0%	-	-	-	-	-	-	0.1%	-	-	-	0.1%	0.2%
19	0.0%	0.0%	-	-	-	1.7%	2.6%	0.9%	-	-	-	0.1%	5.3%
20	0.0%	0.1%	-	-	-	4.0%	4.8%	1.0%	-	-	-	0.6%	10.6%
21	0.1%	0.1%	-	-	-	1.9%	1.0%	0.0%	-	-	-	1.3%	4.5%
22	0.2%	0.2%	-	-	-	0.3%	0.1%	-	-	-	-	1.9%	2.7%
23	0.2%	0.2%	-	-	-	0.2%	0.0%	-	-	-	-	2.6%	3.3%
24	0.2%	0.2%	-	-	-	0.6%	0.0%	0.0%	-	-	-	2.8%	3.9%
Total	**5.2%**	**34.9%**	**-**	**-**	**-**	**11.8%**	**8.8%**	**3.0%**	**-**	**-**	**-**	**36.3%**	**100.0%**

Table 33: CTP 2036 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.1%	0.3%	-	-	-	1.2%	0.1%	0.1%	-	-	-	0.5%	2.3%
2	0.1%	0.5%	-	-	-	0.6%	0.1%	0.3%	-	-	-	0.5%	2.1%
3	0.1%	0.8%	-	-	-	0.1%	0.0%	0.3%	-	-	-	0.7%	2.1%
4	0.2%	1.8%	-	-	-	0.1%	-	0.1%	-	-	-	1.2%	3.4%
5	0.6%	3.5%	-	-	-	0.1%	-	0.0%	-	-	-	2.3%	6.7%
6	0.9%	8.2%	-	-	-	0.0%	0.0%	0.0%	-	-	-	4.9%	14.1%
7	1.4%	15.8%	-	-	-	-	0.0%	-	-	-	-	11.2%	28.5%
8	1.5%	10.2%	-	-	-	-	-	-	-	-	-	9.9%	21.6%
9	0.1%	0.8%	-	-	-	-	-	-	-	-	-	1.1%	2.0%
10	-	0.0%	-	-	-	-	-	-	-	-	-	0.1%	0.1%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
18	0.0%	-	-	-	-	-	-	0.0%	-	-	-	0.1%	0.1%
19	0.1%	0.0%	-	-	-	0.1%	0.1%	0.1%	-	-	-	0.2%	0.5%
20	0.1%	0.1%	-	-	-	0.6%	0.6%	0.1%	-	-	-	0.7%	2.1%
21	0.1%	0.2%	-	-	-	0.3%	0.2%	0.0%	-	-	-	2.1%	2.8%
22	0.3%	0.5%	-	-	-	0.0%	0.0%	-	-	-	-	2.8%	3.6%
23	0.4%	0.6%	-	-	-	0.1%	0.0%	-	-	-	-	3.2%	4.4%
24	0.4%	0.4%	-	-	-	0.8%	0.1%	0.0%	-	-	-	1.8%	3.6%
Total	6.5%	43.9%	-	-	-	4.1%	1.1%	1.0%	-	-	-	43.4%	100.0%

Table 34: CTP 2040 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.4%	0.9%	-	-	-	0.1%	0.0%	-	-	-	-	2.6%	4.0%
2	0.3%	1.0%	-	-	-	0.2%	0.1%	-	-	-	-	0.8%	2.3%
3	0.3%	1.1%	-	-	-	0.2%	0.0%	-	-	-	-	1.3%	2.9%
4	0.4%	1.3%	-	-	-	0.1%	-	-	-	-	-	1.5%	3.5%
5	0.7%	2.1%	-	-	-	0.2%	-	-	-	-	-	2.8%	5.7%
6	1.0%	3.5%	-	-	-	0.1%	-	-	-	-	-	5.2%	9.8%
7	1.8%	6.6%	-	-	-	-	-	-	-	-	-	10.1%	18.5%
8	2.4%	8.3%	-	-	-	-	-	-	-	-	-	13.3%	24.1%
9	0.4%	2.8%	-	-	-	-	-	-	-	-	-	3.6%	6.8%
10	0.0%	0.3%	-	-	-	-	-	-	-	-	-	0.5%	0.8%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	0.0%	-	-	-	-	0.0%
17	-	-	-	-	-	-	-	-	-	-	-	0.1%	0.1%
18	-	-	-	-	-	-	-	-	-	-	-	0.2%	0.2%
19	0.0%	0.0%	-	-	-	0.0%	0.1%	0.1%	-	-	-	0.5%	0.8%
20	0.2%	0.0%	-	-	-	0.1%	0.2%	0.1%	-	-	-	1.1%	1.8%
21	0.2%	0.1%	-	-	-	0.1%	-	-	-	-	-	2.5%	2.9%
22	0.4%	0.2%	-	-	-	-	-	-	-	-	-	3.2%	3.8%
23	0.5%	0.3%	-	-	-	-	-	0.1%	-	-	-	4.6%	5.5%
24	0.6%	0.6%	-	-	-	0.1%	-	0.1%	-	-	-	5.1%	6.5%
Total	9.7%	29.4%	-	-	-	1.2%	0.4%	0.4%	-	-	-	59.0%	100.0%

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Table 35: CTP 2040 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.2%	0.5%	-	-	-	0.1%	0.0%	-	-	-	-	0.7%	1.5%
2	0.1%	0.6%	-	-	-	0.1%	0.0%	-	-	-	-	0.9%	1.8%
3	0.2%	0.8%	-	-	-	0.1%	0.0%	-	-	-	-	1.2%	2.3%
4	0.4%	1.2%	-	-	-	0.0%	-	-	-	-	-	1.7%	3.3%
5	0.6%	2.0%	-	-	-	0.0%	-	-	-	-	-	3.3%	6.0%
6	1.1%	4.4%	-	-	-	0.0%	-	-	-	-	-	6.9%	12.5%
7	2.3%	9.2%	-	-	-	-	-	-	-	-	-	15.0%	26.5%
8	2.1%	7.4%	-	-	-	-	-	-	-	-	-	12.7%	22.1%
9	0.1%	0.5%	-	-	-	-	-	-	-	-	-	0.9%	1.5%
10	0.0%	0.0%	-	-	-	-	-	-	-	-	-	0.1%	0.1%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	0.0%	-	-	-	-	0.0%
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
18	-	-	-	-	-	-	-	-	-	-	-	0.2%	0.2%
19	0.0%	0.0%	-	-	-	0.0%	0.0%	0.0%	-	-	-	0.7%	0.7%
20	0.1%	0.1%	-	-	-	0.0%	0.0%	0.0%	-	-	-	1.6%	1.8%
21	0.3%	0.1%	-	-	-	0.0%	-	-	-	-	-	3.3%	3.8%
22	0.6%	0.3%	-	-	-	-	-	-	-	-	-	4.3%	5.2%
23	0.7%	0.5%	-	-	-	-	-	0.1%	-	-	-	5.2%	6.4%
24	0.6%	0.6%	-	-	-	0.0%	-	0.0%	-	-	-	3.0%	4.2%
Total	**9.5%**	**28.3%**	**-**	**-**	**-**	**0.3%**	**0.1%**	**0.1%**	**-**	**-**	**-**	**61.7%**	**100.0%**

Table 36: CTP 2045 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	1.4%	0.5%	-	-	-	0.0%	0.0%	-	-	-	-	0.2%	2.1%
2	1.8%	0.4%	-	-	-	-	-	-	-	-	-	0.1%	2.3%
3	2.3%	0.4%	-	-	-	-	-	-	-	-	-	0.1%	2.9%
4	3.3%	0.5%	-	-	-	-	-	-	-	-	-	0.3%	4.1%
5	5.1%	0.9%	-	-	-	-	-	-	-	-	-	0.4%	6.3%
6	8.2%	1.4%	-	-	-	-	-	-	-	-	-	0.6%	10.3%
7	15.1%	2.7%	-	-	-	-	-	-	-	-	-	1.3%	19.1%
8	20.5%	3.6%	-	-	-	-	-	-	-	-	-	1.7%	25.9%
9	9.6%	1.7%	-	-	-	-	-	-	-	-	-	0.2%	11.5%
10	1.3%	0.2%	-	-	-	-	-	-	-	-	-	0.1%	1.5%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-	-
18	0.1%	-	-	-	-	-	-	-	-	-	-	-	0.1%
19	0.2%	-	-	-	-	0.9%	0.7%	0.2%	-	-	-	-	2.0%
20	0.3%	-	-	-	-	2.1%	2.4%	0.4%	-	-	-	0.1%	5.3%
21	0.5%	-	-	-	-	0.3%	0.3%	0.0%	-	-	-	0.2%	1.3%
22	0.9%	0.1%	-	-	-	0.0%	-	-	-	-	-	0.3%	1.3%
23	1.3%	0.2%	-	-	-	0.0%	-	-	-	-	-	0.3%	1.9%
24	1.4%	0.3%	-	-	-	0.0%	-	-	-	-	-	0.3%	2.1%
Total	**73.5%**	**12.9%**	**-**	**-**	**-**	**3.4%**	**3.4%**	**0.6%**	**-**	**-**	**-**	**6.1%**	**100.0%**

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Table 37: CTP 2045 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.9%	0.2%	-	-	-	0.0%	0.0%	-	-	-	-	0.1%	**1.1%**
2	1.3%	0.1%	-	-	-	-	-	-	-	-	-	0.1%	**1.5%**
3	2.0%	0.2%	-	-	-	-	-	-	-	-	-	0.1%	**2.4%**
4	3.6%	0.3%	-	-	-	-	-	-	-	-	-	0.1%	**4.0%**
5	6.5%	0.6%	-	-	-	-	-	-	-	-	-	0.2%	**7.4%**
6	12.8%	1.5%	-	-	-	-	-	-	-	-	-	0.6%	**14.9%**
7	24.5%	3.2%	-	-	-	-	-	-	-	-	-	1.4%	**29.1%**
8	25.5%	3.2%	-	-	-	-	-	-	-	-	-	1.1%	**29.8%**
9	3.2%	0.2%	-	-	-	-	-	-	-	-	-	0.1%	**3.5%**
10	0.1%	0.0%	-	-	-	-	-	-	-	-	-	0.0%	**0.1%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	-	-	-	-	-	-	-	**-**
18	0.0%	-	-	-	-	-	-	-	-	-	-	-	**0.0%**
19	0.1%	-	-	-	-	0.0%	0.0%	0.0%	-	-	-	-	**0.2%**
20	0.3%	-	-	-	-	0.1%	0.2%	0.0%	-	-	-	0.0%	**0.7%**
21	0.5%	-	-	-	-	0.0%	0.0%	0.0%	-	-	-	0.1%	**0.7%**
22	0.9%	0.1%	-	-	-	0.0%	-	-	-	-	-	0.3%	**1.3%**
23	1.2%	0.2%	-	-	-	0.0%	-	-	-	-	-	0.3%	**1.8%**
24	1.1%	0.2%	-	-	-	0.0%	-	-	-	-	-	0.2%	**1.6%**
Total	**84.6%**	**10.1%**	**-**	**-**	**-**	**0.2%**	**0.2%**	**0.0%**	**-**	**-**	**-**	**4.8%**	**100.0%**

Table 38: HEG 2036 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.1%	0.5%	-	-	-	0.8%	0.1%	-	-	-	-	0.6%	**2.0%**
2	0.1%	0.4%	-	-	-	0.9%	0.0%	-	-	-	-	0.5%	**1.8%**
3	0.1%	0.5%	-	-	-	0.8%	0.1%	-	-	-	-	0.7%	**2.1%**
4	0.1%	0.9%	-	-	-	0.8%	0.1%	-	-	-	-	0.9%	**2.8%**
5	0.1%	2.3%	-	-	-	0.7%	0.0%	-	-	-	-	1.4%	**4.6%**
6	0.1%	4.2%	-	-	-	0.2%	0.0%	-	-	-	-	2.1%	**6.6%**
7	0.3%	7.6%	-	-	-	-	-	-	-	-	-	4.7%	**12.6%**
8	0.5%	8.8%	-	-	-	-	-	-	-	-	-	6.0%	**15.3%**
9	0.2%	2.0%	-	-	-	-	-	-	-	-	-	1.7%	**3.9%**
10	0.0%	0.0%	-	-	-	-	-	-	-	-	-	0.1%	**0.2%**
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	-	-	0.0%	-	-	-	0.0%	**0.0%**
18	0.0%	0.1%	-	-	-	-	-	0.0%	-	-	-	0.3%	**0.5%**
19	0.0%	0.1%	-	-	-	3.1%	4.2%	1.5%	-	-	-	0.5%	**9.5%**
20	0.1%	0.1%	-	-	-	7.9%	7.8%	2.3%	-	-	-	1.3%	**19.5%**
21	0.1%	0.1%	-	-	-	3.8%	1.4%	0.5%	-	-	-	1.7%	**7.6%**
22	0.1%	0.2%	-	-	-	0.1%	0.2%	0.1%	-	-	-	2.2%	**2.9%**
23	0.2%	0.4%	-	-	-	0.1%	0.0%	-	-	-	-	2.9%	**3.6%**
24	0.2%	0.6%	-	-	-	0.5%	0.1%	-	-	-	-	3.1%	**4.5%**
Total	**2.2%**	**28.8%**	**-**	**-**	**-**	**19.7%**	**14.0%**	**4.3%**	**-**	**-**	**-**	**30.9%**	**100.0%**

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Suite 575
Hoover, AL 35244

Table 39: HEG 2036 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.1%	0.2%	-	-	-	1.4%	0.1%	-	-	-	-	0.7%	2.5%
2	0.0%	0.3%	-	-	-	0.9%	0.0%	-	-	-	-	0.8%	2.0%
3	0.0%	0.4%	-	-	-	0.3%	0.1%	-	-	-	-	1.1%	1.9%
4	0.0%	1.1%	-	-	-	0.2%	0.1%	-	-	-	-	1.6%	3.0%
5	0.1%	3.0%	-	-	-	0.3%	0.0%	-	-	-	-	2.9%	6.3%
6	0.1%	7.1%	-	-	-	0.0%	0.0%	-	-	-	-	4.9%	12.2%
7	0.5%	14.5%	-	-	-	-	-	-	-	-	-	9.2%	24.2%
8	0.7%	10.1%	-	-	-	-	-	-	-	-	-	8.6%	19.5%
9	0.1%	0.4%	-	-	-	-	-	-	-	-	-	0.8%	1.3%
10	0.0%	0.0%	-	-	-	-	-	-	-	-	-	0.1%	0.1%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	0.0%	-	-	-	0.0%	0.0%
18	0.0%	0.0%	-	-	-	-	0.0%	0.0%	-	-	-	0.1%	0.1%
19	0.1%	0.1%	-	-	-	0.1%	0.3%	0.2%	-	-	-	1.2%	1.9%
20	0.1%	0.3%	-	-	-	1.1%	1.1%	0.4%	-	-	-	2.5%	5.4%
21	0.2%	0.5%	-	-	-	0.3%	0.2%	0.1%	-	-	-	4.2%	5.4%
22	0.3%	0.7%	-	-	-	0.0%	0.0%	0.0%	-	-	-	3.9%	4.9%
23	0.3%	0.8%	-	-	-	0.2%	0.0%	-	-	-	-	3.9%	5.3%
24	0.3%	0.6%	-	-	-	0.9%	0.1%	-	-	-	-	1.9%	3.9%
Total	**3.0%**	**40.2%**	**-**	**-**	**-**	**5.7%**	**2.0%**	**0.6%**	**-**	**-**	**-**	**48.6%**	**100.0%**

Table 40: HEG 2040 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.1%	1.2%	-	-	-	0.8%	0.2%	-	-	-	-	0.5%	2.8%
2	0.0%	0.7%	-	-	-	0.6%	0.0%	-	-	-	-	0.4%	1.8%
3	0.0%	1.0%	-	-	-	0.5%	0.0%	0.0%	-	-	-	0.7%	2.2%
4	0.1%	1.4%	-	-	-	0.6%	0.0%	0.0%	-	-	-	0.7%	2.9%
5	0.1%	2.5%	-	-	-	0.4%	0.0%	0.0%	-	-	-	1.0%	4.1%
6	0.2%	4.7%	-	-	-	0.1%	-	-	-	-	-	2.1%	7.1%
7	0.6%	9.2%	-	-	-	-	-	-	-	-	-	5.2%	15.0%
8	0.8%	10.6%	-	-	-	-	-	-	-	-	-	6.8%	18.1%
9	0.2%	2.2%	-	-	-	-	-	-	-	-	-	2.1%	4.5%
10	-	-	-	-	-	-	-	-	-	-	-	0.3%	0.3%
11	-	-	-	-	-	-	-	-	-	-	-	0.1%	0.1%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	0.1%	0.1%
18	-	0.1%	-	-	-	-	-	-	0.1%	-	-	0.2%	0.4%
19	-	0.1%	-	-	-	1.7%	2.1%	0.6%	-	-	-	0.7%	5.2%
20	0.0%	0.3%	-	-	-	3.8%	4.5%	1.1%	-	-	-	1.8%	11.6%
21	0.1%	0.2%	-	-	-	1.8%	0.6%	0.2%	-	-	-	3.2%	6.1%
22	0.1%	0.5%	-	-	-	0.1%	-	0.0%	-	-	-	3.9%	4.7%
23	0.1%	1.0%	-	-	-	0.3%	-	-	-	-	-	4.9%	6.3%
24	0.2%	1.1%	-	-	-	0.6%	0.1%	-	-	-	-	4.7%	6.8%
Total	**2.6%**	**36.8%**	**-**	**-**	**-**	**11.6%**	**7.5%**	**2.0%**	**0.1%**	**-**	**-**	**39.4%**	**100.0%**

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Hoover, AL 35244

Table 41: HEG 2040 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.0%	0.5%	-	-	-	0.8%	0.1%	-	-	-	-	0.4%	1.8%
2	0.0%	0.5%	-	-	-	0.4%	0.1%	-	-	-	-	0.5%	1.3%
3	0.0%	0.3%	-	-	-	0.1%	0.0%	0.0%	-	-	-	0.6%	1.2%
4	0.1%	0.9%	-	-	-	0.1%	0.0%	0.0%	-	-	-	1.1%	2.1%
5	0.1%	3.4%	-	-	-	0.1%	0.0%	0.0%	-	-	-	1.6%	5.2%
6	0.2%	7.2%	-	-	-	0.0%	-	-	-	-	-	3.4%	10.8%
7	0.7%	15.1%	-	-	-	-	-	-	-	-	-	8.9%	24.7%
8	0.9%	10.2%	-	-	-	-	-	-	-	-	-	8.4%	19.5%
9	0.0%	0.2%	-	-	-	-	-	-	-	-	-	0.6%	0.8%
10	-	-	-	-	-	-	-	-	-	-	-	0.1%	0.1%
11	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	0.1%	0.1%
18	-	0.0%	-	-	-	-	-	-	0.0%	-	-	0.3%	0.3%
19	-	0.1%	-	-	-	0.1%	0.1%	0.0%	-	-	-	1.1%	1.4%
20	0.0%	0.2%	-	-	-	0.6%	0.5%	0.2%	-	-	-	3.2%	4.6%
21	0.1%	0.3%	-	-	-	0.2%	0.0%	0.0%	-	-	-	6.2%	6.8%
22	0.1%	0.8%	-	-	-	0.0%	-	0.0%	-	-	-	6.3%	7.2%
23	0.1%	1.7%	-	-	-	0.3%	-	-	-	-	-	5.5%	7.6%
24	0.2%	1.4%	-	-	-	0.9%	0.1%	-	-	-	-	1.7%	4.3%
Total	**2.6%**	**42.7%**	**-**	**-**	**-**	**3.7%**	**0.9%**	**0.3%**	**0.0%**	**-**	**-**	**49.8%**	**100.0%**

Table 42: HEG 2045 LOLH Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.2%	0.2%	-	-	-	0.2%	0.0%	-	-	-	-	0.4%	1.0%
2	0.3%	0.1%	-	-	-	0.0%	-	-	-	-	-	0.2%	0.6%
3	0.5%	0.1%	-	-	-	-	-	-	-	-	-	0.3%	0.9%
4	0.7%	0.1%	-	-	-	-	-	-	-	-	-	0.4%	1.2%
5	1.3%	0.4%	-	-	-	-	-	-	-	-	-	0.3%	2.1%
6	2.5%	1.0%	-	-	-	-	-	-	-	-	-	0.5%	4.0%
7	4.7%	2.2%	-	-	-	-	-	-	-	-	-	1.1%	8.1%
8	6.6%	2.8%	-	-	-	-	-	-	-	-	-	1.4%	10.8%
9	3.3%	0.8%	-	-	-	-	-	-	-	-	-	0.3%	4.3%
10	0.5%	-	-	-	-	-	-	-	-	-	-	0.2%	0.7%
11	0.1%	-	-	-	-	-	-	-	-	-	-	-	0.1%
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	0.0%
18	-	0.1%	-	-	-	-	0.0%	0.1%	-	-	-	0.1%	0.3%
19	-	0.1%	-	-	-	9.2%	8.0%	2.6%	-	-	-	0.1%	20.0%
20	0.1%	0.1%	-	-	-	15.9%	15.4%	3.0%	-	-	-	0.3%	34.7%
21	0.2%	0.0%	-	-	-	3.5%	2.0%	0.2%	-	-	-	0.6%	6.6%
22	0.3%	0.2%	-	-	-	0.0%	0.0%	-	-	-	-	0.8%	1.3%
23	0.3%	0.2%	-	-	-	0.0%	0.0%	-	-	-	-	1.0%	1.5%
24	0.3%	0.3%	-	-	-	0.2%	0.0%	-	-	-	-	1.0%	1.8%
Total	**21.9%**	**8.6%**	**-**	**-**	**-**	**29.1%**	**25.6%**	**6.0%**	**-**	**-**	**-**	**8.9%**	**100.0%**

Table 43: HEG 2045 EUE Heat Map

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0.2%	0.0%	-	-	-	0.1%	0.0%	-	-	-	-	0.2%	**0.6%**
2	0.3%	0.1%	-	-	-	0.0%	-	-	-	-	-	0.2%	**0.5%**
3	0.7%	0.0%	-	-	-	-	-	-	-	-	-	0.3%	**1.0%**
4	1.6%	0.0%	-	-	-	-	-	-	-	-	-	0.3%	**1.9%**
5	3.1%	0.2%	-	-	-	-	-	-	-	-	-	0.4%	**3.8%**
6	7.9%	2.0%	-	-	-	-	-	-	-	-	-	0.8%	**10.7%**
7	18.2%	5.9%	-	-	-	-	-	-	-	-	-	2.2%	**26.3%**
8	18.9%	5.3%	-	-	-	-	-	-	-	-	-	2.2%	**26.3%**
9	2.5%	0.1%	-	-	-	-	-	-	-	-	-	0.5%	**3.1%**
10	0.1%	-	-	-	-	-	-	-	-	-	-	0.1%	**0.2%**
11	0.0%	-	-	-	-	-	-	-	-	-	-	-	**0.0%**
12	-	-	-	-	-	-	-	-	-	-	-	-	**-**
13	-	-	-	-	-	-	-	-	-	-	-	-	**-**
14	-	-	-	-	-	-	-	-	-	-	-	-	**-**
15	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	-	-	-	-	-	-	-	-	-	-	-	-	**-**
17	-	-	-	-	-	-	-	-	-	-	-	0.0%	**0.0%**
18	-	0.0%	-	-	-	-	0.0%	0.0%	-	-	-	0.1%	**0.1%**
19	-	0.0%	-	-	-	1.1%	0.6%	0.4%	-	-	-	0.3%	**2.4%**
20	0.1%	0.0%	-	-	-	4.7%	2.5%	0.9%	-	-	-	0.8%	**9.0%**
21	0.2%	0.0%	-	-	-	0.8%	0.3%	0.0%	-	-	-	2.2%	**3.5%**
22	0.6%	0.5%	-	-	-	0.0%	0.1%	-	-	-	-	2.9%	**4.1%**
23	0.6%	0.9%	-	-	-	0.0%	0.1%	-	-	-	-	2.4%	**4.0%**
24	0.3%	0.5%	-	-	-	0.4%	0.1%	-	-	-	-	1.2%	**2.4%**
Total	**55.3%**	**15.6%**	**-**	**-**	**-**	**7.0%**	**3.6%**	**1.3%**	**-**	**-**	**-**	**17.2%**	**100.0%**

In 2036 the stakeholder-proposed scenario portfolio exceeds the reserve margin target, at 25.0%. In 2040, the LOLE of 0.30 is higher than the estimated reserve margin of 17.5% would suggest, reflecting an overstatement of the DR ELCC as well as storage ELCC because the portfolio has less solar energy to charge the storage than the CTP 2040 portfolio. In 2045, the scenario meets the 0.1 LOLE target on an estimated reserve margin of 11.9%, well below the 14.5% PRM, reflecting the same modest 2045 understatement of firm capacity described for the CTP and HEG portfolios above. Results are summarized in **Table 44**.

Table 44: Stakeholder Proposed Scenario Reliability Results

Study Year	LOLE (days/year)	EUE (MWh)	Estimated Reserve Margin (%)
2036	0.01	5	25.0%
2040	0.30	329	17.5%
2045	0.10	65	11.9%

Resiliency Analysis

Portfolio Resiliency

The CTP and HEG portfolios calibrated to 0.1 LOLE were simulated for the selected summer and winter extreme weather years across the 2036, 2040, and 2045 study years. An additional island sensitivity was also conducted to understand the system's resiliency under extreme conditions with no external assistance. The resulting weekly EUE is shown below for each portfolio and study year. Weekly dispatch charts for all portfolio, study year, season, and interconnected/islanded combinations are provided in the **Appendix**; selected charts are reproduced in this section to illustrate the discussion.

Table 45: Summer Resiliency Results

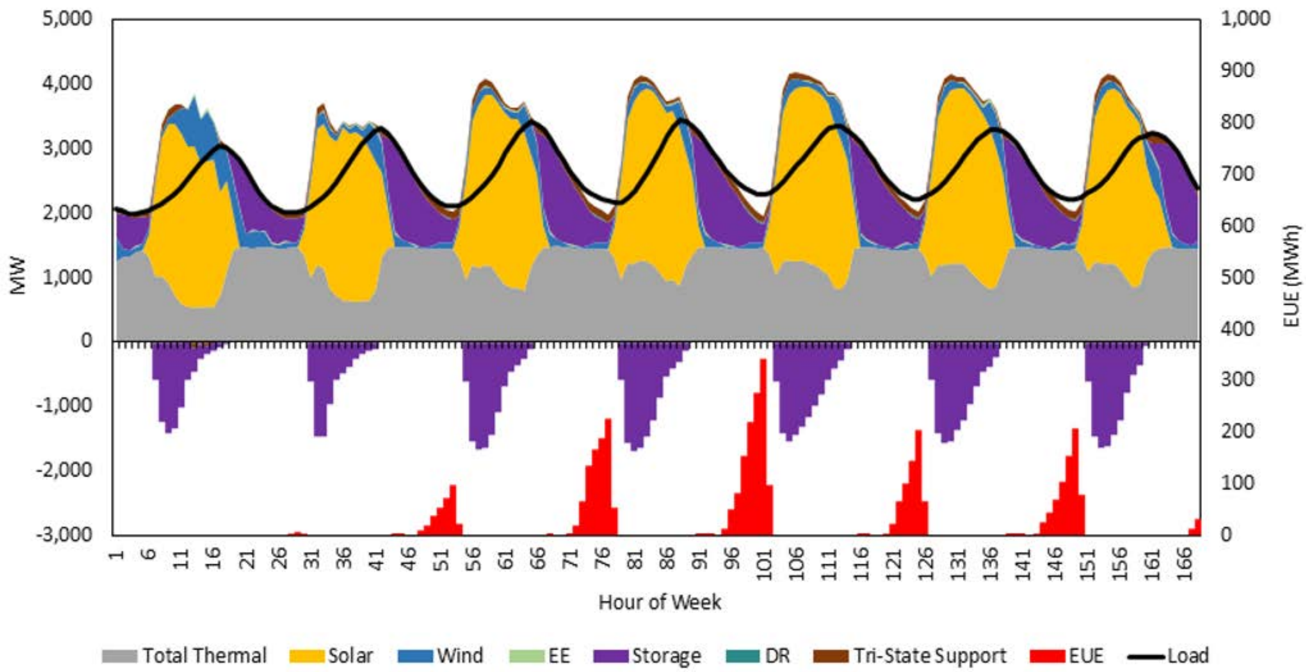
Portfolio	Year	Interconnected Weekly EUE (MWh)	Islanded Weekly EUE (MWh)
CTP	2036	6	3,758
CTP	2040	1	4,383
CTP	2045	4	2,509
HEG	2036	33	3,892
HEG	2040	13	3,596
HEG	2045	7	1,152

Table 46: Winter Resiliency Results

Portfolio	Year	Interconnected Weekly EUE (MWh)	Islanded Weekly EUE (MWh)
CTP	2036	259	9,259
CTP	2040	614	10,237
CTP	2045	76	3,823
HEG	2036	252	17,187
HEG	2040	528	6,061
HEG	2045	54	2,470

Generally, in summer, unserved energy in these islanded cases occurs in the early morning hours rather than at the evening net-load peak that drives summer risk in the base case. Storage discharges through the evening peak, is drawn down overnight, and reaches its lowest point shortly before sunrise, leaving a shallow shortfall in the pre-dawn hours that ends as solar generation returns for the day. The 2036, islanded, summer, CTP weekly dispatch is shown in **Figure 15** below and illustrates the frequent, lower EUE events that characterize summer LOLE.

Figure 15: CTP 2036 Summer Islanded Weekly Dispatch



In winter, loads are dual-peaking and during the intervals between successive peaks there is not enough energy to charge the storage resources. State of charge declines progressively across the week rather than recovering each night. This results in generally larger but less frequent EUE events concentrated at the end of the week, once storage is fully depleted. Winter therefore produces fewer hours of unserved energy than summer but far more unserved energy in total. This aligns with the heat maps and takeaways discussed in earlier sections, which likewise show greater EUE in winter than in summer. The 2036, islanded, winter, CTP weekly dispatch is shown in **Figure 16** and illustrates the higher magnitude EUE events that characterize winter LOLE.

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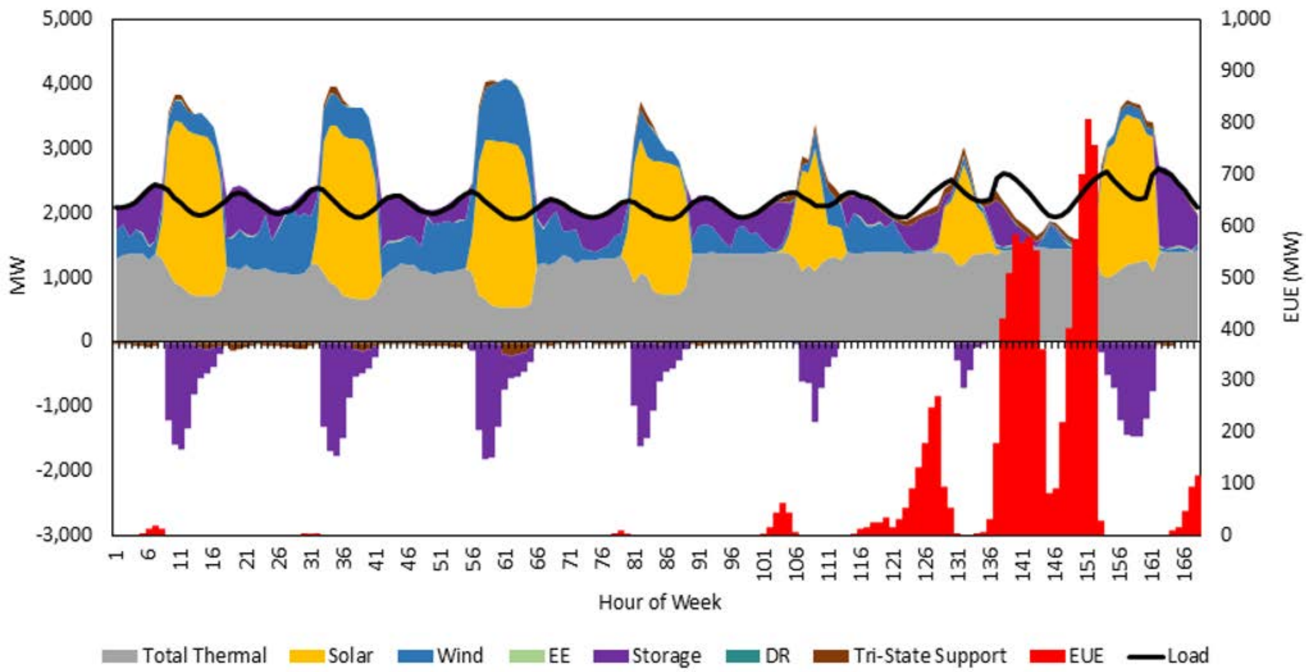
Figure 16: CTP 2036 Winter Islanded Weekly Dispatch



For further interpreting the weekly EUE results, a useful metric is firm capacity as a percentage of peak load forecast. This is calculated as the combined nameplate capacity of combined cycle, combustion turbine, steam turbine, linear generator, nuclear, and geothermal resources, divided by the peak load forecast for the given portfolio and study year. Firm, dispatchable capacity is available albeit absent forced or planned outages irrespective of weather, time of day, or stored energy, and it is therefore what remains to serve load once storage has been depleted and solar and wind have receded. **Table 47** shows the calculated firm capacity ratios. Because the 0.1 LOLE calibration adjusts 4HR storage only, these ratios apply equally to the calibrated portfolios simulated in the resiliency analysis.

Table 47: Firm Capacity Ratio for Expansion Portfolios

Portfolio	Year	Firm / load	Summer Islanded Weekly EUE (MWh)	Winter Islanded Weekly EUE (MWh)
CTP	2036	42.5%	3,758	9,259
CTP	2040	39.8%	4,383	10,237
CTP	2045	47.4%	2,509	3,823
HEG	2036	37.6%	3,892	17,187
HEG	2040	37.8%	3,596	6,061
HEG	2045	45.3%	1,152	2,470

Both portfolios improve considerably by 2045, when combined cycle, steam turbine, and geothermal capacity retire and are replaced by 1,022 MW of small modular nuclear capacity. That addition is large enough to raise firm capacity to its highest share of the three study years in both portfolios, despite 2045 also carrying the highest load.

For the CTP portfolio as seen in Table 46, weekly EUE moves inversely with the firm capacity share in all three islanded cases. The 2040 case has the lowest firm capacity share of the three study years, because firm capacity falls in absolute terms between 2036 and 2040 as combustion turbine capacity retires faster than linear generation is added, while the load forecast continues to rise. It also produces the highest unserved energy in the winter week and summer islanded case. The 2045 case is the reverse, with the highest firm capacity share and the lowest unserved energy in summer and winter.

The HEG portfolio follows the same pattern where the lowest firm capacity share shows the higher EUE. The study year 2036 has the lowest firm capacity share and we see the EUE increase rapidly. At this point, we see the additional firm capacity in 2040 versus 2036 makes a substantial difference during the winter resiliency week because the storage fleet is able to be more fully charged entering into the week. The HEG 2036 case is a marked outlier. HEG 2036 and HEG 2040 provide almost exactly the same share of peak load from firm capacity, yet 2036 produces roughly three times the islanded winter unserved energy of 2040. The two cases do not, however, enter the week with identical storage: the 0.1 LOLE calibration removed 230 MW of 4HR storage from HEG 2036 and added 20 MW to HEG 2040, leaving 2036 with roughly 250 MW less short-duration storage. The 2036 and 2040 winter, islanded, HEG dispatches are shown in **Figure 17** and **Figure 18**.

