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April 1, 2014

Docket Control
Arizona Corporation Commission
1200 W. Washington
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ORIGINAL

RE: Arizona Public Service Company's 2014 Resource Plan
Docket No. E-00000V-13-0070

Arizona Public Service Company submits its 2014 Resource Plan pursuant to A.A.C. R14-2-703(C), (D), (E), (F), (H), and (I). The competitively confidential portion of this filing is being provided to Staff in a subsequent filing pursuant to an executed Protective Agreement in this matter. This filing will also be available on APS's website at www.aps.com/resources.

If you have any questions regarding this information, please contact Gregory Bernosky at (602)250-4849.

Sincerely,

for

Lisa Malagon

LM/cd
Attachment

cc: Steve Olea
Brian Bozzo
Terri Ford
Rick Lloyd

Arizona Corporation Commission
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2014 INTEGRATED RESOURCE PLAN

APRIL 2014 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

Forward-Looking Statements

This report contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "forecast," "estimate," "projection," "may," "believe," "expect," "plan," "require," "intend," "assume," and similar words. Because actual results may differ materially from expectations, APS cautions against placing undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by APS. A discussion of some of these risks and uncertainties is contained in APS's Annual Report on Form 10-K filed with the Securities and Exchange Commission, available on APS corporate parent's website at www.pinnaclewest.com, which should be carefully reviewed before placing any reliance on APS's forward-looking statements, financial statements or disclosures. APS assumes no obligation to update any forward-looking statements, even if internal estimates change, except as may be required by applicable law.

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EXECUTIVE SUMMARY

The 2014 Resource Plan at a Glance

The 2014 Integrated Resource Plan (2014 IRP) lays out how APS is planning to meet the projected nearly 13,000 MW resource requirement within its service territory by 2029. When combining load growth with contract expirations and unit retirements, APS anticipates needing over 6,600 MW of additional resources. To meet that need, APS evaluated several combinations of resource options in compliance with the Arizona Corporation Commission (ACC) Resource Planning and Procurement Rules, and Renewable Energy and Energy Efficiency Standards. The 2014 IRP details the inputs that went into the portfolio evaluation process, including a broad array of resources, costs and environmental variables, and the analytical framework used in the evaluation. The conclusion of this process was clear: low natural gas prices combined with the cost of environmental regulations and increases in self-dispatching solar generation will favor highly flexible natural gas resources over traditional baseload resources. Continued investment in advanced grid technologies is expected to provide further flexibility to the APS system.

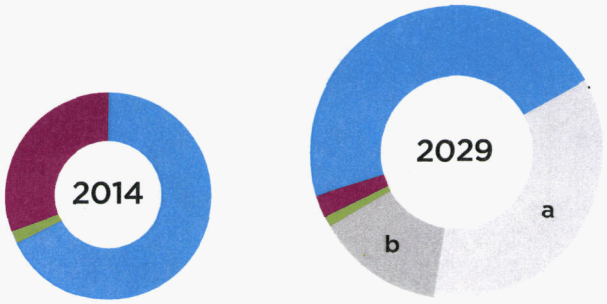
2014-2029 (PROJECTED)

FUTURE ADDITIONAL RESOURCES: 6,613 MW AT PEAK MET WITH

a. New Utility-Scale Resources
   Natural Gas - **4,205 MW**
   Renewable Energy - **425 MW** (818 MW Nameplate Capacity)

b. New Customer Resources
   Energy Efficiency - **1,447 MW**
   Distributed Energy - **261 MW** (722 MW Nameplate Capacity)
   Demand Reponse - **275 MW**

- Exisitng Customer Resources
- Existing Contracts
- Existing Utility-Scale Resources
- a New Utility-Scale Resources
- New Customer Resources



8,124 MW peak requirement **100%** met with existing resources

12,982 MW peak requirement **50%** met with existing resources

Figure ES-1 - 2014 vs. 2029 Peak Requirements

INVESTING IN ARIZONA'S ENERGY FUTURE

ENERGY PORTFOLIO INVESTMENT

$13.6 billion

Planned to secure sufficient assets to meet requirements under the Selected Portfolio

TRANSMISSION INVESTMENT

$496 million

Needed to support reliability, coordination, aging infrastructure and integration of renewable energy

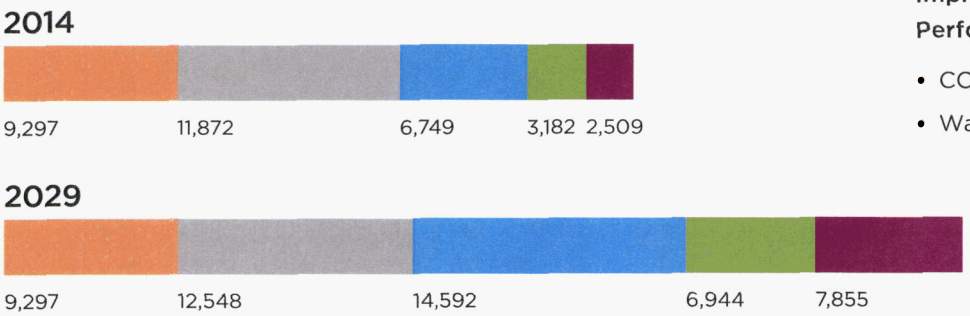
ADVANCED GRID INVESTMENT

$300 million

Planned to support reliability, integrate distributed energy and emerging technologies

HOW THE PORTFOLIO MAY CHANGE

COMPOSITION OF ENERGY MIX BY RESOURCE (GWH)



Improves Environmental Performance:

- CO2 Intensity ▼ **14%**
- Water Intensity ▼ **24%**

■ Nuclear ■ Coal ■ Natural Gas ■ Renewable Energy ■ Energy Efficiency

Figure ES-2 - 2014 vs. 2029 Energy Mix

Portfolio Selection

APS analyzed four portfolios before arriving at the Selected Portfolio as the most reasonable mix of resources for the 2014 IRP. The analysis focused on flexibility, reliability, cost, environmental impact and risk, among others.

The following table summarizes the analysis of the portfolios, including criteria considered for each. All portfolios include modernizing the Ocotillo power plant to support Valley reliability and renewable energy integration.

TABLE ES-1 - 2014 IRP PORTFOLIO SELECTION

2014 IRP PORTFOLIOS CONSIDERED	SELECTED PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Description	**Modernize Ocotillo; continue coal operations; EE and RE compliance**	**Modernize Ocotillo; continue coal operations; EE compliance; RE well above compliance**	**Modernize Ocotillo; replace Cholla with gas and renewable generation; EE compliance; RE slightly above compliance**	**Modernize Ocotillo; convert Cholla to gas operation; EE and RE compliance**
RESOURCE CONTRIBUTIONS (2029 PEAK CAPACITY CONTRIBUTION / % ENERGY MIX)				
Nuclear	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%
Coal	1,932 MW / 24.5%	1,932 MW / 23.4%	1,285 MW / 16.9%	1,285 MW / 16.9%
Natural Gas	7,137 MW / 28.5%	6,933 MW / 21.9%	7,749 MW / 35.0%	7,784 MW / 36.1%
Renewable Energy & Distributed Energy	1,088 MW / 13.6%	1,298 MW / 21.3%	1,117 MW / 14.7%	1,088 MW / 13.6%
Energy Efficiency & Demand Response	1,722 MW / 15.3 %	1,722 MW / 15.3%	1,722 MW / 15.3%	1,722 MW / 15.3%

WHY THE SELECTED PORTFOLIO WAS CHOSEN

Resource planning does not establish a guarantee of future conditions or develop a transactional roadmap. Rather, the IRP process enables APS to develop long-term plans and evaluate which resource options may be appropriate given today's forecasts of future energy needs, resource costs and associated uncertainties. In the formulation of the 2014 IRP, uncertainties regarding environmental regulation and the evolving nature of the electric industry significantly influenced the selection process. The Selected Portfolio was chosen because it provides the most reasonable combination of overall economic performance, and flexibility in the generation fleet to support grid reliability, integrate renewable energy and manage uncertainties. Moving through the Planning Period, circumstances governing current assumptions and forecasts will undoubtedly change and will be updated in future resource plans, potentially shifting the preferred portfolio.

Emerging Trends Altering Industry

Across the country and throughout the world, the electric utility industry is changing. Technological advancements, regulatory requirements and increasing levels of variable generation are reshaping not only how and where APS generates energy, but also how customers use it. Important for APS is the growth of solar generation, one of the fastest-growing energy sources in the Company's service territory. Solar generation adds environmentally-friendly energy when the sun shines, and it also requires a responsive, supportive electric grid and additional flexible resources to balance the system in order to continue meeting customers' energy needs reliably.

Conventional resources, such as coal and nuclear, have provided steady, reliable generation to Arizonans for decades, but due to their relatively inflexible operation, traditional baseload resources will begin to be challenged. Natural gas, propelled by technological innovation in its exploration and extraction, will play an increasingly important role in transforming the resource portfolio into one that is more flexible and responsive to the needs of customers, as well as the broader electric grid.

APS is transitioning toward an energy resource portfolio that is not just reliable and cost-effective, but increasingly flexible and responsive

VARIABILITY REQUIRES FLEXIBILITY

Over the long run, integrating the next generation of energy assets will require more than just an increasing role for natural gas. An adaptation of current systems is also needed. The energy infrastructure in place today was designed to flow power to customers. Now, and increasingly in the future, power is not only flowing to customers, but is also flowing from customers and is challenging the scope of today's grid. This change is ushering in new platforms—a broader spectrum of energy resources, a two-way, real-time communication network to support them, and a smarter energy system to integrate them. Managing and meeting these challenges will guide the industry in developing needed assets, integrating advanced technologies and adding responsiveness to conventional resource fleets, including at APS. To make the development and implementation of these advancements possible, a comprehensive effort towards greater flexibility will be needed across the entire energy spectrum, including utilities, customers, regulators and other stakeholders.

CUSTOMERS: APS'S ENERGY PARTNERS

As the industry navigates through these changes over the coming decades, the call for adaptability will become increasingly clear. Innovation will continue to redirect the narrative and in doing so, refocus options. Already, the changes have been significant. Electric grids are making it possible for customers to generate electricity not only for their own use but also for sale back to the grid. Distributed generation, as well as energy efficiency, is transforming customer relationships into that of energy partners. Demand response is also enabling customers more control over when their energy is delivered and at what price points. In virtually every phase of the energy process, APS's interaction with customers has deepened and that trend is projected to continue.

2014 RESOURCE PLAN: KEY ELEMENTS

The 2014 IRP is organized across six broad sections: (a) Executive Summary - discusses changes in the energy industry and the increasing need for flexibility in responding to those changes, (b) IRP Overview - discusses steps included in the preparation of the IRP, (c) Needs & Resources - identifies the resource need and resources to fill that need, (d) Planning Inputs & Other Considerations - includes an overview of analytical inputs used in the portfolio selection model, (e) Determining the Most Reasonable Plan - lays out how those inputs were utilized in the portfolio selection process and (f) 2014-2018 Action Plan - details the 2014-2018 Action Plan

Change Has Already Transformed the Portfolio

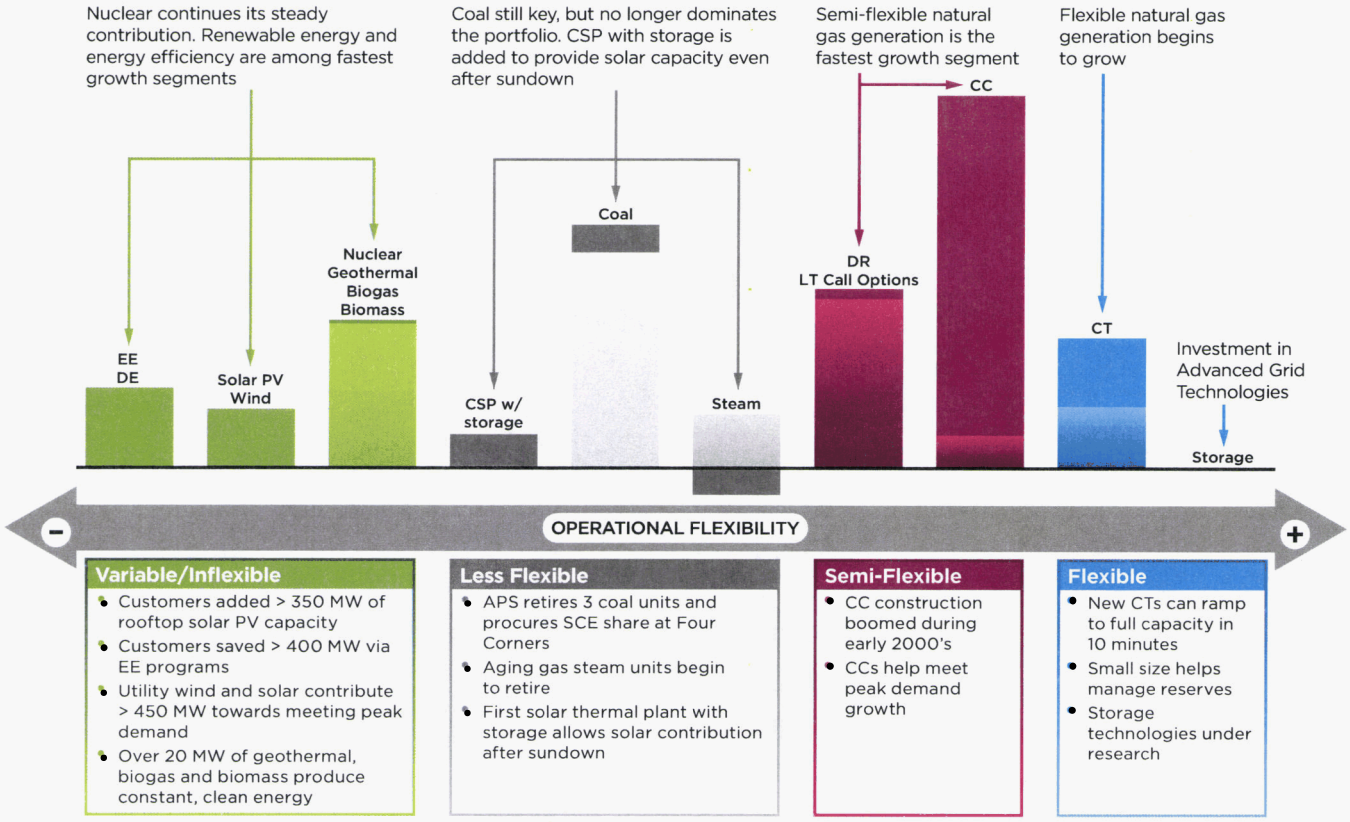
ASSET CLASSIFICATIONS TO FIT THE TIMES

To better reflect the changing environment, APS has developed a method of viewing asset classifications based on operational flexibility.

- **Variable/Inflexible** – These are assets that cannot be dispatched flexibly. In some cases, resources in this group are variable and dispatch themselves, such as solar and wind, and also require additional operational flexibility from other generation resources. With the exception of nuclear, energy production of this group is not fully managed by APS. Resources include nuclear, energy efficiency, distributed solar PV, utility-scale solar PV, wind, geothermal, biogas and biomass.
- **Less Flexible** – Less flexible assets have limited capability to adjust output in response to other resources or system needs. Resources include coal, older steam plants and solar with storage capabilities.
- **Semi-Flexible** – Semi-flexible assets are able to adjust output to help integrate variable resources and can generally respond to system needs. These assets however, have relatively limited stopping and starting capabilities. Resources include combined cycle units and market purchases.
- **Flexible** – This group of assets is able to start and adjust output quickly, and is capable of multiple starts/stops per day. Flexible assets complement variable resources and respond to system needs quickly. Resources include combustion turbines and eventually, storage.

2000 – 2014

RENEWABLE ENERGY AND ENERGY EFFICIENCY MORE PROMINENT IN PORTFOLIO



Darker areas above the line represent resource additions
Darker areas below the line represent resource retirements/contract expirations
Refer to the Glossary and Table of Acronyms for terms used in this chart

Figure ES-3 - 2000–2014 Asset Classification

Continuing the Evolution to 2029

15 YEARS MAKES A DIFFERENCE: FROM 2000 TO TODAY

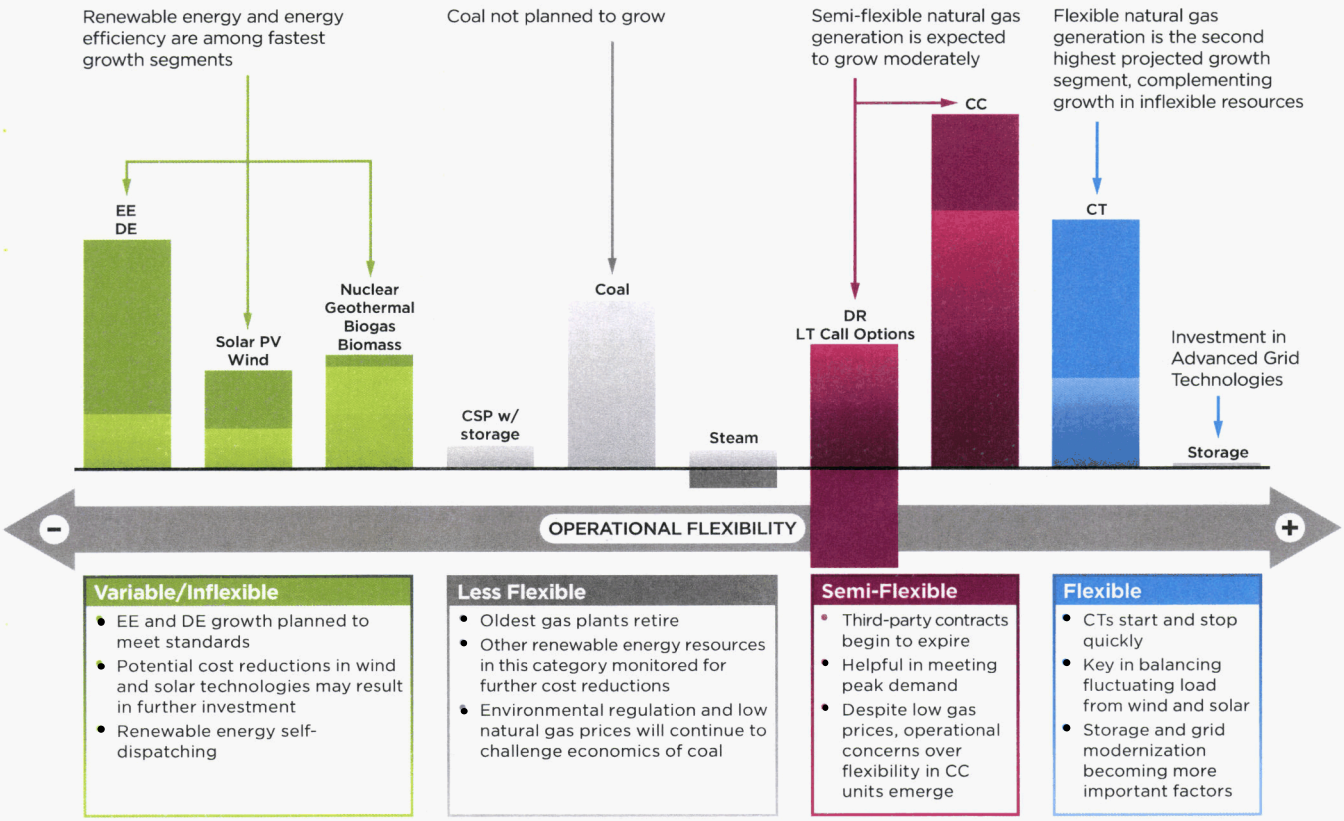
- **Variable/Inflexible** - Fifteen years ago, APS had limited variable/inflexible resources. Today, this category is projected to have the highest growth of the analyzed portfolios.
- **Less Flexible** - Once the dominant asset group, coal and natural gas steam resources are not projected to have growth.
- **Semi-Flexible** - Semi-flexible resources have evolved from being a small contributor to the largest asset class.
- **Flexible** - Projected growth in these assets complements the variable/inflexible group, an important concept moving forward.

BALANCED PORTFOLIO GROWTH AT BOTH ENDS OF THE FLEXIBILITY SPECTRUM POSITIONS APS FOR THE FUTURE

At the end of the current 15-year Planning Period, operating conditions are expected to be considerably different than they are today. Increases in variable generation will require corresponding increases in highly flexible, complementary resources to provide APS with the tools to manage an increasingly evolving energy system.

2014 – 2029

MORE FLEXIBILITY IN GENERATION AND GRID TECHNOLOGIES REQUIRED



Darker areas above the line represent resource additions
Darker areas below the line represent resource retirements/contract expirations
Refer to the Glossary and Table of Acronyms for terms used in this chart

Figure ES-4 - 2014–2029 Asset Classification

Solar Energy's Influence

As distributed energy penetration increases across the region, so does its influence on conventional power generation. The discussion below details how customer power consumption patterns may change if distributed energy penetration growth rates continue to increase, and how APS is positioning its conventional generation fleet to respond.

From a net customer demand perspective, the dips in the following charts indicate the portion of the day when solar PV produces energy and how that production does not align with peak power consumption. Solar PV energy can significantly reshape net consumption patterns. Due to the misalignment of solar production with peak energy consumption, the resulting residual demand that APS and other utilities must meet requires generation that is able to start up in the morning, shut down by mid-day to accommodate the increase in solar production, and then start back up in the evening as the sun sets and solar production shuts down. This dual-peak nature of net customer demand will require a significantly more flexible and responsive resource portfolio across the region and may drive competition for natural gas resources.

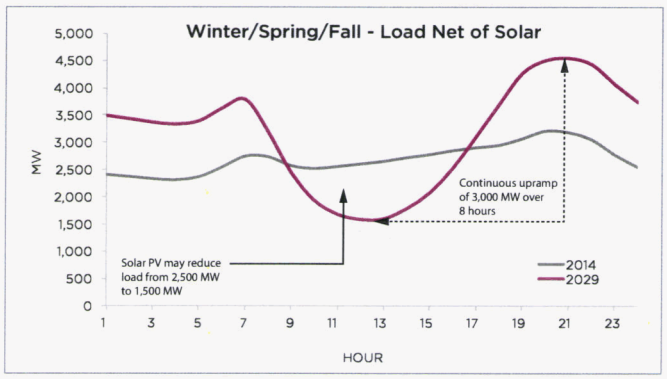


Figure ES-5 - Winter/Spring/Fall - Load Net of Solar

- As the forecast progresses to 2029, the peak hour will shift to later in the day as solar production decreases
- Solar PV may reduce minimum load to 1,500 MW from 2,500 MW
- Lower midday demand may result in over-generation conditions during certain hours
- Increased need for system voltage support
- Future generation technology needs change

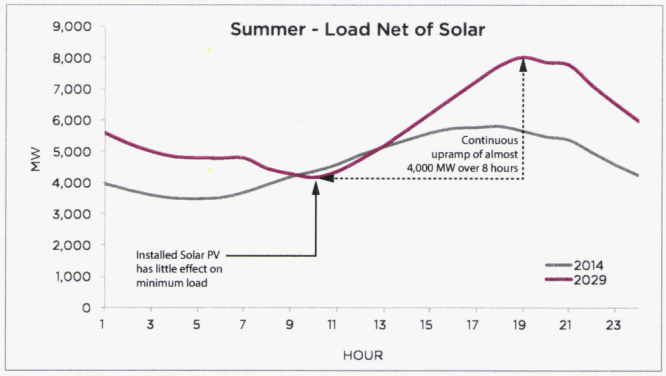


Figure ES-6 - Summer - Load Net of Solar

- As more solar PV is installed, its contribution to peak diminishes, resulting in customers essentially paying twice for resources—once for rooftop solar and again for the utility resources to meet peak demand once the sun sets
- Greater need for system visibility and two-way communication

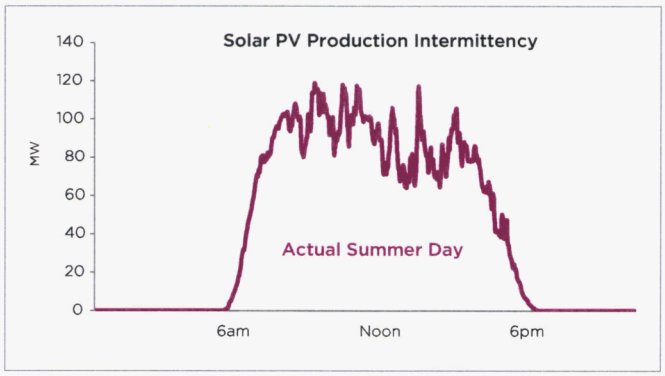


Figure ES-7 - Solar PV Production Intermittency

The graph on the left depicts minute-by-minute production from solar resources and illustrates how solar energy's output must be complemented by conventional resources and supported by the grid.

- As solar penetration increases, reliance on conventional resources and grid responsiveness will also increase
- Forecasting becomes critical in order to manage appropriate reserve margins

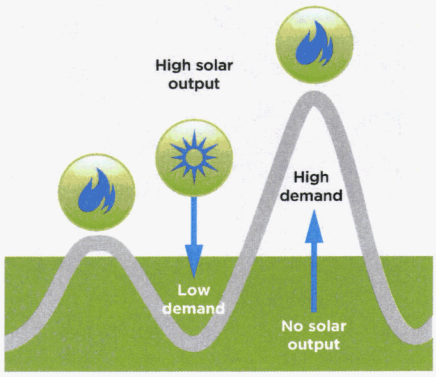
Flexible Generation: A Complementary Resource

Most power plants operating today are relatively inflexible, meaning they cannot easily accommodate the variability of renewable and customer resources to ensure a continuous power supply. This has not yet impacted system reliability for APS, because customer demand has been largely predictable and levels of variable resources are still a modest percentage of the overall energy mix.

However, the potential growth of renewable energy—particularly in solar-rich areas such as Arizona—is significant and transformative. Supply intermittency is projected to be a greater factor in day-to-day power operations and will require complementary resources, such as quick-starting combustion turbine natural gas generation, to respond quickly to changes on the electric grid while continuing to reliably meet customer demand.

CHARACTERISTICS OF FLEXIBLE GENERATION

Variability is not new. Over the past century, power system operators have developed mechanisms to manage sudden changes in demand, unscheduled outages and transmission contingencies. The variability of these types of events is ad hoc by nature and successfully managed through reserve margins and thorough planning. The variability from renewable generation, however, is more profound—it is a permanent and growing part of the energy system. To address this development, responsive operational capabilities must be deployed. Flexible generation assets, forming part of a diverse portfolio, will help balance the grid by bridging the gap between conventional and renewable resources and enabling further integration of variable energy sources as they continue to grow.



Flexible generation assets help balance the grid by bridging the gap between traditional and renewable resources

KEY CHARACTERISTICS OF FLEXIBLE RESOURCES INCLUDE:

- **Fast ramp rates:** Ramp rates depict how fast power plants can increase (ramp up) or decrease (ramp down) generation to balance the system. To support renewable energy generation, flexible assets must ramp quickly; they also must be able to start and stop quickly, sometimes several times a day.
- **Short start-up times:** The shorter the start-up time, the faster a power plant can supply energy into the grid. Customer demand and renewable generation are both variable, going in opposite directions in the afternoon and early evening hours when customers increase power consumption as solar power production decreases. With the growth in solar PV generation, the impacts of cloud cover on the grid will magnify. Quick-starting, flexible generating capacity effectively bridges these gaps.

START-UP TIMES - HOURS FROM COLD-START TO MAXIMUM OUTPUT

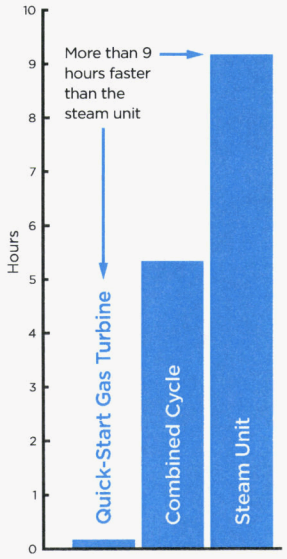


Figure ES-8 - Comparison of Start-Up Times

OCOTILLO MODERNIZATION PROJECT

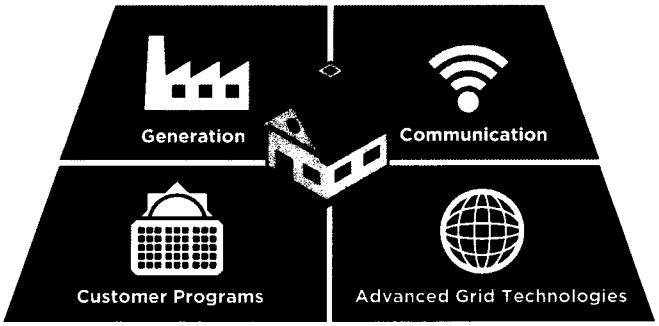
Ocotillo's central location in the Phoenix Metro area and proximity to customer demand is ideal for placement of flexible generation on the transmission system. In 2016, APS plans to begin construction on a project modernizing the Ocotillo Power Plant in Tempe to enhance its contribution to system reliability in the APS service territory. The proposed project consists of replacing two 1960s-era steam generators with five quick-start natural gas combustion turbine units with capacities of 102 MW each. Scheduled to begin commercial operation in 2018, the Ocotillo Modernization Project will provide cleaner, more efficient megawatt-hours, maintain grid reliability and add beneficial operational flexibility.

