


Tucson Electric Power

2016 Preliminary Integrated Resource Plan

March 1, 2016




Foreword

New environmental regulations, emerging technologies and changing energy needs have reinforced the importance of long-term resource planning to Tucson Electric Power ("TEP") and other electric utilities. Whatever the future may bring, our 2016 preliminary Integrated Resource Plan ("IRP") outlines our plan to ensure that TEP's safe, affordable and reliable service remains a constant in our complex, evolving industry.

We will continue to expand our use of cost-effective renewable energy resources and energy efficiency programs for customers. We expect our renewble energy portfolio to exceed 370 megawatts ("MW") by the end of 2016. We also will expand our energy effficiency resources through several new programs available this year. In the future, demand response partnerships with customers could help TEP manage peak load demands while reducing the need for new infrastructure.

As requested by the Commission, this preliminary IRP report addresses the status of emerging resource options like energy storage technologies and small nuclear reactors. Two 10-MW storage projects will be installed on TEP's local distribution system in 2016, and we will continue to evaluate the potential for other new technologies as part of our resource planning process.

We will study how natural gas-fired resources can be best used to replace existing coal capacity. While we remain open to the possibility of using additional natural gas power plants to meet base load requirements, we will also study fast-response generating resources like reciprocating natural gas engines, which can be used to stabilize intermittent renewable resources.

While the status of the Clean Power Plan ("CPP") is in question after the U.S. Supreme Court issued a stay suspending its enforcement pending further ligitation,TEP continues to evaluate its potential impact. The resource plan outlined in this document should put us in a strong position to comply with the new rules, which would require a 32-percent reduction in carbon dioxide ("CO_2") emissions from Arizona power plants.

Our drive to reduce CO_2 emissions must be balanced against our continued need for reliable, cost-effective generating resources, such as Springerville Generating Station ("SGS"). Although we previously decided to acquire half of Unit 1 upon the expiration of TEP's long-term lease, we are preparing for the potential acquisition of the other half as part of the resolution of ongoing legal disputes with the other co-owners of that 387-MW unit. TEP also owns Unit 2 at that eastern Arizona facility, so this would anchor our long-term baseload resource in our newest and most efficient coal plants.

TEP will continue to look for opportunities to economically reduce its interest in its other coal-fired facilities. Strategies may include changes in plant ownership shares, unit shutdowns or the sale of generation assets. We remain committed to a long-term strategy that diversifies our energy resource portfolio as demonstrated by recent coal plant retirement commitments at our Sundt and San Juan generating stations.

TEP will continue to look for new resource options and cost-effective ways of providing reliable electric service to our customers. We intend to provide more robust resource planning information in TEP's final IRP in 2017.

David G. Hutchens
President and CEO

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TABLE OF CONTENTS

CHAPTER 4 - EMERGING TECHNOLOGIES

CHAPTER 5 - OTHER RESOURCE PLANNING TOPICS

CHAPTER 6 - FUTURE RESOURCE ASSUMPTIONS

CHAPTER 7 - MARKET ASSSUMPTIONS & SCENARIOS

CHAPTER 8 - RISK ANALYSIS AND SENSITIVITIES

CHAPTER 9 - ACTION PLAN

Chapter 1

Executive Summary

Introduction

Tucson Electric Power Company's (TEP's or the Company's) 2016 preliminary Integrated Resource Plan ("IRP") introduces and discusses the issues that TEP plans to analyze in detail for the final 2017 Integrated Resource Plan. The purpose of this report is to provide regulators, customers and other interested stakeholders an opportunity to understand the current planning environment and provide feedback on the Company's future resource plans prior to the 2017 final IRP submittal on April 1, 2017.

In addition to providing a snapshot of TEP's current loads and resources, this report provides an overview of current resource cost assumptions, forward market conditions as well as a discussion on some new emerging technologies. This report also highlights a number of changes in the Company's resource plans since the 2014 IRP and discusses some of the new infrastructure requirements and policy decisions that must be addressed over the next few years.

2016 Preliminary Integrated Resource Plan Requirements

In accordance with Decision No. 75269 (Docket No. E-00000V-15-0094), the Commission ordered the Arizona load serving entities to file a preliminary IRP on March 1, 2016 with the final IRP report due April 1, 2017. This order stipulated that the preliminary IRP includes the following topics;

- Load Forecast
- Load and Resource Table (including technology discussion)
- Sources of Assumptions and Technologies Evaluated
- Status update on Company's plan to participate in the Energy Imbalance Market ("EIM")
- Scenarios Requested in 2014 IRP Decision (No. 75068)
    - Energy Storage
    - Small Nuclear Reactors
    - Expanded Renewables (including distributed resources): biogas, solar, wind, geothermal, etc.
    - Expanded Energy Efficiency/demand response/integrate demand side management (which shall include the effect of micro-grids and combined heat and power)
- Proposed Sensitivities
- Future Action Plan

Updates on TEP's Resource Planning Strategy Since the 2014 IRP

Coal Resources

H. Wilson Sundt Generating Station

In 2015, the depletion of the Company's existing coal inventory at the Sundt Generation Station and low natural gas prices supported the transition on Sundt Unit 4 from coal to natural gas two and half years ahead of the December 2017 deadline in its agreement with the Environmental Protection Agency ("EPA"). This transition to natural gas will reduce TEP's near-term fuel supply costs for customers and marks the end of Sundt's twenty seven years of operations on coal.

San Juan Generating Station

A key component of TEP's 2014 IRP was the planned reduction of coal capacity at the San Juan Generating Station ("San Juan"). In October 2014, the EPA published a final rule approving a revised State Implementation Plan ("SIP") covering Best Available Retrofit Technology ("BART") requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017 and the installation of Selective Non-Catalytic Reduction ("SNCR") on Units 1 and 4. In January 2016, a new coal supply and participant restructuring agreements became effective, which enables TEP to reduce its coal capacity at San Juan from 340 MW to 170 MW by the end of December 2017. These new agreements enable the Company to take advantage of significantly lower coal supply costs for the next seven years while providing a commercially viable option to exit San Juan Unit 1 in July 2022.

Four Corners Power Plant

As part of the previous 2014 IRP filing, TEP's resource plans assumed that the Company would maintain its ownership positions in Units 4 and 5 at the Four Corners Power Plant ("FCPP") through July 2031. This decision was a result of the negotiations between the co-owners at Four Corners and the EPA that resulted in an alternative BART compliance plan that required the permanent closure of Units 1, 2, and 3 by January 1, 2014 and installation and operation of Selective Catalytic Reduction ("SCR") controls on Units 4 and 5 by July 31, 2018. TEP expects the plant operator to complete the SCR upgrades on both units by April 2018.

Barring any future environmental regulations on the Navajo Nation that would significantly change the economics of the plant, TEP plans to remain a plant participant through the term of its existing coal supply ("CSA") agreement, which is July 2031. TEP will continue to evaluate the long-term viability of its coal operations at FCPP and will determine whether or not it will remain in the facility beyond 2031 in subsequent IRP planning cycles. TEP owns 110 MW or 7% of Four Corners Units 4 and 5.

Navajo Generating Station

In February 2013, the EPA issued a proposed BART rule for the Navajo Generating Station ("NGS") under the Regional Haze Rule of the Clean Air Act. EPA's proposal required SCR emission control technology to be installed on all three NGS units by 2018. Given the direct economic impacts a potential closure of NGS would have on the Navajo and Hopi Tribes, the EPA invited the plant owners to submit a "Better-than-Bart" alternative that would result in greater emission reductions than EPA's original proposal. As a result, a Technical Work Group ("TWG") was formed and consisted of representatives from the Central Arizona Water Conservation district, the Environmental Defense Fund, the Gila River Indian Community, the Navajo Nation, Salt River Project, the U.S. Department of the Interior, and Western Resource Advocates. In July 2013, the TWG submitted an alternative plan to the EPA for final consideration. The TWG proposal included two emission reduction alternatives that would achieve “Better-than-BART” results. Based on the current status of negotiations with the owner-participants of NGS, both Los Angeles Department of Water and Power (“LADWP”) and NV Energy (“NVE”) have made commitments to exit the project by the end of 2019. With the departure of LADWP and NVE, the remaining NGS participants will cease operations of one of three 750 MW units at the power plant by January 1, 2020 and consolidate the remaining ownership into the other two remaining units. In addition, the alternative that TWG proposed requires SCR controls to be installed by 2030 in order for the facility to remain in-service beyond that date. In light of the potential environmental emission guidelines under the Clean Power Plan, and the significant cost of SCR investments required to keep the plant in operation beyond 2030, the Company will evaluate the viability of its coal operations at NGS and will determine whether or not it will remain in the facility beyond 2030 in subsequent IRP planning cycles. TEP owns 168 MW or 7.5% of NGS Units 1-3.

Springerville Generating Station

Prior to 2015, TEP operated 387 MW or 100% of Springerville Unit 1 (“SGS Unit 1”) under operating leases and pursuant to project agreements entered into in 1986. Today, TEP owns 192 MW or 49.5% of SGS Unit 1. The remaining 195 MW or 50.5% of SGS Unit 1 is owned by two third-party owners (the “Co-Owners”). TEP continues to operate 100% of SGS Unit 1 pursuant to agreements entered into in 1986.

As part of the 2014 IRP, TEP was planning to use its expiring lease obligations to reduce its coal capacity commitments on SGS Unit 1 from 387 MW to 192 MW at the end of 2014. Beginning in late 2014, the Co-Owners instituted various legal proceedings against TEP regarding SGS Unit 1. Additionally, since January 2015, the Co-Owners have failed to pay their share of O&M and capital expenses of SGS Unit 1. In response, TEP filed a separate legal proceeding to recover these amounts. In February 2016, the parties agreed to a settlement of these legal matters, the terms of which include TEP’s acquisition of the Co-Owners interest in Unit 1, subject to FERC approval. This acquisition would result in a temporary increase in TEP’s coal-fired capacity.

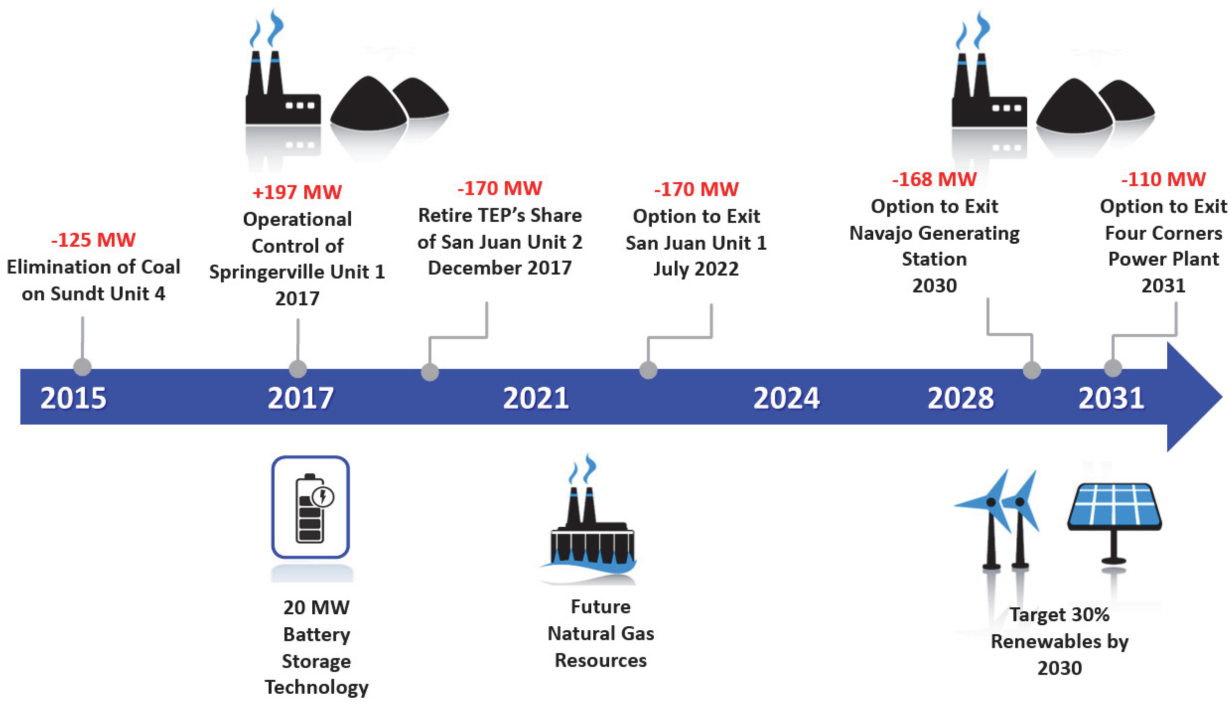
Overview of Coal-Fired Generation in Arizona and New Mexico

Chapter 5 provides a detailed summary on the remaining eight coal-fired generating plants located in Arizona and New Mexico. This summary on Page 63 provides an overview of current plant operations, ownership participation as well as an update on the status of current operating and coal supply agreements.

TEP's Long-Term Resource Diversification Strategy

As shown in Figure 1 below, TEP's existing generation fleet faces a number of uncertainties tied to plant participation and final outcomes on State Implementation Plans tied to the Clean Power Plan ("CPP"). Given this uncertainty, TEP may consider options that include changes in plant ownership shares, unit shutdowns or sale of generation assets to third parties. TEP is committed to follow through on its long-term portfolio diversification strategy to take advantage of other near-term opportunities to reduce its coal exposure at higher cost TEP owned coal facilities. TEP plans to file more details on its diversification strategy in the final IRP that is due April 1, 2017.

Figure 1 - TEP's Long Term Resource Diversification Strategy



Natural Gas Resources

Gila River Unit 3

In December 2014, TEP and UNS Electric acquired Unit 3 at the Gila River Generating Station for $219 million. Gila River Unit 3 is a 550 MW natural gas combined-cycle power plant located in Gila Bend, Arizona. Today, low natural gas prices make Gila River Unit 3 one of lowest cost generation assets for both TEP and UNS Electric. Gila River's fast ramping capabilities, along with its real-time integration into TEP's balancing authority, provide both TEP and UNS Electric with an ideal resource to support the integration of future renewables.

Transmission Resources

Pinal Central to Tortolita 500 kV Transmission Upgrade

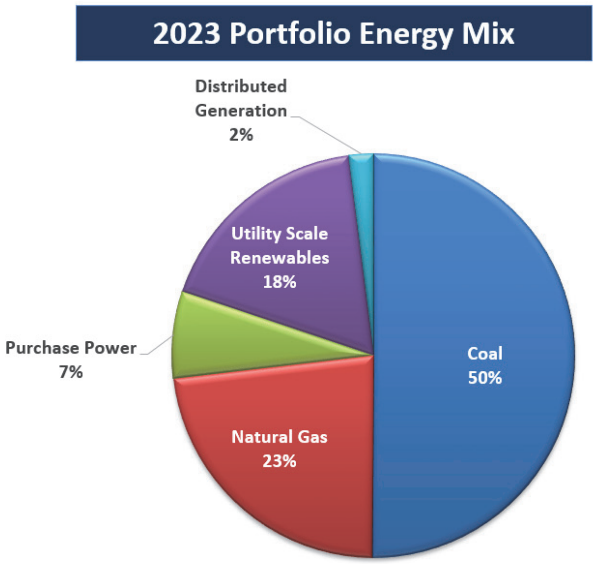
In November 2015, TEP energized its newest 500 kV transmission expansion project at Pinal Central. The Pinal Central to Tortolita line will help meet Tucson's future energy demands by adding a second extra high voltage ("EHV") transmission connection between Tucson and the Palo Verde wholesale power market. This line ties in the existing Salt River Project Southeast Valley transmission project that extends from Palo Verde to Pinal Central into Tortolita. This new transmission interconnection will further improve TEP's access to a wide range of renewable and wholesale market resources located in the Palo Verde area while improving TEP's system reliability.

Figure 2 - Tortolita Substation

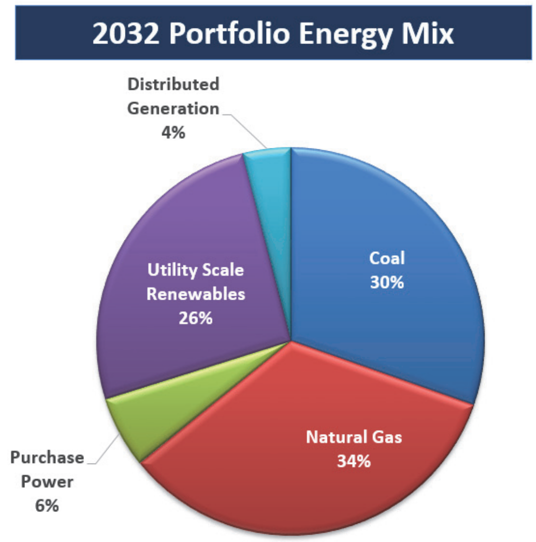
Targeting 30% Renewables by 2030

As stated in TEP's IRP filings and TEP's current rate case, the Company plans to meet a target of 30% of TEP's retail energy needs with renewable energy resources by 2030. This target is double that of the current Arizona Renewable Energy Standard that targets 15% by 2025 (A.A.C. R14-2-1804).

Figure 3 – TEP Portfolio Energy Mix



Results assume the exit from San Juan Unit 1 in 2022. Utility Scale Renewables and Distributed Generation reflect 20% of Retail Sales



Results assume the exit from Navajo Generating Station in 2030 and the Four Corners Power Plant in 2031. Utility Scale Renewables and Distributed Generation reflect 30% of Retail Sales

Supporting Future Renewable Integration

As part of this IRP planning cycle, TEP is evaluating a number of technologies to support TEP's ramp up in renewable resources. Technologies such as reciprocating engines and battery storage are two technologies being considered to support renewable integration.

Natural Gas Reciprocating Engines

Reciprocating engines, while not new technology, are emerging as potential alternatives in large-scale electric generation. Advances in engine efficiency and the need for fast-response generation make reciprocating engines a viable option to stabilize variable and intermittent electric demand and renewable resources. As part of the Company's commitment to target higher levels of renewables, TEP is evaluating the cost and operational characteristics of reciprocating engines as an alternative to both frame and aeroderivative natural gas combustion turbines. As part of the 2017 IRP filing, TEP plans to provide an in-depth analysis on costs, uses and potential benefits of this technology to support renewable integration.

Battery Storage

In the spring of 2015, TEP issued a request for proposals ("RFP") for the design and construction of utility-scale energy storage systems. Currently TEP is working with two vendors to finalize the plans for two 10 MW lithium ion battery storage projects. While 20 MW represents only 1% of TEP's peak retail load, these projects are large enough to have a measurable impact on supporting grid operations. Assuming the performance from these first two installations is favorable, TEP would then consider future energy storage projects as a viable option for regulation and frequency response to support the expanded use of renewable resources. Both of these projects await Commission approval through TEP's 2016 Renewable Energy Standard and Tariff Implementation Plan (A.A.C. R14-2-1813) (Docket E-01933A-15-0239). If approved, TEP anticipates that the pending storage projects will be in service during the early part of 2017. Chapter 6 provides more detail on these TEP specific projects along with an in-depth analysis by Lazard[1] on storage technologies that highlight storage costs, end-uses and technology combinations.

Energy Efficiency Implementation Plan

TEP's 2016 Energy Efficiency Implementation Plan, approved in February 2016 by the Arizona Corporation Commission, includes new programs and measures that can help customers save money, reduce impacts on the environment, and limit the long-term need for new energy resources.

The new offerings, which will become available in the coming months, include a program to help schools improve their energy efficiency. While schools may participate in other TEP Energy Efficiency programs, this new program will be developed specifically for their needs. Preference will be given to schools that have not recently installed energy efficiency measures.

In addition, TEP customers can now receive rebates for the purchase of energy efficient variable-speed pool pumps from qualified pool professionals. Variable-speed pumps last longer than regular pool pumps as they can be programmed to operate at high speed only when necessary. With proper calibration, variable-speed pumps can reduce energy use by 70 percent.

Another new program will provide instant discounts for residential customers who purchase certain Energy Star-certified products from participating retailers, including air conditioners and washing machines.

New incentives will be available to homeowners and apartment owners who improve the efficiency of their existing heating, ventilation and air conditioning, or HVAC, systems with "advanced tune-up" measures. "Tuning up" an existing HVAC system can cost significantly less than buying a new unit. Homeowners who arrange for a TEP-qualified HVAC professional to perform a thorough HVAC tune-up will receive a discount through the new program and will be eligible to purchase smart thermostats at a discount.

Since 2011, TEP has helped customers save more than 812,000 megawatt-hours, enough energy to power nearly 78,000 homes for a year. These savings help TEP work toward the goals in the Arizona Electric Energy Efficiency Standards ("EE Standard"), which calls on utilities to achieve cumulative energy savings of 22 percent by 2020.

[1] Lazard is a preeminent financial advisory and asset management firm. More information can be found at https://www.lazard.com

Compliance with the Clean Power Plan

On October 23, 2015, the EPA published a final rule regulating, for the first time, "CO_2" emissions from existing power plants. In general, this final rule, referred to as the "Clean Power Plan" ("CPP"), aims to reduce CO_2 emissions from U.S. power plants by 32% from 2005 levels by 2030. More specifically, the rule establishes emission guidelines based on EPA's determination of the "best system of emission reductions", which states and tribes (hereto referred to as "states") must use to set standards applicable to the affected plants in their jurisdictions.

Arizona is one of 27 states challenging the EPA's rule making authority and Arizona has filed suit against the EPA. On February 9, 2016, the United States Supreme Court issued a stay of the CPP[2] meaning that the rule has no legal effect pending the resolution of the state and industry challenge to the rule. That challenge is currently before the U.S. Court of Appeals for the D.C. Circuit, which will hear oral arguments on June 2, 2016. In all likelihood, this means a D.C. Circuit decision will not be issued until early fall, at the earliest. Given all that's at stake, either *en banc* review on the D.C. Circuit or a petition for certiorari likely will follow.

The CPP establishes emission goals for two subcategories of power plants in the form of an emission rate (lbs/MWh) that declines over the period from 2022 to 2030. Those subcategories are:

- Fossil fired steam electric generating units ("Steam EGUs") - includes coal plants and oil and natural gas-fired steam boilers
- Natural gas-fired combined-cycle plants ("NGCC")

Then using these rates ("Subcategory Rates") and the proportional generation from steam EGUs and NGCC plants in each state, the CPP derives state specific goals ("State Rates"). The CPP also converts these emission rate goals to total mass (i.e. short tons) goals for each state. Each state is required to develop a State Plan that will regulate the affected plants in their jurisdiction. TEP has affected plants in three separate jurisdictions, Arizona, New Mexico, and the Navajo Nation, and therefore, will be subject to three State Plans. Table 1 below shows the applicable rate goals.

Table 1 – CPP Rate Goals

CO_2 Rate (lbs/MWh)	2022-2024	2025-2027	2028-2029	2030+
Subcategorized Rate - Steam EGUs	1,671	1,500	1,308	1,305
Subcategorized Rate - NGCC	877	817	784	771
State Rate - Arizona	1,263	1,149	1,074	1,031
State Rate - New Mexico	1,435	1,297	1,203	1,146
State Rate - Navajo Nation	1,671	1,500	1,380	1,305

There are three primary forms of the State Plan available to states (with sub-options):

Rate Plants are required to meet an emission rate standard (lbs/MWh) equal to the plant's emissions divided by the sum of its generation and the generation from qualifying

[2] http://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf

renewable energy projects and/or verified energy efficiency savings. A rate plan could be administered through the use of emission rate credits ("ERCs"), where sources with emissions above the standard generate negative ERCs when they operate, and sources with emissions below the standard (or no emissions) generate positive ERCs. At the end of a compliance period, each affected plant must have at least a "zero" balance of ERCs.

Under the rate approach, states have the option of measuring compliance against the *State Rate* or the *Subcategory Rates*.

Mass

Plants are allocated (or otherwise acquire) allowances, the total of which equals the state's mass goal, and each plant must surrender an allowance for each ton of CO_2 emitted during a compliance period. Owners of plants that do not have sufficient allowances can reduce emissions by curtailing production, re-dispatching to a lower emission resource, or retiring the plant and re-distributing allowances to their remaining plants.

State Measures

Instead of regulating power plants directly, a state could implement policies that will have the effect of reducing emissions in their state such as building codes, renewable energy mandates or energy efficiency standards. Compliance is measured based on emissions from the affected plants.

Navajo Nation

In the proposed Federal Plan and Model Rules[3], EPA asked for comments on whether it was "necessary or appropriate" to regulate EGUs on the Navajo Nation under the CPP. TEP's parent company, UNS Energy Corporation, submitted comments stating that it was not appropriate or necessary to regulate the EGUs on the Navajo Nation because EGU retirements that have already occurred or are planned prior to 2022 will achieve essentially the same emission reductions as will be achieved through implementation of the CPP.

If the EPA determines that it is inappropriate or unnecessary to regulate EGUs on the Navajo Nation, then TEP will be relieved of any CPP requirements for the Navajo Generating Station and the Four Corners Power Plant. If EPA elects to proceed with regulating these EGUs under the CPP, details of that regulation will be provided in the final Federal Plan, which is expected later in 2016.

New Mexico

Rather than be subject to a Federal Implementation Plan, the State of New Mexico intends to submit a State Implementation Plan ("SIP") as well, believing that a New Mexico developed SIP will provide the flexibility needed to minimize costs passed on to its citizens. It has initiated a series of outreach meetings at different locations through the state. TEP attended a meeting on November 13, 2015 for owners of the affected plants. The State of New Mexico is the early stages of their state planning process and intends to submit an interim plan in September 2016, with a request for a two-year extension. However, the timing of this submittal will be delayed in light of the U.S. Supreme Court stay of the rule.

