UNS Electric Inc.

2017 Integrated Resource Plan

April 3, 2017

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List of Acronyms

ACRONYMS

ACC – Arizona Corporation Commission
ACE – Area Control Error
ANPR – Advanced Notice of Proposed Rulemaking
APS – Arizona Public Service Company
BA – Balancing Authority
BART – Best Available Retrofit Technology
Bcf – Billion Cubic Feet
BES – Bulk Electric System
BEV – Battery Electric Vehicles
BTA – Biennial Transmission Assessment
Btu – British Thermal Unit
C&I – Commercial and Industrial
CAES – Compressed Air Energy Storage
CBM – Coal Bed Methane
CC – Combined Cycle Plant Technology
CCCT – Combined Cycle Combustion Turbine
CCR – Coal Combustion Residuals
CCS – Carbon Capture and Sequestration; Carbon Capture and Storage
CFL – Compact Fluorescent Light Bulb
CAISO - California Independent System Operator
CO_2 – Carbon Dioxide
CPP – Clean Power Plan
CSP – Concentrating Solar Power
CT – Combined Turbine
DER – Distributed Energy Resources
DG - Distributed Generation
DOE – U.S. Department of Energy (Federal)
DLC – Direct Load Control
DMS – Distribution Management System
DR – Demand Response
DSM – Demand Side Management
EAF – Equivalent Availability Factor
EE – Energy Efficiency
EHV – Extra High Voltage
EIA - Energy Information Administration
EIM – Energy Imbalance Market
ELCC – Effective Load Carrying Capacity
EMS – Energy Management System

EPA - Environmental Protection Agency
EPRI – Electric Power Research Institute
EPS – Emission Performance Standard
ERC – Emission Rate Credit
ESS – Energy Storage System
EV – Electric Vehicles
FERC – Federal Energy Regulatory Commission
FIP – Federal Implementation Plan
GIS – Geographic Information System
GHG – Greenhouse Gas
GW – Gigawatt,
GWh – Gigawatt-Hour
HAPS – Hazardous Air Pollutants
HEV – Hybrid Electric Vehicle
HRSG – Heat Recovery Steam Generator
IGCC – Integrated Gasification Combined Cycle
IRP – Integrated Resource Plan
ISCC – Integrated Solar Combined Cycle
ITC – Investment Tax Credit
kW – Kilowatt
kWh – Kilowatt-Hour
kWyr – Kilowatt-Year
LCOE – Levelized Cost of Electricity
LNG – Liquefied Natural Gas
MACT – Maximum Available Control Technology
Mcf – Million Cubic Feet
MER – Measurement, Evaluation, and Research
MMBtu – Million British Thermal Units, also shown as MBtu
MBtu – Million British Thermal Units, also shown as MMBtu
MW – Megawatt
MWh – Megawatt-Hour
NAAQ – National Ambient Air Quality Standards
NaS – Sodium Sulphur
NASNRC – National Academies of Science National research Council
NEC – Navopache Electric Cooperative
NERC - North American Electric Reliability Corporation
NGCC – Natural Gas Combined Cycle
NGS – Navajo Generating Station
NITS – Network Integration Transmission Service
NMED – New Mexico Environmental Department
NNT – No-Notice Transportation
NO_X – Nitrogen Oxide(s)
NPV – Net Present Value
NPVRR – Net Present Value Revenue Requirement
NRC – Nuclear Regulatory Commission
NREL – National Renewable Energy Laboratory
NSPS – New Source Performance Standards

NTUA – Navajo Tribal Utility Authority
O&M – Operations and Maintenance
PEV – Plug-in Electric Vehicles
PM - Particulate matter
PNM – Public Service Company of New Mexico
PPA - Purchased Power Agreement
PTC – Production Tax Credit
PSD – Prevention of Significant Deterioration
R&D – Research and Development
RCRA – Resource Conservation and Recovery Act
REC – Renewable Energy Credit
RES – Renewable Energy Standard
RICE – Reciprocating Internal Combustion Engine
RFP – Request for Proposal
ROB – Replace on Burnout
ROD – Record of Decision
ROW – Right of Way
RTO - Regional Transmission Organization
RTP – Renewable Transmission Project
RUCO - Residential Utility Consumer Office
SAT – Single-Axis Tracking
SCADA – Supervisory Control and Data Acquisition
SCE – Southern California Edison
SCR – Selective Catalytic Reduction
SCT – Societal Cost Test
SCCT – Simple Cycle Combustion Turbine
SGS – Springerville Generating Station (aka Springerville)
SIP – State Implementation Plan
SJCC – San Juan Coal Company
SJGS – San Juan Generating Station
SMR – Small Modular (Nuclear) Reactor
SNCR – Selective Non-Catalytic Reduction
SRP – Salt River Project
SRSG – Southwest Reserve Sharing Group
SO_2 – Sulfur Dioxide
STG – Steam Turbine Generator
SWEEP – Southwest Energy Efficiency Project
TEP – Tucson Electric Power Company
TOU – Time-of-Use
TOUA - Tohono O'odham Utility Authority
TRICO – Trico Electric Cooperative
UAMPS - Utah Associated Municipal Power System
UES – UniSource Energy Services (Parent Company of UNS Electric)
VAR – Volt-Ampere Reactive; Reactive Power
WECC - Western Electricity Coordinating Council

Forward

As new technologies develop and our customers' energy habits change, UNS Electric will build a stronger, more flexible resource portfolio to continue providing reliable, affordable service to communities throughout Arizona.

Our 2017 Integrated Resource Plan (IRP) describes our continuing efforts to become more self-reliant by expanding our generating resources with cost-effective renewable energy and highly efficient natural gas resources as we continue to collaborate with customers through energy efficiency and demand response programs.

UNS Electric is working to deliver 20 percent of its power from renewable resources by 2020, surpassing the capacity and deadline requirements of the state Renewable Energy Standard. We expect to acquire access to more than 50 megawatts (MW) of renewable generating capacity with this year's completion of a 5 MW solar project and next year's completion of a 46 MW solar project.

To manage the intermittency and variability of an expanded renewable energy portfolio, the IRP Reference Case Plan includes investments in new fast-responding generating resources over the next five years, including 37 MW of flexible reciprocating internal combustion engines that can run efficiently at varying loads without regard to frequent starts and cycling operations.

Beginning in 2019, we expect to add two small energy storage projects that will provide additional grid support. We're optimistic that utility scale energy storage technologies, which can boost power output levels more quickly than conventional generating resources, will provide an increasingly economical and reliable solution for providing both ancillary services for renewable resources and capacity during peak times.

Although UNS Electric will continue to make short-term capacity purchases, we'll also monitor the wholesale market for long-term power purchases and low-cost plant acquisitions. Our Reference Case Plan recommends adding over 100 MW of natural gas combined cycle capacity by 2022.

UNS Electric and project partners also continue efforts to build a new 150 MW interconnection that would connect the electric grid in southern Arizona with electric facilities in northwestern Mexico. The Nogales Interconnection would support reliable electric service for UNS Electric customers, allow access to additional energy sources, and support business growth in the region. This report also describes how new smart grid technologies identified in UNS Electric's 10-year transmission and distribution plans would improve service reliability by providing increased system capacity and contingency support for the distribution network.

Building the most reliable and cost-effective resource portfolio of the future requires us to consider the price, benefits and feasibility of our expanding resource options. Although we must consider our existing infrastructure, environmental factors and other operating conditions unique to our company, it's clear that renewable resources, energy efficiency measures and demand response technologies will play important roles in our future resource plans. Renewable resource costs are becoming competitive with conventional generation, while energy efficiency remains the lowest-cost option. That's why we believe utility-specific clean energy standards should be determined through the IRP process instead of mandatory, numeric-driven statewide standards.

As our approach to resource planning evolves, UNS Electric will maintain its commitment to building a more sustainable, responsive portfolio that satisfies the needs of our customers.

David G. Hutchens
President and CEO

CHAPTER 1

EXECUTIVE SUMMARY

Introduction

UNS Electric Inc., (UNSE) has historically relied on long-term purchased power agreements (PPAs) and the wholesale power market to meet the majority of customers' energy needs. Customer usage and peak demand steadily increased over the years with increased population within the UNSE service territories. Natural gas fired combustion turbines, as well as purchased power, provided the capacity needed to meet summer peak demand. Since UNS Energy Corporation acquired UNSE (formerly Citizens Arizona Electric) in 2003, UNSE has added approximately 250 MW of new generating resources to enhance reliability and reduce its reliance on the market.

UNSE took a significant step in that direction with the 2015 acquisition of a 25% ownership share in Block 3 of the Gila River Generating Station ("Gila River"), UNSE's first intermediate-load generating resource. This acquisition has, and will continue to further enhance reliability while reducing costs for UNSE's customers. This trend toward a greater self-reliance on generation is expected to continue, along with the expansion of renewable energy resources and implementation of cost-effective energy efficiency and demand response programs.

While making this transition, UNSE must navigate the influence of several new factors that have come into play. Changing customer use patterns have resulted in lower load growth, yet there exists the potential for achieving new efficiencies through improved communication and coordination between customers and the grid. Operating requirements relating to reliability, grid security, clean energy standards, and environmental compliance are becoming continuously more stringent at the same time that we prepare for the operating challenges relating to integrating higher levels of renewable energy. Wholesale market fundamental are shifting, resulting in different price signals, and a need for the right balance of resources to take advantage of lower-cost opportunities. Given all these changes, we need to view resources differently, to be better aligned with the role each resource plays in meeting the economical and reliable delivery of energy to our customers.

Furthermore, the traditional role of resource planning itself has changed. While we still must provide for reliable and safe power at affordable rates, our stakeholders expect us to achieve those objectives while improving environmental performance and mitigating risk. To meet these expanded objectives, UNSE must be prepared to make changes while maintaining optionality to account for the uncertainty inherent in a long-term outlook.

UNSE's 2017 Integrated Resource Plan identifies the current and anticipated changes facing the utility industry, and UNSE specifically, and outlines a plan to meet our customers' energy needs in light of these changes. The IRP presents a snap shot of current loads and resources and projects future energy and capacity needs through 2032. UNSE presents the 2017 Reference Case Plan that provides a reasonable path forward in terms of reliability, affordability, environmental performance and risk.

UNSE shares several business functions with its sister company, Tucson Electric Power (TEP), including but not limited to:

- Resource Planning and Acquisition
- Balancing Services
- Transmission Planning
- Corporate Environmental Compliance
- Energy Efficiency Coordination and Implementation
- Management of Gila River

Therefore, in order to avoid unnecessary duplication of vastly similar information, this IRP refers to and incorporates by reference the following sections of the Tucson Electric Power 2017 Integrated Resource Plan. TEP's IRP can be found at: https://www.tep.com/projects/#resource

- Future Drivers that May Influence the Long-Term Load Forecast – Chapter 2, Page 42.
- Balancing Authority Operations – Chapter 3, Page 55.
- Environmental Regulations – Chapter 3, Page 73.
- A New Integration Approach to Resource Planning– Chapter 4, Page 83.
- Load Serving Resources – Chapter 6, Page 125.
- Grid Balancing and Load Leveling Resources – Chapter 7, Page 169.
- Regional Transmission Planning – Chapter 8, Page 185.
- PACE Global Future States of the World – Appendix A
- Burns and McDonnell 2017 Flexible Generation Technology Assessment – Appendix B

Renewable Energy Integration and Diversification

UNSE continues to expand its portfolio of renewable energy resources and expects to serve 20% of retail load with renewable energy by 2020. This pace of renewable energy deployment is well ahead of that required by Arizona's Renewable Energy Standard of 15% by 2025. UNSE's renewable energy expansion will include primarily solar resources to compliment the large scale wind resources already serving the Company.

UNSE's high penetration of renewable energy will come with its own set of challenges and will require UNSE to expand its flexible and responsive generation portfolio. A large accumulation of solar PV in UNSE's portfolio introduces operational challenges at certain times of the year, most notably steep ramping periods in the morning and evening on sunny, winter and spring days. UNSE's portfolio must have the capability to accommodate these rapid ramping requirements (up and down), and strategies are needed to take advantage of low spot market pricing due to over generation that may be occurring regionally.

Initially, Arizona's clean energy standards relating to renewable energy and energy efficiency provided the catalyst for many of the changes we are experiencing. Going forward, future clean energy targets should be developed on a utility-by-utility basis. While these standards have produced real and tangible benefits, clean energy standards applied at a statewide level are inherently inflexible, and fail to take into account the unique circumstances of each utility. This inflexibility creates inefficiencies in resource acquisitions and system dispatch, which ultimately results in higher costs passed on to customers. UNSE believes that the IRP is a better mechanism to develop utility-specific clean energy targets than a state-wide, "one size fits all" rulemaking. The IRP provides the most holistic consideration of the very goals that clean energy standards aim to achieve, while balancing the cost of achieving those goals for our customers.

Grid Balancing Resources

As part of UNSE's 2017 Reference Case Plan, planned energy storage systems (ESSs) will play a greater role in the integration of more renewable energy into UNSE's resource portfolio. These ESSs will be readily available to provide ancillary power services such as frequency response, regulation and voltage support that are more challenging to maintain under the demands of a system with high levels of renewable energy penetration.

In addition, new fast start, fast ramping thermal resources with mechanical inertia will also have to be added in order to help balance grid operations. Reciprocating internal combustion engines (RICEs) are fast response resources designed to flexibly dispatch to meet changes in load and can provide 100% of their effective load carrying capability (ELCC) during peak periods. These units are not degraded by the number of start-ups, as are combustion turbines, and they are capable of running at an efficient heat rate even at 30% of their designed capacity. A 10 MW unit can idle down to 3 MWs under spin and stand ready to react to system disturbances or renewable intermittent variability as needed.

Under today's Direct Load Control (DLC) programs, UNSE is able to rely on approximately 4.5 MW of interruptible commercial and industrial loads to reduce summer peaking capacity requirements. As part of the 2017 IRP Reference Case Plan, UNSE plans to evaluate the cost-effectiveness of future DLC programs. Future DLC programs will be proposed as part of the Company's annual energy efficiency implementation filings. In order to achieve higher levels of DLC, UNSE would likely need to expand its DLC program design beyond the Commercial and Industrial sectors. Going forward, rather than focusing specifically on summer peaking requirements, UNSE intends to transition from conventional peak shaving demand response (DR) programs to more advanced DR programs[1] that are capable of cost-effectively addressing grid balancing needs such as short-run ramps and disturbances at timescales ranging from seconds up to an hour, throughout the year.

Regional Infrastructure Projects

UNSE and TEP are involved in the development of the Nogales Interconnection Project, a proposed direct current interconnection, which will allow for an asynchronous interconnection between the electric grids in southern Arizona and the northwest region of Mexico. The project will support the reliability of the electric system, including providing bidirectional power flow and voltage support, as well as emergency assistance, as needed, for the electric systems both north and south of the border.

Regional Transmission Organizations

Seeing a need for greater coordination, a "Working Group" consisting of investor owned utilities, cooperative power providers and public power entities was formed to consider and analyze potential alternatives to joining the California Independent System Operator (CAISO) Energy Imbalance Market (EIM). The objectives of the Working Group are as follows:

- Determine economic benefits of potential alternatives and weigh opportunities for market participation

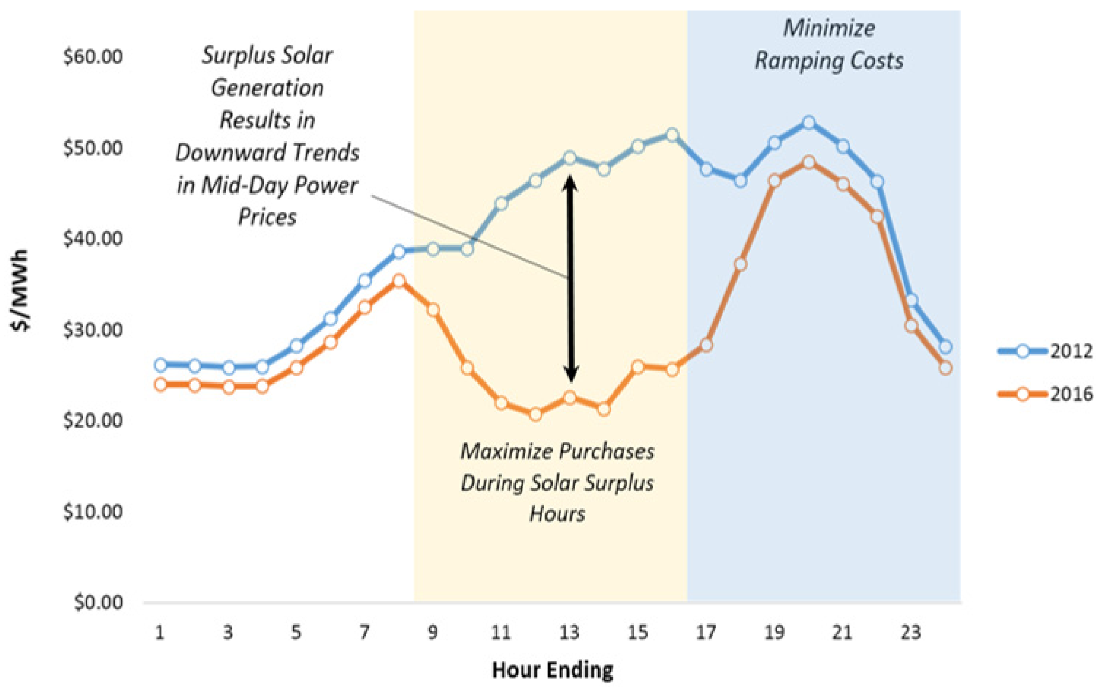
[1] Lawrence Berkeley National Laboratory. California Demand Response Potential Study - Charting California's Demand Response Future, November 2016. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451541

- Determine if the CAISO EIM and regulated markets in the Midwest and Mountain West offer certain economic benefits related to more efficient utilization of generating assets and transmission infrastructure
- Evaluate operational benefits especially as they relate to renewable resource integration and system regulation
- Establish if EIM/Regulated Markets and certain alternatives may offer reliability benefits related to the grid operations
- Consider governance structure and implications for resource control

The Working Group discussed various options with the CAISO, the Southwest Power Pool, and the Mountain West Transmission Group. Currently there is recognizable value to establishing a regional market. However, the cost of joining or establishing a regional market have yet to be determined or fully evaluated. UNSE will continue to engage with market operators to determine the best path forward for its customers.

Market Fundementals

With the rapid increase in renewable resource penetration throughout the region, a transformation of market fundamentals is currently underway and is changing how both load-serving entities and wholesale merchants transact. As shown in the figure below, surplus solar output is causing a downward shift in market prices from the hours of 8 AM to 4 PM.



In addition to surplus renewable generation, low cost shale gas production has also played a significant role in transforming the supply and demand economics of natural gas. As we saw in 2015 and 2016, expanded natural gas production from shale formations is negatively impacting the economic viability of many baseload coal and nuclear resources. Alternatively, resources like natural gas combined cycle (NGCC) units that have much lower capital and fixed costs are more competitive than coal and nuclear in today's wholesale power markets. This competitive advantage will likely result in NGCC units displacing many coal and nuclear plants as baseload resources since they are better positioned to maintain profitability in a market driven by low natural gas prices.

Energy Efficiency

UNSE recognizes energy efficiency (EE) as a cost-effective way to reduce our reliance on fossil fuels. To evaluate EE in terms of UNSE's overall resource portfolio, UNSE determined the hourly savings of each individual EE measure using widely used and recognized third-party load shapes, and then aggregated them at the portfolio-level by customer rate class. From these composite program-level savings, UNSE is able to analyze peak periods to determine coincident and non-coincident peak demand savings. The level of energy savings was based on compliance with the EE standard through 2020, excluding program credits, and an estimate of "achievable" EE developed by the Electric Power Research Institute (EPRI) for all years after 2020. Then, to evaluate EE as a resource for replacement of generation, the specific types of measures being implemented are modeled like other resources against the forecasted system load. Using these results, UNSE can target measures that coincide with periods of high ramp rate, periods dominated by high cost resources, or the system peaks, both daily and annually.

A New Integration Approach to Resource Planning

With the increasing cost-competiveness of certain renewable resources, many resource planners are in the process of integrating higher levels of renewable technologies as a complement to their existing conventional generation fleet. Because of the unique challenges that high levels of renewable energy place on grid operations, the UNSE 2017 IRP takes a new approach in categorizing the capabilities for each type of resource in order to better reflect the role these resources will play as the Company adjusts its resource portfolio over the next decade.

- **Load Modifying Resources** – includes EE, distributed generation (DG), and time of use tariffs, whose effects are primarily "behind the meter" and are therefore, largely, if not entirely beyond the view and control of the balancing authority.
- **Renewable Load Serving Resources** – include both utility scale solar and wind technologies.
- **Conventional Load Serving Resources** – include coal, nuclear and natural gas technologies that are fully dispatchable and are used to supply the vast majority of the energy needed to meet load.
- **Grid Balancing Resources** – include natural gas combustion turbines, DR, natural gas RICEs and storage technologies that are fast ramping and flexible, as needed to maintain grid reliability.

The table below provides a brief overview of the types of resources that will be included and evaluated in the resource planning process within the 2017 IRP.

Category	Type	Zero Carbon Production	State of Technology	Primary Use	Dispatchable by Balancing Authority
Load Modifying Resources	Energy Efficiency	Yes	Mature	Base Load Reduction	No
	Distributed Generation	Yes	Mature	Intermediate Load Reduction	No
	Rate Design	(1)	Mature	Targeted Load Usage / Reductions	No
Load Serving Renewable Resources	Wind	Yes	Mature	Intermediate Generation	No
	Solar	Yes	Mature	Intermediate Generation	No
Load Serving Conventional Resources	Natural Gas Combined Cycle	No	Mature	Base Load Generation	Yes
	Pulverized Coal	No	Mature	Base Load Generation	Yes
	Small Modular Nuclear (SMR)	Yes	Emerging	Base Load Generation	Yes
Grid Balancing Resources	Reciprocating Engines	No	Mature	5 - 10 Minute Ramping	Yes
	Combustion Turbines	No	Mature	10 - 15 Minute Ramping	Yes
	Pumped Hydro Storage	(1)	Mature	1 Minute Ramping	Yes
	Demand Response	Yes	Mature	1 Minute Ramping	Yes
	Battery Storage	(1)	Emerging	1 Second Ramping	Yes

(1) Carbon intensity is dependent upon the resources that would be displaced by this rate tariff or storage technology net of charging.

Summary of the 2017 IRP Reference Case Plan

UNSE's 2017 IRP Reference Case Plan continues the Company's strategy of increasing self-generation capacity with the addition of high-efficiency natural gas resources, expanding the deployment of renewable energy resources with a target of serving 20% of its retail load using renewable energy by 2020, and continued development and implementation of cost-effective EE measures.

Planned Load Serving Additions

The 2017 Reference Case Plan includes the addition of a NGCC resource by 2022. This intermediate load to baseload facility will significantly reduce the Company's reliance on market purchases, and will bring the total intermediate load to baseload capacity to over 270 MW.

Planned Renewable Resource Additions

The 2017 Reference Case Plan includes a new, large renewable energy project consisting of 46 MW_{ac} of solar single-axis tracking PV. The project is expected to be in-service by mid-2018 and will provide energy under a 20-year PPA.

Planned Grid Balancing Resources

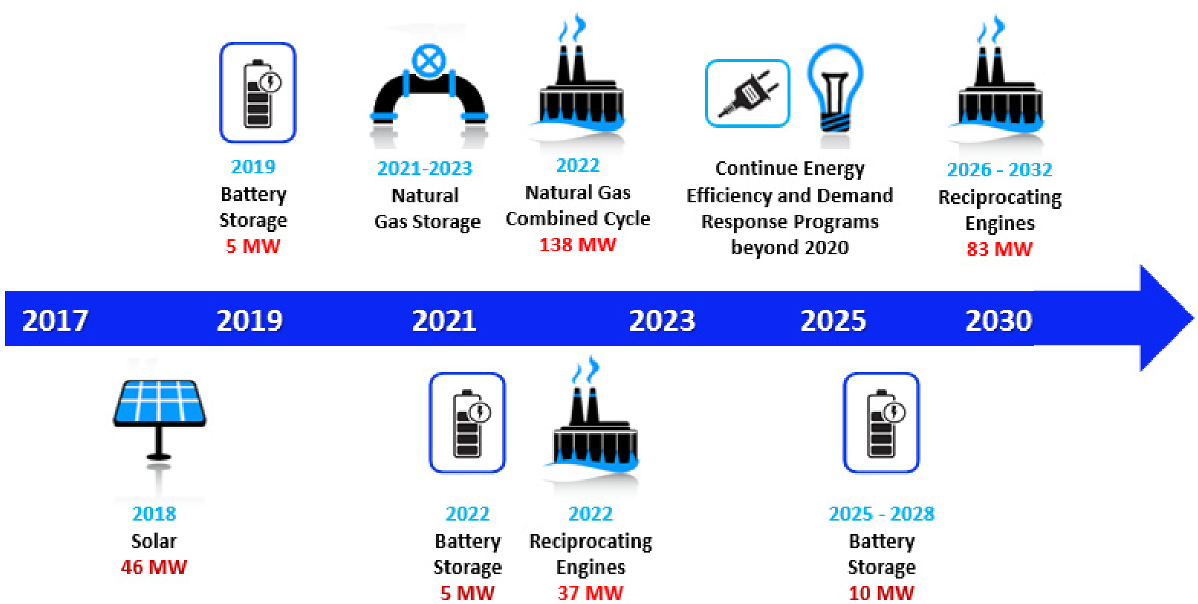
To support the system in light of this high penetration in intermittent renewable energy, and to provide capacity to address peak load growth, it is assumed that UNSE constructs 37 MW of natural gas fired RICEs by 2022. Moreover, a number energy storage projects are planned to come on line between 2019 and 2022 to provide additional renewable energy support and other ancillary services. These systems would likely be sized as 5 MW projects with a storage discharge capacity of 5 MWh. Additional grid balancing resources are assumed later in the planning period.

Planned Energy Efficiency Commitments

UNSE's EE programs will continue to comply with the Arizona Energy Efficiency Standard that targets a cumulative energy savings of 22 % by 2020. From 2021 through the end of the planning period, the estimated annual savings in the 2017 Reference Case Plan are based on an assessment of "achievable potential" in energy savings from EE programs conducted by the EPRI. By 2032, this offset to future retail load growth is expected to reduce UNSE's annual energy requirements by approximately 500 GWh and reduce UNSE's system peak demand by 125 MW. A timeline of UNSE's Reference Case Plan is presented below.

UNSE's 2017 IRP Reference Case Plan

Milestone Timeline



CHAPTER 2

ENERGY DEMAND AND USE PATTERNS

Load Forecast

In the IRP process it is crucial to first estimate the load obligations that existing and future resources will be required to meet for both short and long term planning horizons. As a first step in the development of the current resource plan, a long term load forecast was produced. This chapter provides an overview of the anticipated long term load obligations at UNSE, a discussion of the methodology and data sources used in the forecasting process, and a summary of the tools used to deal with the inherent uncertainty currently surrounding a number of key forecast inputs.

The sections in this chapter include:

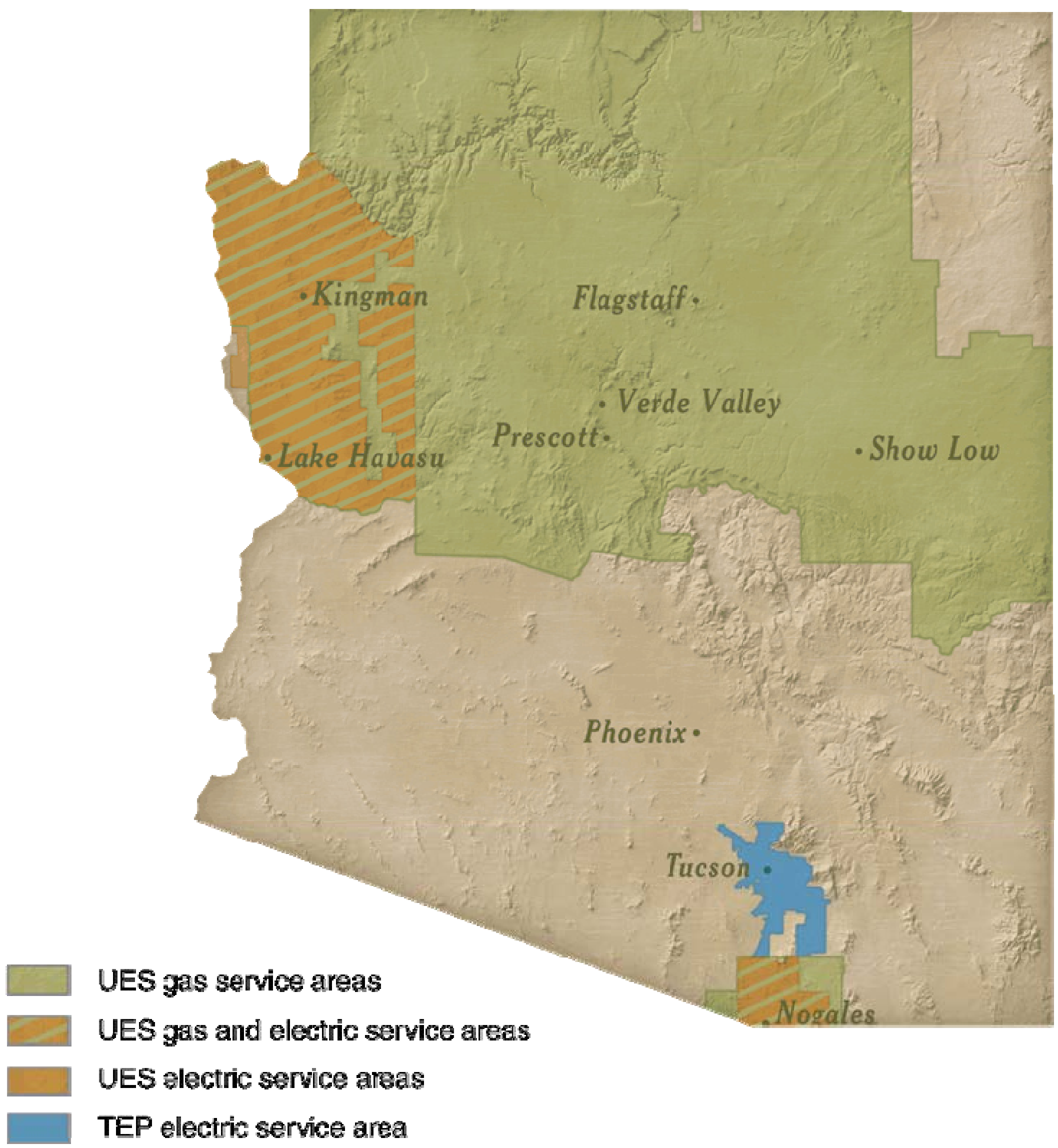
- **Company Overview:** UNSE geographical service territory, customer base, and energy consumption by rate class
- **Reference Case Forecast:** An overview of the Reference Case forecast of energy and peak demand used in the planning process
- **Summary:** Compilation of results from this analysis

Geographical Location and Customer Base

UNSE currently provides electricity to approximately 95,500 customers in two geographically distinct areas. In northwest Arizona, UNSE provides service to the majority of Mohave County. This segment of the service territory includes approximately 76,000 customers located primarily in the Kingman and Lake Havasu City areas. In addition to Mohave County, UNSE also provides service to the majority of Santa Cruz County in southern Arizona. This southern service territory includes approximately 19,500 customers located primarily in the Nogales area.

The two regions are very different both in terms of population and geography. For instance, Mohave County is estimated to have a current population of approximately 206,000 and has experienced an estimated 1.54% annual growth over the last decade, while Santa Cruz County is estimated to have a current population of approximately 46,000, and has grown at an estimated 0.44% annual rate over the same period. In addition to the varying population dynamics, the geography and weather of the two service areas are also distinctly different. For example, Lake Havasu City sits at an elevation of approximately 735 feet, while Nogales is located in mountainous terrain and sits at 3,823 feet. The differences in population growth rates, topography, and weather result in distinct patterns of demand, consumption, and customer growth within each region that must be taken into account during the planning process.