Figure 17: HEG 2036 Winter Islanded Weekly Dispatch

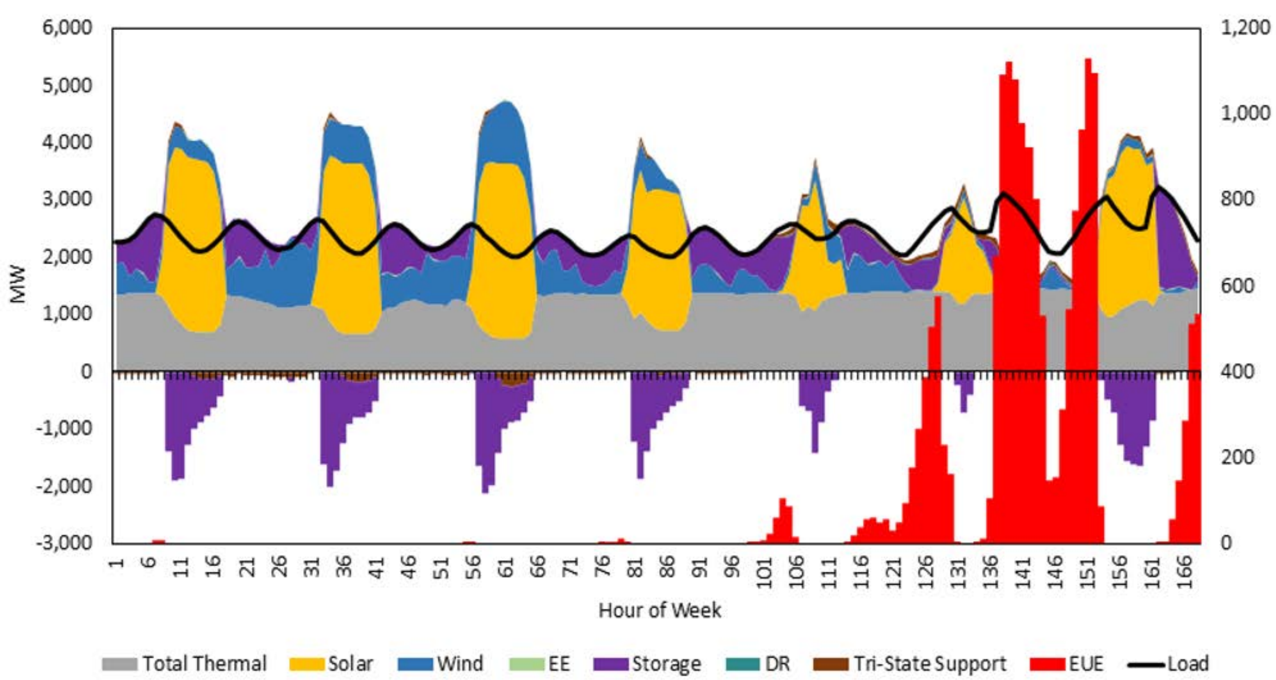
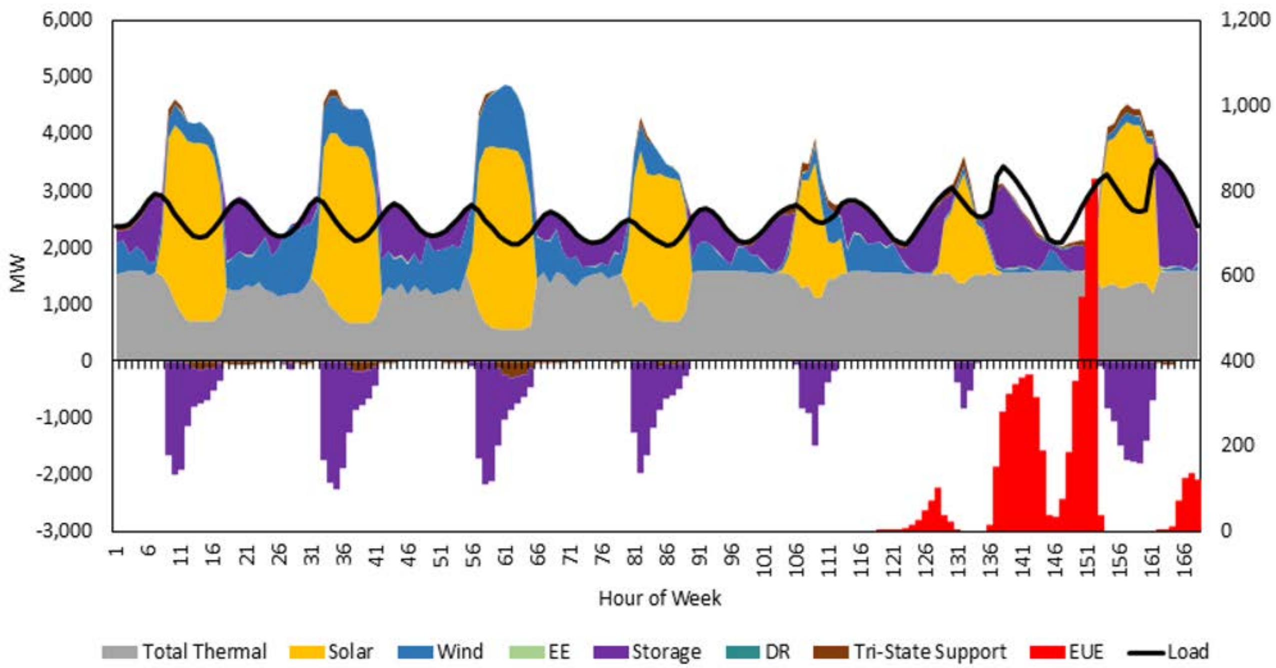


Figure 18: HEG 2040 Winter Islanded Weekly Dispatch



The explanation for the high 2036 unserved energy lies largely in how additional firm capacity performs across a sustained multi-day extreme weather period. The HEG 2040 portfolio carries over 100 MW more firm capacity than the HEG 2036 portfolio, and across the resiliency week that capacity delivers appreciably more energy despite serving higher load. It also begins the week with more short-duration storage. The difference is apparent from the beginning of the week. In the 2036 case small shortfalls appear on the first day and recur on most days that follow, indicating an energy shortfall from the outset. HEG 2040 records no unserved energy at all through the first four days of the extreme winter week.

Resiliency Comparison of Different Technologies

The second part of the resiliency analysis compares how different resource technologies perform under extreme conditions when each is sized to provide the same reliability. Starting from the CTP 2036 portfolio calibrated to 0.1 LOLE, 100 MW of load was added, and each of four technologies (an LM6000 combustion turbine, 4HR storage, DR, and solar paired with storage at a 2:1 solar-to-storage ratio) was then added independently in the amount required to return the system to 0.1 LOLE. Because every scenario is calibrated to the same annual LOLE, the EUE differences highlight how each technology helps the portfolio when the system experiences extreme weather. Each scenario was evaluated first on EUE across a full simulation of all weather years, and then on EUE and system dispatch during the same extreme summer and winter weeks used in the portfolio resiliency analysis. The results of this analysis are shown in **Table 48**.

Table 48: Resiliency Comparison of Different Technologies

Marginal Resource	Marginal MW	Full Study Annual EUE (MWh)	Summer Extreme Week EUE (MWh)	Winter Extreme Week EUE (MWh)
LM6000	105	67	26	145
4HR	345	107	13	603
Demand Response	580	73	0	474
Solar and Storage	580/290	100	<1	463

Across the full simulation of all weather years, the LM6000 produces the lowest annual EUE at 67 MWh, followed by DR at 73 MWh, solar and storage at 100 MWh, and 4HR storage at 107 MWh. The ordering reflects how much each resource is limited by energy rather than capacity. The LM6000 can serve a deficit of any duration once committed unless it is on forced outage or planned maintenance, so the capacity added closely matches the capacity the system was short. DR is constrained by the number and length of events it can be called for, but those events are long enough to cover most hours in which the system is short. The solar and storage case and the 4HR resource depend on stored energy and on the opportunity to recharge, so a portion of their capacity is unavailable in the longest events and considerably more of it is required to reach the same annual reliability.

The extreme summer week reverses part of that ordering. With 100 MW of additional load, the 4HR and the solar and storage scenarios record 13 MWh and less than 1 MWh of unserved energy, and DR records none, against 26 MWh for the LM6000. Summer shortfalls are concentrated in a few late afternoon and evening hours, which is within the discharge duration of storage. Because the energy limited resources require far more installed capacity to reach the same annual reliability, 345 MW of 4HR, 580 MW of solar with 290 MW of storage, and 580 MW of DR against 105 MW of the LM6000, that additional capacity is available in the hours when the system is short and the events are brief enough that stored energy is not exhausted. DR clears the extreme summer week with no unserved energy for the same reason: the large amount of DR added (580 MW) overcomes the summer events. The extreme winter week results are aligned with the annual results. Winter risk is driven by cold that persists across several days and a morning and evening peak rather than by a single evening peak, leaving the energy limited resources (even with much higher capacity levels) unable to sustain output through the event or to fully recharge between days. The LM6000 holds winter extreme week EUE to 145 MWh, while DR reaches 474 MWh, solar and storage 463 MWh, and 4HR storage 603 MWh despite their much larger installed capacity. DR clears the summer week but is constrained in winter by the number and duration of events it can be called, so it cannot cover a multi-day cold event and performs in line with the energy limited resources rather than with the LM6000. Sustained winter conditions therefore favor firm capacity.

Appendix

Table 49: PNM Solar Profile Locations

Profile Name	Latitude	Longitude
Alamogordo	32.8863	−105.9708
Alamosa	35.0780	−106.7083
Albuquerque	35.0840	−106.6500
Alta Luna	32.5708	−107.4885
Arroyo Solar	35.9715	−107.5602
Bluewater	35.2578	−107.9396
Britton	35.0129	−106.0954
Cimarron	36.4681	−104.6396
Cuba	36.0174	−106.9460
Encino	35.3266	−106.8562
Escalante	35.4161	−108.0873
Estancia	34.7826	−106.0558
Jicarilla Solar I	36.3284	−107.2779
NMRD	35.0747	−106.8644
Quail Ranch Solar	35.2164	−106.8358
Route 66	35.1029	−107.6158
San Juan Solar	36.8021	−108.4425
Sky Ranch	34.7826	−106.7798
Spanish Peaks	37.3770	−104.4590
Springer	36.3981	−104.5942
Storrie	35.6569	−105.1839
TAG Solar PV	35.3297	−106.8549
Alamogordo	32.8863	−105.9708

Table 50: Neighbor Solar Profile Locations

Profile Name	Latitude	Longitude
Arizona 1	35.85	−111.90
Arizona 2	36.29	−109.70
Arizona 3	34.65	−109.42
Arizona 4	35.29	−114.22
Arizona 5	32.93	−109.70
Arizona 6	31.45	−109.70
EPE 1	31.61	−105.02
EPE 2	32.13	−105.70
PSCo 1	40.53	−105.74
PSCo 2	38.29	−103.30

3000 Riverchase Galleria
Suite 575
Hoover, AL 35244

Figure 19: CTP 2036 Summer Interconnected Weekly Dispatch

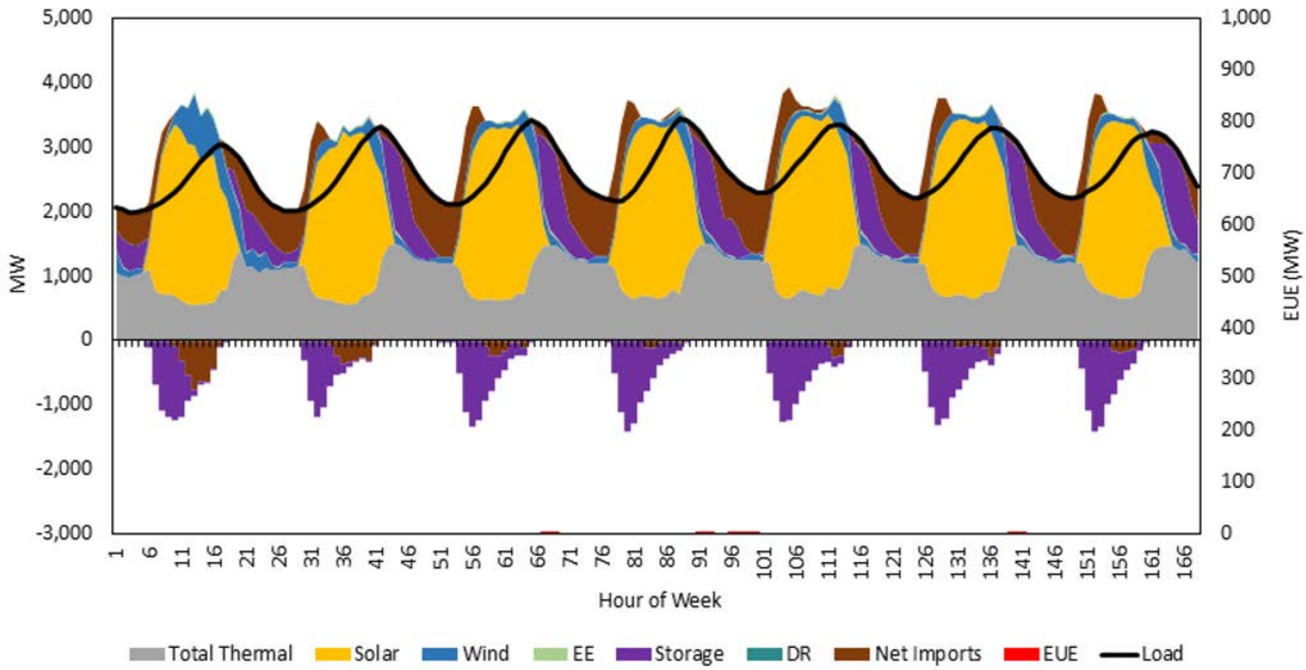
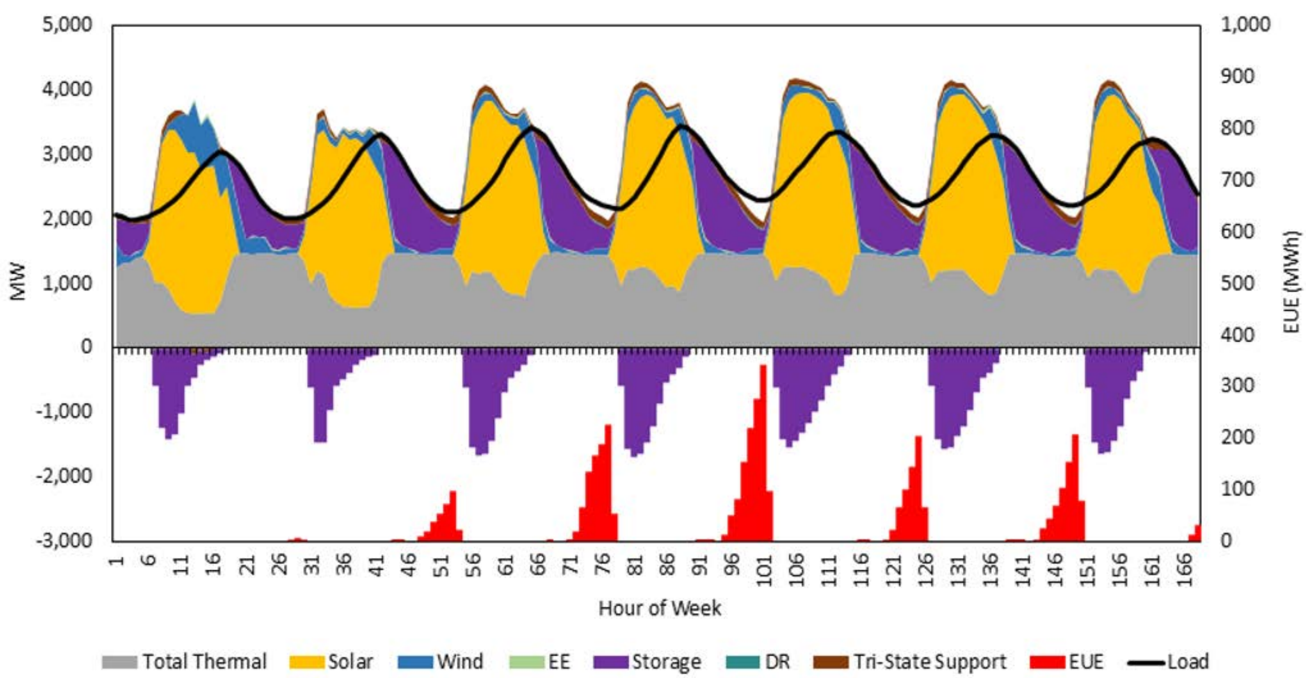


Figure 20: CTP 2036 Summer Islanded Weekly Dispatch



POWERGEM
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Suite 575
Hoover, AL 35244