[3] Federal Plan Requirements for Greenhouse Gas Emissions for Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Frame Regulations; Proposed Rule [80 FR 64966] dated October 23, 2015

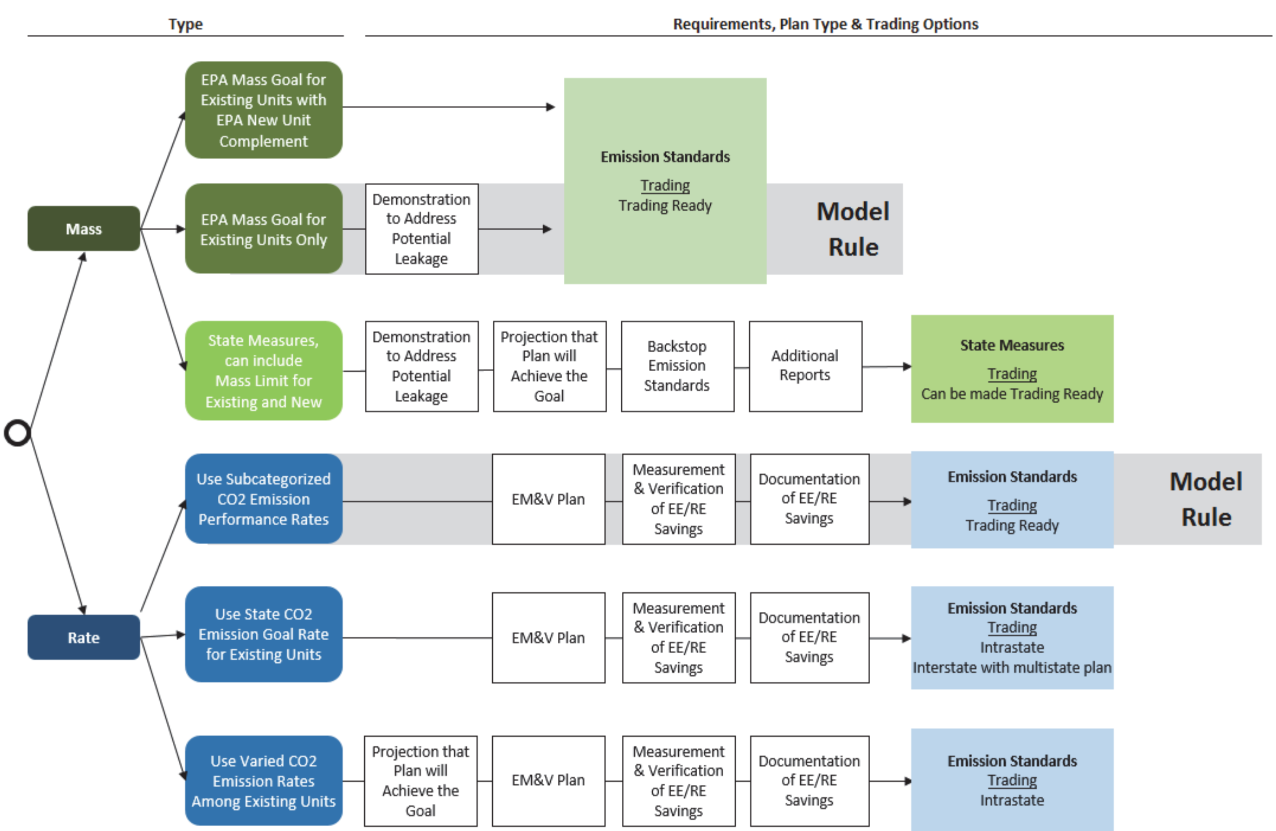
Arizona

The State of Arizona has been proactive in planning for CPP compliance. Following submittal of comments to EPA's proposed rule, and prior to the EPA issuing the final rule, the Arizona Department of Environmental Quality ("ADEQ") continued working with stakeholders, and through a series of meetings accumulated a list of Potential Compliance Strategies[4]. After the final rule was issued, ADEQ continued to meet with stakeholders and one of its initial steps was to develop 10 Principals of an Arizona Response to the Clean Power Plan[5]. During this phase of CPP planning ADEQ formed a Technical Working Group to assist in evaluating technical aspects of the plan.

The State of Arizona has previously stated it is committed to developing a State Plan. Due to the complexities inherent in developing a State Plan, the State of Arizona also indicated that it would file an interim plan prior to September 6, 2016, and request a two-year extension for filing the final State Plan. However, this timing will be delayed in light of the U.S. Supreme Court stay of the rule.

In preparing for the initial plan submittal, ADEQ organized the options for the form of a State Plan into subsets of Rate or Mass, and has expressed an interest in focusing on the most likely options.

Chart 1 – ADEQ Regulatory Framework Options[6]

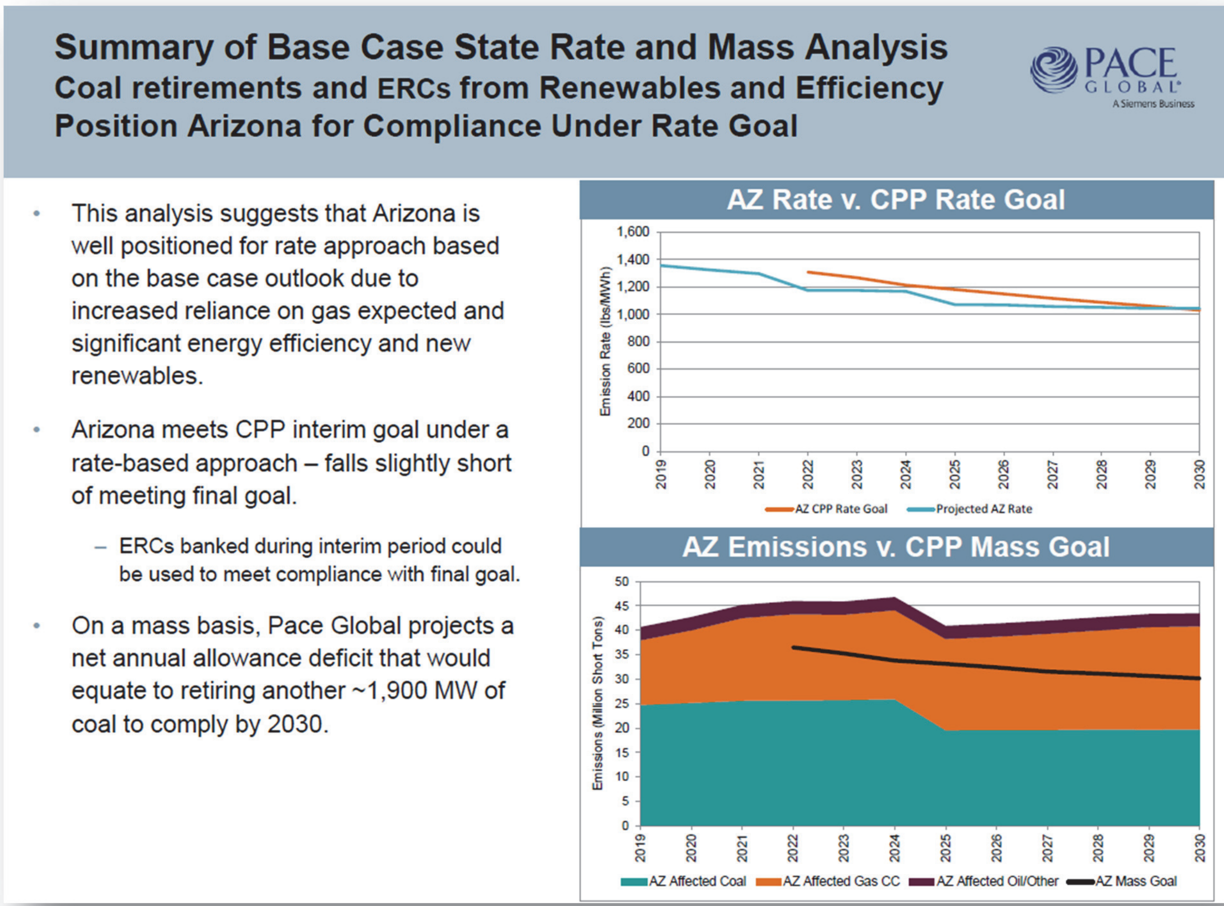


[4] http://www.azdeq.gov/environ/air/phasetwo.html
[5] http://www.azdeq.gov/environ/air/phasethree.html
[6] Ibid, ADEQ "EPA's Final Clean Power Plan: Overview, Steve Burr, AQD, SIP Section, September 1, 2015

PACE Global Arizona CPP Analysis

To help evaluate the relative benefits of Rate versus Mass for Arizona, the Arizona utilities hired PACE Global ("PACE") to conduct a modeling assessment of the relative compliance position compared to the State Rate and Mass goals based on a base case outlook. The results[7] of that assessment indicate that Arizona would likely fall short of the allowances needed to cover emissions using a mass approach. However, Arizona was able to meet the rate goals for the vast majority of the compliance period studied. A rate based plan, in general, better accommodates the need to meet future load growth with existing plants, and the subcategory rate approach is generally considered better for resource portfolios with a high percentage of coal-fired generation.

Figure 4 – PACE Global Arizona CPP Analysis



While the final legal status of the CPP has yet to be determined, it is worth noting that TEP's ongoing resource diversification plan is consistent with the goals of the CPP including reduced reliance on coal, and greater use of natural gas, renewable energy, and energy efficiency.

[7] More information can be found at ADEQ's website http://www.azdeq.gov/environ/air/phasethree.html#technical

Energy Efficiency in the Clean Power Plan

In the final rule, EPA identifies a variety of energy efficiency measures, programs, and policies that can count toward compliance of the CPP. These include utility and nonutility energy efficiency programs, building energy codes, combined heat and power, energy savings performance contracting, state appliance and equipment standards, behavioral and industrial programs, and energy efficiency in water and wastewater facilities, among others.

Energy Efficiency under Mass Based Compliance Programs

Under a mass based approach, energy efficiency inherently counts toward compliance and states can use an unlimited amount to help achieve their state goals. Energy efficiency inherently counts toward compliance under a mass based approach since it displaces actual fossil generation and the associated emissions under a mass cap, freeing up allowances for sources use towards their remaining effected EGUs or to trade. There is no limit on the use of energy efficiency programs and projects, and energy efficiency activities do not need to be approved as part of a state plan, therefore, Evaluation, Measurement and Verification (EM&V) is generally not required for mass based approaches under the Clean Power Plan.

Energy Efficiency under Rate Based Compliance Programs

Under rate based plans, quantified and verified megawatt hours (MWh) from eligible energy efficiency measures in a rate based state can be used to generate ERCs and adjust the CO_2 emission rate of an affected EGU, regardless of where the emission reductions occur. Energy efficiency under ate rate based plan must undergo EM&V. The final CPP gives states with rate based plans the ability to design their programs so that they are ready for interstate trading of ERCs, including those issued for energy efficiency, without the need for formal arrangements between individual states. These state plans recognize ERCs issued by any state that also uses a specified EPA approved or EPA administered tracking system.

Energy Efficiency and the Clean Energy Incentive Program ("CEIP")

EPA has also proposed an early credit option for states called the CEIP. The CEIP awards early credit for low-income energy efficiency programs and certain renewable energy projects implemented in 2020 and 2021. The program offers a two-to-one match for state energy efficiency savings in order to incent these efforts prior to the start of the compliance period. The final rule also requires states to incorporate the needs of low-income and underserved communities within their compliance plans, and fully engage these communities along with other stakeholders during the planning process.

Transmission and Distribution Efficiency Measures

EPA's final rule also allows transmission and distribution ("T&D") measures that improve the efficiency of the T&D system to count towards emission reductions and compliance options. This includes T&D measures that reduce line losses[8] of electricity during delivery from a generator to an end-user and T&D measures that reduce electricity use at the end-user, such as conservation voltage reduction (CVR)[9].

[8] T&D system losses (or ''line losses'') are typically defined as the difference between electricity generation to the grid and electricity sales. These losses are the fraction of electricity lost to resistance along the T&D lines, which varies depending on the specific conductors, the current, and the length of the lines. The Energy Information Administration (EIA) estimates that national electricity T&D losses average about 6 percent of the electricity that is transmitted and distributed in the U.S. each year.

[9] Volt/VAr optimization (VVO) refers to coordinated efforts by utilities to manage and improve the delivery of power in order to increase the efficiency of electricity distribution. VVO is accomplished primarily through the implementation of smart grid technologies that improve the real-time response to the demand for power. Technologies for VVO include load tap changers and voltage regulators, which can help manage voltage levels, as well as capacitor banks that achieve reductions in transmission line loss.

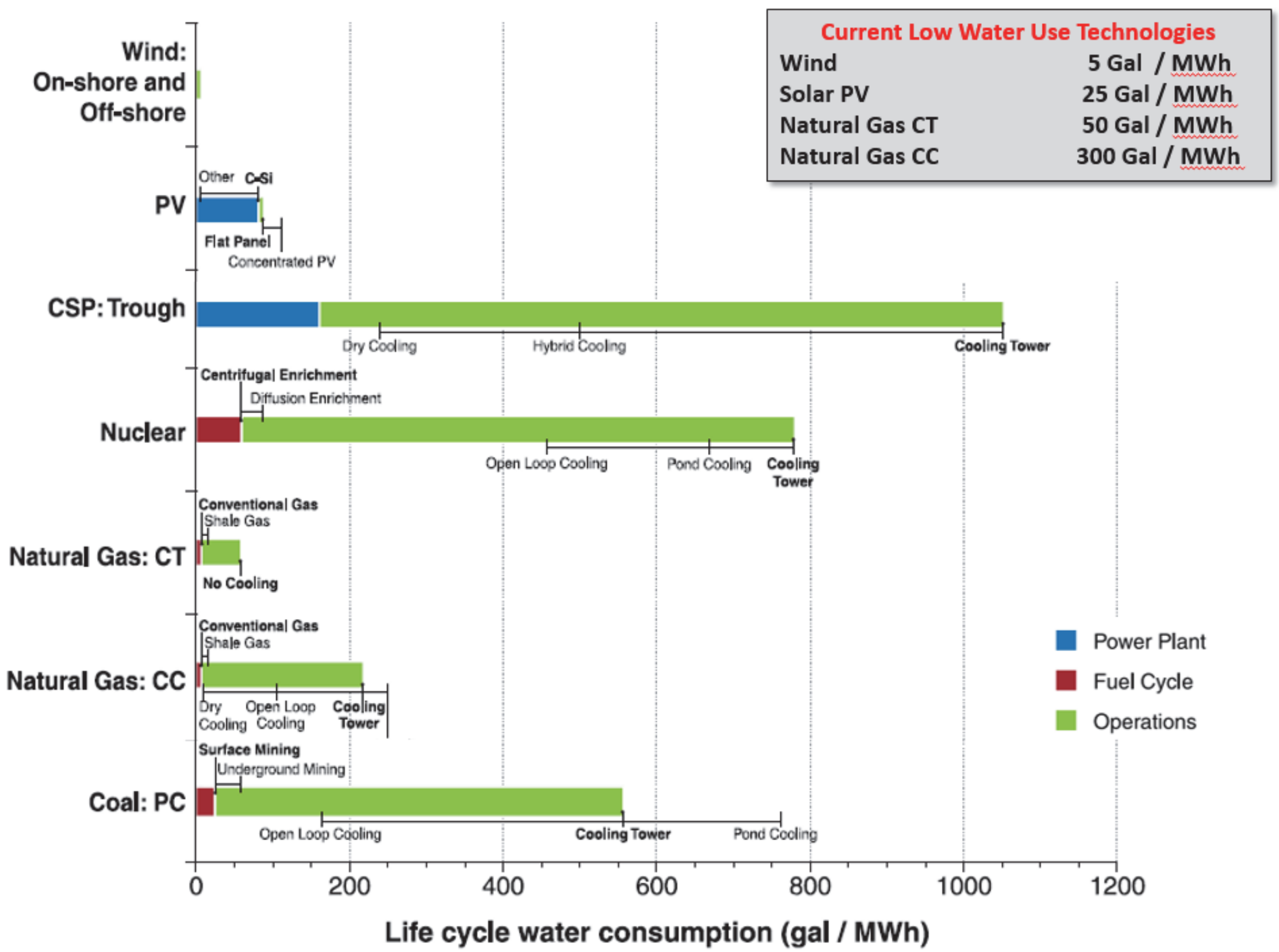
Planning for the Future of Energy Efficiency

TEP's energy efficiency programs will continue to comply with the Arizona Energy Efficiency Standard that targets a cumulative energy savings of 22 % by 2020. In future planning cycles, TEP plans to expand its energy efficiency resource portfolio to be compliant ready under the provisions of the CPP. TEP plans to partner with states and local organizations to leverage EPA’s CEIP to identify opportunities to improve energy efficiency for low and moderate income customers while supporting private sector and foundation initiatives. In the 2017 Final IRP, TEP plans to highlight the company's strategy on how it plans to make this transition. This transition from the current Arizona Energy Efficiency standard to compliance under the CPP will play a key role in achieving low cost energy alternatives for TEP's customers.

Power Generation and Water Impacts of Resource Diversification

The CPP achieves CO_2 emission reductions primarily by replacing generation from higher emitting coal-fired resources with a corresponding amount of generation from lower emitting NGCC plants and zero-emission renewable resources[10]. Fortunately, water use among these power generation technologies is analogous to their respective CO_2 emissions. See Chart 2 below for average water consumption rates for various electricity generation technologies. Based on these water consumption rates, implementation of the CPP should result in lower water consumption for power generation overall.

Chart 2 – Life Cycle Water Use for Power Generation[11]



However, unlike CO_2 emissions, water consumption has a much more localized environmental impact. The availability of water that is withdrawn from surface waters, as in the case of the Navajo Generating Station (Lake Powell), the Four Corners Power Plant (Morgan Lake and the San Juan River), and the San Juan Generating (San Juan River), is highly dependent on precipitation and snow pack, as well as other uses.

[10] Energy Efficiency is also an important tool for achieving the CO_2 emission reductions called for under the CPP.
[11] 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

Similarly, the availability of water that is withdrawn from groundwater aquifers, as in the case of Springerville, Sundt, Gila River, and Luna power plants, 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.

To the extent that the "replacement" power generation is located at or near to the coal-fired generation it is replacing, water availability will become less of an issue under CPP implementation. However, if the "replacement" power generation is located elsewhere, the water availability in that area may need to be evaluated.

There is over 6,000 MW of existing NGCC capacity located west of Phoenix, Arizona (in proximity to the Palo Verde Nuclear Generating Station) that is likely to see a significant increase in generation as a result of CPP implementation. While these generating facilities are expected to have the requisite legal rights to withdraw the amount of water necessary to meet expected higher demand for electricity, the risk associated with the cumulative impact of higher groundwater withdrawal on hydrogeological availability should be assessed. TEP plans to include a qualitative assessment as part of the 2017 Final IRP.

Chapter 2

LOAD FORECAST

In the IRP process, it is crucial to 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 resource plan, a long term load forecast is produced. This chapter will provide an overview of the anticipated long term load obligations at TEP, 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 surrounding a number of key forecast inputs.

Geographical Location and Customer Base

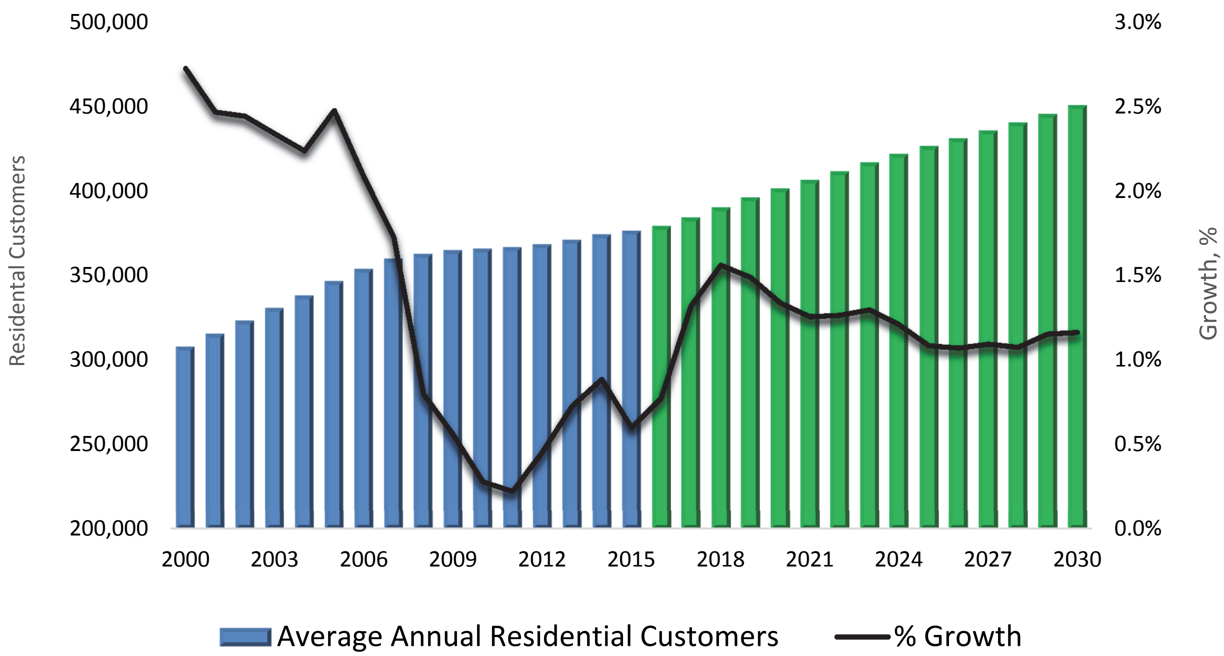
TEP currently provides electricity to more than 400,000 customers in the Tucson metro area (Pima County). Pima County has experienced positive growth over the last decade and is now estimated to have a population of approximately 1,000,000 people.

Tucson is the second-largest city in Arizona and the seat of Pima County. It is located in the southeast part of the state on the Santa Cruz River. Tucson is a growing, important and popular vacation destination. Visitors are attracted to its sunny, warm, and dry climate, making tourism an important component of the city's economy. TEP provides electric service to major industries in aerospace and defense systems and also to large electronic, biotechnology, optics and manufacturing companies in Tucson. Tucson also serves as a major commercial and distribution center for agricultural and mining industries. The city is also home to the University of Arizona, Pima Community College and other institutions of higher learning.

Customer Growth

In recent years, population growth in Pima County and customer growth at TEP have slowed dramatically as a result of the severe recession and subsequent economic weakness. While customer growth is currently rebounding from its recessionary lows, it is not expected to return to its pre-recession level. Chart 3 outlines the historical and expected customer growth in the residential rate class from 2000-2030. As customer growth is the largest factor behind growth in TEP's load, the continuing customer growth will necessitate additional resources to serve the increased load in the medium term.

Chart 3- Estimated TEP Customer Growth 2000-2030

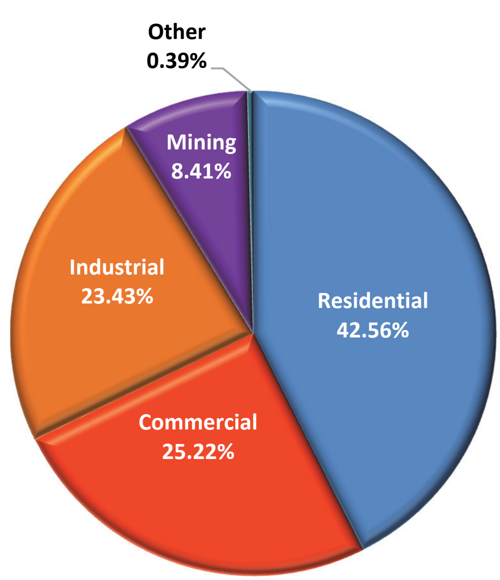


Retail Sales by Rate Class

In 2015, TEP experienced a retail peak demand of approximately 2,214 MW with approximately 9,026 GWh of sales. Approximately 68% of 2015 retail energy was provided to the residential and commercial rate classes and approximately 32% sold to the industrial and mining rate classes.

Chart 4 depicts a detailed breakdown of the estimated 2016 retail sales by rate class.

Chart 4 – Estimated 2016 Retail Sales % by Rate Class



Load Forecast Process

Methodology

The load forecast presented in this PIRP was derived using a "bottom up" approach. A monthly energy forecast was prepared for each of the major rate classes (residential, commercial, industrial, and mining). As the factors impacting usage in each of the rate classes vary significantly, the methodology used to produce the individual rate class forecasts also varies. However, the individual methodologies fall into two broad categories:

1) For the residential and commercial classes, forecasts are produced using statistical models. Inputs may 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 are produced for each individual customer on a case by case basis. Inputs include historical usage patterns, information from the customers themselves (e.g. timing and scope of expanded operations), and information from TEP staff who work closely with the mining and industrial customers.

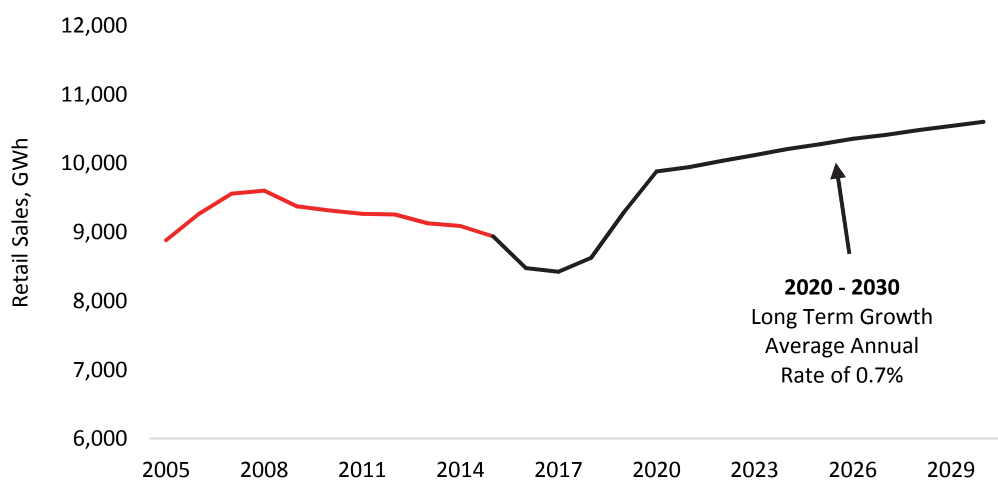
After the individual monthly forecasts are produced, they are aggregated (along with any remaining miscellaneous consumption) to produce a monthly energy forecast for the company.

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. The peak demand model is based on historical relationship between hourly load and weather, calendar effects, and sales growth. Once these relationships are estimated, more than 60 years of historical weather scenarios are simulated to generate a probabilistic peak forecast.