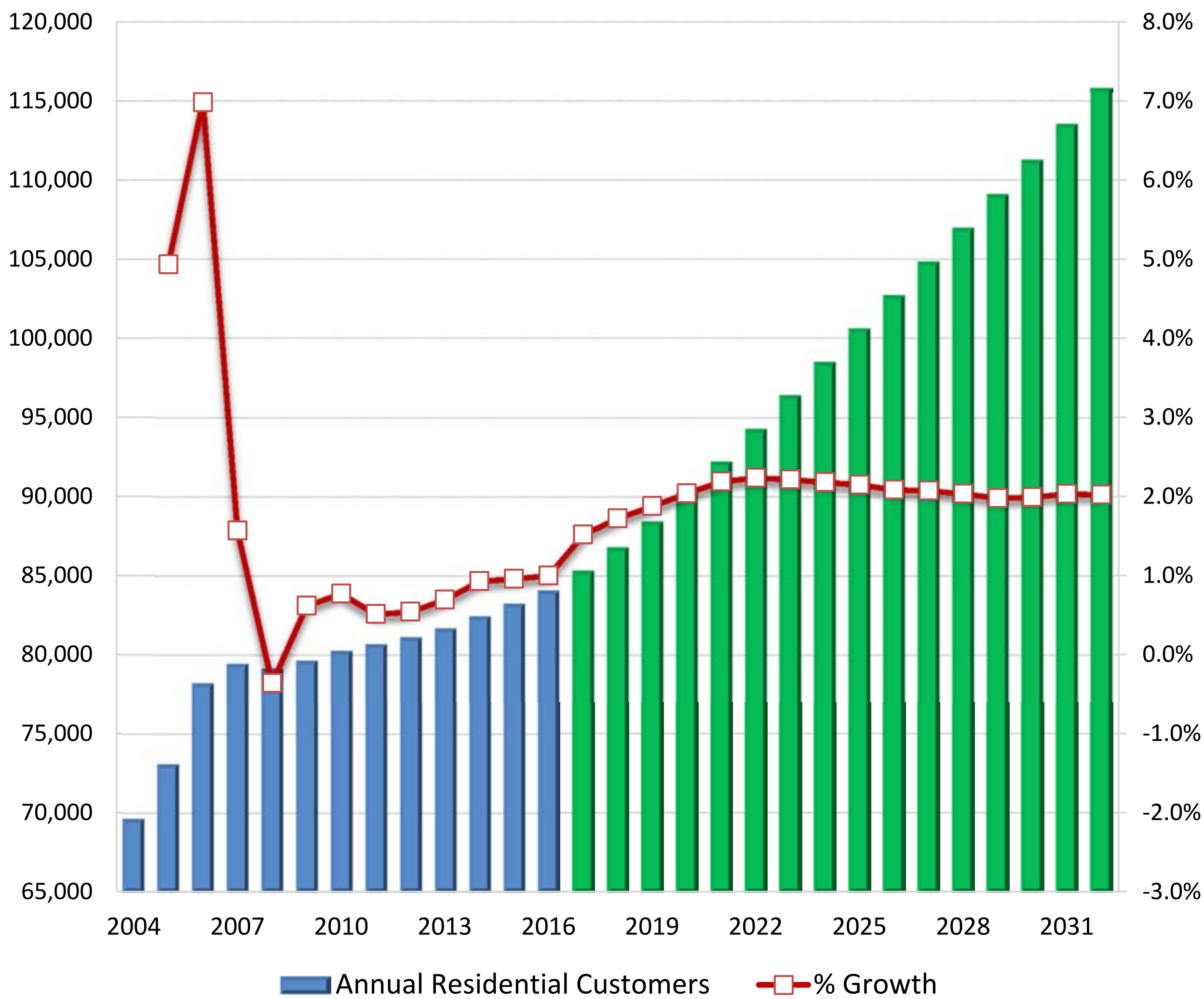
Map 1 - Service Area of Tucson Electric Power and UES Utilities



Customer Growth

While the economic climate has slowed population growth significantly in recent years, UNSE's service areas are still expected to experience significant growth after the recessionary environment in Arizona subsides. Chart 1 outlines the historical (blue bars) and expected (green bars) customer count and corresponding growth in the residential rate class from 2000-2032. As customer growth is the largest factor behind growth in UNSE's load, the continuing customer growth will necessitate additional resources to serve the increased load in the medium term.

Chart 1 - Estimated UNSE Residential Customer Growth 2000-2032

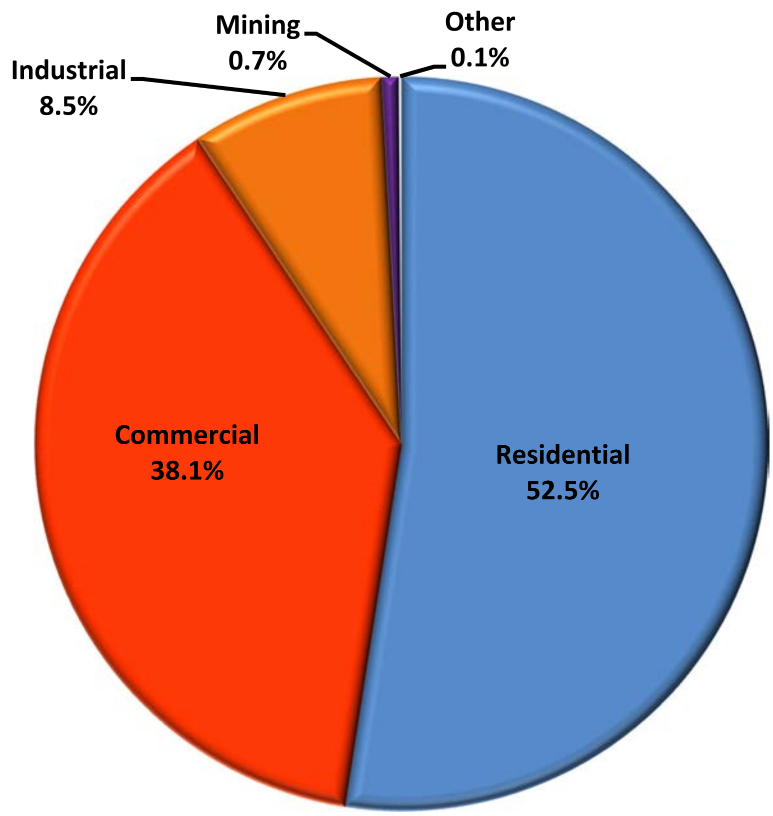


Retail Sales by Rate Class

In 2016 UNSE experienced peak demand of approximately 450 MW, while generating approximately 1,600 GWh of retail sales. Approximately 91% of 2016 retail sales were generated by the residential and commercial rate classes, with approximately 9% generated by the industrial and mining rate classes.

Chart 2 gives a detailed breakdown of the estimated 2016 retail sales by rate class.

Chart 2 – Estimated 2017 Retail Sales (GWh) % by Rate Class



Reference Case Forecast

Methodology

The load forecast used in the UNSE IRP process was produced using a "bottom up" approach. A separate monthly energy forecast was prepared for each of the major rate classes (residential, commercial, industrial, and mining). Widely varying customer usage patterns and weather in Mohave and Santa Cruz counties, as well as significant differences between customer usage and weather in the Kingman area and the Lake Havasu City area within the Mohave service territory also require that the forecasts be further segmented into three distinct geographical projections. The forecast methodologies fall into two broad categories:

1) For the residential and commercial classes, forecasts were produced using statistical models. Inputs include factors such as historical usage, weather (e.g. average temperature and dew point), demographic forecasts (e.g. population growth), and economic conditions (e.g. Gross County Product and disposable income).
2) For the industrial and mining classes, forecasts were produced for each individual customer. Inputs include historical usage patterns, information from the customers themselves (e.g. timing and scope of expanded operations), and information from internal company resources working closely with the mining and industrial customers.

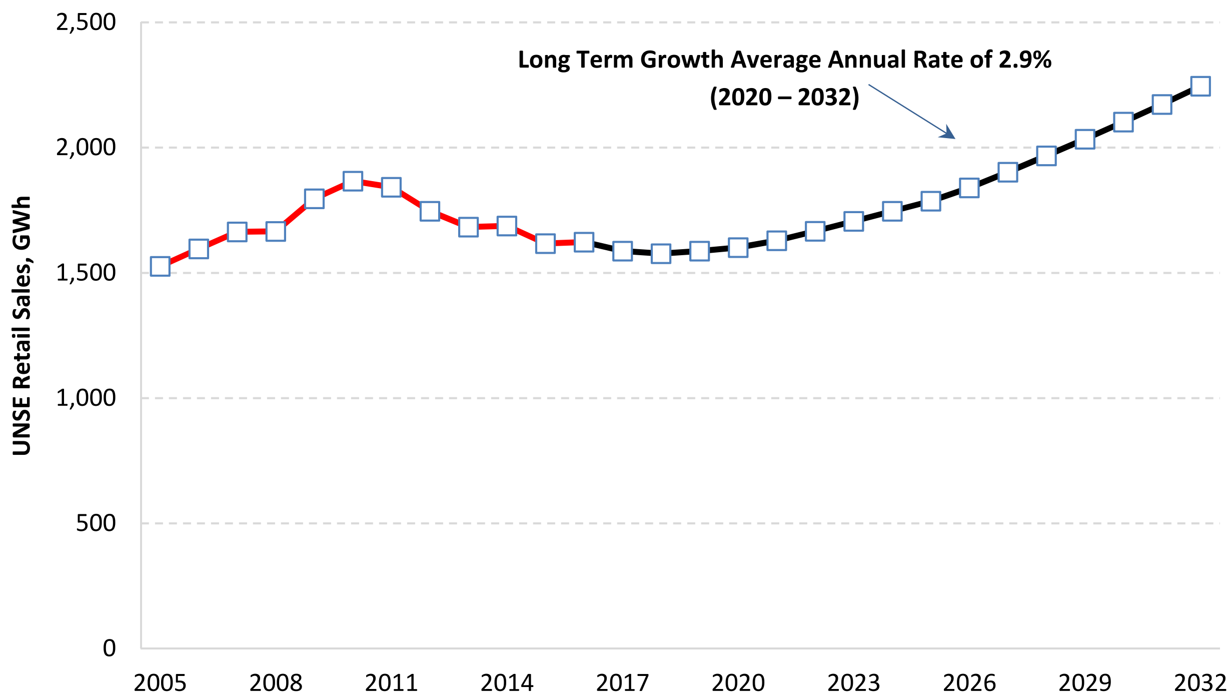
After the individual monthly forecasts were produced, they were aggregated (along with any remaining miscellaneous consumption falling outside the major categories) to produce a monthly energy forecast for the company.

After the monthly energy forecast for the company was produced, the anticipated monthly energy consumption was used as an input for another statistical model used to estimate the peak demand for each month based on the historical relationship between consumption and demand in the month in question. Annual peak demand was then calculated by simply taking the maximum monthly peak demand for each year in the forecast period.

Reference Case Plan Retail Energy Forecast

As illustrated in Chart 3, UNSE's retail sales, in aggregate, are expected to be relatively flat over the next few years. Total energy sales are expected to increase steadily throughout the forecast horizon.

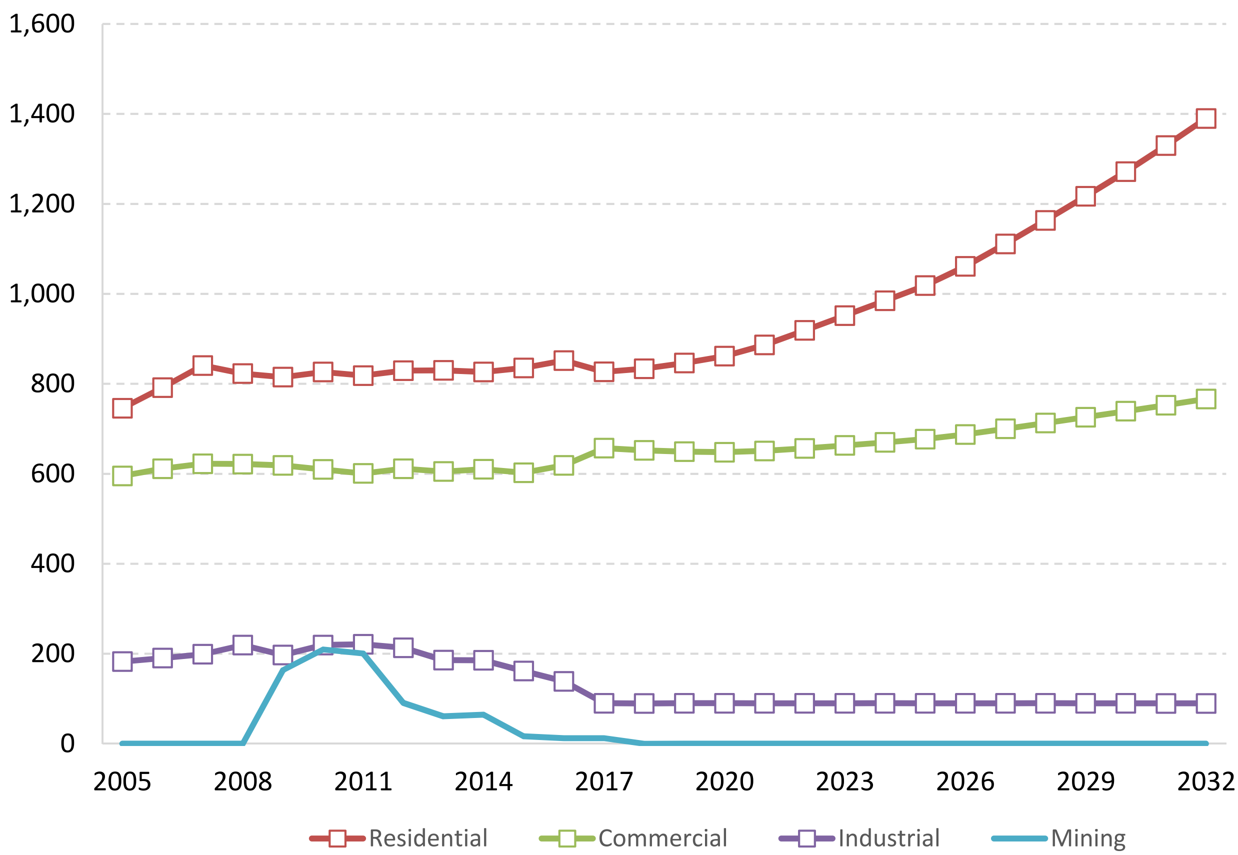
Chart 3 - Reference Case Retail Energy Sales, Weather-Normalized Historical



Reference Case Retail Energy Forecast by Rate Class

As illustrated in Chart 3, the Reference Case forecast assumes steady energy sales growth at UNSE throughout the planning period. However, the growth rates vary significantly by rate class. The energy sales trends for each major rate class are detailed in Chart 4. The loss of mining sales due to economic weakness can be seen beginning in 2010.

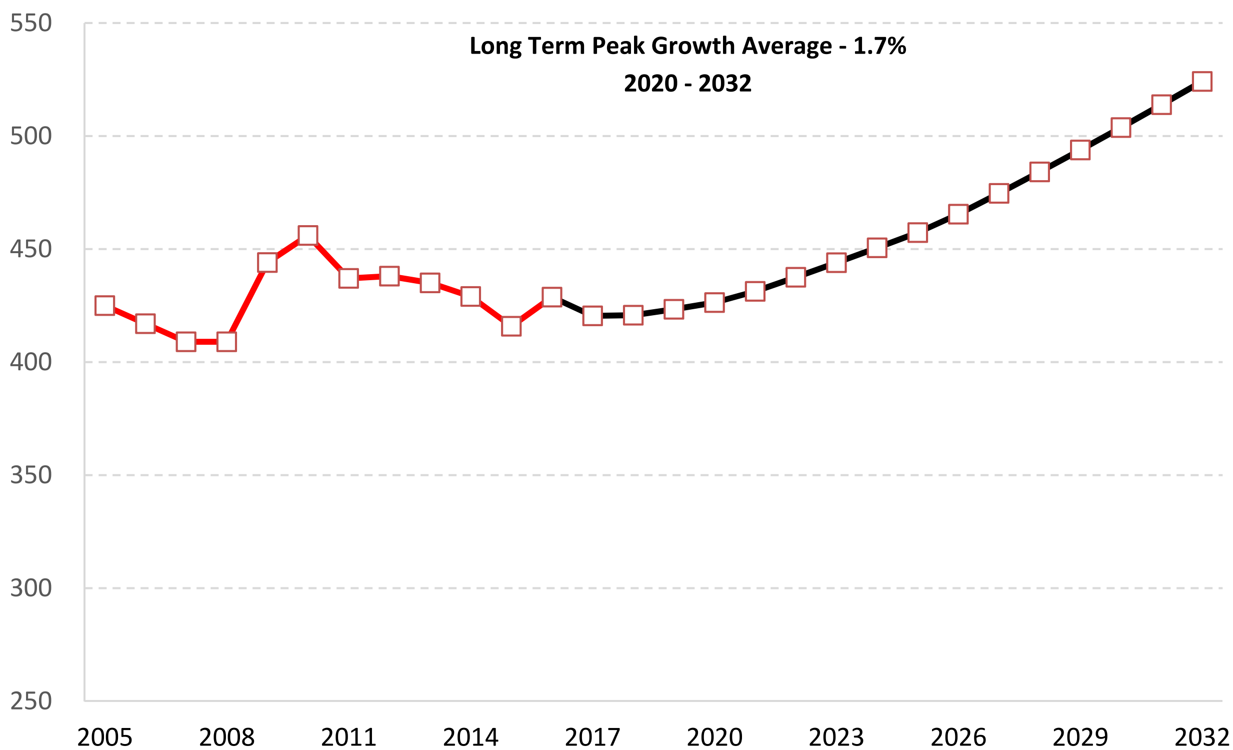
Chart 4 – Historical and Reference Case Retail Energy Sales by Rate Class (GWh)



Reference Case Peak Demand Forecast

As show in Chart 5, UNSE's peak demand is expected to increase throughout the forecast period. All references to peak demand are "coincidental" peak system demand (i.e. the highest demand seen simultaneously in the Mohave and Santa Cruz service areas). Due to geography, the two service areas typically experience individual service area peaks at different times with the Santa Cruz peak typically occurring in June and the Mohave peak typically occurring in July or August. Because Mohave County generates much higher demand (and energy sales), the UNSE coincidental system peak also typically occurs in July or August.

Chart 5 – Historical and Reference Case Peak Demand (MW)



Data Sources Used in Forecasting Process

As outlined above, the Reference Case plan forecast requires a broad range of inputs (demographic, economic, weather, etc.) For internal forecasting processes, UNSE utilizes a number of sources for these data:

- IHS Global Insight
- The University of Arizona Forecasting Project
- Arizona Department of Commerce
- U.S. Census Bureau
- National Oceanic and Atmospheric Administration (NOAA)
- Weather Underground Forecasting Service

Risks to Reference Case Plan Forecast and Risk Modeling

As always, there is a large amount of uncertainty with regard to projected load growth. Some, but certainly not all of the key risks to the current forecast include:

- Strength and timing of the economic recovery
- Possible structural changes to customer behavior (i.e. do post-recession customers have consumption patterns different from those seen pre-recession?)
- Volatility in industrial metal prices and associated shifts in mining consumption
- Efficacy of EE programs (i.e. what percentage of load growth can be offset by demand side management?)
- Technological innovations (e.g. plug in hybrid vehicle penetration)
- Volatility in demographic assumptions (e.g. much higher or lower population growth than currently assumed)

CHAPTER 3

OPERATIONAL REQUIREMENTS AND RELIABILITY

Load and Resource Adequacy

A critical component of the IRP planning process is the assessment of available firm resource capacity to meet firm load obligations and to maintain a planning margin above a utilities forecasted load. As part of UNSE's long-term planning process, the Company targets a 15% planning reserve margin in order to cover for forecasting variances and any system contingencies related to unplanned outages on its generation and transmission system.

Chart 6 - UNSE's 2017 Loads and Resource Assessment – Existing Resources

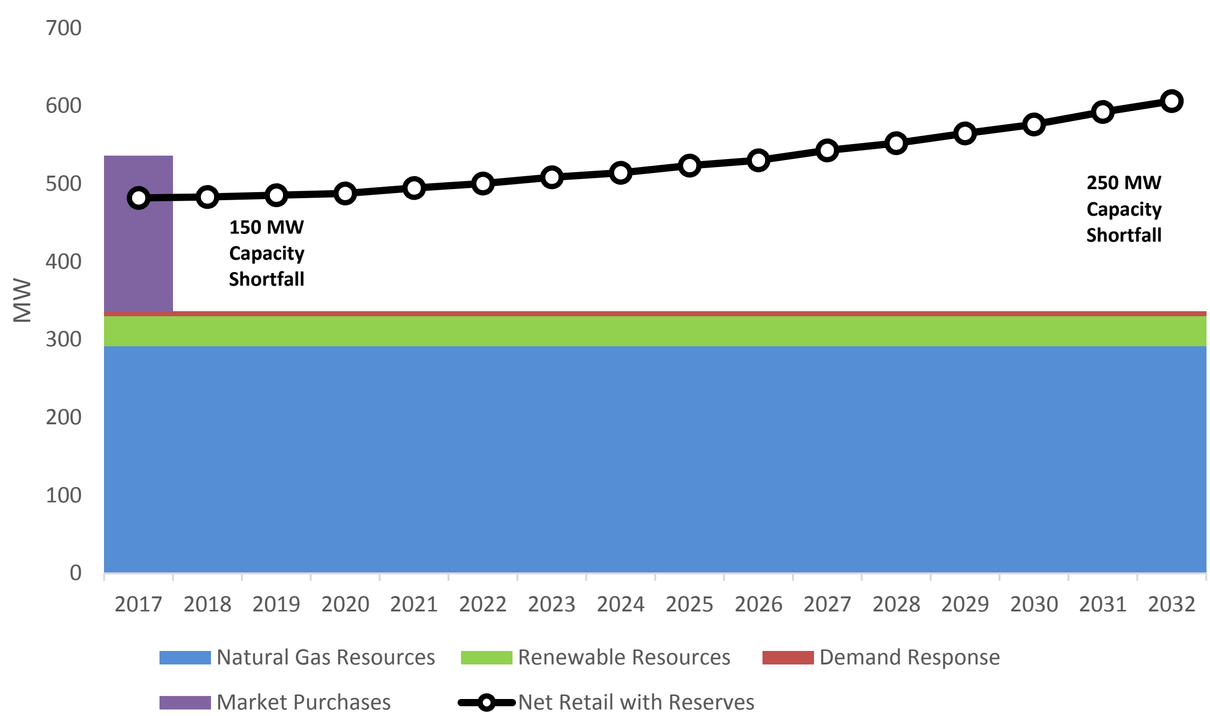


Chart 6 above illustrates UNSE's existing resource portfolio compared to the retail load forecast which includes planning reserves. This loads and resource assessment indicates that UNSE has a capacity shortfall of 150 MW beginning in 2018. UNSE has relied on the market to secure its near term capacity needs. That shortfall increases to approximately 250 MWs by the end of the 15-year planning horizon. The Reference Case Plan assumes that much of this resource need is met by additional NGCC generating capacity, in addition to the 138 MW of Gila River 3 capacity currently owned by UNSE.

The emergence of renewable resources, combined with evolving operational requirements, present challenges but also an opportunity to build a sustainable and economically sound resource portfolio. This IRP presents a Reference Case Plan that achieves a renewable target of generating 20% of retail load by 2020. UNSE is in compliance of the Arizona Renewable Energy Standard for the duration of the planning period without adding additional renewable resources after 2018. UNSE is also committed to its EE programs. The renewables target and EE projections will be complimented, as reflected in the Reference Case Plan, with proposed installations of ESSs and RICEs.

Table 1 summarizes UNSE's gross retail peak demands by year based on its September 2016 load forecast projections. These demands are summarized by customer class and by the Company's assumptions on coincident peak load reductions from DG and EE. Table 1 summarizes the Company's reserve margin positions based on the capacity resources shown in Table 2**.**

Table 2 summarizes UNSE's firm resource capacity based on its current planning assumptions related to its natural gas resources. Additional resources such as DR programs, short-term market purchases along with capacity sourced from its proposed battery storage projects are also part of UNSE's Reference Case Plan resource portfolio. The resource portfolio also includes the addition of NGCC resources and RICE to meet system peak and help mitigate intra-hour intermittency and variability challenges introduced by renewable resources.

Future Load Obligations

The following two tables provide a data summary of UNSE's loads and resources. Table 1 shows UNSE's projected firm load obligations, which include retail demand and planning reserve margins.

Table 1 - Firm Load Obligations, System Peak Demand (MW)

Firm Load Obligations (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential	304	309	316	322	329	336	344	351	359	367	377	387	397	408	421	434
Commercial	144	146	149	152	156	159	163	166	170	173	178	183	188	193	199	205
Industrial	30	31	31	32	33	33	34	35	36	36	37	38	39	40	42	43
Mining	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3
Other	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1
Retail Peak Demand	480	488	498	508	520	530	543	554	568	579	595	611	628	645	666	686
Less Energy Efficiency	-40	-45	-51	-57	-62	-66	-71	-76	-81	-86	-91	-98	-104	-111	-118	-125
Less Distributed Generation	-21	-23	-25	-27	-28	-29	-30	-31	-32	-32	-32	-33	-33	-33	-33	-34
Net Retail Demand	419	420	422	424	430	435	442	447	455	461	472	480	491	501	515	527

Reserve Margin	117	71	73	72	77	84	78	73	68	90	79	74	82	72	77	84
Reserve Margin %	28%	17%	17%	17%	18%	19%	18%	16%	15%	20%	17%	15%	17%	14%	15%	16%

System Resource Capacity

Table 2 shows UNSE's Reference Case Plan for firm resource capacity based on each resource's contribution to system peak.

Table 2 – Capacity Resources, System Peak Demand (MW)

Firm Resource Capacity (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Black Mountain	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Valencia	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
Gila River Combined Cycle	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138
Future Natural Gas Resources	0	0	0	0	0	175	175	175	175	202	202	202	221	221	239	258
Natural Gas Resources	292	292	292	292	292	467	467	467	467	494	494	494	513	513	531	550
Utility Scale Renewables	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
Demand Response	6	6	7	8	9	9	10	10	10	11	11	12	12	12	13	13
Coincident Peak Capacity	336	336	337	338	339	514	515	515	515	543	543	544	563	563	582	601
Firm Purchases	200	155	155	155	165	0	0	0	0	0	0	0	0	0	0	0
Future Storage Resources	0	0	3	3	3	5	5	5	8	8	8	10	10	10	10	10
Total Resources	536	491	495	496	507	519	520	520	523	551	551	554	573	573	592	611

Typical Dispatch Profiles

The previous section described how the UNSE Reference Case Plan will address peak hour demand. This IRP, more than previous ones, required additional analysis on the inter and intra-hour demand requirements and the response of the optimal resource mix. The figures below represent demand profiles for a typical day representative of each respective season in 2016.

Chart 7 illustrates the manner in which existing resources were routinely dispatched to meet anticipated load requirements during a summer peak day in 2016. In Chart 7 we observe that the high peak demand experienced in the summer can be met with substantial market purchases and the utilization of existing peaking resources. The contribution from renewables, shown in green, is shifting these traditional peakers further into the evening hours. UNSE experiences its peak demand at 4 to 5 PM in either July or August. Increased penetration of solar PV is having the net effect of shifting this peak to later hours, ultimately onto 7 to 8 PM as the sun sets. Meanwhile, system operators are deploying their fastest ramping units upward to respond to the ramp-down of solar resources.

Chart 7 - Example Summer Day Dispatch

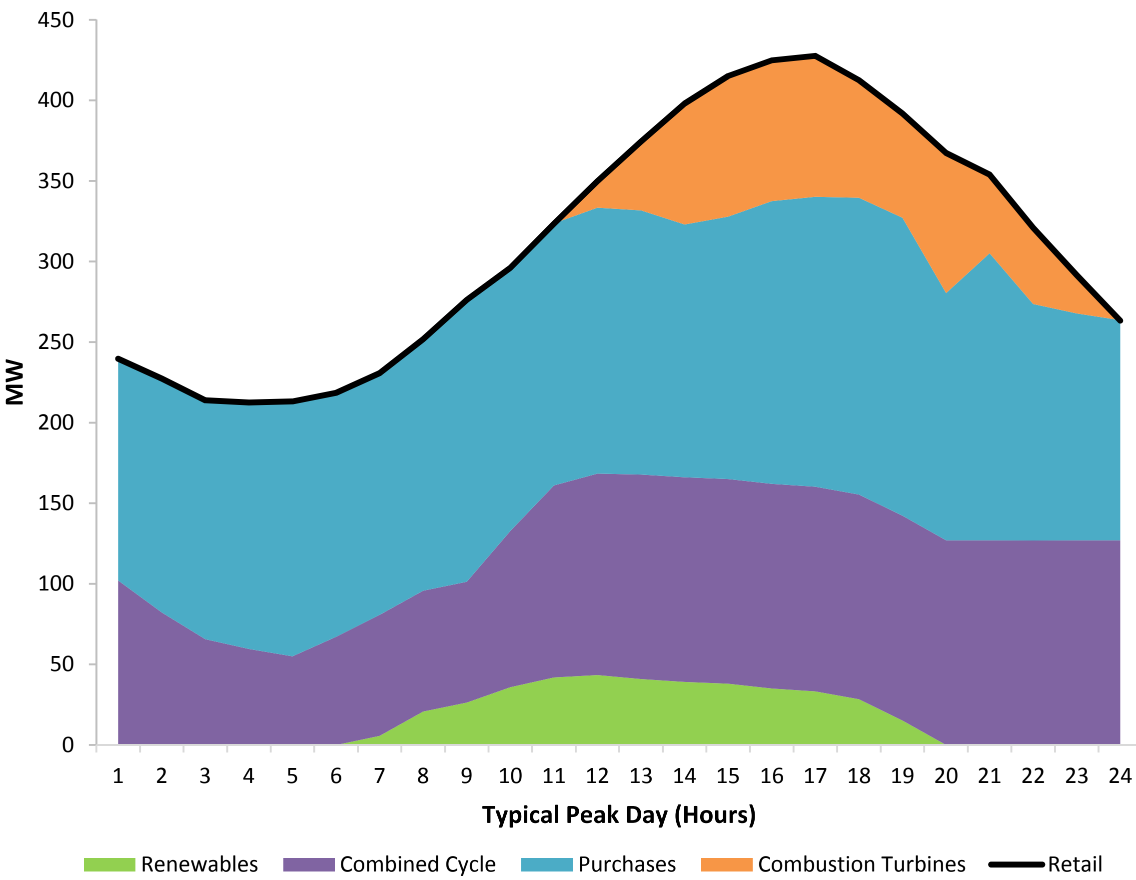
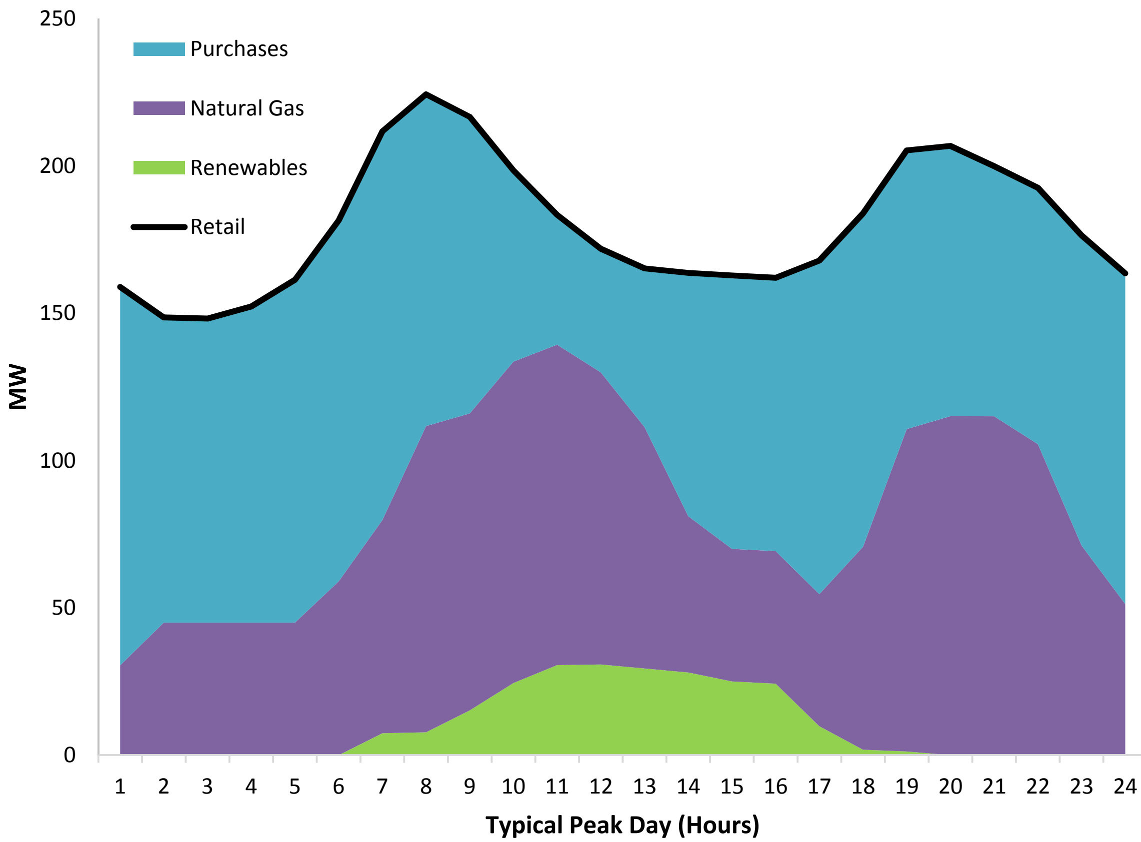


Chart 8 - 2017 Example Winter Day Dispatch



The UNSE winter load profile, as seen in Chart 8 above, differs significantly from the summer profile. The peak demand experienced on weekdays in the winter is measurably lower than those seen in the summer. In the winter months, the load peaks in the early morning hours and then again in the late evening. The dispatch strategy in the winter differs significantly from the strategy in the summer. A different set of challenges emerges with increased solar generation during the winter. A more pronounced 'duck curve' creates ramp down and ramp up challenges.