Figure 21: CTP 2040 Summer Interconnected Weekly Dispatch

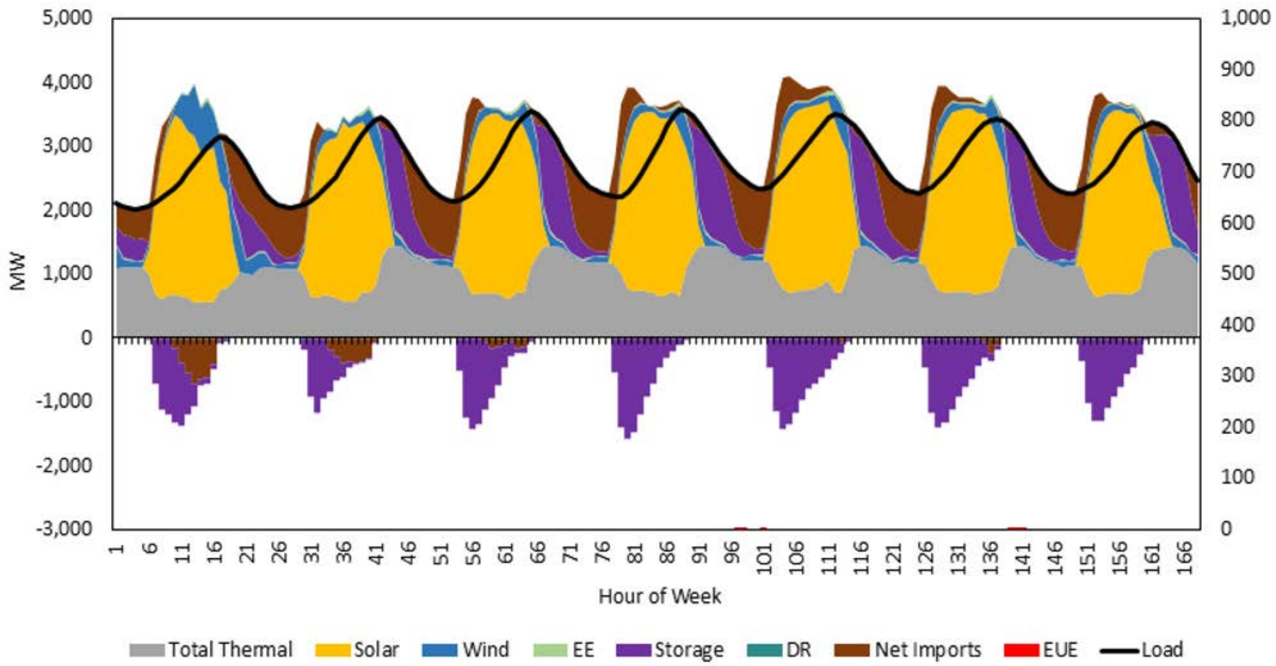

Figure 22: CTP 2040 Summer Islanded Weekly Dispatch

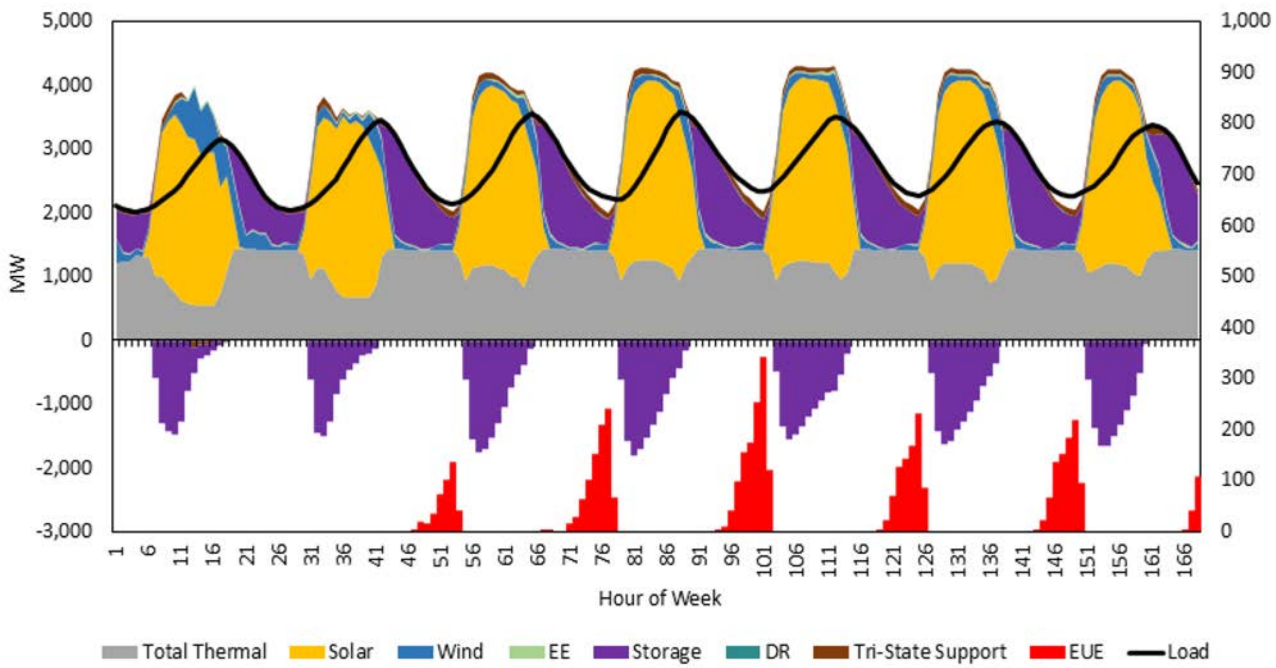

Figure 23: CTP 2045 Summer Interconnected Weekly Dispatch

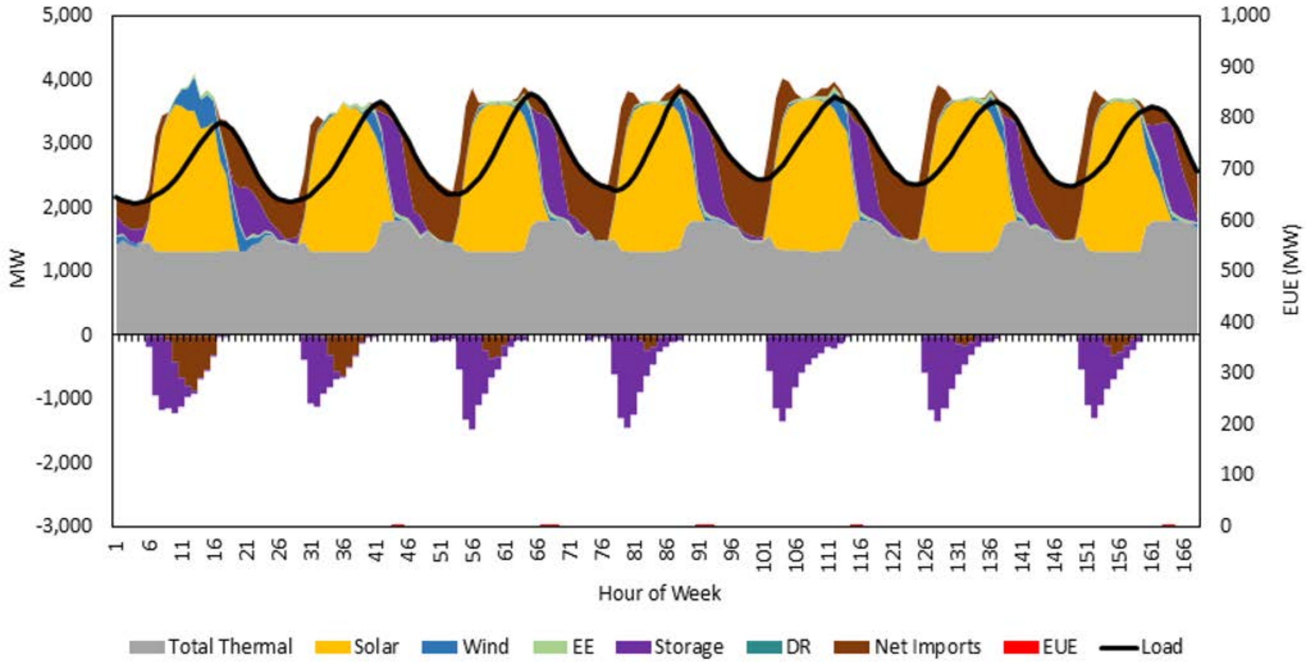

Figure 24: CTP 2045 Summer Islanded Weekly Dispatch

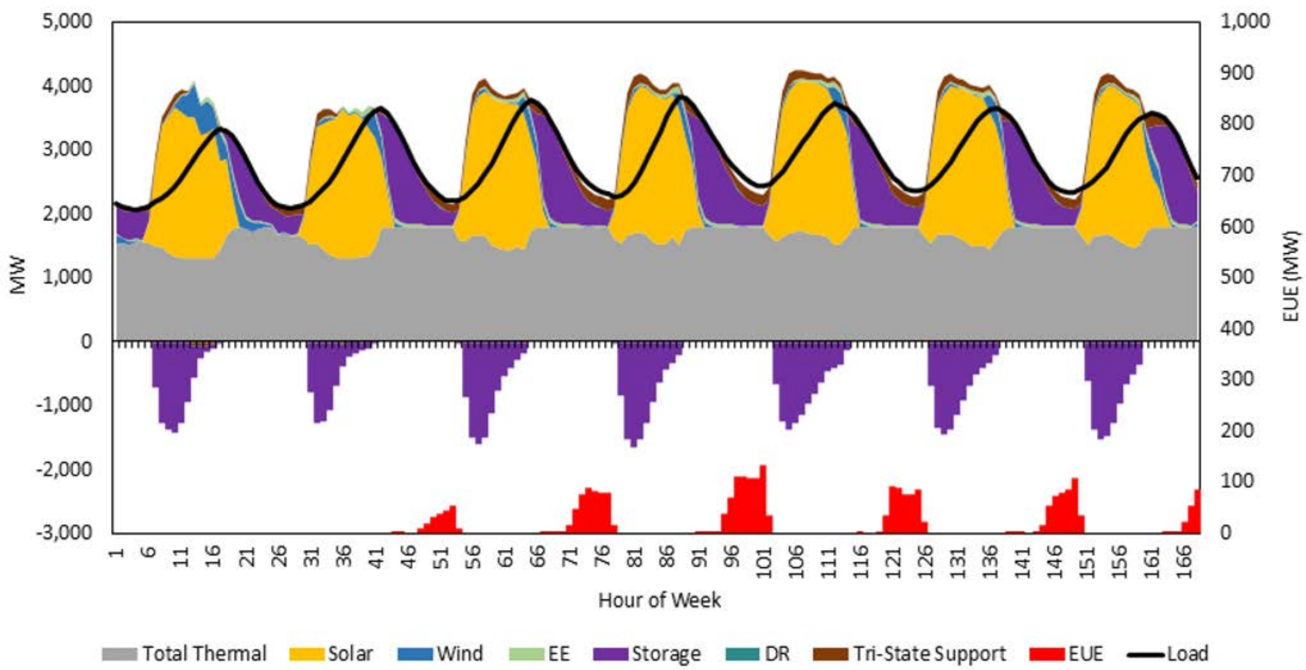

Figure 25: CTP 2036 Winter Interconnected Weekly Dispatch

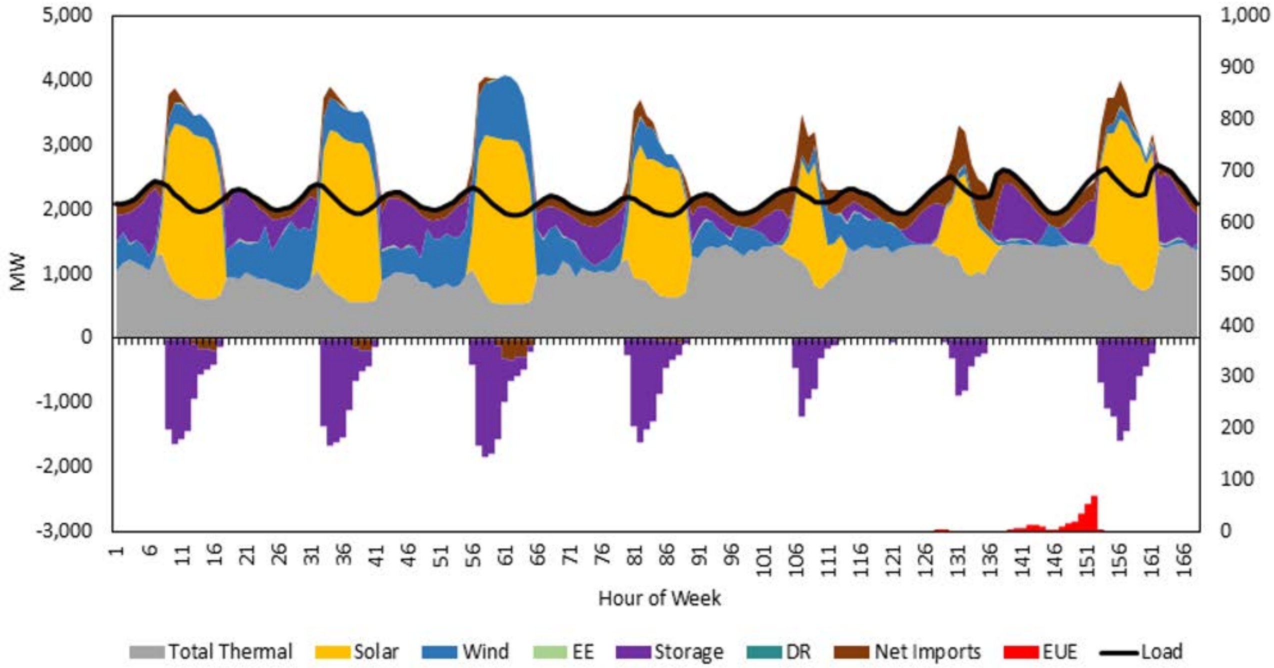

Figure 26: CTP 2036 Winter Islanded Weekly Dispatch

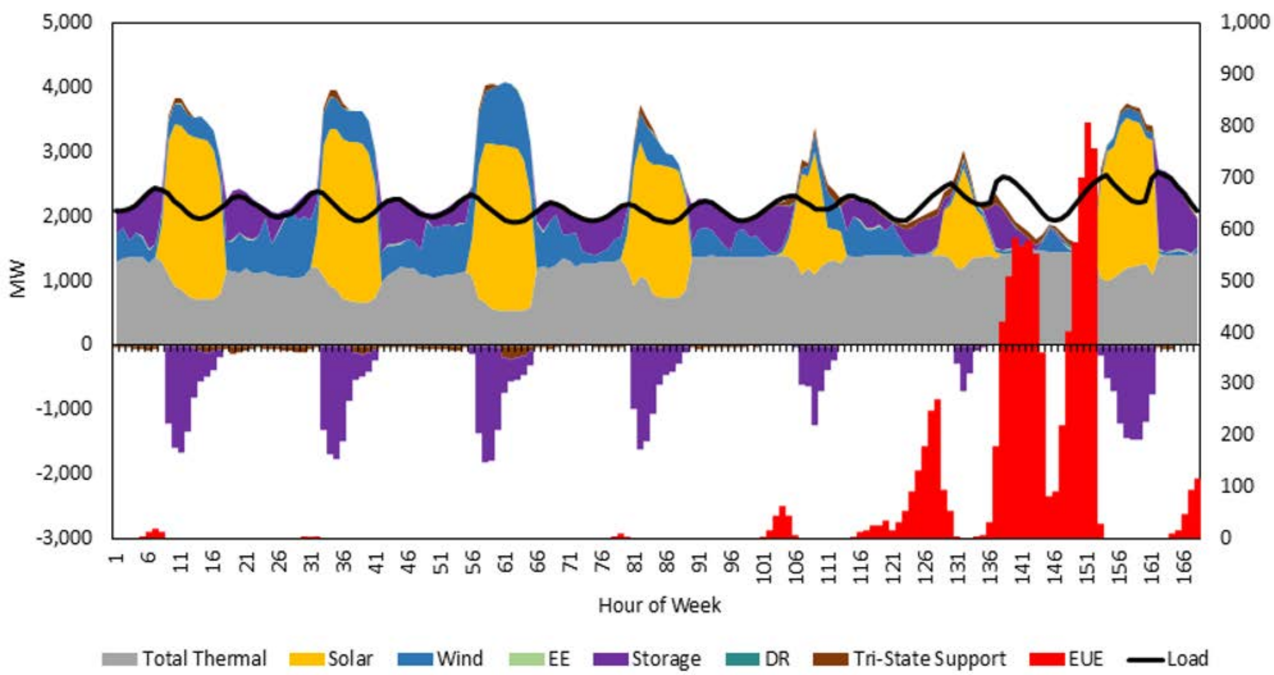

Figure 27: CTP 2040 Winter Interconnected Weekly Dispatch

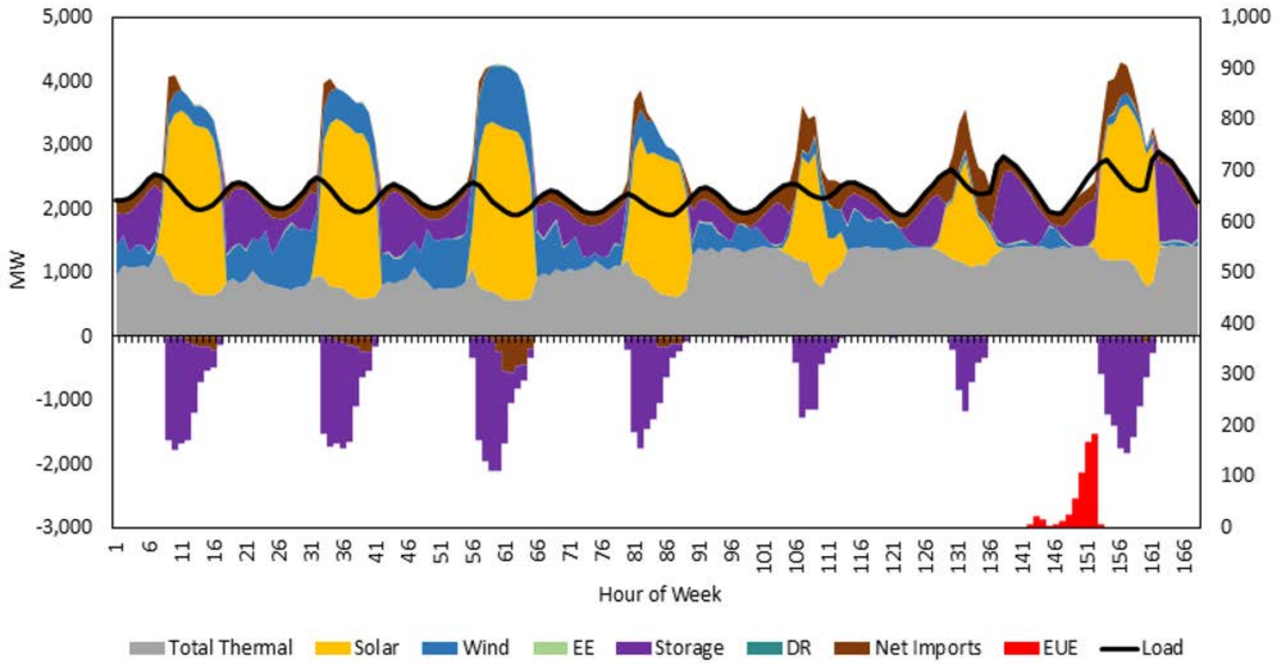

Figure 28: CTP 2040 Winter Islanded Weekly Dispatch

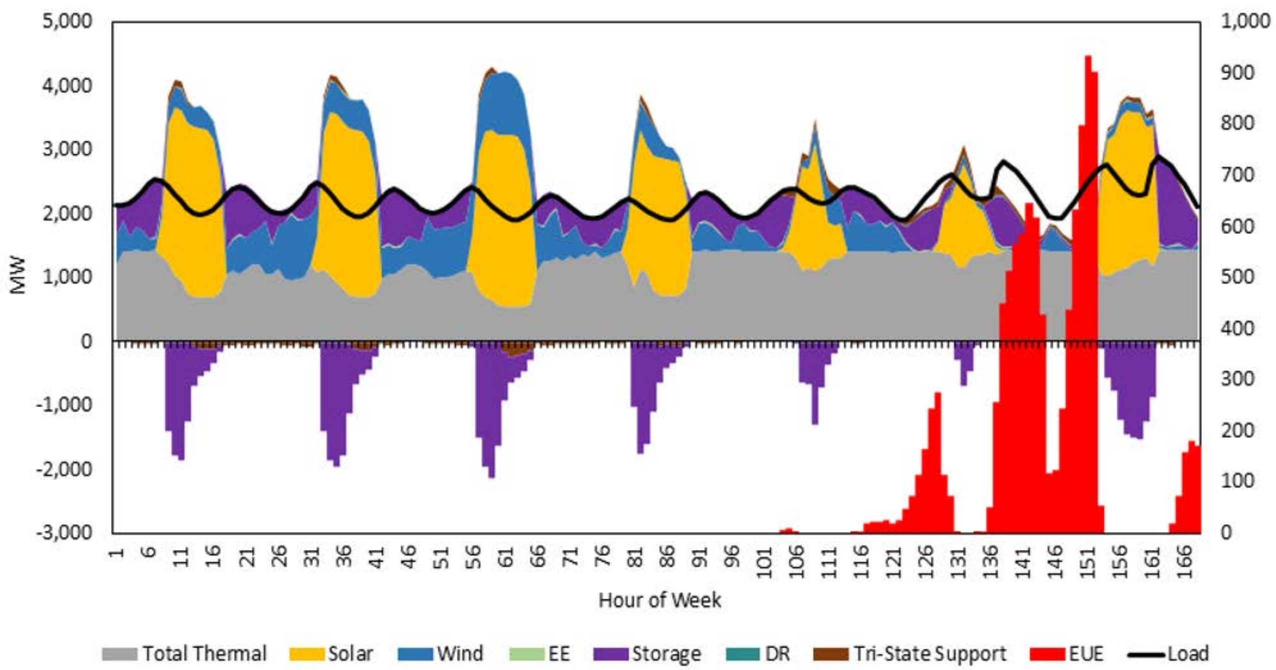

Figure 29: CTP 2045 Winter Interconnected Weekly Dispatch

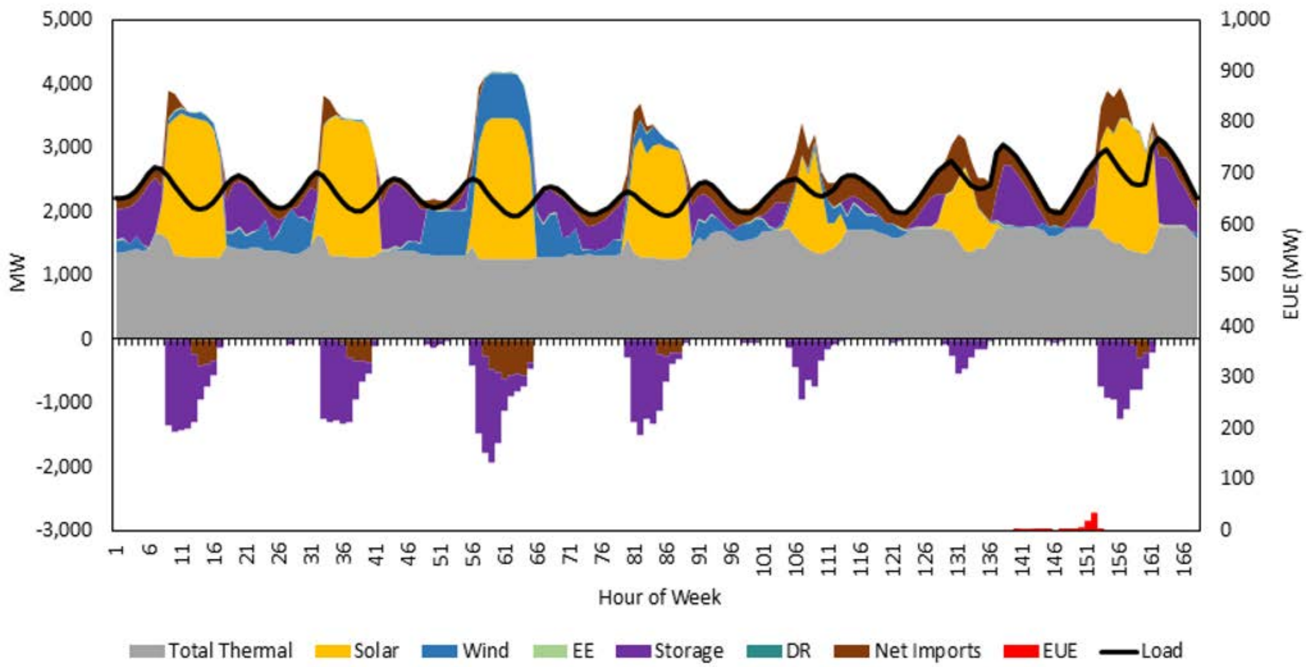

Figure 30: CTP 2045 Winter Islanded Weekly Dispatch

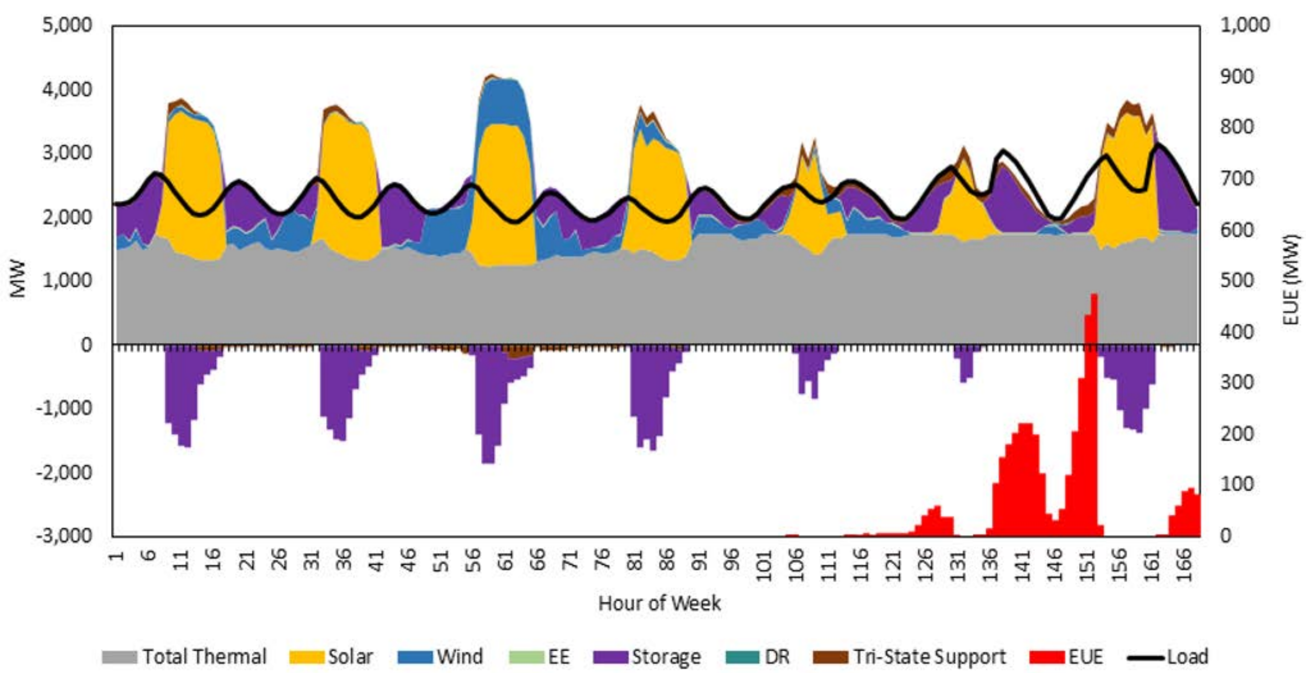

Figure 31: HEG 2036 Summer Interconnected Weekly Dispatch

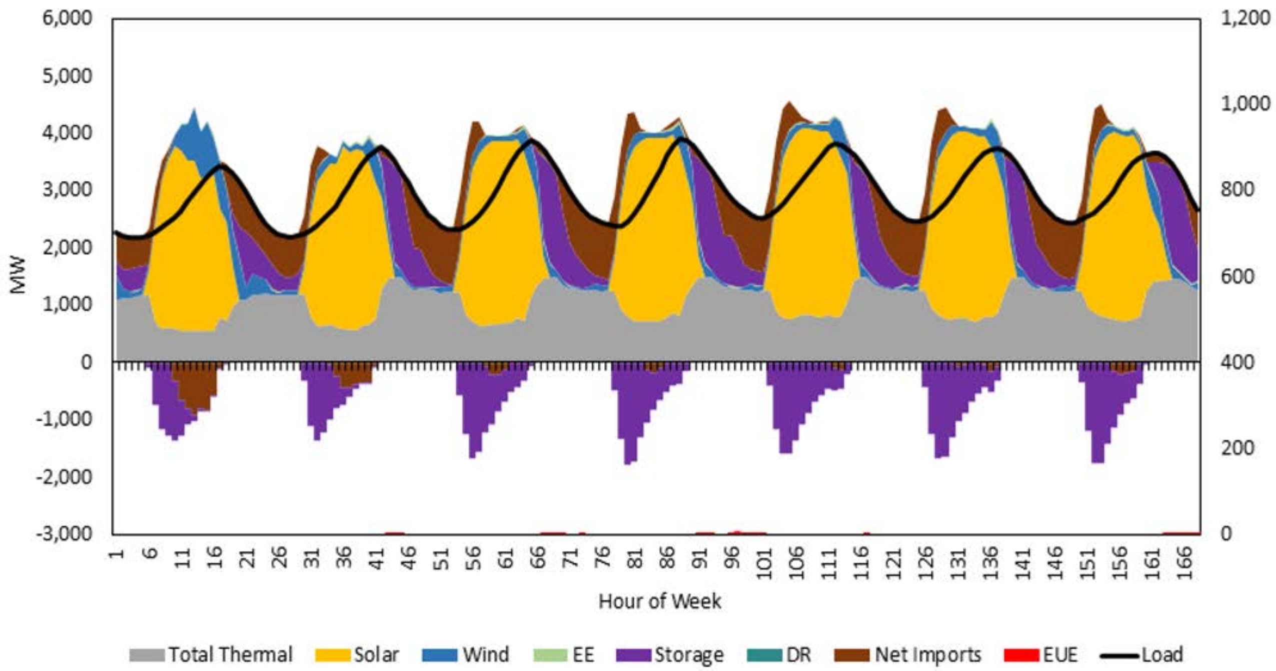

Figure 32: HEG 2036 Summer Islanded Weekly Dispatch

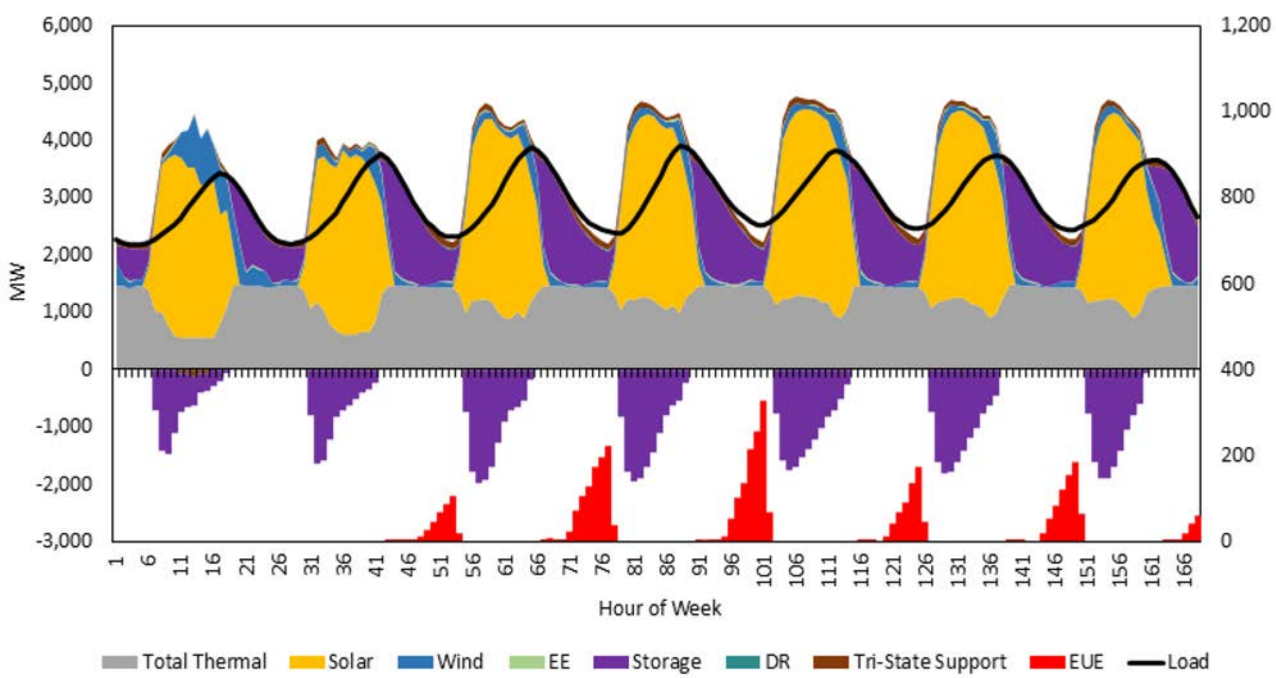

Figure 33: HEG 2040 Summer Interconnected Weekly Dispatch

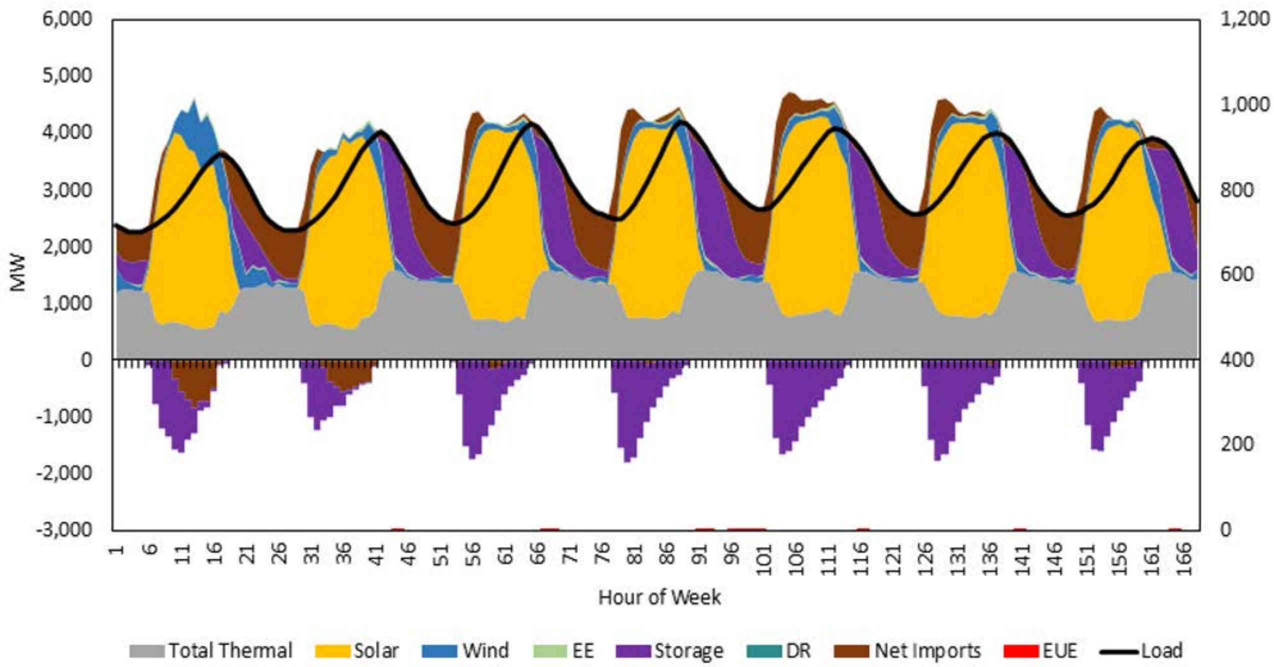

Figure 34: HEG 2040 Summer Islanded Weekly Dispatch

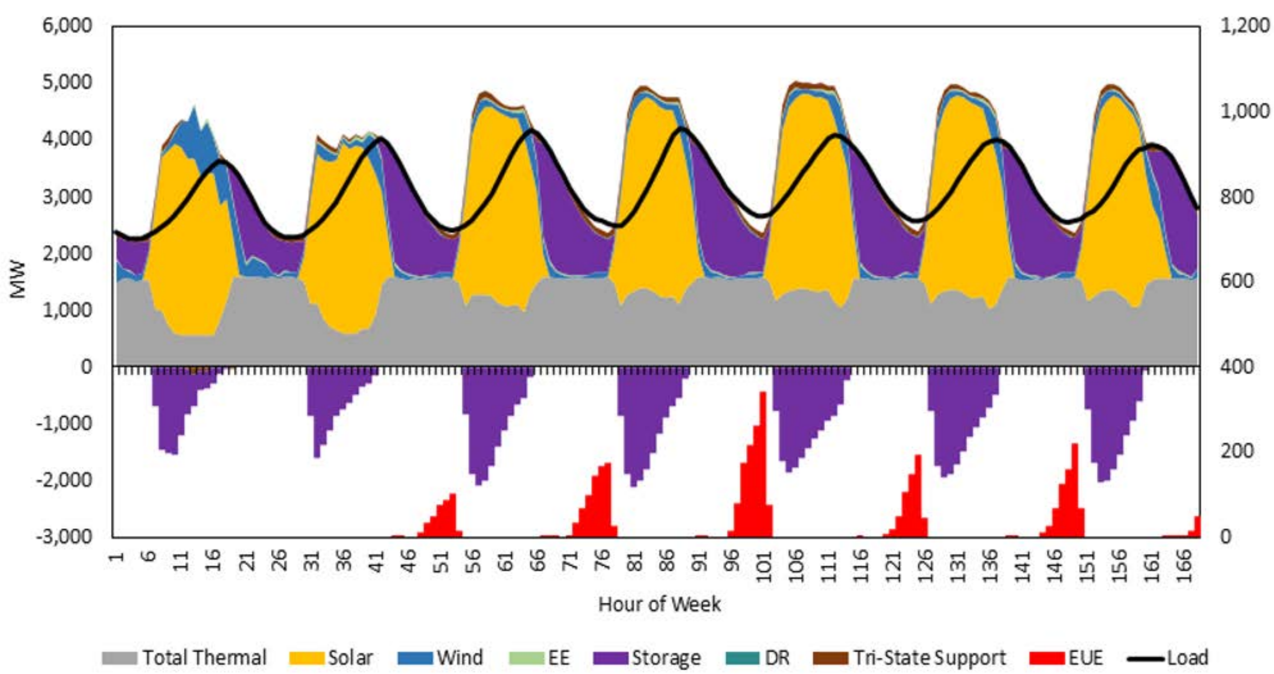

Figure 35: HEG 2045 Summer Interconnected Weekly Dispatch

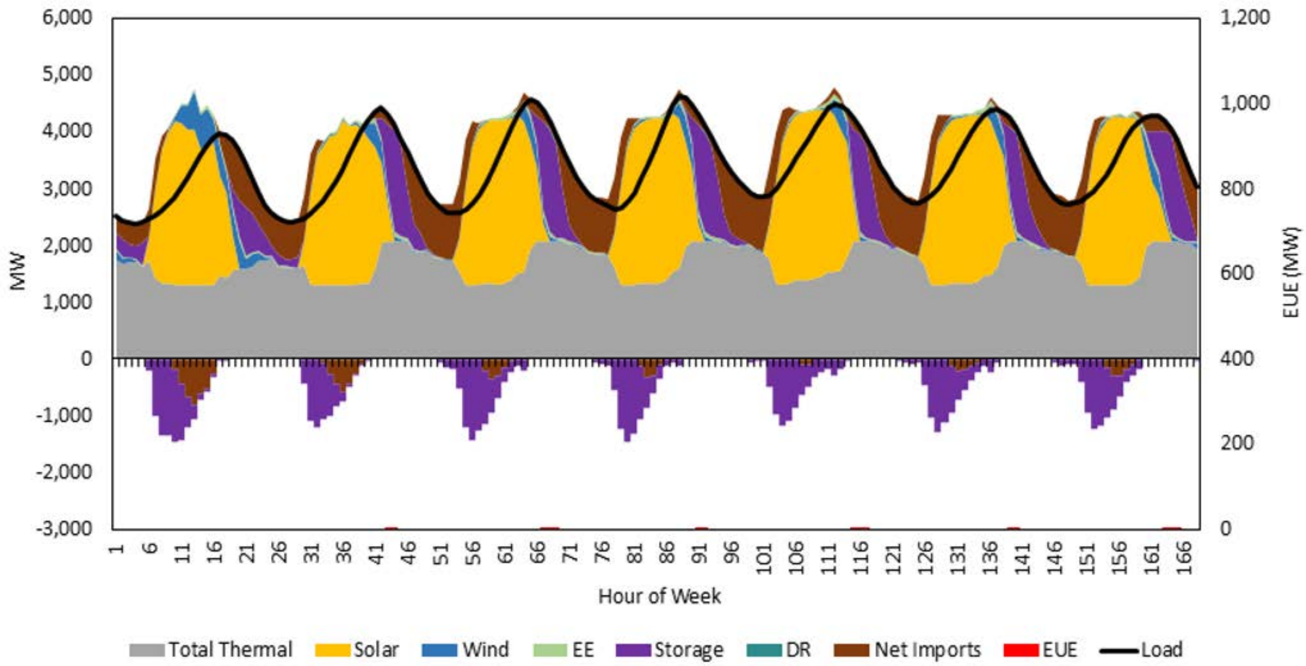

Figure 36: HEG 2045 Summer Islanded Weekly Dispatch

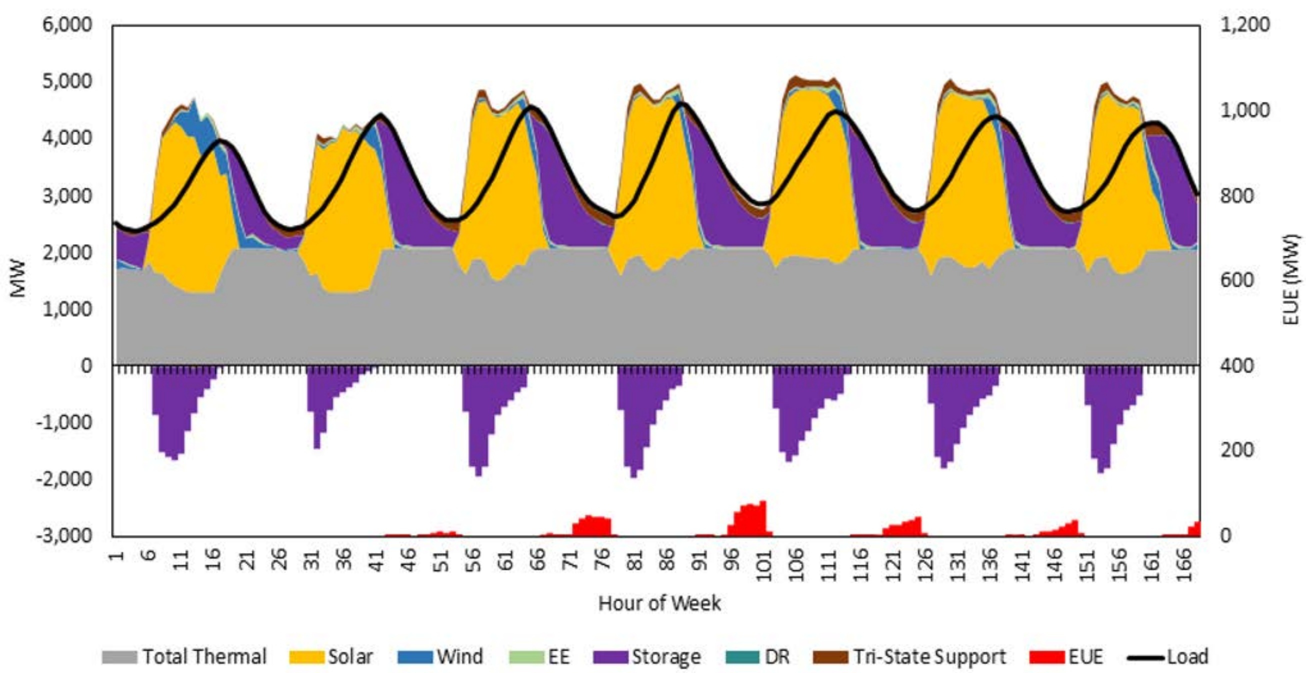

Figure 37: HEG 2036 Winter Interconnected Weekly Dispatch

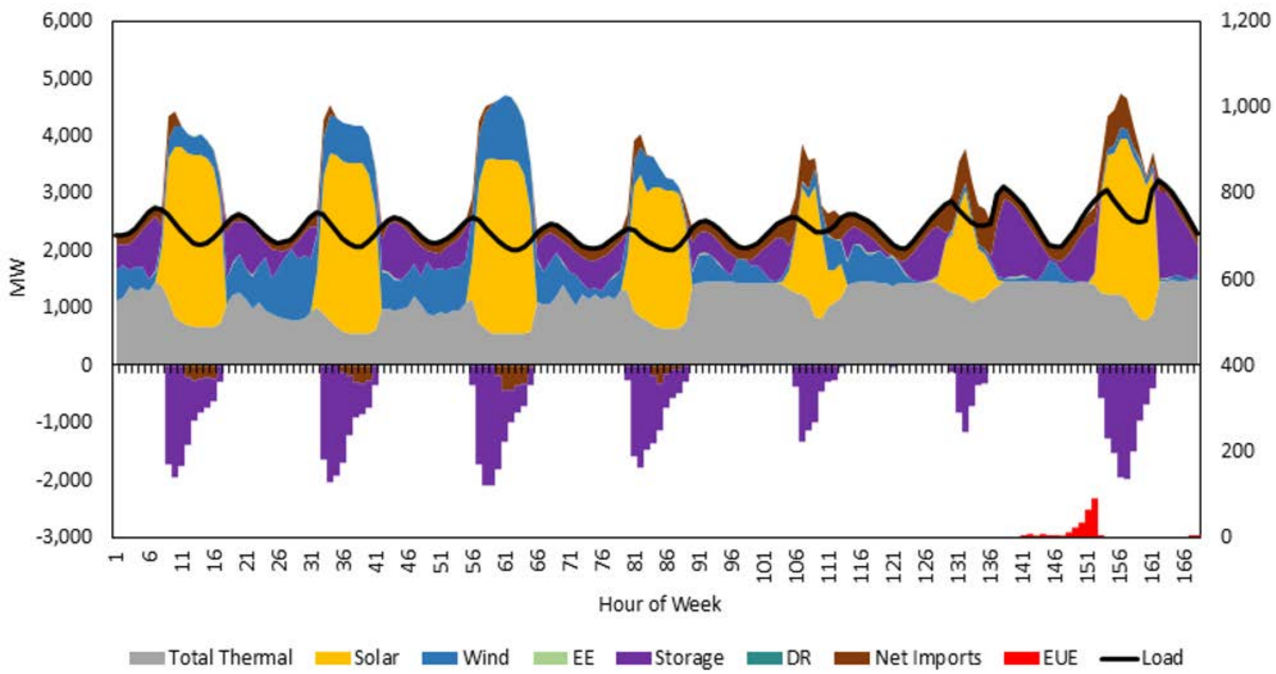

Figure 38: HEG 2036 Winter Islanded Weekly Dispatch

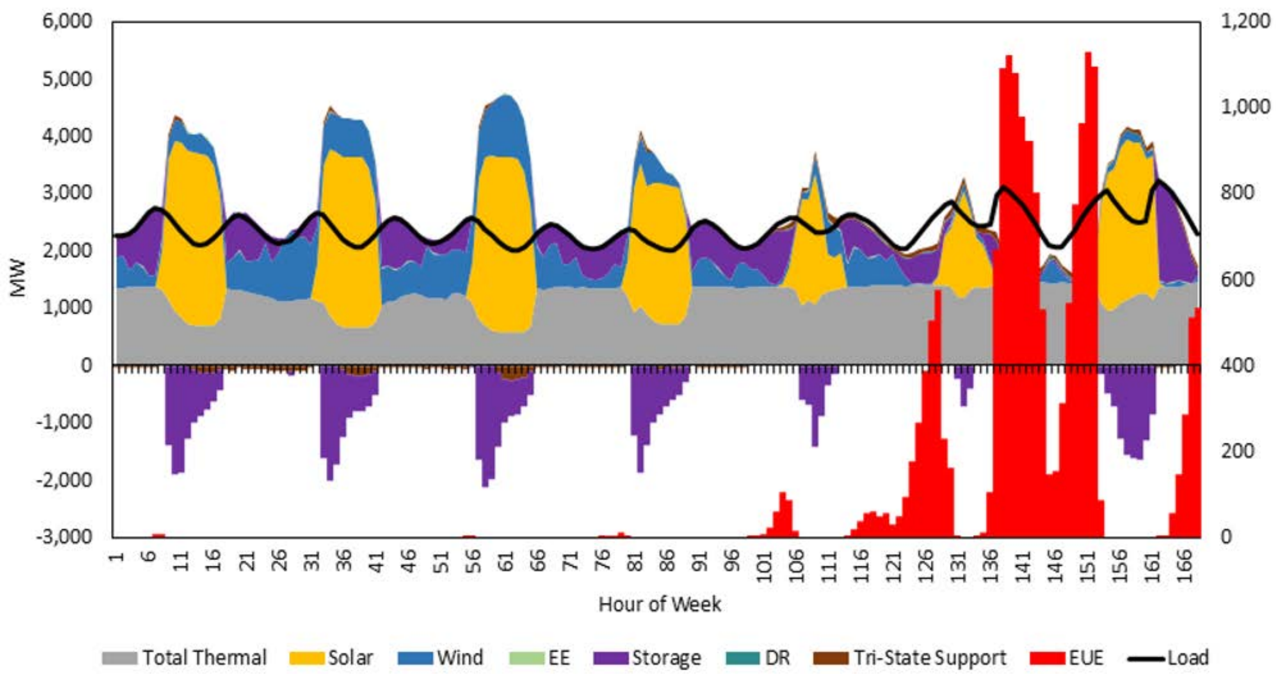

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Figure 39: HEG 2040 Winter Interconnected Weekly Dispatch

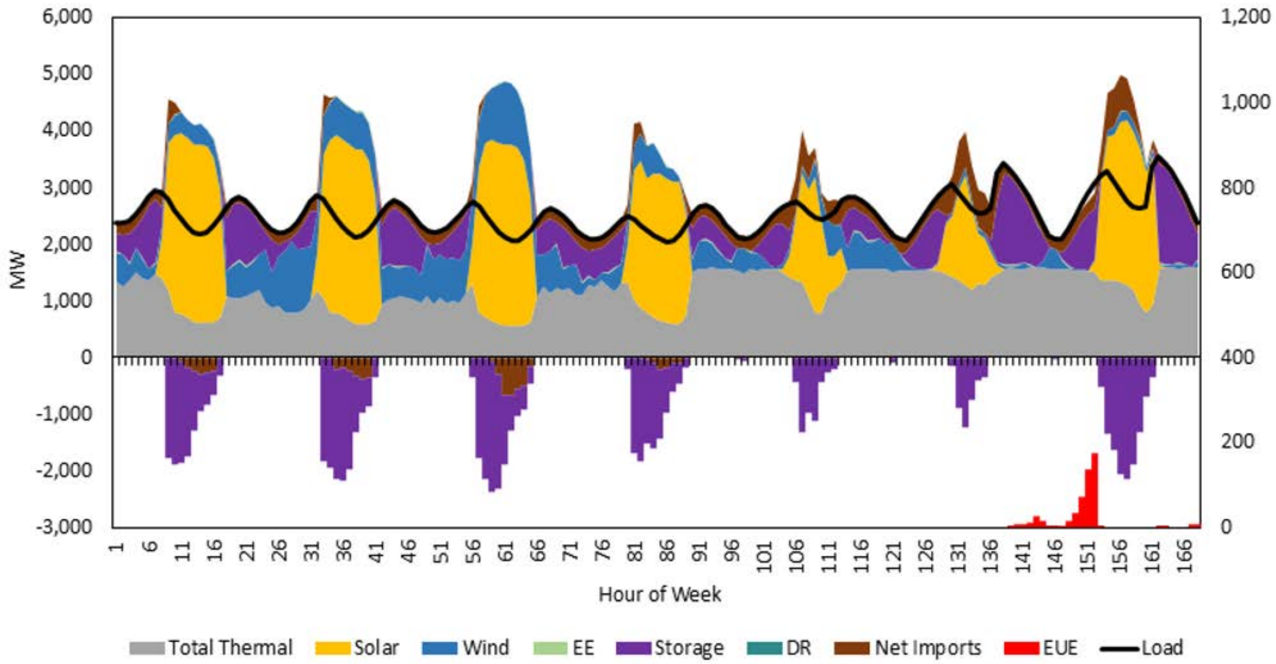


Figure 40: HEG 2040 Winter Islanded Weekly Dispatch

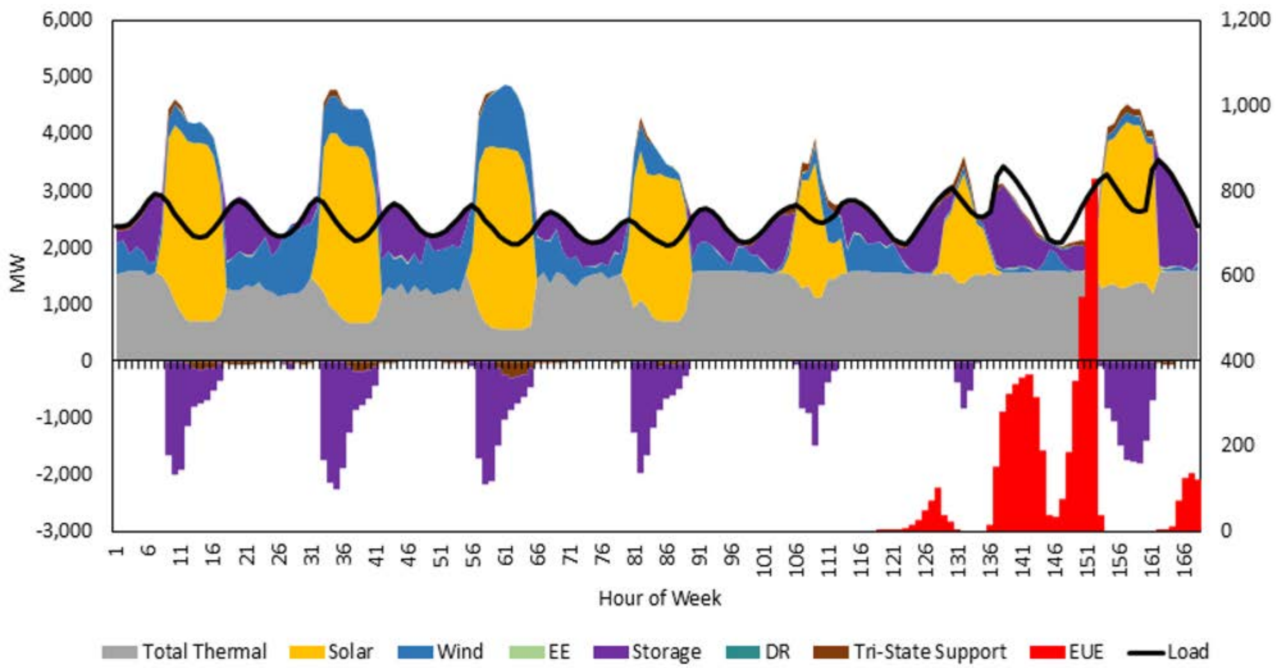


Figure 41: HEG 2045 Winter Interconnected Weekly Dispatch

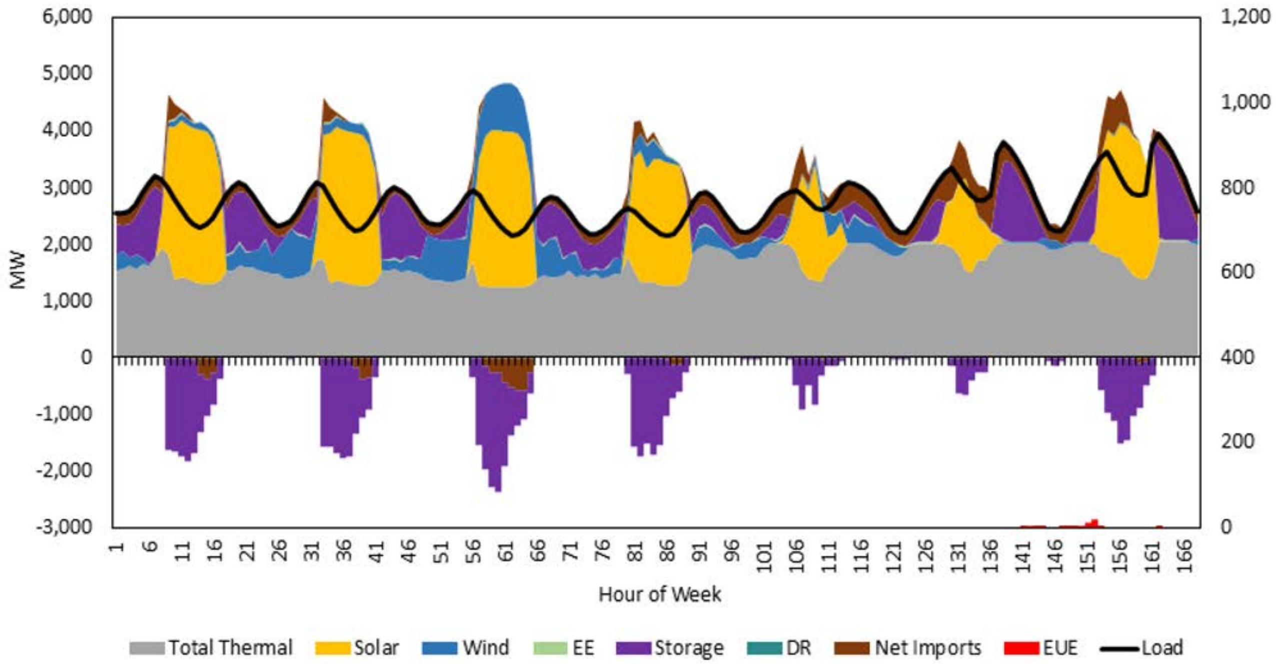
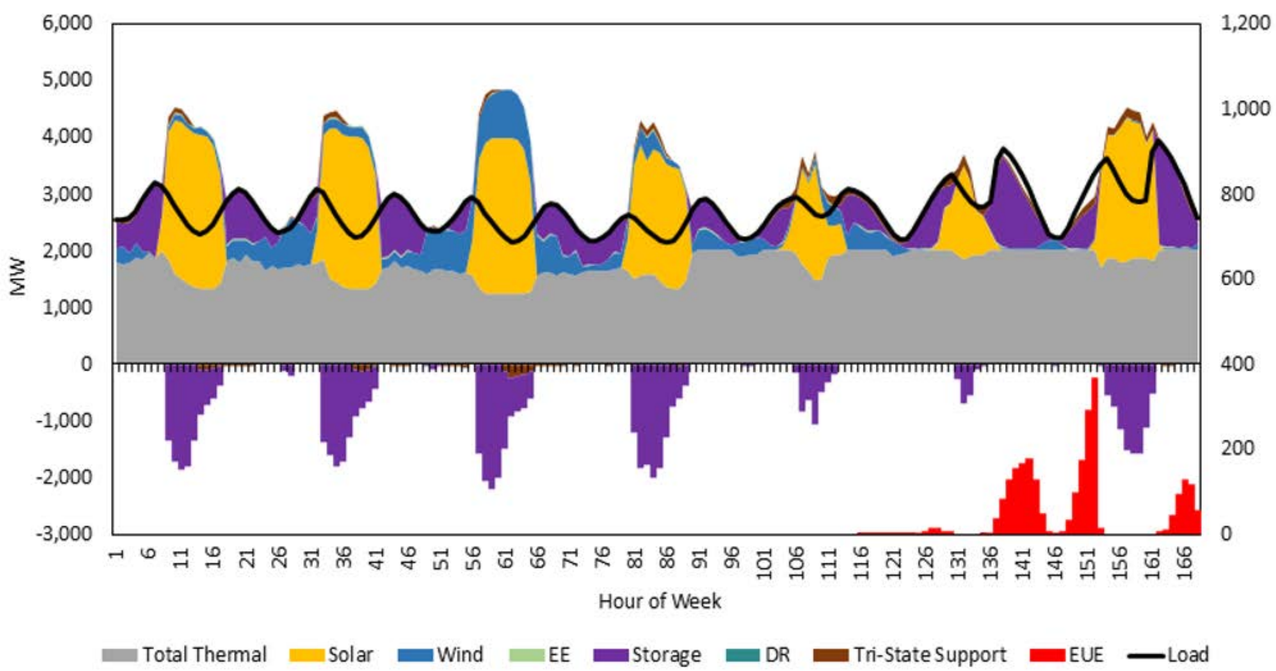


Figure 42: HEG 2045 Winter Islanded Weekly Dispatch



APPENDIX N: SUMMARY RESULTS FOR EACH PORTFOLIO

This appendix provides detailed summaries of the results of each scenario modeled in a standardized and consistent format.