The Need for a Modernized and Flexible Grid

Adding more adaptable generation is just one factor in managing projected growth. Creating more flexible transmission and distribution systems and accounting for greater customer involvement contribute as well. Grid modernization merges these elements together, and once fully implemented, will redefine how energy is generated, measured and delivered. Through a complex network of sensing and communication devices, modernized grids are projected to create a real-time energy dialogue among sources of energy, customers and various grid components to keep everything in balance. In the face of greater resource intermittency, that dialogue will improve efficiency, reliability, resiliency and security of the energy system.

The grid is already adapting, but further innovation will be needed in the coming years. In recognition of that need, APS anticipates investing more than $300 million in smart grid technology through 2025. This is just the beginning of the process, not only for the Company but also for customers. Longer-term, utility-scale and customer-sited generation systems will communicate through a network designed to meet the following goals:

- **Maintain reliability** – As distributed generation and other forms of renewable energy grow to meet customer energy demand, monitoring and maintaining stable system operating conditions including voltage is becoming more important to ensure a balanced grid.
- **Empower customers** – The two-way flow between customers and utilities is opening doors to real-time operations unprecedented in this industry's history. Smart grid systems increase situational awareness, letting utilities know about changes in customer demand, enabling quicker response.
- **Integrate resources** – While the cost to operate renewable energy assets is less variable than conventional generation, the energy output of these resources is more variable. High degrees of fluctuation can and do occur, and real-time communication between conventional and renewable energy resources is needed to dynamically manage voltage, compensating VAR flows, and overall system reliability.



In the face of greater intermittency, investments in advanced grid technologies will be needed in order to provide greater operational visibility, system reliability and overall system efficiencies

TO MEET THESE GOALS, APS IS CURRENTLY DEVELOPING AND/OR IMPLEMENTING A NUMBER OF ADVANCED TECHNOLOGIES INCLUDING:

- Advanced Operational Platforms
- Automated Switches
- Communicating Fault Indicators
- Advanced Analytics
- Substation Health Monitors
- Communication Infrastructure
- Downed Conductor Detection
- Advanced Metering Infrastructure
- Phasor Measurement Units
- Network Protectors

STORAGE

In addition to these technologies, the industry, including APS, is reviewing energy storage options to take advantage and leverage supply/demand imbalances by being able to store energy during low demand periods, and releasing that energy when customers need it most. As part of that effort, initial deployments are being developed to assess the performance of various storage technologies to determine their suitability in meeting customer needs and supporting the overall resource portfolio.

2014–2018 Action Plan

While other components of the 2014 IRP elaborate on a wide range of developments and uncertainties and contemplate how various resource portfolios might best address them, the Action Plan lays out specific activities anticipated to occur in the near-term, designed to position APS for the challenges ahead.

AGAINST THAT BACKDROP, APS ESTABLISHED SEVEN DISTINCT PRIORITIES FOR THE 2014-2018 TIMEFRAME:

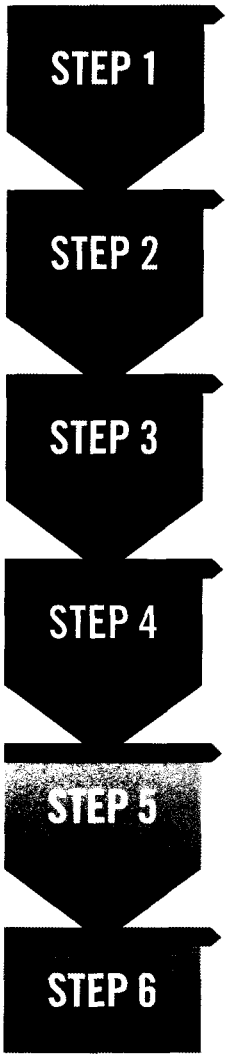
- **Transition resource portfolio while ensuring an adequate supply of resources** – By 2018, load is projected to grow almost 1,100 MW while resources to meet that growth will decline largely due to the expiration of just under 1,400 MW in purchased power contracts. The combination of these circumstances will have a significant impact on the portfolio. By 2017, APS anticipates needing to add 360 MW of additional capacity. This need is anticipated to grow to over 700 MW by 2018. To fill the gap, APS plans to utilize a combination of market-based solutions, along with highly flexible generating capacity at Ocotillo. These needs are in addition to resource contributions anticipated from the Energy Efficiency and Renewable Energy Standards.
- **Update conventional generation resources** – As with many utilities across the U.S., portions of APS's fleet are aging beyond their useful life. One way APS is addressing this issue is the modernization of the Ocotillo Power Plant in Tempe. The project, consisting of replacing two 1960s-era steam generators with five quick-start gas turbine units of 102 MW each, will generate cleaner, more efficient energy and improve visual conditions. Scheduled to begin operating in 2018, the new combustion turbine technology will support grid and operational reliability at the heart of APS's load center and complement increases in solar generation capacity. Permitting and CEC filings are planned for 2014.
- **Continue expansion of renewable generation** – Renewable energy resources, and APS's ability to effectively integrate and forecast their variability in production, are focal points of the 2014 Resource Plan, and the Action Plan is no exception. APS customers now benefit from solar capacity across the state, including the new Solana Generating Station, which combines concentrating solar power technology with thermal storage to generate energy even after the sun sets. During the next five years, that trend is expected to continue as APS and its customers are anticipated to pursue further installations of solar technologies.
- **Add transmission resources** – In order to continue accessing markets and the benefits they provide customers, APS will need additional transmission resources. In APS's 10-year transmission plan filed in January 2014, several key transmission projects are outlined that not only provide for increased system reliability, but also enable greater access to the Palo Verde markets through additional import capability into APS's service territory. In addition to these projects, longer term, APS will be evaluating other transmission access into its service territory.
- **Evaluate and decide on remaining coal fleet** – With the purchase of SCE's interest in the Four Corners Generating Station complete, APS will be continuing its evaluation of coal by examining the merits of further investment in the Cholla and Navajo units. Key to this analysis will be penetration of solar PV and its impacts on the need for operational flexibility, natural gas prices and the impacts of environmental regulations. Completion of analysis and a decision regarding Cholla is expected by 2016, followed by Navajo before 2019.
- **Continue implementation of customer resources** – APS has several customer-side resources that include distributed energy, energy efficiency and demand response. Over the next five years, the Company plans to continue working with customers to optimize the value of these programs to the overall portfolio.
- **Invest in advanced grid technologies** – Over the Action Plan Period, APS plans to invest $170 million in advanced grid technologies; including communication infrastructure, voltage management, automated switching, asset health monitoring, and operational platforms. The investment will support grid overall reliability and the integration of renewable energy and emerging energy technologies.

CHAPTER 1:
IRP OVERVIEW

Chapter 1

IRP Overview

The 2014 IRP is the culmination of a comprehensive decision-making process aimed at meeting future customer needs, achieving regulatory targets and managing environmental impacts during the Planning Period. Underpinning that overall purpose are (1) APS's long-standing commitment to reliability, cost-effectiveness and diversity; and (2) the ongoing need to adapt the energy portfolio to respond to long-term industry developments.



ASSESS NEEDS
Examine forecasts of load growth, plant conditions, contract terms and operational constraints to define needed resources over the 15-year planning horizon.

CONSIDER RESOURCE SOLUTIONS
Evaluate available generation resources, including conventional, renewable and customer-side solutions to identify the role each will play in meeting customer needs.

EXAMINE PLANNING FRAMEWORK AND RISKS
Assess challenges inherent in today's planning environment. Formulate a multi-faceted risk management approach that considers how plan drivers may change during the Planning Period.

DEVELOP PORTFOLIOS
Develop portfolios through an automated resource selection process. Inputs into the process include determinations reached in Steps 1 – 3.

PERFORM SCENARIO ANALYSIS
Load portfolios into a simulation model that filters each one through a series of scenario variables to produce key decision metrics such as cost, environmental attributes, fuel usage and capital expenditures.

SELECT PLAN
Select portfolio from the scenario analysis process that will reliably and sustainably serve demand, utilize renewable and energy efficient resources and account for inherent risks at a reasonable long-term cost.

Figure 1: Planning Process Steps

Figure 1 summarizes the steps APS undertook in preparing the 2014 IRP, each of which is discussed further in this chapter. Following a look at the broad trends affecting the energy industry as explored in the *Executive Summary*, the process began with the evaluation of two core resource planning questions: What quantity of resources does APS need? What is the timing of those needs? Using those questions as a backdrop, both existing and future resources (utility-side and customer-side) were considered, major risks inherent in long-term energy planning efforts were identified, and analytical models were developed and implemented to produce a series of resource portfolios for further evaluation. As a result of that process, the Selected Portfolio was chosen to represent the most reasonable overall value to customers for the Planning Period. In addition to the various inputs and planning objectives that formed the basis of the analysis, the stakeholder meetings held in June 2013 provided valued perspectives that were considered throughout the process.

Resource Planning Model

Figure 2 is a graphic representation of how planning steps 1-6 were used in the Resource Planning Model. The arrows indicate how the load, generation and industry inputs were processed through (1) the resource optimizer to generate the resource portfolios considered during the preparation of the 2014 IRP, and (2) a Scenario Analysis process to test each portfolio against a broad range of economic conditions. The final result of the process was the Base Portfolio which, with the minor modifications described in *Chapter 4 - Determining the Most Reasonable Plan*, became the Selected Portfolio.

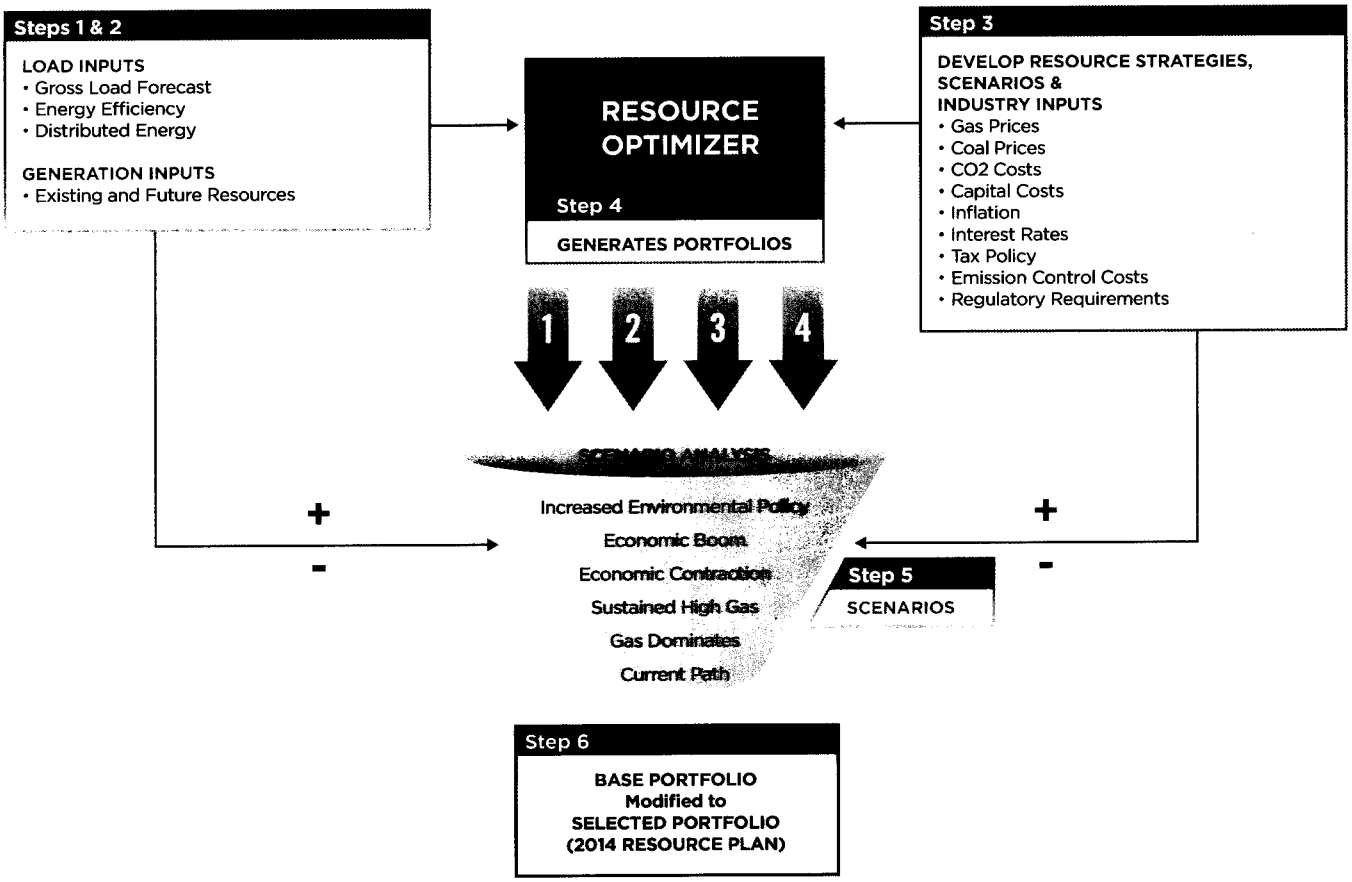


Figure 2: Resource Planning Model

Planning Process Steps

STEP 1 – ASSESS NEEDS

SEE ALSO CHAPTER 2 AND RESPONSE TO RULES: SECTION C - LOAD

Load forecasting for the Planning Period evaluates how energy demand will grow in the APS territory over the next 15 years and provides a logical starting point for resource planning. Population trends, economic outlooks, electricity prices, new technologies, projected consumption behaviors and seasonal patterns impact APS's view of future resource needs and are incorporated accordingly into the planning process.

For the 2014 IRP:

- The base assumption is that peak load growth will average approximately 3% annually over the next 15 years and result in a peak load of close to 13,000 MW, including planning reserves, representing an increase of over 50% from 2014 load requirements. The load forecast does not include customer-side resources, such as energy efficiency, distributed energy and demand response, as APS views these components as resources.
- To account for the range of economic conditions that could occur during the Planning Period, the scenario analysis phase stressed the base assumption down (-) to 1-1.5% and up (+) to 4-4.5%.
- Load growth is not the only reason to add resources. Contract expirations and plant retirements of nearly 3,000 MW contribute to the need for additional resources.
- Changes in both customer usage and increased customer-sited generation create the need for grid modernization, in the form of transmission and distribution investments.

STEP 2 – CONSIDER RESOURCE SOLUTIONS

SEE ALSO CHAPTER 2 AND RESPONSE TO RULES: SECTION D - SUPPLY

The need for new resources is determined by comparing peak capacity contributions of existing resources over the Planning Period against forecasted loads and reserve requirements. The 2014 IRP identified a need for over 6,600 MW in new resources to meet customer requirements. To fill that need, the planning process assessed possible supply-side resource options on the basis of their technological viability, reliability, construction costs, fuel price outlook, and environmental impact including associated costs and useful life. Some available technologies, including fuel cells and storage, were considered but must still be proven at the utility-scale level. Customer-side solutions were also assessed, based on existing and projected programs and their associated costs.

STEP 3 – EXAMINE PLANNING FRAMEWORK AND RISKS

SEE ALSO CHAPTER 3 AND RESPONSE TO RULES: SECTION E - RISK

Unlike load and supply considerations, which provide the parameters of the Planning Period's resource need and the array of options to meet the resource need, this step develops resource strategies and identifies uncertain industry challenges inherit in the planning environment. The resource strategies represent possible future outlooks such as higher Renewable Energy Standards (RES) or less coal. Evaluating these challenges or risks for each resource strategy will assess how well the resource options perform under a variety of operating conditions. Risk inputs include gas prices, coal prices, carbon dioxide (CO2) costs, inflation, interest rates, gross load MWs, environmental control costs, capital costs, and regulatory requirements. The probability is that none of these risks will remain static over the course of the Planning Period and some may experience significant change that could affect the robustness of selected resources. To account for these fluctuations, six scenarios were developed to test each portfolio generated by the resource optimizer against potential movements in each of those factors.

STEP 4 – DEVELOP PORTFOLIOS

SEE ALSO CHAPTER 4 AND RESPONSE TO RULES SECTION F - 2014 IRP

Resource portfolios were developed for the 2014 IRP using Ventyx's resource expansion plan optimizing software, PROVIEW. Existing generation and contracts were input into the model as fixed assets, and the program chose from a list of potential future resources to meet load growth and reliability constraints. Potential future generation technologies were first pre-screened for cost-effectiveness. Once these technologies were deemed cost-effective, they were then entered into PROVIEW. To meet load growth and address reliability constraints, PROVIEW evaluated thousands of resource combinations. Resource plans with the lowest net present value of revenue requirements were chosen for further detailed analysis in PROMOD IV and subjected to scenario analysis.

STEP 5 – PERFORM SCENARIO ANALYSIS

SEE ALSO CHAPTER 4 AND RESPONSE TO RULES SECTION F - 2014 IRP

To assess the economic risk associated with each portfolio, six scenarios were developed based on uncertain economic, political, and technological factors that are difficult to predict at this time. These scenarios try to capture possible interrelationships between the following key variables: natural gas prices, CO2 costs, technology capital costs, tax policy, environmental policy, load growth, degree of energy efficiency and distributed generation penetration and interest rates. Ranges in the assumptions (low – base - high) for the individual variables and the correlation between variables within the scenarios were subsequently evaluated.

STEP 6 – SELECT PLAN

SEE ALSO CHAPTER 4 AND RESPONSE TO RULES SECTION F - 2014 IRP

Based on the results of the Scenario Analysis, APS identified the portfolio expected to provide the most reasonable value to customers over the Planning Period, with one modification. The resource optimizer selected a 500 MW natural gas unit to be in service in 2017. To retain more flexibility and better match loads and resources, APS opted instead to plan short-term purchases in 2017 and 2018, then add the 500 MW of natural gas in 2019. This is reflected in the Selected Portfolio.

CHAPTER 2:
NEEDS & RESOURCES

Chapter 2 Needs & Resources

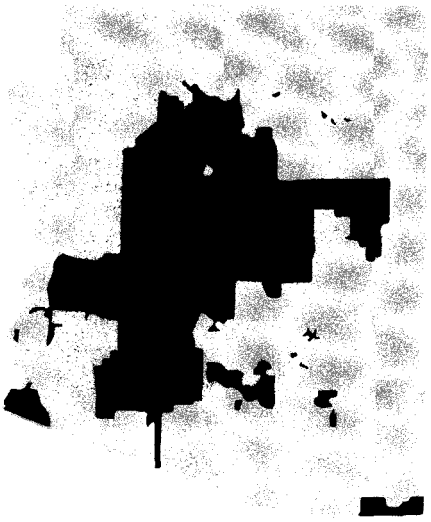


Figure 3: APS Service Territory

APS BACKGROUND

With operations dating back to 1886, APS is both the largest and longest-serving electric utility in the state of Arizona. APS currently provides electricity to 1.2 million customers in 11 of Arizona's 15 counties. APS's diverse energy portfolio includes over 9,100 MW, including purchased power agreements, and transmission and distribution lines of over 33,000 miles. The company's 34,646-square mile service territory spans most of the state of Arizona, with the major exceptions of roughly one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. Wholly-owned by Pinnacle West Capital Corporation, APS is regulated by the Arizona Corporation Commission (ACC).

TABLE 1 - SUMMARY LOADS AND RESOURCES

2014 IRP (VALUES IN MW AT PEAK)				
	2014	**2019**	**2024**	**2029**
TOTAL PROJECTED LOAD REQUIREMENTS (NEEDS)	**8,124**	**9,543**	**11,276**	**12,982**
EXISTING RESOURCES AS OF DEC. 31, 2013				
APS-Owned Generation	6,315	6,086	6,063	6,066
Long-Term Contracts	2,872	1,490	389	346
Total Existing Resources as of Dec. 31, 2013	**9,187**	**7,576**	**6,452**	**6,412**
FUTURE* PROJECTED CUSTOMER RESOURCES				
Energy Efficiency	109	877	1,230	1,447
Distributed Energy	45	109	203	261
Demand Response	0	0	150	275
Total Future* Customer Resources	**153**	**986**	**1,584**	**1,983**
FUTURE* PROJECTED GENERATION RESOURCES				
Natural Gas	0	1,010	3,030	4,205
Renewable Energy	0	57	295	425
Total Future* Projected Utility Resources	**0**	**1,067**	**3,325**	**4,630**
Total Future* Projected Resource Additions	**153**	**2,053**	**4,909**	**6,613**
Total Resources	**9,340**	**9,630**	**11,361**	**13,025**

*Future resources added after December 31, 2013

Overview: Supply-Demand Gap

The supply-demand gap, depicted in the blue and green areas in Figure 4, refers to the difference between the resources APS has and the resources needed to meet customer demand growth. Customer demand requirements are forecasted to grow by over 4,800 MW. Although growth in customer needs is expected to be limited in 2014, it is expected to accelerate from 2015 through 2029 at an average rate of approximately 3% per year, prior to customer resources.

APS has sufficient existing resources to meet forecasted customer needs through 2016. Starting in 2017, as load requirements increase and several existing power contracts that have helped meet those needs expire, additional resources will be required. By 2019, APS's need for new resources is expected to exceed 2,000 MW, and over 6,600 MW by the end of the Planning Period.

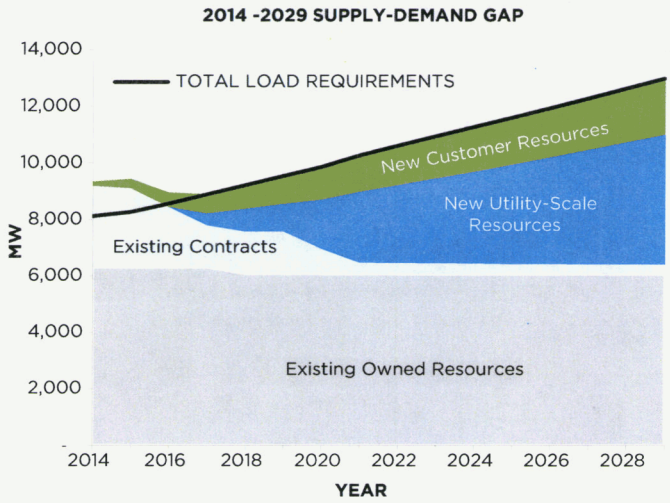


Figure 4: 2014 - 2029 Supply-Demand Gap

Load Growth Forecast

Forecasting load is the foundation of resource planning, fundamental to analyzing not only how many resources the Company needs and when, but to an increasing degree, the type of resources needed. While weather, population growth, economic trends and energy consumption patterns all play a role in developing a forecast, each is subject to change, producing actual results that may vary from original estimates. A more important, yet often challenging element, in long-term resource planning is evaluating *how* those variables synergistically interact over the course of a 15-year period. Although future unknowns cannot be removed from the forecasting process, APS's robust forecasting methodologies are structured to address uncertainty over the Planning Period.

LOAD REQUIREMENTS EXPECTED TO NEAR 13,000 MW BY 2029

By 2029, Arizona's population is projected to reach more than nine million. During that time, APS is projected to add 600,000 customers, increasing total electricity consumption by over 50%, or 3%, on a compounded annual growth rate basis, prior to customer resources. This growth rate translates to a projected load that will require an additional 6,600 MW by the end of the Planning Period.

HOW THE NEED IS FORECASTED

Given that load projections are subject to change, future resource requirements are calculated based on a peak consumption hour growth rate under three scenarios – Current Path, Low Load Growth and High Load Growth. As illustrated in Figure 5, the Current Path assumption is that peak load growth, prior to customer resources, is expected to average approximately 3% annually over the next 15 years and result in a peak load of close to 13,000 MW, including reserves. Under Low Load Growth conditions, the expectation within APS's service territory over the next 15 years is 1.6% average annual peak demand growth, which would result in a peak hour demand in 2029 that is roughly 1,500 MW higher than that expected for 2014. Under High Load Growth conditions, the peak load annual average growth rate of 4.2% would result in over 7,000 MW of additional resource requirements by 2029. The 2014 IRP is based on the Current Path assumption.

FACTORS AFFECTING LOAD GROWTH

POPULATION AND ECONOMIC GROWTH

Economic growth rates are typically the single most influential factor when forecasting long-term changes in electricity demand. In Arizona, high population migration rates have contributed to the state's rapid growth in electricity demand and the need for greater supply. That demand has been bolstered by larger homes, more consumer electronics, and greater commercial activity. Although the recent economic downturn paused that trajectory, APS expects that future growth will once again be driven by these factors as it has in the past.

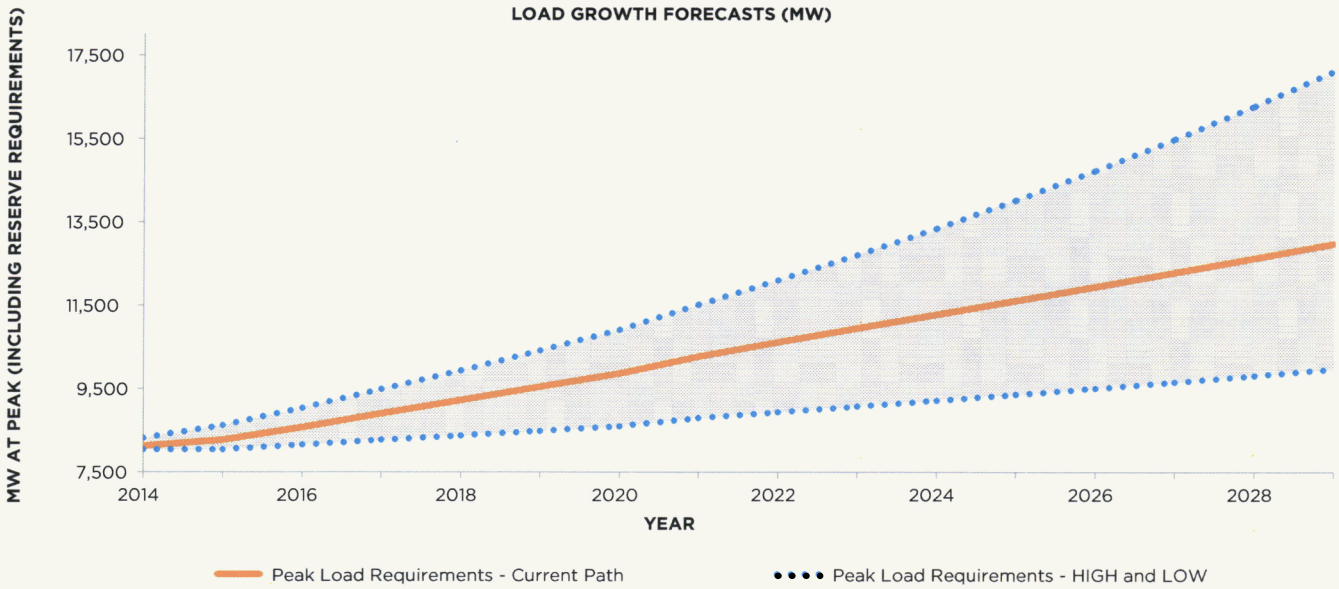


Figure 5: Load Growth Forecasts

NEW TECHNOLOGIES

The emergence of new technologies presents uncertainties to the pace of future electricity demand. New technologies can result in increased efficiency of existing appliances, transformational shifts in the use of electricity – electric vehicles replacing gasoline-powered vehicles, for example, or new uses like the increase of personal computers and cell phones over the last two decades. The impact of new technologies on electricity consumption and peak demand is difficult to forecast due to the lack of historical data, but must be closely monitored as new technologies emerge.

ENERGY PRICES

Electricity usage has historically been unyielding to price fluctuations. However, the current state of the industry's infrastructure may place inflationary pressures on electricity prices that, in some cases, may be more significant than in the past. Environmental regulation, the need for infrastructure development, the higher cost of emerging technologies, and fuel cost trends will also likely influence the direction of power prices. The rising costs of generation may be ultimately be reflected in the prices customers pay.

CUSTOMER RESOURCES

The three categories of customer resources, energy efficiency, distributed energy, and demand response, are expected to contribute an increasing percentage to the APS resource mix over the course of the Planning Period. Energy efficiency resources are expected to increase over 1,400 MW to meeting peak demand, distributed energy is anticipated to increase over 260 MW additional at peak, and demand response resources are projected to increase an additional 275 MW. Achieving these levels will require significant participation by APS's customer base, which may be challenging depending on economic conditions. In addition, the costs associated with achieving these contributions over the next 15 years are uncertain.

PLANNING RESERVES

APS's capacity reserves provide at least a 15% planning reserve margin during APS's summer peak. The values presented in Table 1 include these reserves.

Existing Resources

Conventional fossil fuel-fired generation has been a core part of APS's resource mix for many years and will continue to play an important role in meeting customer needs throughout the Planning Period. More recent additions to the portfolio, such as renewable energy and customer-side energy resources, are also contributors and increasingly more prominent – a trend that is expected to continue and further challenge the scope of resources and the grid. The map below details the location of APS's existing resource mix, with the exception of small-scale solar projects, customer-side resources such as energy efficiency, distributed energy and demand response and conventional purchased power contracts. These resources are existing as of the end of 2013.