Distribution System Enhancements

Distribution Capacity Expansion

The UNSE service areas have been broken down into three main districts due to a number of specific distribution system requirements. Specific details related to distribution system capacity expansion are provided below by district.

Kingman District

The Kingman District's long term distribution system capacity requirements are supported by targeting areas where new substations can be built, increasing existing substation capacity, conversion of voltage, conversion from delta to wye convention, and the replacement of ageing equipment.

New Transmission Substation Addition

A new 230kV substation has been identified in the Company's 10 year transmission plan. Justification for a new substation has been driven primarily from the lack of capacity, voltage support, and contingency support on the transmission and distribution system for the northern Mohave County area.

By providing a transmission source further north on the system, improved reliability on the 69kV transmission system will be attained and the northern area distribution system loads will be sourced from a more reliable 230kV system.

Benefits Realized from New Substations

- Improved voltage support for the outlying areas
- Increased contingency support and operational flexibility
- Enhanced technology integration such as remote control switching and monitoring
- Reduced outage times by using remote switching and monitoring
- Reduced peak loading on existing system
- Retirement of ageing substations
- Improved Industrial and Commercial reliability
- Additional capacity to support future growth
- Improved service for critical customers

Existing Substation Upgrades

Ageing substation transformers and circuit breakers need to be replaced throughout the system. Reliability of equipment, lack of supplier technical support, and the inability to obtain replacement parts are major driving factors in identifying equipment for replacement. Once the equipment has been identified to be replaced, a scope of work is developed, priority is established, and a budget is developed for inclusion in the capital budget. During the review, increasing transformer capacity is considered since additional capacity will improve operational flexibility and system reliability.

12kV Delta System Conversion

A conversion from a 12 kV delta connected system to a 20.8 kV wye connected system is expected to be complete in 2018 in one of our outlying areas. A new 20.8 kV substation has been placed in service to facilitate the conversion.

12kV Delta System Conversion Benefits

- Increased circuit capacity with voltage conversion
- Increased contingency support and improve outage restoration time
- Improved system reliability by creating stronger ties with the existing distribution system
- Backup tie capabilities between substations
- Reduced system losses from higher voltage
- Replacement of aging equipment

Lake Havasu District

The Lake Havasu District's long term distribution system capacity requirements are being supported by strategically targeting areas where new substations can be built, increasing existing substation capacity, and optimizing the replacement of ageing equipment.

New Substations

Historically, justification for new substations in the 10 year plan has been driven primarily from capacity needs on the sub-transmission (69 kV) and distribution (13.2 kV and 20.8 kV) systems. New substations not only help support and increase system capacity, they provide additional contingency support for the existing network.

No new substations will be required in the Lake Havasu District during the next 10 years. Load growth and contingency support can be obtained through upgrading existing substations (replacing existing transformers and/or adding new transformers to existing substations).

Existing Substation Upgrades

Continued focus on utilizing the Asset Management Group to analyze and monitor all of UNSE's existing substation equipment will help identify which ageing substation transformers are in need of replacement throughout the system. Once the transformers have been identified for replacement, they are evaluated in relation to current system conditions to determine a proper replacement strategy. In many cases, increased transformer capacity and addition of new feeders are required. Similar to what has been described above, increased transformer capacity and the addition of new feeders improve operational flexibility and system reliability.

Santa Cruz District

The Santa Cruz District's long term distribution system capacity requirements are being supported by strategically targeting areas where new substations can be built, increasing existing substation capacity, and optimizing the replacement of ageing equipment. Several key distribution lines have also been identified for upgrades to improve service.

New Substations

A new 138kV substation has been identified as part of the proposed interconnection across the border with Mexico's Federal Electricity Commission (CFE)(see Chapter 5). This substation will be utilized as part of the intertie and also serve local distribution load; helping to support and increase system capacity as well as provide additional contingency support for the existing network. Several other substations are presently under analysis that would be used for serving new large customers and enhancing load serving capability in remote areas of the system.

Existing Substation Upgrades

Continued focus on utilizing the Asset Management Group to analyze and monitor all of UNSE's existing substation equipment will help identify which ageing substation transformers are in need of replacement throughout the system. Once the transformers have been identified for replacement, they are evaluated in relation to current system conditions to determine a proper replacement strategy. In many cases, increased transformer capacity and addition of new feeders are required. Similar to what has been described above, increased transformer capacity and the addition of new feeders improve operational flexibility and system reliability.

Distribution Line Upgrades

Several major distribution line projects have been identified in the Santa Cruz District. One of the projects will create a tie between two major distribution circuits, improving contingency support in the area. A phased rebuild of another distribution line that serves more rural load has also been identified to improve load serving capability.

Clean Energy Standards

Beginning in 1999, with the Environmental Portfolio Standard, the Arizona Corporation Commission (ACC or "Commission") has adopted *clean energy standards*, which establish goals for all Arizona load serving entities regulated by the Commission, such as UNSE to (1) utilize renewable energy resources to meet a portion of its retail load, and (2) design and implement EE programs to reduce some percentage of customer energy use. These standards were intended to, and in fact have, accrued certain benefits to customers, as well as broader society including:

- Reduced emissions of greenhouse gases and other air pollutants though a reduction in fossil-fuel-generation
- Reduced renewable energy unit costs by contributing to a larger and more certain market for renewable energy manufacturers and installers
- Reduced overall customer bills, by promoting cost-effective EE measures

Renewable Energy Standard Compliance

The Renewable Energy Standard[2] ("RES") sets forth a requirement for all Arizona load serving entities to meet a percentage of their retail load using renewable energy resources. This percentage increases annually until it reaches 15% in 2025. In 2017 the RES target for UNSE will be approximately 115 GWh based on 7.0% of 2016 retail sales. UNSE anticipates reaching an annual requirement of approximately 20% by 2020 and will remaining above the 15% RES standard through 2032.

Energy Efficiency Standard Compliance

The Arizona Energy Efficiency Standard (EE Standard) sets forth a requirement for all Arizona load serving entities to achieve energy savings based on a percentage of the prior year retail load, growing to a cumulative load reduction of 22% by 2020. Table 3 below shows UNSE's progress towards meeting the standard annually. In 2016 UNSE was at approximately 12.0%. In 2017, UNSE's target for energy savings will be 43,611 MWh, based on 14.5% of 2016 retail sales. For resource planning purposes, UNSE has assumed that it maintains compliance with Arizona EE Standard through 2020 when the Arizona program sunsets. Assumptions for EE savings after 2020 are addressed in Chapter 6.

[2] Renewable Energy Standard and Tariff, A.C.C. R14-2-1801

Table 3 - Energy Efficiency Cumulative Annual Savings Progress towards the Standard

Year	Retail Energy Sales (MWh)	Incremental Annual Energy Savings (MWh)	Cumulative Annual Energy Savings (MWh)	Cumulative Annual Savings as a % of previous year Retail Sales	Cumulative EE Standard
2010	1,857,160				
2011	1,852,904	15,005	15,005	0.81%	1.25%
2012	1,755,541	35,032	50,037	2.70%	3.00%
2013	1,699,307	34,764	84,801	4.83%	5.00%
2014	1,677,445	38,829	123,630	7.28%	7.25%
2015	1,628,035	32,317	155,947	9.30%	9.50%
2016	1,637,808	37,924	193,871	11.91%	12.00%
2017		43,611	237,482	14.50%	14.50%

Utility-Specific Standard Derived Through the IRP Process

While RES and EE standards have produced real and tangible benefits as noted above, Clean Energy Standards applied at a statewide level are inherently inflexible and fail to take into account the unique circumstances of different utilities. This creates inefficiencies in resource acquisition and dispatch, which ultimately results in higher costs passed on to customers. In the early years of these programs, when the goals were modest, the impact of these inefficiencies was not significant. However, as these clean energy goals approach higher percentages of the total retail load, UNSE anticipates that the negative impact of these inefficiencies will become more pronounced.

Proper consideration of cost and benefits of various resources is a fundamental function of integrated resource planning. In fact the IRP provides the most holistic consideration of the very goals that clean energy standards aim to achieve, while balancing the cost of achieving those goals. Since integrated resource planning was reinstated in 2011, the goal of the IRP has shifted from focusing on the least-cost portfolio to the best case portfolio considering cost, environmental factors, and reducing long-term risk.

Addressing clean energy requirements within the IRP would address the cost, reliability and integration of renewable energy, EE, and DR on a level playing field with conventional resources based on their role in creating a sustainable resource portfolio. Adding to the logic of this approach is that many renewable energy technologies are at or approaching parity with conventional resources, and cost effective EE remains the lowest cost resource. Finally, IRP tools are continually being adapted to account for emerging hourly and sub-hourly operational issues that accompany certain renewable energy and DR products. Therefore, UNSE believes that the IRP would be a better mechanism to develop utility-specific targets for clean energy standards than a state-wide, "one size fits all" rulemaking.

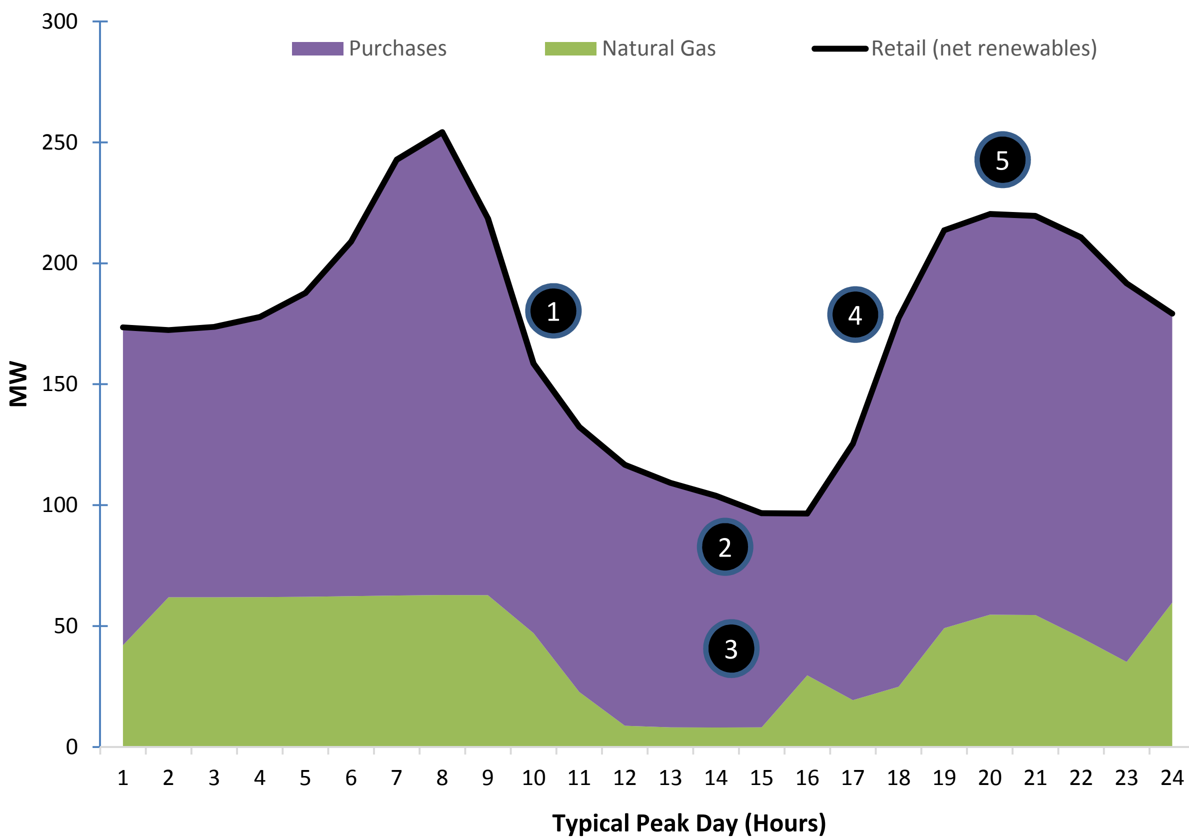
Renewable Energy Integration

UNSE is well ahead of the RES to reach a renewable portfolio that will supply 15% of its retail load requirement by 2025. The addition of the Grayhawk Solar Project will put UNSE at 20% by 2020. The renewable portfolio at UNSE will come with its own set of challenges and it will require UNSE to derive a balanced, responsive, and diverse generation portfolio to integrate this level of renewable energy. This section will point out and explain the operational challenges that UNSE will face as it increases its use of solar PV generation.

Operational Challenges

Historically, electric utilities with predominant air conditioning load set a peak demand between 4:00 PM to 5:00 PM on a summer day. The winter load requirements are lower than they are for the summer but, the challenges that emerge on a daily basis (with heavy solar penetration) are more pronounced. Chart 9 below illustrates a sample winter day for UNSE with a high penetration of solar energy. On a typical winter day, retail load tends to peak at day-break and again after the sun sets as consumers turn on appliances and lighting.

Chart 9 – Operational Challenges due to Solar Production – 2030 Typical Day



1 - Ramp Down **2 -** Minimum Generation **3 -** Over-Generation **4 -** Ramp Up **5 -** Peak Shift

The accumulation of solar PV introduces operational challenges on a daily basis. As we review Chart 9 above, showing the load shape of a typical 2030 winter day, we make the following observations:

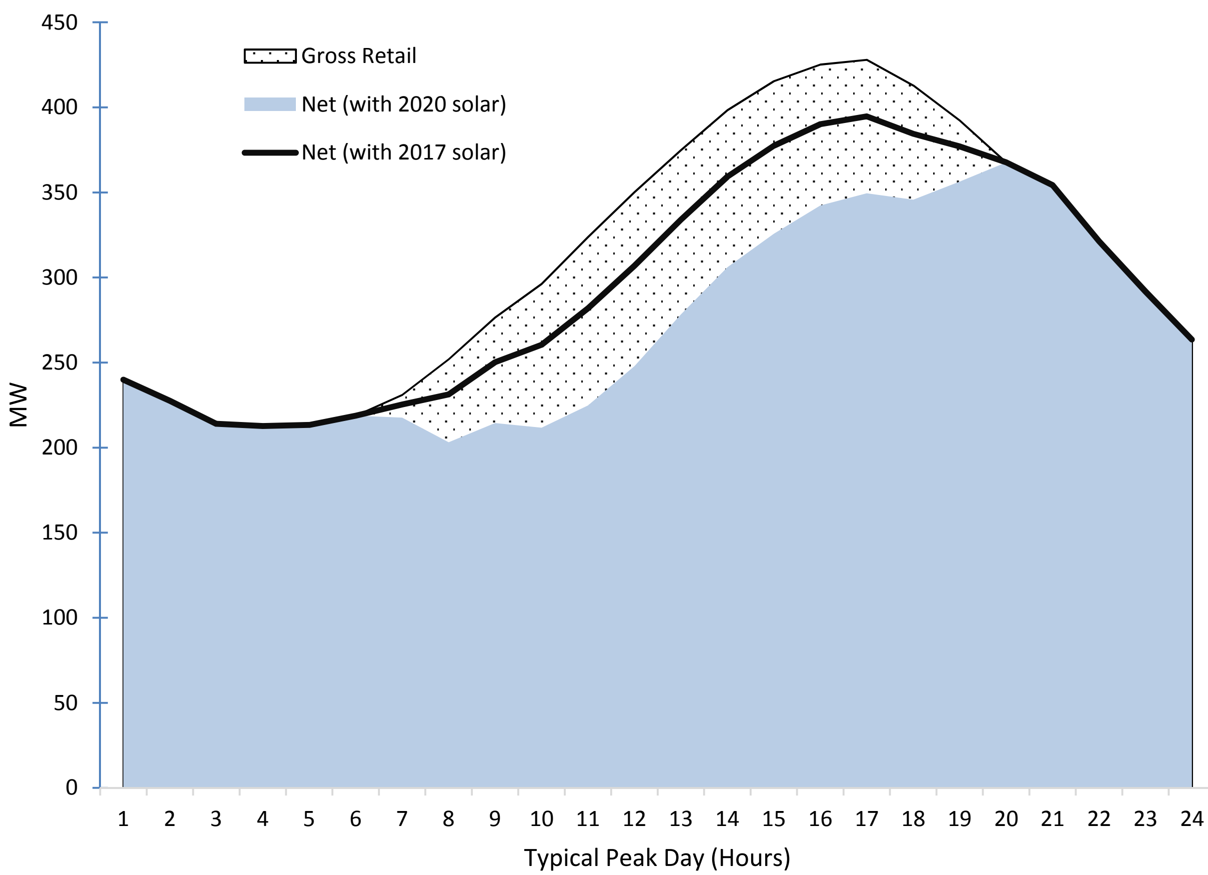
1. ***Ramp Down*** – Absent solar PV, the demand profile on a typical winter day includes a peak in the morning and one in the evening. The morning peak occurs during the coldest hours as the sun rises and while consumers wake, homes and businesses are warmed and commuters head to work. The retail load, on its own, would trend downward modestly as the sun rises and tracks along the horizon. This ramp-down was typically managed with coal and natural gas resources. The net effect of addition solar PV will cause a more drastic ramp-down. Fast-response resources, such as RICEs, will play a key role in managing this steep reduction in net load. These units will likely be prescheduled to contribute to the morning peak and then utilized to ramp down to give way to the solar generation.
2. ***Minimum Generation*** – As solar PV generation reaches its peak, and after ramp-down, generating units must have the capability to generate at reduced output levels during the midday hours. Modifications may be required on units to allow them to cycle off. If cycling is not an option for generators, UNSE must rely on its combined-cycle generation to power down to minimum generation.
3. ***Over-Generation*** – The CAISO is already experiencing negative pricing for over-generation during peak PV generating hours. Adjacent utilities and entities have been the beneficiaries of this pricing. The opportunity to charge ESS, such as batteries or hydro pumped-storage, presents itself during these hours to take advantage of excess generation at low cost. Increased PV at UNSE will not yet contribute to over-generation but given its access to the wholesale power markets it may be a beneficiary of low cost, over-generation from other utilities.
4. ***Ramp Up*** – The sun begins to set, fast-responding resources must now ramp up to displace the demand that solar PV relinquishes. At this point, a utility must utilize flexible resources to equally offset the drop in solar generation. The ramp-up may be mitigated in the near term by combustion turbines and NGCC generators. As the ramp-up steepens, it will necessitate the inclusion of ESS, RICE, and/or DR technologies.
5. ***Peak Shift*** – Solar PV will only reduce demand until the sun sets. This results in a narrowing and net shift of peak demand. CAISO has also demonstrated escalated pricing in these evening and night hours. While ESS charges during the 'over-generation' hours, this peak period may present an opportunity to discharge these systems, especially if we observe a transformation of hourly peak and off-peak pricing.

From a resource planning context, renewable resources add significant long-term benefits to the UNSE resource portfolio. Renewable resources provide UNSE the option to lock in long-term fixed, low cost, zero-emission, zero water consumption resources for significant portion of its resource portfolio. However, with the increasing penetration of renewable generation, we must take into consideration the right combination of resources to respond to the variability and intermittency of renewable systems. A portfolio with a high penetration of solar and wind resources will necessitate the use of fast start, fast ramping technologies including energy storage to reliability integrate these low cost, sustainable resources.

Shifting Net Peak

Chart 10 represents a projected 2030 typical summer peak day for UNSE excluding any solar generation. In addition, both 2017 and 2020 net retail demands are shown offset by varying levels of solar penetration as forecast in the UNSE 2017 Reference Case Plan. The chart below illustrates how increased penetration of utility scale solar and distributed solar ultimately shifts the net retail peak demand from approximately 4 PM to 8 PM. In 2017 it is projected that the net peak demand will be reduced by 33 MW due to solar generation and by 2020 the net peak demand will be reduced by 51 MW. Finally in 2020, the diminishing returns of solar capacity is realized as the net peak demand also shifts into the evening hours. This effect is often referred to as the diminishing return of solar's capacity value. Because at high-levels of solar penetration, solar generation does not offset future capacity requirements due to the fact that the system peak now occurs in non-daylight hours.

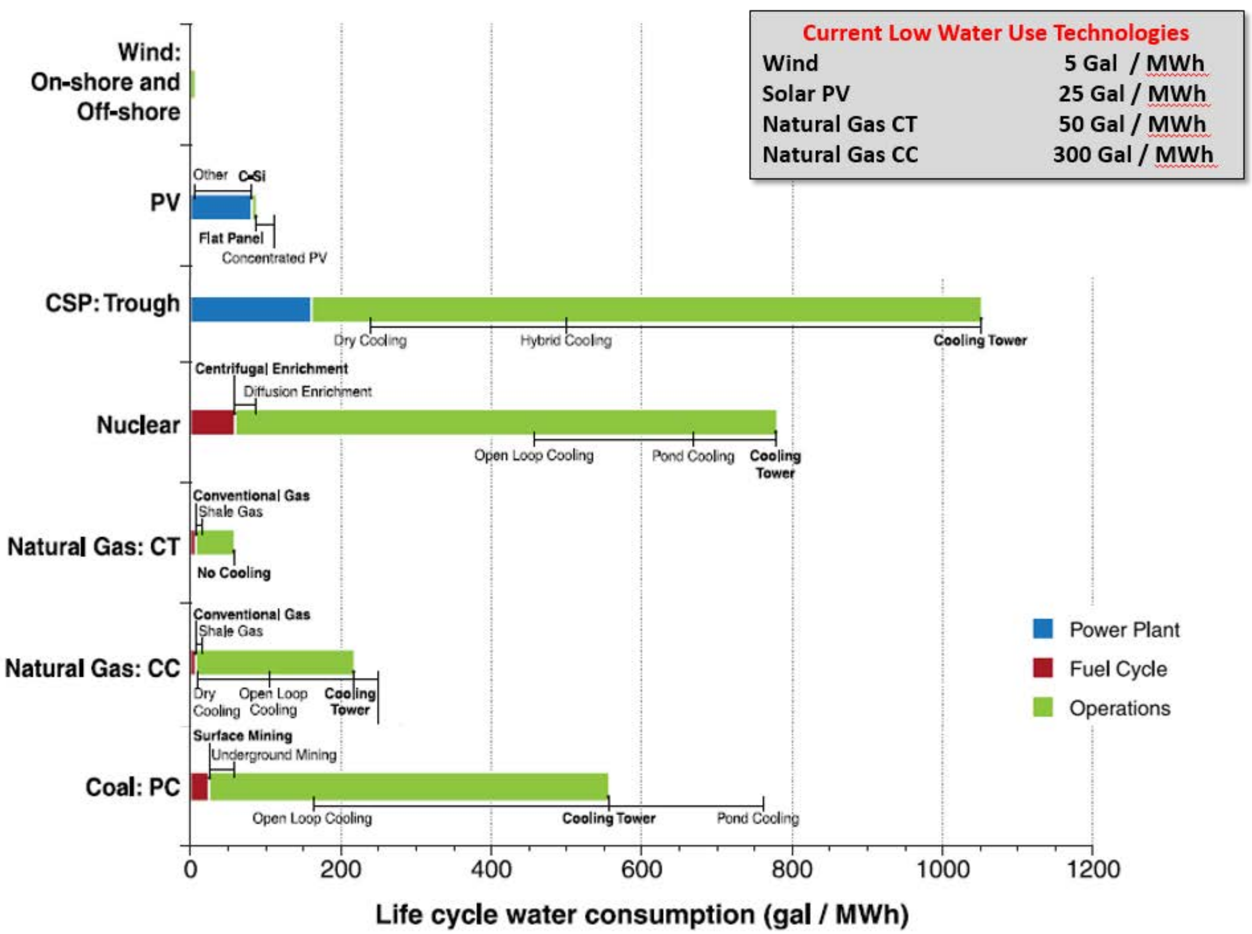
Chart 10 – Peak Demand Contribution from PV



Power Generation and Water Impacts of Resource Choices

UNSE has historically relied on purchased power to provide the majority of the energy it delivers to its customers. With the acquisition of a share of Block 3 at Gila River Generating Station in 2015, UNSE is providing more energy from owned resources. This reliance on owned resources is expected to continue at UNSE and will result in more direct exposure to water availability risk. Figure 1 below shows average water consumption rates for various electricity generation technologies. UNSE is managing its overall water availability risk by procuring resources with low water consumption rates such as NGCC, Solar PV and Wind.

Figure 1 - Life-Cycle Water Use for Power Generation[3]



[3] Adapted from Meldrum et. al. "Life cycle water use for electricity generation: a review and harmonization of literature estimates", published March 3, 2013, http://iopscience.iop.org/article/10.1088/1748-9326/8/1/015031

However, water consumption has a localized environmental impact as well. The availability of water that is withdrawn from groundwater aquifers, as in the case of Gila River, is dependent on the recharge to and other withdrawals from the aquifer, but is also a function of the hydrogeological characteristics of the aquifer itself.

Gila River Block 3 is located west of Phoenix, Arizona (in proximity to the Palo Verde Nuclear Generating Station), where there is over 6,000 MW of existing NGCC capacity that is likely to see a significant increase in generation as utilities replace coal-fired generation with generation from NGCC plants. These facilities are too far apart to have a direct impact on each other in terms of groundwater availability. However, the expected increased water use as a result of increased generation needs to be evaluated.

For the IRP, UNSE will include for the Reference Case Plan portfolio, the annual amount of water consumed for power generation such that it can be weighed as a risk factor for that portfolio.

CHAPTER 4

Energy Efficiency

UNSE recognizes EE and DR as cost-effective ways to reduce its reliance on fossil fuels. UNSE offers a variety of energy saving options for customers encouraging both homeowners and businesses to invest in EE upgrades through Demand Side Management (DSM) incentivized programs.

UNSE has made great strides towards achieving the goals set by Arizona's EE Standard (the EE Standard). The EE Standard calls on investor-owned electric utilities in Arizona to increase the kilowatt-hour savings realized through customer ratepayer-funded EE programs each year until the cumulative reduction in energy achieved through these programs reaches 22 percent of the previous year's retail sales by 2020.

This section presents an overview of the proposed UNSE DSM programs targeted at the residential, commercial and industrial (C&I), and utility improvement sectors.

UNSE, with input from other parties such as Navigant Consulting, Inc. ("Navigant"), the Residential Utility Consumer Office (RUCO) and the Southwest Energy Efficiency Project (SWEEP), has designed a comprehensive portfolio of programs to deliver electric energy and demand savings to meet annual DSM energy savings goals outlined in the EE Standard. These programs include incentives, direct-install and buy-down approaches for energy efficient products and services; educational and marketing approaches to raise awareness and modify behaviors; and partnerships with contractors to obtain the most cost-effective return on the rate-payer dollars invested in DSM programs.

2017 Implementation Plan, Goals, and Objectives

UNSE's high-level EE-related goals and objectives are as follows:

- Implement only cost-effective EE programs.
- Design and implement a diverse group of programs that provide opportunities for all customers to participate in.
- Achieve energy savings goals set in the EE Standard through 2020.
- When feasible, maximize opportunities for program coordination with other efficiency programs (e.g. UNS Gas Inc., TEP) to yield maximum benefits.
- Maximize program savings at a minimum cost to the customer through comprehensive and cost-effective programs.
- Provide UNSE customers and contractors with direct web access to detailed information on all efficiency programs (residential and commercial) for electricity savings opportunities at http://www.UESAZ.com
- Expand the EE infrastructure in the state by increasing the number of available qualified contractors through training and certification in specific fields.
- Use trained and qualified trade allies such as electricians, HVAC contractors, builders, manufacturers, architects, and engineers to transform the market for efficient technologies.
- Inform and educate customers to modify behaviors that enable them to use energy more efficiently.

Planning Process

UNSE's portfolio of programs incorporates elements of the most successful EE programs across North America. Programs are designed in consideration of the UNSE market and provide cost-effective programs for UNSE customers. A substantial amount of information including evaluations, program plans and studies were used to develop specific programs for UNSE. With input from Navigant, RUCO and SWEEP, UNSE also used a benchmarking process to review the most successful EE programs from across the country, with a focus on successful Desert Southwest programs to help shape the portfolio.

UNSE used the following strategies to produce the lowest cost portfolio of EE programs:

- Implementing primarily industry accepted programs that have been successfully applied by other utilities in the Southwest and across the country.
- Implementing programs through a combination of third-party contractors and UNSE staff. UNSE utilizes implementation contractors that provide particular industry expertise and/or tools.

Program Screening

UNSE uses rigorous models to evaluate the costs, benefits, and risks of EE and DSM programs and measures. These models are designed to estimate the capacity and energy values of EE and DR measures at an hourly level. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, UNSE is able to measure the risks and benefits of employing EE and DSM measures versus traditional generation capacity additions, and further, it ensures that DSM resources are compared to supply side resources relatively.

The analysis of EE and DSM cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the Societal Cost Test (SCT). As detailed in Table 4, there are five major benefit-cost tests commonly utilized in the EE industry, each of which addresses different perspectives. The EE Standard established that the societal cost test should be used as the key perspective for determining the cost-effectiveness of EE measures and programs. Regardless of which perspective is used, benefit-cost ratios greater than or equal to 1.0 are considered cost-effective. While various perspectives are often referred to as tests, the following list of criteria demonstrates that decisions on program development go beyond a pass/fail test.

Table 4 - Comparative Benefit-Cost Tests

	SOCIETAL COST TEST	TOTAL RESOURCE COST TEST	UTILITY RESOURCE COST TEST	PARTICIPANT COST TEST	RATE IMPACT MEASURE TEST
BENEFITS					
Reduction in Customer's Utility Bill				✓	
Incentive Paid by Utility				✓	
Any Tax Credit Received		✓		✓	
Avoided Supply Costs	✓	✓	✓		✓
Avoided Participant Costs	✓	✓		✓	
Participant Payment to Utility			✓		✓
External Benefits	✓				
COSTS					
Utility Administration Costs	✓	✓	✓		✓
Participant Costs	✓	✓		✓	
Incentive Costs			✓		
External Costs	✓				
Lost Revenues					✓

Utility Resource Cost Test

The Utility Resource Cost Test (UCT), also referred to as the Program Administrator Test, measures the net benefits of a DSM program as a resource option based on the costs and benefits incurred by the utility (including incentive costs) and excluding any net costs incurred by the customer participating in the efficiency program. The benefits are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation and capacity valued at marginal costs for the periods when there is a load reduction. The costs are the program costs incurred by the utility, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased.

Total Resource Cost

The Total Resource Cost (TRC) is a test that measures the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers. Resource costs include changes in supply and participant costs. A DSM program that passes the TRC test (i.e., has a ratio greater than 1) is viewed as beneficial to the utility and its customers because the savings in electric costs exceed the DSM costs incurred by the utility and its customers.

Participant Cost Test

The Participant Cost Test illustrates the relative magnitude of net benefits that go to participants compared with the net benefits achieved from other perspectives. The benefits derived from this test reflect reductions in a customer's bill and energy costs plus any incentives received from the utility or third parties, and any tax credit. Savings are based on gross revenues. Costs are based on out-of-pocket expenses derived from program participation, plus any increases in the customers' utility bills.

Rate Impact Measure Test

The Rate Impact Measure (RIM) Test measures the change in utility energy rates resulting from changes in revenues and operating costs. Higher RIM test scores indicate there will be less impact on increasing energy rates. While the RIM results provide a guide as to which technology has more impact on rates, generally it is not considered a pass/fail test. Instead, the amount of rate impact is usually considered at a policy level. The policy level decision is whether the entire portfolio's impact on rates is so detrimental that some net benefits have to be forgone.

Societal Cost Test

The SCT is similar to the TRC test, but it is also intended to account for the effects of externalities (such as reductions in carbon dioxide (CO_2), nitrogen oxides (NOx), and sulfur dioxide (SO_2). One additional difference between the TRC and the SCT is that the SCT uses a societal discount rate in its analysis. The SCT is the regulated benefit/cost analysis required in the EE Standard. UNSE has provided a SCT that accounts for the societal discount rate.