Retail Energy Forecast

As illustrated in Chart 5, after the period of relatively rapid growth from 2005 to 2008, TEPs weather-normalized retail energy sales experienced a gradual decrease. While use per customer is expected to remain weak over the near-term, the largest impact on near-term sales is the anticipated curtailment of copper mining operations recently announced by TEP's largest retail customer. TEP's forecast assumes that commodity prices will eventually recover and that mining loads will increase due to the resumption of existing mining operations and the anticipated addition of the Rosemont copper mine. After 2020, sales growth is dominated by residential and commercial sales but at a pace below the historical average.

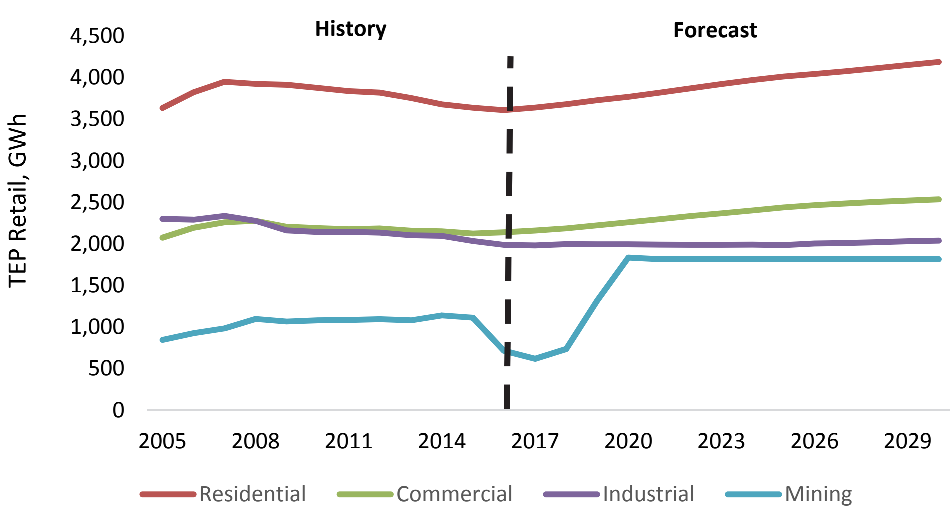
Chart 5 - Retail Energy Sales (Weather Normalized)



Retail Energy Forecast by Rate Class

The retail energy sales forecast assumes significant short-term changes for the next few years followed by slow steady growth beginning in 2020. However, the growth rates vary significantly by rate class. The energy sales trends for each major rate class are detailed in Chart 6.

Chart 6 - Retail Energy Sales by Rate Class

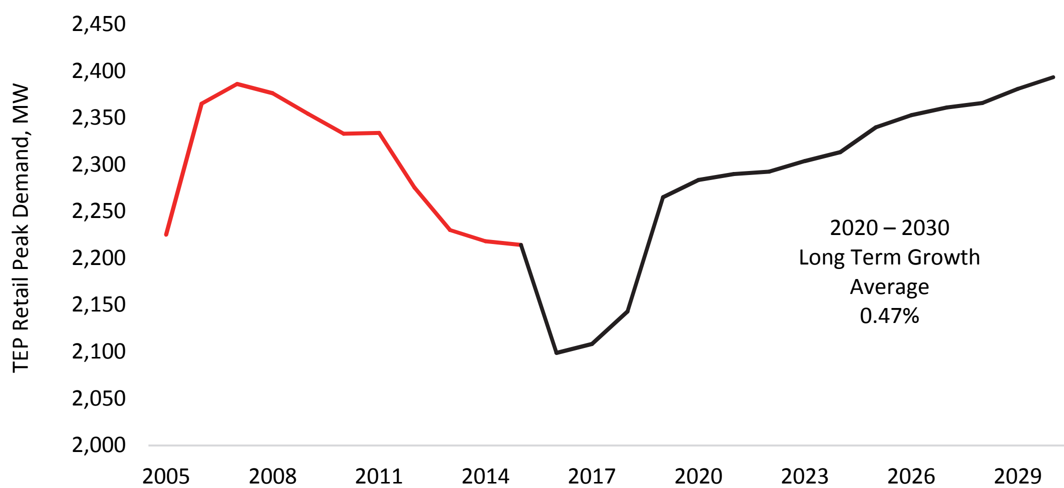


After experiencing consistent year-over-year growth throughout the past, both residential and commercial energy sales fell or remained flat from 2008 to 2015. Both classes are assumed in the Retail Energy Sales Forecast to increase steadily after 2016. However, industrial energy sales are expected to increase much more slowly than those in either the residential or commercial classes. In addition, mining sales are assumed to significantly fall in the coming years due to the known mine curtailment related to low commodity prices, and then rebound as these prices return to more historical averages.

Peak Demand Forecast

As shown in Chart 7 below, after declining from 2007 to 2015, demand is expected to drop in 2016. This is largely attributed to the mining class. Afterward, TEP's retail peak demand is expected to grow over time.

Chart 7 - Plan Peak Demand



Data Sources Used in Forecasting Process

As outlined above, the development of the load forecast is dependent on a broad range of inputs (demographic, economic, weather, etc.) and sources. For internal forecasting processes, TEP 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

Firm Wholesale Energy Forecast

In addition to retail sales directly to customers, TEP is currently under contract to provide wholesale energy and demand to five electric power customers:

1) Salt River Project ("SRP") through May 2016
2) Navajo Tribal Utility Authority ("NTUA") through December 2021
3) Tohono O'odham Utility Authority ("TOUA") through August 2019
4) Trico Electric Cooperative ("TRICO") through December 2024
5) Shell through December 2017
6) Navopache Electric Cooperative ("Navopache") from January 2017 through December 2041

TEP's 100 MW on-peak sales contract with Salt River Project expires in May of 2016. In the fall of 2015, TEP signed a new wholesale sales agreement with Navopache Electric Cooperative to provide wholesale energy beginning in January 2017. TEP's expected firm wholesale obligations, coincident to peak retail demand, are detailed Table 2 below. It is important to note that contract extensions have not been assumed. However, there is a possibility that any or all agreements could be extended. This would require current resource plans to be revised to account for the additional energy sales and peak summer load requirements.

Table 2 - Firm Wholesale Requirements

Firm Wholesale, GWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
SRP	205										
NTUA	253	262	266	277	288	291					
TOUA	26	26	26	17							
TRICO	40	31	83	112	133	127	163	182	185		
Shell	355	234									
Navopache		315	401	401	403	401	401	401	403	401	401
Total Firm Wholesale Sales	879	868	776	807	824	819	564	583	588	401	401

Coincident Peak Demand, MW	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NTUA	51	53	53	53	53	53					
TOUA	4	4	4	4							
TRICO	50	50	85	85	85	85	85	85	85		
Shell	100	100									
Navopache		44	44	44	44	44	44	44	44	44	44
Total Firm Demand	205	251	186	186	182	182	129	129	129	44	44

Summary of Load Forecast

A summary of the Retail and Firm Wholesale Load Forecast in presented in Table 3 , including reductions in load due to the impact of distributed generation and energy efficiency.

Table 3- TEP Forecast Summary

Retail Sales, GWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Customer Count, 000	420	426	432	438	444	449	455	460	466	471	475
Residential	3,608	3,638	3,679	3,727	3,767	3,817	3,869	3,921	3,969	4,012	4,043
Commercial	2,138	2,158	2,185	2,221	2,258	2,295	2,334	2,366	2,401	2,438	2,464
Industrial	1,986	1,980	1,995	1,993	1,993	1,988	1,988	1,987	1,988	1,983	2,003
Mining	713	617	735	1,317	1,833	1,813	1,813	1,813	1,818	1,813	1,813
Other	33	33	33	33	33	33	33	33	33	33	33
Total Retail	8,477	8,425	8,627	9,290	9,883	9,946	10,036	10,120	10,209	10,279	10,356

Residential Sales Growth %	-2.4%	0.8%	1.1%	1.3%	1.1%	1.3%	1.4%	1.3%	1.2%	1.1%	0.8%
Commercial Sales Growth %	0.5%	0.9%	1.3%	1.7%	1.6%	1.7%	1.7%	1.4%	1.4%	1.5%	1.1%
Industrial Sales Growth %	-3.5%	-0.3%	0.8%	-0.1%	0.0%	-0.2%	0.0%	0.0%	0.0%	-0.3%	1.0%
Mining Sales Growth %	-35.9%	-13.4%	19.1%	79.2%	39.2%	-1.1%			0.3%	-0.3%	
Other Sales Growth %	0.6%										
Total Retail Sales Growth %	-6.1%	-0.6%	2.4%	7.7%	6.4%	0.6%	0.9%	0.8%	0.9%	0.7%	0.8%

Firm Wholesale Sales, GWh	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
SRP	205										
NTUA	253	262	266	277	288	291					
TOUA	26	26	26	17							
TRICO	40	31	83	112	133	127	163	182	185		
Shell	355	234									
Navopache		315	401	401	403	401	401	401	403	401	401
Total Firm Wholesale	879	868	776	807	824	819	564	583	588	401	401

Retail Peak Demand, MW	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Retail Demand	2,109	2,122	2,153	2,336	2,414	2,417	2,424	2,439	2,446	2,479	2,512
Retail Demand Growth %	4.76%	0.62%	1.49%	8.47%	3.34%	0.14%	0.29%	0.64%	0.29%	1.34%	1.33%

Firm Wholesale Peak Demand, MW	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NTUA	51	53	53	53	53	53					
TOUA	4	4	4	4							
TRICO	50	50	85	85	85	85	85	85	85		
Shell	100	100									
Navopache		44	44	44	44	44	44	44	44	44	44
Total Firm Demand	205	251	186	186	182	182	129	129	129	44	44

Total Retail & Firm Peak Demand, MW	**2,314**	**2,372**	**2,339**	**2,521**	**2,595**	**2,599**	**2,553**	**2,568**	**2,575**	**2,523**	**2,537**

Chapter 3

TEP Loads and Resources

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

Table 4 – Firm Load Obligations, System Peak Demand (MW)on Page 34 summarizes TEP gross retail peak demands by year based on its January 2016 load forecast projections. These demands are broken down by customer class and the Company's assumptions on coincident peak load reductions from distributed generation and energy efficiency. In addition, TEP includes a summary of projected firm wholesale customer demands along with demand associated with system losses. Finally, Table 4 summarizes the Company's reserve margin positions based on the capacity resources shown in Table 5.

Table 5 on Page 35 summarizes TEP's firm resource capacity based its current planning assumptions related to its coal and natural gas resources. Table 5 also reflects TEP's plan to source 30% of TEP's retail loads from renewable generation resources by 2030. Additional resources such as demand response programs, short-term market purchases along with capacity sourced from its proposed battery storage project are also shown in the TEP resource portfolio. Based on TEP's assumptions in this March 1, 2016 filing, the Company is showing 15% reserve margin for both 2016 and 2017. Beyond 2017, TEP plans to file its Reference Case plan in April 2017 that will detail its strategy to meet both its short and long-term resource requirements over the fifteen year IRP planning horizon. Chart 8 on Page 36 shows a visual depiction of the Company's loads and resource assessment.

Future Load Obligations

The tables shown on the next two pages provide a data summary on TEP's loads and resources. Table 4 below shows TEP's projected firm load obligations which includes retail, firm wholesale, system losses and planning reserves.

Table 4 – Firm Load Obligations, System Peak Demand (MW)

Demand, MW	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential	1,139	1,101	1,115	1,212	1,259	1,269	1,281	1,296	1,308	1,332	1,354	1,377	1,401	1,425	1,455	1,473	1,494
Commercial	508	479	475	516	536	540	545	552	557	567	576	586	596	606	619	627	636
Industrial	485	444	443	482	500	504	509	515	520	529	538	547	557	566	578	586	594
Mining	124	292	337	366	380	383	387	392	395	402	409	416	423	430	439	445	451
Other	28	5	5	5	5	5	5	6	6	6	6	6	6	6	6	6	6
Gross Retail Peak Demand	2,284	2,321	2,375	2,581	2,680	2,703	2,728	2,760	2,785	2,836	2,882	2,933	2,983	3,034	3,097	3,137	3,182

Distributed Generation	-32	-35	-39	-42	-45	-48	-51	-54	-56	-58	-59	-60	-62	-63	-65	-68	-69
Energy Efficiency	-143	-163	-183	-202	-221	-237	-253	-268	-283	-299	-312	-327	-341	-356	-383	-394	-411
Net Retail Peak Demand	2,109	2,122	2,153	2,336	2,414	2,417	2,424	2,439	2,446	2,479	2,512	2,546	2,580	2,615	2,650	2,676	2,702

Firm Wholesale Demand	205	251	186	186	182	182	129	129	129	44	44	44	44	44	44	0	0
System Losses	209	211	214	232	240	240	241	242	243	246	249	253	256	260	263	266	268
Total Firm Load Obligations	2,524	2,583	2,552	2,754	2,835	2,839	2,794	2,810	2,818	2,769	2,806	2,843	2,880	2,919	2,957	2,942	2,970

Reserve Margin	432	457	74	-108	-159	-144	-243	-246	-227	-166	-169	-206	-211	-244	-250	-402	-541
Reserve Margin, %	15%	15%	3%	-4%	-6%	-5%	-10%	-10%	-9%	-6%	-6%	-8%	-8%	-9%	-9%	-16%	-22%

System Resource Capacity

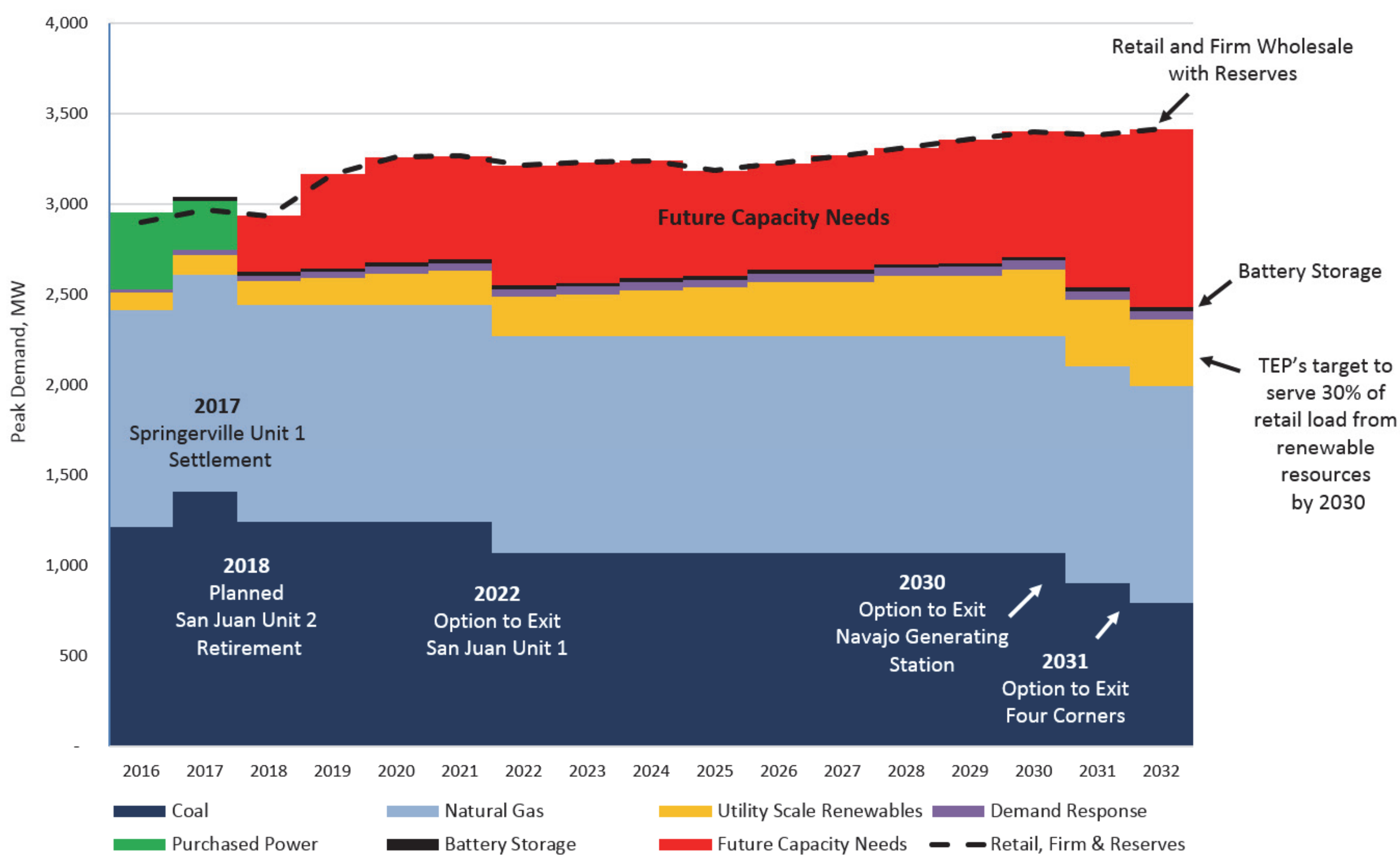
Table 5 shows TEP's preliminary firm resource capacity based on a resource's contribution to system peak.

Table 5 – Capacity Resources, System Peak Demand (MW)

Firm Resource Capacity (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	
Navajo	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168		
San Juan	340	340	170	170	170	170											
Springerville	598	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793
Remote Coal Resources	1216	1411	1241	1241	1241	1241	1071	1071	1071	1071	1071	1071	1071	1071	1071	903	793
Sundt 1-4	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422
Luna Energy Facility	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
Gila River Power Station	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374
DeMoss Petrie CT	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
North Loop CT 1-4	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Sundt CT 1-2	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Total Natural Gas Resources	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Utility Scale Renewables	97	110	136	149	176	189	215	228	255	268	301	301	334	334	367	367	367
Demand Response	19	24	29	35	40	45	45	45	45	45	45	45	45	50	50	50	50
Total Renewable & EE Resources	116	134	165	184	216	234	260	273	300	313	346	346	379	384	417	417	417
Short-Term Market Resources	425	275	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Storage Resources	0	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Total Firm Resources	2956	3040	2626	2645	2677	2695	2551	2564	2591	2604	2637	2637	2670	2675	2708	2540	2430

Preliminary Loads and Resource Assessment

Chart 8 – TEP's 2016 Preliminary Loads and Resource Assessment



Community Scale Renewables and Distributed Generation

Renewable Overview

Over the last several years, TEP has constructed or entered into power purchased agreements ("PPAs") for solar and wind resources to provide renewable energy for its service territory. This is part of TEP's commitment to meeting the Arizona Annual Renewable Energy Requirement of 15% by 2025 as set forth in A.A.C. R14-2-1804 (the "Annual Renewable Energy Requirement"). Table 6 below lists TEP's existing and planned renewable resources.

Table 6 – TEP's Existing Renewable Resources

Resource- Counterparty	Owned/PPA	Location	Operator-Manufacturer	Completion/ Estimated Date	Capacity MW
Fixed Photovoltaic					
Springerville	Owned	Springerville, AZ	Various	Dec-2010	6.4
Solon UASTP III	Owned	Tucson, AZ	Solon	Jan-2012	5
Gato Montes	PPA	Tucson, AZ	Astrosol	Jun-2012	6
Solon Prairie Fire	Owned	Tucson, AZ	Solon	Oct-2012	5
TEP Warehouse	Owned	Marana, AZ	Various	2012	0.5
Ft Huachuca I	Owned	Sierra Vista, AZ	Solon	Dec-2014	17.2
Ft Huachuca II	Owned	Sierra Vista, AZ	Solon	Q3 2016	5
Community Solar	Owned	Tucson, AZ	TBD	Q4 2016	5
Single-Axis Tracking Photovoltaic					
Solon UASTP I	Owned	Tucson, AZ	Solon	Dec-2010	1.6
E.On UASTP	Owned	Tucson, AZ	Suntech	Dec-2010	6.6
FRV Picture Rocks	PPA	Tucson, AZ	MEMC	Oct-2012	25
NRG Solar Avra Valley	PPA	Tucson, AZ	First Solar	Oct-2012	35
E.On/TEP Valencia	PPA	Tucson, AZ	Areva	Jul-2013	13.2
Avalon Solar I	PPA	Sahuarita, AZ	Avalon	Dec-2014	35
Red Horse Solar	PPA	Willcox, AZ	Torch	Sep-2015	51.25
Avalon Solar II	PPA	Sahuarita, AZ	Avalon	Feb-2016	21.53
Concentrated Photovoltaic					
Amonix UASTP II	PPA	Tucson, AZ	Amonix	Apr-2011	2
Cogenera	PPA	Tucson, AZ	Cogenera	Jul-2014	1.38
Areva Solar	Owned	Tucson, AZ	Areva	Dec-2014	5
Wind					
Macho Springs	PPA	Deming, NM	Element Power	Nov-2011	50.4
Red Horse Wind	PPA	Willcox, AZ	Torch	Sep-2015	30

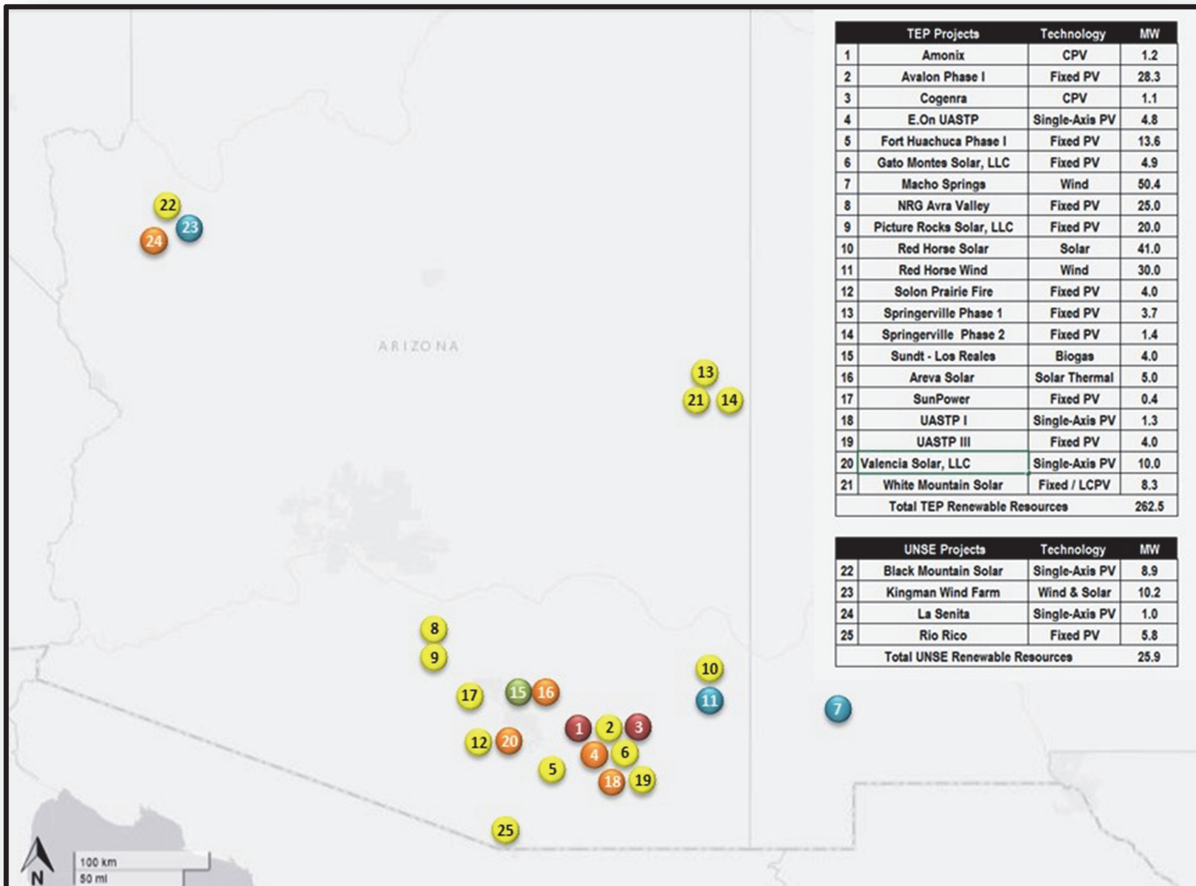
Community Scale Renewables

TEP's current renewable acquisition strategy focuses on developing a number of small to mid-scale renewable projects diversified across a wide-range of technologies, projects and counterparties. The table above lists the existing and contracted renewable energy projects in TEP's resource mix. In the 2014 IRP, TEP had a combined total of approximately 157 MW of renewable projects in service as of the April 1, 2014 filing. Since then, TEP has added an additional 161 MW of renewable projects and plans to have approximately 328 MW of renewable projects on line by the end of 2016[12]. TEP is currently over-compliant on the RES and expects to continue to meet or exceed the standard. The 2017 Final IRP to be filed in April of 2017 will detail TEP's expanded commitment to renewable energy.

[12] Project totals represent AC capacities of owned and contracted renewable resources.

Locations of UNS Renewables Projects

Figure 5 – UNS Renewable Projects



	TEP Projects	Technology	MW
1	Amonix	CPV	1.2
2	Avalon Phase I	Fixed PV	28.3
3	Cogenra	CPV	1.1
4	E.On UASTP	Single-Axis PV	4.8
5	Fort Huachuca Phase I	Fixed PV	13.6
6	Gato Montes Solar, LLC	Fixed PV	4.9
7	Macho Springs	Wind	50.4
8	NRG Avra Valley	Fixed PV	25.0
9	Picture Rocks Solar, LLC	Fixed PV	20.0
10	Red Horse Solar	Solar	41.0
11	Red Horse Wind	Wind	30.0
12	Solon Prairie Fire	Fixed PV	4.0
13	Springerville Phase 1	Fixed PV	3.7
14	Springerville Phase 2	Fixed PV	1.4
15	Sundt - Los Reales	Biogas	4.0
16	Areva Solar	Solar Thermal	5.0
17	SunPower	Fixed PV	0.4
18	UASTP I	Single-Axis PV	1.3
19	UASTP III	Fixed PV	4.0
20	Valencia Solar, LLC	Single-Axis PV	10.0
21	White Mountain Solar	Fixed / LCPV	8.3
	Total TEP Renewable Resources		262.5

	UNSE Projects	Technology	MW
22	Black Mountain Solar	Single-Axis PV	8.9
23	Kingman Wind Farm	Wind & Solar	10.2
24	La Senita	Single-Axis PV	1.0
25	Rio Rico	Fixed PV	5.8
	Total UNSE Renewable Resources		25.9

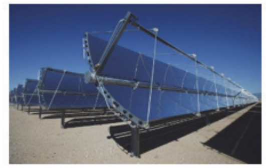
Distributed Generation

By the end of 2015, TEP had approximately 86 MW of rooftop solar PV and solar hot water heating capacity. Distributed generation is expected to supply at least 159 GWh of energy in 2016. Only a small portion of this generation is attributable to TEP's rooftop solar plan that was initiated in 2015.