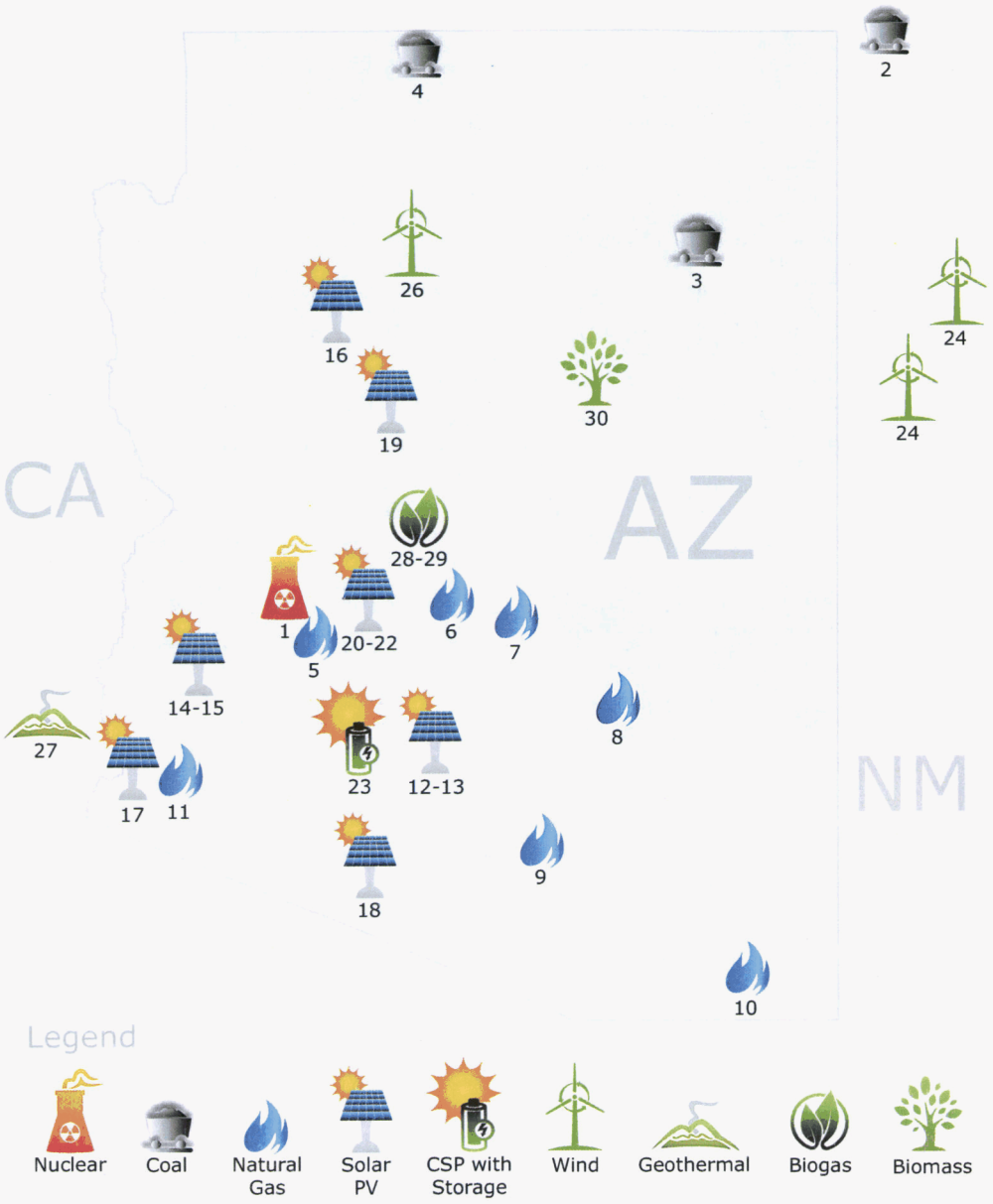


Figure 6: Existing Resources

Table 2, organized by resource type, provides details on APS's resource mix. Unless otherwise indicated, MW represents total facility nameplate capacity with the exception of natural gas facilities, which are represented in peak coincident capacity.

TABLE 2: EXISTING RESOURCES

MAP NUMBER	DESCRIPTION	APS-ENTITLED MW
	NUCLEAR	
1	Palo Verde Nuclear Generating Station (PVNGS) is located about 55 miles west of downtown Phoenix and has three units capable of generating 3,937 MW of electricity. Because of its desert location, Palo Verde is the only nuclear plant in the United States that does not sit near a large body of water. Instead, it uses treated effluent from several area municipalities to meet its cooling water needs, recycling approximately 20 billion gallons of wastewater each year. Owned by a consortium of seven utilities, APS is the sole operator and has a 29.1% ownership share.	1,146
	TOTAL NUCLEAR	**1,146**
	COAL	
2	Four Corners Power Plant is a 2-unit coal-fired power plant located in the northwestern corner of New Mexico. APS operates the plant and owns 63% of the capacity. On November 8, 2010, APS and SCE entered into an asset purchase agreement providing for the purchase by APS of SCE's 48% interest in each of Units 4 and 5 of Four Corners, allowing APS to acquire 739 MW from SCE. On December 30, 2013, APS and SCE closed this transaction. As a result of the transaction, APS retired units 1-2-3. Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects.	970
3	Cholla Power Plant is a four-unit 1,027 MW plant located in northeastern Arizona near Holbrook. APS operates the plant and owns Units 1, 2 and 3, and PacifiCorp owns the 380 MW Unit 4 – the largest unit at the plant. Cholla is fueled by coal from the Lee Ranch and El Segundo mines in New Mexico.	647
4	The Navajo Generating Station (NGS) is located in northern Arizona on the Navajo Reservation near Page, and features three 750 MW coal-fired electric generating units. An electric railroad delivers coal to the plant from a mine on the Navajo and Hopi Reservations at Black Mesa in northern Arizona. The plant is operated by Salt River Project, and is owned by a partnership of five utility companies and the U.S. Bureau of Reclamation. APS owns 14% of the plant.	315
	TOTAL COAL	**1,932**
	NATURAL GAS	
5	Redhawk Power Station, which began operating in mid-2002, consists of two identical 500 MW natural gas-fueled combined-cycle units. Located near PVNGS west of Phoenix, the station employs treated effluent purchased from Palo Verde to meet its cooling needs. Redhawk also is a zero liquid discharge site, meaning that the cooling water is continually reclaimed and reused and no water is released to the environment. The plant is owned and operated by APS.	1,000
6	West Phoenix Power Plant, located in southwest Phoenix, has seven natural gas-fueled generating units – two combustion turbine units and five units that employ combined-cycle technology. The plant is owned and operated by APS.	998
7	Ocotillo Power Plant is currently a 4-unit gas plant. In early 2014, APS announced a $600-$700 million project to modernize the plant, which will involve retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this will increase the capacity of the site by 290 MW, to 620 MW, with completion targeted for summer 2018. The plant is owned and operated by APS.	320
8	Sundance Generating Station in Coolidge, Arizona, is a natural gas-fueled combustion turbine plant that consists of 10 quick-start units. The plant is owned and operated by APS.	410
9	Saguaro Power Plant a natural gas fueled facility located north of Tucson, Arizona, had two older steam units, which retired in June 2013, and three combustion turbine units. The plant is owned and operated by APS.	176
10	Douglas Power Plant, located in the town of Douglas in southeastern Arizona, is comprised of one 15 MW combustion turbine peaking unit and is put into service only when demand for electricity is high in the Douglas area. The plant is owned and operated by APS.	15
11	Yucca Power Plant, a natural gas-fueled plant near Yuma in southwestern Arizona, has (a) six combustion turbine units that produce 233 MW which are owned and operated by APS and (b) one 75 MW steam turbine and one 22 MW combustion turbine, both of which are owned by Imperial Irrigation District but operated by APS.	233
	TOTAL NATURAL GAS	**3,152**
	TOTAL CONVENTIONAL RESOURCES (excludes purchased power agreements)	**6,230**
	TOTAL PURCHASED POWER AGREEMENTS FOR CONVENTIONAL RESOURCES	**2,460**
	TOTAL PURCHASED POWER AGREEMENTS FOR CONVENTIONAL RESOURCES	**8,690**

MAP NUMBER	RENEWABLE ENERGY RESOURCES (*denotes capacity from a purchased power agreement)	APS-ENTITLED MW
	SOLAR	
12	Paloma Solar Plant is a photovoltaic facility located in Gila Bend, AZ. The plant began serving customers in the third quarter of 2011, and is comprised of 275,000 thin-film fixed tilt modules. The plant is owned and operated by APS.	17
13	Cotton Center Plant is a photovoltaic facility also located in Gila Bend, AZ. The plant began serving customers in the third quarter of 2011, and is comprised of about 93,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.	17
14	Hyder Solar Plant is a photovoltaic facility located in Hyder, AZ. The plant began serving customers in the fourth quarter of 2011, and is comprised of about 70,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.	16
15	Hyder II Solar Plant is a photovoltaic facility located in eastern Yuma County, AZ. The plant began serving customers in the fourth quarter of 2013, and is comprised of more than 71,000.	14
16	Chino Valley Plant is a photovoltaic facility located in Chino Valley near Prescott, AZ. The plant began serving customers in the fourth quarter of 2012, and is comprised of about 80,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.	19
17	Foothills Plant is a photovoltaic facility located near Yuma, AZ. Construction of the plant, which began serving customers in the first quarter of 2013, was completed in the fourth quarter of 2013. The plant is comprised of more than 150,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.	35
18*	Ajo Project, a Crystalline PV Single Axis Tracking system, is located near Ajo, AZ and reached commercial operation in September 2011. APS has a 25-year purchased power agreement (PPA) to purchase the entire project output.	5
19*	SunEdison Prescott Project, located 2 miles north of Prescott Regional Airport, is a Crystalline PV Single Axis Tracking system. APS purchases the generation output from SunEdison under a 30-year agreement, which began in November 2011.	10
20*	Saddle Mountain Project is a Crystalline PV Single Axis Tracking system located near Tonopah, AZ. APS purchases the generation output from SunEdison under a 30-year agreement, which began in December 2012.	15
21*	PSEG Badger-Desert Sky Project, a Crystalline PV Single Axis Tracking system located near Tonopah, AZ, reached commercial operation in November 2013. APS has a 30-year PPA to purchase the entire output.	15
22*	RE Gillespie, located near Arlington, AZ, is a Crystalline PV Single Axis Tracking system. APS purchases the generation output from Recurrent Energy under a 30-year agreement, which began in December 2013.	15
23*	Solana, located near Gila Bend, AZ, uses concentrated solar power (CSP) technology with a thermal energy storage system. APS purchases the generation output from Arizona Solar One (Abengoa) under a 30-year agreement, which began in October 2013.	270
	TOTAL SOLAR	**448**
	WIND	
24*	Aragonne Mesa Wind Project, located in New Mexico, delivers its capacity to APS at the Four Corners switchyard. APS has a 20-year PPA to purchase the entire project output; the project began making energy deliveries to APS in December 2006.	90
25*	High Lonesome Wind Project, located in New Mexico, delivers its capacity to APS at the Four Corners switchyard. APS has a 30-year PPA to purchase the entire project output; the project began making energy deliveries to APS in 2009.	100
26*	Perrin Ranch Wind Project, located near Williams, AZ, this plant reached commercial operation in June 2012. APS has 25-year PPA to purchase the entire project output.	99
	TOTAL WIND	**289**
	OTHER RENEWABLE ENERGY	
27*	Salton Sea Geothermal Project, located in the Salton Sea area of southeastern California, delivers capacity to the APS system in Yuma. APS has a 23-year PPA to purchase the output that began delivering energy to APS in January 2006.	10
28*	Glendale Biogas Project, which commenced operations in late January 2010, sells all its energy to APS under a 20-year PPA.	3
29*	NW Regional Biogas Project, located in Surprise, AZ, commenced operations in August 2012 and sells all its energy to APS under a 20-year PPA.	3
30*	Snowflake Biomass Project, which commenced commercial operations in June 2008, sells part of its output to APS under a 15-year PPA.	14
	TOTAL OTHER RENEWABLE ENERGY	**30**
	TOTAL RENEWABLE ENERGY RESOURCES (includes purchased power agreements)	**767**

CUSTOMER-SIDE RESOURCES	MW
ENERGY EFFICIENCY	
The Energy Efficiency (EE) Standard requires that APS achieves cumulative energy savings of 22% of its retail sales by 2020[1]. APS's EE portfolio includes a mix of programs that address APS's diverse customer base in both residential and non-residential categories. These programs include, but are not limited to, the following:	**403**
• Residential Existing Homes Program, which supports the proper installation, maintenance and repair of air conditioning systems, as well as the increased energy efficiency of the whole home. • Residential New Construction Program promotes high-efficiency construction practices for new homes. • Consumer Products Program promotes the use of high-efficiency lighting and pool pumps. • Solutions for Business Program provides incentives and training to non-residential facilities of all sizes for efficiency improvements in lighting, motors, cooling, and refrigeration. • Schools Program provides assistance in reducing energy used in schools, including public, private and charter schools (K-12). • Energy Codes & Standards Initiative encourages energy savings from improved compliance building with codes and appliance standards throughout APS's service area. • Resource Savings Initiative encourages energy savings from improvements to APS transmission and delivery systems, generation, and facilities. APS may propose specific projects for consideration in future Demand Side Management (DSM) implementation plans[2]. • The Home Energy Information Pilot Program (HEI Pilot) described in the demand response (DR) section below also contains a Pre-Pay Pilot to determine if there are EE savings associated with a Prepaid Program.	
DISTRIBUTED ENERGY	
The Renewable Energy Standard (RES) requires that APS satisfy a percentage of the annual renewable energy requirement through the addition of distributed energy (DE) resources[3] to the APS system. The required DE percentage increased to 30% of the total RES requirement in 2012 and will remain at that level for the duration of the Standard. For 2014, APS expects to exceed the DE requirement. Additional information pertaining to the total installed DE capacity, energy production and total residential and non-residential compliance can be found in the annual RES Compliance Report. DE number includes Bagdad and APS-owned Schools & Government programs, in addition to the Flagstaff Community Power projects. DE resources include but are not limited to:	**360**
• Rooftop/Customer-Sited Solar PV consists of rooftop solar systems on the APS system that convert the sun's energy into electricity. As of year-end 2013, APS had over 22,000 grid-tied customer-owned/leased distributed PV systems and over 125 APS-owned distributed PV systems on residential customer premises as part of the Flagstaff Community Power Project. In most cases, these systems are interconnected to the APS grid from the customer side of the meter. • Solar Water Heating uses thermal energy from the sun to heat the water used in both commercial and residential applications. APS has been providing rebates to encourage the installation of solar water heaters since 2002. As a result, there were 8,950 units installed as of the end of Q3 2013.	
DEMAND RESPONSE	
APS's DR programs include: • APS Peak Solutions is a 25 MW commercial and industrial DR program for APS's Yuma and Phoenix metropolitan customers. • Peak Event Pricing (or Critical Peak Pricing), for residential and business customers, is a rate rider that provides a high price signal over a small number of core summer peak days and hours. • The HEI Pilot is a comprehensive residential DR pilot program designed to test available home area network technologies and determine the most effective communication devices, demand response strategies, and mix of in-home applications.	**21**
TOTAL CUSTOMER-SIDE RESOURCES	**784**
TOTAL RESOURCES	**10,241**

[1]Arizona Administrative Code (A.A.C.) R14-2-2404 (EE Standard)
[2]Pursuant to Commission Decision No. 74406 (March 19, 2014)
[3]A.A.C. R14-2-1805

Risks Related to Expanding Existing Resources

APS anticipates meeting its new resource requirements with a diverse mix of conventional generation, renewable energy resources, and customer resources. Each of the options listed below is unique in its contribution to the APS resource portfolio and presents new opportunities while also introducing new uncertainties. For additional qualitative factors related to existing resource technologies, refer to *Chapter 3 - Planning Inputs & Other Considerations*. For cost information, refer to Attachment D.3.

Flexible resources that the utility can dispatch are an important part of any utility's generation fleet, and APS is no exception. Flexible natural gas resources save customers money, provide reliable power, and help manage generation overages and shortfalls. Intermittent energy sources, such as wind and solar, do not offer this flexibility. Customer resources, such as energy efficiency and distributed energy, present additional challenges related to: (1) managing the availability of the resource, (2) controlling the timing and quantity when the resource becomes available and (3) an inability to curtail these sources if they are not needed. Figures ES-3 and ES-4 of the Executive Summary provide more detailed information on flexible resources.

RISKS BY RESOURCE TYPE

NUCLEAR

The ultimate disposal of spent nuclear fuel adds a technological uncertainty to nuclear power additions. To date, the federal government has not succeeded in establishing a permanent repository for nuclear waste. Spent nuclear fuel from existing nuclear power plants continues to be stored at the individual power plant sites, either in spent fuel pools or in dry cask storage facilities. Any utility considering the pursuit of new nuclear capacity must have considerable financial strength given the significant financial and time commitments involved.

These uncertainties notwithstanding, APS will continue to closely follow developments in this industry as they relate to new developments in construction and the potential for smaller modular units.

COAL

New pulverized coal plants are capital intensive. The installed cost for a new pulverized coal plant is approximately $3,000 per kW, or $3.0 billion for a 1,000 MW coal plant. This is approximately three times the cost of a new natural gas combined cycle plant. Pulverized coal units also involve longer construction periods. APS estimates that it takes approximately nine years from the start of the permitting process to commercial operation.

In addition, pulverized coal plants have compliance cost risk related to potential environmental regulations. As discussed in *Chapter 3 - Planning Inputs & Other Considerations*, the Envrionmental Protection Agency (EPA) has already implemented air quality regulations governing new coal plants for certain emissions, and is expected to promulgate additional regulations in the future. In addition, climate change policies pertaining to GHGs may be put in place at the national level. It is uncertain how these programs would be structured or how commercially viable or technically feasible it will be to retrofit a pulverized coal unit to allow for carbon capture and sequestration.

NATURAL GAS

- **NATURAL GAS COMBINED CYCLE (CC):** The primary risk associated with this technology is the price of natural gas. Potential compliance costs with CO2 regulation is also a concern as these units emit CO2, albeit at a much lower rate than coal-fired generation plants.
- **COMBUSTION TURBINES (CT):** The primary risks associated with CT technology is the price of natural gas. Although CTs emit CO2, they are not expected to become a major source of CO2 emissions because of the limited run time of peaking units.

UTILITY-SCALE SOLAR

Solar energy is expected to become increasingly important in APS's resource mix. However, this technology presents several risk factors that need to be considered: (1) cost (including system integration cost), intermittency and lack of operational alignment with actual customer energy requirements; (2) although a solar plant has no fuel costs once in operation, its development costs are higher than that of conventional generation; (3) solar energy projects require a significant amount of land compared with conventional generation; and (4) tax policy changes may result in significant cost increases for this technology.

WIND

Predominantly regional, wind energy production primarily occurs in the spring when APS's customer loads are at reduced levels. Wind energy's contribution to meeting summer peak demand is expected to be a fraction of the rated generation output. Because wind is an intermittent resource, system integration costs and back-up capacity must be factored in when evaluating wind against other resource options. Tax policy and regional wind resource quality are also key factors in the economics of this resource.

GEOTHERMAL

Location of geothermal resources is a key consideration in geothermal power, as these naturally occurring resource locations are generally a significant distance from APS's load centers and transmission infrastructure. Moreover, a geothermal project must go through the identification, exploration, and drilling phases before production can begin, and lead times for these facilities tend to be longer and development costs higher than for other renewable resources.

BIOMASS AND BIOGAS

Although biomass and biogas facilities utilize a combustion process that emits CO2, they are widely considered "carbon neutral" as carbon emissions are offset by the prior absorption of carbon through photosynthesis that occurred throughout the lifecycle of the growth of the plants before they were harvested to produce the source of waste.

ENERGY EFFICIENCY

- Uncertainty regarding customer behavior and participation – Energy efficiency measures typically require customers to make an upfront investment in exchange for savings that occur over the lifetime of the product. Because that investment decision is made by customers, there is uncertainty regarding the amount of energy efficiency that will be implemented.
- Uncertainty regarding cost recovery - Energy efficiency measures reduce revenues necessary to recover APS's fixed costs. In its 2012 Settlement Agreement[4], APS agreed to a limited Lost Fixed Cost Recovery Mechanism; however, in the future, APS will need a more comprehensive ratemaking mechanism to address the recovery of the fixed cost investments. Moreover, from a resource parity perspective, a reasonable performance incentive is required for energy efficiency to be pursued on financial par with supply-side resources.

[4]ACC Decision No. 73183 (May 2012)

DISTRIBUTED ENERGY

As the amount of distributed energy capacity increases, it also presents challenges and risks to both customers and the efficient management of the APS grid.

- Cost shifting and recovery of utility fixed costs – In a recent ruling, the ACC recognized a cost shift exists between customers with PV installations and those customers not using PV. This is especially true for residential customers, most of whom have a rate design in which fixed utility costs are recovered through a single kWh charge. That single kWh charge combines generation costs (for which PV customers are avoiding and should not be charged) and fixed costs (from which all customers benefit and should be charged). Because solar customers consume less "kWh", they are not being fully charged for their fair portion of fixed cost used to maintain the grid that their system relies on. Those fixed charges that are not paid will have to be addressed by a change in rate design for solar customers, or by shifting those cost to non-solar customers.
- Back-up generation costs – An increase in distributed PV may also have an unintended effect of adding complexity to managing the amount of utility generation needed to meet customer demands as well as adding to generation costs. Renewable resources such as PV are non-firm (they rely on an intermittent resource and APS does not control the operation or maintenance systems themselves), but customer demand will be present whether or not the PV system is producing at its capacity or at all. Because APS is required to meet customer demand, it must have flexible generation resources ready that are capable of making up for low production from distributed generation. Because of the longer ramp-up time, lower cost production facilities, such as combined cycle gas, do not provide the production flexibility needed. Therefore, other, more expensive generation will need to be used to meet customer demand.
- Peak shifting – The addition of increasing amounts of PV to the APS grid can have the effect of shifting our peak to different times of the day, depending on the weather and season. During spring months when the APS load is lower but solar production is high, energy from PV could make up a significant portion of our overall load on non-cloudy days. As solar production begins to decrease in the early afternoon, traditional generation resources will be required to make up for the loss of the solar resource. During summer months, the APS load peaks in the late afternoon/ early evening. Because solar production fluctuates, it can add volatility to the APS load curve and increased complexity to resource management.
- Planning reserves - APS's planning reliability criterion states the Company should provide sufficient capacity such that the expected probability of a service outage is less than or equal to one event in ten years. From a practical perspective, the resource planning process determines the quantity of planning reserves that are required to satisfy this reliability criterion. The planning reserves provide additional resources that can be called upon in the event that generating units experience unplanned outages and/or customer loads are higher than anticipated. Therefore, APS plans for reserves based upon forecasted amounts of distributed generation, but ultimately the decision to supply distributed generation is left to the customer. This creates a risk of planning too many or too little planning reserves for distributed generation resources.

DEMAND RESPONSE

Similar to energy efficiency, demand response initiatives are contingent upon customer participation. Factors such as comfort impact, usability of technology, load reduction (kW) per household, and incentives for participation will all influence the ultimate impact of such a program. Programs aimed at commercial and industrial customers such as Thermal Energy Storage (TES) and Standby Generation can require significant upfront capital investments in order to participate.

RISKS RELATED TO PERMITTING/LICENSING

Construction of new electric facilities – whether for electric generation or for transmission – requires extensive permitting processes. Depending on the specifications of the facility and its location, the permitting process may take up to 24 months or more before construction begins. Permits required by federal, state, and local authorities are described below.

FEDERAL:

- Environmental Assessment – Pursuant to the National Environmental Policy Act (NEPA), an environmental assessment (EA) is a concise document that provides sufficient evidence and analysis for determining whether or not to prepare an environmental impact statement (EIS) or a finding of no significant impact (FONSI) for NEPA compliance; aids an agency's compliance with NEPA when no EIS is necessary; and facilitates the preparation of an EIS when one is necessary. An EA is generally a more concise document than an EIS[5].
- Environmental Impact Statement – NEPA requires federal agencies to prepare an EIS on proposals for major federal actions significantly affecting the quality of the human environment. The EIS describes the environmental impacts of a proposed action and alternative actions that may be taken instead of the one proposed. An EIS may be required when a development is proposed for a site on undisturbed or federal land, or has been federally funded or approved.
- Right-of-Way for Use of Tribal Lands – When constructing generation facilities or installing transmission lines on tribal lands, a right-of-way easement granted by the tribe and approved by the Secretary of the Interior is required.
- NRC Nuclear Generation Licensing Process - Despite the recent increase in federal support for nuclear power projects, including loan guarantees and the Nuclear Regulatory Commission's (NRC) improved licensing process, the period from design to commissioning is double that for other technologies while costs are considerably higher. New nuclear generator units have a lead time of over nine years because: (1) new reactor licenses must be approved by the NRC, which can take between two and a half to five years, and (2) after the review process is complete, construction can take roughly six additional years for each reactor.

[5]http://www.epa.gov/reg3esd1/nepa/eis.htm

STATE:

- Certificate of Environmental Compatibility – Utilities, with proposed power plants or transmission lines subject to the jurisdiction[6] of the Commission and the Arizona Power Plant and Line Siting Committee (Committee), are required to make an application with the Commission for a Certificate of Environmental Compatibility (CEC). The Committee considers, during public hearings, the application relative to a series of factors[7] including the status of all applicable permits. Following these deliberations, the Committee makes a recommendation to the Commission regarding the CEC. The Commission then makes a final determination on the CEC application.
- Title I Preconstruction Permit – The state of Arizona has full approval to implement the federal Title I preconstruction permit program established by the federal Clean Air Act, and is the local permitting authority for all of Arizona, except Maricopa County, Pima County, Pinal County, and tribal lands. The EPA administers this program for sources on tribal lands, where the tribe does not have its own approved program or has agreed not to exert regulatory jurisdiction over a source.
- Title I preconstruction permits, commonly known as "Prevention of Significant Deterioration" (PSD) permits in geographical locations that meet or exceed the National Ambient Air Quality Standards (NAAQS) and as "Nonattainment New Source Review" (NNSR) permits in locations that fail to meet the NAAQS, must be obtained and effective prior to beginning construction of a new major source of air emissions, and prior to making a major modification to an existing source of air emissions. PSD permits are legally binding air quality permits that include enforceable emission limitations with which the emission source owner/operator must comply. These emission limitations are known as "Best Available Control Technology" (BACT) for attainment areas and as "Lowest Achievable Emission Rate" (LAER) for nonattainment areas. These limits are then rolled into the Title V air quality permits referenced below.
- Title V Air Quality Permit – The state of Arizona has full approval to implement the federal Title V operating permit program, established by the 1990 federal Clean Air Act Amendments. As the state agency charged with environmental affairs, Arizona Department of Environmental Quality (ADEQ) delegated this authority to three of the 15 counties within the state – Maricopa, Pima, and Pinal – with the remaining 12 counties continuing under ADEQ jurisdiction. The EPA administers the Title V operating permit program on tribal lands when the tribe does not have its own approved program or has agreed not to exert regulatory jurisdiction over a source. Title V permits must be obtained and effective for all major stationary sources of air emissions. Title V permits are legally binding air quality permits that include enforceable conditions with which the emission-source owner/operator must comply. The permit conditions establish limits on the types and amounts of air pollution allowed, operating requirements for pollution control devices or pollution prevention activities, and monitoring and record-keeping requirements.
- Aquifer Protection Permit – ADEQ also issues Aquifer Protection Permits (APPs) to power plants that have regulated facilities, such as impoundments, that have the potential to impact aquifer water quality. Power plants have monitoring programs that include collection of water quality samples from monitoring wells that are located down gradient of regulated facilities. These sample results are reported to ADEQ on frequencies established in the APP and provide evidence that aquifer water quality standards are met.

LOCAL:

- Maricopa County Air Quality Department (MCAQD) – MCAQD issues Title I preconstruction and Title V operating permits for facilities located within Maricopa County, which include APS's Redhawk, West Phoenix, and Ocotillo power plants. As with ADEQ, MCAQD requires a Title V permit for any major stationary source of air emissions. MCAQD also requires a Title I preconstruction permit for any new major source of air emissions or for major modifications to existing sources of air emissions.
- Other local agencies – APS's natural gas-fired Saguaro and Sundance power plants are located in Pinal County. Therefore, these plants are under the jurisdiction of the Pinal County Air Quality Control Department, which issues Title I preconstruction and Title V operating permits for facilities located within Pinal County.

[6]Applies to construction of a new thermal electric, nuclear, or hydroelectric facility of 100 MW or more of a transmission line of 115kV or more.
[7]Specified in Section 40-360.06 of the Arizona Revised Statutes

Potential Future Resources

Due to contract expirations and unit retirements, existing resources are projected to meet only half of the 2029 13,000 MW need and future customer-side resources are planned to meet a further 15%. The remaining are projected to come from added resources, either from the technologies previously described and/or from generation technologies that are not currently in use at APS due to factors such as operational concerns or higher costs. A more detailed discussion of these technologies can be found in *Appendix A – Resource Technologies*. Costs for some of these technologies can be found in Attachment D.3.

NUCLEAR

SMALL MODULAR REACTORS (SMR)

The EIA estimates that SMR will be the nuclear technology of choice after 2025[8]. With an anticipated construction period of three years, SMRs are smaller than 300 MW and can be built in modular arrangements in a manufacturing plant. The reactor units can be shipped to the plant site, inserted into the plant foundation structure and connected to the balance-of-plant steam and auxiliary systems.

COAL

ULTRA-SUPERCRITICAL STEAM TURBINES (USC)

USC steam pulverized coal power plants are still considered to be an early commercial technology.

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

IGCC plants integrate coal gasification with combined-cycle technology.

CARBON CAPTURE AND SEQUESTRATION (CCS)

CCS, the process of capturing waste CO2 sources from fossil fuel power plants and sequestering them where they will not enter the atmosphere, is currently costly and energy intensive. For a 600 MW power plant, the auxiliary loads have been estimated at 150 MW – 180 MW, not only resulting in additional CO2 emissions but also in increased water consumption. In addition, plant efficiency was also estimated to drop from 39% to 28%[9].