Current Energy Efficiency and DSM Programs

UNSE's 2015 Energy Efficiency Plan was filed on June 1st, 2014, in accordance with Section R14-2-2405 of the EE Standard, for approval of proposed EE and DSM programs with the ACC (Docket No. E-04204A-14-0178). On August 25, 2015 UNSE filed a request to consider the pending 2015 plan as the 2016 plan. UNSE received the final order for approval for these programs from the ACC in Decision No. 75297 on October 27, 2015. UNSE has requested that the ACC continue the implementation plan approved in Decision No. 75297 to program year 2017.

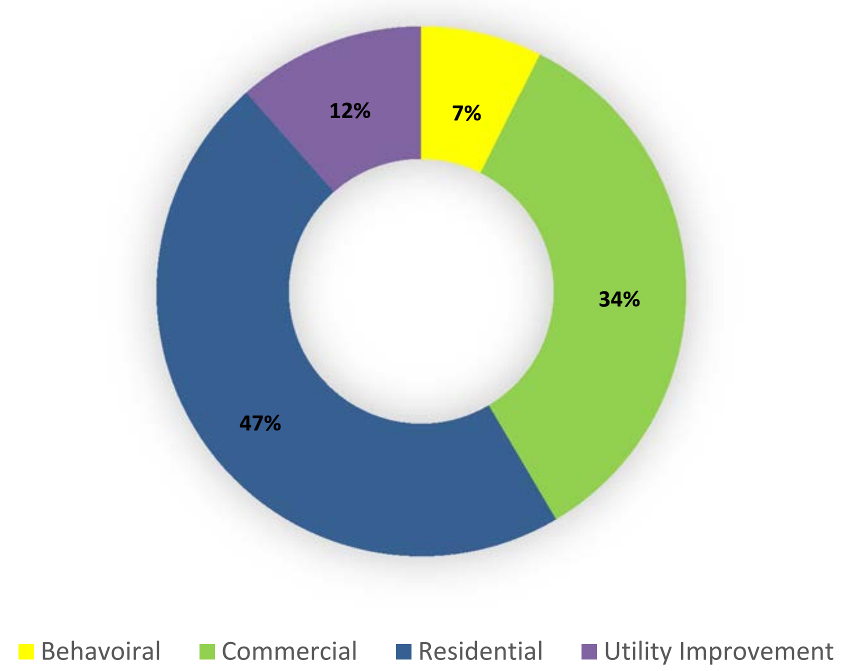
UNSE uses EE programs to efficiently and cost-effectively alter customer energy demand and consumption and reduce the long-term supply costs for energy and peak demand. UNSE's portfolio of programs is divided into residential, commercial, behavioral, support, and utility improvement sectors with administrative functions providing support across all program areas. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories, 1) EE programs that reduce energy consumption, and 2) DR programs that reduce peak demand. Table 5, below lists the Commission-approved EE and DR programs currently in the UNSE portfolio. Details of these programs can be found in the 2016 Energy Efficiency Plan

Table 5 - Current Energy Efficiency Programs

Residential Sector	Appliance Recycling
	Efficient Products Program
	Existing Homes
	Low Income Weatherization
	Multi-Family Direct Install
	Residential New Construction
	Shade Trees
Behavioral Sector	Behavioral Comprehensive
	Home Energy Reports
Commercial & Industrial Sector	Bid for Efficiency
	C&I Facilities/Schools
	C&I Direct Load Control
	Retro-Commissioning
Support Sector	Education and Outreach
	Energy Codes & Standards Enhancement

Chart 11 shows the actual segmentation of energy savings across sectors as a result from the 2016 implementation.

Chart 11 – 2016 DSM Portfolio Composition by Sector



Resource Planning Integration

DSM Forecasting

Consistent with the ACC's Decision No. 71435 on Resources Planning, UNSE forecasted cumulative energy savings for UNSE's DSM portfolio over a 15-year time period from 2017 – 2032 to include meeting Arizona's EE Standard, which concludes in 2020. UNSE prepared monthly energy and peak reduction forecasts for all years in the IRP planning period. The savings were distributed based on the actual hourly shape of all historical measures installed from 2011 through 2015 and are carried forward for the planning period. Cost dispatch modeling using this shape will approximate the impacts of EE savings on the actual system load. In addition, UNSE prepared an hourly savings distribution based on the impacts of EE in 2015 and compared EE savings distribution to the shape distribution of the actual UNSE system load for 2015.

In order to integrate the hourly savings impact of UNSE's portfolio of DSM programs into a 15-year planning horizon, UNSE determined the hourly savings of each individual EE measure and then aggregated them at the portfolio-level by customer rate class. The hourly savings resolution can be summed into monthly energy savings and used to find peak demand savings.

UNSE considered several available resources and options for determining EE measure hourly level savings data. One option was to conduct long-term end-use metering and analysis for the measures installed at customer premises, which would take many years and be very costly. Another option was to utilize data made available from national and other state-level funded multi-year studies and research that incorporated best practices for determining hourly level measure savings. UNSE found this latter option to be more prudent given that it is less time intensive and less costly.

UNSE relied upon 8,760 hourly savings load shapes taken from widely referenced and recognized industry sources for individual EE measures that comprised each particular DSM program. These sources include:

- California's Database for Energy Efficient Resources (DEER), which is developed by the California Public Utilities Commission;
- California's Commercial End-Use Survey (CEUS), which was prepared by Itron, Inc. for the California Energy Commission in cooperation with California's investor-owned utilities (i.e., Pacific Gas and Electric, San Diego Gas and Electric, Southern California Edison, Southern California Gas Company), and the Sacramento Municipal Utilities District;
- Building America – National Residential Efficiency Measures Database, which is developed by the National Renewable Energy Laboratory (NREL) with support from the U.S. Department of Energy (DOE).

These load shapes were developed through extensive end-use metering and energy simulation modeling and were normalized for historical weather conditions and patterns applicable to particular climate regions. The load shapes selected from these sources address the residential and non-residential sectors separately with different building end-uses that relate to the EE measures in the programs. UNSE selected the load shapes carefully to account for seasonal or diurnal variations in operational or end-use patterns for different measures. UNSE utilized the California-based DEER and CEUS load shapes only as a means to develop 8,760 hourly shaping on the EE measures. The annual savings values that will be attributed to these hourly savings load shapes are calculated specifically for UNSE's programs through program design and third-party Measurement, Evaluation, and Research (MER).

Since the weather-sensitive EE measure load shapes from DEER and CEUS were developed for California, UNSE had to apply adjustment factors for its service territories in Arizona. First, for weather calibration purposes, UNSE utilized typical meteorological year (TMY3) weather data for the UNSE territory and compared that to the load shapes developed for California's Climate Zone 15, which is the closest geographically as well as the most compatible weather region in California to UNSE's service territory, and then adjusted hourly indexed values as needed. This approach of weather calibration ensures that weather-sensitive EE measures that have seasonal or diurnal variations in energy savings would have the appropriate effect for UNSE's climate region. Furthermore, the TMY3 weather data sets, which were developed by NREL with support from DOE, are based on climate data from a period from 1991-2005. Utilizing recent historical weather data helps to weather normalize the savings effects of weather-sensitive EE measures at the hourly level. The Building America database included measure savings load shapes developed utilizing TMY3 weather data for the UNSE territory; therefore, no such weather adjustments were needed for these load shapes.

After determining the measure shapes, UNSE applied a measure's annual energy savings value with the appropriate measure end-use load shape to determine a unique measure-specific savings load shape. UNSE was then able to aggregate the hourly savings value for all given measures in a particular program to determine a program-level savings load shape. From these composite program-level savings load shapes, UNSE was able to apply its definition of peak periods to determine coincident and non-coincident peak demand savings.

While the focus of this IRP is on future resources planning, UNSE also acknowledges the importance of attributing verified savings values for individual measures and programs from MER results. UNSE has retained the services of Navigant to serve as the third-party evaluation contractor for UNSE's portfolio of DSM programs. Navigant verifies energy savings for programs utilizing rigorous industry evaluation standards and protocols outlined by the International Performance Measurement and Verification Protocol, Federal Energy Management Plan and the Uniform Methods Project of NREL.

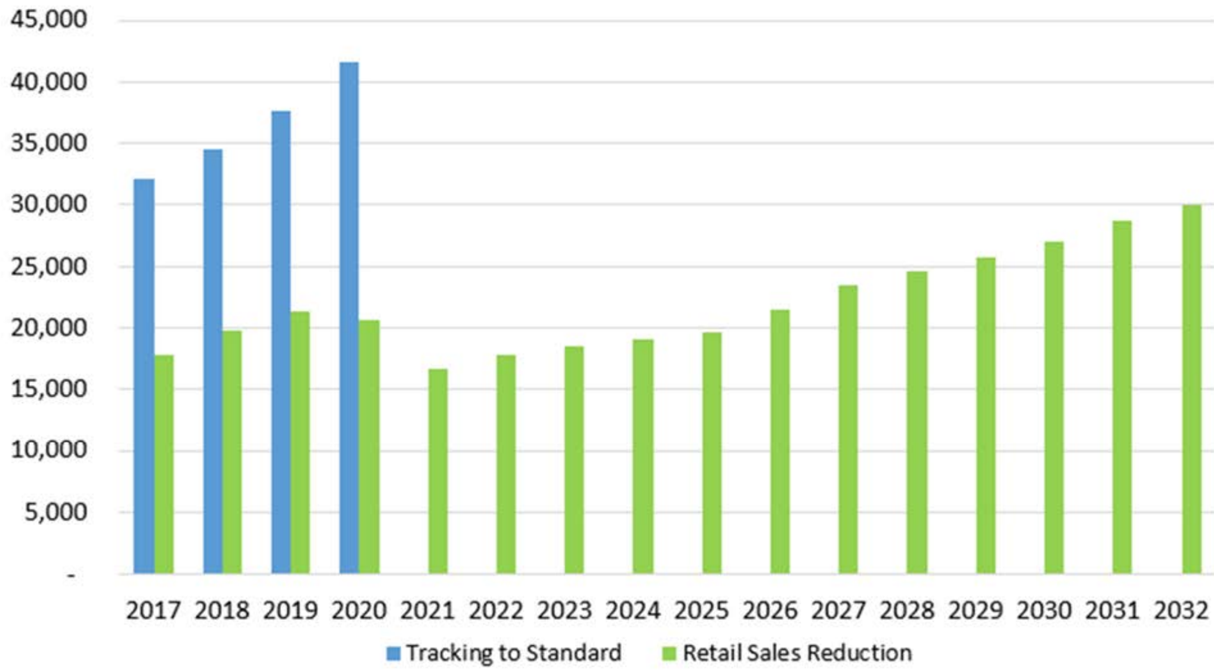
Load Shape Results

The hourly savings determined through the methodology described above allowed UNSE to forecast annual energy and peak demand savings for UNSE's 2017 portfolio of DSM programs both to determine a 15-year outlook on resources and to meet the EE Standard savings targets by 2020.

To estimate the level of cost-effective energy savings beyond 2020, UNSE relied on a report published by the EPRI titled "U.S. Energy Efficiency Potential Through 2035". Further details on UNSE's assumptions for future EE are include in Chapter 6.

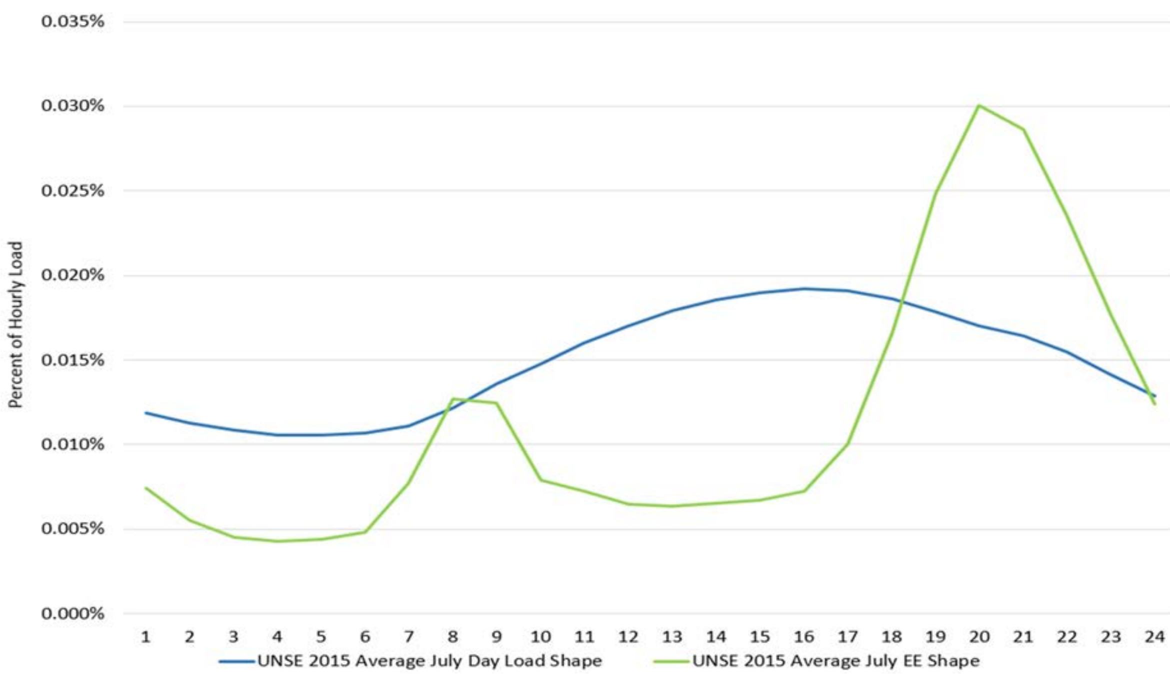
Chart 12 shows the EE annual savings (MWh) required to meet the Standard (including credits) through 2020, and the corresponding estimated actual reduction in retail sales through 2032.

Chart 12 – EE Annual Energy Goals (The Standard) vs. EPRI Estimated Retail Sales Reduction (MWh)



In order to evaluate EE as a resource for replacement of generation in the context of the IRP, the specific types of measures being implemented are modeled, like other resources against the forecasted system load. Modeling EE measures as a resource in UNSE's cost production model will provide a more accurate indication of the potential cost savings associated with these measures, through displacing energy (i.e. fuel) or capacity from conventional resources. Using these results, UNSE can target measures that coincide with high cost resources or the system peaks, both daily and annually. Chart 13 provides a sample of how current EE measures interact with UNSE's system loads.

Chart 13 – July 2015 UNSE System Load Shape vs. Cumulative EE Load Shape



The climate has a great impact on the system's generation needs. As expected, UNSE is a summer peaking utility, generally experiencing its greatest demand occurring in July. As shown in Chart 13, the cumulative impact of EE for UNSE in 2015 peaked during the 6:00PM-12:00PM timeframe. However, the UNSE system load peak is between 1-8PM. In order to truly replace generation needs, EE targets and goals would need to focus more on the installation of EE measures that coincide with the system peak.

The cumulative annual peak demand savings from UNSE's DSM programs does reduce the system peak with the increase in cumulative annual savings target goals in the Standard and beyond.

The continuation of UNSE's DSM programs will help UNSE meet the cumulative annual savings targets in the EE Standard and incorporate EE into its 15-year resource planning time-frame. EE is an important part of UNSE's future resource mix. Furthermore, stratifying measure-level energy savings on an hourly level will help the planning process by identifying EE measures and programs that best fit UNSE's resource needs. UNSE will continue to monitor DSM program activity and research EE industry best practices to determine the most cost-effective portfolio of programs that provide EE solutions to its customers and incorporates DSM investments in UNSE's resource planning.

CHAPTER 5

UNSE EXISTING RESOURCES

UNSE's Existing Resource Portfolio

This section provides an overview of UNSE's existing thermal generation, renewable generation, and transmission resources. For the thermal generation resources it provides details on each station's ownership structure, fuel supply, environmental controls, and a brief future outlook. For the renewable generation resources, it provides capacity and technology information as well as certain details on the construction of the facilities. Information on connections to the bulk electric system is provided in the transmission section.

UNSE's existing thermal resource capacity currently owned by the Company is 291 MW. In addition, the Company also relies on the wholesale market for firm capacity PPAs to meet its summer peak obligations. Table 6 below provides a summary of UNSE's existing thermal resources.

Table 6 - UNSE Existing Thermal Resources

Generating Station	Unit	Primary Fuel Type	Net Nominal Capability MW	Commercial Operation Year	Operating Agent	UNSE's Share %	UNSE Planning Capacity
Valencia	1	Gas	14	1989	UNSE	100	14
Valencia	2	Gas	14	1989	UNSE	100	14
Valencia	3	Gas	14	1989	UNSE	100	14
Valencia	4	Gas	21.5	2006	UNSE	100	21.5
Black Mountain	1	Gas	45	2008	UNSE	100	45
Black Mountain	2	Gas	45	2008	UNSE	100	45
Gila River	3	Gas	550	2003	TEP	25	137.5
Total Planning Capacity							**291**

Valencia Generating Station

Valencia Generating Station

The Valencia Generating Station ("Valencia") is located in Nogales, Arizona and provides UNSE with 64MW of combustion turbine capacity.

Ownership:

All four of the Valencia units are owned by UNSE. Units 1 through 3 were acquired with the purchase from Citizens Utilities in 2003. They are rated at 14 MW each. Valencia Unit 4 is rated at 21.5 MW and was constructed in 2006.

In-Service Date:

Valencia Unit 1	1989
Valencia Unit 2	1989
Valencia Unit 3	1989
Valencia Unit 4	2006

Fuel Supply:

UNSE purchases natural gas on the spot market and through hedging contracts that are consistent with Company's hedging policy.

Pollution Control:

Valencia's combustion turbine Units 1-4 burn natural gas and diesel fuel, and each unit is equipped with water spray injection for control of NOx. Plant-wide emission limits of 250 tons per year for SO2 and NOx were incorporated into the Title V permit in order to maintain below "major source" thresholds. Each of the units is required to meet NSPS for NOx and SO2. However, each of these units is less than 25MW capacity; therefore, they are not subject to Acid Rain provisions.

Outlook:

The Valencia units are an added layer of reliability for UNSE's customers in Nogales. The service area's power needs are primarily met by market purchases and transmitted via the Vail to Valencia 138 KV line which went into service in 2014.

Black Mountain Generating Station

Black Mountain Generating Station

The Black Mountain Generating Station ("Black Mountain") is located approximately five miles south of Kingman, Arizona and provides UNSE with 90 MW of combustion turbine capacity from two units.

Ownership:

Black Mountain is wholly owned by UNSE

In-Service Date:

Black Mountain Unit 1	2008
Black Mountain Unit 2	2008

Fuel Supply:

UNSE purchases natural gas on the spot market and through hedging contracts that are consistent with Company's hedging policy.

Pollution Control:

The Black Mountain units are natural gas-fired combustion turbines with dry Low NOx Burners for NOx control. As a greenfield site, a Prevention of Significant Deterioration (PSD) permit was obtained prior to construction. A PSD permit requires that BACT be applied for control of SO_2 and NOx, and the facility must comply with the Acid Rain program limits for SO_2 and NOx.

Outlook:

The Black Mountain units provide peaking capacity and reliability services to UNSE's Kingman and Lake Havasu Districts.

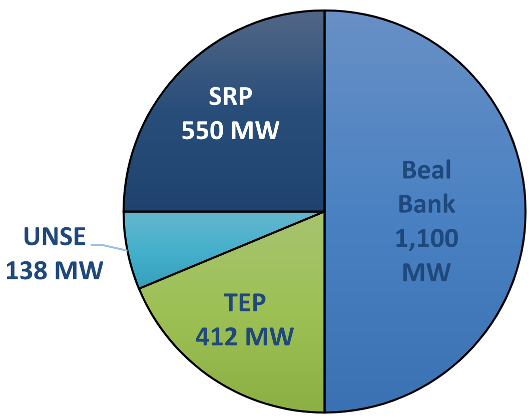
Gila River Generating Station

Gila River Generating Station

Gila River Generating Station ("Gila River") is a 2200 MW four block, 2 on 1 natural gas-fired combined cycle electric generating station located three miles north of the town of Gila Bend, in Maricopa County, Arizona.

Ownership:

Units 1 and 2 are owned by Beal Bank, Unit 3 is owned 75% by TEP and 25% by UNSE. Unit 4 was purchased in 2016 by Salt River Project. Under that agreement, Salt River Project will take ownership of the unit in 2017.



Units	Capacity (MW)	Entered Service	Planned Retirement
Power Block 1	550	2006	Not Planned
Power Block 2	550	2006	Not Planned
Power Block 3	550	2006	Not Planned
Power Block 4	550	2006	Not Planned

Fuel Supply:

Each Gila River participant manages its own gas supply. TEP and UNSE purchases natural gas on the spot market and through hedging contracts that are consistent with Company's hedging policy.

Pollution Controls:

Block	SO_2	NOx	PM	Hg
1	NA	SCR	NA	NA
2	NA	SCR	NA	NA
3	NA	SCR	NA	NA
4	NA	SCR	NA	NA

SCR – Selective Catalytic Reduction
NA – Not Applicable

Outlook:

Low natural gas prices make Gila River Block 3 the lowest cost generation assets for UNSE. Gila River's fast ramping capabilities, along with its real-time integration into TEP's balancing authority, provide both TEP and UNSE with an ideal resource to support the integration of future renewables.

Renewable Resources

Over the last several years, UNSE has developed and constructed its own renewable energy resources as well as worked with third-party contractors to develop renewable resource projects within UNSE's service territory. The table below provides an overview of UNSE's renewable energy portfolio.

Table 7 – UNSE's Renewable Resources (Existing and Planned)

Resource-Counterparty	Owned/ PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MWac
Western Wind	PPA	Wind	Kingman, AZ	Brookfield Renewable	Sept 2011	10
La Senita School	Owned	SAT PV	Kingman, AZ	UNSE	Nov 2011	1
Black Mountain	PPA	SAT PV	Kingman, AZ	Duke Energy	Dec 2012	8.9
Rio Rico	Owned	Fixed PV	Rio Rico, AZ	UNSE	Mar 2014	6
Red Horse Solar 3	PPA	SAT PV	Willcox, AZ	D. E. Shaw & Co., L.P.	Jun 2016	30
Jacobson Solar	Owned	Fixed PV	Kingman, AZ	UNSE	Mar 2017	4
Grayhawk (planned)	PPA	SAT PV	Kingman, AZ	Torch Renewables	Q2 2018 (est.)	46

Notes: PPA – Purchased Power Agreement – Energy is purchased from a third party provider.
SAT PV – Single Axis Tracking Photovoltaic
Fixed PV – Fixed-Tilt Panel Photovoltaic

Western Wind Project

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MWac
Western Wind	PPA	Wind	Kingman, AZ	Brookfield Renewable	Sept 2011	10

The Western Wind project is a 10 MW renewable energy project that commenced operations in the September 2011. The project is sited on 1,100 acres in Kingman, Arizona. UNSE has entered into a 20-year PPA for 100% of the output from the facility, which includes a relatively small integrated solar energy project. The assets include five (5) Gamesa turbines, 500 KW_{DC} of Suntech Crystalline PV solar cells, a collection system, a substation, roads, interconnection facilities, and a maintenance building.

Western Wind & Solar Project

Black Mountain Solar Project

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Black Mountain	PPA	SAT PV	Kingman, AZ	Duke Energy	Dec 12	8.9

This 8.9 MW solar project is located on approximately 60 acres of land near UNSE's Black Mountain Generating Station, which lies within the Mohave County Energy Overlay–Solar Photovoltaic Zone. The system was commissioned and in-service in December 2012.

In total, the system features 60 single-axis trackers, utilizing more than 40,000 solar modules. UNSE is purchasing the power generated at the Black Mountain site through a 20-year PPA with Duke Energy.

Black Mountain Project Under Contruction

La Senita Elementary School Solar Project

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
La Senita School	Owned	SAT PV	Kingman, AZ	UNSE	Nov 2011	1

This 1 MW facility sits six acres owned by the Kingman Unified School District, behind La Senita Elementary School. It is one of the largest single PV systems on school property in the state of Arizona. This system went into service in November 2011, and is owned and operated by UNSE.

La Senita Single-Axis Tracker

Red Horse 3 Solar Project

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Red Horse Solar 3	PPA	SAT PV	Wilcox, AZ	D. E. Shaw & Co., L.P.	Jun 2016	30

The Red Horse 3 Solar project is a 30 MWac solar site built in proximity to the Red Horse 2 wind farm and is located on 220 acres about 20 miles west of Wilcox, AZ. The Red Horse project is owned by Red Horse 2 LLC, which was formed by Torch Renewable Energy. This project commenced commercial operation June 2016. UNSE receives power from this project under a 20-year PPA.

Red Horse 3 Single-Axis Tracker

Jacobson Solar Project

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
UNSE	Owned	PV	Kingman, AZ	UNSE	Mar 17	4

The Jacobson Soar Project is a 4 MW solar site located in Kingman, Arizona. The project uses REC 315-watt Peak Energy 72 Series modules and Schletter fixed PV tracking. Jacobson Solar is the largest UNSE-owned facility in Kingman and sits on 32 acres within the city limits. UNSE is responsible for the design, procurement and construction of the project.

Jacobson Solar Fixed PV Rack

Grayhawk Solar Project

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Torch Renewables	PPA	SAT PV	Kingman, AZ	Torch Renewables	Q2 2018	46

Grayhawk Solar is a 46 MW SAT solar project scheduled to be complete in the second quarter of 2018. The project will be constructed in Mohave County, Arizona, near the city of Kingman. The Grayhawk project will be developed by Torch Renewables, which has entered into a 20-year PPA to provide power to UNSE.

Distributed Generation Resources

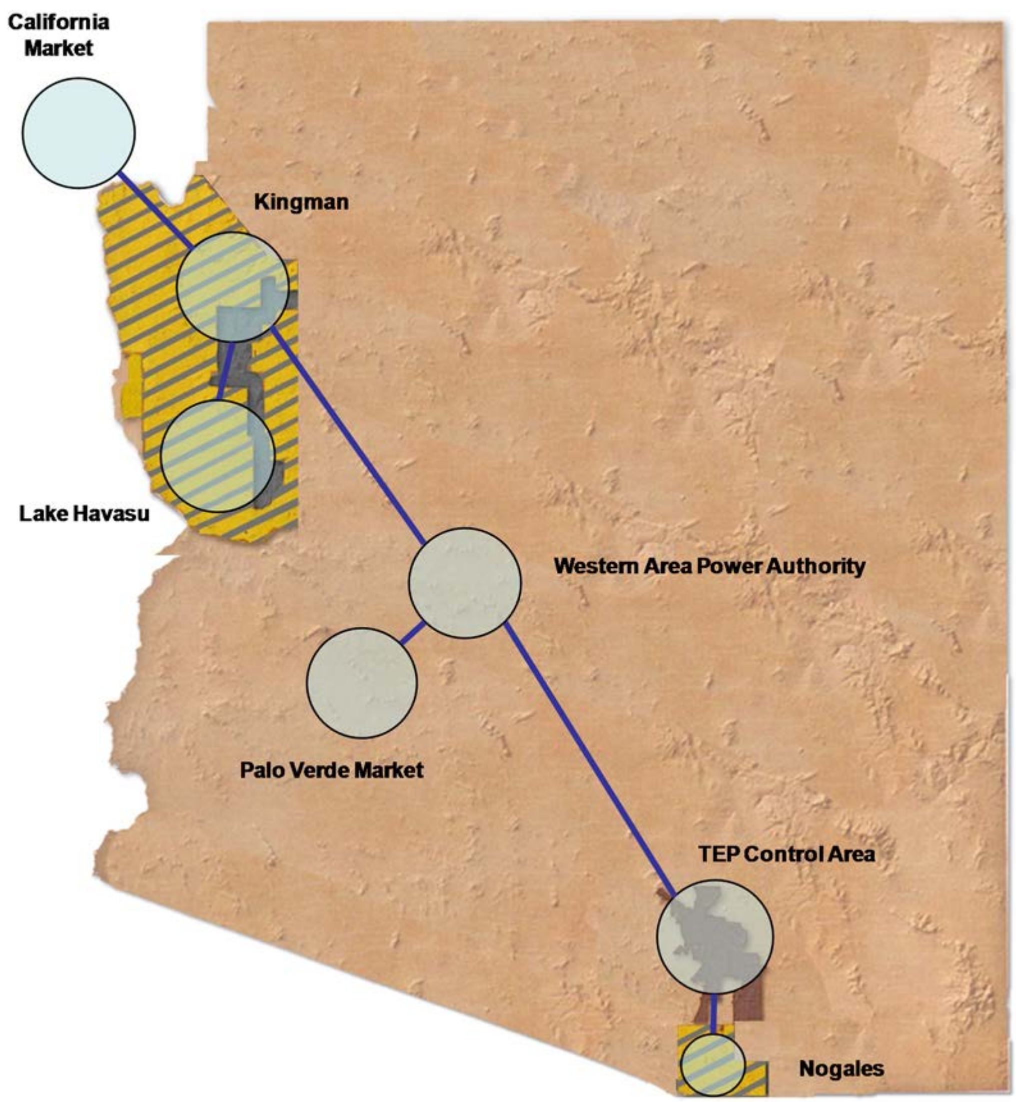
Distributed generation resources are small-scale renewable resources sited on customer premises. The Arizona RES requires that a portion of renewable energy requirements be obtained from residential and commercial DG systems. The required DG percentage is 30% of the total renewable energy requirement. UNSE expects approximately 40 MW of DG to be in place by the end of 2017.

Transmission

UNSE Transmission Resources

UNSE's transmission resources include approximately 339 miles of transmission lines owned by UNSE, long-term transmission rights (Point to Point and Network service) purchased from Western Area Power Administration (WAPA), and Point-to-Point transmission purchased from other transmission providers on an ad hoc basis. Given UNSE's dependence on third-party transmission providers, UNSE works closely with WAPA's transmission planning group to ensure adequate long-term transmission capacity is available to serve the Mohave service territories. WAPA conducted a System Impact Study (SIS) for UNSE to address current and future load growth options. UNSE load and market delivery points are shown on Map 2, below.

Map 2 – UNSE Load and Market Delivery Points



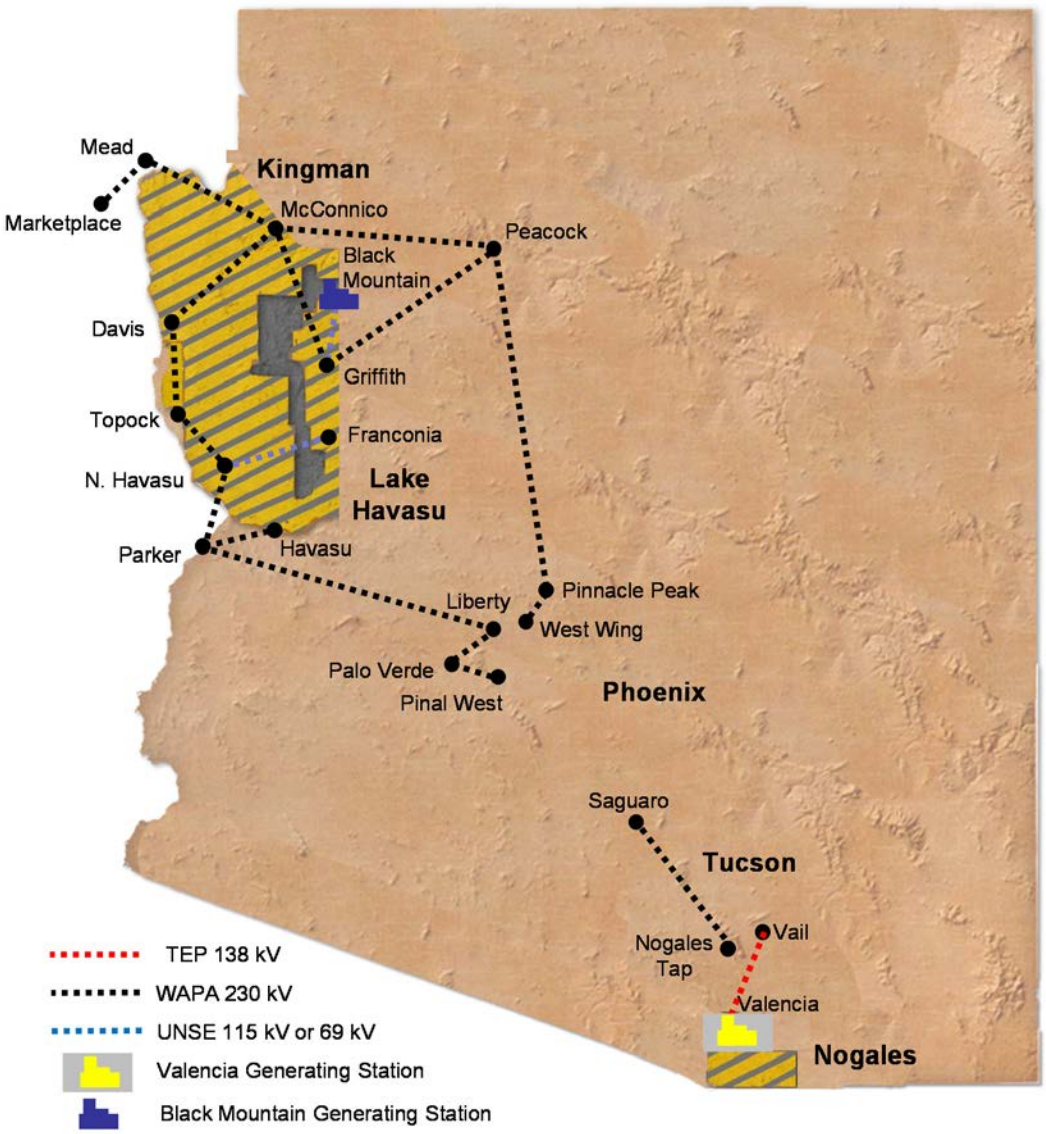
Control Area Services Agreement

Beginning in June 2008, UNSE entered into a long-term Control Area Services Agreement with TEP. At that time UNSE became part of the TEP Balancing Authority under which TEP provided for a fee, the required Balancing or Ancillary Services. These services include: Control Area Administration, Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance, Spinning Reserve and Supplemental Reserves. The Services and charges under this Control Area Services Agreement are approved by and on file with FERC.