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Portfolio Summary

Scenario Information

Scenario: *CTP P2 8760*
Future: *CTP*
Sensitivity: *Current Trends & Policies base case*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.327	B$
20-Year Carbon Emissions	42.055	M Tons
20-Year Water Consumption	7.292	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	20.88	20.28	18.37	18.16	17.62	17.25	16.38	14.40	14.40	14.40	14.48	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	199	198	198	198	197	197	197	198	170	149	122	-
Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,315	1,319	1,356	1,371	1,395	1,405	1,436	1,448	1,684	1,854	1,947	2,322	3,146
Carbon Emission	k-tons	2,602	2,912	2,892	3,000	3,315	2,975	1,902	1,915	1,927	1,931	1,947	1,965	1,963	1,991	2,017	2,069	1,795	1,595	1,340	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	287	287	287	286	287	285	282	270	293	279	264	267	109

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,776	2,779	2,858	2,910	2,947	2,956	3,068	3,053	3,041	3,010	2,998	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,285	2,392	2,428	2,580	2,462	2,248
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	160	160	160	160	160
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,476**	**8,508**	**8,512**	**8,588**	**8,651**	**8,685**	**8,824**	**8,775**	**9,032**	**8,849**	**9,105**	**9,060**	**7,826**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,693	7,951	7,964	8,197	8,358	8,462	8,487	8,809	8,788	8,695	8,661	8,497	7,632	6,740
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,736	4,741	4,738	4,753	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	48	56	47	49	36	41	54	43	40	30	10	8	7	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,876	2,701	2,801	2,726	2,813	2,792	2,657	2,753	2,641	2,835	2,722	2,455	2,340	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,014	1,150	1,109	1,169	1,151	1,189	1,262	1,249	972	859	588	475	251	72
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	573	672	572	533	374	363
Total Generation	**GWh**	**13,902**	**15,173**	**16,032**	**19,662**	**20,329**	**20,843**	**19,624**	**19,814**	**19,994**	**20,098**	**20,316**	**20,553**	**20,595**	**20,937**	**21,157**	**21,630**	**21,820**	**22,218**	**22,746**	**21,568**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**748**	**768**	**752**	**748**	**755**	**708**	**745**	**719**	**649**	**447**	**397**	**287**	**132**	**635**
Market Sales	**GWh**	**2,201**	**1,867**	**1,424**	**1,336**	**1,497**	**1,790**	**944**	**978**	**1,015**	**936**	**997**	**1,000**	**964**	**1,043**	**1,096**	**1,268**	**1,347**	**1,523**	**1,795**	**1,027**
Net Generation *	**GWh**	**13,643**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,080**	**19,228**	**19,402**	**19,498**	**19,690**	**19,892**	**19,940**	**20,245**	**20,440**	**20,892**	**21,066**	**21,448**	**22,013**	**20,896**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP P2 8760*
Future: *CTP*
Sensitivity: *Current Trends & Policies base case*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.327 B$
20-Year Carbon Emissions 42.055 M Tons
20-Year Water Consumption 7.292 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	111	17	93	66	94	23	125	-	-	-	-	155	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	35	107	36	152	151	237
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**237**	**44**	**121**	**90**	**118**	**47**	**151**	**186**	**317**	**206**	**322**	**623**	**854**

Portfolio Summary

Scenario Information

Scenario: *CTP-CO2 Fed P2 8760*
Future: *CTP*
Sensitivity: *Federal CO2 tax beginning 2030*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.605 B$
20-Year Carbon Emissions 39.501 M Tons
20-Year Water Consumption 7.114 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.80	18.98	19.98	20.92	20.30	18.39	18.19	17.62	17.26	16.37	14.80	14.40	14.40	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	313	267	200	199	199	198	198	198	197	197	158	138	118	127	102	-
Revenue Requirement	M$	523	572	693	1,197	1,243	1,325	1,295	1,338	1,345	1,383	1,402	1,427	1,442	1,475	1,525	1,755	1,923	1,979	2,349	3,144
Carbon Emission	k-tons	2,602	2,912	2,892	3,000	3,049	2,676	1,926	1,929	1,935	1,942	1,961	1,964	1,969	1,989	1,650	1,441	1,241	1,325	1,098	-
Water Consumption	k-gallons	569	610	616	610	616	431	295	289	288	287	287	287	286	282	268	255	245	239	241	112

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,512	2,690	2,750	2,817	2,804	2,890	2,952	2,947	2,977	3,064	3,049	3,037	3,005	2,994	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,310	2,347	2,413	2,298	2,140
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	120	120	120
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	200	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,886**	**8,431**	**8,321**	**8,518**	**8,533**	**8,544**	**8,630**	**8,651**	**8,706**	**8,819**	**8,761**	**8,971**	**8,789**	**8,993**	**8,957**	**7,778**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,185	7,704	7,898	8,071	8,035	8,291	8,481	8,460	8,546	8,796	8,765	8,677	8,640	8,484	7,632	6,743
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,737	4,741	4,737	4,752	3,932	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,125	378	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	3,549	4,816	5,965	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	52	88	52	61	51	51	40	43	56	44	38	6	4	4	3	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,761	2,887	2,868	2,690	2,795	2,716	2,799	2,783	2,646	2,747	2,464	2,495	2,311	2,265	2,062	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,117	1,581	1,053	1,174	1,122	1,189	1,178	1,190	1,275	1,248	917	496	312	294	152	104
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	130	110	364	245	313
Total Generation	**GWh**	**13,902**	**15,173**	**16,032**	**19,662**	**20,000**	**20,567**	**19,864**	**19,953**	**20,075**	**20,204**	**20,455**	**20,547**	**20,659**	**20,918**	**21,567**	**21,579**	**21,881**	**21,662**	**22,236**	**21,553**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**383**	**300**	**642**	**710**	**718**	**704**	**701**	**712**	**721**	**728**	**523**	**536**	**445**	**562**	**301**	**646**
Market Sales	**GWh**	**2,201**	**1,867**	**1,424**	**1,336**	**1,282**	**1,565**	**1,062**	**1,048**	**1,055**	**988**	**1,065**	**1,000**	**997**	**1,034**	**1,352**	**1,276**	**1,424**	**1,197**	**1,417**	**957**
Net Generation *	**GWh**	**13,643**	**14,864**	**15,601**	**19,170**	**19,510**	**20,022**	**19,304**	**19,356**	**19,476**	**19,594**	**19,812**	**19,887**	**19,997**	**20,227**	**20,822**	**20,812**	**21,095**	**20,848**	**21,467**	**20,815**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-CO2 Fed P2 8760*
Future: *CTP*
Sensitivity: *Federal CO2 tax beginning 2030*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.605	B$
20-Year Carbon Emissions	39.501	M Tons
20-Year Water Consumption	7.114	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	80	192	74	82	0	101	76	52	43	100	-	-	-	-	160	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	60	36	66	156	291
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	-	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-	80	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	100	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**126**	**557**	**99**	**208**	**27**	**128**	**100**	**76**	**68**	**126**	**177**	**271**	**206**	**270**	**633**	**909**

Portfolio Summary

Scenario Information

Scenario: *CTP-CO2_400thru44 P2 8760*
Future: *CTP*
Sensitivity: *ETA 400 through 2044, zero CO2 by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.188 B$
20-Year Carbon Emissions 48.675 M Tons
20-Year Water Consumption 8.006 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	18.02	17.41	15.70	15.52	14.96	14.59	14.72	14.40	14.48	14.40	14.48	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	262	276	277	274	267	267	257	268	204	183	158	157	120	-

Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,250	1,246	1,255	1,294	1,316	1,340	1,360	1,401	1,490	1,729	1,899	1,982	2,360	3,178
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,315	2,975	2,669	2,829	2,862	2,845	2,779	2,781	2,659	2,795	2,152	1,931	1,688	1,665	1,322	-
Water Consumption	k-gallons	569	610	616	610	647	466	359	372	377	375	368	383	363	368	311	291	281	271	262	109

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,685	2,671	2,763	2,819	2,799	2,790	2,776	2,762	2,750	2,718	2,854	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,272	2,272	2,301	2,597	2,462	2,248
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	80	160	160	160	160	160
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,285**	**8,300**	**8,316**	**8,397**	**8,402**	**8,419**	**8,472**	**8,476**	**8,666**	**8,476**	**8,977**	**9,060**	**7,826**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,693	7,686	7,650	7,919	8,093	8,030	8,004	7,963	7,937	7,846	7,812	8,082	7,632	6,740
Wind	GWh	2,198	2,229	2,197	4,962	4,945	4,974	4,962	4,980	4,956	4,738	4,756	4,737	4,741	4,738	4,753	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	3,549	4,816	5,965	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	118	163	162	168	145	181	165	158	76	17	7	11	5	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	3,109	2,913	3,081	2,939	3,055	3,042	2,846	3,047	2,703	2,781	2,666	2,518	2,315	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,978	2,312	2,240	2,306	2,149	2,124	2,087	2,008	1,239	726	488	518	244	73
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	223	381	620	526	566	369	365
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**20,892**	**21,032**	**21,206**	**21,289**	**21,398**	**21,447**	**21,237**	**21,482**	**21,720**	**21,766**	**22,003**	**21,947**	**22,708**	**21,570**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**222**	**252**	**234**	**266**	**276**	**324**	**439**	**413**	**348**	**344**	**260**	**329**	**130**	**631**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,497**	**1,790**	**1,691**	**1,721**	**1,749**	**1,685**	**1,651**	**1,583**	**1,371**	**1,390**	**1,442**	**1,392**	**1,486**	**1,339**	**1,756**	**1,026**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**20,352**	**20,487**	**20,654**	**20,729**	**20,823**	**20,860**	**20,654**	**20,898**	**21,086**	**21,120**	**21,343**	**21,222**	**21,976**	**20,899**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-CO2_400thru44 P2 8760*
Future: *CTP*
Sensitivity: *ETA 400 through 2044, zero CO2 by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.188	B$
20-Year Carbon Emissions	48.675	M Tons
20-Year Water Consumption	8.006	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	20	-	106	70	36	5	-	-	-	-	147	300	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	22	-	29	297	134	237
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	-	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	80	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**46**	**27**	**133**	**95**	**61**	**29**	**66**	**239**	**251**	**198**	**567**	**751**	**854**

Portfolio Summary

Scenario Information

Scenario: *CTP-HEV P2 8760*
Future: *CTP*
Sensitivity: *High Electric Vehicle forecast impact to CTP*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.989 B$
20-Year Carbon Emissions 43.170 M Tons
20-Year Water Consumption 11.493 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,294	2,531	2,791	3,292	3,363	3,403	3,416	3,504	3,554	3,636	3,676	3,729	3,778	3,848	3,880	3,920	3,938	3,964	4,019	4,098
PRM	%	14.99	14.95	19.15	18.95	17.18	18.04	18.63	19.11	20.54	18.27	17.59	16.57	15.65	15.22	14.45	14.40	14.40	14.49	14.40	14.75
Carbon Intensity	lbs/MWh	382	392	372	314	336	296	200	199	199	199	198	198	198	197	198	199	180	159	128	-
Revenue Requirement	M$	523	573	694	1,201	1,211	1,297	1,288	1,334	1,383	1,420	1,439	1,468	1,486	1,541	1,593	1,853	2,043	2,156	2,559	3,419
Carbon Emission	k-tons	2,604	2,917	2,901	3,012	3,340	3,017	1,923	1,930	1,966	1,990	1,999	2,019	2,027	2,064	2,100	2,145	1,970	1,770	1,475	-
Water Consumption	k-gallons	569	610	617	612	649	472	294	289	603	606	632	631	631	657	636	671	659	638	630	387

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,455	2,491	2,627	2,739	2,819	2,890	3,026	3,057	3,101	3,142	3,256	3,241	3,229	3,198	3,186	3,320	2,701
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,275	2,292	2,506	2,449	2,298
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	240	240	280	280	280	280
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	200	200	200	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,824**	**7,864**	**8,368**	**8,310**	**8,519**	**8,719**	**8,779**	**8,835**	**8,905**	**8,971**	**9,151**	**9,148**	**9,382**	**9,221**	**9,538**	**9,629**	**8,457**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,901	7,124	7,520	7,866	8,076	8,287	8,685	8,786	8,908	9,025	9,355	9,334	9,241	9,207	9,047	8,394	7,504
Wind	GWh	2,198	2,229	2,197	4,962	4,945	4,974	4,962	4,980	4,955	4,738	4,756	4,737	4,741	4,738	4,753	3,932	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,110	1,139	1,171	396	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	81	81	38	72	137	49	59	47	48	40	45	63	37	20	22	8	6	7	-
Gas Combined Cycle	GWh	2,610	2,826	2,680	2,821	2,851	3,013	2,879	2,701	2,818	2,740	2,831	2,814	2,671	2,772	2,640	2,841	2,768	2,486	2,387	-
Gas/Hydrogen Turbine	GWh	527	871	899	1,004	1,415	1,937	1,044	1,171	1,160	1,253	1,218	1,254	1,345	1,224	759	759	539	450	236	72
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	190	1,086	987	988	935	652	664
Total Generation	**GWh**	**13,906**	**15,181**	**16,045**	**19,707**	**20,390**	**20,934**	**19,831**	**19,964**	**20,384**	**20,683**	**20,833**	**21,093**	**21,239**	**21,661**	**21,983**	**22,390**	**22,778**	**23,175**	**23,818**	**22,633**
Market Purchases	**GWh**	**41**	**121**	**323**	**308**	**278**	**242**	**741**	**813**	**727**	**675**	**735**	**716**	**752**	**728**	**652**	**533**	**438**	**339**	**170**	**688**
Market Sales	**GWh**	**2,199**	**1,859**	**1,410**	**1,329**	**1,480**	**1,762**	**963**	**945**	**1,060**	**1,047**	**1,029**	**1,008**	**983**	**1,057**	**1,118**	**1,191**	**1,342**	**1,446**	**1,704**	**838**
Net Generation *	**GWh**	**13,648**	**14,872**	**15,614**	**19,215**	**19,902**	**20,402**	**19,275**	**19,369**	**19,748**	**20,022**	**20,153**	**20,381**	**20,523**	**20,909**	**21,211**	**21,572**	**21,952**	**22,340**	**22,993**	**21,843**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-HEV P2 8760*
Future: *CTP*
Sensitivity: *High Electric Vehicle forecast impact to CTP*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.989 B$
20-Year Carbon Emissions 43.170 M Tons
20-Year Water Consumption 11.493 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	137	50	150	126	94	85	150	45	101	54	128	-	-	-	-	229	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	25	17	214	213	299
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	200	-	40	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,419**	**96**	**515**	**151**	**221**	**212**	**178**	**69**	**125**	**79**	**194**	**231**	**295**	**227**	**384**	**759**	**917**

Portfolio Summary

Scenario Information

Scenario: *CTP-LateLDES P2 8760*
Future: *CTP*
Sensitivity: *Late Long Duration Energy Storage available beginning 2036*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.290	B$
20-Year Carbon Emissions	42.016	M Tons
20-Year Water Consumption	7.321	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	18.15	17.57	15.78	15.60	15.10	14.75	15.97	14.40	14.55	14.40	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	198	198	198	197	197	196	188	198	173	150	121	-
Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,278	1,288	1,327	1,344	1,371	1,382	1,448	1,494	1,713	1,871	1,960	2,338	3,173
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,315	2,975	1,902	1,904	1,913	1,930	1,948	1,972	1,971	1,988	2,014	2,047	1,810	1,598	1,323	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	287	286	286	286	287	284	268	291	297	285	271	270	112

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,743	2,738	2,855	2,915	2,970	2,982	3,021	3,006	2,994	2,962	2,951	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,269	2,417	2,298	2,140
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	80	80	120	120	120	120	120
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,343**	**8,367**	**8,409**	**8,493**	**8,573**	**8,611**	**8,756**	**8,698**	**8,902**	**8,702**	**8,954**	**8,957**	**7,778**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,693	7,854	7,846	8,188	8,372	8,523	8,560	8,670	8,635	8,558	8,524	8,362	7,632	6,743
Wind	GWh	2,198	2,229	2,197	4,962	4,945	4,974	4,962	4,980	4,956	4,738	4,756	4,737	4,741	4,738	4,752	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	3,549	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	48	58	48	51	39	44	54	26	56	36	16	16	7	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,876	2,699	2,797	2,718	2,806	2,785	2,647	2,750	2,605	2,842	2,750	2,468	2,336	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,014	1,131	1,090	1,171	1,155	1,201	1,280	998	1,128	936	678	545	288	104
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	376	356	497	443	421	292	313
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**19,624**	**19,699**	**19,853**	**20,084**	**20,329**	**20,624**	**20,676**	**20,903**	**22,162**	**21,409**	**21,677**	**22,061**	**22,697**	**21,553**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**748**	**820**	**822**	**758**	**761**	**692**	**724**	**734**	**290**	**547**	**471**	**345**	**145**	**646**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,498**	**1,790**	**944**	**947**	**968**	**949**	**1,035**	**1,092**	**1,048**	**1,069**	**1,780**	**1,128**	**1,261**	**1,396**	**1,708**	**957**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,080**	**19,146**	**19,285**	**19,501**	**19,721**	**20,000**	**20,045**	**20,255**	**21,482**	**20,652**	**20,906**	**21,264**	**21,914**	**20,815**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-LateLDES P2 8760*
Future: *CTP*
Sensitivity: *Late Long Duration Energy Storage available beginning 2036*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.290	B$
20-Year Carbon Emissions	42.016	M Tons
20-Year Water Consumption	7.321	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	78	10	131	74	111	26	52	-	-	-	-	203	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	-	19	148	152	291
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	-	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	80	-	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**104**	**36**	**158**	**98**	**136**	**51**	**158**	**177**	**265**	**188**	**318**	**672**	**909**

Portfolio Summary

Scenario Information

Scenario: *CTP-NoETA P2 8760*
Future: *CTP*
Sensitivity: *No CO2 emission limits, No RPS, No CO2 free by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	13.703	B$
20-Year Carbon Emissions	51.460	M Tons
20-Year Water Consumption	12.231	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.16	18.25	19.25	17.48	19.52	17.62	17.42	16.83	16.48	15.52	14.76	15.65	14.40	16.11	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	335	293	263	276	267	265	256	258	243	253	237	208	212	185	175	170
Revenue Requirement	M$	523	572	693	1,197	1,197	1,280	1,243	1,240	1,294	1,325	1,344	1,365	1,385	1,406	1,435	1,632	1,690	1,749	2,021	2,333
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,320	2,979	2,673	2,830	2,769	2,764	2,681	2,700	2,532	2,655	2,448	2,128	2,137	1,894	1,791	1,753
Water Consumption	k-gallons	569	610	616	610	647	466	359	372	655	654	674	694	671	726	676	656	661	655	654	605

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,689	2,781	2,865	2,929	2,892	2,938	2,924	2,909	2,897	2,930	2,918	3,110	2,471
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	2	5	10	12	14	15	15	15	16	16	16	16	17	17	17	19
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,130	2,047
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	434	580	726	872
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	666	666	666	666	666	666
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,826**	**8,330**	**8,221**	**8,260**	**8,479**	**8,488**	**8,577**	**8,565**	**8,636**	**8,648**	**8,621**	**8,730**	**8,429**	**8,533**	**8,472**	**7,778**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,877	7,100	7,497	7,693	7,699	7,969	8,217	8,412	8,302	8,433	8,393	8,371	8,277	8,430	8,267	7,783	6,838
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,737	4,741	4,738	4,753	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	2	6	12	16	18	19	20	20	21	21	21	22	22	22	22	22
Coal	GWh	1,090	1,073	1,109	1,139	1,171	396	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	3,491	4,807	6,063	7,042
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	69	128	119	164	140	143	110	149	135	150	102	36	36	28	21	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	3,109	2,911	3,074	2,946	3,041	3,033	2,817	3,011	2,817	2,897	2,931	2,636	2,738	2,628
Gas/Hydrogen Turbine	GWh	525	866	891	990	1,391	1,899	1,983	2,314	2,125	2,202	2,046	2,039	1,943	1,976	1,895	1,401	1,393	1,215	974	1,023
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,323**	**20,838**	**20,886**	**21,033**	**21,368**	**21,453**	**21,555**	**21,581**	**21,451**	**21,601**	**21,317**	**21,139**	**20,808**	**21,148**	**21,165**	**21,158**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**269**	**235**	**223**	**251**	**202**	**230**	**236**	**288**	**379**	**394**	**534**	**623**	**807**	**725**	**766**	**744**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,495**	**1,786**	**1,688**	**1,722**	**1,832**	**1,766**	**1,716**	**1,636**	**1,464**	**1,430**	**1,221**	**1,036**	**841**	**975**	**932**	**871**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,837**	**20,309**	**20,349**	**20,488**	**20,769**	**20,846**	**20,928**	**20,949**	**20,806**	**20,957**	**20,680**	**20,484**	**20,150**	**20,462**	**20,517**	**20,630**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-NoETA P2 8760*
Future: *CTP*
Sensitivity: *No CO2 emission limits, No RPS, No CO2 free by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	13.703	B$
20-Year Carbon Emissions	51.460	M Tons
20-Year Water Consumption	12.231	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	50	150	74	24	105	99	77	20	59	-	-	-	64	-	286	280
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	16	-	-	-	-	-	-	-	-	-	1	-	-	-	-	2
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	-	-	-	150	367
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	-	146	146	146
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	179	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**66**	**515**	**100**	**51**	**232**	**124**	**102**	**45**	**83**	**26**	**207**	**171**	**88**	**170**	**607**	**820**

Portfolio Summary

Scenario Information

Scenario: *CTP-NoNewGas P2 8760*
Future: *CTP*
Sensitivity: *Remove all new gas fired resource candidates*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.370	B$
20-Year Carbon Emissions	40.985	M Tons
20-Year Water Consumption	7.361	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	20.88	20.28	18.37	18.16	17.73	17.49	16.58	15.01	14.40	14.40	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	199	198	198	197	197	196	183	159	136	142	108	-
Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,315	1,319	1,356	1,371	1,398	1,411	1,439	1,482	1,718	1,885	1,946	2,323	3,151
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,315	2,975	1,902	1,915	1,927	1,931	1,947	1,956	1,978	1,972	1,947	1,683	1,448	1,500	1,182	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	287	287	287	286	287	287	281	305	292	276	279	264	132

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,776	2,779	2,858	2,910	2,854	2,888	2,874	2,860	2,848	2,816	2,854	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,414	1,451	1,470	1,470	1,470	1,164	1,164	914	930
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,408	2,445	2,464	2,336	2,162
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	300	300	300
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,476**	**8,508**	**8,512**	**8,588**	**8,616**	**8,712**	**8,744**	**8,686**	**8,954**	**8,772**	**8,998**	**9,089**	**7,909**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,693	7,951	7,964	8,197	8,358	8,190	8,288	8,248	8,221	8,131	8,097	8,084	7,635	6,745
Wind	GWh	2,198	2,229	2,197	4,962	4,945	4,974	4,962	4,980	4,956	4,738	4,756	4,937	5,066	5,130	5,147	4,325	3,956	3,736	3,150	3,191
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	3,549	4,816	5,965	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	48	56	47	49	36	41	56	38	79	29	9	22	8	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,876	2,701	2,801	2,726	2,813	2,800	2,668	2,780	2,624	2,695	2,574	2,484	2,242	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,014	1,150	1,109	1,169	1,151	1,170	1,274	1,205	1,233	815	540	669	332	279
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**19,624**	**19,814**	**19,994**	**20,098**	**20,316**	**20,470**	**20,747**	**20,747**	**21,933**	**21,839**	**22,117**	**21,903**	**22,754**	**21,862**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**748**	**768**	**752**	**748**	**755**	**721**	**653**	**753**	**304**	**331**	**238**	**370**	**121**	**572**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,497**	**1,790**	**944**	**978**	**1,015**	**936**	**997**	**960**	**1,036**	**943**	**1,535**	**1,372**	**1,490**	**1,265**	**1,694**	**1,097**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,080**	**19,228**	**19,402**	**19,498**	**19,690**	**19,838**	**20,104**	**20,111**	**21,224**	**21,113**	**21,369**	**21,108**	**21,924**	**21,029**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-NoNewGas P2 8760*
Future: *CTP*
Sensitivity: *Remove all new gas fired resource candidates*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.370	B$
20-Year Carbon Emissions	40.985	M Tons
20-Year Water Consumption	7.361	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	111	17	93	66	-	48	-	-	-	-	49	300	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	58	36	20	-	-	-	-	-	15
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	158	36	19	142	276
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	-	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	200	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**237**	**44**	**121**	**90**	**83**	**109**	**46**	**177**	**329**	**206**	**292**	**759**	**908**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS ETA Step Down 8760*
Future: *CTP*
Sensitivity: *Smooth out' the acquisition of new clean firm resources*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.676 B$
20-Year Carbon Emissions 34.211 M Tons
20-Year Water Consumption 6.604 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.16	18.25	19.25	21.30	20.69	19.10	18.89	18.33	21.87	20.88	15.43	17.33	17.03	14.48	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	335	293	199	199	199	154	154	153	109	109	109	65	65	65	65	-
Revenue Requirement	M$	523	572	693	1,197	1,201	1,284	1,269	1,336	1,336	1,402	1,412	1,432	1,568	1,590	1,523	1,862	2,011	1,985	2,294	3,075
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,320	2,979	1,901	1,938	1,947	1,509	1,524	1,541	1,114	1,119	1,126	686	711	700	688	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	289	290	243	246	247	205	207	211	174	189	187	193	111

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,846	2,840	3,112	3,177	3,229	3,216	3,282	3,281	3,269	3,238	3,226	3,213	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,103	1,103	853	853
Demand Response	MW	70	70	70	70	2	5	10	12	14	15	15	15	16	16	18	20	21	21	21	21
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,656	2,656	2,656	2,656	2,656	2,656	2,656	2,656	2,656	2,656	2,657	2,424	2,166
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	434	434	434	726	872	872	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	120
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,826**	**8,330**	**8,221**	**8,822**	**8,845**	**9,094**	**9,184**	**9,261**	**9,419**	**9,511**	**9,322**	**9,578**	**9,359**	**9,419**	**9,219**	**7,827**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,877	7,100	7,497	7,693	8,153	8,141	8,934	9,135	9,277	9,234	9,419	9,438	9,299	9,219	9,106	8,077	6,743
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,922	4,940	4,920	4,924	4,920	4,935	4,108	3,748	3,527	2,941	2,930
Demand Response	GWh	29	29	29	29	2	6	12	16	18	19	20	20	21	21	22	22	22	22	22	22
Coal	GWh	1,090	1,073	1,109	1,139	1,171	396	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	3,572	3,462	3,549	6,053	7,201	7,281	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	69	128	48	57	47	19	15	15	4	3	6	1	1	1	0	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,874	2,705	2,814	2,484	2,583	2,569	2,154	2,181	2,137	1,536	1,579	1,534	1,490	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,391	1,899	1,013	1,181	1,131	695	653	692	295	287	332	38	49	59	25	78
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	67	287
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,323**	**20,838**	**19,609**	**20,041**	**20,194**	**20,260**	**20,516**	**20,794**	**21,229**	**21,380**	**21,465**	**22,051**	**22,760**	**22,361**	**21,974**	**21,672**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**269**	**235**	**755**	**622**	**648**	**748**	**732**	**693**	**572**	**623**	**622**	**475**	**221**	**453**	**495**	**614**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,495**	**1,786**	**938**	**1,055**	**1,102**	**1,025**	**1,107**	**1,179**	**1,349**	**1,333**	**1,340**	**1,673**	**2,057**	**1,719**	**1,291**	**1,035**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,837**	**20,309**	**19,067**	**19,451**	**19,593**	**19,586**	**19,822**	**20,086**	**20,499**	**20,631**	**20,711**	**21,270**	**21,952**	**21,478**	**21,147**	**20,925**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS ETA Step Down 8760*
Future: *CTP*
Sensitivity: *Smooth out' the acquisition of new clean firm resources*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.676	B$
20-Year Carbon Emissions	34.211	M Tons
20-Year Water Consumption	6.604	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	50	150	74	181	8	286	79	109	-	80	15	-	-	-	81	146
Wind	MW	-	-	-	800	-	-	-	-	-	53	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	16	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	406	-	-	-	-	-	-	-	-	-	1	37	193
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	146	-	-	292	146	-	146	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**66**	**515**	**100**	**613**	**35**	**365**	**103**	**133**	**171**	**106**	**46**	**317**	**170**	**125**	**469**	**696**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS Geo 8760*
Future: *CTP*
Sensitivity: *At most one 50MW conventional geothermal, and unlimited 50MW EGS can be selected*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.327	B$
20-Year Carbon Emissions	41.998	M Tons
20-Year Water Consumption	7.312	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	20.88	20.28	18.37	18.16	17.62	17.25	16.38	14.40	14.89	14.58	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	199	198	198	198	197	197	197	198	170	148	121	-
Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,315	1,319	1,356	1,371	1,395	1,405	1,436	1,448	1,695	1,853	1,939	2,315	3,152
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,315	2,975	1,902	1,915	1,927	1,931	1,947	1,965	1,963	1,991	2,017	2,060	1,782	1,575	1,325	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	287	287	287	286	287	285	282	270	298	282	268	270	112

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,776	2,779	2,858	2,910	2,947	2,956	3,068	3,053	3,041	3,010	2,998	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,285	2,285	2,285	2,412	2,298	2,140
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	120	120	120	120	120
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	200	200	200	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,476**	**8,508**	**8,512**	**8,588**	**8,651**	**8,685**	**8,824**	**8,775**	**8,985**	**8,766**	**8,997**	**8,957**	**7,778**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,693	7,951	7,964	8,197	8,358	8,462	8,487	8,809	8,787	8,695	8,661	8,497	7,632	6,743
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,736	4,741	4,738	4,753	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	48	56	47	49	36	41	54	43	40	38	15	15	8	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,876	2,701	2,801	2,726	2,813	2,792	2,657	2,752	2,642	2,841	2,722	2,438	2,336	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,014	1,150	1,109	1,169	1,151	1,189	1,262	1,250	971	947	658	535	288	104
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	572	509	436	413	295	313
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**19,624**	**19,814**	**19,994**	**20,098**	**20,316**	**20,553**	**20,595**	**20,937**	**21,157**	**21,570**	**21,761**	**22,149**	**22,701**	**21,553**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**748**	**768**	**752**	**748**	**755**	**708**	**745**	**720**	**649**	**494**	**450**	**332**	**147**	**646**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,497**	**1,790**	**944**	**978**	**1,015**	**936**	**997**	**1,000**	**964**	**1,043**	**1,096**	**1,218**	**1,302**	**1,451**	**1,716**	**957**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,080**	**19,228**	**19,402**	**19,498**	**19,690**	**19,892**	**19,940**	**20,244**	**20,440**	**20,795**	**20,969**	**21,332**	**21,920**	**20,815**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS Geo 8760*
Future: *CTP*
Sensitivity: *At most one 50MW conventional geothermal, and unlimited 50MW EGS can be selected*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.327	B$
20-Year Carbon Emissions	41.998	M Tons
20-Year Water Consumption	7.312	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	111	17	93	66	94	23	125	-	-	-	-	155	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	35	-	-	127	156	291
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**237**	**44**	**121**	**90**	**118**	**47**	**151**	**186**	**271**	**170**	**297**	**628**	**909**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS Geo Force 50MW Base & 200MW Deep 8760*
Future: *CTP*
Sensitivity: *50 MW of conventional geothermal and 200 MW of enhanced geothermal forced in.*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.480 B$
20-Year Carbon Emissions 41.616 M Tons
20-Year Water Consumption 22.536 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.68	20.05	20.51	19.56	20.33	19.61	19.28	18.26	14.40	14.40	14.40	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	198	198	197	196	196	195	187	166	142	142	108	-
Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,319	1,344	1,396	1,431	1,447	1,458	1,481	1,461	1,707	1,877	1,941	2,324	3,131
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,316	2,975	1,884	1,937	1,987	2,004	2,042	2,027	2,033	2,020	1,983	1,764	1,528	1,516	1,194	-
Water Consumption	k-gallons	569	610	616	610	647	466	291	767	1,041	1,318	1,598	1,594	1,586	1,583	1,593	1,577	1,564	1,557	1,554	1,397

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,628	2,614	2,600	2,586	2,572	2,515	2,546	2,532	2,745	2,733	2,701	2,841	3,046	2,428
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,255	2,367	2,406	2,406	2,287	2,131
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	580	872	1,164
Geothermal	MW	11	11	11	11	11	11	11	61	111	161	211	211	211	211	211	211	211	211	200	200
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	80	80	80	80	80
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,199**	**8,264**	**8,329**	**8,289**	**8,350**	**8,319**	**8,375**	**8,388**	**8,456**	**8,718**	**8,538**	**8,847**	**8,947**	**7,770**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,544	7,479	7,444	7,405	7,373	7,207	7,295	7,254	7,885	7,797	7,763	8,044	7,594	6,704
Wind	GWh	2,198	2,229	2,197	4,962	4,945	4,974	4,962	4,980	4,955	4,738	4,756	4,737	4,741	4,738	4,752	3,932	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	4,807	7,303	9,516
Geothermal	GWh	60	61	61	61	60	61	61	437	813	1,190	1,571	1,566	1,566	1,566	1,571	1,566	1,566	1,506	1,510	1,506
Gas Steam Generator	GWh	55	80	81	36	68	127	47	63	54	54	42	47	46	31	69	18	7	12	6	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,877	2,714	2,813	2,757	2,850	2,820	2,711	2,838	2,647	2,725	2,612	2,467	2,220	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	985	1,163	1,183	1,252	1,264	1,254	1,338	1,238	1,153	720	466	523	241	24
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	184	303	249	272	181	136
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**19,446**	**19,753**	**20,319**	**20,553**	**20,996**	**20,903**	**21,032**	**20,951**	**21,591**	**21,608**	**21,869**	**21,839**	**22,652**	**21,526**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**839**	**614**	**442**	**394**	**277**	**383**	**367**	**475**	**294**	**282**	**193**	**286**	**101**	**732**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,498**	**1,790**	**868**	**1,090**	**1,345**	**1,369**	**1,551**	**1,415**	**1,396**	**1,225**	**1,538**	**1,441**	**1,550**	**1,402**	**1,888**	**1,286**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,313**	**18,913**	**19,494**	**20,042**	**20,285**	**20,721**	**20,632**	**20,749**	**20,671**	**21,237**	**21,230**	**21,472**	**21,328**	**22,138**	**21,059**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS Geo Force 50MW Base & 200MW Deep 8760*
Future: *CTP*
Sensitivity: *50 MW of conventional geothermal and 200 MW of enhanced geothermal forced in.*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.480	B$
20-Year Carbon Emissions	41.616	M Tons
20-Year Water Consumption	22.536	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	23	-	-	-	-	-	44	-	227	-	-	152	300	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	5	112	38	-	151	294
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	-	292	292
Geothermal	MW	-	-	-	-	-	-	-	100	50	50	50	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**48**	**126**	**77**	**77**	**74**	**25**	**69**	**26**	**303**	**323**	**208**	**375**	**768**	**912**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS Geo Force Base 8760*
Future: *CTP*
Sensitivity: *50 MW of conventional geothermal forced in*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.350	B$
20-Year Carbon Emissions	41.713	M Tons
20-Year Water Consumption	9.955	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.78	19.04	18.43	16.68	16.55	16.04	15.67	14.83	14.40	14.55	14.40	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	198	198	197	197	196	196	182	197	168	146	114	-

Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,300	1,307	1,346	1,362	1,387	1,398	1,429	1,498	1,718	1,875	1,964	2,347	3,172
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,316	2,975	1,899	1,906	1,912	1,918	1,935	1,959	1,956	1,984	1,953	2,036	1,756	1,550	1,251	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	489	487	487	489	489	483	483	496	504	485	474	468	314

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,669	2,655	2,641	2,725	2,782	2,835	2,842	2,953	2,938	2,926	2,895	2,883	3,051	2,433
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,260	2,260	2,278	2,427	2,303	2,145
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	80	80	80	80	80
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,241**	**8,256**	**8,270**	**8,278**	**8,360**	**8,438**	**8,471**	**8,609**	**8,600**	**8,804**	**8,604**	**8,857**	**8,914**	**7,735**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,665	7,600	7,564	7,810	7,984	8,133	8,155	8,474	8,442	8,362	8,328	8,167	7,609	6,719
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,955	4,738	4,756	4,737	4,741	4,738	4,752	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	3,549	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	48	58	48	48	38	42	51	42	63	45	17	16	7	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,875	2,709	2,809	2,731	2,821	2,802	2,670	2,764	2,602	2,861	2,747	2,476	2,279	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,009	1,126	1,078	1,145	1,123	1,169	1,243	1,230	1,150	999	693	562	280	101
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	179	350	302	281	195	221
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**19,590**	**19,451**	**19,572**	**19,690**	**19,924**	**20,217**	**20,254**	**20,594**	**21,817**	**21,157**	**21,354**	**21,754**	**22,513**	**21,433**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**765**	**780**	**801**	**785**	**770**	**708**	**748**	**719**	**287**	**518**	**463**	**332**	**125**	**603**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,498**	**1,790**	**930**	**951**	**958**	**886**	**948**	**995**	**950**	**1,034**	**1,717**	**1,145**	**1,226**	**1,369**	**1,773**	**1,056**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,313**	**19,048**	**19,188**	**19,296**	**19,412**	**19,625**	**19,887**	**19,923**	**20,235**	**21,423**	**20,698**	**20,879**	**21,250**	**21,999**	**20,957**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS Geo Force Base 8760*
Future: *CTP*
Sensitivity: *50 MW of conventional geothermal forced in*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.350	B$
20-Year Carbon Emissions	41.713	M Tons
20-Year Water Consumption	9.955	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	64	-	-	98	70	110	21	125	-	-	-	-	262	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	10	-	19	148	147	292
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	-	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**90**	**76**	**27**	**125**	**95**	**134**	**46**	**151**	**226**	**265**	**188**	**318**	**726**	**909**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS Geo Force Deep 8760*
Future: *CTP*
Sensitivity: *50 MW of enhanced geothermal forced in*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.332 B$
20-Year Carbon Emissions 41.716 M Tons
20-Year Water Consumption 10.920 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.78	19.04	18.42	16.64	16.54	16.01	15.64	14.80	14.40	14.55	14.40	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	198	198	197	197	196	196	182	196	168	146	112	-
Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,297	1,304	1,342	1,359	1,383	1,394	1,425	1,495	1,715	1,873	1,961	2,346	3,170
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,315	2,975	1,897	1,917	1,923	1,924	1,944	1,956	1,954	1,983	1,949	2,032	1,753	1,551	1,235	-
Water Consumption	k-gallons	569	610	616	610	647	466	292	564	563	561	563	562	559	557	569	578	561	548	539	387