Overview of the UNS Renewable Portfolio

Amonix
Dual Axis Concentrated PV
1.2 MW

Avalon
Fixed PV
28.3 MW



Cogenra
SAT Concentrated Thermal PV
1.1 MW

E. ON.
Single Axis Tracking PV
4.8 MW

Fort Huachuca
Fixed PV
13.6 MW

Gato Montes Solar
Fixed PV
4.9 MW

Macho Springs
Wind
50.4 MW

NRG Avra Valley
Fixed PV
25 MW

Picture Rocks Solar
Fixed PV
20 MW

Red Horse Solar
Fixed PV
40 MW

Red Horse Wind
Wind
30 MW

Solon Prairie Fire
Fixed PV
4.0 MW

Springerville
Fixed PV
5.1 MW

Los Reales Landfill Gas
Biogas
4.0 MW

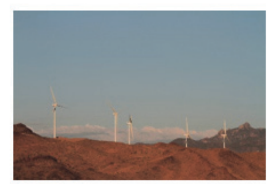
Areva Solar
Concentrated Solar Thermal
5.0 MW

Valencia Solar
Single Axis Tracking PV
10 MW

Solon UASTP 1
Single Axis Tracking PV
1.3 MW
500 kW of Lithium-Ion
Battery Storage

Solon UASP 3
Fixed PV
4.0 MW

White Mountain Solar
SAT Concentrated Thermal PV
8.3 MW



Kingman Wind & Solar
Wind & Fixed PV
10.2 MW

Energy Efficiency

Overview

This section is an overview of the Demand-Side Management ("DSM") programs that target the residential, commercial and industrial ("C&I") sectors, as well as their associated proposed implementation costs, savings, and cost-benefit results.

TEP recognizes that energy efficiency can be a cost-effective way to reduce our reliance on fossil fuels. TEP offers a variety of energy saving options for customers, from simple consultation to incentives that encourage both homeowners and businesses to invest in efficient heating and cooling and other energy efficiency upgrades.

TEP, with input from other parties such as Navigant Consulting, Inc. ("Navigant") and the Southwest Energy Efficiency Project ("SWEEP"), has designed a comprehensive portfolio of programs to deliver electric energy and demand savings to meet the annual DSM energy savings goals outlined in the 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 trade allies to apply as much leverage as possible to augment the return of rate-payer dollars invested.

Through TEP's DSM programs TEP continues to make great strides toward meeting the aggressive goals in the Standard. The Standard calls on investor-owned electric utilities in Arizona to increase the kilowatt-hour savings realized through customer ratepayer-funded energy efficiency programs each year until the cumulative reduction in energy achieved through these programs reaches 22 percent by 2020.

Current Implementation Plan, Goals, and Objectives

TEP's high-level energy efficiency-related goals and objectives are as follows:

- Implement cost-effective energy efficiency programs.
- Design and implement a diverse group of programs that provide opportunities for participation for all customers.
- When feasible, maximize opportunities for program coordination with other efficiency programs (e.g., Southwest Gas Corporation, Arizona Public Service Corporation) to yield maximum benefits.
- Maximize program energy savings at a minimum cost by striving to achieve comprehensive cost-effective savings opportunities.
- Provide TEP customers and contractors with web access to detailed information on all efficiency programs (residential and commercial) for electricity savings opportunities at www.tep.com.
- Expand the energy efficiency 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, architects and engineers to transform the market for efficient technologies.
- Educate customers to modify behavior modifications that enable them to use energy more efficiently.

Program Portfolio Overview

As illustrated in Table 7, TEP's portfolio of programs can be divided into residential, behavioral, C&I, support, and utility improvement sectors, with administrative functions providing support across all program areas. With the Commission's approval of TEP's 2016 EE Plan, TEP has added new programs and measures within existing programs including energy star appliances, smart thermostats, home energy reports, schools (pilot program), HVAC, and lighting measures.

Table 7 - TEP Portfolio of Programs

Residential Sector	Appliance Recycling
	Energy Star Appliances
	Existing Homes
	Home Energy Reports
	Low Income Weatherization
	Multi-Family Homes
	New Construction
	Shade Trees
Behavioral Sector	Community Education
	K-12 Energy Education
Commercial & Industrial Sector	C&I Comprehensive
	Small Business Direct Install/Schools
	Commercial New Construction
	Bid for Efficiency
	Retro-Commissioning
	Combined Heat & Power
Support Sector	Consumer Education and Outreach
	Energy Codes and Standards Enhancement
Utility Improvement Sector	Conservation Voltage Reduction
	Generation Improvement and Facilities Upgrade
	C&I Direct Load Control

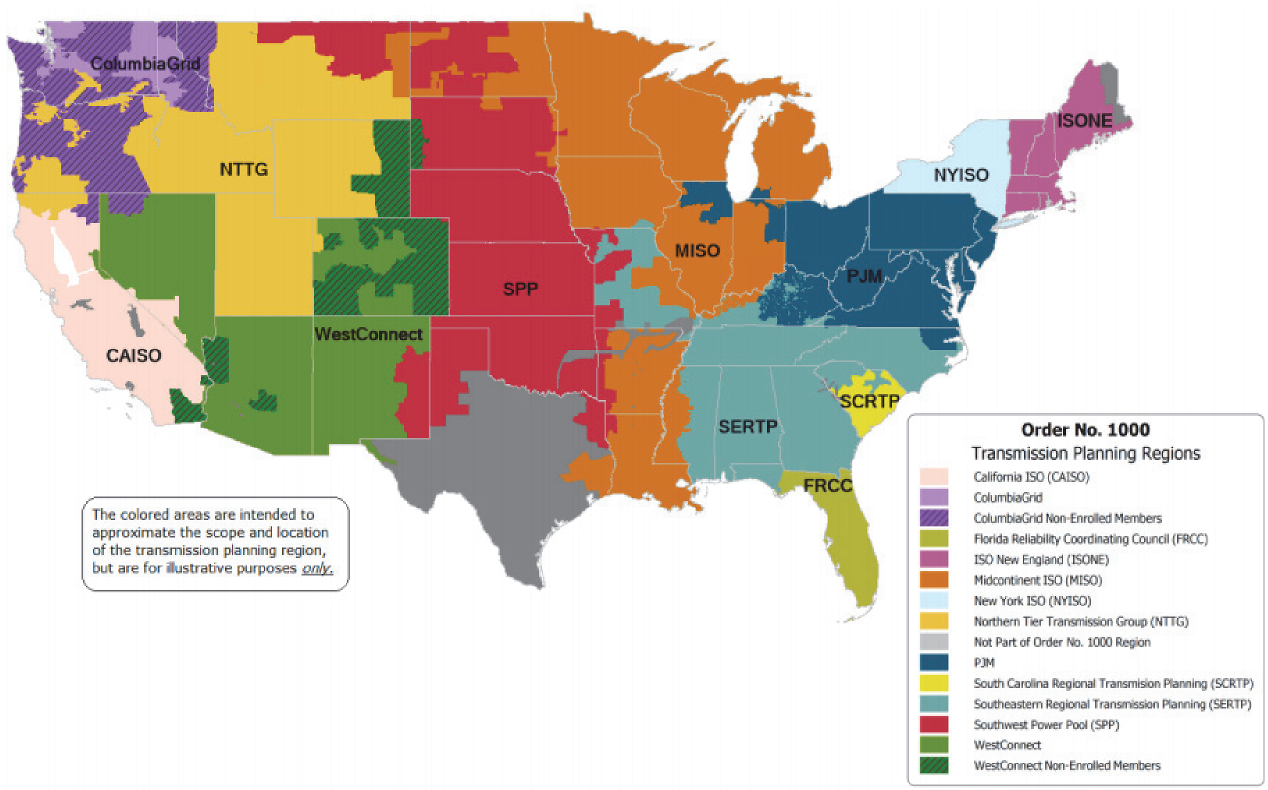
Transmission

Overview

Transmission resources are a key element in TEP's resource portfolio. Adequate transmission capacity must exist to meet TEP's existing and future load obligations. TEP'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, TEP participates in the ACC's Biennial Transmission Assessment ("BTA") which produces a written decision by the ACC regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of Arizona in a reliable manner.

TEP actively participates in the regional transmission planning and cost allocation process of WestConnect as an enrolled member of the Transmission Owners with Load Service Obligations ("TOLSO") sector in compliance with FERC Order No. 1000 ("FERC Order 1000"). This final rule reforms FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. WestConnect is composed of utility companies providing transmission of electricity in the western United States working collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to the western wholesale electricity market.

Figure 6 - FERC Order 1000 Transmission Planning Regions



Since FERC Order 1000, WestConnect went through its first one-year regional planning and cost allocation process upon completion and approval of the 2015 Regional Transmission Plan in December 2015. No project submittals, and therefore no cost allocation was required since no regional transmission needs were identified in this abbreviated 2015 cycle.

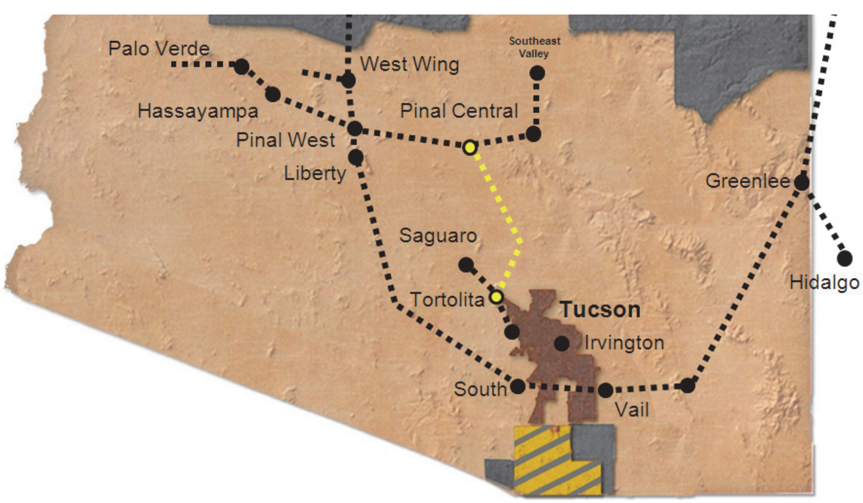
Preparation for the first WestConnect biennial regional transmission planning and cost allocation process covering the period January 1, 2016 through December 31, 2017 began in the last quarter of 2015. Preparation included initiation of the 2016-17 Regional Study Plan process and scenarios to be evaluated for inclusion in the study plan were submitted prior to December 31, 2015. WestConnect conducts an assessment of transmission planning models incorporating these scenarios to identify the need for new transmission. The key deliverable is a regional transmission plan that selects regional transmission projects to meet identified reliability, economic, public policy, or combination thereof, transmission needs.

To assist with Arizona's CPP state planning efforts, TEP participated with APS, SRP, Southwest Transmission Cooperative and UNS Electric on a scenario based on modeling of a CPP compliance plan, and prepared and submitted a joint Arizona Utility Group ("AUG") study request to WestConnect to be included in the 2016-17 Regional Planning Process. Working through the regional planning process is the most efficient method of achieving a credible outcome because it is accomplished in coordination with the other three western Planning Regions (California Independent System Operator ("CAISO"), Columbia Grid and Northern Tier Transmission Group) and therefore in coordination with other states. A key objective is to have access to the WestConnect power flow base case to perform a more credible reliability analysis on the Arizona transmission system assessing the impact of the CPP and meeting BTA planning requirements.

Pinal Central to Tortolita 500 kV Transmission Upgrade

In November 2015, TEP energized its 500 kV transmission expansion project between Pinal Central Substation and Tortolita Substation. The Pinal Central to Tortolita line will help meet Tucson's future energy demands by adding a second extra high voltage ("EHV") transmission connection between Tucson and the Palo Verde wholesale power market. This line ties in the existing Salt River Project Southeast Valley transmission project (TEP is a participant) from Pinal Central into Tortolita. This new transmission interconnection will further improve TEP's access to a wide range of renewable and wholesale market resources located in the Palo Verde area while improving TEP's system reliability.

Map 1 - Pinal Central - Tortolita 500kV Project



Chapter 4

EMERGING TECHNOLOGIES

Small Modular Nuclear Reactors

Small modular nuclear reactors ("SMR"), approximately one-third the size of current nuclear plants, are compact in size (300 MW or less) and are expected to offer many benefits in design, scale, and construction (relative to the current fleet of nuclear plants) as well as economic benefits. As the name implies, being modular allows for factory construction and freight transportation to a designated site. The size of the facility can be scaled by the number of modules installed. Capital costs and construction times are reduced because the modules are self-contained and ready to be "dropped-in" to place.

A World Nuclear Association 2015 report on SMR standardization of licensing and harmonization of regulatory requirements, said that the enormous potential of SMRs rests on a number of factors:

- Because of their small size and modularity, SMRs could almost be completely built in a controlled factory setting and installed module by module, improving the level of construction quality and efficiency.
- Their small size and passive safety features make them favorable to countries with smaller grids and less experience with nuclear power.
- Size, construction efficiency and passive safety systems (requiring less redundancy) can lead to easier financing compared to that for larger plants.
- Moreover, achieving 'economies of series production' for a specific SMR design will reduce costs further.

The World Nuclear Association lists the features of an SMR, including:

- Small power, compact architecture and usually employment of passive concepts (at least for nuclear steam supply system and associated safety systems). Therefore, there is less reliance on active safety systems and additional pumps, as well as AC power for accident mitigation.
- The compact architecture enables modularity of fabrication (in-factory), which can also facilitate implementation of higher quality standards.
- Lower power leading to reduction of the source term as well as smaller radioactive inventory in a reactor (smaller reactors).
- Potential for sub-grade (underground or underwater) location of the reactor unit providing more protection from natural (e.g. seismic or tsunami according to the location) or man-made (e.g. aircraft impact) hazards.
- The modular design and small size lends itself to having multiple units on the same site.

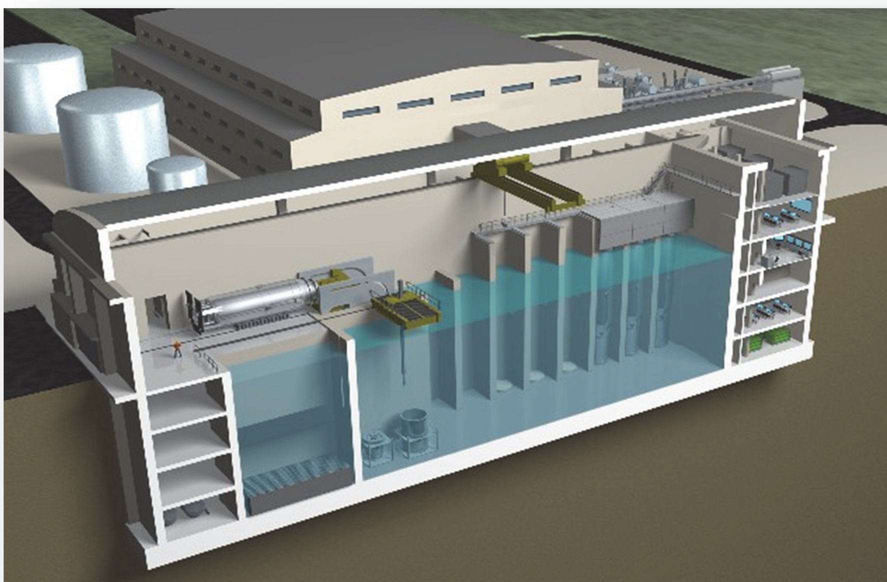
- Lower requirement for access to cooling water – therefore suitable for remote regions and for specific applications such as mining or desalination.
- Ability to remove reactor module or in-situ decommissioning at the end of the lifetime

The World Nuclear Association website has detailed information related to SMRs. The website is located at: http://www.world-nuclear.org/info/nuclear-fuel-cycle/power-reactors/small-nuclear-power-reactors/

50 MWe NuScale Power Module

NuScale Power™ is developing 50 MWe modules that can be scaled up to 600 MWe (12 modules). The scalability of SMRs allows for small utilities like TEP to consider their viability while lessening the financial risk. In December of 2013, NuScale was awarded a grant by the Department of Energy ("DOE") that would cover half (up to $217 million) to support development and receive certification and licensing from the Nuclear Regulatory Commission ("NRC") on a single module.

In the fall of 2014, NuScale signed teaming agreements with key utilities in the Western region, which include Energy Northwest in Washington State and the Utah Association of Municipal Power Systems ("UAMPS"), representing municipal power systems in Utah, Idaho, New Mexico, Arizona, Washington, Oregon, and California. This initial project, known as the UAMPS Carbon Free Power Project, would be sited in eastern Idaho and is being developed with partners UAMPS, which will be the plant owner, and Energy Northwest, which will be the operator. The team expects that the 12-module SMR will be operation in 2024.



NuScale Cross-section of Typical NuScale Reactor Building

Reciprocating Internal Combustion Engines

Reciprocating Internal Combustion Engines ("RICE") are simply combustion engines that are 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. RICE are characterized by the type of combustion: spark-ignited, like in a typical gas powered vehicle or compression-ignited, also known as diesel engines.

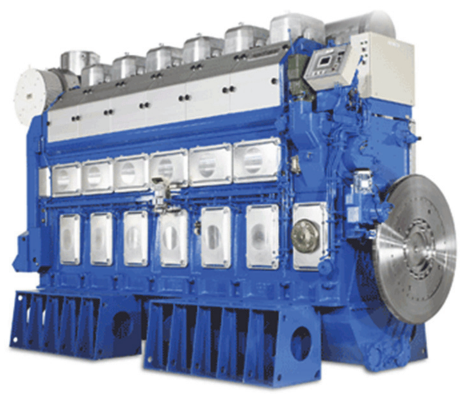


Figure 7 – Wartsila-50DF

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

- 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.

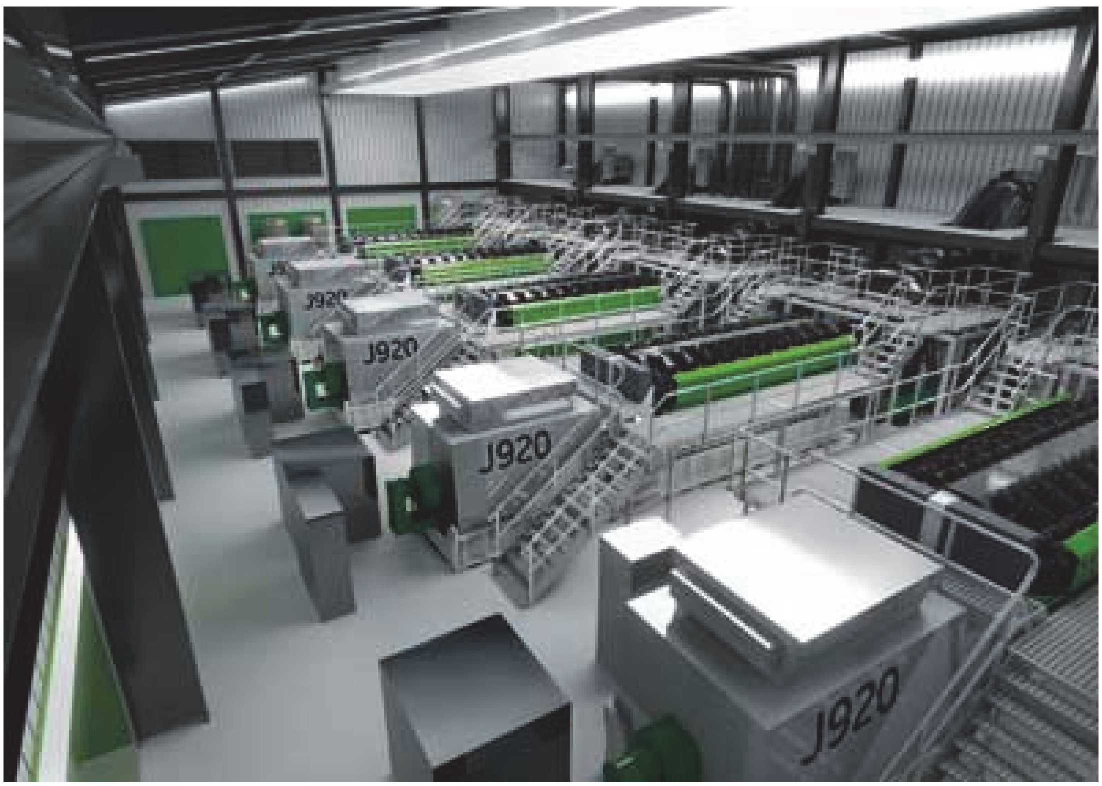
- Reduced Equivalent Forced Outage Rate ("EFOR") – Each RICE has an EFOR of less than 1%. A facility with multiple RICE will have a combined EFOR that is exponentially less by a factor of the number of units at the facility.

- 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 RICE is its potential for regulating the variability and intermittency of renewable resources. In the final IRP, TEP will explore the possibility of natural gas powered RICE in its proposed scenarios.

Figure 8 – Reciprocating Internal Combustion Engine Facility



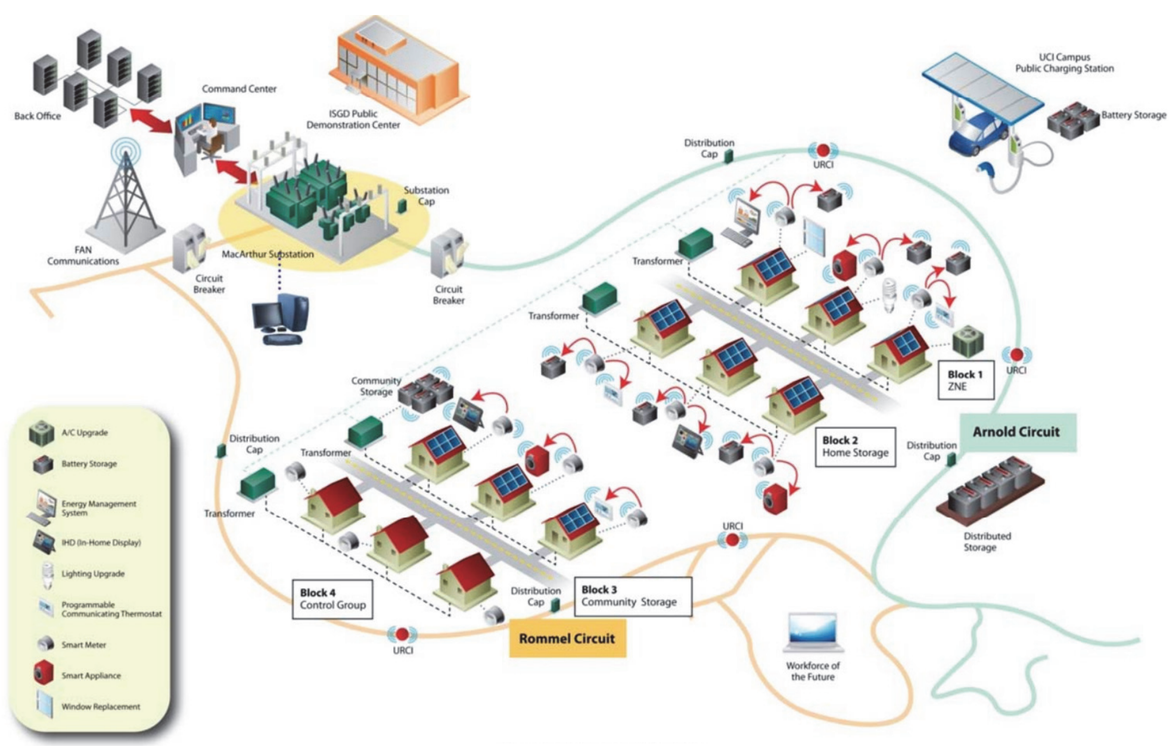
DELIVERY TECHNOLOGY

The Future of the Distribution Grid

Changes in the supply, demand, and delivery of electricity are remodeling electric distribution systems at most North American utilities. Distributed Energy Resources ("DERs") are leading many of these changes. By creating energy supply in new, small, intermittent, and distributed locations across the grid, DERs have required new levels of system flexibility. DERs have also created new opportunities for electric utilities to improve performance, to lower costs, and to improve customer satisfaction.

To accommodate DERs and other innovations, electric utilities need to do more than make their distribution systems bigger. Instead, utilities need to make their distribution systems smarter. Smart distribution systems provide flexibility, capability, speed and resilience. To achieve new levels of performance, these smart distribution systems include new types of software, networks, sensors, devices, equipment, and resources. To achieve new levels of economic value, these smart distribution systems operate according to new strategies and metrics. With more distributed generation resources being deployed on TEP's distribution system, higher demands and lower energy consumption is occurring today. This puts demands on the transmission and distribution systems that were not contemplated in the original designs and requirements of the system. To meet these new demands, new methods and technology needs to be developed and implemented. TEP is investigating technology to add more sensing and measurement devices and new methods for managing and operating the distribution system. This approach turns a distribution feeder into an effective micro grid system.

Figure 9 – Smart Grid Systems



With increased demand and lower energy consumption, new techniques and strategies need to be developed and implemented to effectively manage costs. By adding additional measurement and sensing capabilities the situational awareness of the distribution system will be increased. The situational awareness allows for real time operations and planning opportunities for efficiency and productivity changes. To utilize the existing distribution system more efficiently, TEP is investigating the use of DERs, energy storage, energy efficiency, and targeted demand response capabilities in conjunction with optimization software to reduce the infrastructure additions required due to higher customer demand. This strategy is much different than how the distribution system has been managed in the past. We are now using a bottom up planning and design process that needs to be integrated with the IRP process. New tools and capabilities will be required as a result of the new opportunities and capabilities envisioned.