Existing Transmission Resources

UNSE's existing transmission system as constructed is contained within two service areas in Arizona, being Mohave and Santa Cruz counties. As shown on Map 3, the UNSE-Mohave service territory is supplied by WAPA's 230 kV network which is interconnected to the Extra High Voltage (EHV) transmission system via three 345 kV substations: Mead, Liberty and Peacock. Firm system purchases designated as Network Resources are delivered to Pinnacle Peak substation. UNSE-Mohave receives Network Integration Transmission Service (NITS) from WAPA at several 230 kV points of delivery including Hilltop, McConnico, Black Mesa, North Havasu, and Griffith. These substations interconnect and supply energy to the local system. With the completion of the Vail to Valencia 138kV line, the UNSE Santa Cruz service territory is served by TEP's system. UNSE owns approximately 2796 miles of 69kV transmission lines in Mohave County and 60 miles of 138kV transmission lines in Santa Cruz County.

Map 3 - UNSE Transmission Delivery Points

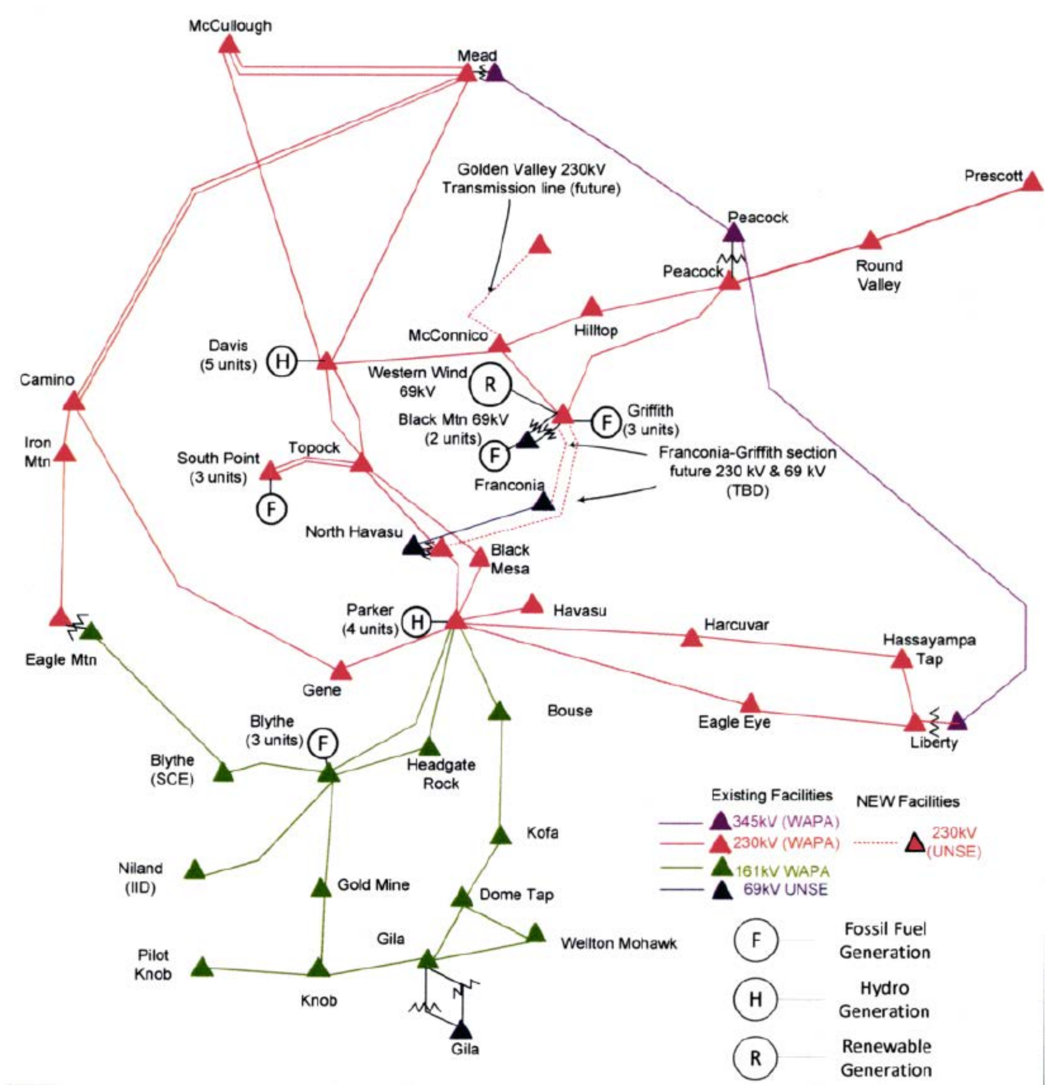


Mohave County Transmission Overview

UNSE has current transmission contracts with WAPA totaling approximately 480 MW, which includes network service on WAPA's system. The network service currently has Pinnacle Peak as a receipt point and Hilltop, Duval-Warm Springs, Planet Ranch, McConnico and North Havasu as delivery points in Mohave County.

In addition UNSE has point to point service on both WAPA's Parker Davis System and its Central Arizona Power System and a separate point to point service on WAPA's Intertie Power System and on its Central Arizona Power System again. UNSE also buys point to point transmission over WAPA's Open Access Same-Time Information System (OASIS), on an ad hoc basis. UNSE is able to purchase access on transmission systems of other providers in the region as needed.

Map 4 - Mohave County Transmission Delivery Points

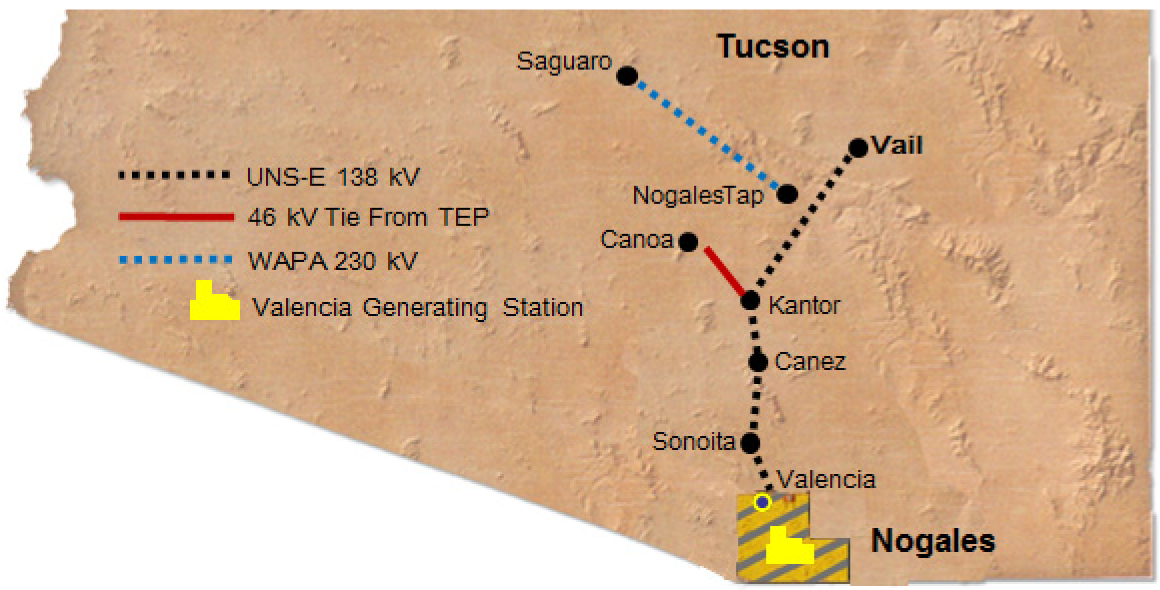


Santa Cruz County Transmission Overview

Santa Cruz County relies on a single 138 kV transmission line to serve the local distribution grid located in the City of Nogales as shown on Map 5. The Vail to Valencia project, described below, upgraded an existing 115 kV transmission line with a 138 kV transmission line between the Vail Substation, located southeast of Tucson, and the Valencia Substation in Nogales, Arizona. The existing transmission line is the primary source of electrical service for customers in Nogales, Arizona and surrounding communities.

As discussed further below, UNSE is partnering with Hunt Power, L.P. and others to develop a DC interconnection between the Western Interconnection in the United States and the Mexico grid. This project will be developed in two phases, ultimately allowing 300MW to be transferred in either direction.

Map 5 - Santa Cruz County Transmission Delivery Points



Vail to Valencia 138kV Upgrade

In 2013, UNSE upgraded an existing 115 kV transmission line with a 138 kV transmission line between the Vail Substation, located southeast of Tucson, and the Valencia Substation in Nogales, Arizona. This project was completed in December 2013. This project converted the existing 115kV line that interconnected to the WAPA 115kV network at Nogales Tap to a 138kV line that interconnects to the TEP transmission network via a 345/138kV transformer at the Vail Substation.

Primary elements of the project included:

- Changing the interconnection point from the current location at Western Area Power Administration's "Nogales Tap" to Tucson Electric Power's Vail Substation
- Replacing the existing 115kV line with a new 138 kV line
- Replacing transformers at three of the four UES substations
- Replacing aging wooden H-frame structures with steel monopoles

Comparison of the recently installed steel monopole structures alongside old wooden "H-frame" structures along the Vail to Valencia Transmission route. The H-frame structures were removed after construction of the new facilities in 2014.

Nogales DC Intertie

The Nogales Interconnection Project is a proposed direct current interconnection, commonly known as a "DC tie," which will allow for an asynchronous interconnection between the electric grids in southern Arizona and the northwest region of Mexico. The project will support the reliability of the electric system, including providing bidirectional power flow and voltage support, as well as emergency assistance, as needed, for the electric system both north and south of the border.

Map 6 - Nogales DC Intertie Study Area and Route

The first phase would consist of a new 150 megawatt DC tie located on property currently owned by Tucson Electric Power; a new 3-mile 138 kV transmission line that would originate at UNSE's Valencia Substation in Nogales, Arizona and extend to the west and south to the new Gateway Substation; and a new approximately 2-mile 230 kV transmission line that would extend south from the Gateway Substation to the U.S.-Mexico border where it would interconnect with a transmission line to be constructed in Mexico. The second phase would expand the DC tie capacity to 300 MW. The timing of the second phase has not been determined.

CHAPTER 6

FUTURE RESOURCE REQUIREMENTS

Future Energy Efficiency Assumptions

UNSE's EE programs will continue to comply with the Arizona EE Standard that targets a cumulative energy savings of 22% by 2020. For this IRP, EE is modeled as a resource and is dispatched to meet load based on the EE shape described in Chapter 4. The energy savings reflected in our reference case forecast through 2020 represent an estimate of the energy savings needed to meet the standard, excluding savings associated with program credits[4]. From 2021 through the end of the planning period, the estimated annual savings are based on an assessment of "achievable potential" in energy savings from EE programs conducted by EPRI.[5] This "achievable potential" represents "an estimate of savings attainable through actions that encourage adoption of energy efficient technologies, taking into consideration technical, economic, and market constraints."[6] Market constraints include both market acceptance factors such as transactional, informational, behavioral, and financial barriers, as well as program implementation factors, which account for recent utility experience with EE programs.[7]

UNSE will pursue a range of cost-effective and industry-proven programs to meet future EE targets. UNSE's proposed EE portfolio, in addition to maintaining compliance with the Arizona EE Standard, is expected to be compliant-ready under the provisions of the CPP. Given the uncertainty around the status of the CPP, UNSE notes that EE is an effective compliance tool under virtually any policy aimed at reducing carbon emissions. Under a mass-based approach, EE aids in compliance by displacing actual fossil generation and the associated emissions. Under a rate-based approach similar to the CPP, EE measures that undergo appropriate Evaluation, Measurement and Verification can be used to reduce the emission rate of affected fossil-fired generators. By 2032 this offset to future retail load growth is expected to reduce UNSE's annual energy requirements by approximately 500 GWh and reduce UNSE's system peak demand by 125 MW.

Future Renewable Energy Assumptions

Arizona's renewable energy requirement is 15% by 2025. By early 2018 UNSE expects to have 106 MW of combined utility-scale renewable generation capacity and 45 MW of DG on its system. Renewable energy generated by these resources will be approximately 20% of retail sales (exceeding the state standard) through 2022.

Technology Considerations

UNSE continues to evaluate on an on-going basis the most cost-effective renewable energy options currently available. This evaluation includes the most current market costs of renewable technology, such as wind and solar, system integration availability and associated technologies to facilitate greater renewable penetration, as well as existing and planned transmission availability for regions located outside the Company's service territory. As expected with the current technology cost declines, current tax incentive policies, and solar insolation values in Arizona, utility-scale photovoltaic (PV) solar is the least cost resource on an energy-only

[4] Arizona Administrative Code, R14-2-2404 C.- G.
[5] *U.S. Energy Efficiency Potential Through 2035*, Electric Power Research Institute, dated April 2014. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025477
[6] Ibid, p. v
[7] Ibid p. 2-20

basis, followed closely by higher-capacity wind resources located in central eastern portions of Arizona and western New Mexico.

Although the Company expects to have a higher percentage of solar resources within its service territory, primarily due to favorable production curves, low costs, and lack of available transmission to import other resources, this will ultimately result in operational challenges as discussed above in Chapter 3, including the Company's ability to manage its "duck curve". These integration issues, including any associated with additional wind resources, will require new technologies to manage the variability of these resources. The Company sees this challenge as an opportunity to both explore and utilize newer, fast-acting storage technologies to mitigate system variability due to the intermittent nature of these resources.

Future Grid Balancing Resources

As described in Chapter 3, it is critical for UNSE to maintain adequate resources that can balance load and generation, especially as increased use of renewable energy leads to greater intermittency of generation and greater ramping requirements of non-renewable energy resources. This section of the IRP describes the addition of new grid-balancing and load-leveling resources assumed in the Reference Case.

Energy Storage

UNSE is assuming that its first ESS will be a 5 MW x 5 MWh battery system implemented in 2019. Additional systems of this size and type are assumed to be implemented in 2022, 2025, and 2028 to help integrate the already high and potentially increasing amount of intermittent renewable energy resources tied into UNSE's balancing area.

The siting of larger-scale storage facilities will depend on a number of circumstances, including:

- Primary purpose of facility (distribution or transmission level voltage support, frequency response, generation smoothing and ramping, etc.)
- Secondary and tertiary ancillary services available from the facility relative to its location
- Engineering studies
- Size of facility
- Interconnection feasibility
- Company or third-party owned facility

The Company is closely following the technology advances in large-scale energy storage, specifically as it relates to the development of large-scale (>10 MW), long duration (>4 hrs.), energy storage. Lithium-ion chemistry, for example, is making significant advances towards longer-term, higher capacity energy storage. Additionally, the Company is tracking advancements that have been made in flow-based energy systems, particularly vanadium, iron, zinc, and redox flow technologies. Also, the Company is closely monitoring the progress of pumped hydro storage projects in the West. Although these technologies are still on the high end of the cost curve, their potential to provide long-term, high-capacity energy storage with long life cycles holds significant promise for the utility industry.

Fast Response Thermal Generation

As renewable penetration increases, fast-responding resources will be needed to smooth out the oft-occurring variability of solar and wind generators. Additionally, a certain level of thermal resources with mechanical inertia will have to be maintained in order to help balance the electric system. RICEs are fast to respond to renewable variability but can also provide 100% ELCC during peak periods. The units are only degraded by run-time hours and can withstand multiple start-ups within a day. The units are also capable of running at 30% of their designed capacity. A 10 MW unit can idle down to 3 MWs and spin or stand ready to react to disturbances or renewable generation reductions/increases.

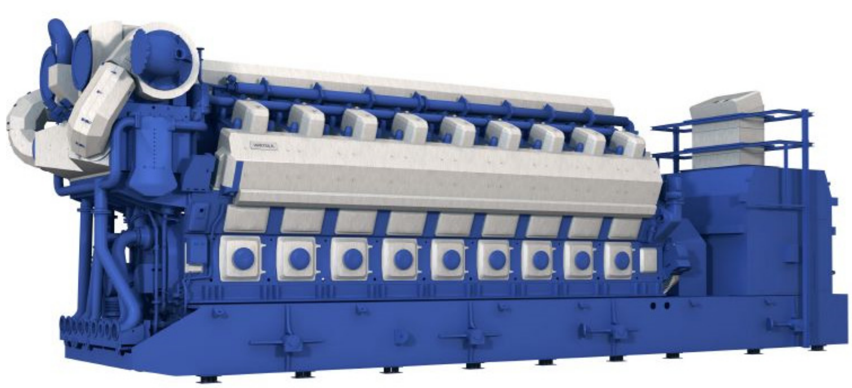
In its fleet of generating resources, UNSE has only three efficient combustion turbines (Black Mountain and Valencia CT#4) to utilize and dispatch to assist with renewable intermittency. UNSE also uses its share of Gila River to help smooth out the effects of solar and wind. The Company has a capacity shortfall of approximately 150 MWs, and the addition of RICEs will assist with renewables variability. As mentioned above, cycling RICEs has no impact on O&M and the 3 to 5 minute start times are not equaled by any existing generator in the UNSE fleet. The RICE units will equally provide summer peaking capability, but more importantly, these fast, responsive, and efficient units are a better fit with renewable energy. Reliability is increased as well because the probability of outages is spread across multiple units.

RICE and combustion turbines (CTs) are the preferred technology that will assist in mitigating renewable energy intermittency and variability. RICEs have quicker start-up and ramping capabilities than most CTs. Aeroderivative CTs are based on aircraft jet engine design with increased cycling capabilities. These units can ramp faster than large frame combustion turbines making them well-suited for peaking and load-following applications. Large frame CTs have higher heat rates than aeroderivative and RICE but they produce higher temperature exhaust, so it makes them more suitable for combined cycle configurations.

Overview of Reciprocating Internal Combustion Engines

Reciprocating Internal Combustion Engines are simply combustion engines, like those used in automobiles, trucks, railroad locomotives, construction equipment, marine propulsion, and backup power applications. Modern combustion engines used for electric power generation are internal combustion engines in which an air-fuel mixture is compressed by a piston and ignited within a cylinder. RICEs are characterized by the type of combustion: spark-ignited, like in a typical gas powered vehicle, or compression-ignited, also known as diesel engines.

Figure 2 – Wartsila-50SG



An emerging use of these engines is in large-scale electric utility generation. The combustion engine is not a new technology, but advances in efficiency and the need for fast-response generation make it a viable option to stabilize variable and intermittent electric demand and resources. RICEs have demonstrated a number of benefits.

- Fast Start Times – The units are capable of being on-line at full load within 5 minutes. The fast response is ideal for cycling operation. RICE can be used to 'smooth' out intermittent resource production and variability.
- Run Time - The units operate over a wide range of loads without compromising efficiency, and can be maintained shortly after shut down. After shut down, the unit must be down for 5 minutes, at a minimum to allow for gas purging.
- Reduced O&M – Cycling the unit has no impact on the wear of RICE. The unit is impacted by hours of operation and not by starts and cycling operations as is the case with combustion turbines.
- Fast Ramping – At start, the unit can ramp to full load in 2 minutes on a hot start and in 4 minutes on a warm start. Once the unit is operational, it can ramp between 30% and 100% load in 40 seconds. This ramping is comparable to the rate that many hydro facilities can ramp at.
- Minimal Ambient Performance Degradation – Compared to Aeroderivative and Frame type combustion turbines, RICE output and efficiency is not as drastically impacted by temperature. The site altitude does not significantly impact output on RICE below 5,000 feet mean sea level.
- Gas Pressure – RICE can run on low pressure gas, as low as 85 PSI. Most CT's require a compressor for pressure at 350 PSI.
- Reduced Equivalent Forced Outage Rate (EFOR) – Each RICE has an EFOR of less than 1%. A facility with multiple RICE will have a combined EFOR that is exponentially less by a factor of the number of units at the facility.
- Low Water Consumption – RICE use a closed-loop cooling system that requires minimum water.
- Modularity – Each RICE unit is built at approximately 2 to 20 MWs and is shipped to the site.

An intriguing application for RICEs are their potential for regulating the variability and intermittency of renewable resources.

Figure 3 – Reciprocating Internal Combustion Engine Facility

Demand Response

The UNSE Commercial and Industrial Demand Response Program is designed to manage peak demand and mitigate system emergencies through a commercial load curtailment program. The program is managed in-house by engaging with our interruptible rate customers to participate in a proactive DR program. For those customers who choose to participate, UNSE installs equipment that provides the Company control of either selected loads or the entire electric load in a facility.

UNSE also installs metering equipment for all participants to enable proper tracking of interval load data to ensure customer participation in any control event and also to provide data for post event analysis. In addition, participants must agree to be placed on UNSE's Interruptible Power Service tariff in lieu of any cash incentive for participation.

UNSE is targeting enrollment of enough customers by 2020 to reach 8 MW of summer peak demand reduction. For planning purposes, UNSE assumes approximately 4% annual growth in DR capacity after 2020, resulting in 13 MW available in 2032 with 2% annual increase in fees needed to achieve that level of growth. These growth assumptions would likely require expanding DLC beyond the Commercial and Industrial sectors.

In addition to meeting peak demand and system emergency needs, UNSE intends to explore designing DLC programs that are capable of cost-effectively addressing periods of significant ramping, anticipated with high penetration of renewable resources.

Future Transmission

Transmission resources are a key element in UNSE's resource portfolio. Adequate transmission capacity must exist to meet UNSE's existing and future load obligations. UNSE's resource planning and transmission planning groups coordinate their planning efforts to ensure consistency in development of its long-term planning strategy. On a statewide basis, UNSE participates in the ACC's Biennial Transmission Assessment (BTA) to develop a transmission plan that ensures that Arizona's transmission organizations are coordinated in their efforts to maintain system adequacy and reliability.

Ten-Year Transmission Plan

On an annual basis, UNSE develops and submits to the Commission a ten year transmission plan for its EHV (230 kV) and High Voltage (HV) (138 kV) transmission networks. This plan reflects planned and conceptual projects on the EHV and HV transmission network used to (1) connect to the Western Area Power Authority (WAPA) and TEP systems, through which Mohave County and Santa Cruz County are served, respectively, and (2) connect to the sub-transmission network and load pockets.

UNSE's 2016 ten year transmission plan includes the following:

- 1 planned EHV transmission line project
- 2 conceptual EHV transmission line projects
- 2 conceptual HV transmission line projects
- 1 conceptual HV reactive projects

Transmission Resources Needed for New Generating Resources

For purposes of this resource plan, the resource planning group developed a set of transmission cost assumptions based on the list of potential generation resources. These generation resource options include the additional costs associated with any transmission improvements that would be required to connect the resources to the transmission system.

For example, some of the larger load-serving resource options may be constructed some distance from the UNSE service territory and would require transmission infrastructure or wheeling rights to deliver energy to the load center(s). Smaller generation facilities, such as those required for grid balancing, would likely be constructed within the Kingman, Lake Havasu, or Nogales local areas and would require a much smaller interconnection investment. Finally, in addition to construction capital, the resource plan also includes the cost of the ongoing O&M that is required to maintain these transmission facilities. These costs are also included and are factored into the total cost of each resource alternative.

CHAPTER 7

ALTERNATIVE FUTURE SCENARIOS AND FORECAST SENSITIVITIES

Modeling the performance of a resource portfolio involves making assumptions about future conditions such as economic growth, fuel and wholesale power markets, regulatory conditions (e.g. emission prices), and the pace of technological development. UNSE seeks to identify a reference case portfolio that provides solid performance under the assumptions selected while maintaining optionality to make course adjustments in response to actual emerging conditions. Due to the inherent uncertainty about these future assumptions, it is necessary to test the performance of each resource portfolio against a range of future conditions to better assess whether a portfolio is robust under varying conditions. Because certain market conditions do not move independently of each other, alternative future scenarios must be identified that capture a range of future conditions, yet represent plausible outcomes in terms of the relative movement of different market forces.

PACE Alternative Future Scenarios

UNSE hired PACE Global (PACE) to develop a base case set of assumptions and two alternative future scenarios for modeling the performance of each resource portfolio. These three future states of the world are characterized by discrete scenarios with varying economic drivers that represent three separate forecasts of forward market conditions (see TEP 2017 IRP, Appendix A).

These scenarios are defined as:

1. Base Case Scenario
2. High Technology Scenario
3. High Economy Scenario

The Base Case Scenario features existing regulations, gradually rising mid-term gas prices (in real terms), continuing technological growth, low load growth, and generally moderate market outcomes. Power market participants are able to adapt and adjust in a timely manner to changing market forces.

The High Technology Scenario is characterized by significant advances in energy storage technology, renewable energy deployment, emissions reduction and CO_2 removal technology, high efficiency natural gas-fired generation, and also natural gas extraction productivity improvements. These conditions tend to subdue fuel prices, power prices, and capital costs, and put pressure on coal plant economics, resulting in additional retirements. However, there are also significant developments in technologies that improve EE, which helps to mitigate load growth that might otherwise be expected in a "high technology" scenario with robust economic growth.

The High Economy Scenario is characterized by a robust and growing U.S. economy that keeps upward pressure on all of the major market outcome categories, including load growth, fuel costs, power prices, and capital costs. This growth is in the absence of a major technological breakthrough. Existing generation resources are needed to maintain this economic expansion, limiting the number of retirements while accelerating the number of capacity additions. While this scenario shares many of the attributes of the previous "High Technology" scenario, the pace of technological innovation is not as dynamic and therefore, not as beneficial to keeping prices and costs in check.

Under the High Technology and High Economy Scenarios, key market indices such as fuel prices, emission prices, and retirements move in opposite directions relative to the base case, thereby providing the range of outcomes desired for portfolio modeling.

The table below represents trends for each variable in the "Base Case Scenario" and the directional shift in trend relative to the base case outlook in "L", "H", and "M" under the "High Economy Scenario" and the "High Technology Scenario". The "L" symbol represents a decline or a reduction in trend compared to the Base Case Scenario, whereas the "H" symbol represents an increase or a rise relative to the base case projection for the corresponding period. Finally, the "M" symbol represents identical movement to the base case or a convergence to the base case for the specific period if the previous trend has caused the variable to go above or below the Base Case.

Table 8 – Summary of PACE's Key Planning Drivers Scenarios

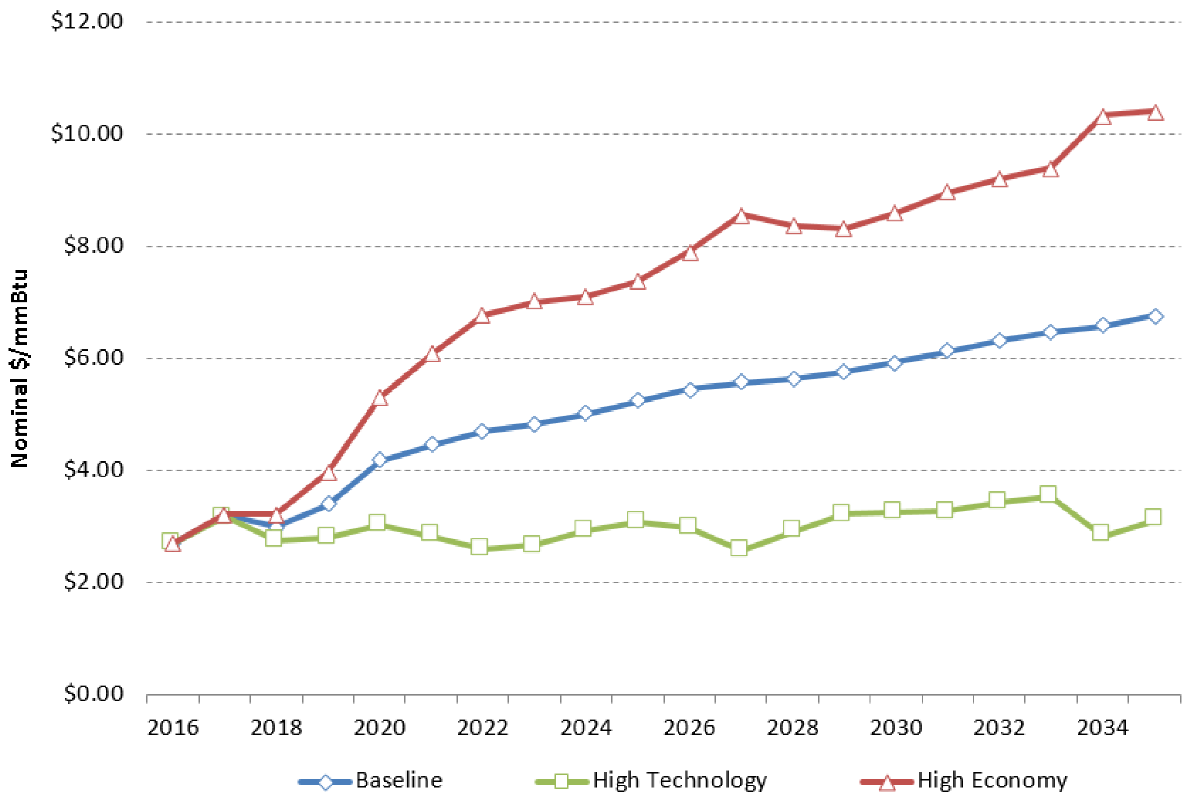
Key Planning Drivers	Base Case Scenario Base Case Natural Gas Pricing			High Economy Scenario High Natural Gas Pricing			High Technology Scenario Low Natural Gas Pricing		
Planning Horizon	Short-Term	Mid-Term	Long-Term	Short-Term	Mid-Term	Long-Term	Short-Term	Mid-Term	Long-Term
Natural Gas Prices	B	Upward Trend	Level Trend	B	H	M	B	L	L
Coal Prices	B	Upward Trend	Upward Trend	B	H	H	B	L	L
Load Growth	B	Level Trend	Upward Trend	B	H	M	B	L**	L**
CO_2 Compliance Prices	B	Upward Trend	Upward Trend	B	H	H	B	L	L
Wholesale Power Prices	B	Upward Trend	Level Trend	B	H	H	B	L	L
Capital Costs	B	Upward Trend*	Upward Trend*	B	H	H	B	L	L
Coal Plant Retirements	B	Upward Trend	Upward Trend	B	L	M	B	H	M
Resource Additions	B	Upward Trend	Upward Trend	B	H	M	B	H	M

Notes:
All scenarios are similar to the Base Case (B) in the short-term, then move low (L), high (H), or moderate (M) relative to the Base Case.
Planning Horizon: Short-Term = 2016-2018, Mid-Term = 2019-2025, Long-Term = 2026-2040
*Certain renewable technologies are on a downward capital cost trend as the technologies continue to mature
**Slightly lower

Natural Gas Prices

Chart 14 shows the Henry Hub natural gas price assumptions for the three scenarios.

Chart 14 - Permian Basin Natural Gas Price Sensitivities



Capital Costs

The capital cost for new resources are based on the Lazard's Levelized Cost of Energy Analysis v.10.0, which presents costs in 2016$. Future nominal costs include an inflation adjustment as well as innovation adjustment developed by PACE to reflect that installed costs of certain technologies are expected to decrease as the technology itself matures, in addition to improvements in manufacturing and delivery processes and supply chain efficiencies. Chart 15 through Chart 17 below present the capital cost assumptions for the technologies representing the most likely future resource additions for each of the three scenarios.