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,666	2,652	2,638	2,709	2,773	2,791	2,801	2,915	2,900	2,888	2,857	2,845	3,040	2,422
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,263	2,263	2,282	2,430	2,306	2,150
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	61	61	61	61	61	61	61	61	61	61	61	50	50
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	80	80	80	80	80
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,237**	**8,302**	**8,316**	**8,312**	**8,402**	**8,445**	**8,480**	**8,621**	**8,616**	**8,820**	**8,620**	**8,872**	**8,956**	**7,779**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,654	7,589	7,553	7,763	7,959	8,007	8,035	8,364	8,333	8,252	8,218	8,058	7,577	6,687
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,955	4,738	4,756	4,737	4,741	4,738	4,752	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	3,549	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	437	436	437	438	437	436	437	438	437	436	377	378	376
Gas Steam Generator	GWh	55	80	81	36	68	127	48	58	49	49	39	42	51	41	61	45	17	16	7	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,875	2,708	2,805	2,728	2,818	2,803	2,670	2,769	2,606	2,860	2,747	2,481	2,265	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,007	1,144	1,096	1,156	1,139	1,165	1,240	1,227	1,147	997	687	561	269	91
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	345	302	279	187	214
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**19,577**	**19,833**	**19,952**	**20,029**	**20,290**	**20,464**	**20,508**	**20,860**	**22,079**	**21,415**	**21,615**	**22,023**	**22,826**	**21,761**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**771**	**724**	**751**	**755**	**730**	**715**	**749**	**714**	**280**	**515**	**453**	**321**	**119**	**585**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,498**	**1,790**	**923**	**999**	**1,014**	**920**	**996**	**982**	**939**	**1,024**	**1,699**	**1,139**	**1,218**	**1,364**	**1,805**	**1,092**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,036**	**19,293**	**19,402**	**19,476**	**19,713**	**19,866**	**19,911**	**20,231**	**21,412**	**20,696**	**20,881**	**21,256**	**22,037**	**21,010**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS Geo Force Deep 8760*
Future: *CTP*
Sensitivity: *50 MW of enhanced geothermal forced in*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.332	B$
20-Year Carbon Emissions	41.716	M Tons
20-Year Water Consumption	10.920	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	61	-	-	85	78	75	23	128	-	-	-	-	290	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	13	-	19	148	146	294
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	-	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**86**	**76**	**27**	**113**	**103**	**99**	**48**	**154**	**230**	**265**	**188**	**318**	**753**	**911**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS Geo+DER+ITC+SMR+no H2&CCS 8760*
Future: *CTP*
Sensitivity: *Follow stakeholder scenarios #2 (updated geothermal cost) and #7 (High BTM solar+TOU+High Battery DLC, etc.); add in ITC assumptions (2026-2033: 30%, 2034: 22.5%, 2035: 15%, 2036-2045: 0) for both geothermal and SMRs; move new SMR first year available date to 2040; remove hydrogen conversion and CCS from project options*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	13.763	B$
20-Year Carbon Emissions	41.639	M Tons
20-Year Water Consumption	32.241	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,287	2,514	2,762	3,250	3,315	3,343	3,335	3,398	3,421	3,477	3,488	3,508	3,524	3,561	3,557	3,557	3,543	3,564	3,610	3,673
PRM	%	15.31	15.75	20.42	20.43	19.09	20.72	22.06	28.65	28.82	27.38	27.95	28.09	28.46	28.11	23.18	18.06	14.52	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	391	369	313	336	294	199	179	180	187	185	189	183	191	177	184	178	145	135	-

Revenue Requirement	M$	523	572	690	1,191	1,204	1,286	1,272	1,341	1,330	1,341	1,352	1,367	1,380	1,401	1,355	1,451	1,523	1,632	2,012	2,836
Carbon Emission	k-tons	2,598	2,902	2,875	2,988	3,306	2,959	1,860	1,897	1,918	1,993	1,967	2,012	1,929	2,028	1,856	1,865	1,790	1,499	1,399	-
Water Consumption	k-gallons	569	608	612	609	646	461	288	2,203	2,203	2,210	2,216	2,214	2,200	2,206	2,205	2,207	2,197	2,176	2,178	2,032

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,429	2,435	2,571	2,557	2,543	2,529	2,515	2,501	2,444	2,431	2,417	2,402	2,473	2,542	2,623	2,796	1,878
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,104	1,150	900	1,061
Demand Response	MW	70	70	70	70	51	71	92	113	133	153	174	194	215	236	256	276	297	318	338	361
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,364	2,193	1,948
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	1,310
Geothermal	MW	11	11	11	11	11	11	11	361	361	361	361	361	361	361	361	361	361	361	350	350
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,798**	**7,827**	**8,349**	**8,181**	**8,563**	**8,597**	**8,526**	**8,557**	**8,546**	**8,578**	**8,611**	**8,425**	**8,492**	**8,300**	**8,678**	**8,768**	**7,485**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,825	6,961	7,358	7,337	7,271	7,235	7,196	7,166	6,998	6,959	6,918	6,892	7,046	7,303	7,401	6,873	5,101
Wind	GWh	2,198	2,229	2,197	4,962	4,945	4,974	4,962	4,981	4,956	4,738	4,756	4,737	4,741	4,738	4,753	3,933	3,748	3,688	3,102	3,643
Demand Response	GWh	29	29	29	29	17	22	27	32	37	41	47	51	56	61	66	71	76	81	86	91
Coal	GWh	1,090	1,073	1,103	1,137	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	2,342	2,254	3,570	4,822	10,753
Geothermal	GWh	60	61	61	61	60	61	61	2,696	2,695	2,696	2,704	2,696	2,695	2,696	2,704	2,696	2,695	2,635	2,643	2,635
Gas Steam Generator	GWh	55	80	80	35	66	119	43	38	31	38	29	34	24	24	36	27	18	9	8	-
Gas Combined Cycle	GWh	2,601	2,807	2,665	2,808	2,847	2,997	2,870	2,641	2,708	2,717	2,818	2,823	2,679	2,827	2,649	2,823	2,817	2,515	2,462	-
Gas/Hydrogen Turbine	GWh	524	860	882	982	1,372	1,880	956	1,182	1,174	1,283	1,183	1,247	1,226	1,274	1,118	1,020	917	666	532	-
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**GWh**	**13,894**	**15,152**	**16,004**	**19,592**	**20,178**	**20,682**	**19,201**	**21,729**	**21,864**	**21,836**	**21,811**	**21,826**	**21,681**	**21,789**	**21,514**	**20,891**	**20,708**	**21,394**	**21,336**	**23,082**
Market Purchases	**GWh**	**40**	**119**	**309**	**292**	**267**	**232**	**865**	**40**	**41**	**40**	**66**	**82**	**131**	**163**	**240**	**499**	**604**	**394**	**418**	**124**
Market Sales	**GWh**	**2,209**	**1,890**	**1,462**	**1,354**	**1,501**	**1,803**	**850**	**2,391**	**2,416**	**2,251**	**2,132**	**2,035**	**1,845**	**1,804**	**1,544**	**1,117**	**997**	**1,337**	**1,165**	**2,358**
Net Generation *	**GWh**	**13,636**	**14,842**	**15,572**	**19,097**	**19,692**	**20,152**	**18,673**	**21,154**	**21,280**	**21,265**	**21,234**	**21,251**	**21,112**	**21,221**	**20,934**	**20,307**	**20,108**	**20,736**	**20,662**	**22,287**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS Geo+DER+ITC+SMR+no H2&CCS 8760*
Future: *CTP*
Sensitivity: *Follow stakeholder scenarios #2 (updated geothermal cost) and #7 (High BTM solar+TOU+High Battery DLC, etc.); add in ITC assumptions (2026-2033: 30%, 2034: 22.5%, 2035: 15%, 2036-2045: 0) for both geothermal and SMRs; move new SMR first year available date to 2040; remove hydrogen conversion and CCS from project options*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	13.763	B$
20-Year Carbon Emissions	41.639	M Tons
20-Year Water Consumption	32.241	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	111	20	150	-	-	-	-	-	-	-	-	-	83	100	92	268	-
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	54	47	-	161
Demand Response	MW	-	-	-	-	359	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	-	-	114	99	205
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	730
Geothermal	MW	-	-	-	-	-	-	-	350	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	(212)
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,393**	**379**	**515**	**25**	**376**	**27**	**26**	**24**	**25**	**25**	**26**	**26**	**108**	**177**	**423**	**738**	**911**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS Geo+DER+ITC+SMR+no H2&CCS+no 29Gas 8760*
Future: *CTP*
Sensitivity: *Follow stakeholder scenarios #2 and #7; add in ITC assumptions for both geothermal and SMRs; move new SMR first year available date to 2040; remove hydrogen conversion and CCS from project options; remove172 MW gas unit added in 2029*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	13.528	B$
20-Year Carbon Emissions	40.256	M Tons
20-Year Water Consumption	32.467	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,287	2,514	2,762	3,250	3,315	3,343	3,335	3,398	3,421	3,477	3,488	3,508	3,524	3,561	3,557	3,557	3,543	3,564	3,610	3,673
PRM	%	15.31	15.75	20.42	15.24	14.40	15.96	17.29	23.96	24.17	22.80	23.39	23.56	23.95	23.64	18.75	14.40	14.51	15.68	14.40	14.60
Carbon Intensity	lbs/MWh	381	391	369	310	328	285	199	177	177	184	182	187	180	188	172	166	143	124	117	-

Revenue Requirement	M$	523	572	690	1,140	1,160	1,244	1,227	1,297	1,288	1,300	1,312	1,328	1,342	1,365	1,322	1,440	1,607	1,728	2,072	2,782
Carbon Emission	k-tons	2,598	2,902	2,875	2,948	3,209	2,845	1,866	1,873	1,881	1,946	1,925	1,979	1,899	1,991	1,788	1,700	1,482	1,309	1,240	-
Water Consumption	k-gallons	569	608	612	626	662	493	309	2,220	2,221	2,229	2,229	2,232	2,214	2,219	2,237	2,212	2,187	2,174	2,182	2,032

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,430	2,458	2,594	2,580	2,566	2,552	2,538	2,524	2,467	2,454	2,440	2,425	2,647	2,615	2,604	2,788	1,875
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	1,062
Demand Response	MW	70	70	70	70	51	71	92	113	133	153	174	194	215	236	258	280	301	322	343	363
Short Duration Storage	MW	992	1,160	1,640	1,950	1,973	2,273	2,273	2,273	2,273	2,273	2,273	2,273	2,273	2,273	2,273	2,318	2,318	2,318	2,263	1,947
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,310
Geothermal	MW	11	11	11	11	11	11	11	361	361	361	361	361	361	361	361	361	361	361	350	350
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	442	442	482	482	482	482	482	482	482	482	482	315	315	315	315	315	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	200	200
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,627**	**7,702**	**8,223**	**8,055**	**8,438**	**8,471**	**8,400**	**8,432**	**8,420**	**8,452**	**8,485**	**8,301**	**8,564**	**8,366**	**8,590**	**8,708**	**7,484**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,827	7,028	7,425	7,404	7,338	7,302	7,263	7,233	7,064	7,026	6,985	6,959	7,546	7,512	7,344	6,849	5,093
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,981	4,956	4,737	4,757	4,737	4,741	4,738	4,753	3,933	3,564	3,344	2,756	3,647
Demand Response	GWh	29	29	29	29	17	22	27	32	37	41	47	51	56	61	66	71	76	81	87	91
Coal	GWh	1,090	1,073	1,103	1,136	1,170	394	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	2,342	3,491	4,807	6,063	10,753
Geothermal	GWh	60	61	61	61	60	61	61	2,696	2,695	2,696	2,704	2,696	2,695	2,696	2,704	2,696	2,695	2,635	2,643	2,635
Gas Steam Generator	GWh	55	80	80	75	105	193	78	79	72	81	59	75	55	53	109	63	14	7	8	-
Gas Combined Cycle	GWh	2,601	2,807	2,665	2,808	2,837	2,985	2,901	2,630	2,696	2,705	2,805	2,813	2,671	2,814	2,636	2,747	2,635	2,393	2,372	-
Gas/Hydrogen Turbine	GWh	524	860	882	847	1,145	1,587	888	1,075	1,049	1,136	1,059	1,119	1,113	1,153	913	751	540	435	332	-
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**GWh**	**13,894**	**15,152**	**16,004**	**19,498**	**20,046**	**20,516**	**19,267**	**21,719**	**21,834**	**21,786**	**21,771**	**21,795**	**21,658**	**21,752**	**21,436**	**21,083**	**21,409**	**21,876**	**21,918**	**23,078**
Market Purchases	**GWh**	**40**	**119**	**309**	**321**	**288**	**260**	**824**	**40**	**44**	**44**	**69**	**93**	**132**	**172**	**268**	**470**	**325**	**236**	**208**	**124**
Market Sales	**GWh**	**2,209**	**1,890**	**1,462**	**1,281**	**1,377**	**1,644**	**861**	**2,363**	**2,369**	**2,184**	**2,078**	**1,996**	**1,803**	**1,755**	**1,468**	**1,216**	**1,354**	**1,578**	**1,491**	**2,355**
Net Generation *	**GWh**	**13,636**	**14,842**	**15,572**	**18,996**	**19,547**	**19,965**	**18,724**	**21,126**	**21,231**	**21,194**	**21,176**	**21,201**	**21,069**	**21,162**	**20,830**	**20,435**	**20,743**	**21,136**	**21,197**	**22,284**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS Geo+DER+ITC+SMR+no H2&CCS+no 29Gas 8760*
Future: *CTP*
Sensitivity: *Follow stakeholder scenarios #2 and #7; add in ITC assumptions for both geothermal and SMRs; move new SMR first year available date to 2040; remove hydrogen conversion and CCS from project options; remove172 MW gas unit added in 2029*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	13.528	B$
20-Year Carbon Emissions	40.256	M Tons
20-Year Water Consumption	32.467	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	112	42	150	-	-	-	-	-	-	-	-	-	233	-	-	280	5
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	262
Demand Response	MW	-	-	-	-	359	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	23	300	-	-	-	-	-	-	-	-	-	45	-	-	215	133
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	584
Geothermal	MW	-	-	-	-	-	-	-	350	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	-	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	(40)
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,222**	**424**	**515**	**25**	**376**	**27**	**26**	**24**	**25**	**25**	**26**	**31**	**303**	**170**	**270**	**766**	**970**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS High BTMS 8760*
Future: *CTP*
Sensitivity: *Change the behind-the-meter solar forecast from Reference to High*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.167	B$
20-Year Carbon Emissions	41.594	M Tons
20-Year Water Consumption	7.273	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,287	2,514	2,762	3,250	3,308	3,338	3,340	3,412	3,447	3,510	3,532	3,563	3,590	3,643	3,658	3,678	3,674	3,680	3,709	3,769
PRM	%	15.32	15.75	20.42	20.44	19.01	20.22	21.07	22.07	21.57	19.90	19.85	19.44	19.17	18.17	14.63	14.40	14.40	14.49	14.40	14.60
Carbon Intensity	lbs/MWh	381	391	369	313	336	294	199	199	199	198	198	198	197	197	197	197	169	147	119	-
Revenue Requirement	M$	523	571	690	1,191	1,196	1,279	1,263	1,304	1,308	1,344	1,358	1,381	1,390	1,420	1,403	1,636	1,814	1,904	2,282	3,106
Carbon Emission	k-tons	2,599	2,902	2,875	2,988	3,312	2,962	1,888	1,885	1,895	1,908	1,926	1,946	1,941	1,968	1,987	2,024	1,750	1,546	1,293	-
Water Consumption	k-gallons	569	608	612	609	646	464	291	284	285	285	284	285	282	280	276	294	279	264	266	111

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,431	2,446	2,582	2,639	2,690	2,686	2,791	2,850	2,896	2,893	3,002	2,988	2,976	2,944	2,933	2,993	2,375
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,349	2,412	2,554	2,445	2,248
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	120	120	120	120	120
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,800**	**7,819**	**8,323**	**8,210**	**8,391**	**8,415**	**8,444**	**8,529**	**8,599**	**8,622**	**8,758**	**8,634**	**8,883**	**8,727**	**8,973**	**8,937**	**7,720**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,829	6,992	7,389	7,575	7,702	7,694	8,001	8,185	8,309	8,304	8,617	8,594	8,502	8,468	8,300	7,437	6,544
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,955	4,738	4,756	4,737	4,741	4,738	4,752	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,103	1,136	1,170	394	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	80	35	68	126	47	52	45	48	36	40	51	41	50	36	13	12	7	-
Gas Combined Cycle	GWh	2,601	2,807	2,665	2,808	2,844	2,993	2,865	2,696	2,791	2,718	2,800	2,776	2,643	2,737	2,635	2,810	2,694	2,426	2,307	-
Gas/Hydrogen Turbine	GWh	524	861	882	982	1,382	1,883	1,000	1,111	1,069	1,139	1,128	1,172	1,239	1,227	1,051	917	632	506	263	93
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385	505	429	404	284	293
Total Generation	**GWh**	**13,894**	**15,152**	**16,004**	**19,594**	**20,214**	**20,714**	**19,480**	**19,518**	**19,670**	**19,861**	**20,105**	**20,368**	**20,372**	**20,705**	**20,858**	**21,310**	**21,505**	**21,899**	**22,441**	**21,323**
Market Purchases	**GWh**	**40**	**119**	**309**	**292**	**265**	**231**	**742**	**820**	**814**	**761**	**751**	**683**	**731**	**707**	**665**	**475**	**411**	**296**	**134**	**604**
Market Sales	**GWh**	**2,209**	**1,889**	**1,461**	**1,355**	**1,503**	**1,798**	**952**	**919**	**956**	**927**	**1,014**	**1,040**	**996**	**1,083**	**1,120**	**1,293**	**1,381**	**1,558**	**1,853**	**1,132**
Net Generation *	**GWh**	**13,636**	**14,843**	**15,573**	**19,100**	**19,726**	**20,180**	**18,931**	**18,937**	**19,084**	**19,258**	**19,470**	**19,696**	**19,706**	**20,000**	**20,132**	**20,556**	**20,733**	**21,107**	**21,687**	**20,636**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS High BTMS 8760*
Future: *CTP*
Sensitivity: *Change the behind-the-meter solar forecast from Reference to High*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.167	B$
20-Year Carbon Emissions	41.594	M Tons
20-Year Water Consumption	7.273	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	113	29	150	71	66	10	119	74	102	11	122	-	-	-	-	155	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	99	63	142	160	254
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,395**	**75**	**515**	**96**	**192**	**36**	**146**	**98**	**126**	**36**	**148**	**111**	**310**	**232**	**312**	**633**	**871**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS High BTMS+TOU 8760*
Future: *CTP*
Sensitivity: *Change the behind-the-meter solar forecast from Reference to High with TOU Forecast*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.045	B$
20-Year Carbon Emissions	41.439	M Tons
20-Year Water Consumption	7.301	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,287	2,514	2,762	3,250	3,315	3,343	3,335	3,398	3,421	3,477	3,488	3,508	3,524	3,561	3,557	3,557	3,543	3,564	3,610	3,673
PRM	%	15.31	15.75	20.42	20.43	18.13	19.39	20.49	21.85	21.70	20.22	20.54	20.52	20.60	20.09	15.96	14.40	14.40	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	391	369	313	336	294	199	199	199	198	198	198	197	197	197	195	166	145	118	-
Revenue Requirement	M$	523	572	690	1,191	1,189	1,271	1,256	1,298	1,302	1,338	1,352	1,374	1,383	1,413	1,377	1,566	1,737	1,838	2,230	3,168
Carbon Emission	k-tons	2,598	2,902	2,875	2,988	3,310	2,964	1,880	1,889	1,896	1,902	1,922	1,942	1,937	1,966	1,978	1,982	1,706	1,527	1,276	-
Water Consumption	k-gallons	568	608	612	609	646	464	291	284	285	284	284	285	282	279	284	302	284	267	268	114

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,429	2,439	2,574	2,627	2,709	2,700	2,784	2,851	2,895	2,894	3,008	2,993	2,981	2,950	2,938	2,997	2,379
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	-	-	-	-	-	0	0	1	1	1	3	5	6	6	6	6
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,251	2,277	2,355	2,300	2,161
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	40	80	80	80
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,798**	**7,780**	**8,281**	**8,158**	**8,367**	**8,385**	**8,392**	**8,484**	**8,553**	**8,577**	**8,718**	**8,554**	**8,665**	**8,472**	**8,694**	**8,711**	**7,551**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,825	6,971	7,368	7,540	7,757	7,735	7,980	8,186	8,308	8,305	8,634	8,609	8,518	8,483	8,305	7,441	6,551
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,955	4,738	4,756	4,736	4,741	4,738	4,753	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0
Coal	GWh	1,090	1,073	1,103	1,137	1,170	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	80	35	67	124	47	53	45	48	36	40	51	41	65	52	25	18	8	-
Gas Combined Cycle	GWh	2,600	2,807	2,665	2,808	2,845	2,995	2,864	2,692	2,791	2,717	2,799	2,775	2,642	2,734	2,644	2,798	2,674	2,385	2,285	-
Gas/Hydrogen Turbine	GWh	524	860	882	982	1,378	1,884	989	1,117	1,069	1,129	1,123	1,166	1,234	1,225	1,150	1,085	770	586	315	147
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	193	158	144	281	201	233
Total Generation	**GWh**	**13,893**	**15,152**	**16,004**	**19,592**	**20,176**	**20,678**	**19,408**	**19,548**	**19,683**	**19,799**	**20,068**	**20,326**	**20,334**	**20,684**	**20,770**	**21,117**	**21,329**	**21,794**	**22,358**	**21,290**
Market Purchases	**GWh**	**41**	**119**	**309**	**292**	**266**	**232**	**759**	**791**	**792**	**768**	**746**	**681**	**726**	**695**	**686**	**554**	**513**	**361**	**153**	**602**
Market Sales	**GWh**	**2,208**	**1,890**	**1,462**	**1,354**	**1,501**	**1,799**	**937**	**954**	**983**	**915**	**1,015**	**1,039**	**997**	**1,096**	**1,102**	**1,240**	**1,362**	**1,578**	**1,843**	**1,158**
Net Generation *	**GWh**	**13,635**	**14,842**	**15,572**	**19,097**	**19,691**	**20,149**	**18,866**	**18,965**	**19,096**	**19,201**	**19,436**	**19,656**	**19,669**	**19,980**	**20,046**	**20,375**	**20,563**	**21,011**	**21,605**	**20,610**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS High BTMS+TOU 8760*
Future: *CTP*
Sensitivity: *Change the behind-the-meter solar forecast from Reference to High with TOU Forecast*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.045	B$
20-Year Carbon Emissions	41.439	M Tons
20-Year Water Consumption	7.301	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	111	24	150	66	97	5	98	81	100	13	128	-	-	-	-	153	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	-	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	1	26	78	215	311
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-	-	40	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,393**	**24**	**515**	**91**	**223**	**32**	**125**	**106**	**125**	**38**	**154**	**71**	**172**	**196**	**287**	**686**	**929**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS High BTMS+TOU+125% PS 8760*
Future: *CTP*
Sensitivity: *Change the behind-the-meter solar forecast from Reference to High with TOU Forecast, 125% Power Saver Program*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.094	B$
20-Year Carbon Emissions	41.503	M Tons
20-Year Water Consumption	7.288	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,287	2,514	2,762	3,250	3,315	3,343	3,335	3,398	3,421	3,477	3,488	3,508	3,524	3,561	3,557	3,557	3,543	3,564	3,610	3,673
PRM	%	15.31	15.75	20.42	20.43	19.68	20.94	22.08	20.83	20.71	19.29	19.61	19.59	19.67	19.16	15.03	14.56	14.40	14.50	14.50	14.60
Carbon Intensity	lbs/MWh	381	391	369	313	335	293	199	199	198	198	198	197	197	196	197	195	167	144	120	-

Revenue Requirement	M$	523	572	690	1,191	1,204	1,287	1,273	1,281	1,290	1,328	1,345	1,370	1,380	1,413	1,378	1,589	1,758	1,867	2,257	3,201
Carbon Emission	k-tons	2,598	2,902	2,875	2,988	3,304	2,958	1,883	1,880	1,890	1,905	1,928	1,947	1,943	1,971	1,983	2,002	1,735	1,516	1,298	-
Water Consumption	k-gallons	569	608	612	609	645	463	290	283	283	284	284	284	281	279	287	297	279	266	271	116

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,429	2,439	2,574	2,627	2,679	2,676	2,787	2,861	2,904	2,906	3,018	3,003	2,991	2,960	2,948	2,959	2,341
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	82	84	85	86	86	86	86	86	86	86	88	90	91	91	91	91
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,277	2,476	2,206	2,068
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	80	80	80	80	80
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,798**	**7,862**	**8,364**	**8,244**	**8,343**	**8,367**	**8,401**	**8,500**	**8,567**	**8,594**	**8,732**	**8,568**	**8,718**	**8,507**	**8,810**	**8,664**	**7,506**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,825	6,971	7,368	7,540	7,670	7,666	7,989	8,214	8,333	8,339	8,660	8,633	8,543	8,502	8,326	7,328	6,439
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,736	4,741	4,737	4,752	3,932	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	17	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Coal	GWh	1,090	1,073	1,103	1,137	1,170	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	80	35	64	122	45	52	43	47	37	40	50	42	69	45	19	17	9	-
Gas Combined Cycle	GWh	2,601	2,807	2,665	2,808	2,845	2,994	2,867	2,695	2,787	2,710	2,796	2,776	2,638	2,731	2,637	2,786	2,664	2,394	2,303	-
Gas/Hydrogen Turbine	GWh	524	860	882	982	1,372	1,877	993	1,103	1,066	1,139	1,132	1,173	1,246	1,234	1,159	1,007	726	570	334	163
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	191	338	289	273	206	243
Total Generation	**GWh**	**13,894**	**15,152**	**16,004**	**19,592**	**20,184**	**20,686**	**19,432**	**19,467**	**19,622**	**19,830**	**20,122**	**20,377**	**20,393**	**20,734**	**20,815**	**21,242**	**21,452**	**21,816**	**22,307**	**21,222**
Market Purchases	**GWh**	**40**	**119**	**309**	**292**	**265**	**231**	**747**	**823**	**821**	**756**	**732**	**670**	**709**	**685**	**680**	**514**	**473**	**342**	**176**	**618**
Market Sales	**GWh**	**2,209**	**1,890**	**1,462**	**1,354**	**1,505**	**1,804**	**946**	**933**	**968**	**946**	**1,070**	**1,119**	**1,066**	**1,179**	**1,192**	**1,374**	**1,504**	**1,634**	**1,815**	**1,122**
Net Generation *	**GWh**	**13,636**	**14,842**	**15,572**	**19,097**	**19,697**	**20,154**	**18,886**	**18,913**	**19,052**	**19,244**	**19,505**	**19,746**	**19,756**	**20,073**	**20,142**	**20,549**	**20,744**	**21,085**	**21,554**	**20,558**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS High BTMS+TOU+125% PS 8760*
Future: *CTP*
Sensitivity: *Change the behind-the-meter solar forecast from Reference to High with TOU Forecast, 125% Power Saver Program*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.094 B$
20-Year Carbon Emissions 41.503 M Tons
20-Year Water Consumption 7.288 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	111	24	150	66	67	11	124	88	100	16	126	-	-	-	-	106	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	85	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	20	-	-	-	-	-	-	-	-	7	199	-	312
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,393**	**108**	**515**	**91**	**113**	**38**	**150**	**112**	**124**	**40**	**152**	**72**	**211**	**177**	**369**	**523**	**930**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS High BTMS+TOU+125% PS+50% Battery 8760*
Future: *CTP*
Sensitivity: *Change the behind-the-meter solar forecast from Reference to High with TOU Forecast, 125% Power Saver Program, 50% BTM Battery*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	13.993	B$
20-Year Carbon Emissions	41.883	M Tons
20-Year Water Consumption	7.305	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,287	2,514	2,762	3,250	3,315	3,343	3,335	3,398	3,421	3,477	3,488	3,508	3,524	3,561	3,557	3,557	3,543	3,564	3,610	3,673
PRM	%	15.31	15.75	20.42	20.43	20.07	21.72	23.26	22.16	22.41	21.34	22.14	22.51	22.94	22.78	17.88	16.65	14.40	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	391	369	313	335	293	199	199	198	198	197	197	196	196	197	188	187	164	141	-

Revenue Requirement	M$	523	572	690	1,191	1,215	1,298	1,285	1,290	1,298	1,337	1,354	1,380	1,391	1,424	1,373	1,565	1,669	1,761	2,139	3,034
Carbon Emission	k-tons	2,598	2,902	2,875	2,988	3,301	2,953	1,885	1,880	1,889	1,899	1,922	1,943	1,939	1,972	1,985	1,922	1,878	1,680	1,474	-
Water Consumption	k-gallons	569	608	612	609	644	461	291	282	283	282	281	281	274	271	295	296	292	273	283	119

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,429	2,439	2,574	2,627	2,625	2,611	2,669	2,743	2,787	2,786	2,914	2,918	2,906	2,967	2,955	2,891	2,219
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,496	1,504	1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,125	1,125	875	875
Demand Response	MW	70	70	70	70	103	125	147	169	190	209	230	250	271	292	312	332	353	374	394	417
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,427	2,464	2,398	1,948
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	434	580	872	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,798**	**7,883**	**8,406**	**8,306**	**8,390**	**8,432**	**8,462**	**8,580**	**8,669**	**8,714**	**8,888**	**8,722**	**8,851**	**8,775**	**8,977**	**8,881**	**7,524**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,825	6,971	7,368	7,540	7,513	7,476	7,648	7,870	7,993	7,993	8,358	8,387	8,298	8,534	8,361	7,146	6,068
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	5,111	5,114	4,994	5,013	4,993	4,997	4,994	5,009	4,189	3,821	3,600	3,013	3,003
Demand Response	GWh	29	29	29	29	22	28	33	38	43	48	53	58	63	67	72	77	82	87	92	97
Coal	GWh	1,090	1,073	1,103	1,137	1,170	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	3,491	4,807	7,303	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	80	35	63	117	44	48	40	41	28	31	30	19	81	41	33	19	10	-
Gas Combined Cycle	GWh	2,601	2,807	2,665	2,808	2,845	2,994	2,871	2,699	2,797	2,725	2,812	2,796	2,661	2,750	2,651	2,783	2,792	2,530	2,559	-
Gas/Hydrogen Turbine	GWh	524	860	882	982	1,369	1,875	995	1,103	1,061	1,127	1,121	1,162	1,246	1,248	1,274	1,126	1,061	823	491	217
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	136	160
Total Generation	**GWh**	**13,894**	**15,152**	**16,004**	**19,592**	**20,186**	**20,689**	**19,451**	**19,462**	**19,619**	**19,770**	**20,068**	**20,333**	**20,351**	**20,748**	**20,831**	**21,087**	**20,755**	**21,217**	**21,558**	**21,156**
Market Purchases	**GWh**	**40**	**119**	**309**	**292**	**265**	**231**	**737**	**818**	**807**	**765**	**719**	**659**	**692**	**641**	**640**	**560**	**719**	**588**	**353**	**617**
Market Sales	**GWh**	**2,209**	**1,890**	**1,462**	**1,354**	**1,506**	**1,808**	**956**	**936**	**968**	**924**	**1,032**	**1,082**	**1,032**	**1,166**	**1,181**	**1,283**	**1,060**	**1,305**	**1,346**	**1,181**
Net Generation *	**GWh**	**13,636**	**14,842**	**15,572**	**19,097**	**19,699**	**20,158**	**18,907**	**18,920**	**19,065**	**19,213**	**19,480**	**19,721**	**19,738**	**20,104**	**20,172**	**20,412**	**20,055**	**20,510**	**20,908**	**20,617**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS High BTMS+TOU+125% PS+50% Battery 8760*
Future: *CTP*
Sensitivity: *Change the behind-the-meter solar forecast from Reference to High with TOU Forecast, 125% Power Saver Program, 50% BTM Battery*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	13.993	B$
20-Year Carbon Emissions	41.883	M Tons
20-Year Water Consumption	7.305	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	111	24	150	66	13	-	72	87	100	13	141	19	-	92	-	31	246
Wind	MW	-	-	-	800	-	-	-	38	8	29	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	414	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	-	177	37	204	-
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	-	146	292	438
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,393**	**437**	**515**	**91**	**78**	**35**	**126**	**112**	**125**	**38**	**167**	**46**	**171**	**293**	**247**	**552**	**711**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS NGH 8760*
Future: *CTP*
Sensitivity: *Use the high natural gas price assumption in CTP*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	15.355	B$
20-Year Carbon Emissions	31.825	M Tons
20-Year Water Consumption	6.242	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.55	18.00	19.27	20.15	22.78	22.20	20.25	19.97	19.36	18.95	17.95	16.38	14.40	14.40	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	375	353	328	265	273	209	178	173	166	163	162	161	154	157	114	100	83	72	73	-

Revenue Requirement	M$	532	632	760	1,269	1,295	1,399	1,361	1,440	1,449	1,484	1,498	1,523	1,538	1,573	1,603	1,792	1,954	2,035	2,379	3,103
Carbon Emission	k-tons	2,532	2,494	2,412	2,426	2,567	2,031	1,717	1,683	1,625	1,602	1,600	1,586	1,503	1,540	1,147	1,000	847	761	753	-
Water Consumption	k-gallons	560	554	553	550	572	363	267	257	251	247	248	248	235	237	212	205	194	188	193	109

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,537	2,595	2,884	2,913	3,047	3,088	3,176	3,162	3,143	3,130	3,116	3,101	3,089	3,058	3,046	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	45	46	46	48	50	51	51	51	51
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,465	2,491	2,462	2,248
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	872	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	160	160
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,906**	**7,969**	**8,625**	**8,484**	**8,927**	**8,996**	**9,008**	**9,019**	**9,025**	**9,037**	**9,050**	**8,992**	**9,102**	**8,919**	**9,089**	**9,061**	**7,826**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	7,139	7,426	8,268	8,373	8,737	8,863	9,117	9,090	9,029	8,991	8,950	8,922	8,831	8,794	8,609	7,632	6,740
Wind	GWh	2,198	2,229	2,196	4,961	4,946	4,975	4,962	4,981	4,955	4,738	4,756	4,737	4,741	4,738	4,752	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,146	1,164	1,182	367	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	3,549	4,816	5,965	7,281	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	49	33	26	3	16	32	34	32	20	22	16	18	14	10	5	2	1	1	-	-
Gas Combined Cycle	GWh	2,540	2,527	2,278	2,326	2,373	2,540	2,661	2,502	2,522	2,458	2,548	2,537	2,403	2,501	2,147	2,048	1,834	1,619	1,570	-
Gas/Hydrogen Turbine	GWh	471	475	414	409	562	878	877	935	847	854	795	778	741	736	354	182	81	55	24	72
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	126	363
Total Generation	**GWh**	**13,775**	**14,439**	**15,138**	**18,846**	**19,318**	**20,015**	**19,939**	**20,165**	**20,324**	**20,406**	**20,406**	**20,433**	**20,284**	**20,280**	**20,811**	**20,839**	**21,215**	**21,822**	**21,494**	**21,568**
Market Purchases	**GWh**	**58**	**388**	**740**	**727**	**722**	**626**	**659**	**674**	**685**	**726**	**805**	**843**	**964**	**1,099**	**893**	**921**	**790**	**608**	**637**	**635**
Market Sales	**GWh**	**2,092**	**1,402**	**954**	**929**	**920**	**1,287**	**1,119**	**1,140**	**1,161**	**1,102**	**1,047**	**952**	**805**	**737**	**942**	**901**	**1,087**	**1,403**	**1,056**	**1,027**
Net Generation *	**GWh**	**13,516**	**14,130**	**14,708**	**18,338**	**18,810**	**19,419**	**19,344**	**19,484**	**19,614**	**19,686**	**19,689**	**19,709**	**19,562**	**19,559**	**20,042**	**20,052**	**20,413**	**21,007**	**20,770**	**20,896**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS NGH 8760*
Future: *CTP*
Sensitivity: *Use the high natural gas price assumption in CTP*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 15.355 B$
20-Year Carbon Emissions 31.825 M Tons
20-Year Water Consumption 6.242 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	219	72	303	43	148	56	101	-	38	-	-	-	-	-	-	107	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	179	-	-	-	-	-	-	-	-	36	26	241	236
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	146	146	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	120	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,501**	**118**	**668**	**68**	**454**	**82**	**127**	**24**	**63**	**25**	**26**	**178**	**171**	**205**	**236**	**639**	**854**

Portfolio Summary

Scenario Information

Scenario: *CTP-SS SERVM Analysis 8760*
Future: *CTP*
Sensitivity: *Stakholder Scenario 10 SERVM Analysis re-ran in Encompass*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.277	B$
20-Year Carbon Emissions	41.983	M Tons
20-Year Water Consumption	7.319	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.03	15.05	19.36	19.24	17.63	18.71	19.70	20.77	20.16	18.24	18.03	17.49	17.10	16.23	13.00	13.00	13.00	13.10	13.00	13.20
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	199	198	198	198	197	197	197	197	169	147	121	-
Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,315	1,319	1,356	1,371	1,395	1,405	1,436	1,423	1,658	1,829	1,921	2,297	3,125
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,315	2,975	1,902	1,915	1,927	1,931	1,947	1,965	1,963	1,991	2,011	2,052	1,778	1,576	1,327	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	287	287	287	286	287	285	282	279	297	282	268	270	112