At the core of these changes is the need for a communications network that allows for intelligent electronic devices to be installed on the distribution system. The communications network allows for the backhaul of information from the intelligent electronic devices to centralized software and control applications. Simply collecting and displaying more sensing and measurement information won't provide the needed benefits. An integrated approach to the installation of field devices, software applications and historical data management will be needed. A distribution management system ("DMS") is the central software application that provides distribution supervisory control and data acquisition ("SCADA"), outage management and geographical information into a single operations view. By combining the information from all three of these systems into a single view an electrical distribution system model can be created for both real time applications and planning needs. The single view provides situational awareness of the distribution system that has not been possible in the past. It also creates a platform from which additional applications can be launched to continue to provide value and new opportunities. The historical information also creates a new opportunity to drive value and decisions based on system performance and dynamic simulations.

With the development of multiple distribution micro grid feeders and DER systems, the challenge of resource dispatching will develop. A solution to dispatch across a fleet of resources of existing centralized generation, purchased power from the market and the intermittency of DER systems to customer demand will be required. The speed in which the resource pool will need to change and optimize for efficiency and cost will require the system to be automated. The distribution microgrid feeder concept is intended to help manage the distribution level intermittency but would need to be monitored and managed by the automated system for resource management. To manage such a large and dynamic system as outlined is a substantial challenge. This type of automated system is not currently available within the utility industry.

Energy Storage

The electric industry has always had an interest in the possibility of storing energy. Utilities have always strived to maintain a safe, reliable and cost effective electric grid. New challenges, such as the emergence of renewable generation has generated a greater interest in electric energy storage. The topic of Energy Storage Systems ("ESS") covers many different types of technology. Each technology has specific attributes and application that lead to using them based on individual system requirements for an identified need. The energy storage technologies are made up of systems such as pumped hydro, compressed air energy storage, various types of batteries, and flywheels.

Pumped Hydro-Power - This technology has been in use for nearly a century worldwide. Pumped hydro accounts for most of the installed storage capacity in the United States. Pumped hydro plants use lower cost off-peak electricity to pump water from a low-elevation reservoir to a higher reservoir. When the utility needs the electricity or when power prices are higher, the plant releases the water to flow through hydro turbines to generate power.

Typical pumped hydro facilities can store up to 10 or more hours of water for energy storage. Pumped hydro plants can absorb excess electricity produced during off-peak hours, provide frequency regulation, and help smooth the fluctuating output from other sources. Pumped hydro requires sites with suitable topography where reservoirs can be situated at different elevations and where sufficient water is available. Pumped hydro is economical only on a large (250-2,000 MW) scale, and construction can take several years to complete.

The round-trip efficiency of these systems usually exceeds 70 percent. Installation costs of these systems tend to be high due to siting requirements and obtaining environmental and construction permits presents additional challenges. Pumped hydro is a proven technology with high peak use coincidence. For TEP, it is a less viable option due to limited available sites and water resources.

Compressed Air Energy Storage ("CAES") – A leading alternative for bulk storage is compressed air energy storage. CAES is a hybrid generation/storage technology in which electricity is used to inject air at high pressure into underground geologic formations. CAES can potentially offer shorter construction times, greater siting flexibility, lower capital costs, and lower cost per hour of storage than pumped hydro. A CAES plant uses electricity to compress air into a reservoir located either above or below ground. The compressed air is withdrawn, heated via combustion, and run through an expansion turbine to drive a generator. The dispatch typically will occur at high power prices but also when the utility needs the electricity,

CAES plants are in operation today— a 110-MW plant in Alabama and a 290-MW unit in Germany. Both plants compress air into underground caverns excavated from salt formations. The Alabama facility stores enough compressed air to generate power for 26 hours and has operated reliably since 1991.

CAES plants can use several types of air-storage reservoirs. In addition to salt caverns, underground storage options include depleted natural gas fields or other types of porous rock formations. EPRI studies show that more than half the United States has geology potentially suitable for CAES plant construction. Compressed air can also be stored in above-ground pressure vessels or pipelines. The latter could be located within right-of-ways along transmission lines. Responding rapidly to load fluctuations, CAES plants can perform ramping duty to smooth the intermittent output of renewable generation sources as well as provide spinning reserve and frequency regulation to improve overall grid operations.

Batteries – Several different types of large-scale rechargeable batteries can be used for ESS including lead acid, lithium ion, sodium sulfur (NaS), and redox flow batteries. Batteries can be located in distribution systems closer to end users to provide peak management solutions. An aggregation of large numbers of dispersed battery systems in smart-grid designs could even achieve near bulk-storage scales.

In addition, if plug-in hybrid electric vehicles become widespread, their onboard batteries could be used for ESS, by providing some of the supporting or "ancillary" services in the electricity market such as providing capacity, spinning reserve, or regulation services, or in some cases, by providing load-leveling or energy arbitrage services by recharging when demand is low to provide electricity during peak demand.

Flywheels – These rotating discs can be used for power quality applications since they can charge and discharge quickly and frequently. In a flywheel, energy is stored by using electricity to accelerate a rotating disc. To retrieve stored energy from the flywheel, the process is reversed with the motor acting as a generator powered by the braking of the rotating disc.

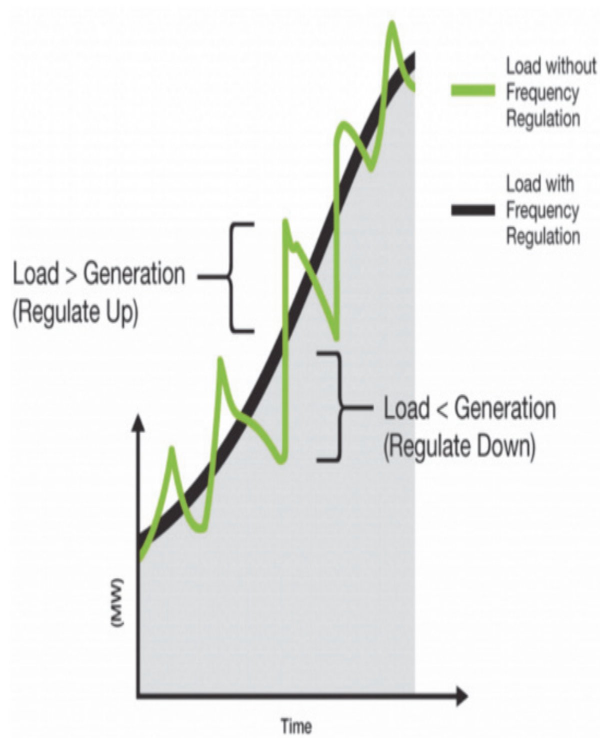
Flywheel systems are typically designed to maximize either power output or energy storage capacity, depending on the application. Low-speed steel rotor systems are usually designed for high power output, while high-speed composite rotor systems can be designed to provide high energy storage. A major advantage of flywheels is their high cycle life—more than 100,000 full charge/discharge cycles.

Scale-power versions of the system, a 100 kW version using modified existing flywheels which was a proof of concept on approximately a 1/10th power scale, performed successfully in demonstrations for the New York State Energy Research and Development Authority and the California Energy Commission.

Energy Storage Applicability

Although the list of energy storage technologies discussed above is not all-inclusive, it begins to illustrate the point that not every type of storage is suitable for every type of application. Typical use applications for energy storage technologies may include:

- Energy Management – Batteries can be used to provide demand reduction benefits at the utility, commercial and residential level. Batteries can be ideal or designed to replace traditional gas peaking resources. They can also be used as short-term replacement during emergency conditions.
- Load and Resource Integration – Energy storage systems can be designed to smooth the intermittency characteristics of specific loads and/or solar systems during cloud migrations.
- Ancillary Services – Flywheels and batteries have the potential to balance power and maintain frequency, voltage and power quality at specified tolerance bands.
- Grid Stabilization – Pumped Hydro, CAES and various batteries can improve transmission grid performance as well as assist with renewable generation stabilization.

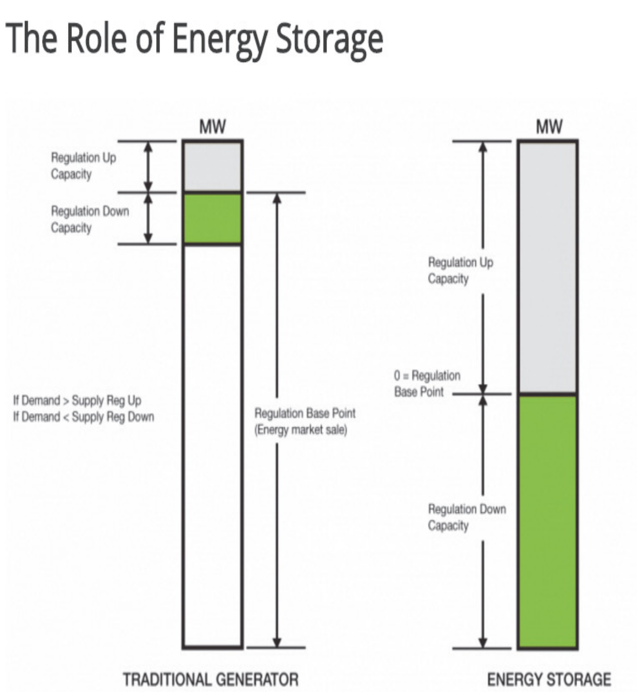


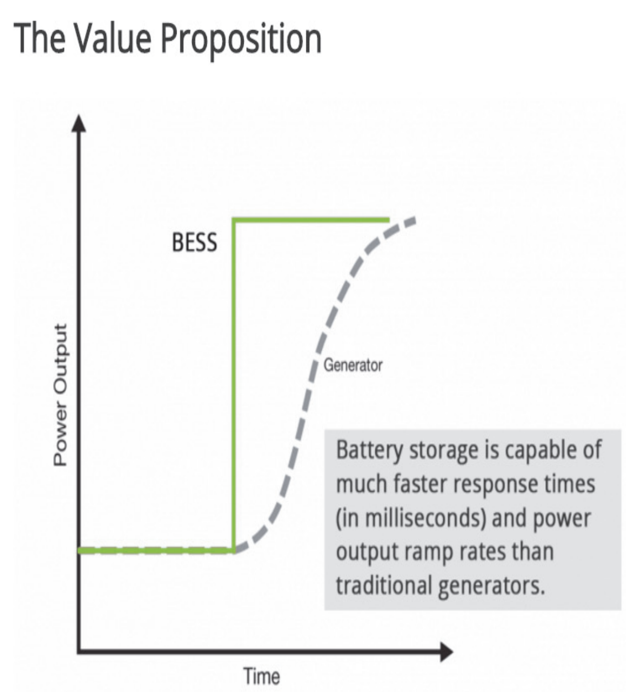
Because of the different use case potentials the technologies can be implemented in a portfolio strategy. There are four challenges related to the widespread deployment of energy storage:

- Cost Competitive Energy Storage Technologies (including manufacturing and grid integration)
- Validated Reliability & Safety
- Equitable Regulatory Environment
- Industry Acceptance

TEP shows the need to develop a portfolio of future storage technologies that will support long-term grid reliability. The need for future storage technologies is focused on supporting the need for quick response time ancillary services. These services are listed below:

- Load Following/Ramping
- Regulation
- Voltage Support
- Power Quality
- Frequency Response



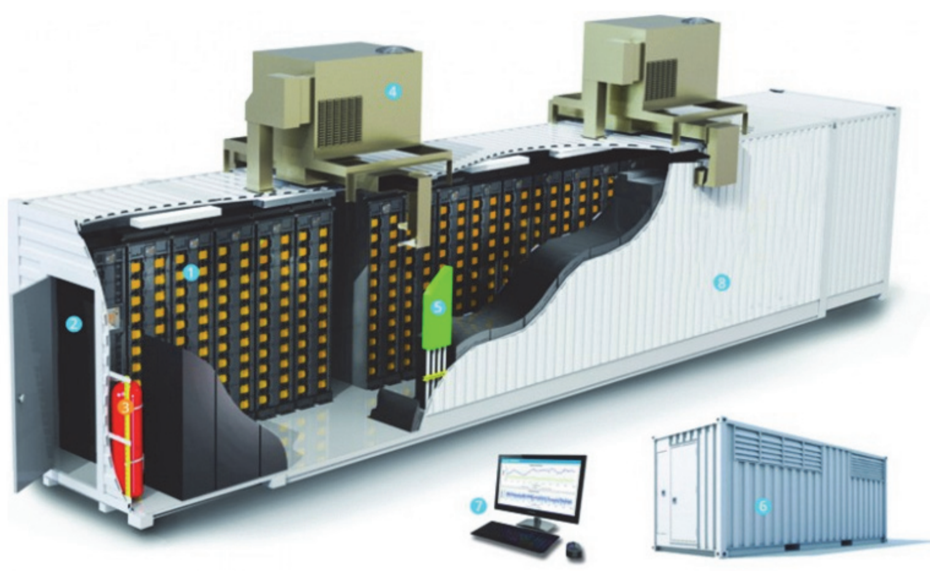


TEP Energy Storage Project

The primary advantage of an Energy Storage System, in the context of a large utility, is often in its ability to very rapidly change power output levels, much faster than the proportional governor response rate of any conventional thermal generation system. This naturally leads to the usage cases of an ESS being centered on short term balancing-type activities. An additional strength is that operating costs of an ESS are generally fixed and independent of usage. In contrast, gas turbine systems have a limited number of start and stop cycles and therefore have an appreciable cost to activate, nor are they necessarily on line when needed.

In the spring of 2015, TEP issued a request for proposals for design and construction of a utility-scale energy storage system. TEP sought a project partner to build and own a 10 MW storage facility under a 10-year agreement. TEP was looking for a cost-effective, proven energy storage system that would help integrate renewable energy into its electric grid.

Figure 10 – Lithium Ion Battery Storage Plant



The aggressive nature of the bidding companies far exceeded expectations. In its solicitation TEP received a total of 21 bids; 20 bids for battery technology and one bid for flywheel technology. Within the battery category, there were 7 different battery types proposed. Ultimately, TEP was able to select two winning bids. One company will provide a 10 MW, Lithium Nickel-Manganese-Cobalt facility; and a separate company will provide a 10 MW, Lithium Titanate facility together with a 2 MW solar facility. Each of these projects represents a significant opportunity for TEP, who will be able to obtain up to 20 MW of total storage capacity for less than the original cost estimate to acquire 10 MW. Additionally, TEP will be able to assess the operational impacts of two of the predominant Lithium technologies available today.

While 20 MWs represents only approximately 1% of TEP's load at any given time, it is large enough to have measurable impact on the grid. Assuming the performance from these first two installations is favorable, TEP would then consider ESS as an option for ancillary support and/or in support of expanded renewable applications. TEP anticipates that the storage projects will be in service during the early months of 2017.

The following is a narrative from Lazard's first version of its Levelized Cost of Energy Analysis[13]. Lazard's first version of its Levelized Cost of Storage Analysis ("LCOE 1.0") provides an independent, in-depth study that compares the costs of energy storage technologies for particular applications.[14] The study's purpose is to compare the cost-effectiveness of each technology on an "apples to apples" basis within applications, and to compare each application to conventional alternatives.[15] Key findings of LCOS 1.0 include: 1) select energy storage technologies are cost-competitive with certain conventional alternatives in a number of specialized power grid uses and 2) industry participants expect costs to decrease significantly in the next five years, driven by increasing use of renewable energy generation, governmental and regulatory requirements and the needs of an aging and changing power grid.

LAZARD'S STORAGE ANALYSIS: KEY FINDINGS

Cost Competitive Storage Technologies

Select energy storage technologies are cost-competitive with certain conventional alternatives in a number of specialized power grid uses, but none are cost-competitive yet for the transformational scenarios envisioned by renewable energy advocates.

Although energy storage technology has created a great deal of excitement regarding transformational scenarios such as consumers and businesses "going off the grid" or the conversion of renewable energy sources to baseload generation, it is not currently cost competitive in most applications. However, some uses of select energy storage technologies are currently attractive relative to conventional alternatives; these uses relate primarily to strengthening the power grid (e.g., frequency regulation, transmission investment deferral).

Today, energy storage appears most economically viable compared to conventional alternatives in use cases that require relatively greater power capacity and flexibility as opposed to energy density or duration. These use cases include frequency regulation and—to a lesser degree—transmission and distribution investment deferral, demand charge management and microgrid applications. This finding illustrates the relative expense of incremental system duration as opposed to system power. Put simply, "battery life" is more difficult and costly to increase than "battery size." This is likely why the potentially transformational use cases such as full grid defection are not currently economically attractive—they require relatively greater energy density and duration, as opposed to power capacity

LCOS 1.0 finds a wide variation in energy storage costs, even within use cases. This dispersion of costs reflects the immaturity of the energy storage industry in the context of power grid applications. There is relatively limited competition and a mix of "experimental" and more commercially mature technologies competing at the use case level. Further, seemingly as a result of relatively limited competition and lack of industry transparency, some vendors appear willing to participate in use cases to which their technology is not well suited

[13] Lazard is a preeminent financial advisory and asset management firm. More information can be found at https://www.lazard.com

[14] Lazard conducted the Levelized Cost of Storage analysis with support from Enovation Partners, an leading energy consulting firm.

[15] Energy storage has a variety of uses with very different requirements, ranging from large-scale, power grid-oriented uses to small-scale, consumer-oriented uses. The LCOS analysis identifies 10 "use cases," and assigns detailed operational parameters to each. This methodology enables meaningful comparisons of storage technologies within use cases, as well as against the appropriate conventional alternatives to storage in each use case.

Future Energy Storage Cost Decreases

Industry participants expect costs to decrease significantly in the next five years, driven by increasing use of renewable energy generation, government policies promoting energy storage and pressuring certain conventional technologies, and the needs of an aging and changing power grid.

Industry participants expect increased demand for energy storage to result in enhanced manufacturing scale and ability, creating economies of scale that drive cost declines and establish a virtuous cycle in which energy storage cost declines facilitate wider deployment of renewable energy technology, creating more demand for storage and spurring further innovation in storage technology

Cost declines projected by Industry participants vary widely between storage technologies— lithium is expected to experience the greatest five year battery capital cost decline (~50%), while flow batteries and lead are expected to experience five year battery capital cost declines of ~40% and ~25%, respectively. Lead is expected to experience 5% five year cost decline, likely reflecting the fact that it is not currently commercially deployed (and, possibly, the optimism of its vendors' current quotes)

The majority of near- to intermediate- cost declines are expected to occur as a result of manufacturing and engineering improvements in batteries, rather than in balance of system costs (e.g., power control systems or installation). Therefore, use case and technology combinations that are primarily battery-oriented and involve relatively smaller balance of system costs are likely to experience more rapid levelized cost declines. As a result, some of the most "expensive" use cases today are most "levered" to rapidly decreasing battery capital costs. If industry projections materialize, some energy storage technologies may be positioned to displace a significant portion of future gas-fired generation capacity, in particular as a replacement for peaking gas turbine facilities, enabling further integration of renewable generation

See the full report at https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf

Chapter 5

OTHER RESOURCE PLANNING TOPICS

Energy Imbalance Market

Energy imbalance on an electrical grid occurs when there is a difference between real-time demand, or load consumption, and generation that is prescheduled. Prior to the emergence of renewable energy technology on the grid, balancing occurred to correct operating limits within 30 minutes. Flows are often managed manually by system operators and typically bilaterally between power suppliers. The intermittent characteristics of wind and solar resources have raised concerns about how system operators will maintain balance between electric generation and demand in smaller than thirty minute increments. Energy Imbalance Markets ("EIMs") create a much shorter window market opportunity for balancing loads and resources. An EIM can aggregate the variability of resources across much larger footprints than current balancing authorities and across balancing authority areas. The sub hourly clearing, in some cases down to 5 minutes potentially provides economic advantage to participants in the market. EIMs propose to moderate, automate and effectively expand system-wide dispatch which can help with the variability and intermittency of renewable resources. EIMs boast to create significant reliability and renewable integration benefits by sharing resource reserves across much larger footprints.

CAISO – EIM

On November 1, 2014, the CAISO welcomed PacifiCorp into the western EIM. Nevada-based NV Energy began active participation in the EIM on December 1, 2015. This voluntary market service is available to other grids in the West. Several Western utilities have committed to join the EIM. Meanwhile, work is underway for Puget Sound Energy in Washington and Arizona Public Service to enter the real-time market in October 2016. In the fall of 2015, Portland General Electric and Idaho Power each announced their intentions to pursue EIM participation.

Participants in the EIM expect to realize at least three benefits:

- Produce economic savings to customers through lower production costs
- Improve visibility and situational awareness for system operations in the Western Interconnection
- Improve integration of renewable resources

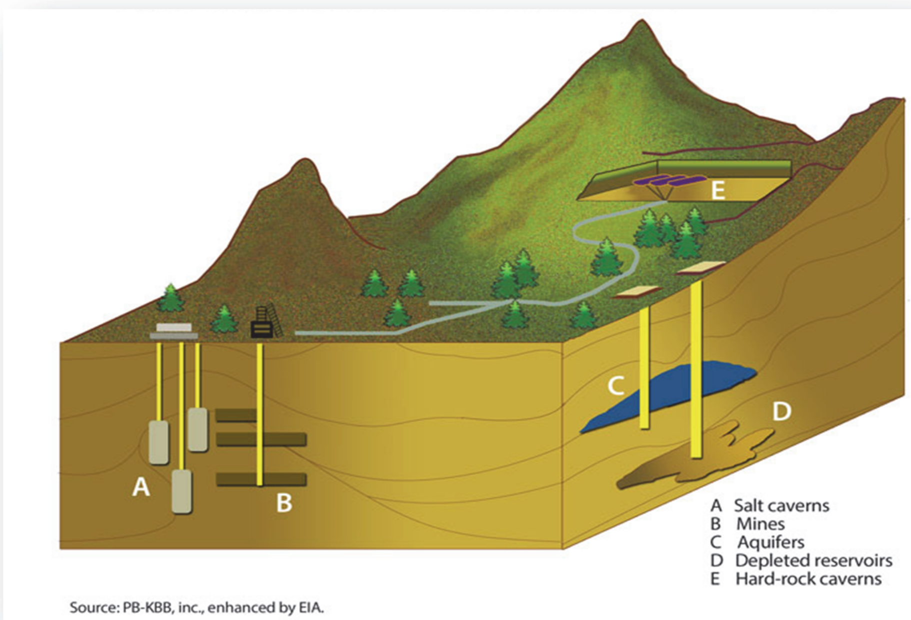
TEP has contracted with the energy consulting firm E3 to perform a study to evaluate the economic benefits of TEP participating in the energy imbalance market. E3 will evaluate EIM benefits to TEP based on a set of study scenarios defined through discussions with TEP to reflect TEP system information, including loads, resources, and potential transmission constraints for access to markets for real-time transactions. The project analysis began in February 2016 and is expected to be completed by the end of June, 2016. TEP will then evaluate the relevant costs and benefits of joining the western EIM.

Natural Gas Storage

Natural gas is a fuel source that produces less carbon dioxide than coal for a given unit of energy generation. Natural gas-powered electric generation can also be more responsive to and supportive of the variability and intermittency of renewable generation. Natural gas usage has historically undergone seasonal flucutations with higher consumption is during the winter months due to residential and commercial heating. The displacement of coal and the emergence of renewable generation will likely shift gas demand increases to the summer months. As utilities potentially began to lean more toward natural gas-powered electric generation, an ensuing issue or concern is the ability of supply and deliverability to meet this increased demand, thus natural gas storage is being considered.

Natural gas is pivotal in maintaining a reliable electric grid. Natural gas storage provides a reliability backstop to a multitude of disruptions that may impact the delivery of natural gas. Storage helps to level the balance of production, which is relatively constant, and the seasonally driven demand or consumption. Gas can be injected into storage while demand is low and released for consumption while demand is high or while there are disruptions in supply. Much like water stored behind dams allows for timely irrigation of seasonal crops. Natural gas is typically stored underground and primarily in three different formations; depleted oil and/or gas reservoirs, aquifers and salt cavern formations.

Figure 11 – Natural Gas Storage Types



Source: EIA Energy Information Administration

Depleted Reservoirs – The reservoirs result from the void remaining in already recovered gas or oil.

Depleted reservoirs are more widely available and the most utilized. This form of storage is the most common for natural gas storage. Their availability, of course, is dependent on the location of existing wells and pipeline infrastructure. To maintain adequate withdrawal pressure, up to 50% of the gas capacity becomes unrecoverable cushion gas, this depends on how much native gas remains in the reservoir. Injection and withdrawal rates are also dependent on the geological characteristics of the site.

Aquifers – The use of aquifers has been more prevalent in the Midwestern United States. In the case of depleted gas and aquifer storage reservoirs, the effectiveness of storage is primarily dependent on the geological conditions. The rock formation porosity, permeability, and retention capability are important. A suitable aquifer is one that is overlaid with impermeable "cap" layer. Unlike depleted reservoirs, where expensive infrastructure was installed during the exploration and extraction of oil and gas, aquifers require extensive capital investment. Since aquifers are naturally full of water, in some instances powerful injection equipment must be used, to allow sufficient injection pressure to push down the resident water and replace it with natural gas. Aquifers typically operate with one withdrawal period per year; this is because of slow fill to push water back.

Salt Caverns – The best opportunity for natural gas storage in Arizona and in the Southwest might be in salt caverns. Salt caverns allow for high withdrawal and injection rates of natural gas. This makes salt caverns ideal to meet demand increases or to operate as emergency back-up systems. Salt caverns are created through a process called solution mining; where fresh water is blasted into salt formations and the mixture is flushed to the surface creating a chamber. The chambers are structurally strong and extremely air tight. While cushion gas is still required at a 20% to 30% level, it is less than required for depleted reservoirs.