SOLAR

SOLAR TOWER SYSTEMS

These systems use a field array of flat mirrors to reflect sunlight onto a central receiver located at the top of the tower. The tower market is still emerging. Should this technology prove reliable and cost-effective, it has the potential to become competitive with parabolic trough with thermal energy storage.

FUEL CELLS

There are many different types of fuel cells such as Alkali (AFC), Phosphoric Acid (PAFC), Molten Carbonate (MCFC), Proton Exchange Membrane (PEM), Solid Oxide fuel cell (SOFC) and Direct Carbon (DCFC). At this time, APS does not view fuel cells as suitable for any of the Company's distributed generation or smart-grid applications until their reliability is improved, costs are reduced, and the cell-stack life is extended.

[8]http://www.eia.gov/forecasts/archive/aeo13/pdf/0383(2013).pdf
[9]Derived from U.S. Energy Information Administration, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013

STORAGE

Storage comes in many forms of technologies. Certain technologies are suitable for grid applications while others are better suited to address seasonal or diurnal needs. At some point in the future, it is possible that APS will utilize storage technologies to support reliability as the Company integrates increasing amounts of variable generation and customer-side resources. APS evaluates these technologies as opportunities arise in conjunction with other renewable or intermittent technologies or for power quality applications while determining their financial and operational strengths and weaknesses.

FLYWHEEL/ROTARY UNINTERRUPTIBLE POWER SUPPLIES (UPS) ENERGY STORAGE FLYWHEELS

Energy storage systems used primarily for short-term energy and power support include voltage stabilization and UPS.

BATTERY STORAGE

Battery energy storage provides a means of storing energy by using energy from the utility grid to charge batteries, and then discharging that energy when needed. In general, battery storage systems are scalable and are either centralized or distributed. Centralized systems contain the entire battery system and controls at a single site, and support the primary distribution system. Distributed energy systems are typically smaller and support secondary level distribution.

ABOVE- AND BELOW-GROUND COMPRESSED AIR ENERGY STORAGE (CAES)

CAES technologies store air, in tanks for above-ground systems and in caverns or aquifers for below-ground systems, when energy is available then use that air to power a turbine generator to produce electricity. Although these systems are considered a mature technology, only a partial percentage of stored air is usable to generate electricity. Future advanced systems are expected to capture, store, and use heat-of-compression energy to reheat the stored compressed air before flowing it through the turbine to generate power.

LIQUEFIED AIR ENERGY STORAGE (LAES)

These systems compress and process large volumes of air into liquid air products stored in cryogenic tanks at off-peak energy periods. Unlike other compressed air storage systems, this technology maintains the air pressure, temperature, and flow to the specified turbine requirements. The success of proposed demonstration projects is expected to provide insight into the technology's potential commercial viability.

TECHNOLOGY ASSESSMENT OF POTENTIAL FUTURE RESOURCES

Technical innovation, environmental concerns and shifting public policies have led to the rapid development of new technologies that are reshaping the energy landscape. In determining the value of these new technologies to the APS portfolio, the energy technology assessment process considers several factors, including energy production potential, technology maturity, reliability, cost, useful life, and environmental impact.

ENERGY PRODUCTION POTENTIAL

The most basic step in evaluating any energy technology is determining its potential to produce energy for APS's service territory when it is most needed. A primary consideration is sufficient supply – or determining if there is enough energy generated from a new technology to justify the level of required investment. This concept is particularly relevant with renewable energy where supply issues may be dictated by regional location and geography. Independent of other factors, such as cost and technology maturity, renewable energy investments in any given region are focused on technologies that support resources that are abundant in that region and not heavily pursued for resources that are scarce. Feasibility must also be considered. Although a technology may appear promising in theory, its implementation, particularly on a utility-scale basis, can prove costly, time-consuming, and even wasteful if it ultimately can not service customers. This could be due to deficiencies in supporting technologies, inadequate supply chains, and other factors.

TECHNOLOGY MATURITY

This criterion goes hand-in-hand with energy production potential. When technologies are in stages of early research and development, there is uncertainty as to whether they can produce a viable energy source. As a technology advances through stages of applied research and development, demonstration, market development, and deployment, risks emerge along the way. These can include cost and time overruns, difficulties in graduating from test-scale to utility-scale, shortfalls in operational capabilities when assessed under a full range of conditions, and limited integrative capacity with resources already in place. In general, a mature technology is one that is well-tested for its ultimate purpose and has been in use long enough to resolve initial deficiencies. APS's stance of concentrating on mature or near-mature technologies mitigates reliability and cost risks and optimizes the use of investment funds for innovations that ultimately will power Arizona homes and businesses.

RELIABILITY

In early stages of development, renewable energy technologies were often cited as unreliable due to their inherent intermittency. However, innovation is rarely developed in isolation. By bundling with related technologies, energy resources can move up the reliability scale and deliver on their promise. One of the most prominent examples of this is the application of storage for solar energy. It is widely expected that once developed for widespread application, storage will assist solar energy by storing surplus production during the day for release over evening peak. In addition, natural gas technology such as combustion turbines help balance the grid by filling in the gaps formed by renewable energy intermittence.

COST

Costs in technology implementation cover a broad range of variables including equipment, pre-construction studies and permits, installation, fuel, operation and maintenance. All of these factors have a direct bearing on the price that will ultimately be paid by the customer. The difficulty in quantifying costs of new technologies includes the level of subsidies as well as the extent of market deployment. Immature technologies tend to display larger cost disparities from their conventional energy counterparts, in part due to lack of scale. In assessing cost, APS evaluates not only current conditions, but also monitors and assesses potential for change due to improved technology, changes in subsidies, or greater market acceptance.

USEFUL LIFE

Useful life is the estimate of how many years an asset can be expected to remain in service. Although an asset's time in service may vary from its original estimate depending on a number of factors, it can be a useful tool in that technology's initial cost-benefit analysis.

Expected useful life varies across technologies and is largely determined by manufacturer specifications, subsequent life-extending innovations and market experience. With the energy industry becoming increasingly technologically-driven, assessing useful life may become more challenging. Innovation tends to accelerate the rate at which technologies are brought to market and the time it takes for an asset – regardless of its operational capability - to become viewed as outdated.

ENVIRONMENTAL IMPACT

One of the rationales for pursuing new technologies is the improved environmental footprint they offer. As federal regulations on pollutants increase, review of new technologies increasingly includes an assessment of their potential to produce energy with less impact to the environment. Although much focus has been on air quality concerns, new technologies may also impact - positively or negatively - other environmental factors such as water resources, noise levels, land use, soil quality and local habitat. APS assesses these considerations when determining the impact that the deployment of a new technology could have on the environment.

The table below details several technologies under consideration at APS and the current assessment of their potential for inclusion in APS's energy mix.

TABLE 3: TECHNOLOGIES UNDER CONSIDERATION

Technology	Maturity Level	Opportunity	Challenges
Conventional Generation			
Coal - Subcritical Steam Plant	High	Primarily Overseas	Regulatory and air permits
Coal - IGCC Steam Plant	Emerging	Could emerge faster due to recently issued CO2 regulations	Currently not cost effective or proven technology
Coal - Supercritical Steam Plant	High	Mainly overseas	Air permits, major component availability, and cost escalations
Natural Gas - Combined Cycle	Mature	High efficiency, low CO2 emissions	Economic viability dependent on fuel price / supply outlook
Natural Gas - Fuel Cells	Emerging to Mid-Level	Low growth, niche markets	Expensive, limited stack life
Natural Gas - Reciprocating Engines	Mature	Mid-growth market due to low natural gas rates	Site retrofits, air permits
Natural Gas - Simple Cycle Turbine	Mature	Supports grid integrated renewable energy	Air permits
Nuclear Power Plants / Small Modular Reactors (SMR)	Mature / Emerging	Growth overseas for large reactors, strong potential domestically for SMRs	Construction costs and duration for large reactors, spent fuel storage issues
Energy Storage			
Batteries	Emerging to Mature	High growth niche markets	Currently not cost competitive
Compressed Air Energy Storage (Above Ground)	Emerging	Low growth	No commercial units, capital costs, round-trip efficiency
Compressed Air Energy Storage (Below Ground)	Emerging	Low growth (only two commercial units built several decades ago)	Limited to sites with suitable geological formations
Flywheel / Rotary UPS	Emerging / Mature	Low growth	Limited by grid / site power quality requirements
Liquefied Air	Emerging	Low growth	Still in development stage
Pumped Hydro	Mature	Low growth	Constrained by site options
Renewable Energy			
Distributed - Geothermal Heat Pumps	Mid-level	Growth market, albeit slow	Niche applications, and AZ soil conditions
Distributed - Solar Photovoltaic	Mature	High growth	Grid integration, variability
Distributed - Solar Water Heating	Mature	Growth market	System performance, operational life, cost effectiveness
Distributed - Wind	Mature	Mid-growth market	Resource limited market, performance challenges, variability
Utility - Biogas Generation	Mature	Many potential sites in Arizona	kW scale is not cost-competitive with other renewable options
Utility - Biomass Steam Plant	Mature	High potential with significant quantities of biomass in Arizona	Fuel accessibility and costs, and competitive renewable energy price
Utility - Cofiring Torrefied Biomass	Emerging	Low risk, low cost option for renewable energy generation	Utility-scale suppliers are slowly emerging in U.S., fuel costs
Utility - Geothermal	Mature	Low growth	Limited proven resource in AZ
Utility - Solar Photovoltaic (Fixed and Single Axis Tracking)	Mature	High growth	Grid interconnection, variability
Utility - Solar Photovoltaic (High Concentration)	Mid-Level	Low growth	Currently not cost competitive with Fixed and SAT photovoltaics
Utility - Solar Thermal Dish	Emerging	Low growth	Costs and operational issues
Utility - Solar Thermal Tower	Mid-Level	Low growth	Costs and operational issues
Utility - Solar Thermal Trough	Mature	Reduced potential	Not competitive with solar PV
Utility - Wind	Mature	Mid-growth in Arizona	Constrained by locations with economical wind resources, variability

Grid Modernization: Improving Resource Performance

Grid modernization is the deployment of new technologies to improve power quality, provide greater grid-operations visibility, reduce customer interruptions, and enhance system efficiencies. Just as the availability of new and improved communications, sensor, and control technologies transformed the telecommunications industry, these same advances are enabling a transformation in how power is transmitted and distributed over the electric grid in a changing marketplace.

By 2025, APS plans to invest more than $300 million in grid modernization technologies, system upgrades, and related management systems through a number of project initiatives. A description of these initiatives and their benefits is provided below.

CUSTOMER RESOURCES

ADVANCED METERING INFRASTRUCTURE (AMI) PROGRAM

AMI is a term used to describe the collection of advanced billing meters, communicating devices, and data management systems required to provide wireless electric metering and two-way communications between utilities and their customers. Benefits include:

- Enabling customers to manage costs by providing monitoring tools for energy usage, change of service plans, or connect and disconnect service from their computer.
- Enabling APS to offer a host of new programs including "Pick a Due Date", which allows customers to choose the payment date that best fits their lifestyle.
- Enabling APS to monitor voltage levels and power quality to help ensure reliable service and effectively plan for future energy needs.
- Providing safety and environmental benefits by avoiding millions of driving miles by APS employees to remotely perform customer read-ins, read-outs, rate changes, disconnects, and reconnects.
- Producing substantial amounts of new data that can be transformed into actions such as reducing the number of unplanned transformer failures, identifying power outages, and optimizing placement of future grid modernization technologies for even more enhanced performance, monitoring, and control.

DISTRIBUTION PROGRAMS

SUBSTATION HEALTH MONITORING (SHM) PROGRAM

SHM is a family of distribution substation equipment monitoring technologies that remotely monitor the health of transformer oil, transformer bushings, and other substation equipment. Use of distribution SHM technology mitigates catastrophic transformer failures and increases visibility for improved operator risk management.

DISTRIBUTION AUTOMATION (DA) PROGRAM

Integrated Volt/VAR Control (IVVC) and Automated Switching are subcomponents of the DA Program. IVVC mitigates low power quality and lowers the need for peak generation, transmission, and distribution systems by continuously controlling regulators and capacitor banks to manage power quality such as power factor and voltage at the feeder level. The Automated Switching subcomponent includes several hardware upgrades that automate the detection of problems along the distribution system and allows for remote operation and faster restoration of power.

DISTRIBUTION ASSET MONITORING (DAM) PROGRAM

DAM consists of two technology deployments:

- Communicating Fault Indicators (CFI): CFIs installed on distribution lines can be used to detect whether current is flowing on the line and then communicate that status via communications or visual indicators. CFIs provide near real-time voltage, current, and fault information, which improve outage restoration times and limit equipment damage risk.
- NETWORK PROTECTORS (NP): NP deployment involves the installation of improved breakers, sensors, and relays at existing NPs. These devices provide greater visibility of status, voltage, and current to Distribution Operations, in addition to offering increased safety for field personnel. Historically, this data had to be obtained manually. It will also permit the Distribution Operations Center to control the NPs in supervisory mode for enhanced operations.

FIRE MITIGATION (FM) PROGRAM

FM technologies mitigate the risk of fire caused by normal operation of a grid located in a forested area. They also have the potential to help APS rapidly determine when equipment has failed and is in need of immediate attention in areas of high fire risk. FM technologies also limit the scope of potential hazards when equipment failures occur.

ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS) PROGRAM

ADMS is an advanced operational platform that manages the operations of the distribution system. It is comprised of three applications: Distribution Supervisory Control and Data Acquisition (DSCADA), Distribution Management System (DMS), and Outage Management System (OMS). Together, they provide an electric grid and individual asset health index, improve outage management (return-to-service), optimize trouble call management, and enable condition-based maintenance programs for resource optimization.

COMMUNICATION INFRASTRUCTURE PROGRAM

Components include the installation of new optical fiber, cell phone networks, microwave communication devices, and data management systems required to serve the overall needs of the enterprise in a secure and reliable manner.

TRANSMISSION PROGRAMS

ENERGY MANAGEMENT SYSTEM (EMS) UPGRADE PROGRAM

EMS is the main operational platform used to monitor, control and optimize the performance of the transmission system. EMS upgrades are expected to provide operators with an enhanced user interface and advanced analytical tools.

STATE ESTIMATION/REAL-TIME CONTINGENCY ANALYSIS

This tool allows the transmission operator the ability to run "what if" scenarios and provides greater situational awareness of grid conditions through enhanced network models.

ADVANCED VISUALIZATION TOOLS

Providing visual analytics and robust reporting for improved operator risk management, these tools allow the operator to assess system conditions more rapidly without having to process a great deal of information or data.

TRANSMISSION SUBSTATION HEALTH MONITORING (SHM) PROGRAM

This program is a family of transmission substation equipment monitoring technologies. Transmission SHM mitigates catastrophic transformer failures and increases system visibility for improved operator risk management.

PHASOR MEASUREMENT UNITS (PMUS)

PMUs provide sub-second information about the operating characteristics of the transmission system which, in turn, provide the operator greater situational awareness of system conditions.

Uses include:

- Reducing the risk of major outages through the use of real-time data for improved operator risk management.
- Post-event diagnostic capability through the analysis of disturbances and protection scheme performance.

STORAGE

In addition to those technologies, APS is reviewing a catalog of energy storage options, including those discussed above under Potential Future Resources, to smooth out the supply imbalances inherent in renewable energy production. As part of that effort, initial developments are being deployed to assess the performance of select products, and further evaluations will be undertaken for new technologies that have reached early commercial status to determine their suitability in supporting the APS portfolio.

Transmission & Distribution: Delivering Generation Resources

Maximizing use of the existing transmission system is important to the resource planning process and the transmission planning process; however, adequate transmission must either currently exist or be planned and constructed to support future generation resources as well as potential contingencies. APS's resource planning and transmission planning organizations coordinate to ensure system needs are met on a timely basis. APS has developed a transmission system that enables delivery of resources to APS load. APS owns all or a part of several major transmission paths in the states of Arizona, New Mexico, and Nevada. These transmission paths deliver energy from fossil, nuclear and renewable facilities as well as various long-term purchase agreements.

Each year APS prepares and files with the ACC a ten-year transmission plan[10]. The 2014-2023 Ten-Year Transmission System Plan describes planned transmission lines of 115kV or higher that APS may construct over the next ten years. The APS investment needed to construct these projects is currently estimated to be approximately $496 million. These projects are designed to provide an increase in the ability to deliver both conventional and renewable resources to APS load centers. These new transmission projects, coupled with additional distribution and sub-transmission investments, will support continued reliable power delivery in APS's service territory, the state of Arizona, and the western United States.

Sub-transmission, which includes 69kV infrastructure, and distribution resources are also expected to be added over the Planning Period. Sub-transmission and distribution changes are necessitated due to electric load changes. Load changes may require elements to have increased capacity or additional elements to be constructed or decreased capacity or elements to be removed. Costs related to these investments are expected to exceed $500 million during the Planning Period. More specific information related to sub-transmission and distribution resources can be found in Response to Rule D.1(f).

The following maps illustrate the existing transmission infrastructure and planned additions that APS intends to construct over the 2014-2023 time period[11].

[10] http://images.edocket.azcc.gov/docketpdf/0000150147.pdf

[11] Plans and in-service dates are subject to change depending on load growth and other factors.

APS EHV & OUTER DIVISION 115/230 KV TRANSMISSION PLANS 2014 - 2023

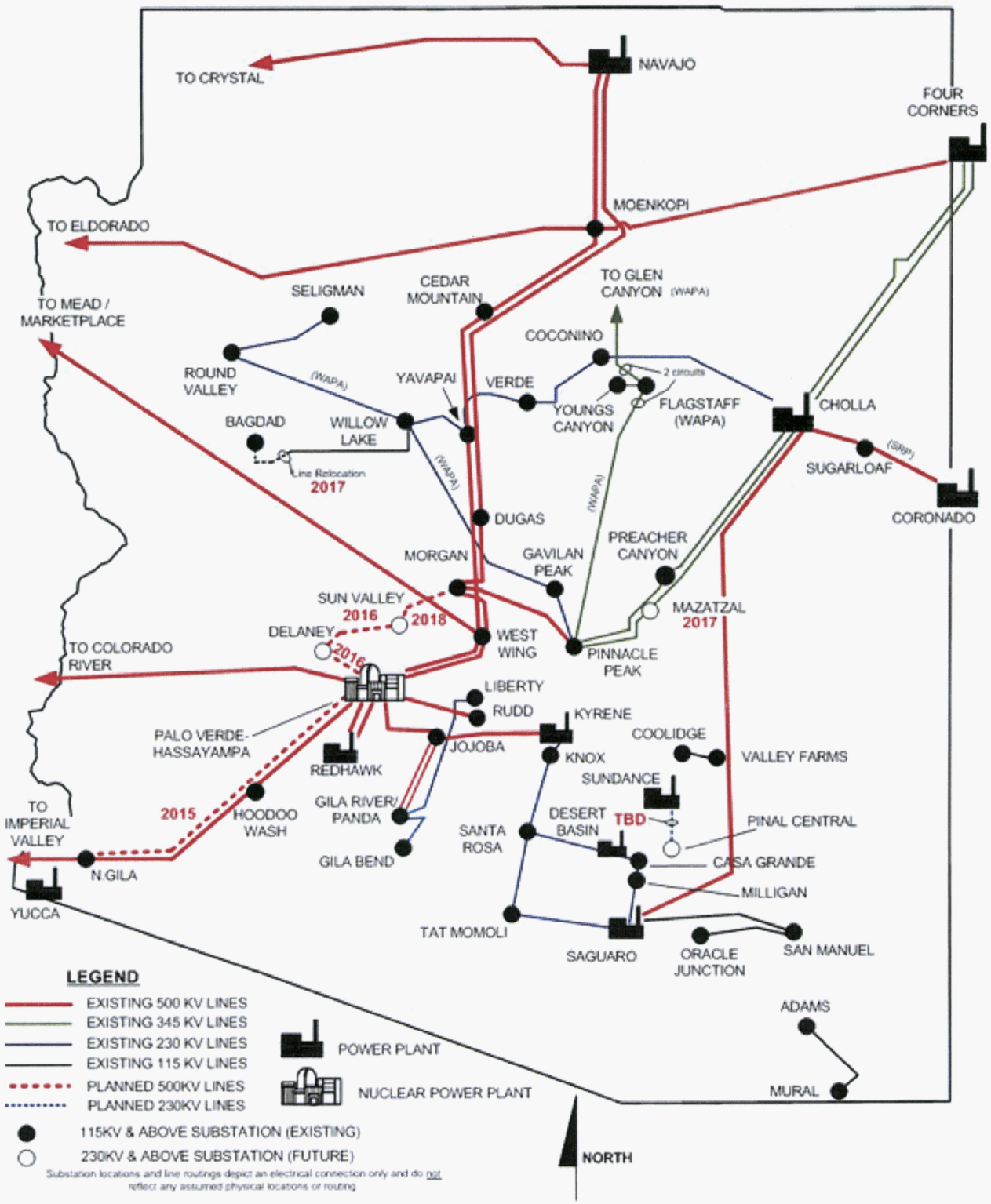


Figure 7: Transmission Plan 2014-2023 State Map

PHOENIX METROPOLITAN AREA TRANSMISSION PLANS 2014 - 2023

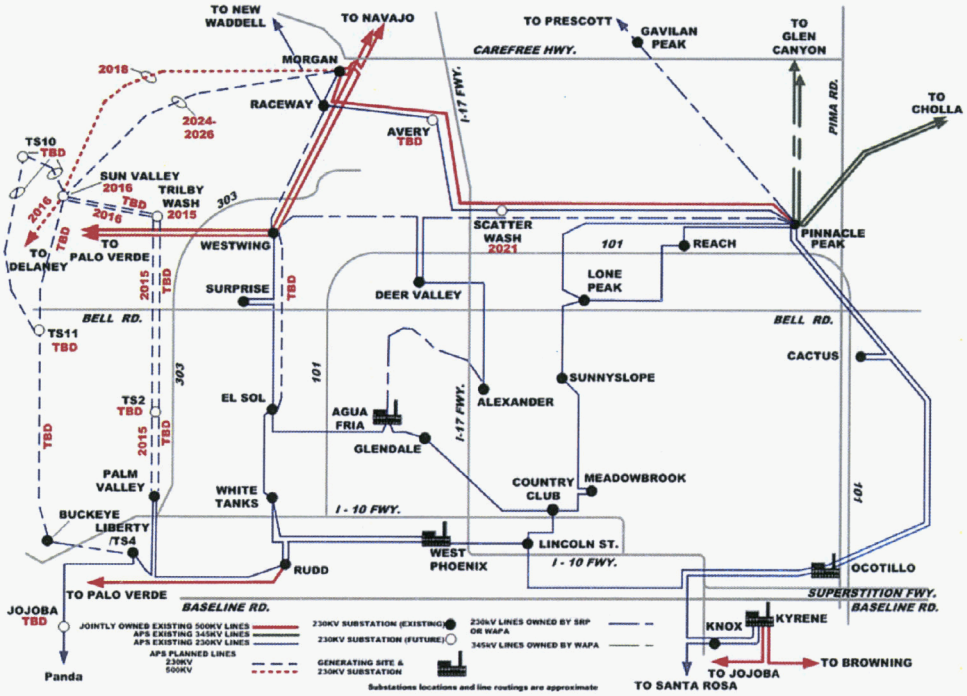


Figure 8: Transmission Plan 2014 - 2023 Phoenix Metro Map

YUMA AREA TRANSMISSION PLANS 2014 - 2023

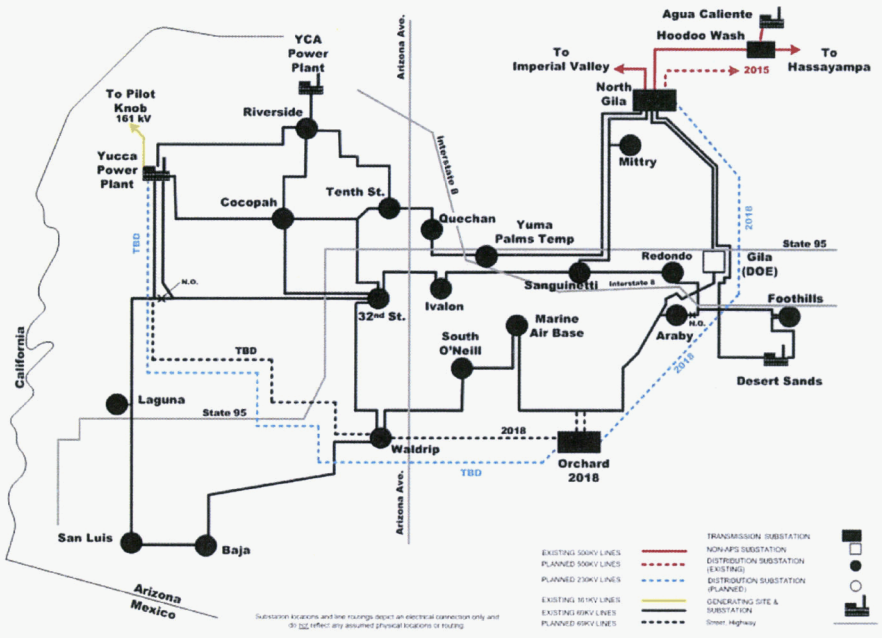


Figure 9: Transmission Plan 2014-2023 Yuma Metro Map

CHAPTER 3:
PLANNING INPUTS & OTHER CONSIDERATIONS

Chapter 3 Planning Inputs & Other Considerations

Surveying the landscape is an important part of the planning process. Understanding current and potential future environmental regulations, ACC requirements, technology costs, operating circumstances, fuel costs and regional plans puts needs and opportunities in context and opens doors to realistic portfolio development.

Planning Challenges

The development of long-term resource plans has historically presented three broad challenges: timing, long-term resiliency, and cost.

TIMING

It takes many years to plan and construct new generation and transmission resources. During that time, economic conditions, population growth, regulatory requirements and/or customer demand patterns may change from original forecasts.

LONG-TERM RESILIENCY

Energy assets are long-lived, capital-intensive and defined by the operating conditions and available technology prevalent at the time of their construction. The first two factors establish the basis for using those assets as long as possible while the third introduces the element of resiliency – that is, an asset's capability to remain technologically relevant over time.

COST

Power plants, by their nature, require significant investment. Financial decisions to move ahead with an energy project are based on a myriad of variables that over the life of the asset will change, and in some cases, change dramatically. Therefore, long-term cost recovery is critical.

These challenges remain in place but may no longer be the most uncertain aspects of planning. Two additional factors, technology and customer preferences, have been introduced in the past few years and are influencing industry developments:

TECHNOLOGY

Innovation has heightened the above risks by accelerating how quickly an asset can become less relevant and less economically viable. While change once occurred slowly, steadily, and was limited to centralized utility resources, change now occurs more broadly. Today, asset selection is driven not only by engineering and cost assessments, but also by technological innovation, which may bring new products to market faster than ever before.

CUSTOMER PREFERENCES

Technology is also influencing customer participation by giving them a more prominent role on the grid. As new products that link centralized and decentralized assets multiply, and customers use their energy assets to supply their own power and sell any excess back to the grid, balancing supply and demand becomes more complex. From a planning perspective, the challenge is assessing the extent to which that trend will become a larger component of the energy mix, and what types of generation assets will be needed to balance the system.

Planning Inputs – Inherent Risks

In formulating this plan, a multi-faceted approach to risk was used to address the uncertainties that are known today, while leaving room for others that may emerge during the Planning Period. This section corresponds to Step 3 of the Resource Planning Model (see *Chapter 1 – IRP Overview*), and profiles the components of that approach, particularly the inputs that drove the development of the portfolios and the drivers that could stress those inputs during the Planning Period. The goal of this process is to ensure that the portfolio selected is sufficiently flexible and responsive to meet a wide range of conditions that may occur as APS progresses through next stage of industry development.

This section provides a qualitative overview of risks and inputs that were incorporated in the 2014 IRP process. For a more detailed qualitative risk discussion, refer to *Response to Rules: Section E – Risk*. For a quantitative review of these issues, refer to *Chapter 4 – Determining the Most Reasonable Plan*.

FUEL PRICES

NATURAL GAS

In terms of fuel costs, natural gas prices have become increasingly important in electric utility planning. They serve as the benchmark against which other resources are compared, fuel generation options, and facilitate the integration of renewable energy. As variable generation resources increase and more natural gas power plants are installed to support them, the reliance on and exposure to this commodity is expected to rise.

Despite the lower volatility of natural gas prices in recent years when compared to past decades, a return to severe market price swings can not be ruled out. While short term price spikes can and do occur, the extreme price volatility of the past is not anticipated. That said, any one of the following events could shift natural gas price and/or supply forecasts: (1) the strength and duration of the economic recovery, (2) environmental regulations, (3) the extent that renewable energy resources penetrate the market, (4) global appetite to import U.S. natural gas, and (5) continued developments in natural gas drilling and extraction.

If more than one of the above factors were to occur simultaneously, the deviation could be more severe. By stress-testing the portfolios through different natural gas price points, electric rate impacts driven by economic factors such as those described above have been considered and incorporated into the analyses and final plan selection.

COAL

Having procured most of its coal supply under long-term contracts, APS's exposure to price swings in this commodity have been mitigated.