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,776	2,779	2,858	2,910	2,947	2,956	3,069	3,054	3,042	3,011	2,999	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,261	2,366	2,402	2,549	2,432	2,227
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	120	120	120	120	120
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,476**	**8,508**	**8,512**	**8,588**	**8,651**	**8,685**	**8,824**	**8,712**	**8,967**	**8,784**	**9,034**	**8,991**	**7,765**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,693	7,951	7,964	8,197	8,358	8,462	8,487	8,811	8,790	8,696	8,662	8,497	7,631	6,740
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,736	4,741	4,738	4,753	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	48	56	47	49	36	41	54	43	53	37	14	13	8	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,876	2,701	2,801	2,726	2,813	2,792	2,657	2,752	2,652	2,838	2,724	2,458	2,348	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,014	1,150	1,109	1,169	1,151	1,189	1,262	1,250	1,072	934	648	524	283	111
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	514	441	414	294	315
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**19,624**	**19,814**	**19,994**	**20,098**	**20,316**	**20,553**	**20,595**	**20,940**	**21,099**	**21,560**	**21,757**	**22,157**	**22,706**	**21,558**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**748**	**768**	**752**	**748**	**755**	**708**	**745**	**719**	**683**	**486**	**434**	**312**	**141**	**642**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,497**	**1,790**	**944**	**978**	**1,015**	**936**	**997**	**1,000**	**964**	**1,044**	**1,073**	**1,235**	**1,319**	**1,483**	**1,761**	**1,025**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,080**	**19,228**	**19,402**	**19,498**	**19,690**	**19,892**	**19,940**	**20,246**	**20,383**	**20,821**	**21,001**	**21,383**	**21,972**	**20,887**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-SS SERVM Analysis 8760*
Future: *CTP*
Sensitivity: *Stakholder Scenario 10 SERVM Analysis re-ran in Encompass*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.277	B$
20-Year Carbon Emissions	41.983	M Tons
20-Year Water Consumption	7.319	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	111	17	93	66	94	23	126	-	-	-	-	155	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	11	105	36	147	153	245
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**237**	**44**	**121**	**90**	**118**	**47**	**152**	**122**	**316**	**205**	**316**	**625**	**863**

Portfolio Summary

Scenario Information

Scenario: *CTP-TOU P2 8760*
Future: *CTP*
Sensitivity: *Time Of Use forecast impact to CTP*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.178	B$
20-Year Carbon Emissions	41.948	M Tons
20-Year Water Consumption	7.318	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,354	3,388	3,386	3,455	3,483	3,546	3,563	3,589	3,611	3,654	3,656	3,661	3,639	3,628	3,640	3,686
PRM	%	15.05	15.10	19.42	19.31	16.86	17.95	18.97	20.21	19.94	18.22	18.29	18.08	17.98	17.34	14.40	14.40	14.42	14.50	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	335	294	199	199	199	198	198	197	197	197	197	197	170	148	121	-

Revenue Requirement	M$	523	572	693	1,197	1,197	1,280	1,266	1,308	1,312	1,348	1,363	1,387	1,397	1,427	1,416	1,643	1,806	1,883	2,249	3,083
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,319	2,983	1,898	1,911	1,920	1,931	1,939	1,960	1,957	1,986	2,006	2,051	1,778	1,577	1,326	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	287	287	286	286	287	285	282	279	297	282	267	270	113

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,468	2,603	2,673	2,767	2,763	2,863	2,892	2,938	2,944	3,058	3,043	3,031	3,000	2,988	3,055	2,437
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	2	5	10	12	14	15	15	16	17	17	19	21	22	22	22	22
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,272	2,345	2,345	2,426	2,260	2,068
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	120	120	120	120	120
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,811**	**8,315**	**8,214**	**8,437**	**8,462**	**8,486**	**8,540**	**8,611**	**8,643**	**8,783**	**8,681**	**8,904**	**8,685**	**8,870**	**8,786**	**7,573**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,055	7,452	7,674	7,923	7,917	8,211	8,306	8,434	8,451	8,779	8,757	8,664	8,630	8,461	7,617	6,723
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,736	4,741	4,738	4,753	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	2	6	12	16	18	19	20	20	21	21	22	22	22	22	22	22
Coal	GWh	1,090	1,073	1,109	1,139	1,172	397	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	67	126	48	56	47	49	36	41	53	43	54	37	15	14	8	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,851	3,005	2,874	2,702	2,801	2,722	2,815	2,792	2,659	2,752	2,652	2,837	2,719	2,439	2,329	-
Gas/Hydrogen Turbine	GWh	525	866	891	990	1,386	1,900	1,009	1,142	1,098	1,172	1,138	1,181	1,252	1,242	1,063	933	653	536	294	123
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	388	512	439	415	297	319
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,661**	**20,278**	**20,799**	**19,587**	**19,768**	**19,924**	**20,098**	**20,240**	**20,505**	**20,538**	**20,887**	**21,045**	**21,512**	**21,711**	**22,105**	**22,674**	**21,546**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**273**	**237**	**747**	**769**	**764**	**729**	**763**	**706**	**746**	**715**	**680**	**482**	**439**	**330**	**158**	**629**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,488**	**1,786**	**943**	**973**	**1,001**	**957**	**977**	**997**	**956**	**1,039**	**1,069**	**1,238**	**1,333**	**1,506**	**1,803**	**1,074**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,795**	**20,274**	**19,047**	**19,187**	**19,339**	**19,499**	**19,622**	**19,850**	**19,888**	**20,200**	**20,335**	**20,779**	**20,960**	**21,336**	**21,943**	**20,894**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-TOU P2 8760*
Future: *CTP*
Sensitivity: *Time Of Use forecast impact to CTP*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.178	B$
20-Year Carbon Emissions	41.948	M Tons
20-Year Water Consumption	7.318	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	35	150	83	108	10	114	43	102	20	127	-	-	-	-	162	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	16	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	22	73	-	81	104	258
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**51**	**515**	**109**	**234**	**37**	**142**	**67**	**127**	**44**	**153**	**132**	**284**	**170**	**251**	**584**	**875**

Portfolio Summary

Scenario Information

Scenario: *CTP-XmsnBW P2 8760*
Future: *CTP*
Sensitivity: *Blackwater DC Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.079 B$
20-Year Carbon Emissions 37.151 M Tons
20-Year Water Consumption 6.832 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	20.88	20.28	18.37	18.16	17.62	17.25	16.38	14.40	14.40	14.40	14.48	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	199	198	158	160	148	149	142	133	117	103	91	-

Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,315	1,319	1,355	1,306	1,327	1,336	1,362	1,380	1,630	1,803	1,893	2,293	3,044
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,315	2,975	1,902	1,915	1,927	1,931	1,501	1,538	1,414	1,448	1,378	1,295	1,167	1,058	979	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	287	287	287	249	253	236	239	220	220	213	208	220	103

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,776	2,779	2,858	2,910	2,947	2,956	3,068	3,053	3,041	3,010	2,998	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,285	2,392	2,428	2,580	2,462	2,248
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	160	160	160	160	160
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,476**	**8,508**	**8,512**	**8,588**	**8,651**	**8,685**	**8,824**	**8,775**	**9,032**	**8,849**	**9,105**	**9,060**	**7,826**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,693	7,951	7,964	8,197	8,358	8,461	8,488	8,811	8,792	8,697	8,663	8,505	7,639	6,750
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,737	4,741	4,738	4,754	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	48	56	47	49	21	25	18	19	11	11	8	7	9	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,876	2,701	2,801	2,726	2,725	2,743	2,585	2,665	2,442	2,376	2,182	1,961	1,820	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,014	1,150	1,109	1,169	487	527	448	443	331	238	203	176	155	5
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	235	241	198	208	195	108
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**19,624**	**19,814**	**19,994**	**20,098**	**19,548**	**19,827**	**19,674**	**20,022**	**19,956**	**20,103**	**20,522**	**21,108**	**21,960**	**21,256**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**748**	**768**	**752**	**747**	**2,583**	**2,580**	**2,711**	**2,692**	**2,828**	**3,075**	**3,068**	**2,918**	**2,577**	**2,742**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,497**	**1,790**	**944**	**978**	**1,015**	**936**	**2,120**	**2,229**	**2,072**	**2,186**	**2,197**	**2,537**	**2,916**	**3,286**	**3,723**	**3,089**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,080**	**19,228**	**19,402**	**19,499**	**18,985**	**19,249**	**19,082**	**19,415**	**19,362**	**19,534**	**19,964**	**20,580**	**21,497**	**20,851**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-XmsnBW P2 8760*
Future: *CTP*
Sensitivity: *Blackwater DC Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.079	B$
20-Year Carbon Emissions	37.151	M Tons
20-Year Water Consumption	6.832	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	111	17	93	66	94	23	125	-	-	-	-	155	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	35	107	36	152	151	237
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**237**	**44**	**121**	**90**	**118**	**47**	**151**	**186**	**317**	**206**	**322**	**623**	**854**

Portfolio Summary

Scenario Information

Scenario: *CTP-XmsnFC P2 8760*
Future: *CTP*
Sensitivity: *Four Corners Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 14.443 B$
20-Year Carbon Emissions 42.052 M Tons
20-Year Water Consumption 7.289 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	20.88	20.28	18.37	18.16	17.62	17.25	16.38	14.40	14.40	14.40	14.48	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	199	198	198	198	197	197	197	198	170	149	121	-

Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,315	1,319	1,356	1,404	1,428	1,438	1,467	1,479	1,714	1,884	1,976	2,351	3,162
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,315	2,975	1,902	1,915	1,927	1,931	1,947	1,965	1,963	1,991	2,017	2,069	1,795	1,595	1,337	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	287	287	287	286	287	285	282	270	293	279	264	267	106

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,776	2,779	2,858	2,910	2,947	2,956	3,068	3,053	3,041	3,010	2,998	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,285	2,392	2,428	2,580	2,462	2,248
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	160	160	160	160	160
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,476**	**8,508**	**8,512**	**8,588**	**8,651**	**8,685**	**8,824**	**8,775**	**9,032**	**8,849**	**9,105**	**9,060**	**7,826**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,693	7,951	7,964	8,197	8,358	8,462	8,487	8,809	8,788	8,695	8,661	8,497	7,632	6,740
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,736	4,741	4,738	4,753	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	48	56	47	49	36	41	54	43	40	30	10	8	7	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,876	2,701	2,801	2,726	2,813	2,792	2,657	2,753	2,641	2,835	2,722	2,455	2,340	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,014	1,150	1,109	1,169	1,151	1,189	1,262	1,249	972	859	588	475	247	28
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	573	672	572	533	374	218
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,844**	**19,624**	**19,814**	**19,994**	**20,098**	**20,316**	**20,553**	**20,595**	**20,937**	**21,157**	**21,630**	**21,820**	**22,218**	**22,741**	**21,379**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**748**	**768**	**752**	**748**	**755**	**708**	**745**	**719**	**649**	**447**	**397**	**287**	**141**	**901**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,497**	**1,790**	**944**	**978**	**1,015**	**936**	**997**	**1,000**	**964**	**1,043**	**1,096**	**1,268**	**1,347**	**1,523**	**1,798**	**1,108**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,080**	**19,228**	**19,402**	**19,498**	**19,690**	**19,892**	**19,940**	**20,245**	**20,440**	**20,892**	**21,066**	**21,448**	**22,008**	**20,711**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-XmsnFC P2 8760*
Future: *CTP*
Sensitivity: *Four Corners Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.443	B$
20-Year Carbon Emissions	42.052	M Tons
20-Year Water Consumption	7.289	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	111	17	93	66	94	23	125	-	-	-	-	155	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	35	107	36	152	151	237
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**237**	**44**	**121**	**90**	**118**	**47**	**151**	**186**	**317**	**206**	**322**	**623**	**854**

Portfolio Summary

Scenario Information

Scenario: *CTP-XmsnRS P2 8760*
Future: *CTP*
Sensitivity: *Rio Sol Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.082	B$
20-Year Carbon Emissions	43.644	M Tons
20-Year Water Consumption	7.529	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	20.88	20.28	18.37	18.16	17.62	17.25	16.38	14.40	14.40	14.40	14.48	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	198	198	197	196	196	195	196	196	197	192	171	-
Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,234	1,271	1,274	1,318	1,340	1,361	1,374	1,399	1,418	1,658	1,817	1,897	2,267	3,089
Carbon Emission	k-tons	2,603	2,912	2,892	3,000	3,315	2,977	1,898	1,911	1,923	1,927	1,943	1,961	1,958	1,988	2,014	2,068	2,160	2,188	2,005	-
Water Consumption	k-gallons	569	610	616	610	647	466	299	298	299	297	296	296	297	296	275	289	315	324	328	104

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,776	2,779	2,858	2,910	2,947	2,956	3,068	3,053	3,041	3,010	2,998	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,285	2,392	2,428	2,580	2,462	2,248
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	160	160	160	160	160
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,476**	**8,508**	**8,512**	**8,588**	**8,651**	**8,685**	**8,824**	**8,775**	**9,032**	**8,849**	**9,105**	**9,060**	**7,826**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,694	7,951	7,965	8,197	8,358	8,462	8,488	8,811	8,793	8,697	8,664	8,505	7,639	6,750
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,955	4,738	4,756	4,737	4,741	4,738	4,754	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	82	99	90	91	78	77	99	87	59	42	58	68	42	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,811	2,646	2,750	2,672	2,769	2,763	2,600	2,740	2,617	2,822	2,905	2,772	2,777	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,896	1,002	1,118	1,075	1,137	1,112	1,147	1,227	1,185	980	831	885	1,001	792	5
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	537	687	710	718	635	137
Total Generation	**GWh**	**13,903**	**15,173**	**16,032**	**19,662**	**20,329**	**20,846**	**19,581**	**19,770**	**19,952**	**20,054**	**20,274**	**20,519**	**20,549**	**20,906**	**21,129**	**21,618**	**22,488**	**23,316**	**24,027**	**21,284**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**2,551**	**2,546**	**2,512**	**2,542**	**2,461**	**2,432**	**2,461**	**2,406**	**2,321**	**2,059**	**1,615**	**1,272**	**867**	**2,192**
Market Sales	**GWh**	**2,202**	**1,867**	**1,424**	**1,336**	**1,497**	**1,789**	**2,720**	**2,725**	**2,757**	**2,727**	**2,740**	**2,795**	**2,729**	**2,833**	**2,891**	**3,050**	**3,429**	**3,817**	**4,022**	**2,523**
Net Generation *	**GWh**	**13,644**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,053**	**19,197**	**19,384**	**19,496**	**19,727**	**19,963**	**19,989**	**20,347**	**20,563**	**21,062**	**21,930**	**22,757**	**23,506**	**20,834**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-XmsnRS P2 8760*
Future: *CTP*
Sensitivity: *Rio Sol Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.082	B$
20-Year Carbon Emissions	43.644	M Tons
20-Year Water Consumption	7.529	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	111	17	93	66	94	23	125	-	-	-	-	155	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	35	107	36	152	151	237
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**237**	**44**	**121**	**90**	**118**	**47**	**151**	**186**	**317**	**206**	**322**	**623**	**854**

Portfolio Summary

Scenario Information

Scenario: *CTP-XmsnSZ P2 8760*
Future: *CTP*
Sensitivity: *SunZia Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	13.822	B$
20-Year Carbon Emissions	46.920	M Tons
20-Year Water Consumption	8.078	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	20.88	20.28	18.37	18.16	17.62	17.25	16.38	14.40	14.40	14.40	14.48	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	402	376	397	362	199	199	198	198	197	196	196	195	196	196	197	197	178	-
Revenue Requirement	M$	523	572	659	1,135	1,139	1,193	1,224	1,260	1,263	1,307	1,331	1,353	1,365	1,390	1,410	1,650	1,808	1,886	2,255	3,082
Carbon Emission	k-tons	2,603	2,913	3,277	3,857	4,209	3,949	1,897	1,910	1,921	1,925	1,941	1,960	1,957	1,986	2,013	2,067	2,159	2,262	2,115	-
Water Consumption	k-gallons	569	610	681	728	797	642	300	298	300	300	299	298	297	297	276	291	317	334	341	103

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,776	2,779	2,858	2,910	2,947	2,956	3,068	3,053	3,041	3,010	2,998	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,285	2,392	2,428	2,580	2,462	2,248
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	160	160	160	160	160
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,476**	**8,508**	**8,512**	**8,588**	**8,651**	**8,685**	**8,824**	**8,775**	**9,032**	**8,849**	**9,105**	**9,060**	**7,826**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,371	6,876	7,101	7,498	7,693	7,951	7,965	8,197	8,358	8,462	8,488	8,811	8,792	8,697	8,663	8,505	7,639	6,750
Wind	GWh	2,198	2,229	2,196	4,962	4,946	4,974	4,962	4,980	4,955	4,738	4,756	4,737	4,741	4,738	4,754	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,073	1,158	1,197	409	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	196	224	338	442	89	104	98	102	89	89	105	97	66	49	66	82	60	-
Gas Combined Cycle	GWh	2,608	2,823	2,885	3,000	2,965	3,227	2,799	2,624	2,727	2,647	2,743	2,735	2,576	2,708	2,588	2,801	2,873	2,811	2,823	-
Gas/Hydrogen Turbine	GWh	525	867	1,262	1,950	2,334	2,873	998	1,124	1,077	1,136	1,112	1,149	1,234	1,191	994	837	891	1,066	888	5
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	531	685	716	730	669	135
Total Generation	**GWh**	**13,903**	**15,174**	**16,690**	**21,013**	**21,694**	**22,379**	**19,572**	**19,759**	**19,938**	**20,039**	**20,259**	**20,504**	**20,538**	**20,891**	**21,115**	**21,609**	**22,477**	**23,445**	**24,221**	**21,282**
Market Purchases	**GWh**	**40**	**119**	**1,394**	**1,427**	**1,322**	**1,290**	**2,837**	**2,840**	**2,812**	**2,855**	**2,767**	**2,723**	**2,758**	**2,706**	**2,607**	**2,359**	**1,915**	**1,490**	**1,034**	**2,415**
Market Sales	**GWh**	**2,202**	**1,867**	**3,204**	**3,815**	**3,923**	**4,377**	**3,000**	**3,011**	**3,045**	**3,026**	**3,033**	**3,077**	**3,023**	**3,127**	**3,174**	**3,350**	**3,726**	**4,180**	**4,396**	**2,765**
Net Generation *	**GWh**	**13,644**	**14,863**	**16,303**	**20,524**	**21,212**	**21,845**	**19,047**	**19,188**	**19,372**	**19,481**	**19,713**	**19,954**	**19,986**	**20,342**	**20,560**	**21,064**	**21,927**	**22,902**	**23,713**	**20,854**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP-XmsnSZ P2 8760*
Future: *CTP*
Sensitivity: *SunZia Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 13.822 B$
20-Year Carbon Emissions 46.920 M Tons
20-Year Water Consumption 8.078 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	111	17	93	66	94	23	125	-	-	-	-	155	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	35	107	36	152	151	237
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**237**	**44**	**121**	**90**	**118**	**47**	**151**	**186**	**317**	**206**	**322**	**623**	**854**

Portfolio Summary

Scenario Information

Scenario: *HEG P3 8760*
Future: *HEG*
Sensitivity: *High Economic Growth base case*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 16.749 B$
20-Year Carbon Emissions 46.763 M Tons
20-Year Water Consumption 11.837 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.40	14.69	19.84	20.86	18.79	18.16	16.97	15.96	15.24	15.26	15.42	14.40	14.47	14.40	14.58
Carbon Intensity	lbs/MWh	394	403	389	319	335	282	200	201	201	200	200	199	199	199	199	200	183	164	137	-

Revenue Requirement	M$	541	605	736	1,280	1,326	1,432	1,421	1,545	1,591	1,637	1,664	1,693	1,717	1,776	1,852	2,117	2,290	2,412	2,823	3,751
Carbon Emission	k-tons	2,733	3,039	3,098	3,195	3,498	3,059	2,072	2,094	2,148	2,185	2,219	2,217	2,255	2,277	2,323	2,380	2,219	2,023	1,727	-
Water Consumption	k-gallons	587	626	644	635	663	477	307	303	636	639	656	655	665	682	652	673	665	643	636	392

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,638	2,763	3,084	3,168	3,274	3,400	3,441	3,461	3,441	3,571	3,639	3,625	3,613	3,581	3,570	3,703	3,084
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,474	1,474	1,485	1,555	1,555	1,555	1,555	1,555	1,555	1,249	1,249	999	999
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,095	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,407	2,621	2,575	2,345
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	280	400	400	400	400	440
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,020**	**8,281**	**8,981**	**8,896**	**9,346**	**9,601**	**9,679**	**9,795**	**9,800**	**9,955**	**10,090**	**10,126**	**10,356**	**10,138**	**10,457**	**10,557**	**9,346**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	7,430	7,915	8,849	9,118	9,399	9,770	9,890	9,963	9,897	10,273	10,470	10,453	10,356	10,322	10,161	9,510	8,616
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,975	4,962	5,033	5,009	5,182	5,443	5,421	5,425	5,423	5,441	4,617	4,248	4,028	3,443	3,431
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,133	1,140	1,172	371	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	93	105	69	92	165	68	80	70	79	77	80	102	77	41	24	15	13	9	-
Gas Combined Cycle	GWh	2,732	2,920	2,747	2,880	2,857	2,961	2,888	2,703	2,817	2,739	2,834	2,833	2,667	2,799	2,661	2,832	2,784	2,506	2,457	-
Gas/Hydrogen Turbine	GWh	625	983	1,094	1,215	1,635	2,048	1,258	1,408	1,423	1,524	1,516	1,512	1,657	1,485	913	714	599	494	299	145
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	197	1,322	1,582	1,439	1,410	1,062	1,290
Total Generation	**GWh**	**14,142**	**15,399**	**16,353**	**20,539**	**21,429**	**22,325**	**21,324**	**21,600**	**22,206**	**22,633**	**23,034**	**23,077**	**23,518**	**23,796**	**24,219**	**24,732**	**25,110**	**25,520**	**26,165**	**25,128**
Market Purchases	**GWh**	**63**	**243**	**470**	**402**	**353**	**243**	**781**	**822**	**695**	**613**	**575**	**703**	**661**	**727**	**642**	**511**	**475**	**397**	**227**	**733**
Market Sales	**GWh**	**1,975**	**1,530**	**1,159**	**1,228**	**1,386**	**1,782**	**1,049**	**973**	**1,143**	**1,152**	**1,199**	**1,057**	**1,113**	**1,062**	**1,122**	**1,244**	**1,339**	**1,390**	**1,553**	**707**
Net Generation *	**GWh**	**13,884**	**15,090**	**15,927**	**20,030**	**20,901**	**21,705**	**20,700**	**20,857**	**21,424**	**21,839**	**22,223**	**22,267**	**22,658**	**22,919**	**23,323**	**23,836**	**24,198**	**24,611**	**25,276**	**24,255**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG P3 8760*
Future: *HEG*
Sensitivity: *High Economic Growth base case*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.749	B$
20-Year Carbon Emissions	46.763	M Tons
20-Year Water Consumption	11.837	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	320	140	335	98	120	140	55	34	37	143	82	-	-	-	-	228	300
Wind	MW	-	-	-	800	-	-	-	16	-	114	70	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	131	311	-	-	-	-	-	-	-	-	-	-	1	214	223	220
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	240	120	-	-	-	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,615**	**317**	**711**	**123**	**462**	**267**	**196**	**129**	**61**	**168**	**148**	**271**	**291**	**171**	**384**	**768**	**878**

Portfolio Summary

Scenario Information

Scenario: *HEG-CO2_400thru44 P3 8760*
Future: *HEG*
Sensitivity: *ETA 400 through 2044, zero CO2 by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.663	B$
20-Year Carbon Emissions	52.237	M Tons
20-Year Water Consumption	12.626	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.84	15.14	18.36	19.40	17.42	16.60	15.44	14.40	14.60	14.40	14.56	14.43	14.49	14.40	14.56
Carbon Intensity	lbs/MWh	394	403	389	312	336	297	268	266	259	248	246	248	242	254	201	186	167	169	137	-

Revenue Requirement	M$	541	605	736	1,284	1,336	1,430	1,401	1,499	1,552	1,604	1,627	1,656	1,683	1,754	1,868	2,137	2,332	2,432	2,850	3,775
Carbon Emission	k-tons	2,733	3,039	3,098	3,141	3,510	3,197	2,899	2,944	2,920	2,830	2,830	2,868	2,787	2,988	2,389	2,229	2,026	2,076	1,732	-
Water Consumption	k-gallons	587	626	644	627	663	496	392	400	732	716	746	763	744	765	702	686	666	641	637	392

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,712	2,763	2,941	3,047	3,186	3,304	3,357	3,403	3,389	3,400	3,386	3,371	3,359	3,328	3,520	3,725	3,107
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,528	1,528	1,555	1,555	1,555	1,555	1,555	1,555	1,555	1,249	1,249	999	999
Demand Response	MW	70	70	70	70	2	5	10	12	14	15	15	16	17	17	19	21	22	22	22	22
Short Duration Storage	MW	992	1,160	1,640	1,951	1,951	2,251	2,251	2,281	2,281	2,281	2,281	2,281	2,281	2,281	2,285	2,285	2,285	2,529	2,492	2,369
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	80	160	280	320	440	440	440
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	100	100	100	300	300	300	300	300	300	300	300	300	300	300	300	300
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,082**	**8,208**	**8,753**	**8,689**	**9,157**	**9,403**	**9,510**	**9,582**	**9,593**	**9,629**	**9,722**	**9,748**	**9,978**	**9,799**	**10,325**	**10,506**	**9,363**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,371	7,647	7,915	8,433	8,764	9,141	9,489	9,645	9,793	9,744	9,776	9,736	9,716	9,620	9,586	10,016	9,573	8,681
Wind	GWh	2,198	2,229	2,197	4,962	4,945	4,975	4,962	5,220	5,195	5,423	5,443	5,422	5,425	5,422	5,440	4,617	4,248	4,028	3,443	3,431
Demand Response	GWh	29	29	29	29	2	6	12	16	18	19	20	20	21	21	22	22	22	22	22	22
Coal	GWh	1,090	1,073	1,133	1,131	1,163	391	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	3,549	4,816	5,965	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	93	105	65	98	181	185	231	204	203	187	228	217	199	94	32	13	11	8	-
Gas Combined Cycle	GWh	2,732	2,920	2,746	2,839	2,855	3,024	3,086	2,868	3,037	2,887	3,026	3,031	2,831	3,044	2,718	2,812	2,741	2,514	2,434	-
Gas/Hydrogen Turbine	GWh	625	983	1,094	1,177	1,661	2,169	2,273	2,438	2,310	2,276	2,196	2,208	2,235	2,139	1,325	802	560	480	274	139
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	399	752	1,130	1,102	1,543	1,131	1,269
Total Generation	**GWh**	**14,142**	**15,399**	**16,353**	**20,663**	**21,438**	**22,116**	**22,290**	**22,864**	**23,340**	**23,639**	**23,834**	**23,955**	**23,867**	**24,271**	**24,663**	**24,844**	**25,178**	**25,488**	**26,236**	**25,154**
Market Purchases	**GWh**	**63**	**243**	**470**	**364**	**355**	**289**	**308**	**280**	**209**	**235**	**263**	**328**	**465**	**441**	**401**	**415**	**388**	**399**	**227**	**728**
Market Sales	**GWh**	**1,975**	**1,530**	**1,159**	**1,305**	**1,366**	**1,627**	**1,544**	**1,702**	**1,782**	**1,770**	**1,681**	**1,546**	**1,327**	**1,345**	**1,367**	**1,304**	**1,370**	**1,387**	**1,612**	**724**
Net Generation *	**GWh**	**13,884**	**15,090**	**15,928**	**20,145**	**20,880**	**21,505**	**21,668**	**22,128**	**22,549**	**22,835**	**23,017**	**23,131**	**23,068**	**23,488**	**23,809**	**23,992**	**24,316**	**24,606**	**25,334**	**24,278**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-CO2_400thru44 P3 8760*
Future: *HEG*
Sensitivity: *ETA 400 through 2044, zero CO2 by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.663	B$
20-Year Carbon Emissions	52.237	M Tons
20-Year Water Consumption	12.626	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	394	65	192	120	153	132	67	60	42	24	-	-	-	-	203	300	300
Wind	MW	-	-	-	800	-	-	-	70	-	130	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	16	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	311	-	300	-	30	-	-	-	-	-	-	4	-	-	244	233	327
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	-	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	80	80	120	40	120	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	100	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,677**	**181**	**557**	**145**	**479**	**258**	**224**	**85**	**67**	**49**	**106**	**261**	**291**	**210**	**591**	**850**	**945**

Portfolio Summary

Scenario Information

Scenario: *HEG-LateLDES P3 8760*
Future: *HEG*
Sensitivity: *Late Long Duration Energy Storage available beginning 2036*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.758	B$
20-Year Carbon Emissions	47.096	M Tons
20-Year Water Consumption	9.297	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.40	14.71	16.28	15.29	14.40	14.59	14.45	14.40	14.65	14.82	14.99	14.87	15.12	14.53	14.57
Carbon Intensity	lbs/MWh	394	403	389	319	335	284	200	200	199	199	199	198	198	198	198	198	196	178	155	-

Revenue Requirement	M$	541	605	736	1,280	1,326	1,431	1,422	1,508	1,523	1,592	1,634	1,685	1,726	1,805	1,906	2,167	2,354	2,467	2,837	3,814
Carbon Emission	k-tons	2,733	3,039	3,098	3,195	3,498	3,077	2,072	2,083	2,106	2,171	2,172	2,200	2,226	2,255	2,282	2,334	2,380	2,212	1,964	-
Water Consumption	k-gallons	587	626	644	635	663	479	307	304	304	297	292	284	276	262	599	590	609	588	579	370

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,638	2,763	3,061	3,168	3,244	3,230	3,325	3,311	3,358	3,428	3,508	3,493	3,481	3,450	3,438	3,459	2,840
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,471	1,513	1,531	1,531	1,531	1,531	1,531	1,531	1,531	1,225	1,225	975	975
Demand Response	MW	70	70	70	70	32	35	40	43	45	46	46	47	47	47	50	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,094	2,407	2,407	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,629	2,379
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	40	80	120	160	240	400	520	560	640	680	720
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,020**	**8,281**	**8,960**	**8,898**	**9,507**	**9,563**	**9,743**	**9,794**	**9,906**	**10,041**	**10,227**	**10,284**	**10,514**	**10,335**	**10,519**	**10,323**	**9,092**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	7,430	7,915	8,782	9,117	9,310	9,274	9,553	9,525	9,656	9,859	10,089	10,074	9,975	9,942	9,778	8,797	7,904
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,975	4,962	5,025	5,144	5,338	5,358	5,336	5,341	5,338	5,355	4,532	4,164	3,943	3,358	3,346
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	33	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,133	1,140	1,172	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	93	105	69	92	167	68	77	66	63	45	35	40	15	16	8	8	6	4	-
Gas Combined Cycle	GWh	2,732	2,920	2,747	2,880	2,857	2,969	2,888	2,731	2,843	2,744	2,846	2,831	2,689	2,788	2,650	2,812	2,837	2,551	2,558	-
Gas/Hydrogen Turbine	GWh	625	983	1,094	1,215	1,635	2,066	1,258	1,374	1,343	1,368	1,187	1,115	1,106	882	584	404	470	341	191	45
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	208	408	598	794	1,114	1,733	1,942	1,933	2,011	1,644	1,769
Total Generation	**GWh**	**14,142**	**15,399**	**16,353**	**20,539**	**21,429**	**22,287**	**21,323**	**21,494**	**21,788**	**22,492**	**22,569**	**22,903**	**23,223**	**23,571**	**23,802**	**24,281**	**25,057**	**25,538**	**25,938**	**24,711**
Market Purchases	**GWh**	**63**	**243**	**470**	**402**	**353**	**250**	**781**	**822**	**837**	**621**	**729**	**722**	**713**	**770**	**733**	**571**	**366**	**325**	**269**	**821**
Market Sales	**GWh**	**1,975**	**1,530**	**1,159**	**1,228**	**1,386**	**1,756**	**1,048**	**952**	**983**	**1,130**	**1,016**	**1,004**	**1,008**	**1,017**	**943**	**1,033**	**1,358**	**1,511**	**1,587**	**640**
Net Generation *	**GWh**	**13,884**	**15,090**	**15,927**	**20,030**	**20,901**	**21,672**	**20,699**	**20,836**	**21,121**	**21,809**	**21,887**	**22,195**	**22,501**	**22,830**	**23,054**	**23,565**	**24,326**	**24,804**	**25,268**	**24,101**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-LateLDES P3 8760*
Future: *HEG*
Sensitivity: *Late Long Duration Energy Storage available beginning 2036*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.758	B$
20-Year Carbon Emissions	47.096	M Tons
20-Year Water Consumption	9.297	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	320	140	312	121	90	-	109	-	104	84	94	-	-	-	-	115	300
Wind	MW	-	-	-	800	-	-	-	13	42	120	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	48	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	131	313	-	492	-	-	-	-	-	-	-	-	-	-	-	200
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	40	40	40	40	80	160	120	40	80	40	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,615**	**318**	**690**	**146**	**621**	**68**	**295**	**64**	**168**	**148**	**200**	**291**	**291**	**210**	**250**	**472**	**858**

Portfolio Summary

Scenario Information

Scenario: *HEG-NoETA P3 8760*
Future: *HEG*
Sensitivity: *No CO2 emission limits, No RPS, No CO2 free by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.263	B$
20-Year Carbon Emissions	54.444	M Tons
20-Year Water Consumption	16.252	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.40	14.61	14.40	17.71	15.39	14.62	17.75	16.67	14.99	16.23	16.13	14.40	15.30	14.40	14.57
Carbon Intensity	lbs/MWh	394	408	389	319	335	285	268	273	262	260	256	263	257	270	178	159	169	152	151	169
Revenue Requirement	M$	541	604	736	1,280	1,323	1,426	1,389	1,435	1,540	1,578	1,605	1,699	1,725	1,760	1,943	2,149	2,212	2,281	2,582	3,033
Carbon Emission	k-tons	2,733	3,094	3,098	3,195	3,498	3,089	2,899	3,003	2,941	2,954	2,927	3,059	2,970	3,148	2,148	1,916	2,002	1,839	1,845	2,086
Water Consumption	k-gallons	587	633	644	635	663	480	392	407	962	984	1,047	985	968	1,066	1,018	1,009	993	987	951	841

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,638	2,763	3,046	3,032	3,163	3,329	3,463	3,522	3,507	3,506	3,493	3,478	3,466	3,435	3,423	3,628	2,839
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	43	45	46	46	47	47	47	50	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,094	2,409	2,409	2,633	2,633	2,633	2,633	2,633	2,633	2,633	2,633	2,633	2,655	2,655	2,597	2,154
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	580	726	726	872	1,018	1,164
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	833	833	833	666	666	666	666	666	845
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200	200	200
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,020**	**8,281**	**8,946**	**8,763**	**9,148**	**9,542**	**9,601**	**9,685**	**9,874**	**9,898**	**9,910**	**9,999**	**10,109**	**9,765**	**9,869**	**9,885**	**8,856**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	7,430	7,915	8,739	8,721	9,076	9,561	9,954	10,141	10,089	10,086	10,045	10,019	9,926	9,896	9,728	9,291	7,905
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,975	4,962	4,980	4,956	4,738	4,756	4,737	4,741	4,738	4,752	3,932	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	33	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,133	1,140	1,172	374	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	4,789	6,053	5,965	7,281	8,543	9,516
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	102	105	69	92	168	184	238	206	238	220	176	166	203	73	39	42	37	34	-
Gas Combined Cycle	GWh	2,732	2,932	2,747	2,880	2,857	2,974	3,097	2,886	3,063	2,924	3,040	3,042	2,849	3,071	2,624	2,710	2,795	2,561	2,661	2,627
Gas/Hydrogen Turbine	GWh	625	1,046	1,094	1,215	1,635	2,077	2,269	2,514	2,321	2,403	2,302	2,603	2,609	2,681	1,582	1,183	1,259	1,162	1,099	1,577
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**GWh**	**14,142**	**15,484**	**16,353**	**20,539**	**21,429**	**22,262**	**22,263**	**22,672**	**23,225**	**23,477**	**23,660**	**23,980**	**23,845**	**24,084**	**24,921**	**24,871**	**24,496**	**24,976**	**25,227**	**25,265**
Market Purchases	**GWh**	**63**	**210**	**470**	**402**	**353**	**255**	**307**	**312**	**233**	**270**	**298**	**322**	**466**	**503**	**310**	**428**	**642**	**600**	**535**	**491**
Market Sales	**GWh**	**1,975**	**1,582**	**1,159**	**1,228**	**1,386**	**1,740**	**1,542**	**1,638**	**1,745**	**1,688**	**1,584**	**1,634**	**1,355**	**1,265**	**1,572**	**1,366**	**1,001**	**1,145**	**1,034**	**874**
Net Generation *	**GWh**	**13,884**	**15,175**	**15,927**	**20,030**	**20,901**	**21,651**	**21,667**	**22,032**	**22,487**	**22,718**	**22,885**	**23,225**	**23,095**	**23,346**	**24,106**	**24,042**	**23,693**	**24,163**	**24,449**	**24,665**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-NoETA P3 8760*
Future: *HEG*
Sensitivity: *No CO2 emission limits, No RPS, No CO2 free by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.263	B$
20-Year Carbon Emissions	54.444	M Tons
20-Year Water Consumption	16.252	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	320	140	297	-	145	179	149	73	42	12	-	-	-	-	-	300	129
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	48	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	131	314	-	224	-	-	-	-	-	-	-	-	21	-	213	7
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	292	146	-	146	146	146
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	179	-	-	-	-	-	-	-	179
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,615**	**318**	**676**	**25**	**396**	**406**	**174**	**98**	**245**	**37**	**26**	**323**	**171**	**45**	**170**	**684**	**486**