Integration of Renewables

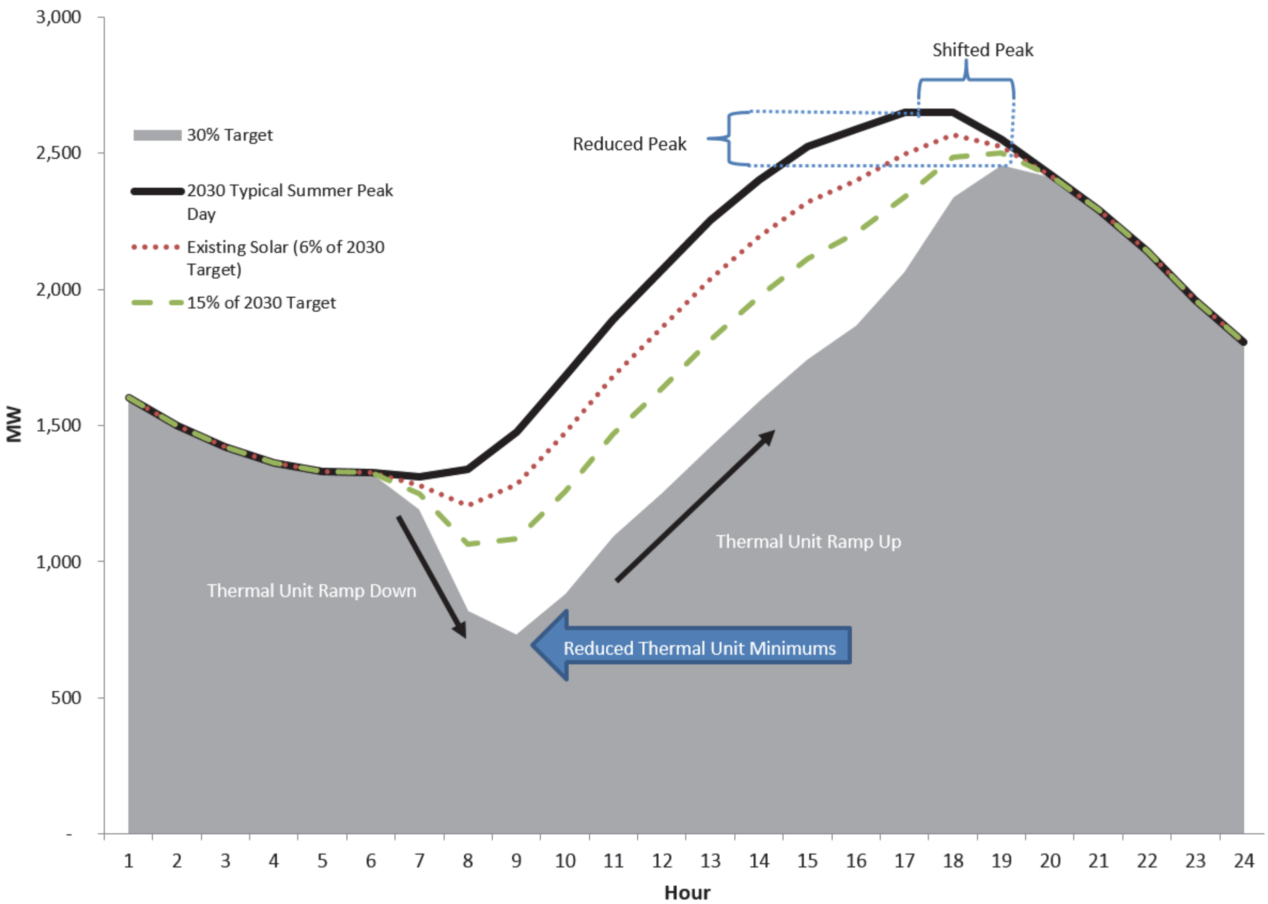
The value and cost of renewable solar PV is estimated to change with increased penetration. To determine the value of solar PV, it's imperative to understand its relationship to consumer load. In the case of Distributed Generation, most renewable solar is sited 'behind the meter' or on customer facilities. The relationship of a DG solar installation at a residential site is assumed to be different than an installation at a commercial site. We can assume that residential peak load occurs soon after consumers arrive home from work. Commercial peak tends to occur during the early to mid-afternoon hours. This is an important distinction in this discussion because the costs and value vary between the multiple customer types. However, for this discussion, we will refer only to the impact on the system in its entirety and for solar as a whole; DG and community-scale installations.

Historically, electric utilities with predominant air conditioning load set a peak demand between 4:00 PM to 5:00 PM on a summer day. Solar PV can help reduce this peak but not at the full potential of its solar output. Fixed array solar peak production is typically at 12:00 to 1:00 PM, while single-axis tracking systems can expand its potential to coincide more with the retail peak demand. TEP's current renewable portfolio (to include DG and wind) is at approximately 6% of 2030 retail energy projection.

Chart 9 below demonstrates that the existing penetration of solar already has an observable reduction to retail peak demand. Closer examination also reveals that the net peak is beginning to shift to the right. The reduction to the peak in 2030 from existing solar is approximately 3%. While a reduction to retail peak is observed, only 30% of the solar installed capacity contributes to that reduction.

TEP is committed to meeting the 15% RES by 2025. By maintaining that commitment through 2030, the solar component of the renewable portfolio reduces peak by another 2.7%. Though there is an obvious reduction in peak, the time the peak is set is shifting closer to the last diurnal hour of a typical clear-sky summer day (7:00 to 8:00 PM). It is significant then to note that though we introduce a 30% renewable target with a high penetration of solar, the reduction to the new shifted (7:00 PM) peak attributed to solar is beginning to diminish. We observe a 1.8% reduction to retail peak but a significant drop (from 30% to 18%) to peak contribution from the incremental solar capacity additions. As retail load grows, solar PV (without storage capabilities) cannot contribute to the reduction of peak demand beyond 7:00 PM; regardless of its penetration.

Chart 9 – Impact of Increased Solar Production (Duck Curve)



While it can be argued that solar may contribute to reduced losses, to apportioned capacity reductions (generation and transmission), and carbon emission reductions among other benefits, we note from the chart above that other challenges arise. As the sun is rising, electric load stabilizes and begins an ascent toward the peak. Increased penetration of solar creates a rapid net drop in load and TEP must have generators that are capable of ramping down at a fast rate. Most base-load units such as coal and natural gas-steam are challenged to respond to this ramp down and subsequent ramp up. It is at this point that the net reduction in load can create the need for rapid responding generators to regulate the initial steep decline in load followed by an immediate rise. From a resource planning context, with the increasing penetration of solar systems, 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 other renewables may necessitate the installation of reciprocating internal combustion engines and/or storage in the form of batteries or natural gas.

Natural Gas Reserves

Proven reserves of natural gas are estimated quantities that analyses of geological and engineering data have demonstrated to be economically recoverable from known reservoirs in the future. According to EIA, major advances in natural gas exploration and technology has increased reserves in 2014 to 388.8 trillion cubic feet (Tcf) from 354.0 Tcf reserves in 2013.

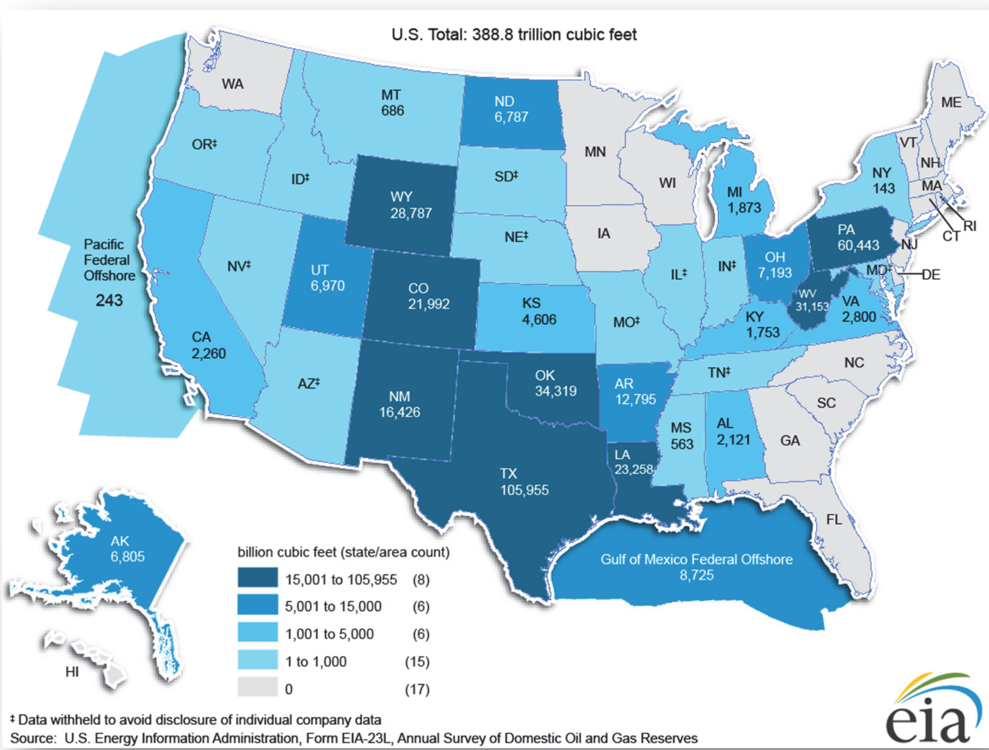
Table 12 – U.S Proved Reserves and Reserve Changes (2013 to 2014)

	Wet Natural Gas -Tcf
U.S. proven reserves at December 31, 2013	**354.0**
Total discoveries	50.5
Net revisions	1.0
Net Adjustments, Sales, Acquisitions	11.5
Production	-28.1
Net additions to U.S. proved reserves	**34.8**
U.S. proven reserves at December 31, 2014	**388.8**
Percent change in U.S. proved reserves	**9.8%**

Notes: Total natural gas includes natural gas plant liquids. Columns may not add to total because of independent rounding.
Source: U.S. Energy Information Administration, Form EIA-23L, Annual Survey of Domestic Oil and Gas Reserves

Proven reserves are added each year with successful exploratory wells and as more is learned about fields where current wells are producing. The application of new technologies can convert previously uneconomic natural gas resources into proven reserves. U.S. proven reserves of natural gas have increased every year since 1999. Figure 13 illustrates the distribution of the reserves by state and offshore area.

Figure 13 – EIA Natural Gas Proven Reserves by State/Area (2014)



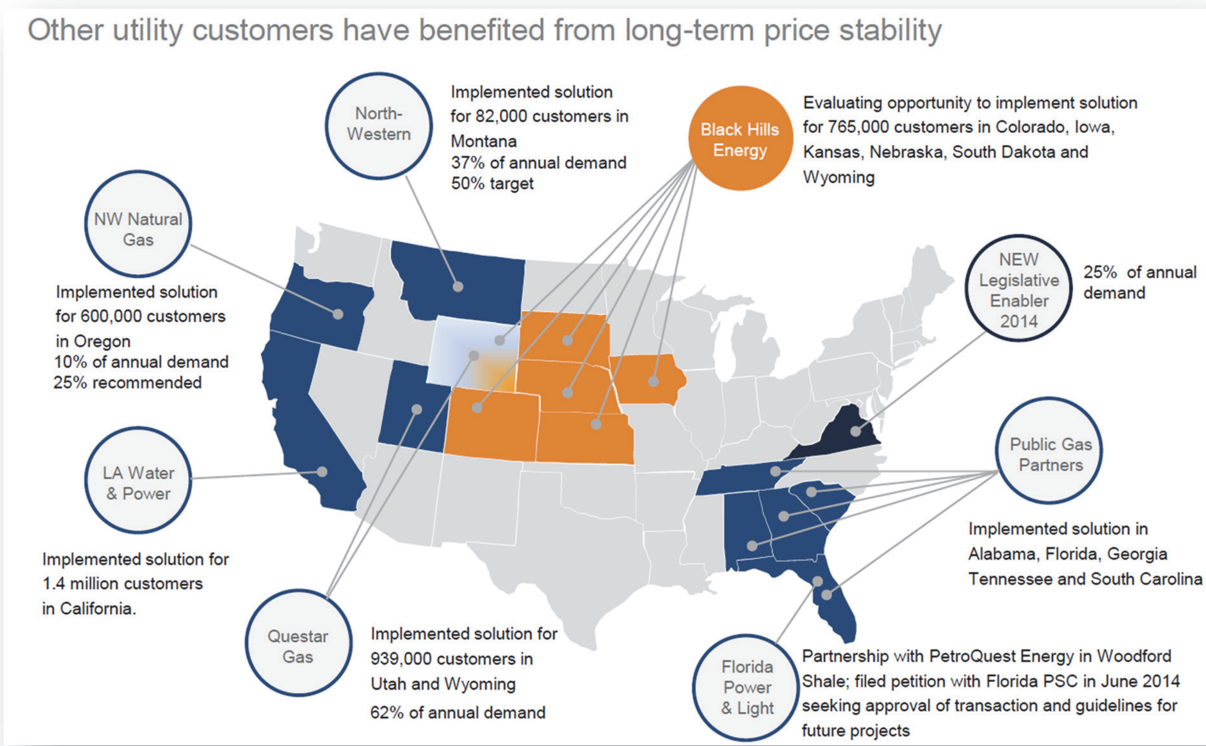
Utility Ownership in Natural Gas Reserves

As TEP transitions its generation portfolio away from coal-fired resources towards more reliance on cleaner more efficient natural gas resources, the Company has been researching new ways to lock in long-term fuel price stability for natural gas. One potential solution being explored by a number of gas and electric utilities is the investment and ownership in physical natural gas reserves.

Over the last few years, a number of utilities have partnered with third party natural gas producers to develop partnerships to acquire and develop natural gas reserves. These partnerships were formed as an alternative approach to existing financial hedging practices and were seen as a way for Companies to develop a long-term physical hedge for its expanding gas generation fleet.

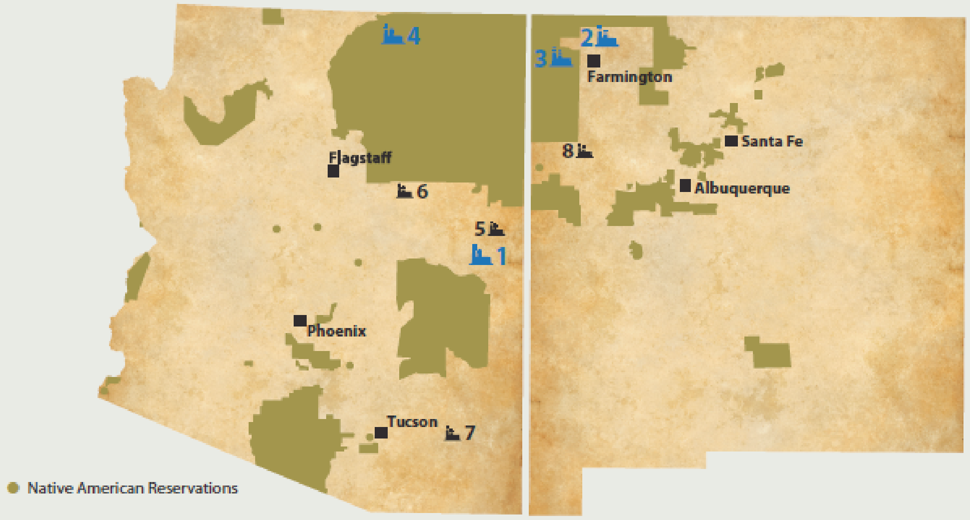
Production of oil and associated natural gas has grown substantially over the last several years leading to a supply surplus that has depressed natural gas prices to the lowest they have been in twenty years. As a result, this environment creates opportunities for utilities and other large gas purchasers to acquire natural gas reserves at historic lows. The figure below highlights a number of Companies who have successfully developed partnerships around natural gas reserve ownership.

Figure 14 - Overview of Recent Utility - Third Party Gas Reserve Projects



In the context of TEP coal diversification strategy and its move to rely on more natural gas, the Company plans to explore how it might pursue similar partnerships with regional gas and electric utilities in an effort secure long-term natural gas price stability for its customers.

Coal-Fired Power Plants in Arizona and Northwest New Mexico



1. Springerville
2. San Juan
3. Four Corners
4. Navajo
5. Coronado
6. Cholla
7. Apache
8. Escalante

Plants partly owned by TEP are shown in blue

SPRINGERVILLE

Output: 1,580 MW
Operator: Tucson Electric Power (TEP)
Owners:

Unit 1 (387 MW; operational in 1985): TEP 49.5% (192 MW), third-party owners* 50.5% (195 MW)
Unit 2 (390 MW; 1990): TEP
Unit 3 (415 MW; 2006): Tri-State Generation & Transmission
Unit 4 (417 MW; 2009): Salt River Project (SRP)

** Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC and LDVF1 TEP LLC*

Coal Supply: Units 1 and 2 – Agreement signed June 17, 2003 with Peabody Energy sourced from El Segundo / Lee Ranch, expires December 31, 2020.

Participation Agreement: Expires January 1, 2078

Outlook: Regional haze regulations will not impact the plant's operations until after 2018. Units 1 and 2 were built in the 1980s, after the timeframe addressed by the Regional Haze BART requirements. Units 3 and 4 were built in the 2000s with state-of-the-art selective catalytic reduction (SCR) equipment.

Emission Control Equipment:

	SO_2	NOx	PM	Hg
Unit 1	SDA	LNB SOFA	FF	ACI, CaBR2 (3/16)
Unit 2	SDA	LNB SOFA	FF	ACI, CaBR2 (3/16)
Unit 3	SDA	SCR	FF	ACI, CaBR2
Unit 4	SDA	SCR	FF	ACI, CaBR2

TEP
Tucson Electric Power

SAN JUAN

Output: 1,683 MW
Operator: Public Service Company of New Mexico (PNM)
Owners:

Unit 1 (340 MW; operational in 1976): TEP 50% (170 MW), PNM 50% (170 MW)
Unit 2 (340 MW; 1973): TEP 50% (170 MW), PNM 50% (170 MW)
Unit 3 (496 MW; 1979): PNM 50% (248 MW), Southern California Public Power Authority (SCPPA) 42% (207 MW), Tri-State Generation & Transmission (TSGT) 8% (41 MW)
Unit 4 (507 MW; 1982): PNM 38% (195 MW), MSR Public Power Agency 29% (146 MW), City of Anaheim 10% (50 MW), City of Farmington 8% (43 MW), Los Alamos County 7% (37 MW), Utah Associated Municipal Power Systems (UAMPS) 7% (36 MW)

Coal Supply: Agreement with Westmoreland Coal Company sourced from San Juan Mine is effective from January 2016 through June 2022

Participation Agreement: Expires June 30, 2022

Outlook: In October 2014, the EPA approved a regional haze compliance plan to shut down Units 2 and 3 at the plant by the end of December 2017 and to install selective non-catalytic reduction (SNCR) equipment on Units 1 and 4 by February of 2016. New Mexico's Public Service Commission approved the plan Dec. 16, 2015. Several current owners would exit the plant under the proposed agreement, leaving the following ownership of the remaining two units:
Unit 1 (340 MW): TEP 50% (170 MW), PNM 50% (170 MW)
Unit 4 (507 MW): PNM 64% (327 MW), Public Service Company of New Mexico Resources and Development (power merchant) 13% (65 MW), Farmington 8% (43 MW), Los Alamos County 7% (36 MW), UAMPS 7% (36 MW)
In 2018, PNM must conduct a review of the plant's economic viability after 2022, when the current participation agreement and coal supply contract expire.

Emission Control Equipment:

	SO_2	NOx	PM	Hg
Unit 1	WFGD	SNCR (3/2016)	FF	ACI
Unit 2	WFGD	LNB	FF	ACI
Unit 3	WFGD	LNB	FF	ACI
Unit 4	WFGD	SNCR (3/2016)	FF	ACI

FOUR CORNERS

Output: 1,540 MW
Operator: APS
Owners:

Unit 4 (770 MW; operational in 1969): APS: 63% (485 MW), PNM 13% (100 MW), SRP 10% (77 MW), TEP 7% (54 MW), El Paso Electric 7% (54 MW)
Unit 5 (770 MW; 1970): APS: 63% (485 MW), PNM 13% (100 MW), SRP 10% (77 MW), TEP 7% (54 MW), El Paso Electric 7% (54 MW)

Coal Supply: Agreement with BHP Billiton expires July 2016. Upon its expiration, a new agreement will take effect with Navajo Transitional Energy Company sourced from Navajo Mine. That agreement will expire in July 2031.

Participation Agreement: Co-tenancy agreement expires July 2041.

Outlook: APS shut down units 1-3 in December 2013 and purchased Southern California Edison's previous share of Units 4 and 5 to comply with regional haze BART requirement issued in August 2012. APS also must install SCR equipment on Units 4 and 5 by end of July 2018. El Paso Electric is seeking final regulatory approval to sell its share of the plant to APS.

Emission Control Equipment:

	SO_2	NOx	PM	Hg
Unit 4	WFGD	SCR (7/2018)	FF	WFGD-FF
Unit 5	WFGD	SCR (7/2018)	FF	WFGD-FF

NAVAJO

Output: 2,250 MW
Operator: SRP
Owners:

Unit 1 (750 MW; operational in 1974): U.S. Bureau of Reclamation 24.3% (182 MW), SRP 21.7% (163 MW), Los Angeles Dept. of Water and Power (LADWP) 21.2% (159 MW), APS 14% (105 MW), NV Energy 11.3% (85 MW), TEP 7.5% (56 MW)
Unit 2 (750 MW; 1975): U.S. Bureau of Reclamation 24.3% (182 MW), SRP 21.7% (163 MW), LADWP 21.2% (159 MW), APS 14% (105 MW), NV Energy 11.3% (85 MW), TEP 7.5% (56 MW)
Unit 3 (750 MW; 1976): U.S. Bureau of Reclamation 24.3% (182 MW), SRP 21.7% (163 MW), LADWP 21.2% (159 MW), APS 14% (105 MW), NV Energy 11.3% (85 MW), TEP 7.5% (56 MW)

Coal Supply: Current agreement with Peabody Energy sourced from Kayenta Mine, expires December 2019

Participation Agreement: Extends to the expiration date of the plant's lease with the Navajo Nation, which is currently set to expire Dec. 20, 2019. A proposed agreement to extend that lease until 2044 is currently under review through the federal NEPA and EIS processes and must be approved by the U.S. Bureau of Reclamation before it can be finalized by all parties.

Outlook: In July 2014, EPA approved a regional haze compliance plan to shut down one unit at the plant by January 1, 2020 and to install SCR technology on the remaining units by the end of 2030; alternately, the plant could close by the end of 2030 if those upgrades are not installed. LADWP and NV Energy plan to exit the plant by 2020; their shared stake in the plant approximately matches the capacity of one unit. Alternately, the plant's stakeholders could choose to curtail operations by one-third to meet an EPA imposed emissions cap. Under either scenario, the plant would cease conventional coal-fired generation by Dec. 22, 2044.

Emission Control Equipment:

	SO2	NOx*	PM	Hg**
Unit 1	WFGD	LNB SOFA	hESP	ACI CaBR2
Unit 2	WFGD	LNB SOFA - SCR (1/2031)	hESP	ACI CaBR2
Unit 3	WFGD	LNB SOFA - SCR (1/2031)	hESP	ACI CaBR2

*SCR to be installed on the remaining two units
**ACI is unconventional; carbon is introduced in the wet scrubber

CORONADO

Output: 773 MW
Operator: SRP
Owner:

Unit 1 (389 MW; operational in 1979): SRP
Unit 2 (384 MW; 1980): SRP

Outlook: In 2014, SRP completed upgrades pursuant to a 2008 agreement with the EPA that included new low NOx burners and SO2 removal systems on both units and SCR technology on Unit 2. The EPA proposed a stricter Federal Implementation Plan for the plant in December 2012 that would require the installation of SCR on Unit 1. Discussions with stakeholders and the EPA are ongoing.

CHOLLA

Output: 1150 MW
Operator: APS
Owners:
Unit 1 (125 MW; operational in 1962): APS
Unit 2 (300 MW; 1978): APS
Unit 3 (300 MW; 1980): APS
Unit 4 (425 MW; 1981): Pacificorp

Outlook: APS shut down Unit 2 in October 2015. The company is seeking EPA and ACC approval to close Unit 2 permanently by April 2016 and to stop burning coal at the other units by April 2025. The plan is an alternative to a December 2012 EPA mandate to install SCRs and other costly emission controls at the plant.

APACHE

Output: 408 MW
Operator: Arizona Electric Power Cooperative (AEPCO)
Owner:

Unit 2 (204 MW; operational in 1979): AEPCO
Unit 3 (204 MW; 1979): AEPCO

Outlook: In February 2015, the EPA approved AEPCO's proposed alternative to the agency's original regional haze compliance plan for the plant, which would have required the installation of SCR on both units. Instead, AEPCO has agreed to operate one of the two units exclusively using natural gas and to install SNCR on the remaining coal-fired unit by Dec. 5, 2017

ESCALANTE

Output: 247 MW
Operator: Tri-State Generation and Transmission Association
Owner:

Unit 1 (247 MW; operational in 1984): Tri-State

Outlook: Primarily fueled by coal, this unit also can burn natural gas.

EMISSION CONTROL TECHNOLOGY ABBREVIATIONS

ACI	Activated carbon injection
CABR2	Calcium bromide (added to coal)
FF	Fabric filter (bag house)
Hg	Mercury
LNB	Low NOx burner
NOx	Nitrogen oxides
PM	Particulate matter
SCR	Selected catalytic reduction
SDA	Spray dryer absorber
SO2	Sulfur dioxide
SOFA	Separated overfire air
SNCR	Selective non-catalytic reduction

TEP
Tucson Electric Power

Chapter 6

FUTURE RESOURCE OPTIONS AND MARKET ASSUMPTIONS

In considering future resources, the resource planning team evaluates a mix of renewable and conventional generation technologies. This mix of technologies included both commercially available resources and promising new technologies that are likely to become technically viable in the near future. The IRP process takes a high-level approach and focuses on evaluating resource technologies rather than specific projects. 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.

Assumptions on cost and operating characteristics are typically gathered from several data sources. Below is a list of resources that TEP relies on to compile capital cost assumptions for thermal and renewable resources:

- U.S. Energy Information Administration - https://www.eia.gov/forecasts/aeo/electricity_generation.cfm
- Western Electricity Coordinating Council (as recommended by E3) - https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf
- Black & Veatch - http://bv.com/docs/reports-studies/nrel-cost-report.pdf
- National Renewable Energy Laboratory - http://www.nrel.gov/analysis/re_futures/index.html
- Lazard - https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf ; https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf

TEP relies on a number of third-party data sources and consultants to derive assumption in its on-going planning practices. In addition, information gathered through our competitive bidding process or request for proposal process can be used to put both self-build resources and market-based purchased power agreements on a comparative basis.