Chart 15 – Capital Cost Assumptions, Solar Technology

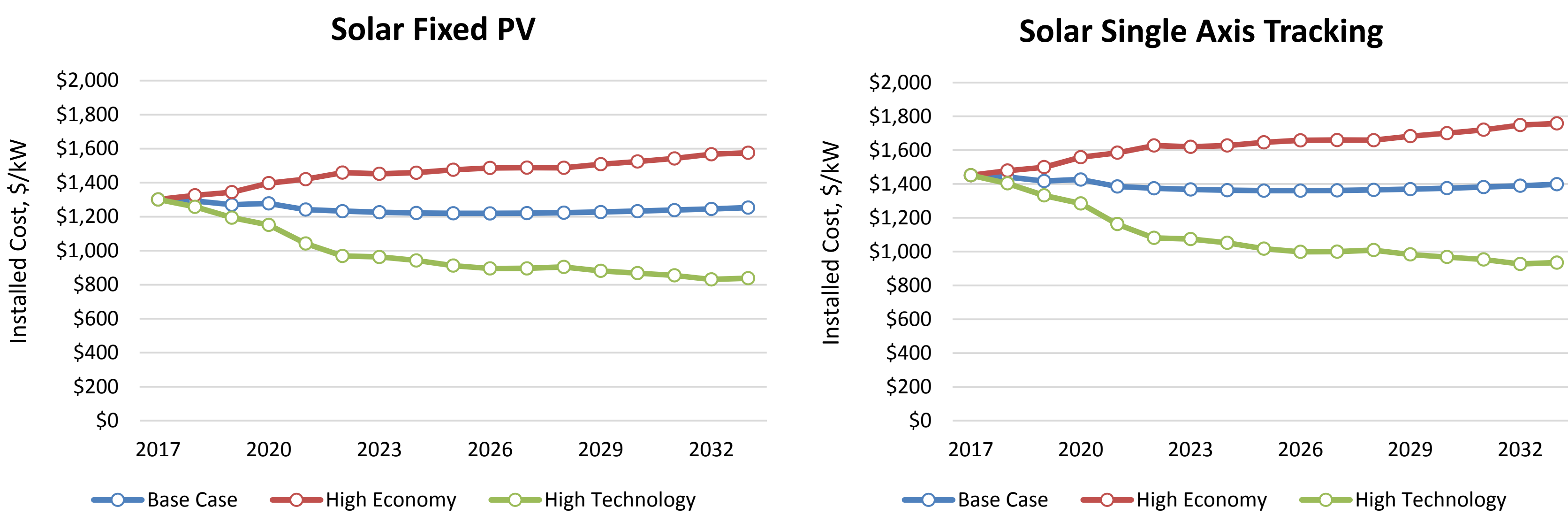


Chart 16 – Capital Cost Assumptions, Wind

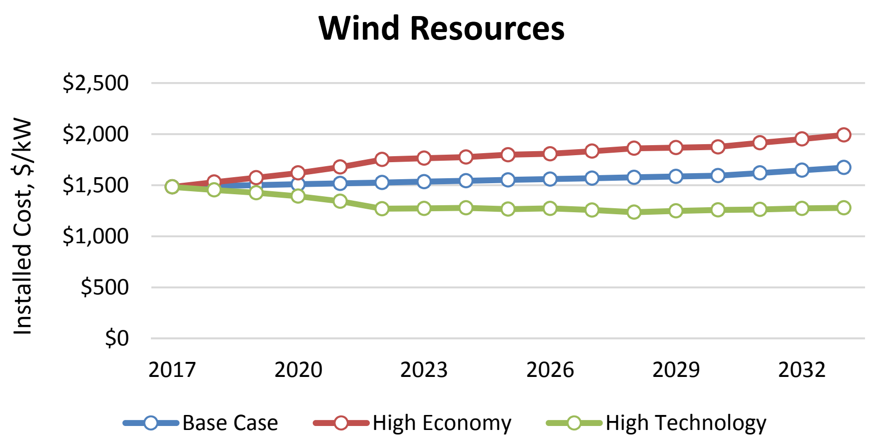
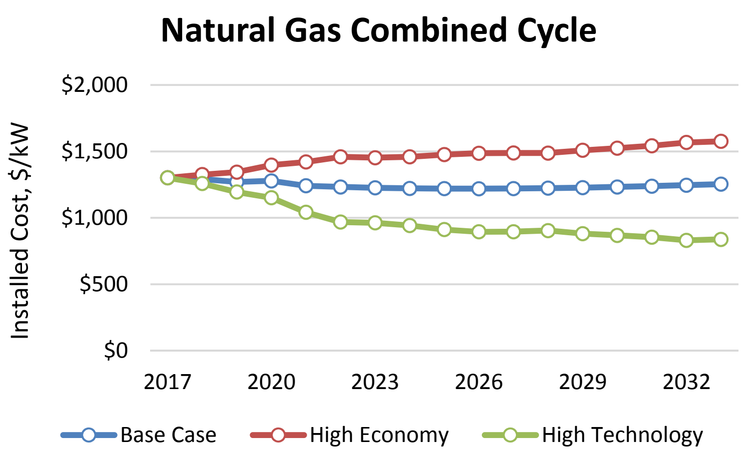
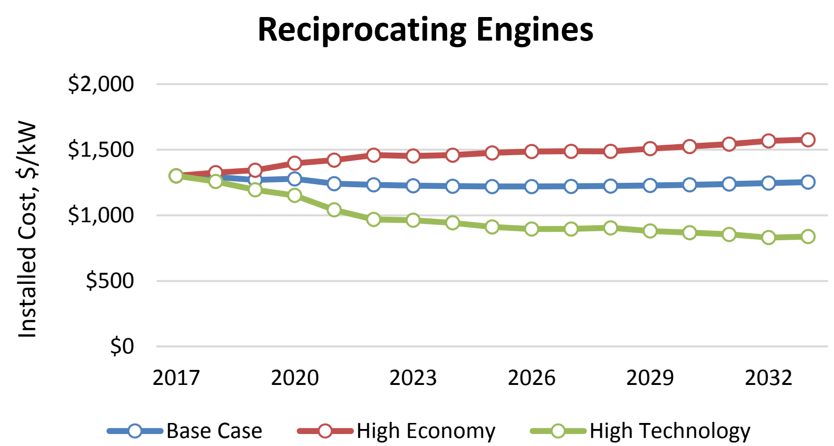


Chart 17 – Capital Cost Assumptions, Natural Gas Technology

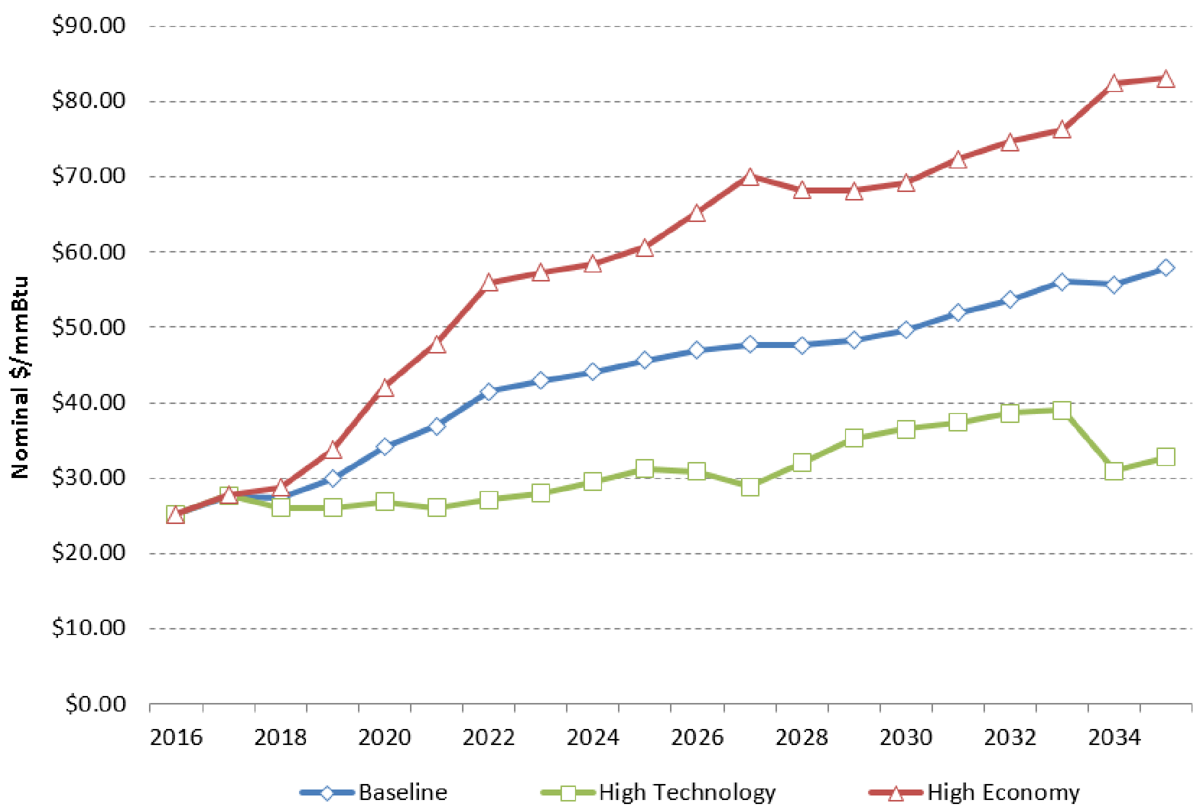




Palo Verde (7x24) Power Market Prices

The forward price assumptions discussed above are fed into PACE's modeling infrastructure to develop a power market price that reflects those assumptions. Chart 18 shows the resulting Palo Verde market price for each of the three scenarios.

Chart 18 - Palo Verde (7x24) Market Price Sensitivities



Load Growth Scenarios

Due to the need for comparability between alternative portfolios, the base case load assumption will be used for all alternative portfolios. Varying assumptions on load growth is analyzed against the Reference Case portfolio only. The 2017 Reference Case Plan projects UNSE peak demand growing approximately 1.7% per year between 2020 and 2032. This change in growth is related to anticipated growth in the residential sector (see Chart 4). In fact, UNSE forecasts large industrial and mining customer loads at levels well below those seen in the past decade. For the load growth scenarios, these base case conditions will be modified to create a high load and low load scenarios.

High Load Scenario

For purposes of testing the Reference Case portfolio against a scenario in which energy use and demand are greater than in the base case, UNSE assumes that mining and/or large industrial customer load rebounds to levels close to those seen in recent history. Under this assumption, there is 30MW of additional peak load beginning in 2020.

Low Load Scenario

For purposes of testing the Reference Case portfolio against a scenario in which energy use and demand are lower than in the base case, UNSE assumes that limited residential mobility results in fewer new customers entering UNSE's service territory. With residential customer growth being the main driver in overall load growth for UNSE, this decrease in new customers is assumed to result in a 0.5% decrease in annual peak load growth between 2020 and 2032.

Fuel, Market and Demand Risk Analysis

For the 2017 IRP the Company developed explicit market risk analytics for each candidate portfolio through the use of computer simulation analysis using AuroraXMP[8]. Specifically, a stochastic based dispatch simulation was used to develop a view on future trends related to natural gas, wholesale market prices, and retail demand. The results of this modeling was employed to quantify the risk of uncertainty and evaluate the cost performance of each portfolio. This type of analysis ensures that the selected portfolio not only has a relatively low expected cost, but is also robust enough to perform well against a wide range of possible load and market conditions.

As part of the Company's 2017 resource plan, UNSE conducted risk analysis around the following key variables:

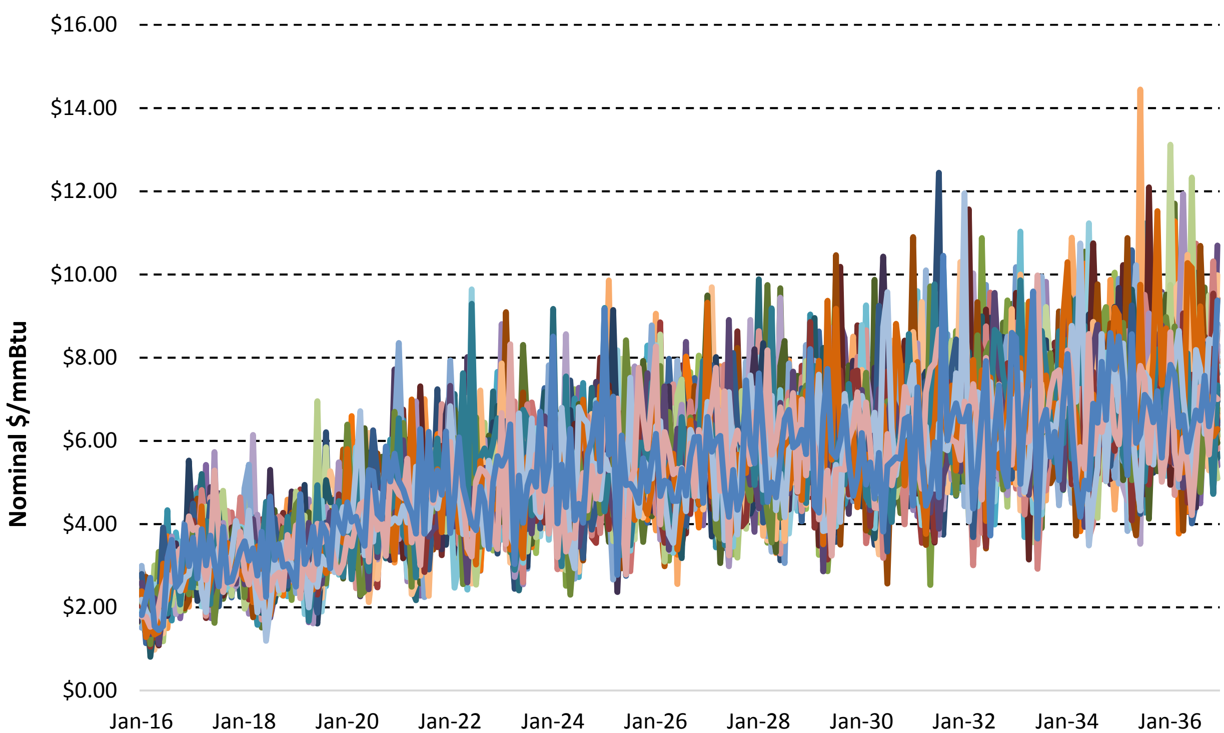
- Natural Gas Prices
- Wholesale Market Prices
- Retail Load and Demand

[8] AURORAxmp is a stochastic based dispatch simulation model used for resource planning production cost modeling. Additional information about AURORAxmp can be found at http://epis.com/

Permian Natural Gas Prices

As part of 2017 IRP analysis, UNSE ran 100 risk simulations to quantify the risk of uncertainty related to Permian natural gas prices. Chart 19 below details the PACE Base Case (Clean Power Plan) Scenario and the natural gas price simulations against which the portfolios were evaluated.

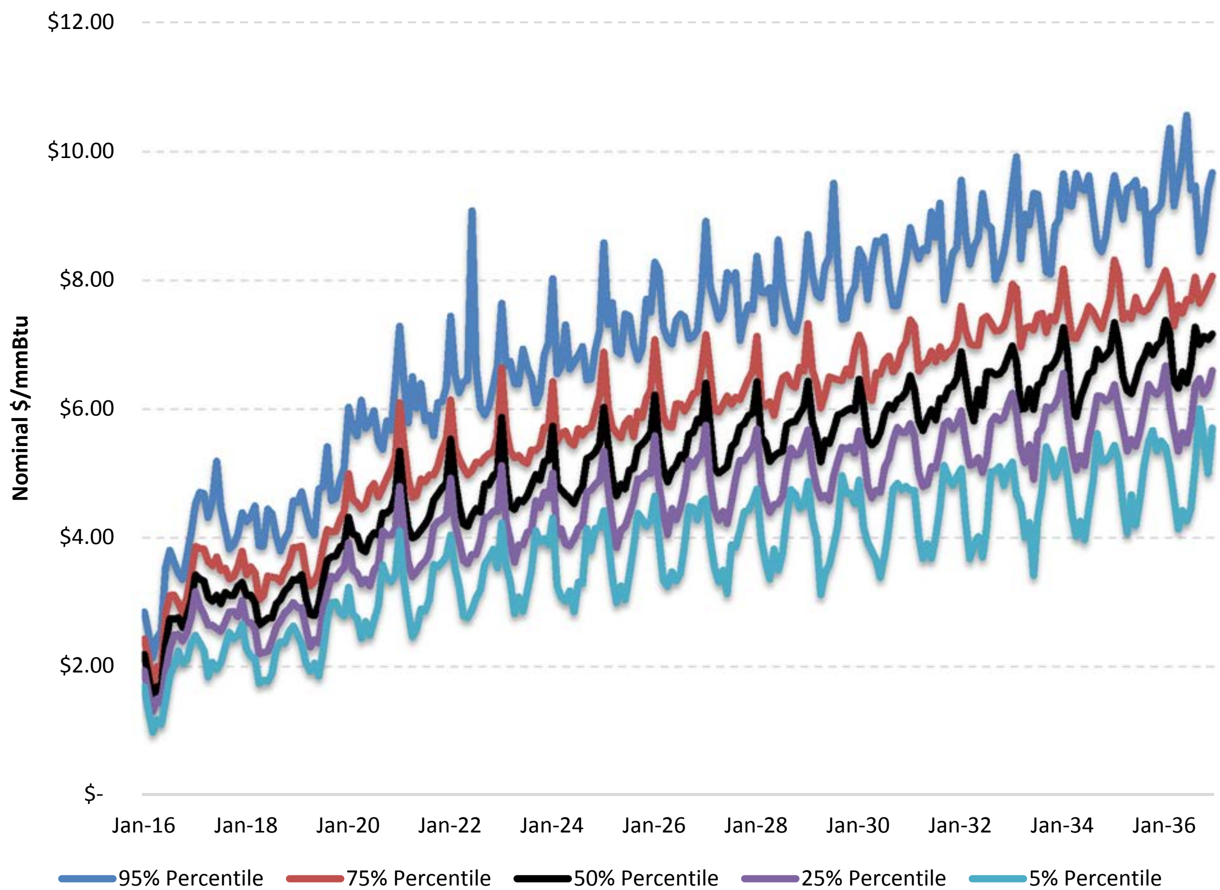
Chart 19 - Permian Basin Natural Gas Price Iterations ($/mmBtu)



Permian Natural Gas Price Distribution

Chart 20 shows the expected price distributions for natural gas sourced from the Permian Basin. These distributions are based on the stochastic data simulations shown in Chart 19 above.

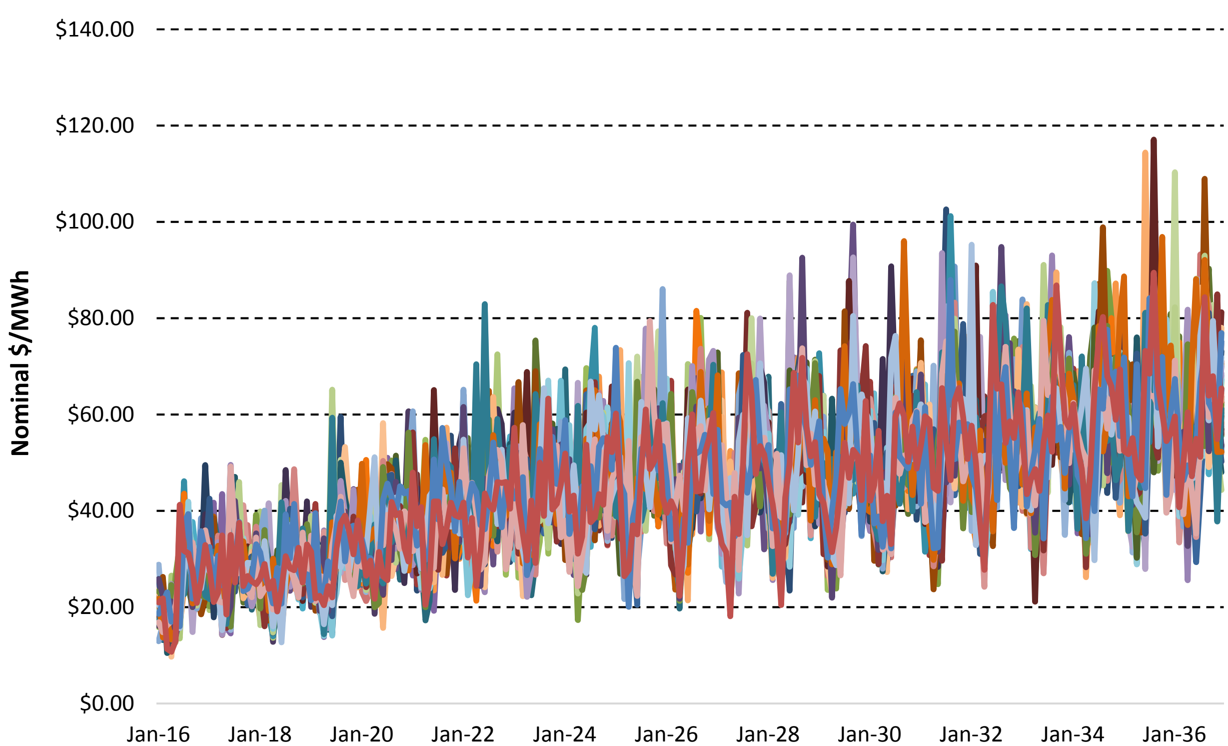
Chart 20 - Permian Basin Natural Gas Price Distributions



Palo Verde (7x24) Wholesale Power Prices

As part of the 2017 IRP analysis, UNSE ran 100 risk simulations to quantify the risk of uncertainty related to wholesale power prices. Chart 21 below details the PACE Base Case (Clean Power Plan) Scenario and the wholesale power price simulations against which the portfolio were evaluated.

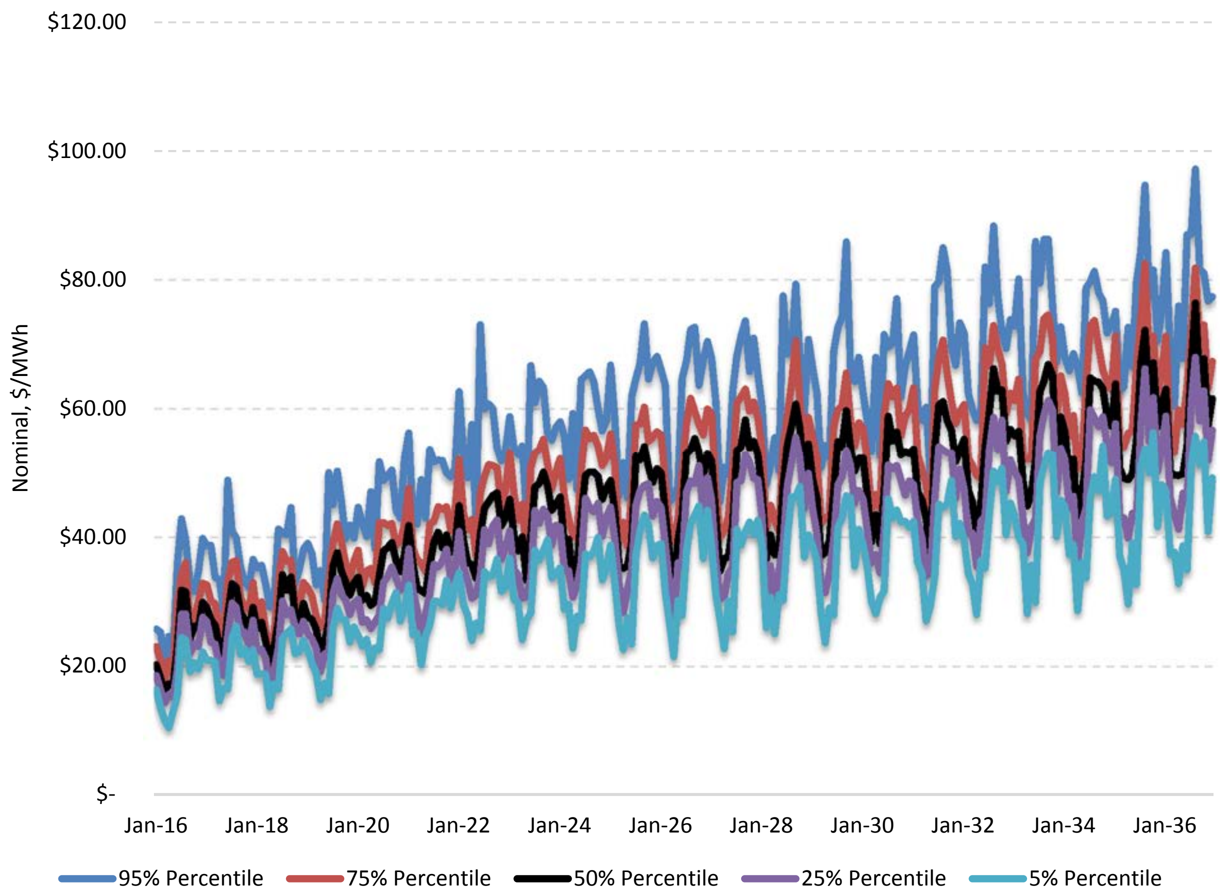
Chart 21 – Palo Verde Wholesale Power Price Iterations ($/MWh)



Palo Verde (7x24) Wholesale Power Price Distribution

Chart 22 shows the expected price distributions for wholesale power sourced from the Palo Verde market. These distributions are based on the stochastic data simulations shown in Chart 21 above.

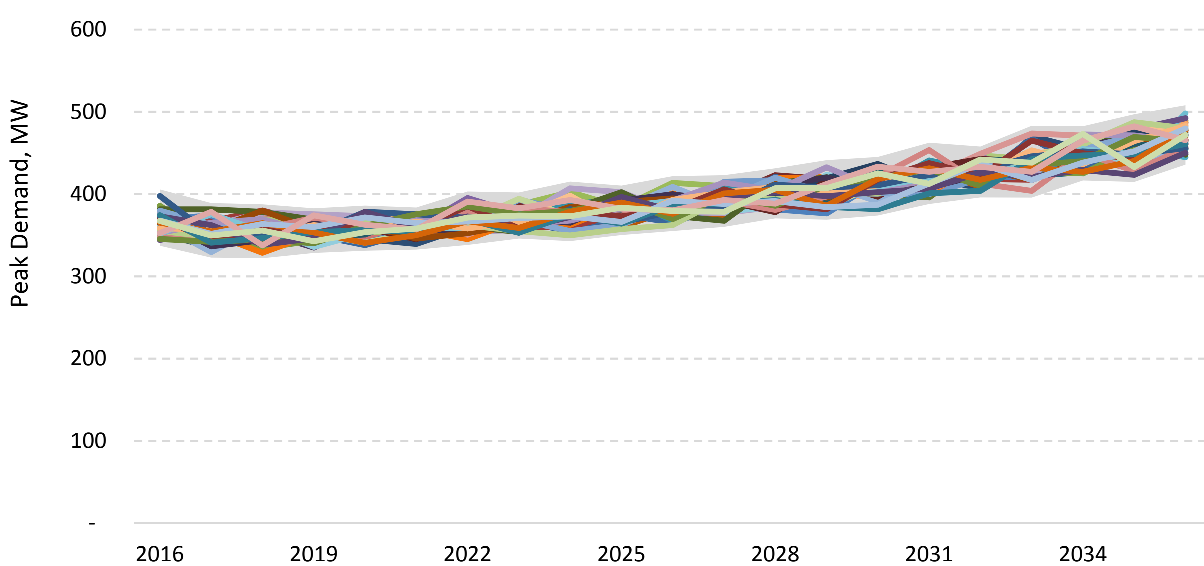
Chart 22 - Palo Verde (7x24) Market Price Distributions



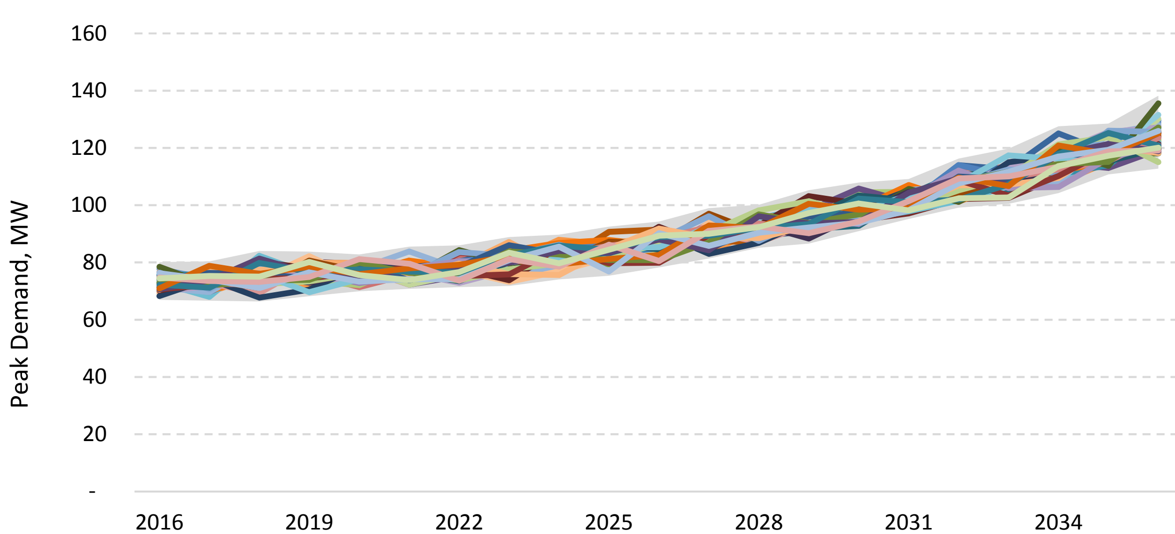
Load Variability and Risk

As outlined in the previous sections, load is also varied within each of the 100 simulations in accordance with the movement of natural gas and wholesale power prices. In this way, a wide variety of possible load growth scenarios are considered in the simulation analysis and are therefore inherent in the resulting risk profiles.

Mohave Peak Retail Demand



Santa Cruz Peak Retail Demand



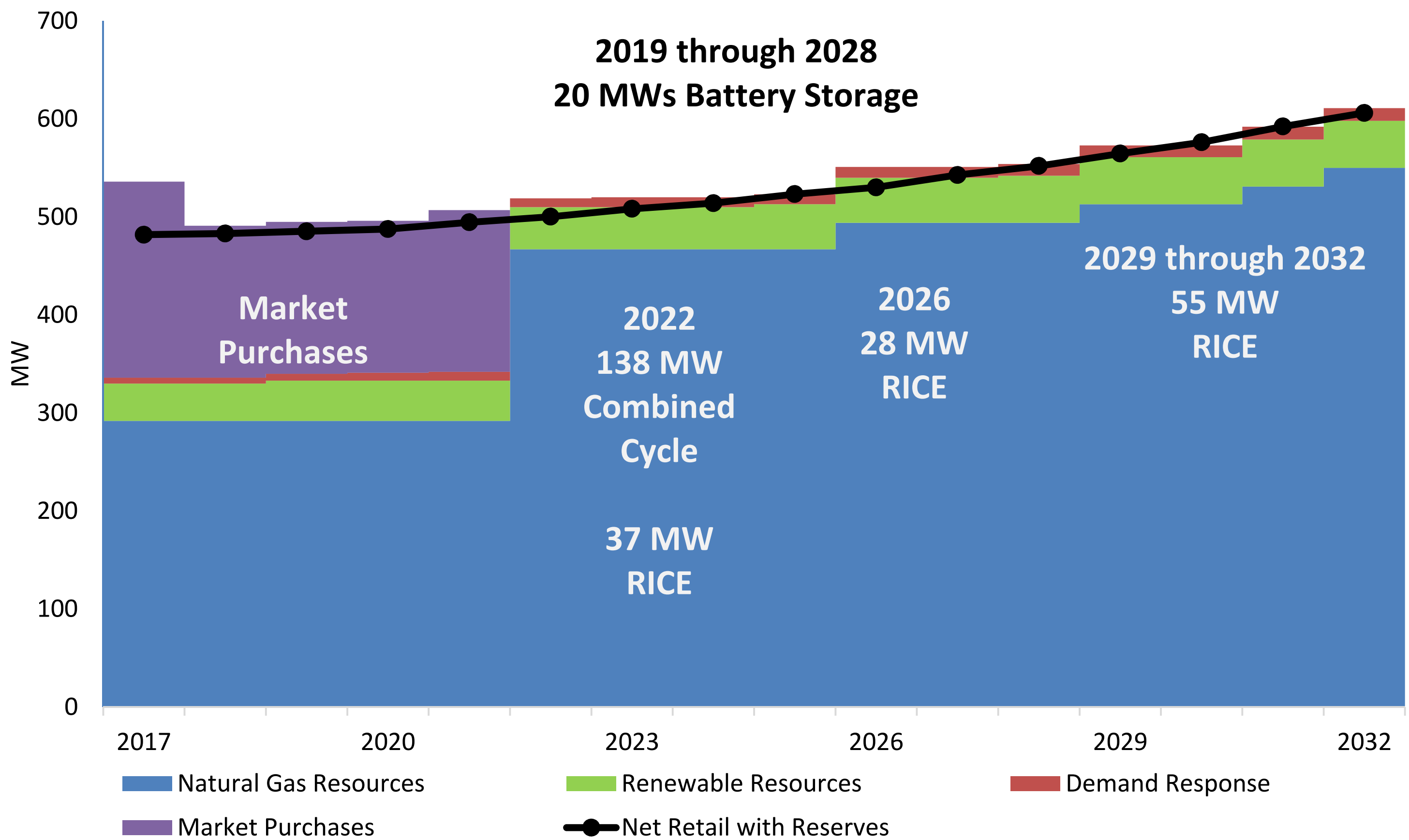
CHAPTER 8

REFERENCE CASE PLAN

UNSE's 2017 IRP Reference Case Plan continues the Company's transition from high dependence on PPAs and market purchases to meet generation requirements, toward greater self-reliance on owned generating assets. The Company also continues expanding the deployment of renewable energy resources, and will continue development and implementation of cost-effective EE measures. As a result of the high penetration of customer-owned DG and the addition of utility-scale renewable energy resources, the Company also plans to expand its grid balancing resources to address the intermittency and ramping requirements that renewable resources introduce to the system.