In recent years, aspects influencing future coal prices have changed. Exports have supported prices while environmental regulations have provided a type of price ceiling. In addition, fuel switching – moving from coal to natural gas – has had an adverse effect on coal's value. With current natural gas prices trending within relatively stable bands and environmental regulations becoming more stringent, utilities are making that switch with increasing frequency.

CO2 PRICES

CO2 prices are challenging to forecast because, despite numerous efforts, the federal government has not reached policy consensus on the magnitude, timing, or need for a carbon tax. Public support for less carbon intensive resource options has garnered strength over the years and that momentum is expected to continue. Therefore, in a 15-year forecast, robust planning suggests the potential for some level of CO2 pricing or regulation. It is difficult to forecast what final form that regulation may take; nonetheless, APS has included in its analysis the potential for carbon pricing. Refer to *Chapter 4 – Determining the Most Reasonable Plan*.

CAPITAL COSTS

As capital cost forecasts are generally based on data from completed construction of projects, the introduction of new technologies into the portfolio may increase the uncertainty in estimating this component. The primary reason being there is not enough history in some technologies to ascertain within reasonable certitude what the project costs could be.

In addition to the unknowns that come with innovation, capital cost uncertainties could arise from adverse developments in:

- Pre-construction activities, such as site preparation;
- Equipment installation;
- Labor and material availability; and
- Electric interconnection costs.

For each of these factors, new generation projects are closely observed within the industry – particularly when related to newer technologies. Project delays, cost overruns and other occurrences set the stage for construction expectations that could adversely influence future investment with regards to timing, scope, choice of technologies, or a combination of these variables.

INFLATION

Inflation estimates are based upon historical trends and the expected future performance of the economy (Arizona and the U.S. as a whole).

APS's 2.5% annual inflation rate estimate was embedded as an input into each portfolio under consideration, with the exception of the Economic Contraction Scenario and the Economic Boom Scenario. These scenarios were 1.5% and 3.5%, respectively. Inflationary pressure can be significant in the planning process as it affects every stage of construction for new resources, as well as maintenance of existing resources – from material costs, labor costs and even the process of construction itself as builders and long-term energy suppliers require inflation clauses in project contracts. There is the potential for inflationary pressures in the next several years due to expected upgrades and additions to generation, and the coincident need to upgrade the transmission grid. This dual-pronged up-tick in energy investments may create upward pressure in materials, equipment, and labor costs for energy projects in the queue.

INTEREST RATES

The level of interest rates directly impacts financing costs associated with infrastructure investment.

A low interest rate environment benefits utilities, particularly during times of expanded investment, by lowering the cost of debt and promoting a lower-risk environment for new technology development. Uncertainty on the interest rate front is the potential for rates to rise rapidly by a magnitude that would adversely affect investments in new generation and transmission resources, most acutely at a time when those investments are needed to meet growing customer demand.

Factors that drive interest rate risk include general economic activity, borrowing levels in both the private and public sectors and Federal Reserve monetary policy. Should a change in these factors impose sufficient upward pressure on rates, the investment outlook throughout the economy would be affected, including the utility industry.

TAXES

PRODUCTION TAX CREDIT

The production tax credit (PTC), a federal financial incentive for the development of renewable energy facilities, expired on December 31, 2013. However, the American Taxpayer Relief Act of 2012 modified the definition of a qualified facility under section 45(d) of the Internal Revenue Code by allowing facilities that began construction prior to January 01, 2014 to qualify[12]. That benchmark can be met by demonstrating that either: (1) physical work of a significant nature has started, or (2) five percent of the total cost of the facility has been incurred by the taxpayer and the taxpayer makes continuous efforts to complete the facility thereafter[13].

Qualified facilities under the PTC include wind, closed-loop biomass, open-loop biomass, geothermal energy, solar energy placed in service before January 1, 2006, municipal solid waste, qualified hydroelectric production, and marine and hydrokinetic renewable energy (150 kW or larger).

Eligibility for the PTC is contingent upon the generated electricity being sold to an unrelated entity.

Note, in lieu of the PTC, a taxpayer may elect to treat qualified property: (1) placed in service after December 31, 2008, and (2) which begins construction before January 1, 2014, as energy property for which a 30% energy investment tax credit is allowable (see below).

INVESTMENT TAX CREDIT

Section 48 of the Internal Revenue Code provides an investment tax credit (ITC) for solar and other renewable energy property. The credit is equal to 30% of the cost of fuel cell property; solar equipment placed in service before January 1, 2017; and qualified small wind energy property. Other qualified renewable energy property (e.g., geothermal) is currently eligible for a credit equal to 10% of the cost of qualified property.

Solar equipment placed in service on or after January 1, 2017 may be eligible for a credit equal to 10% of the qualified cost.

Since the PTC has expired and the ITC will be reduced (for solar) during the timeframe covered by the 2014 Resource Plan, some scenarios are included whereby the tax credits are assumed to be extended beyond their scheduled expiration dates. See *Chapter 4 – Determining the Most Reasonable Plan.*

EMISSION CONTROL COSTS

With regulatory actions to control emissions mounting, environmental controls and their associated costs are becoming more pressing considerations in the planning process. Over the course of the Planning Period, ultimate compliance costs related to federal and state environmental regulations could differ from the amounts estimated today due to: (1) the nature and extent of regulatory requirements in place, (2) changes in the portfolio composition, (3) load levels, (4) environmental controls commercially available at the time regulations become effective and their associated cost, (5) strategic decisions to retire or retrofit on a case-by-case basis and (6) availability of market mitigation tools.

In general, the risk assessment in analyzing emission control costs focuses on direct compliance – that is, the installation (capital costs) and operation (O&M costs) of control equipment to reduce a power plant's environmental impact. Capital costs relate to the construction/installation of the control and can include major equipment, supporting technologies, and engineering studies. O&M costs relate to the everyday operation of those controls materials and added energy demands. Changes in any one of these variables or a combination of these variables could impact the cost and selection of control technology used over the Planning Period. As such, compliance costs have been filtered through several possible scenarios to help ensure selected environmental technologies could withstand deviations from their original cost forecast.

[12]http://www.irs.gov/pub/irs-drop/n-13-60.pdf
[13]http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

Analytical Framework

In addition to the generation technology considerations that were discussed in *Chapter 2 - Needs & Resources* and the planning inputs discussed above, other considerations provided an analytical foundation to the planning process.

ENVIRONMENTAL IMPACT

TECHNOLOGICAL REVIEW

Technology choices for new fossil-fueled generators are reviewed for possible application within the APS fleet, such as natural gas combustion turbines, which are efficient and produce low emissions. These units employ state-of-the-art pollution control equipment necessary to meet or exceed air quality regulations. APS is committed to using state-of-the-art technologies, but is also cognizant of the risk and high initial cost associated with such newer technologies. APS concentrates its focus on proven technologies that have successfully demonstrated industry-wide acceptance, efficiency, and reliability.

WATER

In an effort to address the importance of water in APS's resource planning process, and in recognition of the importance of water as a resource in Arizona, APS utilizes the following assumptions and methodology: (1) the Company is now assuming dry-cooled or hybrid-cooled technology for any newly constructed natural gas generation additions, and (2) for all generation, water consumption for APS's generating units (existing and new) was quantified for each portfolio under review.

COST OF COMPLIANCE

Sulfur dioxide (SO2) emissions have a cap-and-trade program in place to establish cost parameters, while other regulated pollutants do not. For SO2 and other regulated emissions (other than carbon dioxide (CO2)), the costs of EPA-required emission controls are included in this report's prospective analyses. There currently are no laws that require a control technology, cap-and-trade system, or tax for CO2 emissions. Nonetheless, given EPA and Congressional discussions on this issue, APS has incorporated the potential for GHG legislative impacts as a factor in the resource planning process. For the 2014 Resource Plan filing, APS has assumed a price of $13/metric ton starting in 2021 for CO2 as a proxy for a potential CO2 price in resource cost comparisons. Refer to *Chapter 4 - Determining the Most Reasonable Plan* for more detail on CO2 costs.

ENVIRONMENTAL REGULATIONS

Environmental regulations are promulgated on the federal (EPA), state (ADEQ), and county (Maricopa, Pinal, and Pima) levels[14]. EPA, specifically, is considering multiple regulations that may have an impact on APS's operations.

[14]Additional information regarding environmental regulations can be found at response to Rule D.17.

CLEAN AIR ACT

The Clean Air Act (CAA) regulates air emissions from stationary and mobile sources. Numerous programs have been established to protect public health and welfare by controlling emissions of air pollutants.

- **Regional Haze (Visibility)**

  Best Available Retrofit Technology (BART) - Four Corners, Cholla, and Navajo power plants are subject to the CAA's Regional Haze rule, which requires an analysis of the impacts of air emissions from certain industrial facilities and the installation of "best available retrofit technology" to control emissions from those facilities to improve visibility in affected national parks and wilderness areas. The focus of the regulations is to reduce emissions of oxides of nitrogen (NOx), SO2 and particulate matter (PM), which contribute to visibility impairment in these federal areas. Congress enacted the visibility statutes to address the aesthetic effects of air pollution in national parks and wilderness areas, not to protect public health.

  Reasonable Progress - The Regional Haze rule envisions a long period, covered by several planning phases, to meet the congressionally established national visibility goal targeted to be met in 2064. The state of Arizona is required to develop a Regional Haze State Implementation Plan (SIP) for each period, the first of which extends from 2005 through 2018. Each subsequent planning period will run for 10 years. Arizona's first Regional Haze SIP covered the initial planning period extending from 2005 through 2018 and included a BART determination for each BART-eligible source in the state. During the next (i.e. second) planning period, which will run from 2019 through 2028, the state of Arizona must consider man-made sources of visibility-impairing pollutants for potential Reasonable Progress controls. Sources not subject to BART in the first planning period could potentially be subject to additional emission control requirements in the second and subsequent planning periods of the Regional Haze program.

- **Mercury and Air Toxics Standard (MATS)**

  EPA proposed a rule regulating hazardous air pollutants (HAPs) on May 3, 2011, and finalized the regulations on December 16, 2011. The rule establishes standards and requirements for reducing mercury and other HAP emissions from certain electric generating units. APS is evaluating fabric filter baghouses and scrubber upgrades for Cholla Unit 2 and installation of activated carbon injection for Cholla Units 1 - 3.

- **National Ambient Air Quality Standards (NAAQS)**

  For the purpose of protecting public health and welfare, the CAA established NAAQS for six pollutants: ozone, NOx, SO2, PM10, carbon monoxide, and lead.

- **Carbon Pollution Standards for Fossil-fired Electric Generating Units**

  In June 2013, the White House issued a Presidential Memorandum directing EPA to use its existing authorities under the CAA to develop GHG emission standards for new, modified, and existing power plants. The Presidential Memorandum directs EPA to propose GHG emission standards for modified and existing units by June 1, 2014 and to finalize them by June 1, 2015. The memorandum further directed EPA to reissue proposed standards of performance for new power plants by September 20, 2013 and to finalize them in a timely fashion. Consistent with the President's directive, pursuant to its authority under the CAA and its endangerment finding, on September 20, 2013, EPA issued a proposed rule, which would establish New Source Performance Standards for new fossil-fired power plants. EPA is currently working on finalizing the standards.

CLEAN WATER ACT

The Clean Water Act (CWA) establishes the basic structure for regulating discharges of pollutants into waters of the United States and regulating quality standards for surface waters. Under the CWA, EPA has implemented pollution control programs, such as setting wastewater standards for industry and water quality standards for all contaminants in surface waters.

- Cooling Water Intake Structures – Section 316(b) of the Clean Water Act requires cooling water intake structures (CWIS) that withdraw water from a "water of the U.S." to reflect the best technology available for minimizing adverse environmental impacts. Currently, the EPA is engaged in a new Section 316(b) rule-making process to promulgate impingement and entrainment standards for CWIS at existing power plants and other industrial facilities to protect fish and other aquatic organisms. A final rule is anticipated to be issued by April 17, 2014.
- Effluent Limitation Guidelines (ELG) – In 2013, the EPA proposed revised effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil-fired electric generating units. The EPA's proposal offers numerous options that target metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and non-chemical metal cleaning wastes operations. A final rule is anticipated later in 2014 and may impact the current discharge limits for Four Corners, West Phoenix, and Ocotillo power plants.

RESOURCE CONSERVATION AND RECOVERY ACT

The Resource Conservation and Recovery Act (RCRA) gives the EPA the authority to control hazardous waste from "cradle-to-grave." RCRA also regulates the management of non-hazardous solid wastes, as well as underground tanks storing petroleum and other hazardous substances.

- Coal Combustion Residuals – In June 2010, the EPA proposed new rules to regulate coal combustion residuals to prevent contaminants from leaching into groundwater. The EPA's final rule, expected by December 19, 2014, will affect the manner in which coal-fired power plants manage their ash disposal in surface impoundments and landfills.

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

ADEQ is Arizona's primary environmental regulatory agency, with the responsibility for developing and enforcing state regulations that implement Arizona environmental laws, and for helping ensure that businesses and regulated sources operate according to federal and state environmental laws and regulations. Three programmatic divisions – Air Quality, Water Quality, and Waste Programs – carry out ADEQ's core responsibilities. In some areas, Arizona's environmental laws go beyond the federal laws. Examples include the Arizona State Hazardous Air Pollutants Program and the Arizona Aquifer Protection Permit Program.

Similar to EPA delegation authority, ADEQ may delegate some permitting and enforcement responsibilities to counties within the state. ADEQ has delegated CAA permitting and enforcement authority to Pima, Pinal, and Maricopa counties.

ENVIRONMENTAL LEGISLATION

CONGRESS

None of the attempts to pass comprehensive climate change legislation in the 111th Congress were successful. As for the 112th Congress, a number of bills introduced are aimed at delaying, eliminating, defunding, or overseeing EPA's authority to regulate GHGs. Such legislation includes delaying any action by the EPA to regulate GHG emissions from stationary sources for a fixed number of years, stripping the EPA of any CAA authority to regulate GHG emissions, and cutting off funding for the implementation of the agency's GHG rules by prohibiting the use of funds to implement or enforce rules relating to the regulation of GHG emissions from stationary sources. The ultimate outcome of these numerous legislative efforts remains uncertain.

ENERGY EFFICIENCY AND RENEWBLE ENERGY STANDARDS

The ACC has enacted rules regarding energy efficiency that mandate a 22% cumulative energy savings requirement by 2020. The RES requires 15% of retail sales be met by renewable energy by 2025. As part of the RES, APS must also meet a portion of the renewable energy requirement with distributed energy resources – namely, rooftop solar installations.

From a planning perspective, the degree to which customers engage in these programs represents a significant uncertainty and has a direct impact on projected customer demand levels. If customer participation is lower than projected, then demand for energy could exceed forecasted levels as would the need for resources to supply that demand. Conversely, higher than anticipated participation in these programs would lower customer demand for energy resulting in reduced resource needs. Over the 15-year Planning Period, penetration of these programs may be higher or lower than originally forecast depending on many factors such as customer preferences, general economic conditions and availability of affordable technology.

RENEWABLE ENERGY STANDARD (RES)

In 2006, the ACC adopted the RES, under which electric utilities under its jurisdiction must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. The renewable energy requirement was 4% of retail electric sales in 2013 and it increases annually until reaching 15% in 2025. The RES also includes a carve-out for distributed energy systems of 30% of the overall RES requirement per year.

In addition, APS's 2009 rate case settlement agreement[15], requires APS to obtain an additional 1,700 GWh of new renewable resources to be in service by year-end 2015. When combined with compliance obligations under the RES, APS estimates that by the end of 2015, renewable energy in the portfolio is estimated to be approximately 12% of retail sales, which is more than double the RES target of 5% for that year.

Table 4 summarizes the RES percentage requirement (not including the additional commitment required by the settlement agreement discussed above) and its timing for each year under the Planning Period. The Selected Portfolio in addition to the other portfolios that were considered in developing the 2014 IRP meet or exceed the RES requirement percentages.

TABLE 4: RES PERCENTAGE REQUIREMENTS

YEAR	RES REQUIREMENT*
2014	4.50%
2015	5.00%
2016	6.00%
2017	7.00%
2018	8.00%
2019	9.00%
2020	10.00%
2021	11.00%
2022	12.00%
2023	13.00%
2024	14.00%
2025	15.00%

*RES requirement includes a 30% carve-out for distributed energy systems

DEMAND SIDE MANAGEMENT

In 2011, the ACC's Energy Efficiency (EE) rules became effective which include an Energy Efficiency Standard of 22% of cumulative annual energy savings by 2020.

Table 5 summarizes the EE Standard percentage requirement and its timing for each year under the Planning Period. The Selected Portfolio in addition to the other portfolios that were considered in developing the 2014 IRP used the requirement percentages in formulating the 15-year plan.

TABLE 5: EE STANDARD PERCENTAGE REQUIREMENT

YEAR	EE REQUIREMENT
2014	7.25%
2015	9.50%
2016	12.00%
2017	14.50%
2018	17.00%
2019	18.50%
2020	22.00%

[15]ACC Decision No. 71448 (December 20, 2009)

RELIABILITY

Approximately 1.2 million customers rely on APS for reliable and cost-effective electric service. To ensure resources are available when needed, APS uses both probabilistic and deterministic approaches to assessing reliability for its generation and transmission systems. APS also considers the interplay between those two components on the utility system as a whole.

GENERATION

Chapter 2 - Needs & Resources outlined a varied array of resource options. In recognizing that each has its own reliability characteristics - such as the intermittency inherent in variable energy resources versus the continuous generating capabilities of conventional resources - APS structures its asset base along the principles of reliability, cost-effectiveness, environmental sustainability, and fuel and technological diversity. The portfolio of assets selected to best achieve those objectives should be the one that strikes the proper balance and meets the needs anticipated for the Planning Period. Over time, that balance will change as new technologies further expand resource choices.

APS's key planning reliability criterion states the Company should provide sufficient resources such that the expected probability of a service outage is less than or equal to one event in ten years. From a practical perspective, the resource planning process determines the quantity of planning reserves that are required to satisfy this reliability criterion. The planning reserves provide additional resources that can be called upon in the event that generating units experience unplanned outages and/or customer loads are higher than anticipated. APS plans for additional capacity and associated reserves based upon forecasted amounts of distributed generation, but ultimately the decision to supply distributed generation is left to the customer. This creates a risk of planning too many or too little resources for distributed generation resources.

SOLAR PV PENETRATION

Additional Costs Attributed to Operating Renewable Energy

- Additional Up- and Down-Ramp Requirements – An increasing reliance on variable energy resources is expected to create a misalignment between energy production and energy demand, given historical APS service territory demand use curves. As illustrated in Figure 10, as more of these resources enter the mix, the ramps from peak to trough become more severe. For example, the 2029 potential penetration of solar PV may produce a down-ramp of 2,200 MW in the morning to early afternoon hours, requiring a rather swift backing off of generation to match the reduced demand. From there, the up-ramp from midday to evening peak could be even more significant. As the sun fades and customers enter their peak demand hours, 3,000 MW of generation may need to be ramped up to meet the loss of generation from solar PV.

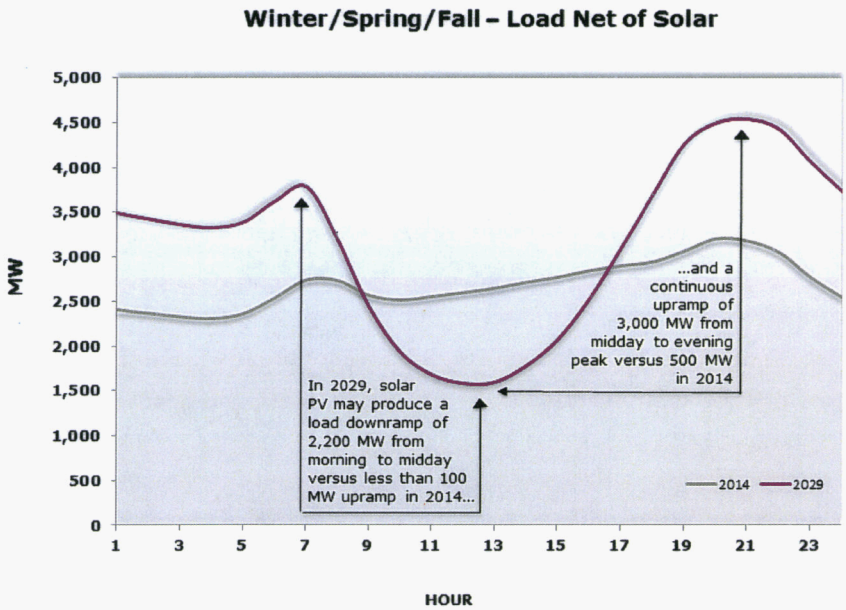


Figure 10: Impact of Solar PV on Load Shape

Putting the two together, the swings in less than a 24-hour period create a need for additional resources that can rapidly ramp up when the sun fades and ramp back down when it shines. Despite customer-side solar PV resources acting to decrease load when generating power, those resources still require operating reserve margins that will grow as penetration grows. However, because solar PV generation output varies in relation to climate conditions, solar PV resources on the customer-side and utility-side create additional reserve requirements.

- Solar Integration Costs – Supply fluctuations from solar resources are daily intra-hour events, similar to those that have historically been limited to load fluctuations. APS has addressed this issue by operating additional conventional resources. In 2012, APS employed Black & Veatch Corporation to analyze the associated cost impacts to providing this backup energy. Black & Veatch found that solar integration costs for expected PV generation on the APS system will be in the range of $2.00/MWh in 2020 and $3.00/MWh in 2030[16], based on compliances to the current RES requirements.

  The analysis assumed that the resource providing the incremental energy is a General Electric LMS100 combustion turbine, such as the five units that are projected to be installed as part of the Ocotillo Modernization Project. Costs for renewable energy levels above the RES requirements may be considerably higher.

- Solar Production Forecasting – These integration costs do not factor error associated with solar production forecasting. Because solar, in installed quantities seen today, is a new phenomenon, solar production forecasting is a new and evolving field. Until solar production forecasting error decreases, the cost associated with forecasting errors will remain.

[16]The Solar Photovoltaic (PV) Integration Cost Study report can be found here http://www.aps.com/library/renewables/PVReserveReport.pdf

TRANSMISSION

ADEQUACY

APS uses a deterministic approach for transmission system planning. System performance must meet certain specific criteria under normal conditions (all lines in-service) and for any single contingency condition (any one element out-of-service). In general, an adequately planned transmission system will:

- Provide an acceptable level of service that is cost-effective for normal and single contingency operating conditions.
- Maintain service in the event of any single contingency outage.
- Not result in overloaded equipment or unacceptable voltage conditions for single contingency outages.
- Not result in cascading for single or double contingency outages.
- Provide for the proper balance between transmission import capability and local generation requirements for an import-limited load area.

REGIONAL PLANNING

As transmission additions must be integrated into regional plans, APS follows the WECC regional planning reliability criteria for system disturbance and performance levels, which consists of: (1) WECC/North American Reliability Corporation (NERC) Reliability Criteria for Transmission System Planning, and (2) Minimum Operating Reliability Criteria. In addition, APS participates in numerous regional planning organizations and in the WestConnect organization[17]. Through membership and participation in these organizations, the needs of multiple entities, and the region as a whole, can be identified and studied.

GRID INTEGRATION

One of the more pressing needs of utilities recently is to integrate higher levels of renewable energy resources into the grid. Renewable energy resource projects are sited where nature provides abundance – that is, where the wind blows or the sun shines – and not necessarily where transmission paths already exist. As a matter of practice, APS routinely includes estimates of grid integration costs into its planning analytics.

SYSTEM STABILITY

The stability of the APS system and neighboring systems must be maintained at all times. To review system needs, APS and SRP conduct joint planning on issues such as system reliability and summer preparedness – how the respective systems are prepared for high summer temperatures. Each spring, APS and other load-serving entities present to the ACC a coordinated plan to serve customers' electricity needs for the upcoming summer, including generation resources, reserve requirements, transmission capacity, and other issues as appropriate. Additionally, the ACC conducts a Biennial Transmission Assessment (BTA) to review the 10-year transmission plans that are developed and filed annually by APS. The primary objective of the BTA is to evaluate system reliability by assessing the adequacy of existing and planned transmission facilities to meet present and future energy needs in a reliable manner.

[17]WestConnect is composed of utility companies providing electric transmission in the western U.S. Members work collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to western wholesale electricity markets.

OTHER RISKS

CREDIT RISK

APS may be exposed to losses in the event of nonpayment or nonperformance of a counterparty. Stringent credit practices mitigate this risk.

FINANCIAL UNCERTAINTY

Competition for available capital investment dollars, especially in today's uncertain economy, will require a strong financial profile. Maintaining APS's financial strength will be necessary to implement the 2014 IRP. This will require, at a minimum, APS to retain its strong investment grade credit ratings have the opportunity APS to earn a competitive return on equity capital.

ACCESSIBLE CAPITAL MARKETS

As capital-intensive businesses, vertically integrated utilities such as APS require reliable access to the capital markets to fund investment in utility infrastructure not otherwise funded by operating cash flows. Access to external capital is also important for refinancing long-term debt that supports existing infrastructure investment as it matures. Recent disruption and distress in the capital markets, most evident in the months following the financial crisis in 2008, highlight the importance of having ready, reliable access to capital at a reasonable cost. Higher costs of capital, or an inability to raise the capital necessary to finance its business, can impact APS's ability to cost-effectively make needed investment in utility infrastructure, which causes higher costs for customers. APS cannot control market-driven events that impact conditions in the capital markets, but having a solid investment-grade credit rating can help ensure APS can reasonably access capital at favorable terms over the long run.

Regional Plans & Programs

RELIABILITY AND RESERVES OPTIMIZATION

Reserve sharing and innovative new or additional ways to achieve these effects have become a topic of growing interest as wind and solar penetration increase across the western US. APS has formally signed an agreement with seven other Balancing Authorities in the Desert Southwest, called the Southwest Variable Energy Resource Initiative (SVERI), to begin to study variable energy's impact on reserve limits and other operating circumstances as a collective of BAs. The group, at this time, is aggregating data and creating tools that provide the participating balancing authorities greater visibility and access to selected operating data. Additionally, SVERI has partnered with the University of Arizona to conduct rigorous data analysis to determine what types of operational issues solar presents and what the group may be able to do to address operating challenges and/or decrease integration costs.

Additionally, APS continues to monitor progress that the Northwest Power Pool Market Assessment Committee (NWPP MC) and the PacifiCorp-California Independent System Operator (CAISO) partnership make in creating tools that may help integrate renewables, such as the Energy Imbalance Market (EIM). The EIM, which is scheduled to begin in 2014, has many potential benefits and costs that are not fully understood. A decision by APS on whether or not to participate cannot be finalized until the market becomes more active.

TRANSMISSION PLANNING

APS has been active in regional and subregional transmission planning organizations for many years, including participation in the Western Electricity Coordinating Council (WECC), WestConnect, as well as the Southwest Area Transmission (SWAT) planning group under Order No. 890. Beginning in 2011 with Order No. 1000 and its progeny[18], Federal Energy Regulatory Commission (FERC) established a number of new requirements applicable to transmission owning and operating public utilities. Those requirements include, but are not limited to, the following:

- Participation in a regional transmission planning process that satisfies the principles outlined in Order No. 890[19] and results in a regional transmission plan.
- Planning processes that explicitly provide for consideration of public policy requirements.
- Opportunities for non-incumbent developers comparable to those of incumbent developers.
- Development of a regional cost allocation method for new transmission facilities that meets the cost allocation principles in Order No. 1000. Those principles are:
  - Allocated costs must be roughly commensurate with estimated benefits.
  - Costs cannot be involuntarily allocated to parties that do not benefit from the project(s).
  - A benefit to cost ratio of greater than 1.25 cannot be used without justification and Commission approval.
  - Costs cannot be allocated outside a region unless agreed upon by the other region.
  - Allocation methods and identification of beneficiaries must be transparent.
  - Different allocation methods may be used for different types of projects.
- Each pair of neighboring regions is required to coordinate in order to determine if there are more efficient or cost-effective solutions to the transmission needs of the two regions. The regions are also required to develop information sharing processes and procedures to jointly evaluate projects proposed to be located in both regions.

[18]Order No. 1000 was issued on July 21, 2011, Order No. 1000-A was issued on May 17, 2012, and Order No. 1000-B was issued on October 18, 2012.

[19]The principles are coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning.

- Each transmission provider must amend its Open Access Transmission Tariff (OATT) to incorporate the processes and methods developed to comply with Order No. 1000.

APS, along with other Western transmission providers, chose to continue building on the processes already established through WestConnect to comply with Order No. 1000. Until FERC grants final approval to the WestConnect compliance filings pending[20], it is difficult to predict who will ultimately join the Region, but eighteen transmission providers, five state commissions, and numerous merchant transmission developers and stakeholder groups have participated in the implementation process thus far. The purpose of the proposed WestConnect transmission planning process is to identify regional needs and to determine the most efficient or cost-effective solutions for those regional needs. WestConnect plans to use both a bottom-up and top-down approach by rolling up the individual transmission provider transmission plans and evaluating regional needs. WestConnect will also propose solutions to regional needs if they are unmet by projects proposed in the biennial planning process.

Projects submitted in the planning process will be evaluated for cost allocation consideration and deemed eligible if they address a Reliability, Economic, or Public Policy objective in the WestConnect Order No. 1000 planning region. Reliability projects are projects identified as necessary to address a regional Transmission Planning (TPL) reliability standard set forth by the North American Electric Reliability Corporation (NERC). Economic projects are projects associated with congestion relief which provide for more economic operation of the regional transmission system. Public Policy projects are those projects proposed to address an enacted public policy requirement. Through its planning process WestConnect will determine the beneficiaries of each proposed project and allocate the costs of that project commensurate with the benefits projected.