Generation Resources – Matrix of Applications

Table 8 provides a brief overview of the types of generating resources that will be included and evaluated in the resource planning process for the 2017 Final IRP. For each technology type a brief summary of potential risks and benefits are listed. In addition, attributes such as costs, siting requirements, dispatchability, transmission requirements and environmental potential are summarized.

Table 8 - Resource Matrix

Category	Type	Zero or Low Carbon Potential	State of Technology	Local Area Option	Intermittent	Peaking	Load Following	Base Load
Energy Efficiency	Energy Efficiency	Yes	Mature	Yes				
Demand Response	Direct Load Control	Yes	Mature	Yes		✓		
Renewables	Wind	Yes	Mature		✓			
	Solar PV	Yes	Mature	Yes	✓	✓		
	Solar Thermal	Yes	Mature		✓	✓	Storage (1)	
Conventional	Reciprocating Engines		Mature			✓	✓	✓
	Combustion Turbines		Mature	Yes		✓	✓	
	Combined Cycle (NGCC)		Mature	Yes		✓	✓	✓
	Small Modular Nuclear (SMR)	Yes	Emerging					✓

(1) Natural Gas hybridization or thermal storage could allow resource to be dispatched to meet utility peak load requirements.

Comparison of Resources

Generation planning and resource analysis can be performed by using a wide spectrum of tools and methodologies. Prior to running detailed simulation models for the 2017 Final IRP, the TEP resource planning team will combine the source information and settle on the cost parameters for the varying technologies. Table 9 and Table 10 shown below demonstrate a comparison of capital cost estimates, used by TEP in the 2012 and 2014 IRPs versus costs published by Third-Party Sources, for thermal and renewable resources respectively. The tables demonstrate the varying range of costs, even within each technology. In the 2017 Final IRP, the resource planning group will incorporate the input from third-party sources, stakeholders and other data sources to derive a reasonable set of cost inputs (construction, EHV/interconnection, construction to include ITC, fixed O&M, variable O&M, and fuel costs).

Table 9 – Capital Cost for Thermal Resources

Plant Construction Costs	Units	Small Aeroderivative Combustion Turbine	Small Frame Combustion Turbine	Natural Gas Reciprocating Engines	Small Modular Reactor (SMR)	Natural Gas Combined Cycle (NGCC)
2012 IRP	2012 $/kW	$1,156	$779	-	-	$1,320
2014 IRP	2014 $/kW	$1,062	$808	-	-	$1,367
Third Party Source	2014 $/kW	$1,150	$825	$1,300	-	$1,125
Third Party Source	2016 $/kW	$800 - $1,000	$800 - $1,000	$1,150	-	$1,000 - $1,300
Preliminary IRP Estimate	2016 $/kW	$1,250	$800	$1,200	$6,400	$1,300

Table 10 – Capital Cost for Renewable Resources

Plant Construction Costs	Units	Solar Thermal 6 Hour Storage (100 MW)	Solar Fixed PV (20 MW)	Solar Single Axis Tracking (20 MW)	Wind Resources (50 MW)
2012 IRP	2012 $/kW	$5,650	$2,350	$2,549	$2,400
2014 IRP	2014 $/kW	$7,144	$1,993	$2,290	$2,278
Third Party Source	2014 $/kW	$7,100	$3,325	$3,800	$2,000
Third Party Source	2016 $/kW	$10,000 - $10,300	$1,400 - $1,500	$1,600 - $1,750	$1,250 - $1,700
Preliminary IRP Estimate	2016 $/kW	$10,000	$1,500	$1,600	$1,450

LEVELIZED COST COMPARISONS

The calculation of the levelized cost of electricity ("LCOE") provides a common measure to compare the cost of energy across different demand and supply-side technologies. The LCOE takes into account the installed system price and associated costs such as capital, operation and maintenance, fuel, transmission, tax incentives and converts them into a common cost metric of dollars per megawatt hour. The calculation for the LCOE is the net present value of total costs of the project divided by the quantity of energy produced over the system life.

Because intermittent technologies such as renewables do not provide the same contribution to system reliability as technologies that are operator controlled and dispatched, they require additional system investment for system regulation and backup capacity. As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change. Further resource utilization is dependent on many factors; the portfolio mix, regional market prices, customer demand and must-run requirements are some considerations outside of LCOE.

The LCOE projection contains many factors that will vary between now and when the final IRP is filed on April 1, 2017. As such, TEP will derive the levelized costs at the time that the capital costs and other inputs are prepared for final analysis.

RENEWABLE TECHNOLOGIES – COST DETAILS

Table 11 includes the renewable technology costs for the 2016 Preliminary Integrated Resource Plan.

Table 11 - Renewable Resource Cost Assumptions

Plant Construction Costs	Units	Solar Thermal 6 Hour Storage (100 MW)	Solar Fixed PV (20 MW)	Solar Single Axis Tracking (20 MW)	Wind Resources (50 MW)
Project Lead Time	Years	4	2	2	2
Installation Years	First Year Available	2020	2018	2018	2018
Peak Capacity	MW	100	20	100	50
Plant Construction Cost	2016 $/kW	$9,800	$1,450	$1,550	$1,250
EHV/Interconnection Cost	2016 $/kW	200	50	50	200
Total Construction Cost	2016 $/kW	$10,000	$1,500	$1,600	$1,450
Operating Characteristics					
Fixed O&M	2016 $/kW	$80.00	$13.00	$10.00	$40.00
Typical Capacity Factor	Annual %	50%	29%	25%	33%
Expected Annual Output	GWh	438	110	127	145
Net Coincident Peak	NCP%	85%	33%	51%	13%
Water Usage	Gal/MWh	800	0	0	0
ITC	Percent	30%	30%	30%	-
PTC	$/MWh	-	-	-	$23.00
Levelized Cost of Energy	$/MWh	$161	$54	$70	$49

CONVENTIONAL TECHNOLOGIES – COST DETAILS

Table 12 includes the conventional resource cost assumptions for the 2016 Preliminary Integrated Resource Plan.

Table 12 - Conventional Resource Cost Assumptions

Plant Construction Costs	Units	Small Aeroderivative Combustion Turbine	Small Frame Combustion Turbine	Natural Gas Reciprocating Engines	Small Modular Reactor (SMR)	Natural Gas Combined Cycle (NGCC)
Project Lead Time	Years	4	4	2	12	4
Installation Years	First Year Available	2020	2020	2018	2028	2020
Peak Capacity , MW	MW	45	75	2	300	550
Plant Construction Cost	2016 $/kW	$1,200	$770	$1,070	$6,000	$1,135
EHV/Interconnection Cost	2016 $/kW	50	30	30	400	165
Total Construction Cost	2016 $/kW	$1,250	$800	$1,200	$6,400	$1,300
Operating Characteristics						
Fixed O&M	2016 $/kW	$12.50	$13.25	$17.50	$29.30	$16.50
Variable O&M	2016 $/kW	$3.50	$3.75	$12.50	$5.00	$2.00
Gas Transportation	2016 $/kW	$16.80	$16.80	$16.80	-	$16.80
Annual Heat Rate	Btu/kWh	9,800	10,500	9,000	10,400	7,200
Typical Capacity Factor	Annual %	15%	8%	45%	85%	50%
Expected Annual Output	GWh	59	53	8	2,234	2,409
Fuel Source	Fuel Source	Natural Gas	Natural Gas	Natural Gas	Uranium	Natural Gas
Unit Fuel Cost	$/mmBtu	$5.67	$5.67	$5.67	$0.90	$5.67
Net Coincident Peak	NCP%	100%	100%	100%	100%	100%
Water Usage	Gal/MWh	150	150	50	800	350
Levelized Cost of Energy	$/MWh	$247	$306	$135	$145	$103

The following is a narrative from Lazard's ninth version of its Levelized Cost of Energy Analysis. Lazard's ninth version of its Levelized Cost of Energy Analysis ("LCOE 9.0") analysis provides an independent, in-depth study of alternative energy costs compared to conventional generation technologies. The central findings of the study are: 1) the cost competitiveness and continued price declines of certain alternative energy technologies; 2) the necessity of investing in diverse generation resources for integrated electric systems for the foreseeable future; and 3) the importance of rational and transparent policies that support a modern and increasingly clean energy economy.

Lazard - https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

LAZARD's LEVELIZED COST OF ENERGY ANALYSIS: KEY FINDINGS

Cost Competiveness of Alternative Energy Technologies

Certain alternative energy technologies (e.g., wind and utility-scale solar) continue to become more cost-competitive with conventional generation technologies in some applications, despite large decreases in the cost of natural gas. Lazard's analysis does not take into account potential social and environmental externalities (e.g., the social costs of distributed generation, environmental consequences of conventional generation, etc.) or reliability- or intermittency-related considerations (e.g., transmission system or back-up generation costs associated with certain alternative energy technologies)

Despite a sharp drop in the price of natural gas, the cost of all forms of utility-scale solar photovoltaic and utility-scale wind technologies continue to remain competitive with conventional generation technologies as illustrated by the proliferation of successful bids by renewable energy providers in open power procurement processes.

Currently, rooftop solar PV is not cost competitive without significant subsidies, due, in part, to the small-scale nature and added complexity of rooftop installation. However, the LCOE of rooftop solar PV is expected to decline in coming years, partially as a result of more efficient installation techniques, lower costs of capital and improved supply chains. Importantly, Lazard excludes from their analysis the value associated with certain uses of rooftop solar PV by sophisticated commercial and industrial users (e.g., demand charge management, etc.), which appears increasingly compelling to certain large energy customers.

Community based solar projects, in which members of a single community (e.g., housing subdivisions, rental buildings, industrial parks, etc.) own divided interests in small-scale ground-mounted solar PV facilities, is becoming more widespread and compelling in certain areas. These projects, which allow participants to receive credits against their electric bills either by state statute or negotiated agreements between the project sponsors and local utilities, provide solar energy access to consumers without the economic means or property rights to install rooftop solar PV. However, while community solar projects benefit from increased scale and decreased installation complexity as compared to rooftop solar PV, most community scale projects are relatively small compared to utility-scale PV projects, and are therefore more expensive compared to utility-scale solar PV.

The pronounced cost decrease in certain intermittent alternative energy technologies, combined with the needs of an aging and changing power grid in the U.S., has significantly increased demand for energy storage technologies to fulfill a variety of electric system needs (e.g., frequency regulation, transmission/substation investment deferral, demand charge shaving, etc.). Industry participants expect this increased demand to drive significant cost declines in energy storage technologies over the next five years. Increased availability of lower-cost energy storage will likely facilitate greater deployment of certain alternative energy technologies.

Energy efficiency remains an important, cost-effective form of alternative energy. However, costs for various energy efficiency initiatives vary widely and may fail to account for the opportunity costs of foregone consumption.

Very large-scale conventional and renewable generation projects (e.g., IGCC, nuclear, solar thermal, etc.) continue to face a number of challenges, including significant cost contingencies, high absolute costs, competition from relatively cheap natural gas in some geographies, operating difficulties and policy uncertainty.

The Need for Diverse Generation Portfolios

Despite the increasing cost-competiveness of certain alternative energy technologies, future resource planning efforts will require diverse generation fleets to meet baseload generation needs for the foreseeable future. The optimal solution for many utilities is to use alternative energy technologies as a complement to existing conventional generation technologies. Overall, the U.S. will continue to benefit from a balanced generation mix, including a combination of alternative energy and conventional generation technologies.

While some alternative energy technologies have achieved notional "grid parity" under certain conditions (e.g., best-in-class wind/solar resources), such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of conventional generation, etc.), or reliability- related considerations.

The Importance of Rational and Transparent Energy Policies

The rapidly changing dynamics of energy costs have important ramifications for the industry, policymakers and the public. In the U.S., a coordinated federal and state energy policy, grounded in cost analysis, could enable smarter energy development, leading to sustainable energy independence, a cleaner environment and a stronger economic base.

Alternative energy costs have decreased dramatically in the past six years, driven in significant part by federal subsidies and related financing tools, and the resulting economies of scale in manufacturing and installation. Many of these subsidies have already or are expected to step down or expire for selected alternative energy technologies. A key question for industry participants will be whether these technologies can continue their cost declines and achieve wider adoption without the benefit of subsidies

The public narrative surrounding alternative energy technologies remains focused to a large degree on rooftop solar PV, notwithstanding its significantly higher LCOE relative to utility- scale solar PV and wind, and its potentially adverse social effects in the context of existing net metering regimes (e.g., high-income homeowners benefiting from such regimes while still relying on the broader power grid, and related cost transfers to the relatively less affluent). This focus, combined with the availability of government incentives for rooftop solar, distorts intelligent system-wide integrated resource planning and policy.

See the full report at https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

Renewable Electricity Production Tax Credit ("PTC")

The federal renewable electricity production tax credit is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service for all facilities.

In December 2015, the Consolidated Appropriations Act, 2016 extended the expiration date for the production tax credit to December 31, 2019, for wind facilities commencing construction, with a phase-down beginning for wind projects commencing construction after December 31, 2016. The Act extended the tax credit for other eligible renewable energy technologies commencing construction through December 31, 2016. The Act applies retroactively to January 1, 2015.

The tax credit amount is adjusted for inflation by multiplying the tax credit amount by the inflation adjustment factor for the calendar year in which the sale occurs, rounded to the nearest 0.1 cents. The Internal Revenue Service ("IRS") publishes the inflation adjustment factor no later than April 1 each year in the Federal Registrar. For 2015, the inflation adjustment factor used by the IRS is 1.5336.

Applying the inflation-adjustment factor for the 2014 calendar year, as published in the IRS Notice 2015-20, the production tax credit amount is as follows:

- $0.023/kWh for wind, closed-loop biomass, and geothermal energy resources
- $0.012/kWh for open-loop biomass, landfill gas, municipal solid waste, qualified hydroelectric, and marine and hydrokinetic energy resources.

The tax credit is phased down for wind facilities and expires for other technologies commencing construction after December 31, 2016. The phase-down for wind facilities is described as a percentage reduction in the tax credit amount described above:

Table 13 – Production Tax Credit Phase Down

Construction Year (1)	PTC Reduction
2017	PTC amount is reduced by 20%
2018	PTC amount is reduced by 40%
2019	PTC amount is reduced by 60%

(1) For wind facilities commencing construction in year.

Note that the exact amount of the production tax credit for the tax years 2017-2019 will depend on the inflation-adjustment factor used by the IRS in the respective tax years. The duration of the credit is 10 years after the date the facility is placed in service.

See http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc for more details.

Energy Investment Tax Credit ("ITC")

The Consolidated Appropriations Act, signed in December 2015, included several amendments to the federal Business Energy Investment Tax Credit which apply to solar technologies and other PTC eligible technologies. Notably, the expiration date for these technologies was extended, with a gradual step down of the credits between 2019 and 2022.

The ITC has been amended a number of times, most recently in December 2015. The table below shows the value of the investment tax credit for each technology by year. The expiration date for solar technologies and wind is based on when construction begins. For all other technologies, the expiration date is based on when the system is placed in service (fully installed and being used for its intended purpose).

Table 14 – Investment Tax Credits by Year and Technology

Technology	2016	2017	2018	2019	2020	2021	2022	Future Years
PV, Solar Water Heating, Solar Space Heating/Cooling, Solar Process Heat	30%	30%	30%	30%	26%	22%	10%	10%
Hybrid Solar Lighting, Fuel Cells, & Small Wind	30%	-	-	-	-	-	-	-
Geothermal Heat Pumps, Microtubines, Combined Heat and Power Systems	10%	-	-	-	-	-	-	-
Geothermal Electric	10%	10%	10%	10%	10%	10%	10%	10%
Large Wind	30%	24%	18%	12%	-	-	-	-

Solar Technologies

Eligible solar energy property includes equipment that uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat. Hybrid solar lighting systems, which use solar energy to illuminate the inside of a structure using fiber-optic distributed sunlight, are eligible. Passive solar systems and solar pool-heating systems are not eligible.

Fuel Cells

The credit is equal to 30% of expenditures, with no maximum credit. However, the credit for fuel cells is capped at $1,500 per 0.5 kilowatt (kW) of capacity. Eligible property includes fuel cells with a minimum capacity of 0.5 kW that have an electricity-only generation efficiency of 30% or higher.

Small Wind Turbines

The credit is equal to 30% of expenditures, with no maximum credit for small wind turbines placed in service after December 31, 2008. Eligible small wind property includes wind turbines up to 100 kW in capacity.

Geothermal Systems

The credit is equal to 10% of expenditures, with no maximum credit limit stated. Eligible geothermal energy property includes geothermal heat pumps and equipment used to produce, distribute or use energy derived from a geothermal deposit. For electricity produced by geothermal power, equipment qualifies only up to, but not including, the electric transmission stage.

Microturbines

The credit is equal to 10% of expenditures, with no maximum credit limit stated (explicitly). The credit for microturbines is capped at $200 per kW of capacity. Eligible property includes microturbines up to 2 MW in capacity that have an electricity-only generation efficiency of 26% or higher.

Combined Heat and Power ("CHP")

The credit is equal to 10% of expenditures, with no maximum limit stated. Eligible CHP property generally includes systems up to 50 MW in capacity that exceed 60% energy efficiency, subject to certain limitations and reductions for large systems. The efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source, but the credit may be reduced for less-efficient systems.

See http://energy.gov/savings/business-energy-investment-tax-credit-itc for more details.

Impacts of Declining Tax Credits and Technology Installed Costs

Chart 10 through Chart 12 shown below reflects the near-term capacity price declines on a $/kW basis from 2016 - 2022 associated with the reduction in the installed costs of solar technologies relative to the levelized cost realized on a $/MWh assuming different levels of investment tax credits by year. The solar ITC assumptions are based on the federal investment tax credit assumptions shown on page 74.

Chart 10 – Solar PV Fixed, Impacts of Declining Tax Credits and Technology Installed Costs

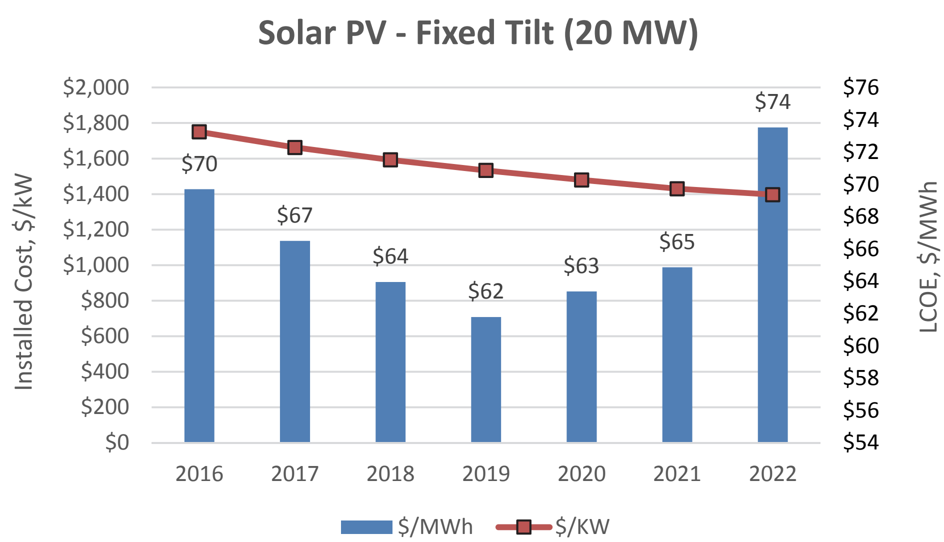


Chart 11 – Solar SAT, Impacts of Declining Tax Credits and Technology Installed Costs

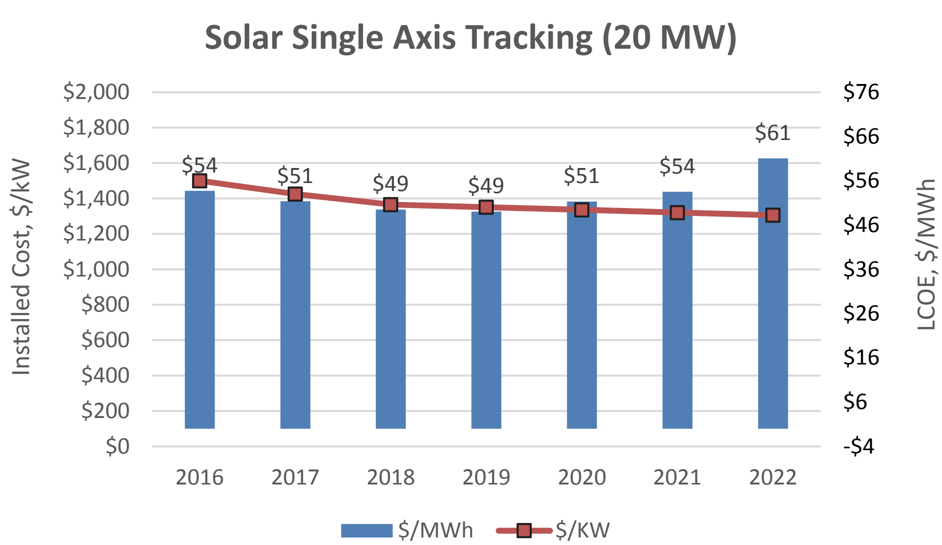
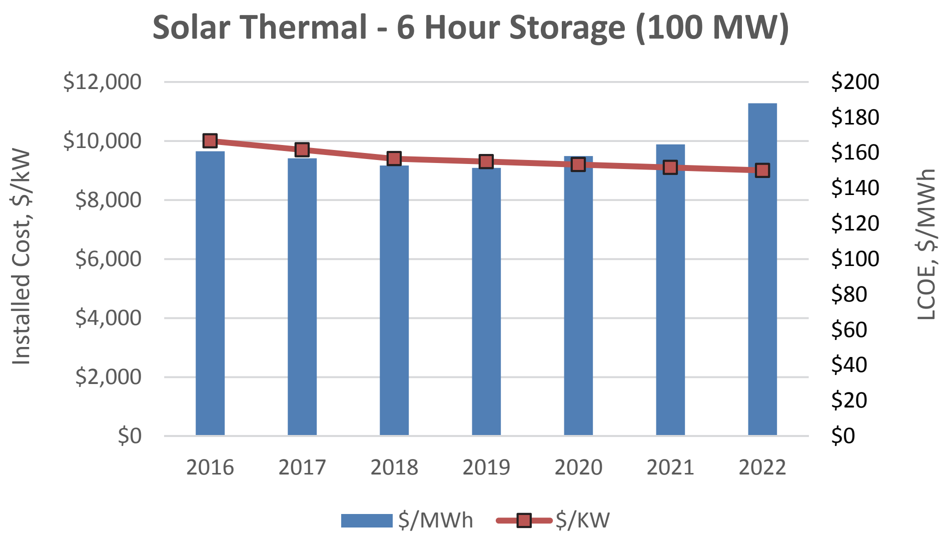


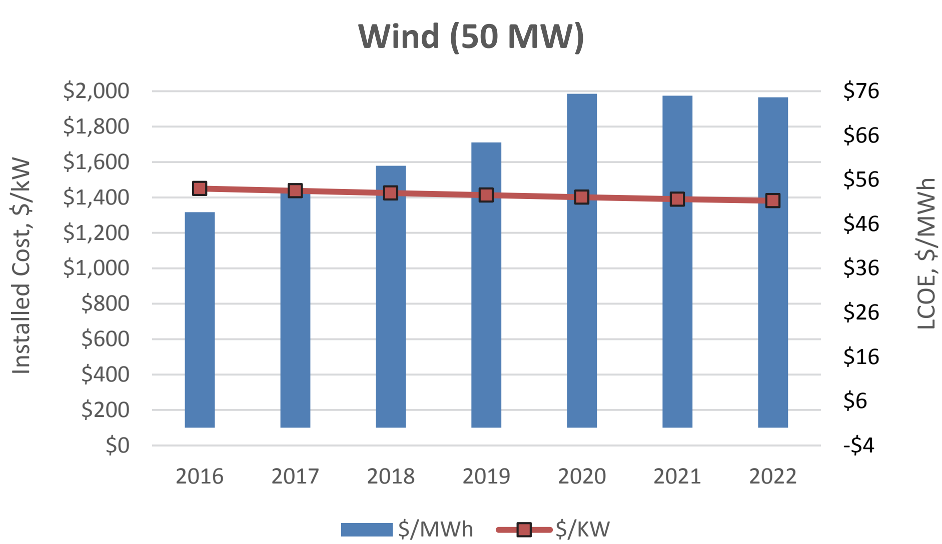
Chart 12 – Solar Thermal, Impacts of Declining Tax Credits and Technology Installed Costs



Impacts of Declining PTC and Technology Installed Costs

Chart 13 shown below reflects the near-term capacity price declines on a $/kW basis from 2016 - 2022 associated with the reduction in the installed costs of wind resources relative to the levelized cost realized on a $/MWh assuming different levels of production tax credits by year. The wind PTC assumptions are based on the federal production tax credit assumptions shown on 73.