Loads and Resource Assessment

Chart 23 – UNSE's 2017 Loads and Resource Assessment



Addition of Resources to Meet System Requirements

In considering future resources, the resource planning team evaluates a mix of load serving and grid balancing technologies. This mix of technologies includes both commercially available resources and developing technologies that are likely to become technically and economically viable in the near future. The IRP process takes a high-level approach and focuses on evaluating resource technologies relevant to the needs of the system, rather than focusing on specific projects. Candidate resource additions designed to meet planning reserve requirements are identified for modeling and through an iterative process, a specific configuration in terms of technology, timing and capacity is determined based on cost, reliability, and environmental performance. This approach allows the resource planning team to develop a wide range of scenarios and contingencies that result in a resource acquisition strategy that contemplates future uncertainties.

Addition of Load Serving Resources

The 2017 Reference Case Plan includes a large renewable energy project coming online in 2018. The addition of this 46 MW single-axis tracking solar PV project in 2018 will bring UNSE's percentage of retail load provided by renewable energy sources to over 19%, exceeding the 15% called for under the RES in 2025. To replace wholesale market purchases, UNSE plans to add approximately 138 MW of NGCC capacity by 2022. NGCC capacity is a high-efficiency intermediate to baseload resource, which given the current outlook on natural gas prices, represents the lowest Levelized Cost of Electricity (LCOE) among fully-dispatchable load-serving resources. NGCC units are also capable of load-following and in the right configuration can provide fast ramping response.

Addition of Grid Balancing and Load Leveling Resources

To support the system in light of this high penetration in intermittent renewable energy, it is assumed in the 2017 Reference Case Plan that UNSE installs approximately 37 MW of natural gas fired RICEs by 2022. Additional renewable energy support and other ancillary services are to be provided by energy storage projects assumed to come on line in 2019 and 2022. These systems would likely be sized as 5 MW batteries with a discharge capacity of 5 MWh.

An additional 83 MW of RICE capacity is assumed to commence operation between 2026 and 2032, which along with increasing amounts of DR meet the increasing peak demand. The high efficiency of these RICE units combined with their modular arrangement and fast start and fast-ramp capabilities make them a highly flexible, cost-effective alternative for meeting peak capacity while also addressing renewable intermittency. The 2017 IRP Reference Case Plan also assumes the implementation of 10 MW of additional energy storage between 2025 and 2028. These systems, while relatively small (5 MW x 5 MWh), could provide a combination of ancillary, peak capacity, and load-leveling services.

Reference Case Plan Summary and Timeline

Chart 24 shows the Reference Case Plan resource capacity additions by year, which provides an indication of the source of make-up power due to increasing load. Chart 25 below details the significant resource planning decisions assumed for the 2017 IRP Reference Case Plan.

Chart 24 - Reference Case Plan - New Resource Capacity (MW)

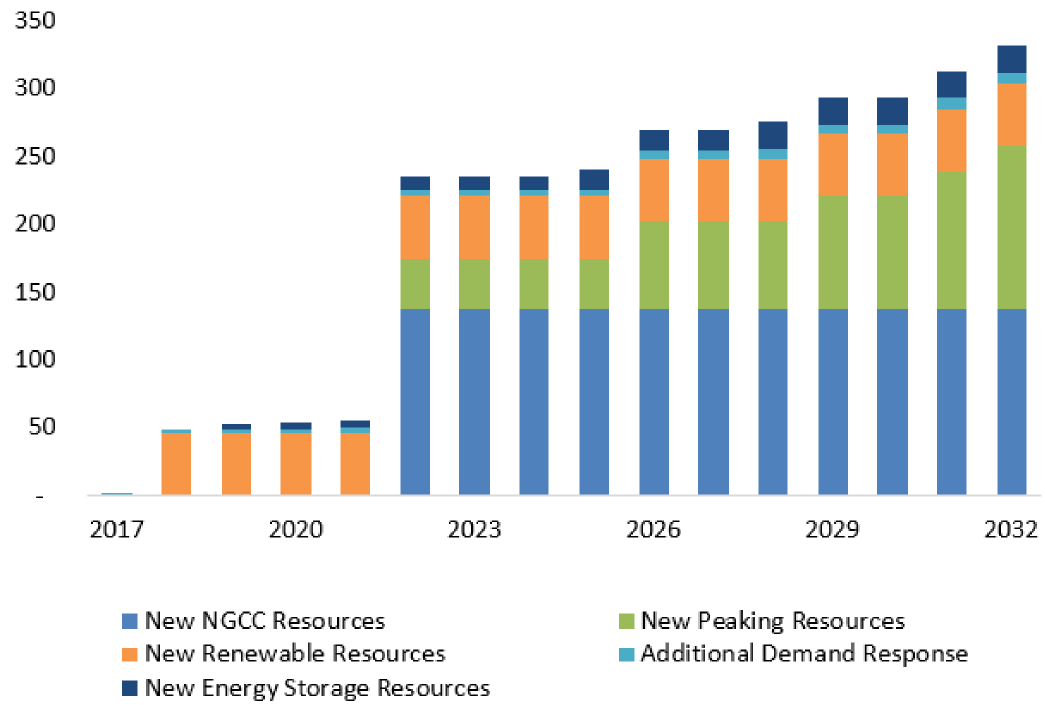
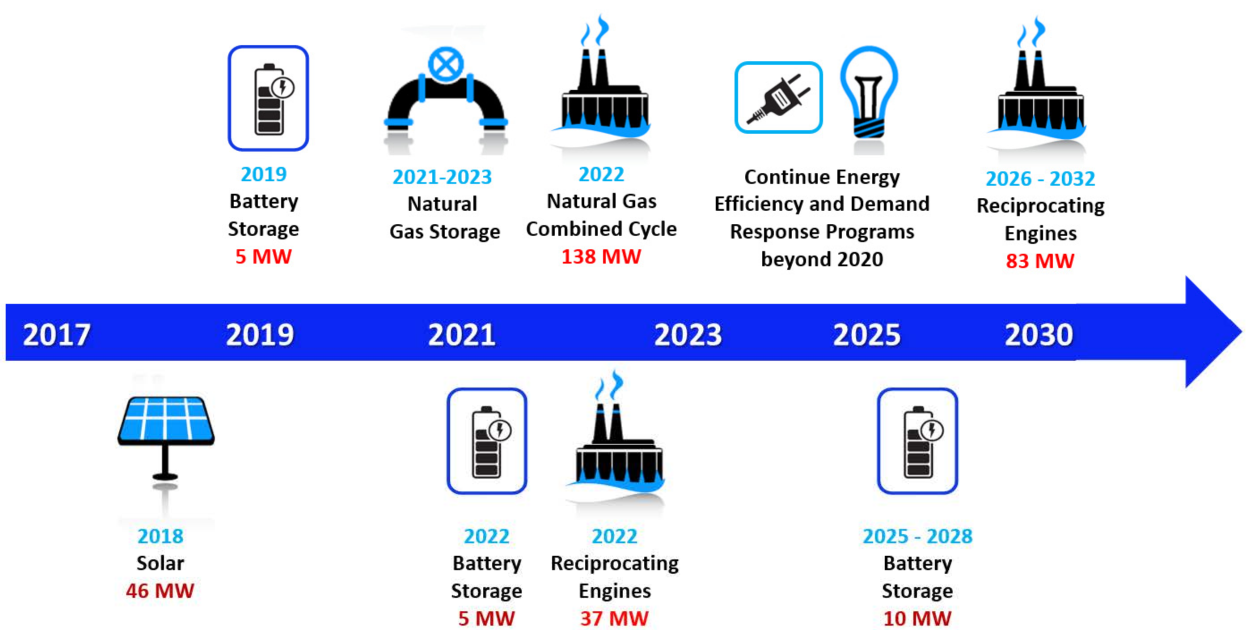


Chart 25 – 2017 IRP Reference Case Plan Resource Timeline



For modeling purposes, the 2017 IRP Reference Case Plan does not include any significant new transmission upgrades over the 15-year timeframe. The UNSE Ten-Year Transmission Plan only includes one "Planned" project,[9] which is anticipated to begin construction in 2018, and will not influence any of the resource options considered in this IRP. Several "Conceptual" projects were identified in the plan; however, the timing of these projects is expected to be determined through future transmission planning activities. UNSE will update these conceptual project descriptions in future IRP filings as they are clarified.

Reference Case Plan Attributes

The primary objective of the Reference Case Plan is to provide a portfolio of resources that reliably meets our customers' energy needs at an affordable rate, while identifying and addressing potential risks to cost and reliability. UNSE's 2017 Reference Case Plan achieves this objective by investing in low cost, flexible resources, thereby steadily increasing the percentage of energy supplied by resources under the Company's direct control. Chart 26 and Chart 27 show the declining reliance on market resources to meet energy and peak capacity requirements, respectively, over the planning period.

[9] Golder Valley 230 kV Transmission Line – 17 mile radial line from Harris Substation to Mineral Park Substation intended to improve load serving capability to West Colder Valley

Chart 26 - Reference Case Plan, Annual Energy by Resource (GWh)

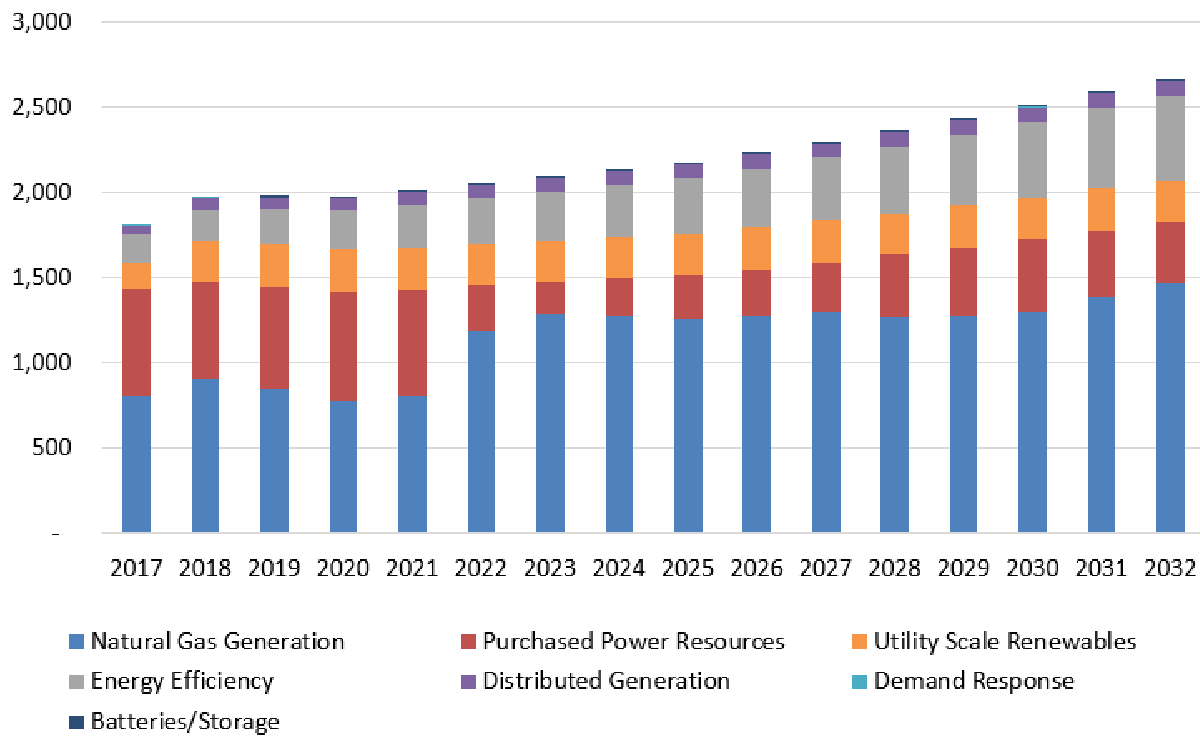
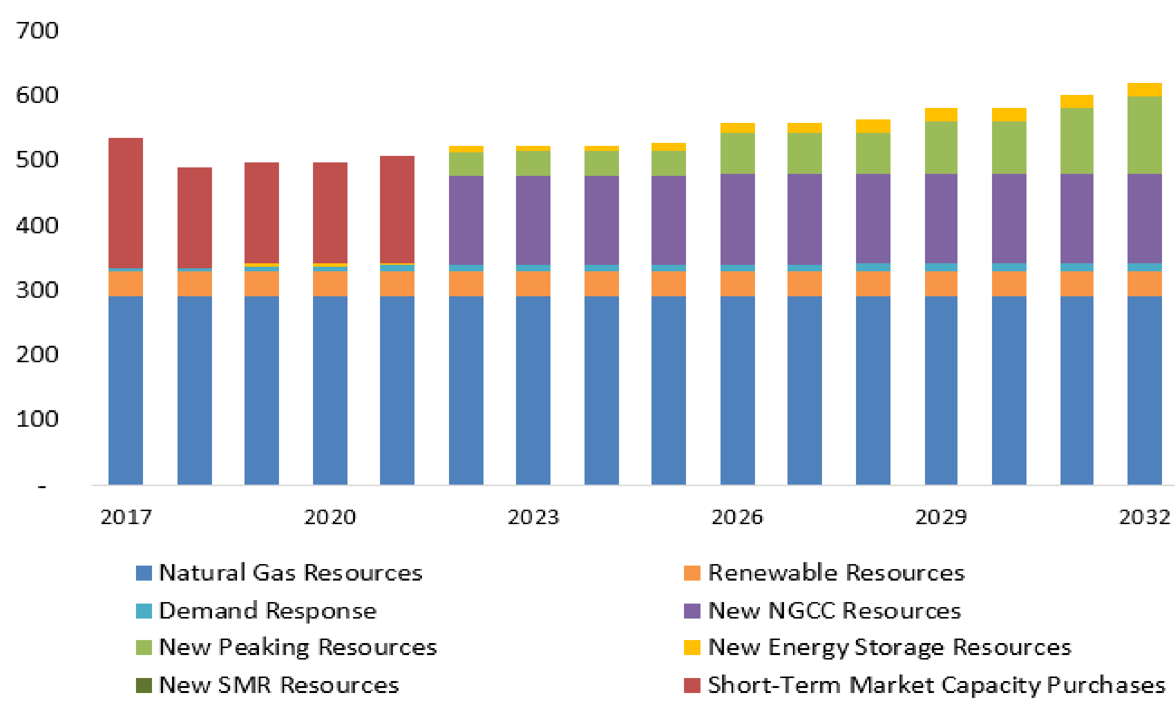


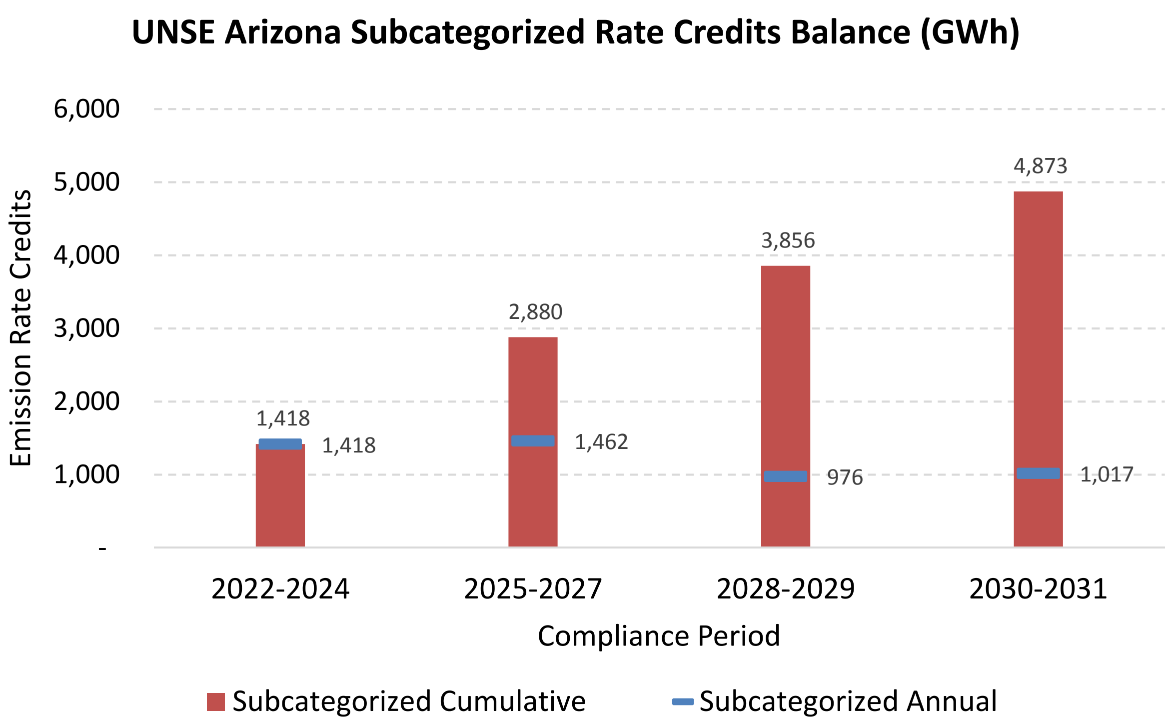
Chart 27 - Reference Case Plan, Total Coincident Peak Capacity (MW)



Clean Power Plan Compliance

UNSE assumes that Arizona would adopt a subcategorized rate based approach for CPP compliance. Chart 28 shows UNSE's compliance position in Arizona under the Reference Case Plan. UNSE's significant investment in renewable energy resources and continued EE deployment result in a surplus of banked emission rate credits that would be available for sale or could be banked for future compliance periods.

Chart 28 - UNSE Reference Case Plan CPP Compliance, Arizona



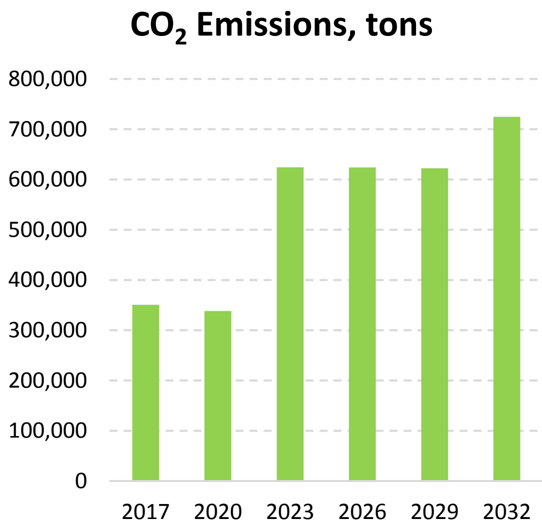
Reference Case Risk Dashboard

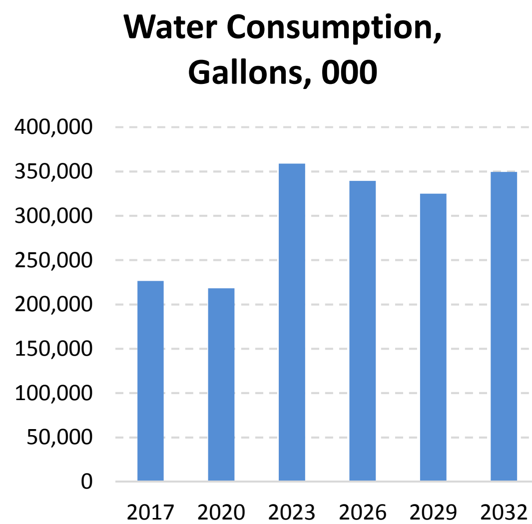
While there are many risk factors directly or indirectly associated with each resource portfolio, they all stem from the fact that operating under a fully integrated electric utility model requires very large capital investments, which generally need to be paid for over many years. Our goal is to develop a Reference Case Plan that provides optionality to make adjustments should there be a major change in future market and regulatory outcomes. Still, risk cannot be eliminated; therefore, key risk factors need to be identified and measured.

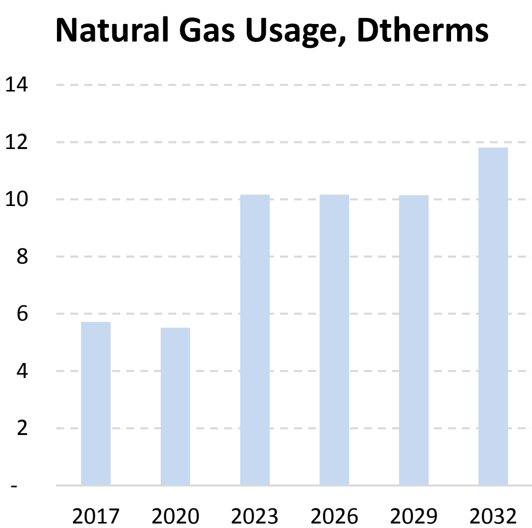
UNSE developed a Risk Dashboard (see Chart 29) as a means to bring attention to the primary risk factors affecting future resource decisions.

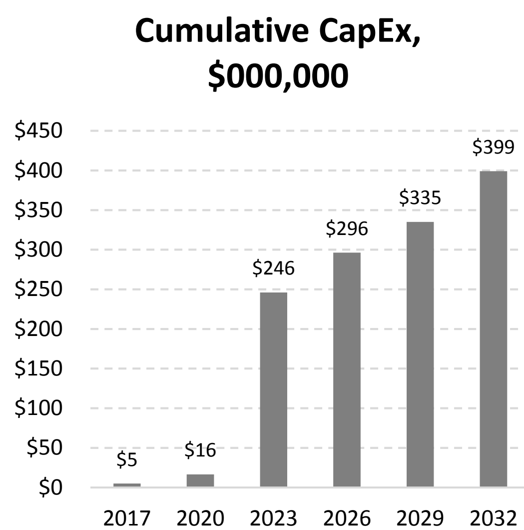
- **CO_2 Emissions** – While the Reference Case Plan is evaluated for comliance with the CPP as discussed above, the ultimate outcome of the CPP litigation is uncertain, and the current IRP planning horizon extends beyond the CPP implementation period. UNSE believes that CO_2 emission reductions will eventually be required, though the timing and magnitude of those reductions remains uncertain. UNSE believes that the Reference Case Plan CO_2 emissions profile represents a balanced position in the event of a future CO_2 emission compliance requirement. While emissions are increasing over the planning period as a result of higher utilization of natural gas-fired resources, the financial liability associated with CO_2 emissions is not necessarily increasing as that liability is also present in power market puchases, which the increased utilization is replacing.
- **Water Consumption** – Water availability for power generation is an ongoing concern, especially in the Desert Southwest. Similar to CO_2, UNSE believes that the modest increase in groundwater consuption under the Reference Case Plan represents a reasonable risk, as the increases is the result of increases utilization of owned assets. Water availabilit risk at the locations where UNSE assets are or will be located can be managed through proper due diligence..
- **Natural Gas Usage** – The 2017 Reference Case plan involves making additional investments in natural gas-fired resources. While the Company is mindful of the potential for an overreliance on natural gas, UNSE believes that current market forecasts support an increase in natural gas investment, and again, absent those investments, UNSE would have a similar exposure through power market purchases.
- **Capital Expenditures** – A long-term resouce plan should provide the optionality to make course corrections to address uncertaintyies (market performance, technolgy development, regulatory changes, etc.) as well as unforeseen circumstances. That optionality can be lost due to large, near-term capital investments. The 2017 Reference Case Plan stages major capital investments farily evenly over the 15-year planning period.

Chart 29 – Reference Case Plan Risk Dashboard







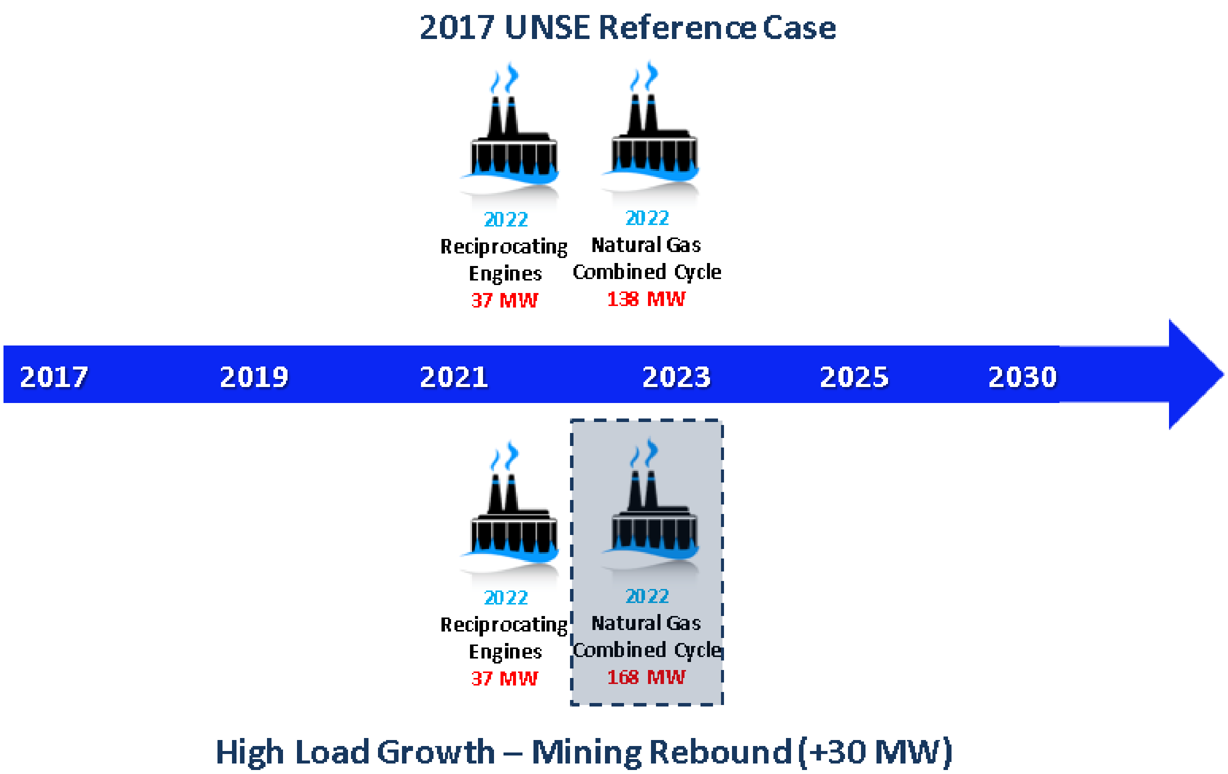


Load Growth Scenario Analysis

High Load Scenario

The high load growth scenario assumes that mining and/or large industrial customer load rebounds to levels closer to those seen in recent history. Under this assumption, there is 30MW of additional peak load beginning in 2020. UNSE would be able to rely on short term capacity market purchases for the first two years of this increase, thus delaying the need for firm capacity to 2022, which coincides with RICE and NGCC resource additions in the Reference Case. Therefore, increasing the amount of additional capacity is a logical approach for adjusting to this increase in load. Given the nature of mining load (approximately 85% load factor), and the fact that the RICE is intended to support increases in renewable energy resources, the high load scenario increases the amount of additional NGCC capacity needed in 2022. Adjustments to the 2017 Reference Case plan are presented on Figure 4.

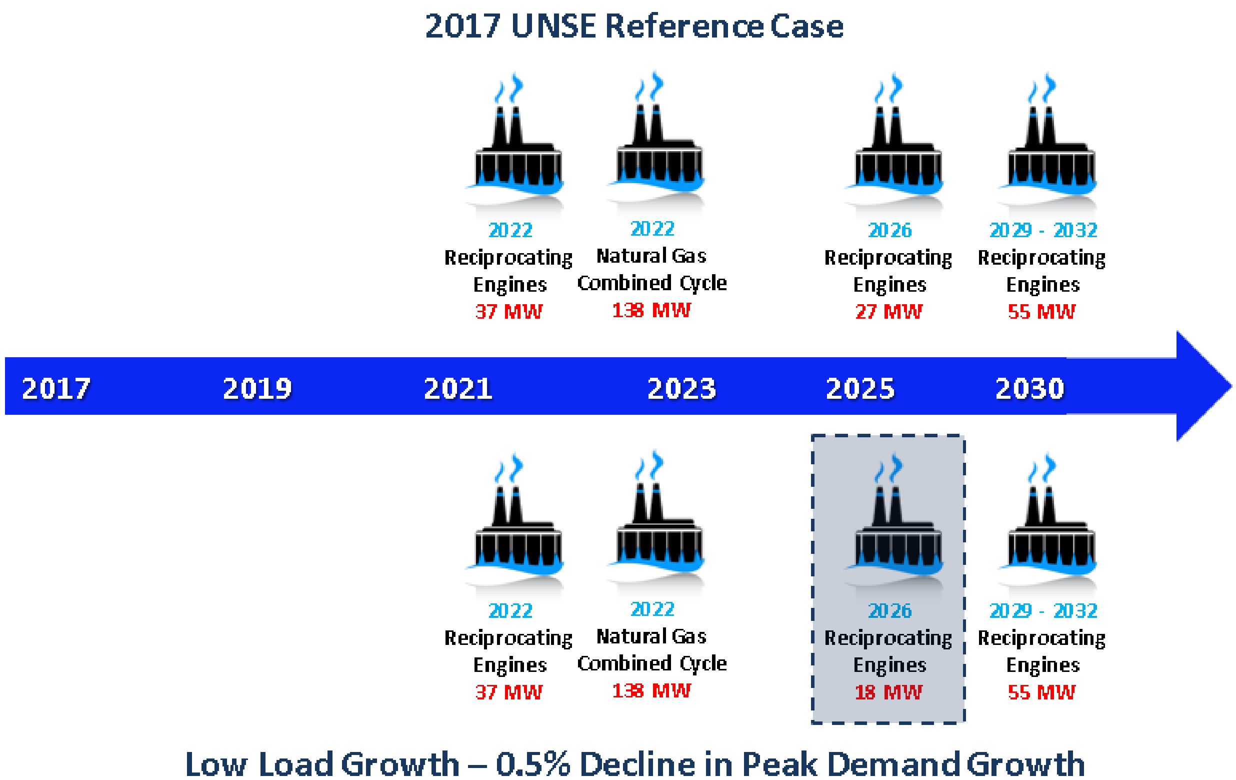
Figure 4 - High Load Scenario Adjustments to the 2017 Reference Case Plan



Low Load Scenario

The low load growth scenario assumes fewer new customers entering UNSE's service territory, resulting in a 0.5% decrease in annual peak load growth between 2020 and 2032. Applying this lower load assumption to the resource mix in the Reference Case, the reserve margin moves well above 15% beginning in 2026, ranging between 17% and 22% through 2032. This lower load negates the need for some peaking capacity planned for this period. Reducing the capacity of new RICEs in 2026 by 9 MW (one unit) brings reserve margins to a more appropriate level of 15% to 20% from 2026 through 2032. Adjustments to the 2017 Reference Case plan are presented on Figure 5.

Figure 5 - Low Load Scenario Adjustments to the 2017 Reference Case



CHAPTER 9

ALTERNATIVE PORTFOLIOS

The following sections present a description and the results of alternative portfolios analyzed as part of this IRP. The list of portfolios analyzed is presented below.

- Expanded Energy Efficiency Case Plan
- Expanded Renewable Energy Case Plan
- Combustion Turbine Case Plan

This list of alternative portfolios varies slightly from the list presented in the March 2016 Preliminary Integrated Resource Plan. High load and low load growth scenarios were analyzed in the context of the Reference Case Plan in Chapter 8, where adjustments were made to the portfolio to account for those differing load assumptions. A Combustion Turbine Case Plan is introduced to represent an alternative to the 2022 NGCC addition in the Reference Case Plan. A specific Energy Storage Case plan is not presented because energy storage has been incorporated into the Reference Case Plan. The only opportunity to introduce additional energy storage, in relation to the needs of UNSE's system, would be in the very near term when the relative percentage of intermittent renewable energy is the highest. UNSE does not believe that the technology is mature enough to justify significant near term investments.