WestConnect also developed common planning and information sharing processes with its neighboring regions, the CAISO, ColumbiaGrid, and Northern Tier Transmission Group (NTTG), throughout 2012 and 2013. The processes the four regions developed resulted in common OATT language each region proposed to FERC in May 2013[21]. The agreed-upon language includes a biannual planning process whereby each Region shares its data, study plans, and assumptions and works collaboratively to address any differences in the way projects applicable to more than one region are analyzed. The Regions have also agreed to a cost allocation process where each Region is assigned its pro rata share of applicable project costs. The individual Regions would then allocate their *pro rata* share of those costs to the beneficiaries identified in their analyses.

GAS-ELECTRIC COORDINATION

In addition to internal fuel analytics and planning, APS is active in initiatives regarding Natural Gas and Electric utility planning. These initiatives include the Gas/Electric infrastructure adequacy study commissioned through the Western Interstate Energy Board where APS currently holds a seat on the study task force. APS also is helping lead the discussion and writing of a response to FERC Docket AD12-12-000 regarding the "Coordination between Natural Gas and Electricity Markets".

This comprehensive planning process including both internal planning processes and active participation in external industry initiatives ensures that APS's natural gas fuel supply future is well understood and adequately coordinated with the changing industry and selected resource plan.

[20]See FERC Docket No. ER13-82-000 for the APS compliance filings. FERC has not responded to the filing as of the date of this publication.

[21]See FERC Docket No. ER13-1450-000 for the APS compliance filing. FERC has not responded to the filing as of the date of this publication.

CHAPTER 4:
DETERMINING THE MOST REASONABLE PLAN

Chapter 4 Determining the Most Reasonable Plan

This chapter discusses the development and analytical evaluation of alternative resource plans and their associated potential risks. Based upon the needs and resources assessment identified in *Chapter 2 - Needs & Resources*, and the challenges of APS's new energy future identified in *Chapter 3 - Planning Inputs & Other Considerations*, a set of responsive portfolios was developed and measured against future challenges. This chapter includes the major assumptions affecting the Company's resource choices, description of the resource plans, future uncertainties and scenarios, along with a comprehensive set of results. Consideration is given to all of these factors to determine which plan best fits with APS customers' long-term needs of reliable, cost-effective and environmentally responsible electricity. The result is APS's 2014 Resource Plan.

Development of Resource Portfolios

The term "resource portfolio" refers to the entire set of resources over the Planning Period designed to meet customers' demand for electric energy. It includes the existing generation fleet and power contracts as well as potential future conventional, renewable, and energy efficiency measures. Portfolio analysis includes dispatch simulations and thus captures how an individual resource would be expected to operate on the APS system. To capture the long-term effects of resource portfolio additions later in the Planning Period, it is necessary to develop revenue requirements beyond the 15-year window. In this filing, revenue requirements are calculated through 2043.

Resource portfolios were developed using Ventyx's resource expansion plan optimizing software, PROVIEW. Existing generation and contracts were input into the model as fixed assets, and the program was allowed to choose from a list of potential future resources to meet load growth and reliability constraints. Initially, generation resources listed in Table 3 were screened for cost effectiveness. Potential future resources included in PROVIEW were natural gas combined cycles, combustion turbines, solar photovoltaic, wind, geothermal, coal and nuclear technologies. PROVIEW used dynamic programming to evaluate thousands of resource combinations to meet load growth and reliability constraints. Resource plans with the lowest net present value of revenue requirements were chosen for further detailed analysis in PROMOD IV and subjected to scenario analysis.

Included in each portfolio is the assumption that APS's aging Ocotillo Steam units are retired and the site modernized by including five new LMS100 combustion turbines. This reflects the importance of the Ocotillo site in terms of reliability in the Phoenix load pocket, as well as meeting the need for increased flexibility that will be required as more variable resources come on to APS system and the Southwest power market in general.

Scenario analysis refers to the grouping together of a set of assumptions of key uncertain variables that could potentially all occur in tandem. The goal of scenario analysis is to illustrate the impact to the portfolios of multiple key variables being stressed in a plausible manner. Results of these studies provide information on diversity, cost, environmental impacts, robustness and overall risk to assist in the selection of a resource plan.

INPUTS, ASSUMPTIONS AND CRITERIA

Each of the resource portfolios assessed incorporate the following criteria, also called the Current Path Scenario:

LOAD FORECAST

The load forecast used throughout the following analysis is based on the best available data as of the end of the third quarter 2013, and is described in more detail in response to Rules C.1 through C.3 and E(a). The current load forecast assumes an annual average of around 3% energy growth year-over-year in load requirements prior to energy efficiency and distributed energy.

PLANNING RESERVES

Resources are installed to maintain at least a 15% planning reserve margin at the time of APS's summer peak, based on loss of load probability criterion.

INFLATION

APS assumes a future inflation rate of 2.5% per year, which is representative of inflation levels over the past ten years. Exceptions to this inflation assumption are described in response to Rule D.1(d).

COMPLIANCE WITH STANDARDS

All portfolios developed either meet or exceed compliance with the EE Standard and the RES, with one exception. In the event that APS's reserve margin exceeds 20% for at least two years in the Planning Period, ACC Decision No. 73884 requires APS to develop a resource plan that attempts to reduce the reserve margin by deferring any incremental capacity additions until such time that the reserve margin no longer exceeds 20%. APS's resource plan does exceed 20% in 2014 through 2016, and therefore a resource plan entitled "Alternative Portfolio" was developed that reduced the amount of EE and Renewables such that APS would not meet compliance with the current EE standards in years 2014 - 2016. This plan is further discussed in the Response to Rules - Other Compliance Requirements section.

NATURAL GAS PRICES

The natural gas price curve utilized in the Current Path analyses was derived from an analysis of the forward market price curve for natural gas as of the end of the third quarter 2013.

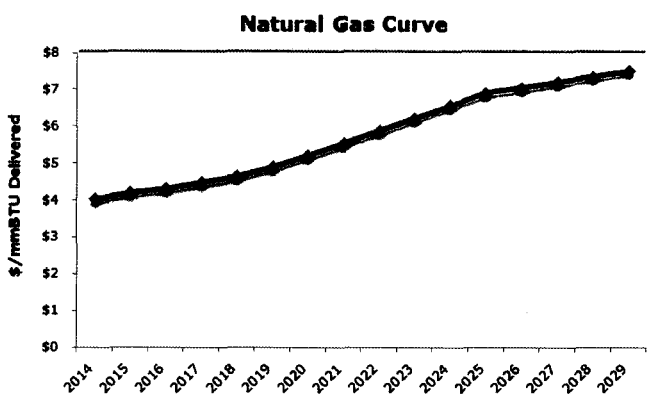


FIGURE 11 - NATURAL GAS PRICE CURVE

CARBON COSTS

APS is incorporating assumed carbon costs based on the actual trading price of CO2 allowances in the California market as of September 24, 2013. For this analysis, it is assumed that federal legislation occurs requiring utilities to acquire carbon allowances beginning in 2021. Carbon prices are then escalated at the rate of inflation.

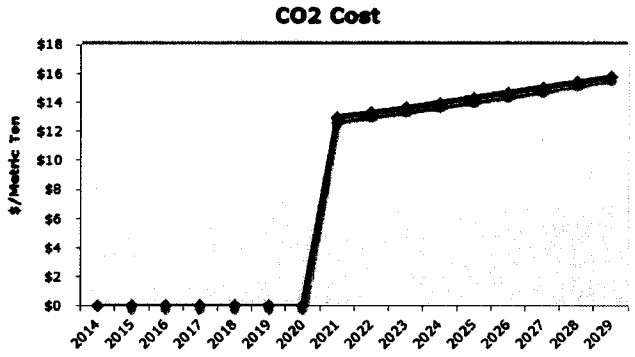


FIGURE 12 - CARBON COST FORECAST

EE COSTS [22]

Energy Efficiency program costs are relatively well known in the near-term and are based on the cost of EE programs employed by APS over the past few years. Over the course of the Planning Period, APS assumes that existing programs will continue to contribute towards the EE goals and will be replaced and/or expanded upon to meet the overall EE Standard of 22% by 2020. Post-2020, EE costs are assumed to continue to be incurred as APS maintains the 22% standard as part of its resource mix. It is important to note that these costs are simply projections based upon current programs; actual future costs of EE programs are a significant unknown at this time, and could be more expensive than those currently in place.

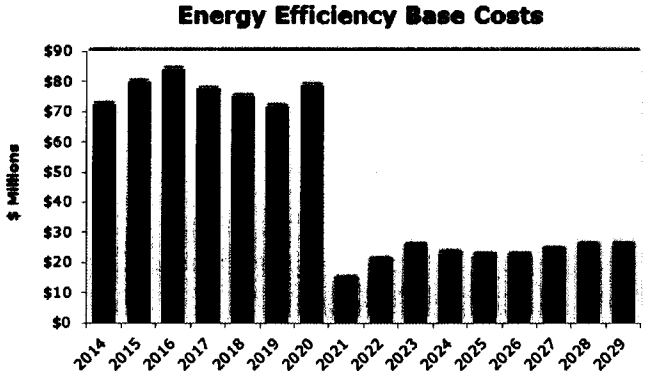


FIGURE 13 - ENERGY EFFICIENCY BASE COSTS

PTC/ITC

APS assumes that the current tax provisions related to production tax credits and investment tax credits change as planned as detailed in *Chapter 3 – Planning Inputs & Other Considerations.*

[22]EE cost curve referenced in the Current Path analyses was derived from third quarter 2013 load with EE and DE compliance.

KEY METRICS

APS specifically monitored the impacts to a set of key metrics that provide insight into the holistic impact of each set of resource combinations. A high-level summary of these metrics is included below while comprehensive and detailed annual values are included in Attachments F.1(b)-F.1(c) for all cases modeled.

FUEL DIVERSITY

A more diverse portfolio relies on a greater number of energy sources, thereby mitigating risks associated with any one particular source. Fuel diversity is quantified by the energy mix by the end of the Planning Period (2029).

PORTFOLIO COSTS[23]

Portfolio costs are measured in terms of net present value (NPV) of revenue requirements over the Planning Period plus an extension period (another 15 years), as well as average system generation cost in $/MWh at the end of the Planning Period[24].

CUMULATIVE CAPITAL EXPENDITURES

Cumulative capital expenditures are an indication of how much capital APS or market participants will need to obtain over the Planning Period to execute each portfolio.

NATURAL GAS BURN

Natural gas burn provides an indication of the amount of gas cost risk inherent in each portfolio.

CO2 EMISSIONS

Total emissions of CO2 give an indication of the amount of carbon cost risk for each portfolio. Assumed carbon costs are modeled as a base assumption.

WATER USE

Water use is another important factor and is quantified in terms of acre-feet per year.

[23]Portfolio costs represent the total costs of the resource additions from a generation and incremental transmission perspective. While it may be indicative of the increasing costs that will develop into future rates, these costs are not inclusive of all rate components (e.g., distribution costs, metering/billing costs, etc.).

[24]Average system generation cost, represented in $/MWh, is not intended to directly correlate to customer rates; rather, it is indicative of the per-unit cost of energy from APS generation resources as outlined in each portfolio, and does not include other components of customer rates such as distribution charges.

Portfolios

All portfolios (1) include the recent acquisition of SCE's share of Four Corners Units 4 and 5, and the related retirements of Units 1, 2, and 3, (2) assume no additional coal or nuclear baseload resources are added over the course of the Planning Period and (3) achieve compliance of the Energy Efficiency Standard.

The following four portfolios developed by PROVIEW were further studied through the more detailed PROMOD, and subjected to scenario analysis. PROVIEW results were reviewed to evaluate whether the ACC's Renewable Energy Standard was met in the portfolios, and a mix of solar photovoltaic, wind and geothermal was added to achieve the standard as necessary. In general, PROVIEW chose a mix of combined cycles, combustion turbines and solar photovoltaics. It did not find either new coal or new nuclear to be economic resources.

TABLE 6 - OVERVIEW OF PORTFOLIOS

	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Description	Modernize Ocotillo; continue coal operations; EE and RE compliance	Modernize Ocotillo; continue coal operations; EE compliance; RE well above compliance	Modernize Ocotillo; replace Cholla with gas and renewable generation; EE compliance; RE slightly above compliance	Modernize Ocotillo; convert Cholla to gas operation; EE and RE compliance
Resource Contributions (2029 Peak Capacity Contribution / % Energy Mix)				
Nuclear	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%
Coal	**1,932 MW / 24.5%**	**1,932 MW / 23.4%**	**1,285 MW / 16.9%**	**1,285 MW / 16.9%**
Natural Gas	7,137 MW / 28.5%	6,933 MW / 21.9%	7,749 MW / 35.0%	7,784 MW / 36.1%
Renewable Energy & Distributed Energy	**1,088 MW / 13.6%**	**1,298 MW / 21.3%**	**1,117 MW / 14.7%**	**1,088 MW / 13.6%**
Energy Efficiency & Demand Response	1,722 MW / 15.3%	1,722 MW / 15.3%	1,722 MW / 15.3%	1,722 MW / 15.3%

BASE PORTFOLIO

The Base Portfolio is designed to deliver a portfolio of generation resources that does not overly rely on one specific fuel source during the 15-year Planning Period. APS achieves compliance with Energy Efficiency and Renewable Energy Standards. The remaining growth is met with demand response and natural gas resources, and assumes compliance with renewable energy. The first conventional resource addition is estimated to occur in 2017.

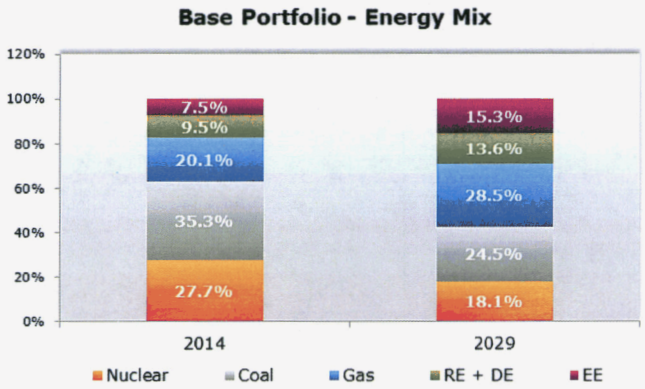


Figure 14 - Base Portfolio - Energy Mix

Two important factors stand out about this portfolio. First, approximately 52% of energy growth is met by emissions-free resources. Second, this portfolio results in a much more diverse set of resources by expanding natural gas, renewables and energy efficiency. By 2029, the contribution of coal and nuclear in this portfolio would be reduced to about 43% due to the fact that load is increasing while the amount of coal and nuclear generation is assumed to stay constant. This resource mix provides customers with greater protection from price volatility associated with a single fuel source however, maintaining coal resources may expose customers to other uncertainties and additional compliance cost obligations not factored into this plan[25]. The Loads & Resources table for this portfolio can be found at Attachment F.1(a)(2).

ENHANCED RENEWABLE PORTFOLIO

The Enhanced Renewable Portfolio is designed to show the impacts of increasing the contribution of renewable energy to 25% of retail sales by 2025[26]. In this portfolio, 1,150 MW nameplate renewable capacity was added over and above what was included in the Base Portfolio, 1,000 MW of solar and 150 MW of geothermal. Due to the high penetration of solar in this case, the additional renewables only contribute about 250 MW of peak capacity value to the resource plan due to APS's thermal peak shifting toward sunset. Conventional generation is still needed in 2017, similar to the Base Portfolio.

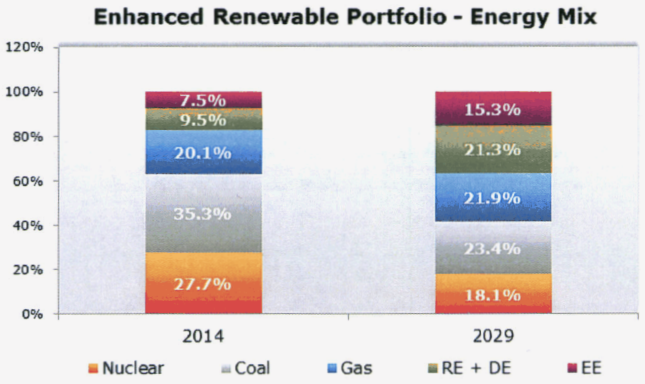


Figure 15 - Enhanced Renewable Portfolio - Energy Mix

This portfolio envisions that 74% of future energy growth is met by emissions-free resources. The Loads & Resources table for this portfolio can be found at Attachment F.1(a)(3).

[25]The percentages depicted in the figures above are based on total energy requirements prior to EE and DE. The RES currently requires 15% of retail sales be met by renewable resources by 2025, which is calculated after the impacts of EE and DE. To illustrate EE's relative contribution to future resources, it is depicted on these graphs and all values are calculated from the load requirements prior to the impacts of EE and DE.

[26]After the effects of energy efficiency and distributed energy.

COAL REDUCTION PORTFOLIO

This portfolio was developed to determine the impact of reducing APS's coal generation and to comply with the ACC directive to evaluate the impact of retiring coal if the Four Corners transaction was consummated, as discussed in *Response to Rules - Other Planning Considerations*. It was assumed that Cholla 2 would retire April 1, 2016 at which time fabric filters and SO2 upgrades would otherwise be required to comply with the MATS rule, and Cholla 1 & 3 would retire December 31, 2024 at the end of their coal contract. PROVIEW replaced the Cholla generation predominantly with gas, plus 200 MW name plate solar capacity (42 MW on peak rating).

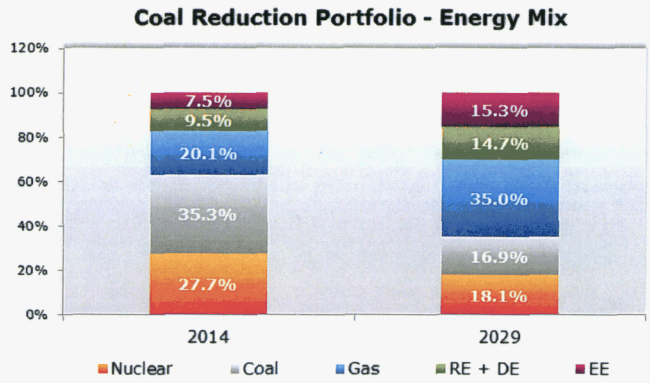


Figure 16 - Coal Reduction Portfolio - Energy Mix

This portfolio reduces APS's coal generation from 24.5% in 2029 in the Base Portfolio to 16.9%, and accordingly reduces future carbon risk as well as the risk of increased environmental controls. The Coal Contingency Portfolio estimates that 55% of future energy growth is met by emissions-free resources. The Loads & Resources table for this portfolio can be found in Attachment F.1(a)(4).

COAL-TO-GAS CONVERSION PORTFOLIO

This portfolio was developed to evaluate the impacts of converting APS's Cholla Units 1,2 & 3 to natural gas operation in the 2016-2017 time frame before fabric filters are required by the EPA on Unit 2, and SCRs are required on Units 2 and 3. It satisfies ACC Decision 73884, which required APS to consider the possible conversion of existing coal generating plants to natural gas.

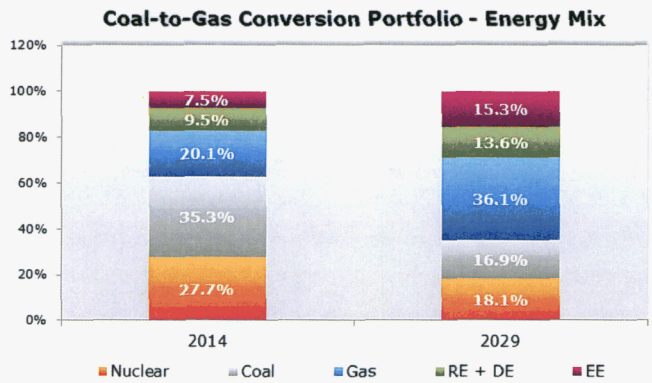


Figure 17 - Coal-to-Gas Conversion Portfolio - Energy Mix

In order to operate on natural gas, three additional costs would be incurred. First is the cost of the boiler modifications necessary to deliver and burn natural gas in the units. The second deals with the construction of a natural gas pipeline of sufficient size to deliver enough gas to run the units, approximately 30 miles in length. The third cost is liquidated damages to the coal supplier as a result of not meeting contractual requirements.

This portfolio reduces APS's reliance on coal in the Base Portfolio from 24.5% in 2029 to 16.9% and accordingly reduces future carbon risk and potential additional costs from future environmental regulations. The Loads & Resources Table for this portfolio can be found at Attachment F.1(a)(5).

Scenario Analysis

Six scenarios were developed to help assess the economic risk associated with each of the four portfolios. They were developed by envisioning different potential futures that could occur based on uncertain economic, political, and technological factors that are difficult to predict at this time. These scenarios try to capture possible interrelationships between the following key variables. Ranges in the assumptions (low - base - high) for the individual variables are shown below and the correlation between variables within the scenarios is subsequently discussed in the description of scenarios.

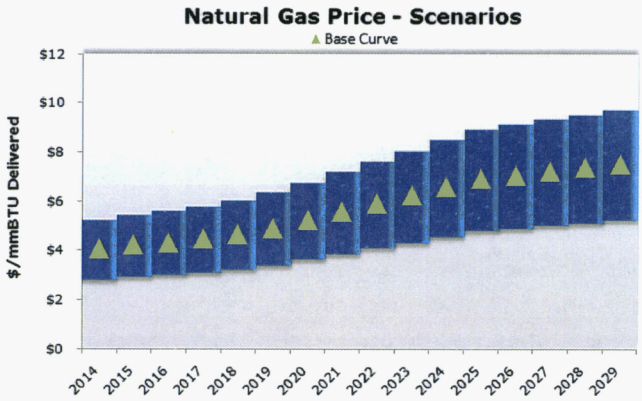


Figure 18 - Natural Gas Price Curves - Scenarios

RANGES IN SCENARIO ASSUMPTIONS

NATURAL GAS PRICES

Natural gas prices were flexed 30% above and below the baseline forecast.

CARBON PRICES

Carbon prices range from a low of zero, representing scenarios in which carbon legislation is not enacted, to a high of $15/ton starting in 2019 and escalating at 7.5% per year. The high case was used in the increased environmental and economic boom scenarios, and was developed by Charles River Associates for APS in its 2012 IRP.

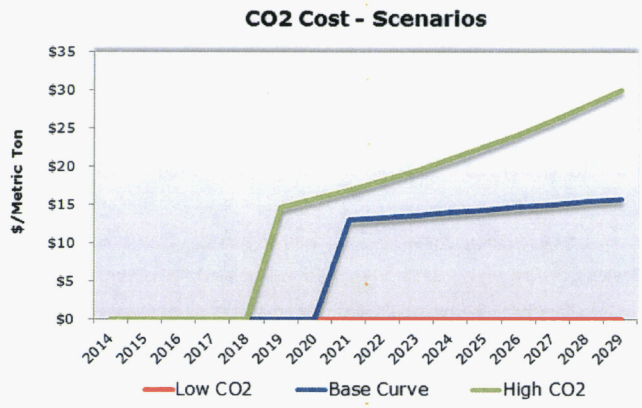


Figure 19 - Carbon Cost Curves - Scenarios

CAPITAL COSTS

Capital costs are flexed plus and minus 20%, with Increased Environmental Policy Scenario increasing future gas capital costs by 30%.

TAX POLICY

Base has ITC reverting back to 10% and PTC expiring, and in some scenarios the ITC/PTC is extended for the duration of the Planning Period.

ENVIRONMENTAL POLICY

The base assumes that SCRs are required on Four Corners 4-5, Cholla 2-3, and Navajo 1-3. In the Increased Environmental Policy Scenario another round of environmental control requirements on coal plants costing about the same as SCRs is assumed.

INFLATION

The base assumed inflation rate is 2.5%; scenarios range from 1.5% in the economic contraction to 3.5% in the economic boom.

LOAD GROWTH

Load growth ranges from 1-1.5% in the Economic Contraction Scenario to 4-4.5% in the Economic Boom Scenario.

ENERGY EFFICIENCY

Energy efficiency ranges from compliance to 10% above compliance in some of the higher cost scenarios – Sustained High Gas Price, Economic Boom, and Increased Environmental Policy.

DISTRIBUTED GENERATION

Distributed generation ranges from compliance to 10% above compliance in some of the higher cost scenarios listed above to 175% above compliance in the Increased Environmental Policy Scenario.

INTEREST RATES

The APS cost of debt ranges from 6.25% in the Economic Contraction Scenario to 8.25% in the Economic Boom Scenario. Return on equity ranges from 9.5% to 11.5% in the same two scenarios.

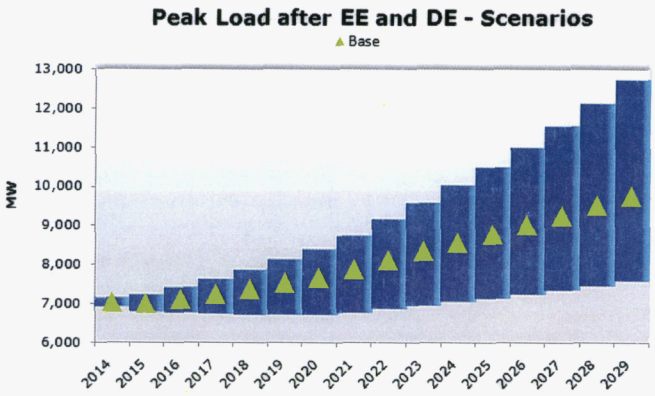


Figure 20 - Peak Load Curves for Scenarios

SCENARIOS

CURRENT PATH

The Current Path Scenario is based on APS base, or expected, assumptions as described above. It represents a slow economic recovery for Arizona in the near-term, continued shale gas development, continued pressure on coal generation with some coal plant retirements in the region, and compliance based distributed generation development. As mentioned in the previous section, resource plans for the four portfolios can be found in Attachment F.1(c)(1).

GAS DOMINATES

The Gas Dominates Scenario assumes limited regulations on hydraulic fracturing and sustained low natural gas prices. This results in wide-spread coal retirements across the U.S. and eliminates any perceived need for a carbon tax. Flexible natural gas is the technology of choice but faces capital cost pressure due to increased demand for the technology. Resource plans for the four portfolios are the same as the Current Path Scenario and can be found in Attachment F.1(c)(2).

SUSTAINED HIGH GAS PRICE

The Sustained High Gas Price Scenario assumes increased regulation of hydraulic fracturing technology and processes. Furthermore, global markets for natural gas results in LNG exports from the U.S. These factors lead to sustained high gas prices over the entire Planning Period. In addition, carbon legislation is assumed to be enacted. Taken as a whole, these factors translate to higher electricity prices resulting in slightly higher customer participation in energy efficiency and distributed generation programs. Resource plans for the four portfolios can be found in Attachment F.1(c)(3)

INCREASED ENVIRONMENTAL POLICY

The Increased Environmental Policy Scenario assumes increased concern regarding climate change and the environment drive high carbon prices, increased shale gas regulation, another round of coal plant environmental control requirements, nation-wide coal plant retirements, and increased demand for renewable generation which increases its capital costs. The effect of increased renewable capital costs is partially offset by continuation of renewable ITC/PTC. These factors result in higher electricity costs to consumers who respond by increasing their participation in energy efficiency measures and distributed generation. Resource plans for the four portfolios can be found in Attachment F.1(c)(4).

ECONOMIC CONTRACTION

The Economic Contraction Scenario is based on economic recovery and load growth rates well below historical levels. Customer usage growth remains 1.0 – 1.5% per year. Due to economic issues, there are no additional environmental regulations (including no carbon tax), and no additional shale gas regulation which leads to low gas prices. Inflation is low, and low demand for generation technology results in low generation capital costs, and ITC/PTC are continued to encourage growth in renewable technologies. Coal prices are lower at contract reopeners. Resource plans for the four portfolios can be found in Attachment F.1(c)(5).

ECONOMIC BOOM

The Economic Boom Scenario entails robust economic recovery with a 3 – 4.5% growth in GDP. Inflation and interest rates are slightly elevated, and environmental policy is more stringent resulting in high carbon costs. Increased gas consumption, along with stringent shale gas regulations, result in high natural gas prices. High demand for generation technologies result in high capital costs. All these factors drive higher electricity prices resulting in increased customer participation in energy efficiency and distributed energy programs. Resource plans for the four portfolios can be found in Attachment F.1(c)(6).