Chart 13 – Wind, Impacts of Declining Production Tax Credits and Technology Price Installed Costs

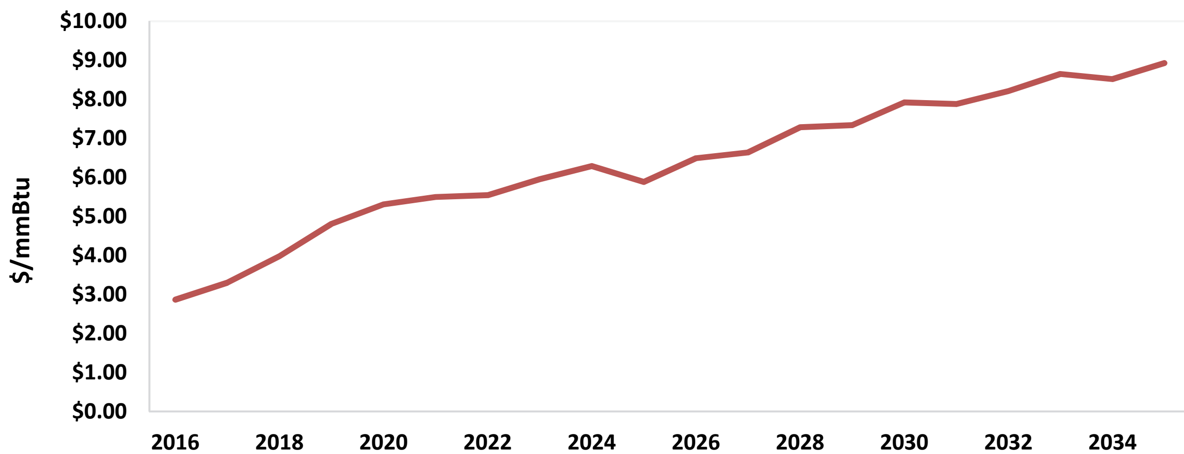


MARKET ASSUMPTIONS

Permian Natural Gas

TEP's current forward price forecast for Permian natural gas starts at $2.86/MMBtu in 2016, and escalates to $8.93/MMBtu in 2035. Chart 14 - Permian Basin Natural Gas Prices shows the 20 year natural gas price projections in nominal dollars.

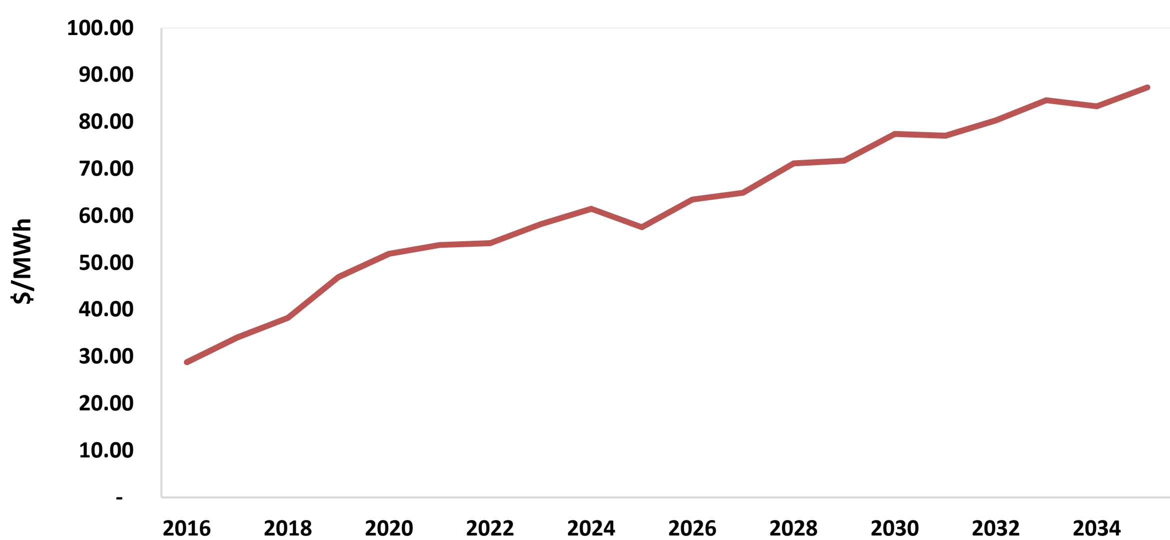
Chart 14 - Permian Basin Natural Gas Prices



Palo Verde (7x24) Market Prices

TEP's current forward price forecast for 7x24 Palo Verde wholesale market prices starts at $28.76/MWh in 2016, and escalates to $87.35/MWh in 2035. Chart 15 shows the 20 year wholesale power price projections in nominal dollars.

Chart 15 - Palo Verde (7x24) Market Prices



Chapter 7

2016 IRP SCENARIOS

The following section provides a description of the different scenarios to be analyzed in the 2017 Final IRP which is due on April 1, 2017. There are a total of 7 scenarios that will be presented in the IRP. The scenarios are listed and grouped as follows;

- Scenarios Requested by Decision No. 75068 (2014 IRP)
  - Energy Storage Case Plan
  - Small Nuclear Reactors Case Plan
  - Expanded Energy Efficiency Case Plan
  - Expanded Renewables Case Plan
- Additional Proposed Scenarios
  - Market Based Reference Case Plan
  - High Load Growth Case Plan
  - Full Coal Retirement Case Plan

Scenarios Requested in Decision No. 75068 (2014 IRP)

Energy Storage Case

In this case, TEP will explore the potential of Energy Storage Systems ("ESS") as a means for solving renewable generation intermittency and variability. The case will be designed to fully meet renewable and energy efficiency standards and to the extent that peaking capacity is required, ESS will be analyzed as a resource to cover peak demand requirements. The potential and applicability of ESS is described in the storage section in Chapter 4.

Small Nuclear Reactors Case

Small Nuclear Reactors ("SMRs") are a technology that can be utilized to lower carbon dioxide ("CO_2") emissions, as well as other pollutants, while providing reliable, sustained and efficient power output. In this case, TEP will study the impact of SMRs as a resource to supplant retiring base load coal assets. This case will be designed to fully meet renewable and energy efficiency standards. This case will also be compliant with the Clean Power Plan.

Low Load Growth Case and Expanded Energy Efficiency

For purposes of this scenario, it is assumed that TEP realizes additional energy efficiency and distributed generation targets (above the EE standard). Under this scenario, TEP's EE programs are expanded by program design and/or by technology efficiency improvements. In addition, any potential mining expansions will be excluded as well.

Expanded Renewables Case

TEP will present this scenario to study the impact of expanded renewable development. Under this scenario, TEP will incrementally develop a community-scale renewable portfolio that ultimately results in TEP serving 30% of its retail load by 2030 (with renewable resources). In this scenario, TEP anticipates that complementary resources will be needed to maintain reliability and to achieve responsiveness to the intermittent and variable characteristics of solar and wind resources. A combination of different technologies (or individual technologies) will be tested to complement the renewables assumptions.

As higher percentages of renewable resources are added to TEP's resource portfolio, TEP anticipates the need for future investments in transmission, quick-start generation, energy storage devices and smart grid technologies in order to maintain reliable grid operations. For purposes of reliability, the 2016 Final IRP will study the expansion of battery storage technology, reciprocating internal combustion engines and other technology to support future ancillary service requirements for the grid.

Additional Proposed Scenarios

Market Based Reference Case

For purposes of the 2016 Final IRP, TEP will again develop a Market Based Reference Case plan. Under this scenario, it is assumed that TEP relies on the wholesale market for limited amounts of firm wholesale purchased power agreements to meet its future summer peaking requirements. This scenario provides some insights into how TEP's resource portfolio might look if there is adequate supply of merchant resource capacity within the Desert Southwest region over the long-term. For purposes of this scenario, it is assumed that TEP develops a portfolio of long and short-term purchased power agreements to cover its summer peaking requirements. It is assumed that TEP limits its reliance on firm market capacity purchases to 400 MW per year. All other assumptions including transmission, CPP compliance, and renewable technology upgrades are the same as the Reference Case plan.

High Load Growth Case - Large Industrial Customer Expansions

For purposes of this scenario, it is assumed that TEP's peak demand increases significantly over the next five years due to an expansion of a new or existing large industrial customer. Under this scenario, TEP's peak demand increases by 125 MW in 2018 and again in 2020 by 125 MW (for a total of 250 MW, a 10% increase in retail demand). This change in the forecast would result in the advancement of both transmission and generation resources in the near term. Given the high load factors associated with these types of customers, this scenario would likely show the need for additional base load and intermediate resources.

Full Coal Retirement Case

As ordered by the ACC in the 2012 IRP, TEP generated a scenario called "Full Coal Retirement Case". This case was studied in the 2014 IRP in anticipation of potential alternative outcomes resulting from EPA Regional Haze mandates. For the 2016 preliminary IRP, TEP will model a similar scenario that replaces 100% or approximately 1,500 MW of TEP's existing coal capacity with new resources by 2031.

Chapter 8

Fuel, Market and Demand Risk Analysis

For the 2017 Final IRP, TEP plans to developed explicit market risk analytics for each candidate portfolio through the use of computer simulation analysis using AuroraXMP[16]. Specifically a stochastic based dispatch simulation will be used to develop a view on future trends related to fuel prices[17], wholesale market prices, and retail demand. The results of this modeling will then be employed to quantify the risk uncertainty and evaluate the cost performance of each portfolio. This type of analysis ensures that the selected portfolio not only has the lowest 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, TEP plans to conduct risk analysis around the following key variables:

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

A summary of the input distributions are shown for all these variables on Chart 16 through Chart 19 below:

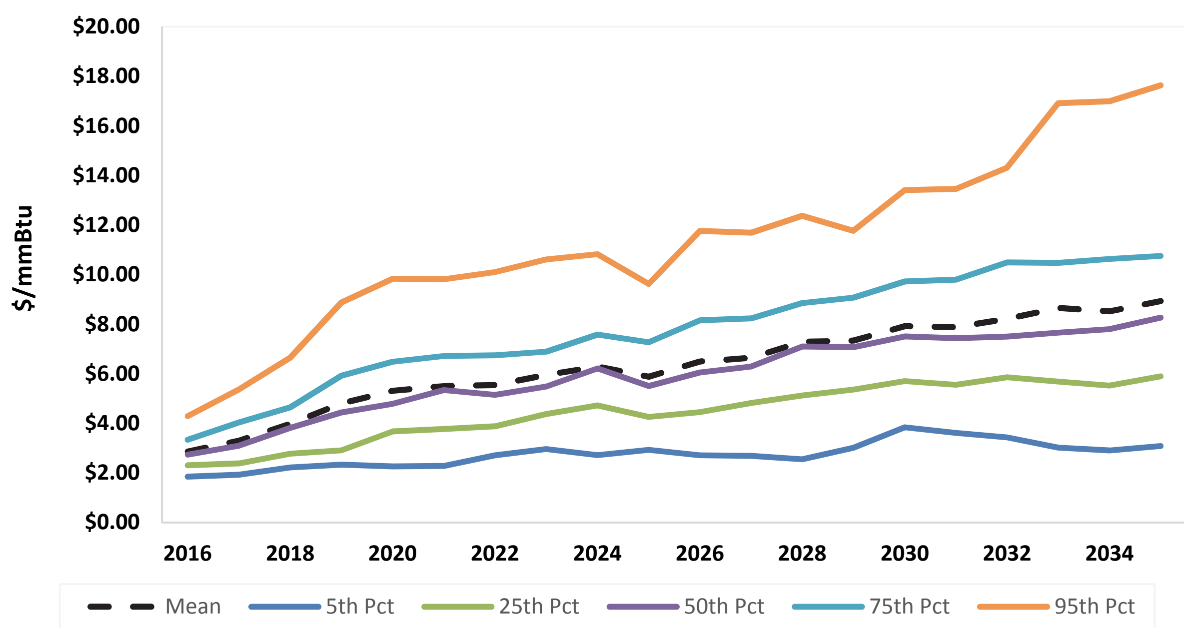
[16] AURORAxmp is a stochastic based dispatch simulation model used for resource planning production cost modeling. Additional information about AURORAxmp can be found at http://epis.com/
[17] Both natural gas and coal.

NATURAL GAS & WHOLESALE MARKET PRICE SENSITIVITY

Permian Natural Gas

Chart 16 shows both the expected forward market prices as well as the expected price distributions for natural gas sourced from the Permian Basin.

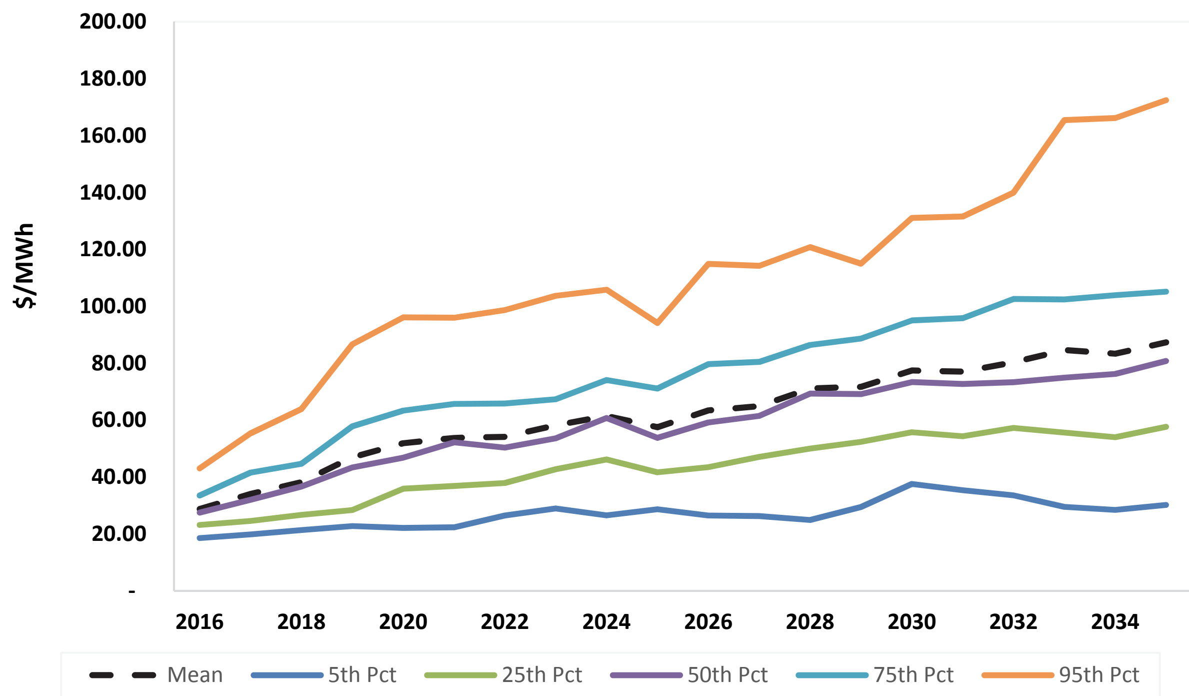
Chart 16 - Permian Basin Natural Gas Price Distributions



Palo Verde (7x24) Market Prices

Chart 17 shows both the expected forward wholesale market prices as well as the expected price distributions for power sourced from the Palo Verde market.

Chart 17 - Palo Verde (7x24) Market Price Distributions

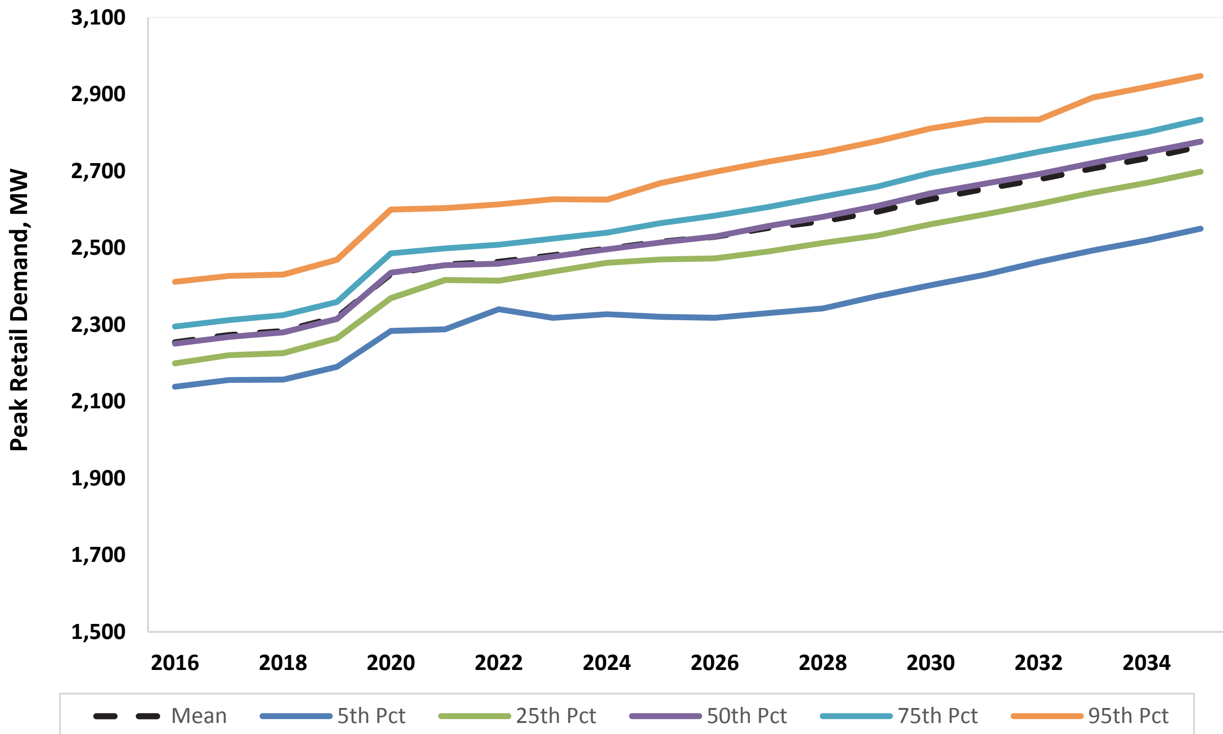


When considering Chart 16 and Chart 17 from above, it is important to note that the summary statistics are aggregations rather than individual price paths. For instance the P95 number for a given year represents the point which 95% of simulated values fall below. Individual price paths mimic realistic behavior by being subject to the price "spikes," mean reversion, and uneven trend observed in actual markets.

LOAD GROWTH SENSITIVITY

Chart 18 shows both the expected retail peak demand as well as the expected demand distributions for TEP's retail customers.

Chart 18 – TEP Peak Retail Demand Distributions



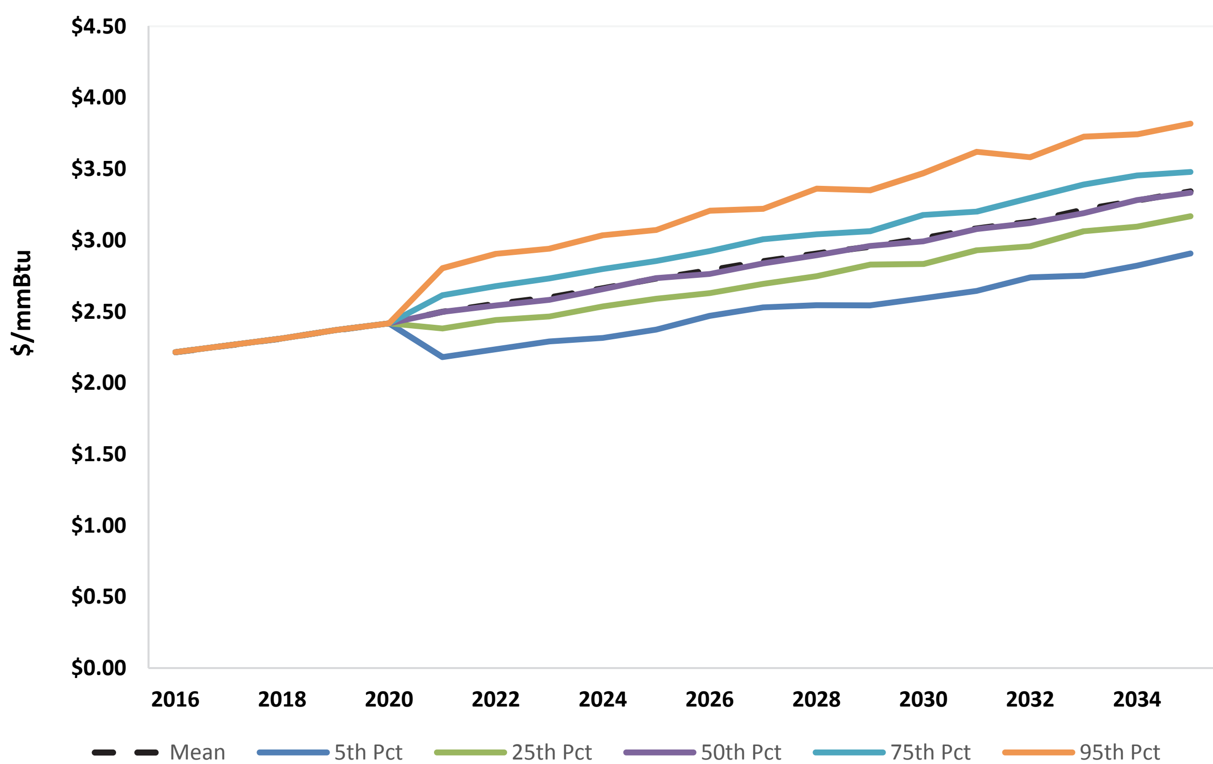
COAL PRICE SENSITIVITY

TEP currently has ownership shares in four coal-fired power plants in Arizona and New Mexico, most of which are under long-term contracts for coal supply.

- **San Juan:** The plant is a mine-mouth facility that receives coal from the San Juan mine. It has recently signed a short-term contract through July 2022.
- **Springerville:** The plant has access to local coal from the El Segundo mine in New Mexico via rail deliveries. Springerville can burn both Western subbituminous coal as well as coal sourced from Power River Basin.
- **Navajo:** The plant receives coal from the Kayenta mine which is adjacent to the plant. TEP is under a long-term coal supply agreement through 2030.
- **Four Corners:** The Four Corners Power plant is sourced from the Navajo Coal mine, which is mine-mouth facility, operated by the Navajo Transitional Energy Company. The Four Corners' CSA runs through 2031.

TEP plans to model coal prices based on contract idiocies and escalators that are driven by the coal market outlook to establish coal price projections for the TEP fleet. Chart 19 reflects the range of coal pricing based on current assumptions.

Chart 19 – TEP Coal Price Distributions



Chapter 9

2016 – 2017 Action Plan

In accordance with Decision No. 75269, this 2016 Preliminary IRP introduces and discusses the issues that TEP may analyze in detail for the2017 Final IRP. TEP will continue to develop a final IRP in accordance with the schedule outlined in Decision No. 75269. The schedule includes the following milestones, which TEP will meet.

File 2016 Preliminary Integrated Resource Plan	March 1, 2016
Submit Preliminary Integrated Resource Plan Update	October 1, 2016
Pre-filing Workshop on Final Integrated Resource Plan	November 2016
File 2017 Final Integrated Resource Plan	April 3, 2017

The decision to defer the deadline for filing a final 2017 IRP was largely due to the impact that the CPP is anticipated to have on future resource plans, and the high degree of uncertainly around how the CPP will be implemented in the jurisdictions where the regulated load-serving entities have facilities. The EPA has responsibility for preparing an implementation plan for the Navajo Nation[18] (including Navajo and Four Corners), and EPA intends to finalize a Federal Plan by September 6, 2016. Much of the detail regarding CPP implementation on the Navajo Nation will be included in the Federal Plan[19]. As described previously, the US Supreme Court has issued a stay of the CPP pending litigation in the DC Circuit Court and including potential US Supreme Court review. During the stay, States are not obligated to begin work on State Plans, and the deadlines for those plans, as well as compliance timelines for affected units, will need to be adjusted if the rule remains in place following litigation. Arizona and New Mexico are currently evaluating if and how to proceed in light of the stay. A final ruling on the CPP litigation is not expected prior to June of 2017, and may not be issued until 2018.

The 2017 Final IRP will be due prior to the completion of all of the State Plans governing CPP implementation, therefore, TEP anticipates that the 2017 Final IRP will have to accommodate significant uncertainty with regard to CPP implementation. Scenarios and/or sensitivities to address this uncertainty will be presented in the October 2016 IRP Update, to the extent they have been identified.

TEP has developed a short-term action plan based on the resource decisions that must be implemented in parallel with development of the 2017 Final 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.

[18] In comments filed on January 21, 2016, in response to EPA's proposed Federal Plan and Model Trading Rules [80 FR 64966], UNS Energy on behalf of TEP commented that it is not "necessary or appropriate" to regulate affected plants on the Navajo Nation, and EPA should not do so.

[19] In comments filed on January 21, 2016, in response to EPA's proposed Federal Plan and Model Trading Rules [80 FR 64966], the Arizona Utilities Group commented that promulgating "model" Federal Plans does not relieve EPA of the responsibility to provide adequate public notice and comment of the agency's intent to impose a Federal Plan on a specific state or tribe.

TEP's near term action plan includes the following:

- TEP is involved in litigation with the two Co-Owners of Springerville Unit 1 over various issues regarding Unit 1. TEP has contested all allegations and vigorously advocated its positions in these matters. The Co-Owners have failed to pay any of the costs and expenses relating to their share of ownership in Springerville Unit 1 since the leases ended in December 2014. All of these proceedings are ongoing, but are currently stayed incident to a settlement agreed to by the parties in February 2016. . As a result of the resolution of these legal matters, TEP is preparing for the acquisition of the un-owned portion of Springerville Unit 1. TEP's current share of Springerville Unit 1 is a vital piece of our supply portfolio.

- TEP plans to continue with its utility scale build out of its current renewable energy standard implementation plans. TEP anticipates that an additional 1100 MW of new renewable capacity will be in-service by the end of 2030 raising the total distributed generation and utility scale capacity on TEP's system to approximately 1500 MW. By the end of 2016, renewable resources will make up close to 13% of TEP's total nameplate generation capacity. As a result, TEP is currently investing its time and resources into a number of research and development activities that will determine the future need for storage and smart grid technologies to support the grid, including two 10MW energy storage projects slated for in service by 2018.

- TEP will continue to implement cost-effective EE programs based on the Arizona EE Standard. TEP will closely monitor its energy efficiency program implementations and adjust its near-term capacity plans accordingly.

- As part of its near-term portfolio strategy, TEP will continue to utilize the wholesale merchant market for the acquisition of short-term market based capacity products. In addition, TEP will continue to monitor the wholesale market for other resource alternatives such long-term purchased power agreements and low cost plant acquisitions. TEP will also monitor its natural gas hedging requirements as it reduces its reliance on coal based generation in favor of natural gas resources and make recommendations on potential fuel hedging changes if they become necessary.

TEP plans to communicate any major change in its anticipated resource plan with the ACC as part of its ongoing planning activities. TEP hopes this dialog will allow the Commission an opportunity to help shape TEP's future resource portfolio outcomes while providing TEP with greater regulatory certainty with regards to future resource investment decisions.