The Small Modular Nuclear (SMR) Reactor Case plan was not analyzed due to the high capital costs for SMR resources relative to UNSE's existing rate base. A Market-Based Reference Case Plan was not analyzed because under the Reference Case Plan, UNSE has capacity in excess of the 15% reserve margin in all years beyond the five years where market purchases can be included in the portfolio.

Overview of Expanded Energy Efficiency

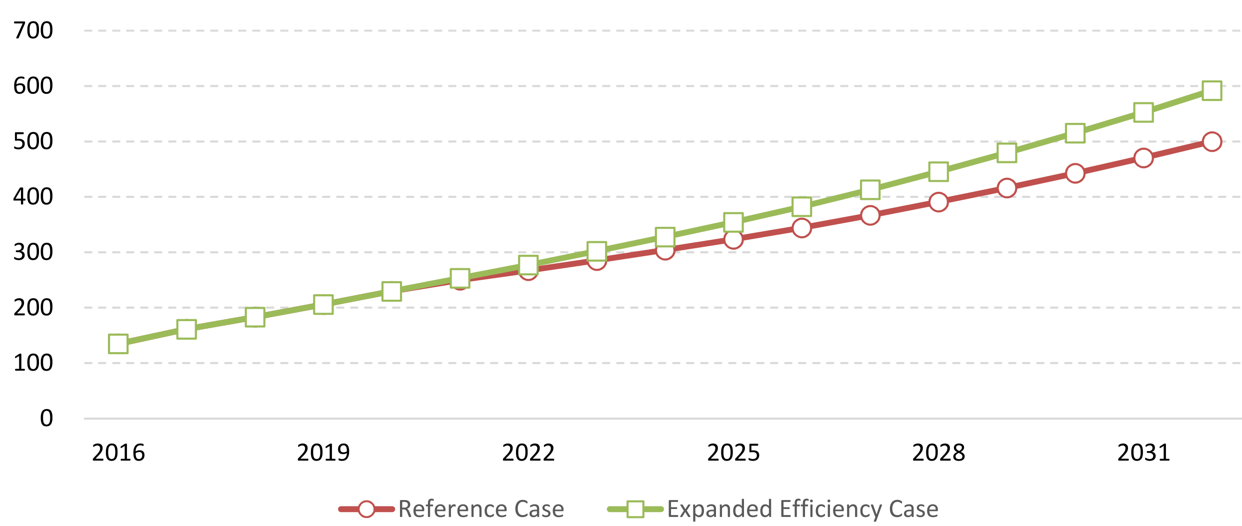
For purposes of this portfolio, it is assumed that UNSE realizes additional EE in the time period from 2021 through the 2032. The higher levels of EE assumed under this portfolio are based on the "*high achievable potential*" estimated by EPRI[10]. In comparison with the "*achievable potential*" assumed in the Reference Case, in which market constraints include both market acceptance factors as well as program implementation factors, the "high achievable potential" excludes program implementation factors.

Higher levels of energy savings will necessitate greater investment in DSM program activities. However, it is difficult to estimate the amount of additional DSM investment needed to attain a particular energy savings goal. Therefore, for this portfolio, UNSE estimated no annual incremental DSM program cost escalation. In other words, the 1st-year $/MWh cost is the same in the Expanded Energy Efficiency Case as it is in the Reference Case. This likely underestimates that cost of achieving the savings assumed in the Expanded Energy Efficiency Case.

Under this portfolio, the total energy savings realized by the Company in 2032 is 592 GWh, compared with 500 GWh in the reference case (see Chart 30). Total DSM program investment for the period from 2021 through 2032 under the Expanded Energy Efficiency portfolio was $236 million compared with $182 million in the reference case. Combining system fuel savings with additional program expenses, the Expanded Energy Efficiency portfolio was $1.5 million net present value more expensive than the Reference Case Plan over the planning period. However, for programs in the latter part of the planning period, energy savings extending beyond the planning period are not captured in the net present value calculation.

The additional energy savings in this portfolio also provides a capacity benefit, as the average reserve margin form 2025 to 2032 is 18.9% compared with 15.3% in the reference case. However, for purposes of this portfolio, neither deferrals of additional capacity nor accelerated retirement of existing capacity were deemed appropriate. Much of the excess reserve margin is associated with replacement of market purchase capacity.

Chart 30 - Projected Energy Savings (GWh)



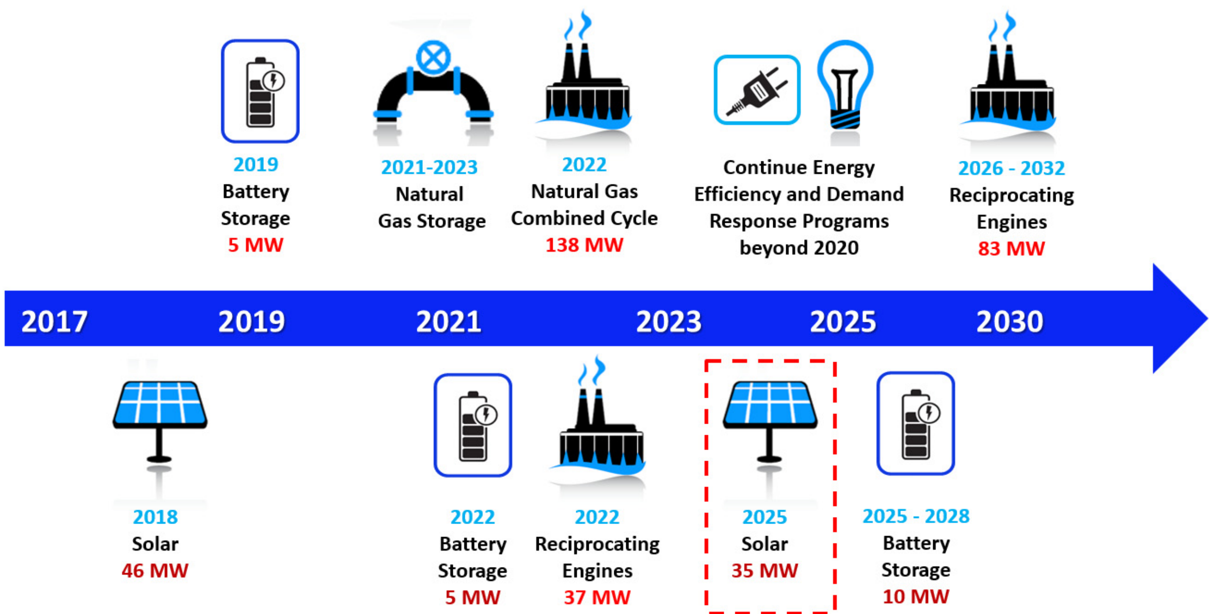
[10] *U.S. Energy Efficiency Potential Through 2035*, Electric Power Research Institute, dated April 2014. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025477

Due to UNSE's limited commercial and industrial base, we did not incorporate expanded DR programs into this portfolio. UNSE will evaluate higher levels of DR in future IRP planning cycles.

Overview of the Expanded Renewable Energy

Current and planned renewable energy projects in UNSE's territory are expected to contribute up to 20% of UNSE's retail sales by 2020 and are expected to persist at that level until approximately 2024. In the expanded renewable portfolio, the objective is to maintain a renewable energy contribution of 20% or more throughout the planning period. As such, the expanded renewable portfolio assumes the addition of a 35 MW single-axis tracking PV system in 2025, whose power would be obtained through a PPA.

Figure 6 – Reference Case with Expanded Renewable Portfolio



Overview of Combustion Turbine Portfolio

The Reference Case plan presents a portfolio that includes the addition of a NGCC plant in 2022. For UNSE, ownership in a NGCC creates a portfolio mixture that fills a need for baseload generation. However, the need for 138 MWs of NGCC in 2022 represents an amount that would likely involve joint ownership in a plant or unit, which may not be available at the time of UNSE's need. UNSE would not likely be able to acquire that amount of capacity on its own.

The Combustion Turbine Portfolio presents an alternative to the Reference Case Plan in that it replaces the NGCC with an equal amount of combustion turbine capacity.

Overview of Major IRP Assumptions by Portfolio

Table 9 below summarizes the major assumptions and upgrades that are included in each case.

Table 9 – Major IRP Assumptions by Case

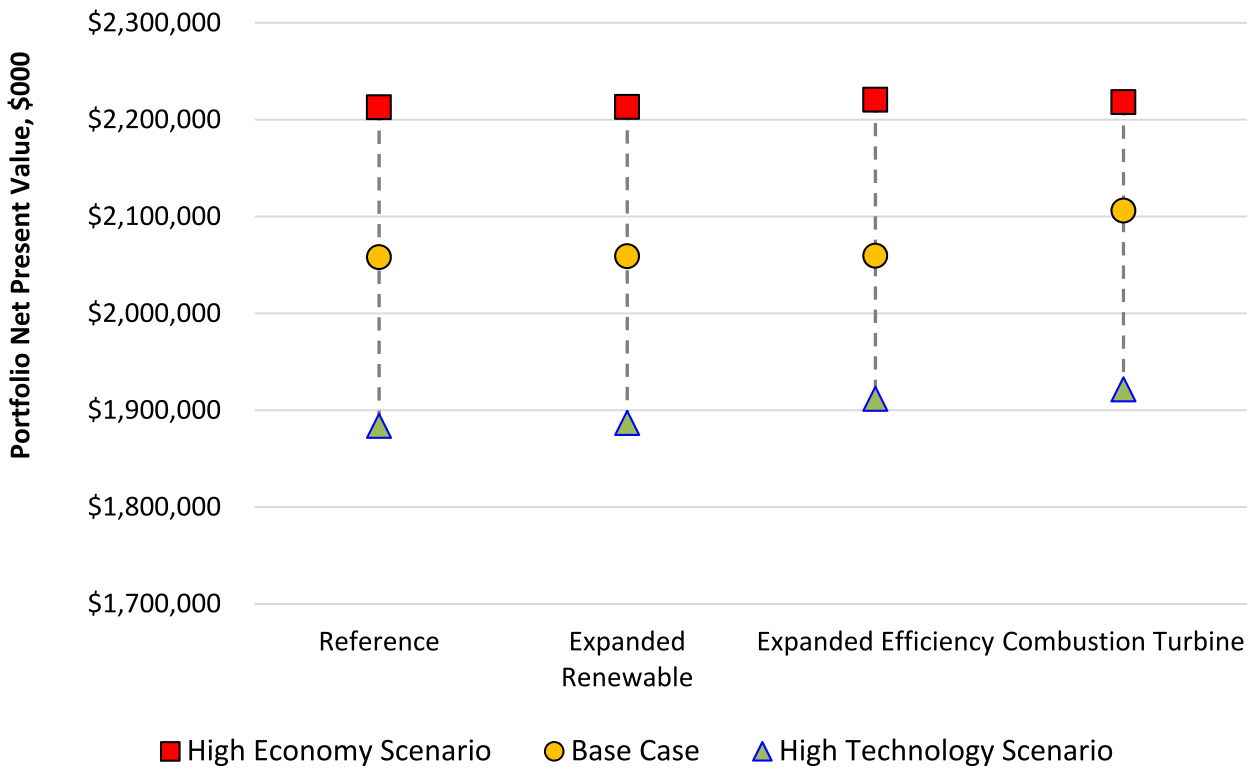
Major Assumptions	Reference	Expanded Renewables	Expanded Energy Efficiency	CT Option
Energy Efficiency	Fully compliant with the Arizona EE Standard (22% by 2020). From 2021 on, EE Programs based on EPRI's estimate of "Achievable" Savings.	Same as Reference Case Plan	Same as Reference Case Plan. From 2021 on, EE Programs based on EPRI's estimate of "High Achievable" Savings	Same as Reference Case Plan
Renewable Energy	Targets Serving 20% of Retail Load from both Utility Scale Renewables and Distributed Generation by 2020	Targets 20% through 2032, Additional 35MW Solar in 2025	Same as Reference Case Plan	Same as Reference Case Plan
Storage Resources	20 MW/20 MWh Staged from 2019 to 2028	Same as Reference Case Plan	Same as Reference Case Plan	Same as Reference Case Plan
Natural Gas Capacity Assumptions	138 MW NGCC in 2022 120 MWs RICE (2022 through 2032)	Same as Reference Case Plan	Same as Reference Case Plan	Replace 2022 NGCC with Combustion Turbines

Capital Expenditures (Nominal $millions)	Reference Case	Expanded Renewables	Expanded Energy Efficiency	CT Option
CapEx 2017-2024	$226	$226	$226	$253
CapEx 2025-2032	$132	$132	$132	$132
Total CapEx	$358	$358	$358	$385

Summary of NPV Revenue Requirements by Scenario

Chart 31 below summarizes the net present value revenue requirements (NPVRR) for each of the PACE scenarios modeled in the 2017 IRP. The Reference Case Plan results in the lowest cost portfolio under the Base Case, High Economy, and High Technology scenarios.

Chart 31 – NPV Revenue Requirements by Scenario



Summary of NPV Revenue Requirements – Base Case Scenario

Table 10 below summaries the NPVRR for each portfolio under the Base Case scenario.

Table 10 – NPV Revenue Requirements – Base Case Scenario

Non Fuel Revenue Requirements, $000	Reference	Expanded Renewable	Expanded Efficiency	CT
Existing T&D Resources	$597,914	$597,914	$597,914	$597,914
Existing Generation Resources	$274,639	$274,639	$274,639	$274,639
New Generation Resources	$215,796	$215,796	$215,796	$230,779
Storage Resources	$9,468	$9,468	$9,468	$9,468
New Renewable Resources	$0	$0	$0	$0
New Transmission Resources	$0	$0	$0	$0
Total Non-Fuel Revenue Requirements	$1,097,817	$1,097,817	$1,097,817	$1,112,800

Existing Transmission Expenses	$16,476	$16,355	$16,092	$16,650
Total Non-Fuel Revenue Requirements	$1,114,293	$1,114,172	$1,113,909	$1,129,450

Fuel & Purchased Power, $000	Reference	Expanded Renewable	Expanded Efficiency	CT
Total PPFAC Costs	$794,907	$796,074	$771,515	$827,916

Energy Efficiency and Renewables, $000	Reference	Expanded Renewable	Expanded Efficiency	CT
Energy Efficiency	$97,339	$97,339	$122,620	$97,339
Demand Response	$1,668	$1,668	$1,668	$1,668
Total Energy Efficiency	$99,007	$99,007	$124,288	$99,007

Total Renewables	$49,925	$49,925	$49,919	$49,925
Total Energy Efficiency and Renewables	$148,932	$148,932	$174,207	$148,932
Total System Revenue Requirements	**$2,058,132**	**$2,059,178**	**$2,059,631**	**$2,106,298**
NPV Difference from Reference Case		**$1,046**	**$1,499**	**$48,166**

Summary of NPV Revenue Requirements – High Economy Scenario

Table 11 below summaries the NPVRR for each portfolio under the High Economy scenario.

Table 11 – NPV Revenue Requirements – High Economy Scenario

Non Fuel Revenue Requirements, $000	Reference	Expanded Renewable	Expanded Efficiency	CT
Existing T&D Resources	$597,914	$597,914	$597,914	$597,914
Existing Generation Resources	$274,639	$274,639	$274,639	$274,639
New Generation Resources	$234,353	$234,353	$234,353	$239,925
Storage Resources	$9,979	$9,979	$9,979	$9,979
New Renewable Resources	$0	$0	$0	$0
New Transmission Resources	$0	$0	$0	$0
Total Non-Fuel Revenue Requirements	$1,116,885	$1,116,885	$1,116,885	$1,122,457
Existing Transmission Expenses	$16,977	$16,857	$16,579	$16,977
Total Non-Fuel Revenue Requirements	$1,133,862	$1,133,742	$1,133,464	$1,139,434

Fuel & Purchased Power, $000	Reference	Expanded Renewable	Expanded Efficiency	CT
Total PPFAC Costs	$937,008	$937,423	$919,924	$936,681

Energy Efficiency and Renewables, $000	Reference	Expanded Renewable	Expanded Efficiency	CT
Energy Efficiency	$97,339	$97,339	$122,620	$97,339
Demand Response	$1,668	$1,668	$1,668	$1,668
Total Energy Efficiency	$99,007	$99,007	$124,288	$99,007
Total Renewables	$43,103	$43,103	$43,099	$43,103
Total Energy Efficiency and Renewables	$142,110	$142,110	$167,387	$142,110
Total System Revenue Requirements	**$2,212,980**	**$2,213,275**	**$2,220,775**	**$2,218,225**
NPV Difference from Reference Case		**$295**	**$7,795**	**$5,245**

Summary of NPV Revenue Requirements – High Technology Scenario

Table 12 below summaries the NPVRR for each portfolio under the High Technology scenario.

Table 12 – NPV Revenue Requirements – High Technology Scenario

Non Fuel Revenue Requirements, $000	Reference	Expanded Renewable	Expanded Efficiency	CT
Existing T&D Resources	$597,914	$597,914	$597,914	$597,914
Existing Generation Resources	$274,639	$274,639	$274,639	$274,639
New Generation Resources	$190,196	$190,196	$190,196	$218,691
Storage Resources	$8,093	$8,093	$8,093	$8,093
New Renewable Resources	$0	$0	$0	$0
New Transmission Resources	$0	$0	$0	$0
Total Non-Fuel Revenue Requirements	$1,070,842	$1,070,842	$1,070,842	$1,099,337

Existing Transmission Expenses	$14,523	$14,471	$14,252	$14,523
Total Non-Fuel Revenue Requirements	$1,085,365	$1,085,313	$1,085,094	$1,113,860

Fuel & Purchased Power, $000	Reference	Expanded Renewable	Expanded Efficiency	CT
Total PPFAC Costs	$635,068	$638,071	$637,893	$637,195

Energy Efficiency and Renewables, $000	Reference	Expanded Renewable	Expanded Efficiency	CT
Energy Efficiency	$97,339	$97,339	$122,620	$97,339
Demand Response	$1,668	$1,668	$1,668	$1,668
Total Energy Efficiency	$99,007	$99,007	$124,288	$99,007

Total Renewables	$64,629	$64,629	$64,621	$64,629

Total Energy Efficiency and Renewables	$163,636	$163,636	$188,909	$163,636

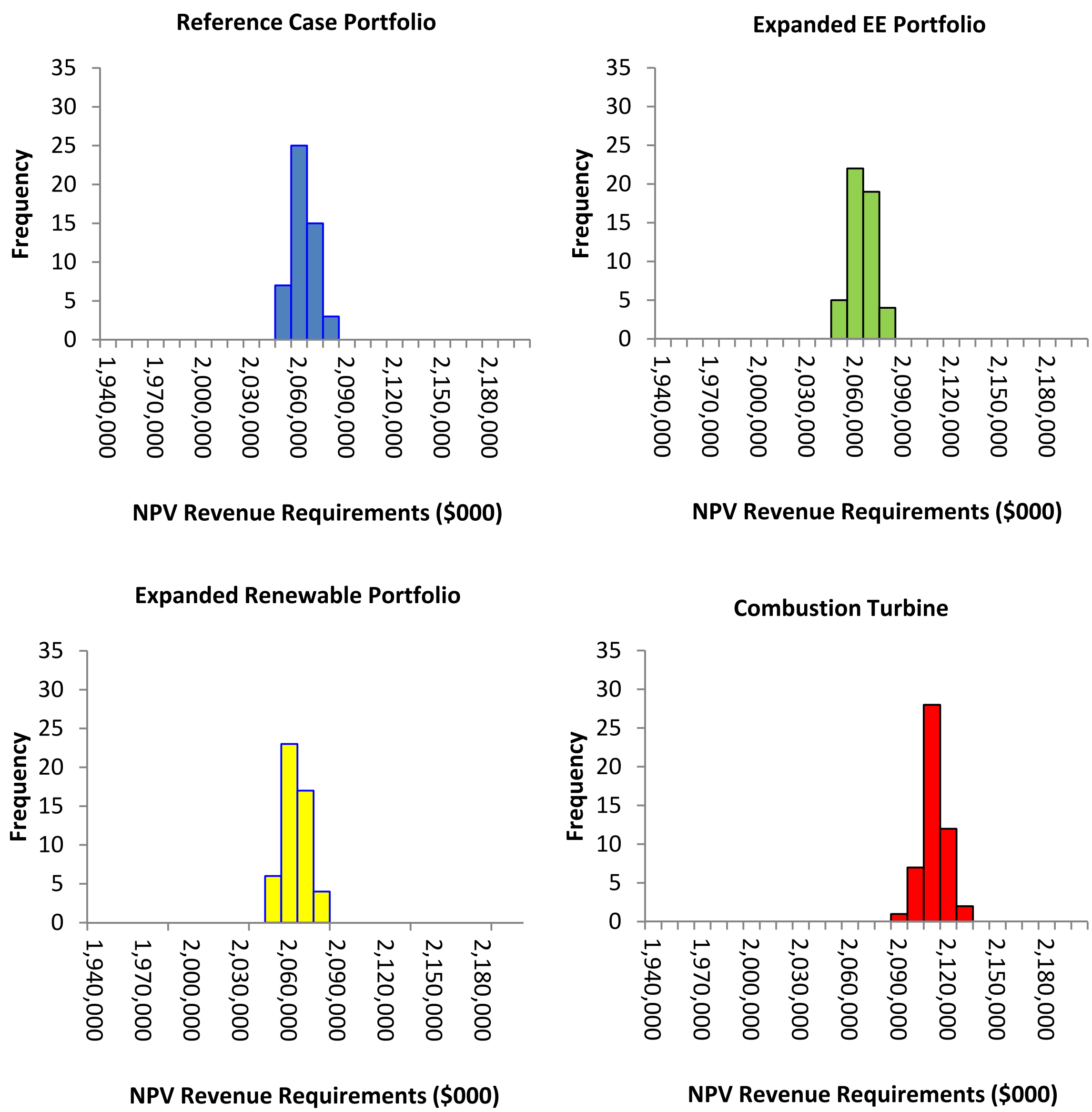
Total System Revenue Requirements	**$1,884,069**	**$1,887,020**	**$1,911,896**	**$1,914,691**

NPV Difference from Reference Case		**$2,951**	**$27,827**	**$30,622**

Distribution of NPV Revenue Requirements by Portfolio

The degree to which each portfolio is able to adequately meet future load serving requirements at a reasonable cost is measured by examining the distribution of its NPVRR outcomes for each portfolio across 50 stochastic iterations. The performance of each portfolio is summarized in the following charts. Chart 32 shows each histogram comparing the frequency of outcomes for each of the candidate portfolios. All histograms are represented on the same scale. Portfolios showing a large number of outcomes (higher bars) on the right side of the graph represent high cost options relative to the others resource portfolios. Higher risk is reflected by lower bars spread over more tranches.

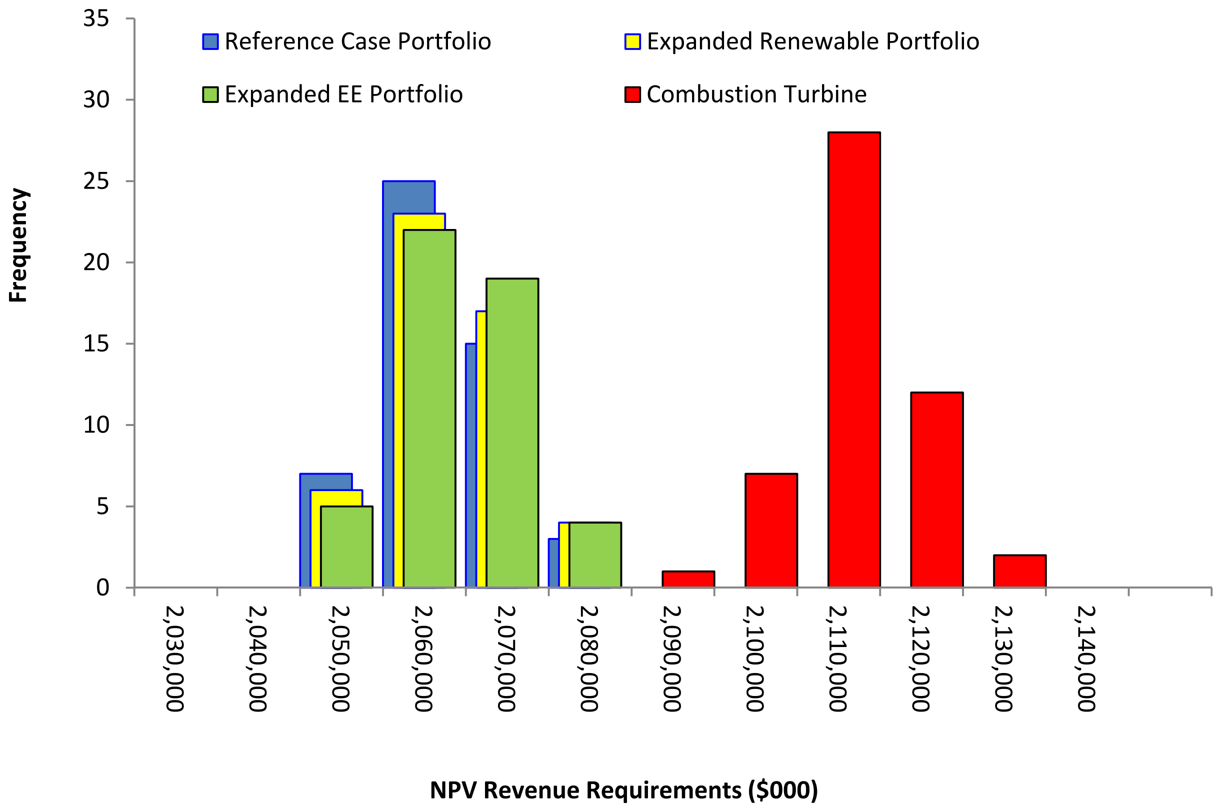
Chart 32 – Distribution of NPVRR by Portfolio



Distribution of NPV Revenue Requirements by Portfolio

Chart 33 below shows the distribution of NPVRR on the same chart.

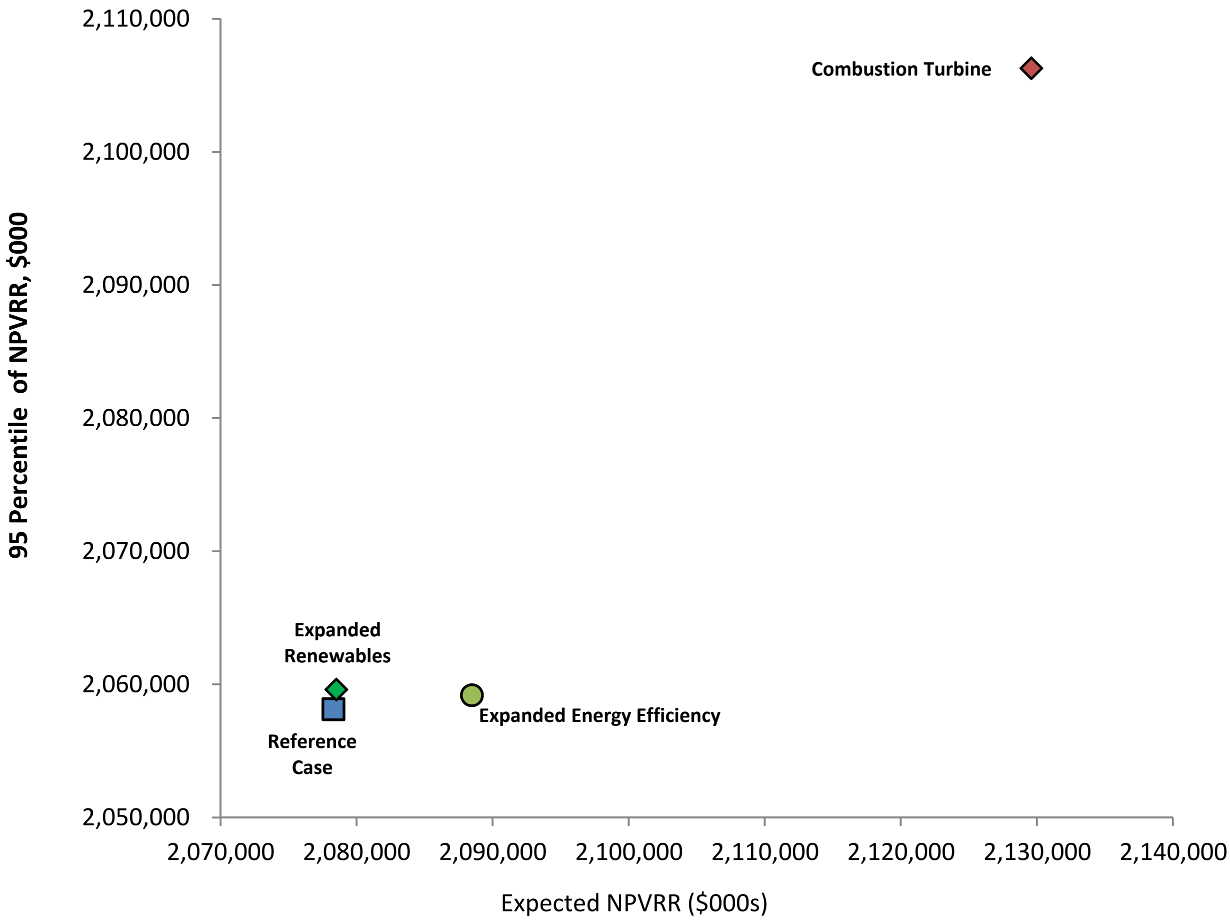
Chart 33 – Aggregated NPVRR by Portfolio



NPVRR Mean and Worst Case Risk

Chart 34 summarizes each portfolio with respect to both the expected average NPVRR and the "worst case" outcome risk as represented by the 95th percentile of its NPVRR outcomes. Values lower on the graph and farther to the left, represent lower risk and lower cost portfolios.

Chart 34 – Summary of NPVRR Mean and Risk



CHAPTER 10

FIVE-YEAR ACTION PLAN

The 2017 Reference Case plan was chosen as the preferred portfolio plan based on current forecasts and assumptions. UNSE has developed a five-year action plan based on the resource decisions that are contemplated in this IRP. Under this action plan, additional detailed study work will be conducted to validate all technical and financial assumptions prior to any final implementation decisions. UNSE's action plan includes the following:

- UNSE plans to continue with its community scale build out of renewable energy and expects to serve 20% of its retail load using renewable energy by 2020. Before the summer of 2017, UNSE will complete a 4.4 MWac solar fixed PV project, and in 2018 the Company is expecting that the 46 MWac Grayhawk Solar project will commence commercial operation. The addition of this project will put UNSE in compliance with the RES beyond the 15-year IRP planning period.

- In order to accommodate this high penetration of renewable energy resources, UNSE plans to add new fast-responding generating resources over the next five years. RICE and CTs are the preferred technologies that will provide capacity and assist in mitigating renewable energy intermittency and variability. UNSE intends to conduct a detailed Technology Assessment and/or issue a Request for Proposal (RFP) for fast-responding resources to be in service by 2022 timeline.

- UNSE will continue to implement cost-effective EE programs based on the Arizona EE Standard. UNSE will closely monitor its EE program implementations and adjust its near-term capacity plans accordingly. UNSE will continue to monitor closely and implement DR programs that are mutually beneficial to the Company and its customers.

- UNSE is optimistic about the potential of ESSs as a technology and as an economically viable solution to provide peak capacity and renewable intermittency mitigation. The Reference Case Plan includes the addition of a 5 MW battery project for 2019 and another 5 MWs for 2022. TEP will continue to monitor the advance of ESS and may opt to issue a RFP in the near future.

- UNSE's 2017 Reference Case Plan recommends the addition of 137 MW of NGCC capacity by 2022. As part of its near-term portfolio strategy, UNSE will continue to utilize the wholesale market for the purchase of short-term market based capacity products. In addition, UNSE will continue to monitor the wholesale market for other resource alternatives such long-term PPAs and near-term low cost plant acquisitions.

- UNSE and other Arizona utilities continue to evaluate the potential benefits of in-ground natural gas storage. Local storage would improve the ability of natural gas generation units to respond to changing loads as well as the intermittency caused by renewable resource. Due to the distance of Arizona's largest load pockets of Phoenix and Tucson from the San Juan and Permian natural gas production basins, local natural gas storage (if available and constructed) would be able to more quickly supply natural gas during shortfalls and store excess natural gas during periods when the natural gas mainlines experience operational limitations.

As with any planning analysis, the 2017 IRP represents a snapshot in time based on known and reasonable planning assumptions. UNSE plans to communicate any major change in its anticipated resource plan with the ACC as part of its ongoing planning activities. UNSE hopes this dialog will engage the Commission on important resource planning issues while providing UNSE with greater regulatory certainty with regards to future resource decisions. UNSE requests that the Commission approve its 2017 Integrated Resource Plan as provided in A.A.C. R14-2-704.B. and the associated actions herein.