Portfolio Summary

Scenario Information

Scenario: *HEG-SS ETA Step Down P3 8760*
Future: *HEG*
Sensitivity: *Smooth out' the acquisition of new clean firm resources*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	17.105	B$
20-Year Carbon Emissions	37.258	M Tons
20-Year Water Consumption	11.184	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.40	14.71	18.31	19.38	17.67	16.89	15.78	18.19	19.86	14.40	15.18	14.40	14.47	14.40	14.56
Carbon Intensity	lbs/MWh	394	403	389	319	335	284	200	200	200	155	155	155	110	110	110	65	65	66	66	-
Revenue Requirement	M$	541	605	736	1,280	1,326	1,431	1,422	1,535	1,583	1,663	1,683	1,717	1,864	1,989	1,933	2,284	2,449	2,522	2,859	3,690
Carbon Emission	k-tons	2,733	3,039	3,098	3,195	3,498	3,076	2,072	2,093	2,151	1,674	1,710	1,746	1,258	1,323	1,327	800	825	822	819	-
Water Consumption	k-gallons	587	626	644	635	663	479	307	304	595	579	610	611	575	629	634	584	600	576	551	394

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,638	2,763	3,062	3,168	3,287	3,425	3,570	3,713	3,843	3,848	3,835	3,820	3,808	3,776	3,844	3,901	3,160
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,555	1,555	1,555	1,555	1,555	1,555	1,555	1,249	1,249	999	999
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,095	2,408	2,408	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,856	2,860	2,661	2,392
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	434	580	580	872	1,018	1,018	1,164	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	200	400
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	200	300	300
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,020**	**8,281**	**8,961**	**8,897**	**9,580**	**9,847**	**10,115**	**10,284**	**10,439**	**10,615**	**10,774**	**10,570**	**10,827**	**10,620**	**10,882**	**10,787**	**9,429**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	7,431	7,915	8,783	9,117	9,435	9,842	10,265	10,696	11,059	11,064	11,000	10,980	10,821	10,756	10,856	10,069	8,833
Wind	GWh	2,198	2,229	2,197	4,961	4,946	4,975	4,962	4,980	4,956	5,422	5,443	5,421	5,424	5,417	5,435	4,605	4,248	4,027	3,443	3,431
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,133	1,140	1,172	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	3,572	4,699	4,789	7,290	8,438	8,518	9,784	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	93	105	69	92	167	68	79	68	26	23	26	7	9	17	2	2	1	0	-
Gas Combined Cycle	GWh	2,732	2,920	2,747	2,880	2,857	2,969	2,888	2,729	2,837	2,542	2,624	2,615	2,232	2,291	2,232	1,735	1,742	1,605	1,529	-
Gas/Hydrogen Turbine	GWh	625	983	1,094	1,215	1,635	2,065	1,257	1,388	1,414	916	918	980	473	540	582	81	119	89	66	159
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	169	268	1,174
Total Generation	**GWh**	**14,142**	**15,399**	**16,353**	**20,538**	**21,428**	**22,287**	**21,323**	**21,589**	**22,234**	**22,389**	**22,905**	**23,434**	**23,831**	**25,076**	**25,115**	**25,562**	**26,281**	**26,128**	**26,003**	**25,243**
Market Purchases	**GWh**	**63**	**243**	**470**	**402**	**353**	**250**	**781**	**787**	**659**	**767**	**733**	**677**	**677**	**329**	**382**	**397**	**212**	**449**	**414**	**718**
Market Sales	**GWh**	**1,975**	**1,530**	**1,159**	**1,228**	**1,386**	**1,756**	**1,048**	**981**	**1,170**	**1,041**	**1,180**	**1,311**	**1,381**	**1,873**	**1,698**	**1,858**	**2,129**	**1,863**	**1,417**	**774**
Net Generation *	**GWh**	**13,884**	**15,090**	**15,927**	**20,030**	**20,901**	**21,672**	**20,699**	**20,900**	**21,487**	**21,573**	**22,046**	**22,547**	**22,909**	**24,128**	**24,160**	**24,564**	**25,251**	**25,032**	**24,953**	**24,337**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-SS ETA Step Down P3 8760*
Future: *HEG*
Sensitivity: *Smooth out' the acquisition of new clean firm resources*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	17.105	B$
20-Year Carbon Emissions	37.258	M Tons
20-Year Water Consumption	11.184	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	320	140	312	121	133	153	158	157	187	18	-	-	-	-	79	152	177
Wind	MW	-	-	-	800	-	-	-	-	-	199	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	131	313	-	435	-	-	-	-	-	-	-	-	13	4	71	182
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	146	146	-	292	146	-	146	146
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	80	200
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	100	100	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,615**	**317**	**690**	**146**	**694**	**279**	**385**	**181**	**212**	**189**	**172**	**31**	**317**	**182**	**327**	**574**	**730**

Portfolio Summary

Scenario Information

Scenario: *HEG-SS Fusion P3 8760*
Future: *HEG*
Sensitivity: *Add fusion as a candidate resource, associated costs and operating characteristics.*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	15.964	B$
20-Year Carbon Emissions	41.849	M Tons
20-Year Water Consumption	15.374	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.40	14.71	15.17	18.43	16.10	15.32	15.17	15.09	14.40	15.51	16.12	18.29	19.92	18.06	14.57
Carbon Intensity	lbs/MWh	394	403	389	319	335	284	200	200	200	200	199	199	199	198	160	122	85	55	44	-
Revenue Requirement	M$	541	605	736	1,280	1,326	1,431	1,422	1,483	1,578	1,616	1,640	1,692	1,731	1,793	1,781	1,928	2,060	2,108	2,263	2,744
Carbon Emission	k-tons	2,733	3,039	3,098	3,195	3,498	3,076	2,072	2,095	2,136	2,155	2,176	2,217	2,231	2,262	1,955	1,516	1,084	727	582	-
Water Consumption	k-gallons	587	626	644	635	663	479	307	304	848	873	941	950	945	977	1,040	1,027	997	968	904	658

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	447	416	387	357	339	365
Solar	MW	1,775	2,025	2,266	2,638	2,763	3,062	3,168	3,294	3,380	3,506	3,572	3,657	3,689	3,797	3,782	3,770	3,739	3,727	3,632	2,714
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,095	2,408	2,408	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,468	2,046
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	40	80	120	120	120	120	120	120	120
Pumped Hydro	MW	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200	200	200
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,020**	**8,281**	**8,961**	**8,897**	**9,382**	**9,697**	**9,747**	**9,838**	**9,988**	**10,086**	**10,260**	**10,050**	**10,008**	**9,643**	**9,601**	**8,957**	**6,922**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	977	915	863	811	790	841
Solar	GWh	4,898	5,582	6,370	7,430	7,915	8,783	9,117	9,455	9,710	10,079	10,286	10,521	10,617	10,926	10,906	10,813	10,782	10,622	9,308	7,545
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,975	4,962	4,980	4,956	4,738	4,756	4,737	4,741	4,738	4,753	3,933	3,563	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,133	1,140	1,172	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,095
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	93	105	69	92	167	68	82	69	75	70	64	71	48	57	17	3	2	1	-
Gas Combined Cycle	GWh	2,732	2,920	2,747	2,880	2,857	2,969	2,888	2,720	2,846	2,751	2,846	2,838	2,686	2,796	2,518	2,451	2,026	1,448	1,235	-
Gas/Hydrogen Turbine	GWh	625	983	1,094	1,215	1,635	2,065	1,257	1,394	1,383	1,473	1,450	1,385	1,349	1,229	1,001	488	205	91	33	6
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	201	413	567	482	329	179	109	66	142
Total Generation	**GWh**	**14,142**	**15,399**	**16,353**	**20,539**	**21,429**	**22,287**	**21,323**	**21,608**	**22,081**	**22,335**	**22,609**	**23,080**	**23,271**	**23,650**	**23,098**	**21,383**	**19,969**	**18,793**	**16,565**	**13,408**
Market Purchases	**GWh**	**63**	**243**	**470**	**402**	**353**	**250**	**781**	**797**	**727**	**742**	**786**	**723**	**759**	**801**	**202**	**113**	**33**	**17**	**4**	**235**
Market Sales	**GWh**	**1,975**	**1,530**	**1,159**	**1,228**	**1,386**	**1,756**	**1,048**	**1,032**	**1,088**	**1,015**	**1,014**	**1,076**	**1,002**	**1,033**	**1,744**	**1,838**	**2,236**	**2,622**	**2,672**	**2,042**
Net Generation *	**GWh**	**13,884**	**15,090**	**15,927**	**20,030**	**20,902**	**21,672**	**20,699**	**20,941**	**21,337**	**21,572**	**21,827**	**22,266**	**22,448**	**22,815**	**24,385**	**24,828**	**25,537**	**26,224**	**26,619**	**26,088**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-SS Fusion P3 8760*
Future: *HEG*
Sensitivity: *Add fusion as a candidate resource, associated costs and operating characteristics.*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 15.964 B$
20-Year Carbon Emissions 41.849 M Tons
20-Year Water Consumption 15.374 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	20	18	24	24	25	25
Solar	MW	-	-	-	320	140	312	121	140	100	140	80	141	46	121	-	-	-	-	-	-
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	131	313	-	330	-	-	-	-	-	-	-	-	-	-	-	28
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300	300	300	300	300
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	40	40	40	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,615**	**317**	**690**	**146**	**496**	**327**	**167**	**104**	**206**	**111**	**187**	**324**	**318**	**324**	**324**	**325**	**353**

Portfolio Summary

Scenario Information

Scenario: *HEG-TOU P3 8760*
Future: *HEG*
Sensitivity: *Time Of Use forecast impact to HEG*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 16.536 B$
20-Year Carbon Emissions 46.634 M Tons
20-Year Water Consumption 11.626 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,635	3,699	3,724	3,824	3,883	3,976	4,024	4,084	4,142	4,223	4,263	4,305	4,323	4,352	4,409	4,496
PRM	%	9.20	8.99	13.64	14.41	14.40	14.40	14.68	16.29	17.68	15.56	15.31	14.54	14.75	14.40	14.66	15.09	14.40	14.47	14.40	14.57
Carbon Intensity	lbs/MWh	394	403	389	319	335	282	200	200	200	199	199	199	198	198	199	199	186	168	139	-

Revenue Requirement	M$	541	605	736	1,280	1,326	1,431	1,420	1,490	1,543	1,585	1,617	1,651	1,691	1,754	1,832	2,097	2,270	2,375	2,783	3,714
Carbon Emission	k-tons	2,733	3,039	3,097	3,195	3,493	3,060	2,065	2,082	2,120	2,141	2,173	2,201	2,217	2,265	2,308	2,364	2,253	2,067	1,762	-
Water Consumption	k-gallons	587	626	644	635	663	476	307	304	610	609	637	644	633	661	638	654	652	635	625	387

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,638	2,755	3,068	3,148	3,134	3,210	3,341	3,335	3,393	3,433	3,582	3,567	3,555	3,524	3,512	3,650	3,032
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,562	1,562	1,460	1,548	1,555	1,555	1,555	1,555	1,555	1,249	1,249	999	999
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,112	2,432	2,432	2,532	2,532	2,532	2,532	2,532	2,532	2,535	2,535	2,535	2,539	2,635	2,564	2,417
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	40	80	320	440	440	440	440	440
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,021**	**8,291**	**8,992**	**8,902**	**9,221**	**9,425**	**9,481**	**9,588**	**9,679**	**9,784**	**10,002**	**10,038**	**10,268**	**10,053**	**10,253**	**10,333**	**9,166**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	7,431	7,890	8,803	9,058	8,991	9,216	9,600	9,597	9,757	9,872	10,301	10,282	10,186	10,153	9,987	9,351	8,457
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,975	4,962	5,337	5,313	5,095	5,418	5,421	5,425	5,422	5,440	4,617	4,248	4,028	3,443	3,431
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,133	1,140	1,173	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	93	105	68	90	162	66	79	72	64	68	75	79	57	30	17	10	10	8	-
Gas Combined Cycle	GWh	2,732	2,920	2,747	2,880	2,862	2,966	2,893	2,728	2,843	2,754	2,853	2,839	2,699	2,799	2,654	2,826	2,797	2,528	2,476	-
Gas/Hydrogen Turbine	GWh	625	983	1,093	1,215	1,624	2,046	1,244	1,372	1,358	1,463	1,444	1,487	1,457	1,347	794	593	561	468	284	146
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	206	402	1,475	1,727	1,562	1,528	1,144	1,302
Total Generation	**GWh**	**14,142**	**15,399**	**16,353**	**20,539**	**21,397**	**22,280**	**21,255**	**21,485**	**21,920**	**22,195**	**22,581**	**22,912**	**23,133**	**23,673**	**24,064**	**24,573**	**25,034**	**25,457**	**26,093**	**24,982**
Market Purchases	**GWh**	**63**	**243**	**470**	**402**	**354**	**245**	**788**	**807**	**768**	**765**	**734**	**744**	**764**	**739**	**663**	**526**	**448**	**383**	**228**	**763**
Market Sales	**GWh**	**1,975**	**1,530**	**1,159**	**1,229**	**1,387**	**1,773**	**1,024**	**972**	**1,058**	**987**	**1,036**	**1,029**	**976**	**1,070**	**1,109**	**1,237**	**1,380**	**1,456**	**1,629**	**772**
Net Generation *	**GWh**	**13,884**	**15,090**	**15,927**	**20,030**	**20,871**	**21,662**	**20,634**	**20,835**	**21,229**	**21,483**	**21,861**	**22,156**	**22,375**	**22,871**	**23,243**	**23,765**	**24,218**	**24,640**	**25,298**	**24,236**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-TOU P3 8760*
Future: *HEG*
Sensitivity: *Time Of Use forecast impact to HEG*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.536	B$
20-Year Carbon Emissions	46.634	M Tons
20-Year Water Consumption	11.626	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	320	131	328	94	-	90	145	8	114	53	162	-	-	-	-	233	300
Wind	MW	-	-	-	800	-	-	-	104	-	-	88	7	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	148	320	-	100	-	-	-	-	-	3	-	-	4	96	198	304
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	40	40	240	120	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,616**	**326**	**712**	**119**	**331**	**217**	**173**	**121**	**146**	**118**	**231**	**271**	**291**	**173**	**266**	**748**	**921**

Portfolio Summary

Scenario Information

Scenario: *HEG-XED P3 APPP1 8760*
Future: *HEG*
Sensitivity: *Increased level of Economic Development*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	31.578	B$
20-Year Carbon Emissions	70.954	M Tons
20-Year Water Consumption	11.857	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	3,022	3,821	4,498	5,029	5,190	5,346	5,465	5,619	5,729	5,853	5,977	6,125	6,226	6,331	6,413	6,504	6,632	6,782
PRM	%	9.20	8.99	12.34	14.40	14.99	14.40	15.59	16.97	16.88	14.50	14.44	14.74	15.46	14.58	14.74	14.64	14.49	14.43	14.79	14.45
Carbon Intensity	lbs/MWh	394	403	401	318	233	255	205	205	204	204	204	204	204	203	202	199	203	203	198	-
Revenue Requirement	M$	541	605	765	1,579	2,527	3,049	3,185	3,260	3,314	3,385	3,475	3,586	3,719	3,806	3,971	4,275	4,497	4,660	5,122	6,826
Carbon Emission	k-tons	2,733	3,039	3,235	3,513	3,403	4,307	3,447	3,517	3,583	3,660	3,754	3,844	3,978	3,981	4,108	4,089	4,180	4,291	4,290	-
Water Consumption	k-gallons	587	626	660	664	636	480	287	286	635	637	660	656	707	678	702	697	617	619	629	394

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	3,238	6,072	6,508	6,794	6,780	6,868	6,991	7,197	7,407	7,394	7,380	7,365	7,353	7,342	7,330	7,433	6,815
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,692	1,753	1,787	1,818	1,818	1,818	1,818	1,818	1,818	1,512	1,512	1,262	1,262
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	2,345	3,602	3,937	4,578	4,578	4,578	4,578	4,578	4,578	4,578	4,578	4,578	4,578	4,578	4,578	4,308	3,858
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	434	434	580	726	726	872	1,164	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	120	600	680	680	680	680	760	880	880	960	1,120	1,280	1,520	1,640	1,760	2,000
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	100	200	300	300	500	500	500	500	500	500	500	500	500	500	500	500	500
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**9,102**	**13,418**	**14,836**	**15,673**	**16,122**	**16,399**	**16,583**	**16,925**	**17,281**	**17,439**	**17,532**	**17,634**	**17,904**	**17,799**	**18,023**	**17,989**	**16,612**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	9,175	17,177	18,767	19,674	19,587	19,848	20,207	20,840	21,413	21,366	21,333	21,328	21,216	21,250	21,089	20,366	19,453
Wind	GWh	2,198	2,229	2,197	4,961	4,861	4,970	4,961	5,784	5,967	6,217	6,349	6,323	6,327	6,325	6,344	5,519	5,151	4,931	4,349	4,334
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,145	1,154	1,073	361	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	3,572	3,462	4,789	6,053	5,965	7,281	9,784	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	92	119	104	182	186	37	50	47	67	61	57	79	53	57	41	16	19	25	-
Gas Combined Cycle	GWh	2,732	2,920	2,783	2,914	2,433	2,884	2,898	2,730	2,905	2,756	2,908	2,859	2,673	2,842	2,709	2,906	2,866	2,612	2,634	-
Gas/Hydrogen Turbine	GWh	625	983	1,243	1,618	1,475	1,931	1,050	1,213	1,245	1,342	1,246	1,075	1,388	1,005	1,014	719	302	337	278	132
Advanced Generator	GWh	-	-	-	-	483	3,041	3,419	3,495	3,423	3,577	3,786	4,280	4,286	4,702	5,127	5,317	6,155	6,608	6,652	8,587
Total Generation	**GWh**	**14,142**	**15,399**	**16,565**	**22,770**	**30,495**	**35,094**	**35,071**	**35,836**	**36,553**	**37,385**	**38,391**	**39,340**	**40,750**	**40,843**	**42,449**	**42,798**	**42,681**	**43,739**	**44,930**	**44,152**
Market Purchases	**GWh**	**63**	**243**	**578**	**587**	**330**	**291**	**873**	**825**	**827**	**818**	**792**	**752**	**454**	**747**	**419**	**487**	**793**	**665**	**415**	**843**
Market Sales	**GWh**	**1,975**	**1,530**	**1,026**	**1,120**	**2,478**	**2,327**	**1,345**	**1,268**	**1,240**	**1,244**	**1,336**	**1,457**	**1,756**	**1,359**	**1,799**	**1,570**	**1,184**	**1,367**	**1,474**	**495**
Net Generation *	**GWh**	**13,884**	**15,090**	**16,145**	**22,109**	**29,205**	**33,723**	**33,659**	**34,345**	**35,043**	**35,848**	**36,774**	**37,664**	**39,033**	**39,190**	**40,743**	**41,119**	**41,126**	**42,187**	**43,396**	**42,739**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-XED P3 APPP1 8760*
Future: *HEG*
Sensitivity: *Increased level of Economic Development*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	31.578	B$
20-Year Carbon Emissions	70.954	M Tons
20-Year Water Consumption	11.857	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	920	2,849	450	300	-	102	137	220	267	-	-	-	-	20	-	198	300
Wind	MW	-	-	-	800	-	-	-	234	60	136	32	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	705	1,257	335	641	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	146	-	146	146	-	146	292	146
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	120	480	80	-	-	-	80	120	-	80	160	160	240	120	120	240
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	100	100	100	-	200	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**2,697**	**4,372**	**1,429**	**1,046**	**461**	**289**	**300**	**356**	**412**	**171**	**106**	**337**	**331**	**283**	**290**	**635**	**711**

Portfolio Summary

Scenario Information

Scenario: *HEG-XmsnBW P3 8760*
Future: *HEG*
Sensitivity: *Blackwater DC Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.481	B$
20-Year Carbon Emissions	41.384	M Tons
20-Year Water Consumption	10.846	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.40	14.69	19.84	20.86	18.79	18.16	16.97	15.96	15.24	15.26	15.42	14.40	14.47	14.40	14.58
Carbon Intensity	lbs/MWh	394	403	389	319	335	282	200	201	201	200	153	159	147	154	158	149	134	118	101	-

Revenue Requirement	M$	541	605	736	1,280	1,326	1,432	1,421	1,545	1,591	1,637	1,610	1,630	1,653	1,704	1,790	2,061	2,231	2,346	2,774	3,574
Carbon Emission	k-tons	2,733	3,039	3,098	3,195	3,498	3,059	2,072	2,094	2,148	2,185	1,634	1,715	1,595	1,705	1,770	1,682	1,538	1,393	1,231	-
Water Consumption	k-gallons	587	626	644	635	663	477	307	303	636	640	584	586	581	597	555	535	535	515	482	356

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,638	2,763	3,084	3,168	3,274	3,400	3,441	3,461	3,441	3,571	3,639	3,625	3,613	3,581	3,570	3,703	3,084
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,474	1,474	1,485	1,555	1,555	1,555	1,555	1,555	1,555	1,249	1,249	999	999
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,095	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,407	2,621	2,575	2,345
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	280	400	400	400	400	440
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,020**	**8,281**	**8,981**	**8,896**	**9,346**	**9,601**	**9,679**	**9,795**	**9,800**	**9,955**	**10,090**	**10,126**	**10,356**	**10,138**	**10,457**	**10,557**	**9,346**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	7,430	7,915	8,849	9,118	9,398	9,770	9,890	9,963	9,897	10,274	10,471	10,456	10,357	10,323	10,165	9,514	8,622
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,975	4,962	5,034	5,009	5,182	5,443	5,422	5,425	5,423	5,441	4,617	4,248	4,028	3,443	3,431
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,133	1,140	1,172	371	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	93	105	69	92	165	68	80	70	79	24	30	23	23	11	9	7	7	7	-
Gas Combined Cycle	GWh	2,732	2,920	2,747	2,880	2,857	2,961	2,888	2,703	2,817	2,739	2,830	2,871	2,694	2,835	2,613	2,610	2,502	2,250	2,065	-
Gas/Hydrogen Turbine	GWh	625	983	1,094	1,215	1,635	2,048	1,258	1,408	1,423	1,524	629	725	666	651	441	308	265	193	149	5
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	125	807	792	637	651	528	171
Total Generation	**GWh**	**14,142**	**15,399**	**16,353**	**20,539**	**21,429**	**22,325**	**21,324**	**21,600**	**22,206**	**22,633**	**22,090**	**22,277**	**22,478**	**22,873**	**23,157**	**23,301**	**23,685**	**24,201**	**25,092**	**23,874**
Market Purchases	**GWh**	**63**	**243**	**470**	**402**	**353**	**243**	**781**	**822**	**695**	**612**	**2,333**	**2,426**	**2,485**	**2,504**	**2,562**	**2,888**	**2,975**	**2,962**	**2,828**	**3,398**
Market Sales	**GWh**	**1,975**	**1,530**	**1,159**	**1,228**	**1,386**	**1,782**	**1,049**	**973**	**1,143**	**1,153**	**2,119**	**2,074**	**2,006**	**2,043**	**2,166**	**2,409**	**2,644**	**2,881**	**3,361**	**2,430**
Net Generation *	**GWh**	**13,884**	**15,090**	**15,927**	**20,030**	**20,901**	**21,705**	**20,700**	**20,857**	**21,424**	**21,841**	**21,385**	**21,562**	**21,727**	**22,122**	**22,447**	**22,624**	**23,004**	**23,537**	**24,483**	**23,313**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-XmsnBW P3 8760*
Future: *HEG*
Sensitivity: *Blackwater DC Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 16.481 B$
20-Year Carbon Emissions 41.384 M Tons
20-Year Water Consumption 10.846 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	320	140	335	98	120	140	55	34	37	143	82	-	-	-	-	228	300
Wind	MW	-	-	-	800	-	-	-	16	-	114	70	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	131	311	-	-	-	-	-	-	-	-	-	-	1	214	223	220
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	240	120	-	-	-	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,615**	**317**	**711**	**123**	**462**	**267**	**196**	**129**	**61**	**168**	**148**	**271**	**291**	**171**	**384**	**768**	**878**

Portfolio Summary

Scenario Information

Scenario: *HEG-XmsnFC P3 8760*
Future: *HEG*
Sensitivity: *Four Corners Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.861	B$
20-Year Carbon Emissions	46.757	M Tons
20-Year Water Consumption	11.891	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.40	14.69	19.84	20.86	18.79	18.16	16.97	15.96	15.24	15.26	15.42	14.40	14.47	14.40	14.58
Carbon Intensity	lbs/MWh	394	403	389	319	335	282	200	201	201	200	200	199	199	199	199	200	183	164	136	-
Revenue Requirement	M$	541	605	736	1,280	1,326	1,432	1,421	1,545	1,591	1,637	1,697	1,726	1,749	1,807	1,883	2,147	2,319	2,441	2,852	3,752
Carbon Emission	k-tons	2,733	3,039	3,098	3,195	3,498	3,059	2,072	2,094	2,148	2,185	2,219	2,217	2,255	2,277	2,323	2,380	2,219	2,023	1,722	-
Water Consumption	k-gallons	587	626	644	635	663	477	307	303	636	639	656	655	665	682	652	673	665	643	637	445

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,638	2,763	3,084	3,168	3,274	3,400	3,441	3,461	3,441	3,571	3,639	3,625	3,613	3,581	3,570	3,703	3,084
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,474	1,474	1,485	1,555	1,555	1,555	1,555	1,555	1,555	1,249	1,249	999	999
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,095	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,407	2,621	2,575	2,345
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	280	400	400	400	400	440
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,020**	**8,281**	**8,981**	**8,896**	**9,346**	**9,601**	**9,679**	**9,795**	**9,800**	**9,955**	**10,090**	**10,126**	**10,356**	**10,138**	**10,457**	**10,557**	**9,346**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	7,430	7,915	8,849	9,117	9,399	9,770	9,890	9,963	9,898	10,273	10,471	10,454	10,356	10,322	10,161	9,510	8,616
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,975	4,962	5,033	5,009	5,182	5,443	5,421	5,425	5,422	5,440	4,617	4,248	4,028	3,443	3,431
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,133	1,140	1,172	371	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	93	105	69	92	165	68	80	70	79	77	80	102	77	41	24	15	13	8	-
Gas Combined Cycle	GWh	2,732	2,920	2,747	2,880	2,857	2,961	2,888	2,703	2,817	2,739	2,834	2,833	2,667	2,799	2,661	2,832	2,784	2,506	2,458	-
Gas/Hydrogen Turbine	GWh	625	983	1,094	1,215	1,635	2,048	1,258	1,408	1,423	1,524	1,516	1,512	1,657	1,485	913	714	599	494	292	64
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	197	1,322	1,582	1,439	1,410	1,060	855
Total Generation	**GWh**	**14,142**	**15,399**	**16,353**	**20,539**	**21,429**	**22,325**	**21,324**	**21,600**	**22,206**	**22,633**	**23,034**	**23,077**	**23,518**	**23,796**	**24,219**	**24,732**	**25,110**	**25,520**	**26,157**	**24,612**
Market Purchases	**GWh**	**63**	**243**	**470**	**402**	**353**	**243**	**781**	**822**	**695**	**613**	**575**	**703**	**661**	**727**	**642**	**512**	**475**	**397**	**242**	**1,253**
Market Sales	**GWh**	**1,975**	**1,530**	**1,159**	**1,228**	**1,386**	**1,782**	**1,049**	**973**	**1,143**	**1,152**	**1,199**	**1,057**	**1,113**	**1,062**	**1,122**	**1,244**	**1,339**	**1,390**	**1,561**	**727**
Net Generation *	**GWh**	**13,884**	**15,090**	**15,927**	**20,030**	**20,901**	**21,705**	**20,700**	**20,857**	**21,424**	**21,839**	**22,223**	**22,267**	**22,658**	**22,919**	**23,323**	**23,836**	**24,198**	**24,611**	**25,269**	**23,755**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-XmsnFC P3 8760*
Future: *HEG*
Sensitivity: *Four Corners Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.861	B$
20-Year Carbon Emissions	46.757	M Tons
20-Year Water Consumption	11.891	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	320	140	335	98	120	140	55	34	37	143	82	-	-	-	-	228	300
Wind	MW	-	-	-	800	-	-	-	16	-	114	70	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	131	311	-	-	-	-	-	-	-	-	-	-	1	214	223	220
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	240	120	-	-	-	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,615**	**317**	**711**	**123**	**462**	**267**	**196**	**129**	**61**	**168**	**148**	**271**	**291**	**171**	**384**	**768**	**878**

Portfolio Summary

Scenario Information

Scenario: *HEG-XmsnRS P3 8760*
Future: *HEG*
Sensitivity: *Rio Sol Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.465	B$
20-Year Carbon Emissions	48.227	M Tons
20-Year Water Consumption	11.302	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.40	14.69	19.84	20.86	18.79	18.16	16.97	15.96	15.24	15.26	15.42	14.40	14.47	14.40	14.58
Carbon Intensity	lbs/MWh	394	403	389	319	335	282	200	200	200	199	198	198	198	197	197	198	198	199	179	-

Revenue Requirement	M$	541	605	736	1,280	1,326	1,432	1,378	1,498	1,538	1,590	1,624	1,655	1,678	1,732	1,817	2,086	2,250	2,363	2,769	3,666
Carbon Emission	k-tons	2,733	3,039	3,098	3,195	3,498	3,060	2,071	2,092	2,147	2,184	2,218	2,215	2,254	2,276	2,320	2,379	2,471	2,575	2,402	-
Water Consumption	k-gallons	587	626	644	635	663	477	321	321	626	618	622	608	623	615	569	569	593	615	610	360

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,638	2,763	3,084	3,168	3,274	3,400	3,441	3,461	3,441	3,571	3,639	3,625	3,613	3,581	3,570	3,703	3,084
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,474	1,474	1,485	1,555	1,555	1,555	1,555	1,555	1,555	1,249	1,249	999	999
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,095	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,407	2,621	2,575	2,345
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	280	400	400	400	400	440
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,020**	**8,281**	**8,981**	**8,896**	**9,346**	**9,601**	**9,679**	**9,795**	**9,800**	**9,955**	**10,090**	**10,126**	**10,356**	**10,138**	**10,457**	**10,557**	**9,346**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	7,430	7,915	8,849	9,118	9,399	9,771	9,891	9,963	9,898	10,274	10,472	10,456	10,357	10,324	10,165	9,514	8,622
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,975	4,962	5,033	5,009	5,182	5,443	5,421	5,425	5,422	5,441	4,617	4,248	4,028	3,443	3,431
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,133	1,140	1,172	371	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	93	105	69	92	165	106	125	113	121	116	109	144	113	57	27	39	52	34	-
Gas Combined Cycle	GWh	2,732	2,920	2,747	2,880	2,857	2,961	2,914	2,727	2,857	2,769	2,867	2,845	2,685	2,825	2,625	2,787	2,823	2,733	2,784	-
Gas/Hydrogen Turbine	GWh	625	983	1,094	1,215	1,635	2,049	1,178	1,320	1,330	1,444	1,434	1,452	1,583	1,416	943	682	742	918	751	5
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	189	1,271	1,652	1,719	1,774	1,591	292
Total Generation	**GWh**	**14,142**	**15,399**	**16,353**	**20,539**	**21,429**	**22,326**	**21,309**	**21,582**	**22,196**	**22,624**	**23,025**	**23,058**	**23,505**	**23,783**	**24,182**	**24,730**	**25,599**	**26,578**	**27,503**	**23,996**
Market Purchases	**GWh**	**63**	**243**	**470**	**402**	**353**	**243**	**2,574**	**2,680**	**2,554**	**2,469**	**2,356**	**2,534**	**2,435**	**2,504**	**2,411**	**2,170**	**1,831**	**1,516**	**1,135**	**2,987**
Market Sales	**GWh**	**1,975**	**1,530**	**1,159**	**1,228**	**1,386**	**1,780**	**2,886**	**2,855**	**3,052**	**3,082**	**3,112**	**2,995**	**3,026**	**3,025**	**3,079**	**3,162**	**3,463**	**3,835**	**4,076**	**2,147**
Net Generation *	**GWh**	**13,884**	**15,090**	**15,927**	**20,030**	**20,901**	**21,702**	**20,745**	**20,881**	**21,475**	**21,913**	**22,356**	**22,374**	**22,797**	**23,104**	**23,511**	**24,095**	**24,967**	**25,937**	**26,890**	**23,442**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-XmsnRS P3 8760*
Future: *HEG*
Sensitivity: *Rio Sol Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 16.465 B$
20-Year Carbon Emissions 48.227 M Tons
20-Year Water Consumption 11.302 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	320	140	335	98	120	140	55	34	37	143	82	-	-	-	-	228	300
Wind	MW	-	-	-	800	-	-	-	16	-	114	70	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	131	311	-	-	-	-	-	-	-	-	-	-	1	214	223	220
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	240	120	-	-	-	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,615**	**317**	**711**	**123**	**462**	**267**	**196**	**129**	**61**	**168**	**148**	**271**	**291**	**171**	**384**	**768**	**878**

Portfolio Summary

Scenario Information

Scenario: *HEG-XmsnSZ P3 8760*
Future: *HEG*
Sensitivity: *SunZia Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	16.368	B$
20-Year Carbon Emissions	50.862	M Tons
20-Year Water Consumption	11.636	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,457	2,720	2,988	3,531	3,627	3,691	3,717	3,821	3,891	3,990	4,048	4,119	4,188	4,278	4,326	4,378	4,407	4,445	4,513	4,609
PRM	%	9.20	8.99	13.65	14.41	14.40	14.40	14.69	19.84	20.86	18.79	18.16	16.97	15.96	15.24	15.26	15.42	14.40	14.47	14.40	14.58
Carbon Intensity	lbs/MWh	394	403	402	369	384	342	200	200	200	199	198	198	198	197	197	197	198	198	187	-

Revenue Requirement	M$	541	605	728	1,241	1,281	1,353	1,381	1,499	1,538	1,593	1,628	1,661	1,685	1,740	1,826	2,095	2,260	2,371	2,776	3,677
Carbon Emission	k-tons	2,733	3,039	3,277	3,902	4,223	3,959	2,069	2,091	2,146	2,183	2,217	2,215	2,253	2,275	2,318	2,378	2,470	2,574	2,538	-
Water Consumption	k-gallons	587	626	682	737	802	646	323	324	631	623	616	603	610	609	556	549	573	593	597	351

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,638	2,763	3,084	3,168	3,274	3,400	3,441	3,461	3,441	3,571	3,639	3,625	3,613	3,581	3,570	3,703	3,084
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,474	1,474	1,485	1,555	1,555	1,555	1,555	1,555	1,555	1,249	1,249	999	999
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,964	2,095	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,406	2,407	2,621	2,575	2,345
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	280	400	400	400	400	440
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100
Long Duration Storage	MW	-	-	-	-	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**8,020**	**8,281**	**8,981**	**8,896**	**9,346**	**9,601**	**9,679**	**9,795**	**9,800**	**9,955**	**10,090**	**10,126**	**10,356**	**10,138**	**10,457**	**10,557**	**9,346**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,371	7,430	7,915	8,850	9,118	9,399	9,770	9,890	9,963	9,898	10,274	10,471	10,456	10,357	10,323	10,165	9,514	8,622
Wind	GWh	2,198	2,229	2,196	4,962	4,945	4,974	4,962	5,033	5,009	5,182	5,443	5,421	5,425	5,423	5,440	4,617	4,248	4,028	3,443	3,431
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,073	1,158	1,196	409	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	70	92	199	243	350	452	115	136	126	134	124	118	151	128	63	32	43	56	55	-
Gas Combined Cycle	GWh	2,732	2,920	2,887	3,003	2,963	3,222	2,893	2,719	2,844	2,748	2,862	2,841	2,679	2,830	2,604	2,757	2,798	2,748	2,821	-
Gas/Hydrogen Turbine	GWh	625	983	1,257	1,996	2,346	2,882	1,178	1,308	1,320	1,439	1,426	1,441	1,577	1,394	960	704	753	913	856	5
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	187	1,258	1,639	1,718	1,756	1,678	260
Total Generation	**GWh**	**14,142**	**15,399**	**16,690**	**21,635**	**22,529**	**23,744**	**21,297**	**21,573**	**22,186**	**22,613**	**23,020**	**23,052**	**23,500**	**23,778**	**24,170**	**24,714**	**25,588**	**26,573**	**27,753**	**23,963**
Market Purchases	**GWh**	**63**	**243**	**1,779**	**1,609**	**1,588**	**1,389**	**2,891**	**3,013**	**2,912**	**2,796**	**2,662**	**2,837**	**2,731**	**2,807**	**2,691**	**2,509**	**2,146**	**1,843**	**1,325**	**3,299**
Market Sales	**GWh**	**1,975**	**1,529**	**2,846**	**3,546**	**3,738**	**4,397**	**3,198**	**3,172**	**3,386**	**3,392**	**3,410**	**3,286**	**3,324**	**3,331**	**3,355**	**3,498**	**3,782**	**4,180**	**4,538**	**2,470**
Net Generation *	**GWh**	**13,884**	**15,090**	**16,305**	**21,141**	**22,018**	**23,174**	**20,739**	**20,865**	**21,450**	**21,896**	**22,347**	**22,361**	**22,799**	**23,107**	**23,508**	**24,092**	**24,970**	**25,954**	**27,163**	**23,452**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *HEG-XmsnSZ P3 8760*
Future: *HEG*
Sensitivity: *SunZia Transmission line included*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 16.368 B$
20-Year Carbon Emissions 50.862 M Tons
20-Year Water Consumption 11.636 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	320	140	335	98	120	140	55	34	37	143	82	-	-	-	-	228	300
Wind	MW	-	-	-	800	-	-	-	16	-	114	70	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	324	131	311	-	-	-	-	-	-	-	-	-	-	1	214	223	220
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	40	240	120	-	-	-	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,615**	**317**	**711**	**123**	**462**	**267**	**196**	**129**	**61**	**168**	**148**	**271**	**291**	**171**	**384**	**768**	**878**