Portfolio Analysis

SUMMARY OF PORTFOLIO ANALYTICS

TABLE 7 - SUMMARY OF PORTFOLIO ANALYTICS

PORTFOLIO	AFFORDABILITY	ENVIRONMENT	FUEL DIVERSITY
Base Portfolio	•$29.3B NPV Revenue Requirements during Planning Period	•CO2 intensity drops 14% by 2029	•113 BCF annual natural gas burn in 2029
	•$47.6B NPV Revenue Requirements through 2043	**•Water intensity drops 24% by 2029**	**•Maintains coal fleet contribution (including recent acquisition of SCE's share of FC Units 4&5, and retirements of Units 1-3)**
	•58% increase in system costs per MWh by 2029	•52% of energy growth met by clean energy resources	•Meets EE and RE compliance
	•$13.6B cumulative CapEx by 2029		
Enhanced Renewable Portfolio	•$29.9B NPV Revenue Requirements during Planning Period	•CO2 intensity drops 23% by 2029	•90 BCF annual natural gas burn in 2029
	•$48.2B NPV Revenue Requirements through 2043	**•Water intensity drops 26% by 2029**	**•Maintains coal fleet contribution (including recent acquisition of SCE's share of FC Units 4&5, and retirements of Units 1-3)**
	•61% increase in system costs per MWh by 2029	•74% of energy growth met by clean energy resources	•Contribution of RE to 25% of retail sales by 2025
	•$16.4B cumulative CapEx by 2029		**•Meets EE compliance**
Coal Reduction Portfolio	•$29.2B NPV Revenue Requirements during Planning Period	•CO2 intensity drops 28% by 2029	•139 BCF annual natural gas burn in 2029
	•$47.6B NPV Revenue Requirements through 2043	**•Water intensity drops 31% by 2029**	**•Cholla Unit 2 retires 4/1/2016 & Cholla Units 1 & 3 retire 12/31/2024**
	•59% increase in system costs per MWh by 2029	•55% of energy growth met by clean energy resources	•Slightly above RE compliance
	•$14.2B cumulative CapEx by 2029		**•Meets EE compliance**
Coal-to-Gas Conversion Portfolio	•$29.3B NPV Revenue Requirements during Planning Period	•CO2 intensity drops 26% by 2029	•143 BCF annual natural gas burn in 2029
	•$47.6B NPV Revenue Requirements through 2043	**•Water intensity drops 31% by 2029**	**•APS's Cholla Units 1-3 converted to natural gas in 2016-2017**
	•57% increase in system costs per MWh by 2029	•52% of energy growth met by clean energy resources	•Meets EE and RE compliance
	•$13.2B cumulative CapEx by 2029		

KEY METRIC COMPARISON

Annual revenue requirements steadily rise over the course of the Planning Period, regardless of the portfolio. Costs are driven by increasing fuel prices, inclusion of assumed carbon tax, increased operation and maintenance costs, and increased capital investment to meet load growth.

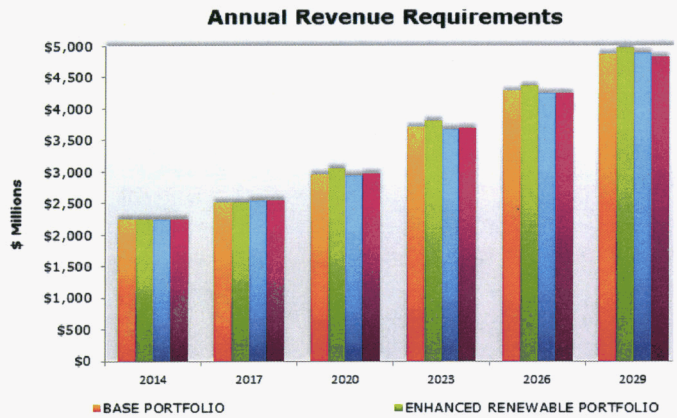


FIGURE 21- COMPARISON OF ANNUAL REVENUE REQUIREMENTS

The net present value of revenue requirements is fairly similar over the long term (30 years). The Base Portfolio, the Coal Reduction Portfolio and the Coal-to-Gas Conversion Portfolio have an NPV of revenue requirements of approximately $47.6 billion while the Enhanced Renewable Portfolio has a roughly $600 million higher NPV at $48.2 billion

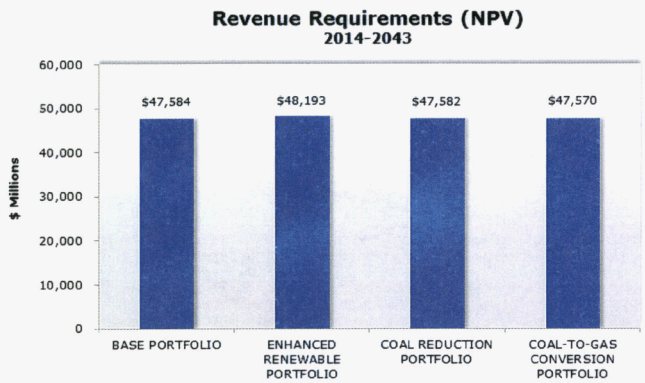


FIGURE 22 - COMPARISON OF NPV REQUIREMENTS (2014-2043)

The cumulative capital expenditures required to support the Coal Reduction Portfolio and the Coal-to-Gas Conversion Portfolio are plus and minus 4% of the Base Portfolio, respectively. While continued operation of Cholla in the Base Portfolio would require $360 million in pollution control upgrades, conversion of the plant to natural gas is expected to cost $199 million including a new natural gas pipeline. The cost of new replacement capacity in the Coal Reduction Portfolio is estimated to be about $1.3 billion. Capital expenditures required to support the Enhanced Renewable Portfolio are about 20% higher than the Base Portfolio. The cost of the

additional renewables is $3.0 billion, only offsetting $0.3 billion of conventional resources due to the low peak capacity value of high levels of solar.

Water consumption is expected to grow from 54,700 acre feet in 2014 to 63,200 acre feet in 2029 in the Base Portfolio, an increase of 16%. This is a modest increase in absolute terms considering that load grows over 50%, and is actually a 25% reduction in water intensity, or water use per MWH. The Coal Reduction and Coal-to-Gas Conversion Portfolios use 9% and 8% less water than the Base Portfolio, respectively, while the Enhanced Renewable Portfolio uses 2% less water.

In the Base Portfolio, CO2 emissions increase by 31% from 2014 to 2029, while load increases by 52%. Therefore, CO2 intensity is actually reduced by 14%. The Coal Reduction and Coal-to-Gas Conversion Portfolios reduce CO2 emissions by 16% and 15% from the Base Portfolio in 2029, while the Enhanced Renewable Portfolio reduces CO2 emissions by 10%.

In the Base Portfolio, APS expects to burn more than 2.5 times as much natural gas in 2029 as it will in 2014. The Coal Reduction or Coal-to-Gas Conversion Portfolios would increase natural gas burn by 23% and 27% above the Base Portfolio in 2029, while the Enhanced Renewable Portfolio would reduce natural gas burn by 20%.

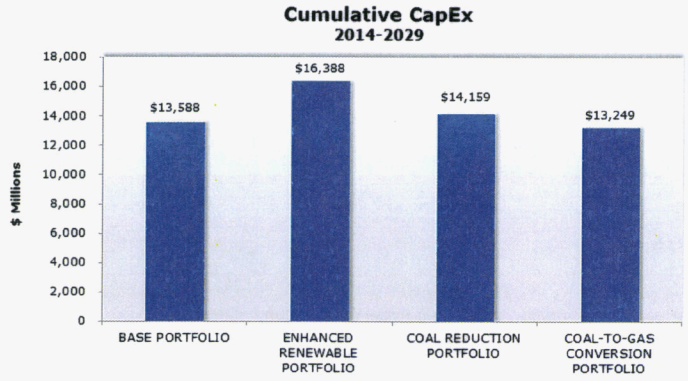


FIGURE 23 - COMPARISON OF CUMULATIVE CAPITAL

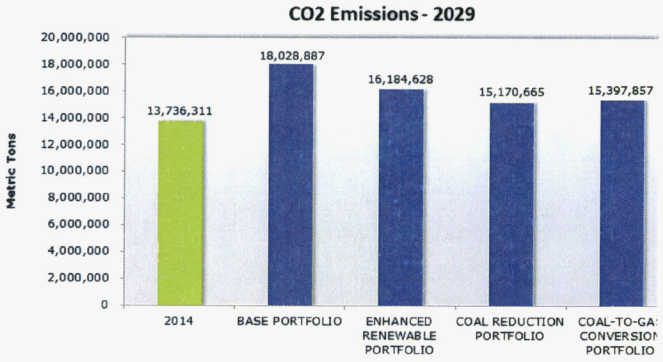


FIGURE 25 - 2029 ANNUAL CO2 EMISSIONS

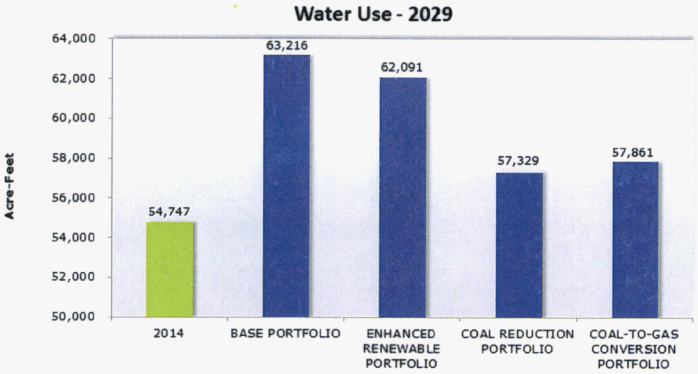


FIGURE 24 - 2029 ANNUAL WATER USE

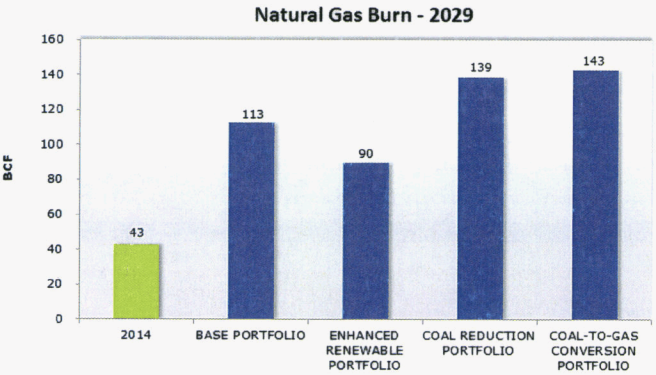


FIGURE 26 - 2029 ANNUAL NATURAL GAS BURN

Discussion of Results

Under the base, or Current Path Scenario, the results presented above illustrate the trade-offs in key metrics between the four portfolios.

The Base Portfolio's cost is about the same as two other portfolios and lower than the Enhanced Renewable Portfolio. It is diverse in terms of fuel mix and has low capital requirements as well as modest gas burns. Its CO2 emissions and water use are higher than the other portfolios.

The Enhanced Renewable Portfolio is the highest cost ($600 million above the Base Portfolio), and the highest capital expenditure requirement. It is likewise diverse with low natural gas burns. Its CO2 emissions and water use are lower than the Base Portfolio, but higher than the other two.

The Coal Reduction Portfolio has NPV of revenue requirements about equal to the Base Portfolio, and has the lowest CO2 emissions and water use. Its gas burn is modestly higher than the Base Portfolio and similar to the Coal-to-Gas Conversion Portfolio.

The Coal-to-Gas Conversion Portfolio has NPV of revenue requirements about equal to the Base Portfolio, and has lower CO2 emissions and water use, and low capital expenditure requirements.

RESULTS OF SCENARIO ANALYSIS

SUMMARY OF SCENARIO ANALYSIS

This section summarizes the ranges of results in the key metrics for the six scenarios and the four portfolios while the next section discusses how each of the portfolios performed for each scenario.

DISCUSSION OF REVENUE REQUIREMENTS

The range of net present value of revenue requirements for each of the portfolios is as follows:

- Base Portfolio: $25.9 billion (-27.1% to +27.3% of base)
- Enhanced Renewable Portfolio: $25.9 billion (-26.6% to +27.2% of base)
- Coal Reduction Portfolio: $26.3 billion (-27.6% to +27.7% of base)
- Coal-to-Gas Conversion Portfolio: $25.6 billion (-26.9% to +26.9% of base)

Revenue requirements are bounded by the Economic Contraction Scenario on the low end of the range and by the Economic Boom Scenario on the high end. The range of revenue requirements is very similar for all four portfolios indicating that none of the portfolios is significantly more or less susceptible to the uncertainties considered, and that the cost of electricity over the next 30 years is more dependent on future economic and environmental conditions (scenarios) than it is the selection of resources (portfolios) considered.

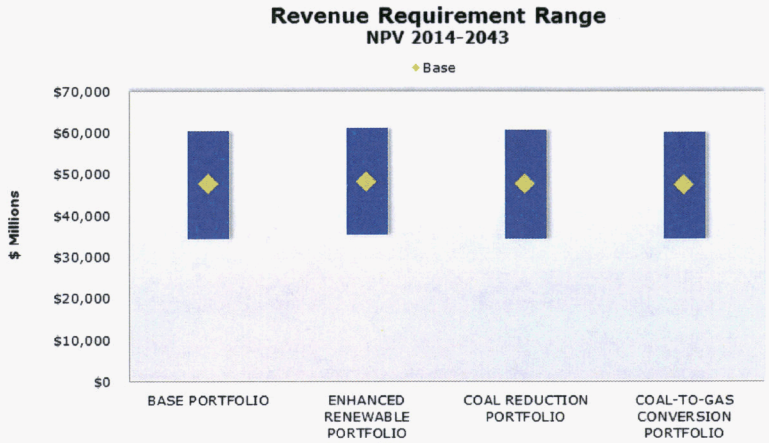


FIGURE 27 - IMPACT OF SCENARIOS ON 2014-2043 REVENUE REQUIREMENTS

DISCUSSION OF NATURAL GAS BURN

The range of natural gas burn in 2029 for each of the portfolios is as follows:

Base Portfolio	139 BCF (-46.0% to +77.2% of base)
Enhanced Renewable Portfolio	121 BCF (-45.2% to +89.9% of base)
Coal Reduction Portfolio	136 BCF (-36.0% to +62.1% of base)
Coal-to-Gas Conversion Portfolio	140 BCF (-38.1% to +60.1% of base)

The low end and the high end of the ranges are again defined by the Economic Contraction and Economic Boom Scenarios respectively, rather than selection of resources.

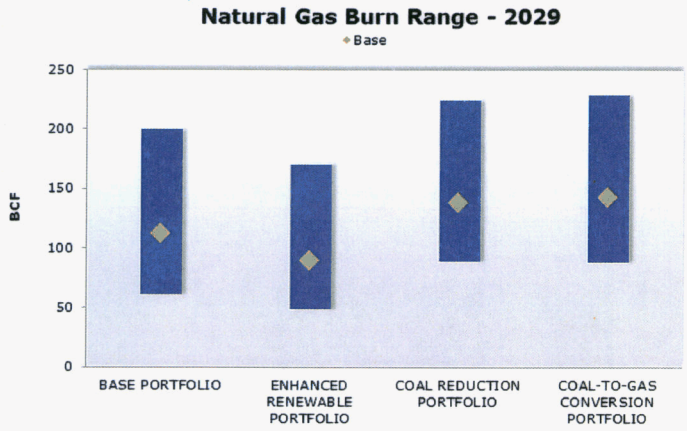


FIGURE 28 - IMPACT OF SCENARIOS ON 2029 NATURAL GAS BURN

DISCUSSION OF CARBON EMISSIONS

The range of carbon emissions in 2029 for each of the portfolios is as follows:

Base Portfolio	7.8 MT (-19.3% to +23.7% of base)
Enhanced Renewable Portfolio	7.2 MT (-19.2% to +25.6% of base)
Coal Reduction Portfolio	7.7 MT (-20.8% to +30.2% of base)
Coal-to-Gas Conversion Portfolio	7.9 MT (-21.3% to +29.9% of base)

The low end and the high end of the ranges are again defined by the Economic Contraction and Economic Boom Scenarios, respectively. The Coal Reduction and Coal-to-Gas Conversion Portfolios indicate the lowest carbon emissions.

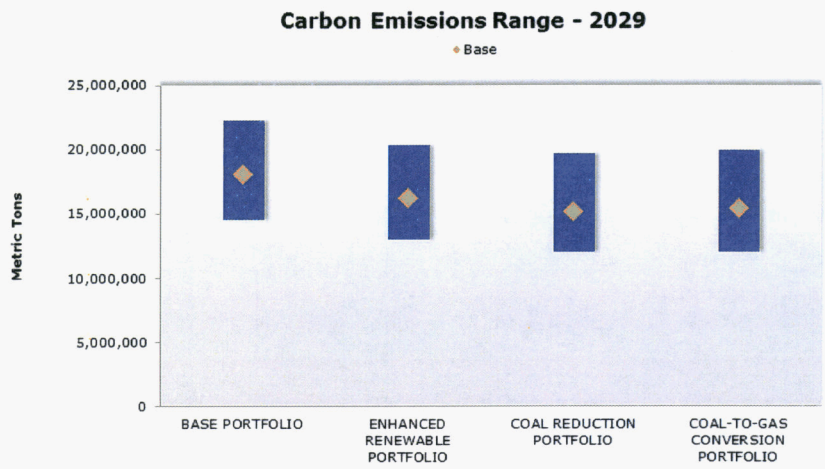


FIGURE 29 - IMPACT OF SCENARIOS ON 2029 CARBON EMISSIONS

DISCUSSION OF WATER USE

The range of water use in 2029 for each of the portfolios is as follows:

Base Portfolio	8.6 KAF (-11.5% to +2.0% of base)
Enhanced Renewable Portfolio	10.2 KAF (-12.9% to +3.5% of base)
Coal Reduction Portfolio	6.6 KAF (-10.4% to +1.1% of base)
Coal-to-Gas Conversion Portfolio	7.9 KAF (-11.1% to +2.42 of base)

While the low end and the high end of the ranges are again defined by the Economic Contraction and Economic Boom Scenarios, respectively, the range of water use across the portfolios and scenarios is much narrower than the ranges of the other metrics discussed. This is reflective of the expectation that whatever new technology APS employs, whether it be renewable or natural gas, water consumption will be improved

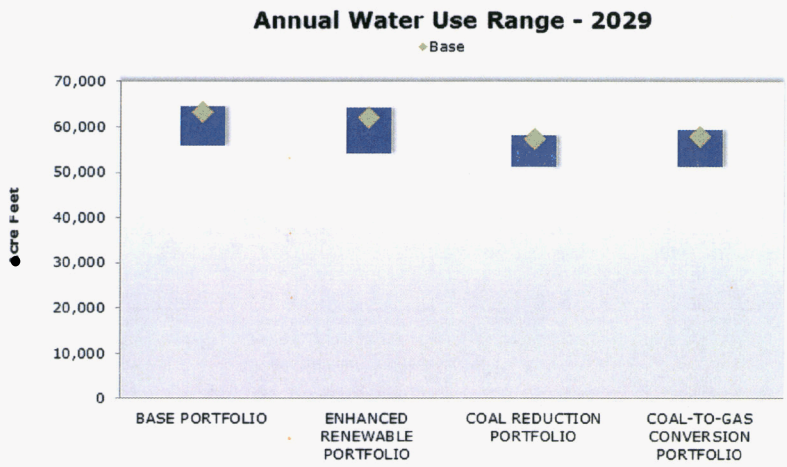


FIGURE 30 - IMPACT OF SCENARIOS ON 2029 WATER USE

DISCUSSION OF SCENARIO RESULTS

Each of the four portfolios was run through scenarios in order to determine how each portfolio would perform relative to the others under plausible futures. The purpose is to identify a portfolio that performs well across many futures and, further, to indicate how resource plans might change if/when it is recognized that one of the alternative futures is becoming the new reality. While summarizing all of the key metrics, the following discussions focus on the economics of the portfolios. Relative comparisons of the other key metrics do not change significantly from the Current Path Scenario.

CURRENT PATH

Results of the Current Path Scenario were discussed above. The following table summarizes the key metrics associated with the portfolios under the Current Path Scenario.

TABLE 8 - SUMMARY OF KEY METRICS IN CURRENT PATH SCENARIO

	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Revenue Requirements ($B NPV 2014-2043)	47.6	48.2	47.6	47.6
Revenue Requirements ($/MWH in 2029)	116.5	118.9	117	115.6
Cumulative Capital Expenditures ($B 2014-2029)	13.6	16.4	14.2	13.2
Gas Burn (BCF in 2029)	112.5	89.5	138.5	142.8
CO2 Emissions (MT in 2029)	18	16.2	15.2	15.4
Water Use (KAF in 2029)	63.2	62.1	57.3	57.9

GAS DOMINATES

Overall, the Gas Dominates Scenario has the lowest revenue requirements of all the scenarios run except the economic contraction scenario which serves much less customer load. In this scenario, the low natural gas prices and lack of carbon prices move against the economics of the Enhanced Renewable Portfolio, increasing its cost from $600 million in the Current Path Scenario to $1.1 billion above the Base Portfolio in this scenario. Economics of the Coal Reduction Portfolio remain break even with the Base Portfolio as the effects of low gas prices and no carbon offset each other. Relative economics of the Coal-to-Gas Conversion Portfolio improve because it is less capital intensive.

TABLE 9 - SUMMARY OF KEY METRICS IN GAS DOMINATES SCENARIO

	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Revenue Requirements ($B NPV 2014-2043)	44.9	46	44.8	44.6
Revenue Requirements ($/MWH in 2029)	107.8	112.3	108.5	106.2
Cumulative Capital Expenditures ($B 2014-2029)	14.6	17.4	15.4	14.3
Gas Burn (BCF in 2029)	117.2	93.9	140.5	144.9
CO2 Emissions (MT in 2029)	17.8	16	15.1	15.3
Water Use (KAF in 2029)	63.1	61.9	57.5	58

SUSTAINED HIGH GAS PRICE SCENARIO

Overall, the Sustained High Gas Price Scenario increases the NPV of revenue requirements about 3% above the Current Path Scenario. Primarily high gas prices favor the economics of keeping coal in operation in the Base Portfolio versus retiring or converting the plant to natural gas operation. While also benefitting the Enhanced Renewable Portfolio, this portfolio is still over $200 million higher cost than the Base Portfolio.

TABLE 10 - SUMMARY OF KEY METRICS IN SUSTAINED HIGH GAS PRICE SCENARIO

	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Revenue Requirements ($B NPV 2014-2043)	48.8	49	49.2	49.4
Revenue Requirements ($/MWH in 2029)	**122.5**	**123.9**	**124.6**	**123.2**
Cumulative Capital Expenditures ($B 2014-2029)	12.9	15.6	13.5	12.5
Gas Burn (BCF in 2029)	**104.5**	**83.5**	**132.5**	**136.6**
CO2 Emissions (MT in 2029)	18.2	16.2	15.1	15.3
Water Use (KAF in 2029)	**63.1**	**61.9**	**56.9**	**57.5**

INCREASED ENVIRONMENTAL POLICY

Due to the combined effects of high gas prices, carbon prices and capital costs, this scenario results in the highest NPV of revenue requirements across all scenarios except the Economic Boom Scenario which serves considerably higher customer load. NPV of revenue requirements is approximately 9% higher than in the Current Path Scenario. The combination of high gas and carbon prices along with continued renewable investment tax credits make the Enhanced Renewable Portfolio the most cost effective portfolio under these conditions, saving nearly $300 million over the Base Portfolio. Economics of reducing coal remain break even with the Base Portfolio while the economics of converting to natural gas operation improve by $100 million.

TABLE 11 - SUMMARY OF KEY METRICS IN INCREASED ENVIRONMENTAL POLICY SCENARIO

	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Revenue Requirements ($B NPV 2014-2043)	51.8	51.5	51.8	51.6
Revenue Requirements ($/MWH in 2029)	**142.0**	**141.0**	**142.9**	**140.6**
Cumulative Capital Expenditures ($B 2014-2029)	14.2	15.9	14.5	13.8
Gas Burn (BCF in 2029)	**105.8**	**91.7**	**134**	**134.1**
CO2 Emissions (MT in 2029)	17.7	16.4	15.1	15.2
Water Use (KAF in 2029)	**59.2**	**59.3**	**54.1**	**54.1**

ECONOMIC CONTRACTION

In the Economic Contraction Scenario, overall NPV of revenue requirements is lower than the Current Path Scenario by 27%. In this scenario, the first year additional conventional generation is needed is 2020 compared to 2017 in the Current Path Scenario. Total future resources are significantly reduced. Relative economics of retiring coal improve from being break even with the Base Portfolio to being $200 million better. Relative economics of converting coal to gas slightly worsen, and the Enhanced Renewable Portfolio stays nearly the same.

TABLE 12 - SUMMARY OF KEY METRICS IN ECONOMIC CONTRACTION SCENARIO

	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Revenue Requirements ($B NPV 2014-2043)	34.7	35.4	34.5	34.8
Revenue Requirements ($/MWH in 2029)	92.1	95.5	90.9	91.2
Cumulative Capital Expenditures ($B 2014-2029)	8.3	10.1	8.1	8.0
Gas Burn (BCF in 2029)	60.8	49.1	88.6	88.4
CO2 Emissions (MT in 2029)	14.5	13.1	12.0	12.1
Water Use (KAF in 2029)	55.9	54.1	51.3	51.4

ECONOMIC BOOM

In the Economic Boom Scenario, overall NPV of revenue requirements is higher than the Current Path Scenario by 27%. In this scenario, the first year additional conventional generation is needed is 2017, similar to the Current Path Scenario. Total future resources are increased above the Current Path Scenario in 2029. Relative economics of converting coal to natural gas improve from being break even with the Base Portfolio to being $200 million better in this scenario. Relative economics of retiring coal is better than adding renewables.

TABLE 13 - SUMMARY OF KEY METRICS IN ECONOMIC BOOM SCENARIO

	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Revenue Requirements ($B NPV 2014-2043)	60.6	61.3	60.8	60.4
Revenue Requirements ($/MWH in 2029)	161.1	163.5	162.4	159.6
Cumulative Capital Expenditures ($B 2014-2029)	24.7	29.0	25.8	24.3
Gas Burn (BCF in 2029)	199.4	170.0	224.5	228.6
CO2 Emissions (MT in 2029)	22.3	20.3	19.7	20.0
Water Use (KAF in 2029)	64.5	64.3	57.9	59.3

2014 Resource Plan

BASED UPON THE FOREGOING PORTFOLIO AND SCENARIO ANALYSIS, THE FOLLOWING OBSERVATIONS ARE MADE:

BASE PORTFOLIO

- Performs well in terms of revenue requirements across all scenarios.
- Second lowest gas burn of the four portfolios across all scenarios
- Second lowest capital expenditure requirement across four of the six scenarios
- Higher CO2 emissions and water use across all scenarios
- Diverse fuel mix

ENHANCED RENEWABLE PORTFOLIO

- Highest revenue requirement across four of the six scenarios
- Highest capital expenditure requirement across all scenarios
- Lowest gas burn across all scenarios
- Second highest CO2 emissions across all scenarios
- High water use across all scenarios
- Diverse fuel mix

COAL REDUCTION PORTFOLIO

- Break even revenue requirements compared to Base Portfolio in three scenarios, higher cost in Sustained High Gas and Economic Boom Scenarios, and lowest cost in Economic Contraction Scenario
- Lowest CO2 emissions and water use across all scenarios
- Modestly higher gas burn
- Less diverse

COAL-TO-GAS CONVERSION PORTFOLIO

- Break even revenue requirements with Base Portfolio in Current Path Scenario, favorable economics in Increased Environmental Policy and Economic Boom Scenarios, and lowest revenue requirement in Gas Dominates Scenarios
- Modestly higher gas burn
- Lowest or second lowest CO2 emissions and water use across all scenarios
- Less diverse

CONCLUSION

As can be seen from the observations above, each of the portfolios has benefits under certain conditions, and no portfolio is the clear winner. There are many economic, environmental and risk trade-offs to be considered in the selection of APS's 2014 resource plan. At this time, APS is selecting the Base Portfolio as its 2014 resource plan with slight modifications discussed below. This plan exhibits a reasonable blend of attributes when compared to the other portfolios. It is recognized that it may be beneficial to retire the Cholla Power Plant or convert it to natural gas operation. It is also recognized that it may be beneficial under certain circumstances to increase the amount of renewable resources in the plan, depending on natural gas pricing, overall solar PV penetration and further environmental regulation. None of these options are foreclosed at this time.

In the near term, APS is confronted with a decision on investing in environmental controls on the Cholla Power Plant versus retiring or converting to natural gas. As solar penetration increases, and outcomes of a lawsuit against the EPA regarding Cholla are determined, a decision on the path forward may become clearer. The Company will continue to evaluate its options and make a decision at the appropriate time.

Also in the near term, APS is currently well above compliance with the ACC's Renewable Energy Standard. APS recognizes however, that renewable costs have been dropping over recent years and will continue to monitor cost trajectories, as well as tax policy as it relates to the economics of investing in renewable energy.

APS 2014 Resource Plan

Based upon the above analysis, APS chose the Base Portfolio as its 2014 Resource Plan with one modification. The resource optimizer program chose a 500 MW natural gas unit to be in service in 2017. APS believes it can retain more flexibility and better match the loads and resources by making short term purchases in 2017 and 2018, then add the 500 MW of natural gas generation in 2019. The resulting resource plan and associated revenue requirements can be found in Attachment F.1(a) and Attachment F.1(b), respectively, and is referred to as the Selected Portfolio. This plan has the following characteristics:

- Significantly diversifies APS energy mix from 2014 to 2029, meeting 52% of growth with non-emitting resources
- Complies with the ACC's Renewable Energy Standard and Energy Efficiency Standard
- Enhances reliability inside the Phoenix load pocket by modernizing the Ocotillo Power Plant
- Reduces intensity of CO2 emissions and water use
- Plans natural gas additions that provide needed flexibility in generation dispatch that will be required due to increased penetration of customer-sited solar PV resources.

CHAPTER 5:
2014-2018 ACTION PLAN

Chapter 5
2014-2018 Action Plan

As discussed in Chapters 1-4, APS determined the Selected Portfolio represented the most reasonable mix of resources to meet customer needs for the Planning Period at this time. Based on that determination, the 2014-2018 Action Plan lays out the specific activities anticipated to occur during the first five years of the 2014 IRP. Note that this five-year Action Plan extends beyond the ACC Resource Planning and Procurement requirement of a three-year Action Plan in order to highlight activities APS expects to undertake during the 2014-2015 timeframe.