Portfolio Summary

Scenario Information

Scenario: *LEG P2 8760*
Future: *LEG*
Sensitivity: *Low Economic Growth base case*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	10.802	B$
20-Year Carbon Emissions	35.040	M Tons
20-Year Water Consumption	6.353	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,069	2,159	2,274	2,722	2,788	2,858	2,847	2,903	2,920	2,965	2,968	2,979	2,988	3,017	3,010	3,009	2,982	2,964	2,966	3,001
PRM	%	27.46	34.80	46.28	43.73	40.37	39.46	40.71	38.73	38.65	36.77	37.25	37.20	37.53	36.92	30.86	24.09	19.53	14.99	14.40	14.65
Carbon Intensity	lbs/MWh	354	340	300	230	254	212	186	196	196	198	198	197	193	196	184	197	197	196	186	-
Revenue Requirement	M$	492	500	553	1,009	990	1,073	1,021	1,011	1,010	1,022	1,029	1,040	1,046	1,057	999	1,077	1,125	1,080	1,418	2,294
Carbon Emission	k-tons	2,326	2,354	2,125	1,965	2,243	1,925	1,686	1,783	1,785	1,794	1,786	1,772	1,723	1,749	1,619	1,654	1,597	1,612	1,540	-
Water Consumption	k-gallons	530	530	498	476	511	345	261	264	264	265	269	269	260	261	253	264	257	252	253	73

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	269	289	310	331	351	369	388	413	439	415	389	361	331	313	338
Solar	MW	1,775	2,025	2,266	2,408	2,394	2,530	2,515	2,501	2,487	2,473	2,459	2,403	2,389	2,376	2,361	2,349	2,318	2,561	2,766	2,121
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	1	2	5	7	8	9	9	10	10	10	12	14	16	17	18	20
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,313	1,894
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	872
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,777**	**7,736**	**8,233**	**8,042**	**8,050**	**8,059**	**7,963**	**7,969**	**7,931**	**7,943**	**7,955**	**7,751**	**7,715**	**7,352**	**7,566**	**7,742**	**6,423**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	535	588	638	691	742	795	845	905	965	925	872	820	767	747	797
Solar	GWh	4,895	5,574	6,350	6,757	6,840	7,238	7,216	7,151	7,116	7,076	7,046	6,878	6,839	6,798	6,771	6,684	6,651	7,227	6,785	5,803
Wind	GWh	2,197	2,226	2,193	4,960	4,945	4,975	4,962	4,981	4,956	4,738	4,756	4,737	4,741	4,738	4,754	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	1	3	8	11	13	14	15	15	16	16	18	19	21	22	22	22
Coal	GWh	1,090	1,073	1,073	1,073	1,073	359	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	2,342	2,254	2,334	3,582	7,042
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	24	19	3	2	4	14	13	21	17	15	16	20	18	13	19	20	13	23	12	-
Gas Combined Cycle	GWh	2,320	2,324	1,996	1,815	2,186	2,467	2,688	2,605	2,670	2,651	2,742	2,715	2,590	2,708	2,531	2,731	2,749	2,551	2,616	-
Gas/Hydrogen Turbine	GWh	332	411	302	174	365	802	841	1,049	1,010	1,044	967	958	968	934	845	753	652	807	550	63
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	106
Total Generation	**GWh**	**13,385**	**14,146**	**14,623**	**17,623**	**18,211**	**18,787**	**18,718**	**18,742**	**18,833**	**18,682**	**18,658**	**18,561**	**18,472**	**18,457**	**18,231**	**17,415**	**16,785**	**17,075**	**17,210**	**16,580**
Market Purchases	**GWh**	**6**	**6**	**16**	**25**	**18**	**48**	**24**	**35**	**31**	**41**	**47**	**54**	**71**	**103**	**131**	**351**	**562**	**572**	**432**	**928**
Market Sales	**GWh**	**2,762**	**2,918**	**2,847**	**2,634**	**2,600**	**2,692**	**2,497**	**2,458**	**2,502**	**2,299**	**2,252**	**2,118**	**2,026**	**1,951**	**1,781**	**1,257**	**930**	**1,176**	**1,189**	**1,105**
Net Generation *	**GWh**	**13,127**	**13,835**	**14,186**	**17,080**	**17,680**	**18,205**	**18,141**	**18,158**	**18,238**	**18,097**	**18,066**	**17,965**	**17,877**	**17,857**	**17,615**	**16,827**	**16,215**	**16,430**	**16,593**	**16,060**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *LEG P2 8760*
Future: *LEG*
Sensitivity: *Low Economic Growth base case*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	10.802	B$
20-Year Carbon Emissions	35.040	M Tons
20-Year Water Consumption	6.353	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	20	20	21	21	20	19	19	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	90	-	150	-	-	-	-	-	-	-	-	-	-	-	255	300	273
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	10	-	-	-	-	-	-	-	-	-	7	-	-	-	-	2
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	-	-	-	333	31
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	438
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,372**	**10**	**510**	**20**	**21**	**21**	**20**	**19**	**19**	**25**	**26**	**33**	**25**	**24**	**279**	**844**	**770**

Portfolio Summary

Scenario Information

Scenario: *LEG-CO2_400thru44 P2 8760*
Future: *LEG*
Sensitivity: *ETA 400 through 2044, zero CO2 by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	10.800	B$
20-Year Carbon Emissions	35.302	M Tons
20-Year Water Consumption	6.377	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,069	2,159	2,274	2,722	2,788	2,858	2,847	2,903	2,920	2,965	2,968	2,979	2,988	3,017	3,010	3,009	2,982	2,964	2,966	3,001
PRM	%	27.46	34.80	46.28	43.73	40.37	39.46	40.71	38.73	38.65	36.77	37.25	37.20	37.53	36.92	30.86	24.09	19.53	14.99	14.40	14.65
Carbon Intensity	lbs/MWh	354	340	300	230	254	212	186	196	196	202	198	201	193	199	184	200	207	196	186	-
Revenue Requirement	M$	492	500	553	1,009	990	1,073	1,021	1,011	1,010	1,022	1,029	1,040	1,046	1,057	999	1,077	1,123	1,080	1,418	2,294
Carbon Emission	k-tons	2,326	2,354	2,125	1,965	2,243	1,925	1,686	1,783	1,785	1,840	1,787	1,816	1,723	1,781	1,619	1,690	1,701	1,612	1,540	-
Water Consumption	k-gallons	530	530	498	476	511	345	261	264	264	268	269	273	260	263	253	268	268	252	253	73

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	269	289	310	331	351	369	388	413	439	415	389	361	331	313	338
Solar	MW	1,775	2,025	2,266	2,408	2,394	2,530	2,515	2,501	2,487	2,473	2,459	2,403	2,389	2,376	2,361	2,349	2,318	2,561	2,766	2,121
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	1	2	5	7	8	9	9	10	10	10	12	14	16	17	18	20
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,313	1,894
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	872
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,777**	**7,736**	**8,233**	**8,042**	**8,050**	**8,059**	**7,963**	**7,969**	**7,931**	**7,943**	**7,955**	**7,751**	**7,715**	**7,352**	**7,566**	**7,742**	**6,423**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	535	588	638	691	742	795	845	905	965	925	872	820	767	747	797
Solar	GWh	4,895	5,574	6,350	6,756	6,840	7,237	7,216	7,151	7,115	7,076	7,045	6,877	6,839	6,798	6,771	6,684	6,651	7,227	6,785	5,803
Wind	GWh	2,197	2,226	2,193	4,961	4,945	4,975	4,962	4,981	4,956	4,738	4,756	4,737	4,741	4,738	4,753	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	1	3	8	11	13	14	15	15	16	16	18	19	21	22	22	22
Coal	GWh	1,090	1,073	1,073	1,073	1,073	359	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	2,342	2,254	2,334	3,582	7,042
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	24	19	3	2	4	14	13	21	17	16	16	22	18	14	19	21	19	23	12	-
Gas Combined Cycle	GWh	2,320	2,324	1,996	1,815	2,186	2,467	2,688	2,605	2,670	2,672	2,742	2,744	2,590	2,723	2,531	2,746	2,820	2,551	2,616	-
Gas/Hydrogen Turbine	GWh	332	411	302	174	365	802	841	1,049	1,010	1,101	968	1,007	968	971	845	800	766	807	550	68
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	140	103
Total Generation	**GWh**	**13,385**	**14,146**	**14,623**	**17,623**	**18,211**	**18,787**	**18,718**	**18,742**	**18,833**	**18,762**	**18,659**	**18,641**	**18,472**	**18,510**	**18,231**	**17,478**	**16,974**	**17,075**	**17,210**	**16,583**
Market Purchases	**GWh**	**6**	**6**	**16**	**25**	**18**	**48**	**24**	**35**	**31**	**32**	**47**	**44**	**71**	**94**	**131**	**327**	**472**	**572**	**432**	**926**
Market Sales	**GWh**	**2,762**	**2,918**	**2,847**	**2,634**	**2,600**	**2,692**	**2,497**	**2,458**	**2,502**	**2,371**	**2,253**	**2,191**	**2,026**	**1,997**	**1,781**	**1,293**	**1,030**	**1,176**	**1,189**	**1,105**
Net Generation *	**GWh**	**13,127**	**13,835**	**14,186**	**17,080**	**17,680**	**18,205**	**18,141**	**18,158**	**18,238**	**18,178**	**18,067**	**18,047**	**17,877**	**17,912**	**17,615**	**16,888**	**16,404**	**16,430**	**16,593**	**16,063**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *LEG-CO2_400thru44 P2 8760*
Future: *LEG*
Sensitivity: *ETA 400 through 2044, zero CO2 by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	10.800	B$
20-Year Carbon Emissions	35.302	M Tons
20-Year Water Consumption	6.377	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	20	20	21	21	20	19	19	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	90	-	150	-	-	-	-	-	-	-	-	-	-	-	255	300	273
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	10	-	-	-	-	-	-	-	-	-	7	-	-	-	-	2
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	-	-	-	333	31
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	438
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,372**	**10**	**510**	**20**	**21**	**21**	**20**	**19**	**19**	**25**	**26**	**33**	**25**	**24**	**279**	**844**	**770**

Portfolio Summary

Scenario Information

Scenario: *LEG-NoETA P2 8760*
Future: *LEG*
Sensitivity: *No CO2 emission limits, No RPS, No CO2 free by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	10.485	B$
20-Year Carbon Emissions	37.261	M Tons
20-Year Water Consumption	6.585	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,069	2,159	2,274	2,722	2,788	2,858	2,847	2,903	2,920	2,965	2,968	2,979	2,988	3,017	3,010	3,009	2,982	2,964	2,966	3,001
PRM	%	27.46	34.80	46.28	43.73	40.37	39.46	40.71	38.73	38.65	36.77	37.25	37.20	37.43	36.72	30.66	27.46	26.53	25.77	17.13	14.65
Carbon Intensity	lbs/MWh	354	340	300	230	254	212	186	196	196	202	198	201	193	200	184	201	208	194	225	214

Revenue Requirement	M$	492	500	553	1,009	986	1,069	1,018	1,008	1,007	1,018	1,026	1,037	1,043	1,053	998	1,076	1,122	1,082	1,196	1,481
Carbon Emission	k-tons	2,326	2,354	2,125	1,965	2,244	1,925	1,686	1,783	1,785	1,840	1,787	1,816	1,726	1,787	1,623	1,695	1,705	1,598	1,784	1,707
Water Consumption	k-gallons	530	530	498	476	511	345	261	264	264	268	269	273	260	263	253	268	268	250	272	262

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	269	289	310	331	351	369	388	407	427	403	378	349	319	301	326
Solar	MW	1,775	2,025	2,266	2,408	2,394	2,530	2,515	2,501	2,487	2,473	2,459	2,403	2,389	2,376	2,361	2,349	2,318	2,600	2,805	2,187
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	1	2	5	7	8	9	9	10	10	10	12	14	16	17	18	18
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	1,980	1,798
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	487
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,777**	**7,736**	**8,233**	**8,042**	**8,050**	**8,059**	**7,963**	**7,969**	**7,931**	**7,937**	**7,944**	**7,739**	**7,703**	**7,340**	**7,593**	**7,250**	**6,475**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	GWh	103	205	308	411	485	535	588	638	691	742	795	845	896	947	907	854	802	749	728	779
Solar	GWh	4,895	5,574	6,350	6,756	6,839	7,237	7,216	7,151	7,116	7,076	7,046	6,877	6,839	6,798	6,771	6,684	6,651	7,338	6,897	6,011
Wind	GWh	2,197	2,226	2,193	4,961	4,945	4,975	4,962	4,981	4,956	4,738	4,756	4,737	4,741	4,738	4,753	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	1	3	8	11	13	14	15	15	16	16	18	19	21	22	22	22
Coal	GWh	1,090	1,073	1,073	1,073	1,073	359	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	2,342	2,254	2,334	2,342	3,332
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	24	19	3	2	4	14	13	21	17	16	16	22	18	14	19	22	19	23	32	-
Gas Combined Cycle	GWh	2,320	2,324	1,996	1,815	2,186	2,467	2,688	2,605	2,670	2,672	2,742	2,744	2,592	2,726	2,533	2,748	2,822	2,534	2,755	2,633
Gas/Hydrogen Turbine	GWh	332	411	302	174	365	802	841	1,049	1,010	1,101	968	1,007	972	978	851	805	771	797	929	934
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation	**GWh**	**13,385**	**14,146**	**14,623**	**17,623**	**18,211**	**18,787**	**18,718**	**18,742**	**18,833**	**18,762**	**18,659**	**18,641**	**18,468**	**18,503**	**18,221**	**17,468**	**16,964**	**17,140**	**16,461**	**16,458**
Market Purchases	**GWh**	**6**	**6**	**16**	**25**	**18**	**48**	**24**	**35**	**31**	**32**	**47**	**44**	**71**	**95**	**133**	**331**	**476**	**561**	**852**	**809**
Market Sales	**GWh**	**2,762**	**2,918**	**2,847**	**2,634**	**2,600**	**2,692**	**2,497**	**2,458**	**2,502**	**2,371**	**2,253**	**2,191**	**2,023**	**1,992**	**1,774**	**1,287**	**1,024**	**1,222**	**894**	**911**
Net Generation *	**GWh**	**13,127**	**13,835**	**14,186**	**17,080**	**17,680**	**18,205**	**18,141**	**18,158**	**18,238**	**18,178**	**18,067**	**18,047**	**17,874**	**17,906**	**17,606**	**16,878**	**16,395**	**16,486**	**15,879**	**15,986**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *LEG-NoETA P2 8760*
Future: *LEG*
Sensitivity: *No CO2 emission limits, No RPS, No CO2 free by 2045*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	10.485	B$
20-Year Carbon Emissions	37.261	M Tons
20-Year Water Consumption	6.585	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	20	20	21	21	20	19	19	19	20	26	25	24	24	25	25
Solar	MW	-	-	-	90	-	150	-	-	-	-	-	-	-	-	-	-	-	294	300	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	10	-	-	-	-	-	-	-	-	-	7	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	268
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,372**	**10**	**510**	**20**	**21**	**21**	**20**	**19**	**19**	**19**	**20**	**33**	**25**	**24**	**318**	**325**	**739**

Portfolio Summary

Scenario Information

Scenario: *LEG-SS ETA Step Down 8760*
Future: *LEG*
Sensitivity: *Smooth out' the acquisition of new clean firm resources*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement 11.233 B$
20-Year Carbon Emissions 26.995 M Tons
20-Year Water Consumption 5.495 M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,069	2,159	2,274	2,722	2,788	2,858	2,847	2,903	2,920	2,965	2,968	2,979	2,988	3,017	3,010	3,009	2,982	2,964	2,966	3,001
PRM	%	27.46	34.80	46.28	43.73	40.37	39.46	40.71	38.73	38.65	36.77	37.25	37.20	37.53	37.16	31.10	34.01	29.76	27.08	19.71	14.65
Carbon Intensity	lbs/MWh	354	340	300	230	254	212	186	196	196	154	153	153	108	108	108	64	64	65	65	-
Revenue Requirement	M$	492	500	553	1,009	990	1,073	1,021	1,011	1,010	1,038	1,046	1,059	1,098	1,117	1,044	1,371	1,404	1,400	1,579	2,237
Carbon Emission	k-tons	2,326	2,354	2,125	1,965	2,243	1,925	1,686	1,783	1,785	1,325	1,318	1,308	878	885	890	554	543	559	541	-
Water Consumption	k-gallons	530	530	498	476	511	345	261	264	264	224	225	222	162	164	167	143	141	142	153	73

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	269	289	310	331	351	369	388	413	439	415	389	361	331	313	338
Solar	MW	1,775	2,025	2,266	2,408	2,394	2,530	2,515	2,501	2,487	2,473	2,459	2,403	2,389	2,463	2,448	2,436	2,465	2,753	2,696	2,078
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	1	2	5	7	8	9	9	10	10	10	12	14	16	17	18	20
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,419	2,149	1,905
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	580	580	580	726	872
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,777**	**7,736**	**8,233**	**8,042**	**8,050**	**8,059**	**7,963**	**7,969**	**7,931**	**7,943**	**8,043**	**7,838**	**8,095**	**7,791**	**8,220**	**7,760**	**6,391**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	535	588	638	691	742	795	845	905	965	925	872	820	767	747	797
Solar	GWh	4,895	5,574	6,349	6,757	6,840	7,237	7,216	7,151	7,116	7,078	7,046	6,878	6,840	7,053	7,027	6,928	7,071	7,726	6,563	5,682
Wind	GWh	2,197	2,226	2,194	4,960	4,945	4,975	4,962	4,981	4,956	4,738	4,756	4,737	4,741	4,739	4,753	3,932	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	1	3	8	11	13	14	15	15	16	16	18	19	21	22	22	22
Coal	GWh	1,090	1,073	1,073	1,073	1,073	359	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	4,816	4,728	4,807	6,063	7,042
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	24	19	3	2	4	14	13	21	17	7	8	7	1	1	2	0	0	1	1	-
Gas Combined Cycle	GWh	2,320	2,324	1,996	1,815	2,186	2,467	2,688	2,605	2,670	2,367	2,437	2,430	1,863	1,897	1,903	1,280	1,257	1,274	1,236	-
Gas/Hydrogen Turbine	GWh	332	411	302	174	365	802	841	1,049	1,010	492	427	415	115	104	105	9	9	18	20	66
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	108
Total Generation	**GWh**	**13,385**	**14,146**	**14,623**	**17,623**	**18,211**	**18,787**	**18,718**	**18,742**	**18,833**	**17,840**	**17,805**	**17,721**	**16,875**	**17,060**	**17,102**	**17,916**	**17,530**	**17,959**	**17,407**	**16,465**
Market Purchases	**GWh**	**6**	**6**	**16**	**25**	**18**	**48**	**24**	**35**	**31**	**212**	**248**	**271**	**649**	**639**	**584**	**325**	**433**	**424**	**488**	**963**
Market Sales	**GWh**	**2,762**	**2,918**	**2,847**	**2,634**	**2,600**	**2,692**	**2,497**	**2,458**	**2,502**	**1,621**	**1,592**	**1,495**	**1,013**	**1,070**	**1,089**	**1,655**	**1,447**	**1,826**	**1,430**	**1,028**
Net Generation *	**GWh**	**13,127**	**13,835**	**14,186**	**17,080**	**17,680**	**18,205**	**18,141**	**18,158**	**18,238**	**17,247**	**17,205**	**17,125**	**16,285**	**16,439**	**16,470**	**17,252**	**16,860**	**17,228**	**16,779**	**15,949**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *LEG-SS ETA Step Down 8760*
Future: *LEG*
Sensitivity: *Smooth out' the acquisition of new clean firm resources*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	11.233	B$
20-Year Carbon Emissions	26.995	M Tons
20-Year Water Consumption	5.495	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	20	20	21	21	20	19	19	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	90	-	150	-	-	-	-	-	-	-	87	-	-	60	300	38	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	10	-	-	-	-	-	-	-	-	-	7	-	-	-	-	2
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	-	-	169	-	206
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	292	-	-	146	146
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,372**	**10**	**510**	**20**	**21**	**21**	**20**	**19**	**19**	**25**	**113**	**33**	**317**	**83**	**493**	**209**	**720**

Portfolio Summary

Scenario Information

Scenario: *LEG-TOU P2 8760*
Future: *LEG*
Sensitivity: *Time Of Use forecast impact to LEG*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	10.766	B$
20-Year Carbon Emissions	34.957	M Tons
20-Year Water Consumption	6.350	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,070	2,159	2,274	2,722	2,795	2,862	2,843	2,891	2,897	2,937	2,930	2,931	2,926	2,941	2,918	2,916	2,909	2,910	2,929	2,972
PRM	%	27.46	34.79	46.28	43.73	40.00	39.26	40.95	39.32	39.72	38.09	39.03	39.48	40.41	40.45	35.02	28.05	22.55	16.96	14.40	14.65
Carbon Intensity	lbs/MWh	354	340	300	230	253	210	185	195	194	198	196	197	191	196	183	197	197	198	190	-

Revenue Requirement	M$	492	500	553	1,009	988	1,071	1,018	1,008	1,007	1,019	1,026	1,037	1,043	1,053	995	1,073	1,120	1,071	1,392	2,280
Carbon Emission	k-tons	2,326	2,354	2,125	1,965	2,233	1,913	1,674	1,769	1,770	1,794	1,772	1,772	1,708	1,749	1,606	1,654	1,596	1,612	1,565	-
Water Consumption	k-gallons	530	530	498	476	510	344	259	262	263	265	268	269	259	261	252	265	257	253	256	74

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	269	289	310	331	351	369	388	413	439	415	389	361	331	313	338
Solar	MW	1,775	2,025	2,266	2,408	2,394	2,530	2,515	2,501	2,487	2,473	2,459	2,403	2,389	2,376	2,361	2,349	2,318	2,494	2,699	2,071
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	1	2	5	7	8	9	9	10	10	10	12	14	16	17	18	18
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	1,864
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	872
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,777**	**7,736**	**8,233**	**8,042**	**8,050**	**8,059**	**7,963**	**7,969**	**7,931**	**7,943**	**7,955**	**7,751**	**7,715**	**7,352**	**7,499**	**7,612**	**6,340**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	535	588	638	691	742	795	845	905	965	925	872	820	767	747	797
Solar	GWh	4,895	5,573	6,349	6,756	6,839	7,237	7,216	7,151	7,115	7,076	7,045	6,878	6,839	6,798	6,771	6,684	6,651	7,037	6,592	5,660
Wind	GWh	2,197	2,227	2,193	4,961	4,945	4,975	4,962	4,981	4,956	4,738	4,757	4,737	4,741	4,738	4,753	3,933	3,564	3,344	2,756	2,747
Demand Response	GWh	29	29	29	29	1	3	8	11	13	14	15	15	16	16	18	19	21	22	22	22
Coal	GWh	1,090	1,073	1,073	1,073	1,073	359	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	2,342	2,254	2,334	3,582	7,042
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	24	19	3	2	4	14	12	20	16	15	15	21	17	13	18	20	13	23	13	-
Gas Combined Cycle	GWh	2,320	2,323	1,996	1,815	2,178	2,462	2,682	2,600	2,664	2,654	2,735	2,714	2,584	2,708	2,526	2,730	2,746	2,569	2,643	-
Gas/Hydrogen Turbine	GWh	332	411	302	174	353	787	826	1,030	992	1,041	951	958	949	933	829	755	655	795	568	72
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	142	105
Total Generation	**GWh**	**13,385**	**14,145**	**14,623**	**17,623**	**18,192**	**18,765**	**18,696**	**18,717**	**18,808**	**18,682**	**18,633**	**18,561**	**18,445**	**18,456**	**18,209**	**17,415**	**16,783**	**16,890**	**17,065**	**16,445**
Market Purchases	**GWh**	**6**	**6**	**16**	**25**	**18**	**48**	**23**	**34**	**30**	**38**	**45**	**49**	**68**	**94**	**126**	**331**	**536**	**599**	**457**	**948**
Market Sales	**GWh**	**2,762**	**2,918**	**2,847**	**2,634**	**2,611**	**2,702**	**2,508**	**2,468**	**2,512**	**2,335**	**2,266**	**2,156**	**2,041**	**1,989**	**1,800**	**1,282**	**953**	**1,087**	**1,144**	**1,052**
Net Generation *	**GWh**	**13,126**	**13,835**	**14,185**	**17,079**	**17,660**	**18,184**	**18,119**	**18,133**	**18,213**	**18,097**	**18,042**	**17,967**	**17,851**	**17,858**	**17,593**	**16,825**	**16,214**	**16,261**	**16,470**	**15,934**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *LEG-TOU P2 8760*
Future: *LEG*
Sensitivity: *Smooth out' the acquisition of new clean firm resources*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	10.766	B$
20-Year Carbon Emissions	34.957	M Tons
20-Year Water Consumption	6.350	M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	20	20	21	21	20	19	19	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	90	-	150	-	-	-	-	-	-	-	-	-	-	-	188	300	289
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	10	-	-	-	-	-	-	-	-	-	7	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	-	-	-	-	270	64
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	438
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,372**	**10**	**510**	**20**	**21**	**21**	**20**	**19**	**19**	**25**	**26**	**33**	**25**	**24**	**212**	**781**	**816**

APPENDIX O: MOST COST EFFECTIVE PORTFOLIO

This appendix provides a Portfolio Capacity Report and Capacity Expansion Report for the Most Cost Effective Portfolio.

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Portfolio Summary

Scenario Information

Scenario: *CTP P2 8760*
Future: *CTP*
Sensitivity: *Current Trends & Policies base case*

Cost & Environmental Metrics

20-Year NPV Revenue Requirement	14.327	B$
20-Year Carbon Emissions	42.055	M Tons
20-Year Water Consumption	7.292	M Gallons

Key Annual Metrics

Metric	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	MW	2,293	2,528	2,785	3,282	3,347	3,381	3,378	3,451	3,489	3,557	3,584	3,620	3,650	3,700	3,711	3,726	3,715	3,722	3,753	3,814
PRM	%	15.05	15.10	19.43	19.32	17.72	18.81	19.81	20.88	20.28	18.37	18.16	17.62	17.25	16.38	14.40	14.40	14.40	14.48	14.40	14.60
Carbon Intensity	lbs/MWh	381	392	371	313	334	293	199	199	199	198	198	198	197	197	197	198	170	149	122	-
Revenue Requirement	M$	523	572	693	1,197	1,205	1,288	1,273	1,315	1,319	1,356	1,371	1,395	1,405	1,436	1,448	1,684	1,854	1,947	2,322	3,146
Carbon Emission	k-tons	2,602	2,912	2,892	3,000	3,315	2,975	1,902	1,915	1,927	1,931	1,947	1,965	1,963	1,991	2,017	2,069	1,795	1,595	1,340	-
Water Consumption	k-gallons	569	610	616	610	647	466	293	287	287	287	286	287	285	282	270	293	279	264	267	109

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	3	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	51	100	153	207	249	274	299	326	352	378	403	427	452	478	454	428	400	369	352	377
Solar	MW	1,775	2,025	2,266	2,447	2,483	2,619	2,679	2,776	2,779	2,858	2,910	2,947	2,956	3,068	3,053	3,041	3,010	2,998	3,059	2,440
Wind	MW	658	658	658	1,458	1,458	1,458	1,458	1,458	1,458	1,356	1,356	1,356	1,356	1,356	1,356	1,356	1,050	1,050	800	800
Demand Response	MW	70	70	70	70	32	35	40	42	44	45	45	46	47	47	49	51	52	52	52	52
Short Duration Storage	MW	992	1,160	1,640	1,950	1,950	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,285	2,392	2,428	2,580	2,462	2,248
Coal	MW	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	434	580	726	1,018	1,310
Geothermal	MW	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-
Gas Steam Generator	MW	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	-
Gas Combined Cycle	MW	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	-
Gas/Hydrogen Turbine	MW	431	431	598	614	614	654	654	654	654	654	654	654	654	654	487	487	487	487	487	338
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	160	160	160	160	160
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Capacity	**MW**	**5,049**	**5,576**	**6,454**	**7,816**	**7,857**	**8,360**	**8,251**	**8,476**	**8,508**	**8,512**	**8,588**	**8,651**	**8,685**	**8,824**	**8,775**	**9,032**	**8,849**	**9,105**	**9,060**	**7,826**

Annual Generation by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	GWh	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	GWh	103	205	308	411	485	543	605	664	725	785	848	907	966	1,027	987	934	882	829	809	859
Solar	GWh	4,898	5,582	6,370	6,876	7,101	7,498	7,693	7,951	7,964	8,197	8,358	8,462	8,487	8,809	8,788	8,695	8,661	8,497	7,632	6,740
Wind	GWh	2,198	2,229	2,197	4,962	4,946	4,974	4,962	4,980	4,956	4,738	4,756	4,736	4,741	4,738	4,753	3,933	3,564	3,343	2,756	2,747
Demand Response	GWh	29	29	29	29	14	18	24	28	30	31	32	32	33	33	34	34	34	34	34	34
Coal	GWh	1,090	1,073	1,109	1,139	1,171	395	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	GWh	2,335	2,225	2,309	2,342	2,254	2,334	2,342	2,225	2,302	2,342	2,261	2,334	2,335	2,225	2,309	3,579	4,728	6,044	8,543	10,753
Geothermal	GWh	60	61	61	61	60	61	61	61	60	61	61	61	60	61	61	61	60	0	-	-
Gas Steam Generator	GWh	55	80	81	36	68	127	48	56	47	49	36	41	54	43	40	30	10	8	7	-
Gas Combined Cycle	GWh	2,608	2,823	2,677	2,815	2,846	3,000	2,876	2,701	2,801	2,726	2,813	2,792	2,657	2,753	2,641	2,835	2,722	2,455	2,340	-
Gas/Hydrogen Turbine	GWh	525	866	891	991	1,385	1,894	1,014	1,150	1,109	1,169	1,151	1,189	1,262	1,249	972	859	588	475	251	72
Advanced Generator	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	573	672	572	533	374	363
Total Generation	**GWh**	**13,902**	**15,173**	**16,032**	**19,662**	**20,329**	**20,843**	**19,624**	**19,814**	**19,994**	**20,098**	**20,316**	**20,553**	**20,595**	**20,937**	**21,157**	**21,630**	**21,820**	**22,218**	**22,746**	**21,568**
Market Purchases	**GWh**	**40**	**119**	**316**	**302**	**268**	**234**	**748**	**768**	**752**	**748**	**755**	**708**	**745**	**719**	**649**	**447**	**397**	**287**	**132**	**635**
Market Sales	**GWh**	**2,201**	**1,867**	**1,424**	**1,336**	**1,497**	**1,790**	**944**	**978**	**1,015**	**936**	**997**	**1,000**	**964**	**1,043**	**1,096**	**1,268**	**1,347**	**1,523**	**1,795**	**1,027**
Net Generation *	**GWh**	**13,643**	**14,864**	**15,601**	**19,170**	**19,841**	**20,312**	**19,080**	**19,228**	**19,402**	**19,498**	**19,690**	**19,892**	**19,940**	**20,245**	**20,440**	**20,892**	**21,066**	**21,448**	**22,013**	**20,896**

* Adjusted for Energy Storage Losses

Capacity Expansion Plan

Scenario Information

Scenario: *CTP P2 8760*
Future: *CTP*
Sensitivity: *Current Trends & Policies base case*

Cost & Environmental Metrics

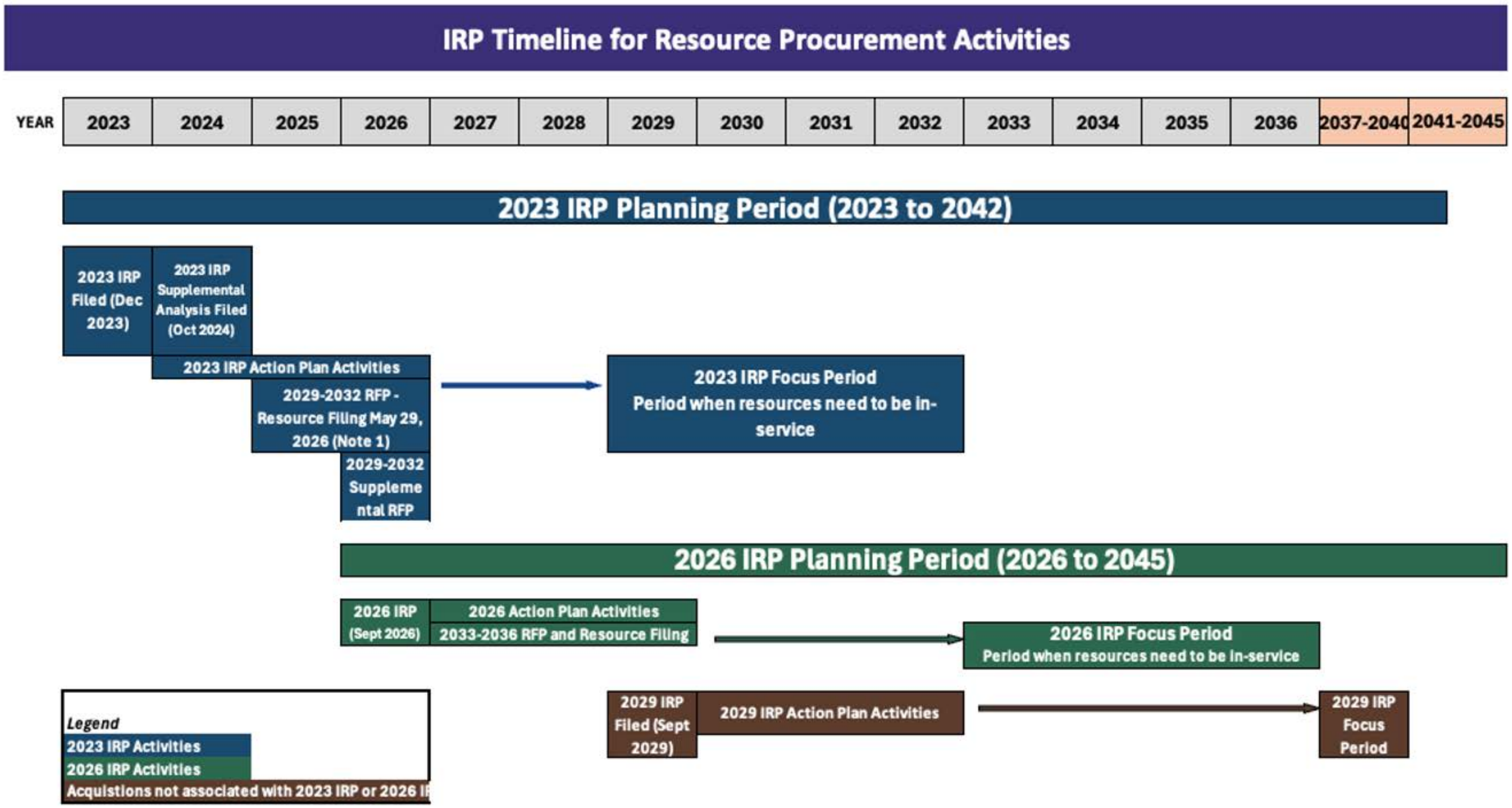
20-Year NPV Revenue Requirement 14.327 B$
20-Year Carbon Emissions 42.055 M Tons
20-Year Water Consumption 7.292 M Gallons

Installed Capacity by Resource Type

Resource Type	Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Capacity Purchases	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficency	MW	-	-	-	-	-	25	25	26	27	26	24	25	25	26	26	25	24	24	25	25
Solar	MW	-	-	-	129	51	150	74	111	17	93	66	94	23	125	-	-	-	-	155	300
Wind	MW	-	-	-	800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Response	MW	-	-	-	-	46	-	-	-	-	2	-	-	-	-	4	-	-	-	-	-
Short Duration Storage	MW	-	-	-	310	-	300	-	-	-	-	-	-	-	-	35	107	36	152	151	237
Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146	146	146	292	292
Geothermal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Steam Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Combined Cycle	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas/Hydrogen Turbine	MW	-	-	-	172	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advanced Generator	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	40	-	-	-	-
Pumped Hydro	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Duration Storage	MW	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity	**MW**	**-**	**-**	**-**	**1,411**	**97**	**515**	**99**	**237**	**44**	**121**	**90**	**118**	**47**	**151**	**186**	**317**	**206**	**322**	**623**	**854**

APPENDIX P: IRP TIMELINE AND PROCUREMENT TIMEFRAMES

IRP Planning, Action Plan And Focus Period Timeline



Notes:

1: 800 MW Wind (Palomas), 610 MW BESS (Cathills 150 MW, Wildcat 50 MW, Gila Monster 150 MW, TAG II 90 MW, Britton 60 MW, Encino 110 MW), 240 MW Solar (Cat Hills 150 MW, Wildcat 90 MW), 186 MW Gas (Reeves Ext 146 MW, La Luz II 40 MW).

2: (50-250 MW Firm Dispatchable (modeled as 172 MW gas in 2026 IRP as proxy pending the Supplemental RFP outcome).

PROCUREMENT TIMEFRAMES

2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037-2040	2041-2045

Existing Resources in 2026 IRP	Pending Near-Term Procurements	2026 IRP Focus Period Procurements	Thru end of Planning Period
Planning Period			

Existing and Approved Resources		2029-2032 Resources	2033-2036 RFP	Future IRP/RFP cycles
All In-service resources by 2026	Resources approved in 2025 with 2027 and 2028 in-service dates (Note 1)	2029-2032 Resource Filing (Note 2) and Supplemental Resource Filing (Note 3) Commercial Operation	Resources aquired by 2026 IRP action plan RFP covering 2033 to 2036 focus period.	Resource additions beyond 2026 IRP focus period.

Legend

- 2023 IRP Activities
- 2026 IRP Activities
- Activities not associated with 2023 IRP or 2026 IRP

Notes:

Note 1 - Valencia Extension (167 MW), Corazon BESS (150 MW), Sun Lasso BESS (150 MW), Sunbelt Solar (100 MW), Sunbelt BESS (50 MW), Four Mile Mesa Solar (100 MW), Starlight Solar(100 MW), Windy Lane Solar (90 MW), Four Mile Mesa BESS (100 MW), Starlight BESS (100 MW), Windy Lane BESS (68 MW)

Note 2: 800 MW Wind (Palomas), 610 MW BESS (Cathills 150 MW, Wildcat 50 MW, Gila Monster 150 MW, TAG II 90 MW, Britton 60 MW, Encino 110 MW), 240 MW Solar (Cat Hills 150 MW, Wildcat 90 MW), 186 MW Gas (Reeves Ext 146 MW, La Luz II 40 MW).

Note 3: 50-250 MW of new Firm Dispatchable Resources, pending final award of resource(s) from PNM's 2029-2032 All-Source Generation Resources RFP Supplement. For the IRP this was modeled as a 172 MW combustion turbine as a proxy.