As with other components of the 2014 IRP, the 2014-2018 Action Plan is based on current information available at the time of this writing and forecasts that have been derived from information gathered in the third quarter of 2013. Actual activities during the Action Plan Period will be based on conditions prevalent at the time of their undertaking, including compliance with current regulatory rules and orders, and may differ from what is delineated here.

ACTION PLAN COMPONENTS

To meet the growth and changing nature of customer demand and to accommodate a greater influx of renewable energy generation in the APS portfolio, the 2014 IRP discusses at length the need for greater flexibility across the energy spectrum, including generation and transmission assets. The Action Plan is a critical building block in that effort, designed to position the Company with a platform of diverse and responsive assets and related processes. In assessing how best to address the path forward, APS identified the following seven distinct priorities for the 2014-2018 timeframe.

1 TRANSITION RESOURCE PORTFOLIO WHILE ENSURING AN ADEQUATE SUPPLY OF RESOURCES

APS currently has surplus reserves. However, by 2018, load is projected to grow almost 1,100 MW while resources to meet that growth will decline largely due to the expiration of just under 1,400 MW in purchased power contracts. The combination of these circumstances will have a significant impact on the portfolio. By 2017, the surplus reserves APS had at the beginning of the Planning Period will be absorbed and a 360 MW need will emerge, growing to over 700 MW by 2018, after accounting for growth in EE and renewables. To fill the gap in those years, APS plans to deploy a combination of market-based solutions, along with additional capacity at Ocotillo. These needs are in addition to resource contributions from energy efficiency and renewable energy standards.

- Market-based solutions
- Solicit bilateral transactions to replace capacity from expiring third-party contracts.
- Add capacity at Ocotillo Power Plant: 2016 - 2018
- The Ocotillo Modernization Project includes adding 290 MW of capacity at the heart of APS's load center. The capacity additions will come from the net effect of retiring two aging steam units totaling 220 MW and adding five new quick-start gas turbines totalize 510 MW.

2 UPDATE CONVENTIONAL GENERATION RESOURCE: OCOTILLO MODERNIZATION PROJECT: 2016 - 2018

As with any utility, portions of APS's fleet are aging beyond their useful life. In 2016, APS has proposed to begin construction on the Ocotillo Modernization Project at the Ocotillo Power Plant in Tempe. Adding 290 MW of capacity, the proposed project will encompass decommissioning and removing the aging natural gas steam generating units built in 1960 along with the oil tanks on the West side of the property, and adding five-102 MW natural gas combustion turbine units. The new generating units are planned for service by summer of 2018 and shortly thereafter, decomissioning and removal of the steam generating units would begin.

The need to upgrade the plant stems from the key balancing role Ocotillo plays within APS's transmission system and Phoenix area load-pocket. This balancing role has been accentuated in the last decade due to the growth of generation assets on the Western side of the Company's service territory near the Palo Verde hub, combined with the retirements of coal assets. Given Ocotillo's key location on the transmission system, having reliable, and flexible, generation at that location is critical.

Having played a significant role in bringing power to the Phoenix area over the past 54 years, the existing steam generating units are relatively inefficient and inflexible, and are becoming costly and difficult to maintain. All of this, coupled with the evolving landscape of integrating renewable energy into the grid, makes the need to modernize this facility with current technology compelling on many levels.

- Uniquely situated: Valley load-serving capability would be negatively impacted if Ocotillo were not in service due to its location on the transmission system and proximity to the Metro Phoenix area. This proximity affords dynamic voltage support, reduced system energy losses, and impact mitigation from transmission line contingencies.
- End of useful life issues: In addition to maintaining a balanced grid, the outdated technologies at the steam units carry a host of other concerns, namely difficulty maintaining outdated technology, replacement part availability, higher fuel consumption, and the resulting environmental impacts.
- Use of existing infrastructure: The Ocotillo Power Plant has the available land as well as capability through existing transmission and natural gas pipeline infrastructure to support the additional generation. Optimizing the site while replacing aging generating units takes advantage of economies of scale and synergies in the permitting and approval process.
- Enhances flexibility of APS portfolio: The state-of-the-art combustion turbine technology proposed for this project will provide APS added flexibility to further integrate renewable energy and quickly respond to system contingencies. The project will consist of replacing two 1960s-era steam generators with five quick-start natural gas combustion turbine units with capacities of 102 MW each. Scheduled to begin commercial operation in 2018, the new combustion turbine technology will add operational flexibility to manage the increase in solar energy, by being able to connect its generation to the grid in 5 minutes and ramp quickly to respond to system needs.

To accommodate commercial operation in 2018, development and permitting work must start this year. APS plans to submit its major permits, including Title V Air Permit, Certificate of Environmental Compatibility Application and Interconnection Application, by August 2014. Construction is planned to commence in March 2016 with the first unit coming on-line in the Fall of 2017 and all five in commercial operation by the Summer of 2018. Additional project details, as well as illustrations and a video fly-through, can be seen at www.azenergyfuture.com/ocotillo.

3 ADD TRANSMISSION RESOURCES

In order to continue accessing markets and the benefits they provide customers, APS will need additional transmission resources. In APS's 10-year transmission plan filed in January 2014[27], several key transmission projects are outlined that not only provide for increased system reliability, but also enable greater access to the Palo Verde markets through additional import capability into APS's service territory. In addition to these projects, longer term, APS will be evaluating other transmission access into its service territory. Several key projects are listed below:

- Palm Valley - Trilby Wash 230kV Line (2014-2015): With construction starting in 2014, the proposed second 230kV source for Trilby Wash provides improved system reliability and continuity of service for communities in the area; such as El Mirage, Surprise, Youngtown, Goodyear, and Buckeye. The first circuit is scheduled to be in-service for the summer of 2015.
- Sun Valley - Trilby Wash 230kV Line (2014-2016): This project is required to (1) serve the need for electric energy in the western Phoenix Metropolitan area, (2) provide more capability to import power into the Phoenix Metropolitan area and (3) improve reliability and continuity of service for communities in the area including El Mirage, Surprise, Youngtown, Buckeye, and unincorporated Maricopa county. The line is expected to be in service in 2016.
- Hassayampa – North Gila 500kV Line (2015): This project will increase the import capability for the Yuma area and export/scheduling capability from the Palo Verde area to provide access to both solar and gas resources. This project will also allow the system to accommodate generation interconnection requests.
- Matatzal 345/69kV Substation Project (2015-2017): This project is needed to provide the electric source and support to the sub-transmission system in the area of Payson and the surrounding communities. Construction will begin in 2015 and is expected to be in service in 2017.
- Delaney - Palo Verde 500kV Line (2016): This line is expected to be in service in 2016. The line will interconnect generation projects at the Delaney switchyard and represents one section of a new 500kV path from Palo Verde around the western and northern edges of the Phoenix area and terminating at Pinnacle Peak. This is anticipated to be a joint participation project with APS serving as the project manager.
- Delaney – Sun Valley 500kV Line (2014-2016) This project will (1) serve projected need in the area immediately north and west of the Phoenix Metropolitan area, (2) increase the import capability to the Phoenix Metropolitan area and (3) expand the export/scheduling capability from the Palo Verde area to provide access to both solar and gas resources. This is a joint participation project with APS as the project manager. Construction will begin in 2014 and is expected to be in service in 2016.
- Morgan – Sun Valley 500kV Line (2015-2018): With construction starting in 2015, this project will (1) serve projected need in the northern Phoenix Metropolitan area, (2) increase the import capability to the Phoenix Metropolitan area and (3) expand the export/scheduling capability from the Palo Verde area to provide access to both solar and gas resources. The project will also increase the reliability of the EHV system by completing a 500kV loop that connects the Palo Verde Transmission system, the Southern Navajo Transmission system, and the Southern Four Corners system. The project is expected to be in service in 2018.
- Bagdad 115kV Relocation Project (2016-2017): Freeport McMoRan Inc. (FMI) has future plans to expand the mine in the location of the existing 115kV transmission line. The relocation project is in response to their request to move the line beyond the limits of the planned expansion. Construction will begin in 2016 and is expected to be in service in 2017.
- North Gila – Orchard 230 kV Line (2016-2018): This project serves the need for electric energy, improved reliability, and continuity of service for the greater Yuma area. Construction will begin in 2016 and is expected to be in service in 2018.

[27]http://images.edocket.azcc.gov/docketpdf/0000150147.pdf

4 EVALUATE AND DECIDE ON REMAINING COAL FLEET

With the purchase of SCE's interest in the Four Corners Generating Station complete, APS will be continuing its evaluation of coal by examining the merits of further investment in the Cholla and Navajo facilities. Key to this analysis will be penetration of solar PV and its impacts on the need for operational flexibility, natural gas prices and the impacts of environmental regulations. Completion of analysis and a decision regarding Cholla is expected by 2016, followed by Navajo before 2019.

5 **CONTINUE EXPANSION OF RENEWABLE RESOURCES**

Renewable energy resources, and APS's ability to continue effectively integrating them, are focal points of the 2014 Resource Plan, and the Action Plan is no exception. APS customers now benefit from solar capacity across the state, including the new Solana Generating Station, which combines concentrating solar power technology with thermal storage to generate energy even after sundown. During the next five years, that trend of renewable expansion is expected to continue as APS and its customers add utility-scale and distributed renewable resources to the portfolio.

On July 12, 2013, APS filed its annual RES Implementation Plan, covering the 2014-2018 timeframe and requesting a 2014 RES budget of approximately $143 million. In a final order dated January 7, 2014, the ACC approved the requested budget. Estimated budget amounts for the years 2015-2018 were approximately $159 million, $137 million, $103 million and $91 million.

Notable approved additions under the RES include two 10MW solar projects in 2015 located at Luke Air Force Base and on City of Phoenix property. Not approved is an additional 30MW project which is still being evaluated. On the customer-side DE front, additions are forecasted to occur throughout the 2014-2018 timeframe. In addition, the 37 MW solar facility at Gila Bend is expected to be in service by year-end.

6 **CONTINUE IMPLEMENTATION OF CUSTOMER-SIDE RESOURCES**

APS has several customer-side resources that include distributed energy, energy efficiency and demand response. Over the next five years, the Company plans to continue working with customers to optimize the value of these programs to the overall portfolio through activities including, but not limited to, the following:

Distributed Energy

- Expand the Schools & Government program
- Expand residential distributed energy resources
- APS does not anticipate material growth in commercial DE resources during the Action Plan Period.

Energy Efficiency

- Consumer programs - lighting, pool pumps
- Large commercial programs - chillers, motors, HVAC (heating, ventilation and air conditioning), lighting
- Existing home programs - HVAC system improvements & products, building envelope improvements
- New residential construction programs - increased energy efficiency in new homes and apartment complexes
- Pre-Pay Pilot Program - pilot to determine potential energy savings from a pre-paid energy program

As part of the IRP process, APS has designed the EE portfolio to comply with the EE Standard, resulting in 22% cumulative energy savings from demand-side resources by 2020. During this time, APS will continue to address program delivery and compliance through implementation plan filings at the Commission. These DSM implementation plan filings will outline the combination of existing and new programs and measures, along with other energy saving initiatives, aimed at delivering cost-effective net benefits to APS and its customers.

Demand Response

- Continue to work with customers on home network technologies via the HEI Pilot Program.

7 **INVEST IN ADVANCED GRID TECHNOLOGIES**

Over the Action Plan Period, APS plans to invest $170 million in advanced grid technologies; including communication infrastructure, voltage management, automated switching, asset health monitoring, and operational platforms. The investment will support grid overall reliability and the integration of renewable energy and emerging energy technologies.

RESPONSE TO RULES SECTION C - DEMAND

Response to Rules Section C - Demand

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(C), which specifically requires information related to system load forecasts.

RULE C.1

Fifteen-year forecast of system coincident peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible power; for resale; and for energy losses.

A fifteen-year forecast of peak load by month and year by customer class is provided in Attachment C.1.(a) and a fifteen-year forecast of energy consumption is provided in Attachment C.1.(b). For the commercial and industrial classes, the information is consolidated into a category for customers with loads less than 3MW and a category for customers with loads greater than or equal to 3MW. Since demand response programs are treated as a resource, there is no load reduction in the forecast attributed to interruptible power.

RULE C.2

Disaggregation of the load forecast of subsection (C)(1) into a component in which no additional demand management measures are assumed, and a component assuming the change in load due to additional forecasted demand management measures.

A disaggregation of the load forecast by month by year into a component in which no additional demand management measures are assumed is provided on the line labeled "Own Load Peak - After DE Before EE/DR" in Attachment C.2. Within the same exhibit, a disaggregation of the load forecast assuming the change in load due to additional forecast demand management measures is provided on the lines labeled "Energy Efficiency Programs" and "Demand Response Programs." Consistent with the definition of Demand Management in R14-2-701 of the Resource Planning Rules, both energy efficiency and demand response are included in the disaggregation because they include programs that could provide a beneficial reduction in the total cost of meeting electric energy service needs by reducing or shifting in time electricity usage. TOU rates may also be considered demand management measures. TOU rates have been in effect at APS since 1982 and have already been accounted for in the Total Own Load Peak forecast in Attachment C.2. APS estimates that residential TOU rates have reduced summer peak loads by over 100 MW since their inception. Given the current TOU rate structures and high penetration levels APS does not expect significant benefits to peak demand mitigation in the future.

RULE C.3

Documentation of all sources of data, analyses, methods, and assumptions used in making the load forecasts, including a description of how the forecasts were benchmarked and justifications for selecting the methods and assumptions used.

The APS load forecast is developed using the most appropriate methods available given the data available for use and the historic performance of alternate techniques. The load forecast is developed from several different class-level analyses, which account for differences in the way customers use electricity. These analyses also reflect the high relative importance of regional population and economic growth as a determinant of future electricity demand. The following discussion outlines the methods used to prepare the load forecasts for each relevant class of customer and, per the requirement of the Rules, provides a description of how the models are benchmarked and the justification for the forecast method.

RESIDENTIAL LOAD: The residential load forecast is the product of a residential customer forecast and a corresponding electricity-use-per-customer forecast. The residential customer forecast is tied to a forecast of statewide population by year, a forecast of the number of people per household, and a forecast of the share of a given region of the state which will be served by APS.

Historical population and household data are reported by the U.S. Census Bureau. The change in annual population is disaggregated into a component driven by net natural increase (number of births each year less the number of deaths each year) and a component driven by net migration. Each of these components is expressed as a growth rate, and these rates are extrapolated forward. The historic net natural increase rate (over the past 40 years) is remarkably stable at about one percent per year, so the extrapolation into the future reflects this constancy. The forecast of the net migration rate reflects the volatility of migration related to the business cycle in the overall economy and also a long-term trend toward a lower overall migration rate.

The forecast of population resulting from the application of these projected growth rates into the future is then benchmarked against other publicly available forecasts for reasonableness. Some of the publicly available sources include the U.S. Census Bureau, the Arizona Department of Administration, and the University of Arizona Keller School of Management and Business.

The projected growth in population necessarily implies a growth in residential households, as well. The relationship between households and population is typically expressed as the number of people per household (PPH). The historical rate of people per household has declined substantially over the last 40 years as the population has aged, although the rate of decline has slowed in more recent years. This historic rate is extrapolated into the future by combining information about the percent of each age cohort who are heads of household with the projected age distribution in order to accurately reflect the impact the continued aging of the population will have on the number of people per household. The forecast of people per household is combined with the forecast of population to derive the residential household forecast.

The number of residential electric customers expected in the future is predominately influenced by the expected growth in residential households, adjusted for service territory shares of various regions within the state. For example, APS serves approximately 45 percent of Maricopa County, but has been receiving about 50 percent of the new households each year. APS serves none of Pima and Mohave counties, but almost all of Yuma, Yavapai, and Coconino counties. These historic trends in the share of new households within a region are extrapolated into the future and reflect an assessment of the degree to which those trends may continue. The result is a forecast of APS residential customers by year which reflects anticipated changes in migration rates, the age distribution of the population, and the regional location of new households.

The forecast of electricity use per customer is prepared by melding together an historical end-use model with more recent historical trends/outcomes, coupled with short-run forecast dynamics that are expected to occur as the business cycle plays itself out.

COMMERCIAL AND INDUSTRIAL CUSTOMERS LESS THAN 3 MW LOAD: The load forecast for the group of commercial and industrial customers with electric demand less than 3 MW is the product of a regression analysis of historical sales growth. A customer forecast is also produced, and the two together provide an implied use-per-customer forecast that serves as a useful diagnostic tool. The total class customer forecast is tied to the residential customer forecast in the long run and so anticipates the population and household growth explicitly accounted for in that forecast.

The regression analysis is a statistical multiple autoregressive regression model which estimates the historical relationship between total commercial and industrial electricity demand (excluding mines) and overall economic growth in the APS Metro Phoenix service territory as measured by occupied commercial floor space. The regression model also includes variables for the real price of electricity and weather. The historical relationship is applied to a forecast of occupied commercial floor space to arrive at a projected electricity demand level for commercial and industrial customers. The forecast of occupied commercial floor space is tied to the population forecast described above via per capita occupied commercial floor space. Historical data on per capita occupied commercial floor space are derived from occupancy data reported by CoStar, a company that tracks commercial real estate in Arizona, and population estimates from the U.S. Census Bureau. The real price of electricity is projected by including any known rate changes; otherwise, the real price is assumed constant over time. As with the residential model, normal weather is defined as the average of the last 10 years.

Once the forecast for total commercial and industrial demand has been completed, the forecast for specific customers with loads greater than 3 MW is subtracted from the total.

As with the residential sector, other modeling approaches are available, including end-use-based models or simpler extrapolative techniques. APS does not employ an end-use model for commercial and industrial sales because of cost; electricity-using appliances and machinery for commercial and industrial customers are much more heterogeneous than those used by residential customers, so the level of detail would need to be much higher to accommodate the differences. These more detailed data would also be more costly to collect from business customers, since the surveys would require a higher level of participation from business and facilities managers to explain the important building attributes. Just adopting simpler methods such as long term historical trends extrapolation are avoided for the same reasons as in the residential sector – too little insight and accuracy.

COMMERCIAL AND INDUSTRIAL CUSTOMERS GREATER THAN 3 MW LOAD: For customers with loads in excess of 3 MW, electricity demand forecasts are prepared individually. These forecasts are developed with input provided by customer account managers who are in routine communication with the customers and are knowledgeable about those customers' substantive near-term plans. In the absence of any additional information, these customers' loads are generally held constant in the outer years of the forecast. APS would be unlikely to find reliable independent causal variables to substitute for this method. No new customers are forecast for this group unless a specific new customer has been identified and it has been determined that the customer has a high probability of connecting to the system in the near future. Longer-term potential growth is captured in the econometric model of total commercial and industrial sales.

IRRIGATION AND STREET LIGHT CUSTOMER LOAD: The irrigation and street light classes represent two very small components of the APS load requirement. The number of irrigation accounts has declined substantially over the last couple of decades as population growth has driven the conversion of agricultural land into residential and commercial uses. Street light electricity demand typically grows in line with overall electricity demand reflecting the natural expansion in cities and towns. The electricity demand for each of these classes is projected by trending both the number of customers and the average use per customer in the class.

RESALE CUSTOMER LOAD: APS has sales contracts with a number of wholesale customers who are partial requirements customers. These customers are primarily electrical and irrigation districts located in western Maricopa County and in Pinal County whose main electricity demand comes from irrigation pumps within their territory. They are referred to as partial requirements because APS serves all of their electricity demand except for a portion which is supplied with federal hydroelectric preference power from the Colorado River and other similar sources. As a group, the districts' total electricity demand is neither expanding nor contracting. Year-to-year volatility emerges in the APS requirement due to changes in the availability of preference power from one year to the next. The load forecast assumes total demand for these customers remains constant through the term of their contracts, with adjustments for known or expected deviations in preference power included. This view is also informed by discussions with the customers. APS would be unlikely to find reliable independent causal variables to substitute for this method.

In addition to this electrical and irrigation district load, APS serves three requirements customers who each have residential and commercial customers in addition to pumping load. For these customers, the load obligation is either contractually determined or small and stable; the load forecast maintains these loads through the terms of their respective contracts.

LINE LOSSES: Transmission and distribution line losses coupled with company use are measured as the difference between the total amount of electricity generated or purchased to meet APS system demands and the total amount of electricity consumed by APS customers at the customer meter level. The most recent five-year average of these energy losses is about 7 percent.

OWN LOAD ENERGY: Own load energy is the summation of the class-level electricity demands plus energy losses.

PEAK DEMAND: The annual peak demands on the APS system are projected by trending the historical system load factor for the summer months of June-September and applying that load factor to the projected own load energy. Certain extra large loads are accounted for separately so that changes in their historical usage patterns do not distort the interpretation of the underlying trend for smaller customers. The historical pattern shows volatility from year to year, but overall within the range of 68 percent to 63 percent for those summer months with some downward trend embedded. The use of historical data allows for a natural benchmarking of load factor. The adopted approach provides the greatest consistency between energy demand growth and peak demand growth with an assurance of reasonableness, accuracy (within an acceptable range), and ease of use.

There are relatively few alternatives to forecasting peak demand. Regression models would require the development of a set of causal variables, and a projected load factor implied by the model results would have to be calculated to gain assurance that the results agree with the historical trend. Typically, peak regression models (due to their inherent statistical approach) have a tendency to under forecast peak conditions and thus suffer forecast bias. Class-based hourly load models may be another option, but currently they require more data precision than is presently available.

RESPONSE TO RULES SECTION D - SUPPLY

Response to Rules Section D - Supply

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(D), which specifically requires information related to system resources.

RULE D.1(A)

A 15-year resource plan, providing for each year: (a) Projected data for each of the items listed in subsection (B)(1), for each generating unit and purchased power source, including each generating unit that is expected to be new or refurbished during the period, which shall be designated as new or refurbished, as applicable, for the year of purchase or the period of refurbishment.

Projected data for each generating unit and purchased power resource is provided in the attachments referenced in Table 14.

TABLE 14 - LIST OF D.1(A) ATTACHMENTS

PROJECTED DATA FOR GENERATING UNITS	ATTACHMENT
B.1(a) In service date and book life	D.1(a)(1)
B.1(b) Type of generating unit or contract	D.1(a)(1)
B.1(c) Share of generating unit capacity in MW	D.1(a)(1)
B.1(d) Maximum generating unit capacity	D.1(a)(1)
B.1(e) Annual capacity factor	D.1(a)(2)
B.1(f) Average heat rate	D.1(a)(3)
B.1(g) Average fuel cost Attachment	D.1(a)(4)
B.1(h) Other variable O&M Attachment	D.1(a)(1)
B.1(i) Purchased power energy costs -long-term contracts	D.1(a)(5)
B.1(j) Fixed O&M of generating units ($/MW)	D.1(a)(6)
B.1(k) Demand charges for purchased power	D.1(a)(7)
B.1(l) Fuel type for each generating unit	D.1(a)(1)
B.1(m) Minimum capacity	D.1(a)(1)
B.1(n) Whether the generating unit must run if available	D.1(a)(1)
B.1(o) Description of each generating unit	D.1(a)(1)
B.1(p) Environmental impacts - CO2	D.1(a)(8)
B.1(p) Environmental impacts - CO	D.1(a)(8)
B.1(p) Environmental impacts - VOC	D.1(a)(8)
B.1(p) Environmental impacts - NOx	D.1(a)(8)
B.1(p) Environmental impacts - SO2	D.1(a)(8)
B.1(p) Environmental impacts - Hg	D.1(a)(8)
B.1(p) Environmental impacts - PM	D.1(a)(8)
B.1(q) Water consumption quantities and rates	D.1(a)(8)
B.1(r) Tons of coal ash collected per unit (fly ash)	D.1(a)(8)
B.1(r) Tons of coal ash collected per unit (bottom ash)	D.1(a)(8)

RULE D.1(B) – B.2(A)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(a): A description of generating unit commitment procedures..

APS optimizes the use of its resources to serve native load in the most economical manner possible, while maintaining grid reliability. The process begins by forecasting the load on a day-ahead basis. The load forecast is entered into a unit commitment and dispatch model (PCI GenTrader®/ GenPortal®) that determines the most economic unit commitment plan for serving load, taking into account generating unit capabilities, intermittent resource production forecasts (e.g., wind and solar), fuel prices, contractual requirements, and transmission constraints. This commitment plan shows the units to be committed each hour, their projected loading level and the quantity of natural gas to be scheduled.

As part of the process, the model calculates prices for blocks of energy to help determine if it would be cheaper to buy power from the market rather than to run generating units. The day-ahead trader compares these calculated block energy prices with actual power prices being offered in the market, then purchases either on-peak or off-peak blocks of energy, if economical. The model also calculates the breakeven price for making sales out of the Company's generating units, after taking into account native load and any other pre-existing power sales commitments. If economical, the day-ahead trader will make power sales in the market.

The day-ahead commitment plan is turned over to real-time operations to implement. The real-time traders update the load and available resource forecasts and re-run the unit commitment and dispatch model to fine-tune the commitment plan. They also check the hourly market to make purchases and sales of power to further optimize the system. Any demand response products that can be utilized within the day are also considered.

The real-time traders commit (start) and de-commit (shutdown) generating units as needed to meet load and sales commitments. They also update the plan as needed for generating unit or transmission outages, optimizing utilization of available resources.

For the duration of the Planning Period, the generating unit commitment procedures are not expected to change from one year to the next.

RULE D.1(B) – B.2(B)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(b): Production cost.

The production costs for the 15-year plan are provided in Table 15. "Production Costs" (defined in R14-2-701(33)) include variable O&M costs of producing electricity through APS-owned generation. "Fuel" includes the commodity portion of fuel costs for APS-owned generating units to meet APS native load plus a long-term sales contract. "Emissions" refers to the costs associated with any SO2 and CO2 emissions. "Purchases" includes the variable O&M and commodity portion of fuel costs for tolled generating units, costs for existing PPAs, and short term market purchases represented in response to Rule D.1(b) – B.2(f). "Sales" are shown as a negative value and reflect revenue from a long-term wholesale sales contract that expires in 2020.

TABLE 15 - TOTAL PRODUCTION COSTS

TOTAL PRODUCTION COSTS - 2014 RESOURCE PLAN
($MILLIONS)

	GENERATION		EMISSIONS	PURCHASES		SALES	TOTAL
	Fuel	Variable O&M	SO2 & CO2	Demand	Energy		$Millions
2014	470.2	50.8	(0.1)	110.5	351.3	(2.0)	980.9
2015	469.4	51.1	(0.1)	111.2	368.4	(0.4)	999.6
2016	471.3	54.1	(0.1)	105.8	357.4	(0.9)	987.6
2017	566.6	60.7	(0.1)	124.8	321.6	(2.4)	1,071.3
2018	650.9	68.0	(0.1)	91.3	292.3	(2.3)	1,100.0
2019	706.6	74.7	(0.1)	62.3	284.8	(2.4)	1,126.0
2020	792.4	85.7	(0.1)	6.0	231.1	(2.5)	1,112.6
2021	869.2	91.5	55.2	5.8	234.0	0.0	1,255.6
2022	938.8	98.1	68.4	6.5	232.6	0.0	1,344.4
2023	1,013.0	102.7	72.6	6.4	228.7	0.0	1,423.4
2024	1,065.5	110.4	87.2	7.2	227.1	0.0	1,497.4
2025	1,127.5	118.0	104.8	8.1	230.0	0.0	1,588.3
2026	1,200.8	124.1	133.8	8.1	233.1	0.0	1,700.0
2027	1,279.5	131.7	176.9	8.1	220.1	0.0	1,816.3
2028	1,333.6	137.2	215.4	8.1	223.7	0.0	1,918.0
2029	1,439.2	143.8	253.8	8.1	226.3	0.0	2,071.3

RULE D.1(B) – B.2(C)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(c): Reserve requirements.

The reserve requirements for the 2014 Resource Plan are provided in Attachment F.9(b) on line 4.

RULE D.1(B) - B.2(D)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(d): Spinning reserve.

APS is one of 15 members of the Southwest Reserve Sharing Group (SRSG)[28]. Individual members' spinning reserve requirements are calculated using a formula that takes into account factors such as each member's hourly loads, purchase and sale transactions, and thermal generation. Currently, APS's SRSG spinning reserve requirement is normally supplied by units fueled by natural gas, depending on economics. If APS was not an SRSG member, this requirement would increase to at least 560 MW to cover the system's largest single hazard. Because SRSG calculations are dependent upon each member's system conditions and the interaction of those systems working together, each member's contribution to SRSG spinning reserve may change over time.

Forecast spinning reserves over the planning horizon are illustrated in Table 16 Half of these requirements can be met with units designed to start within 10 minutes.

TABLE 16 - FORECAST SPINNING RESERVE REQUIREMENT

YEAR	SPINNING RESERVE REQUIREMENT (MW)
2014	378
2015	377
2016	381
2017	386
2018	391
2019	397
2020	402
2021	410
2022	419
2023	427
2024	435
2025	443
2026	452
2027	461
2028	471
2029	480

RULE D.1(B) – B.2(E)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(e): Reliability of generating, transmission, and distribution systems.

GENERATION RELIABILITY

Generation reliability of a resource plan is typically measured in terms of reserve margins or loss of load probability (LOLP). APS's reserve criterion is based on LOLP of one outage in ten years, which currently translates to a 15% reserve requirement. To ensure a reliable generation system, reserves should be greater than or equal to 15%. Table 17 shows the annual reserve requirement amounts based on the 15% requirement (also shown on Attachment F.9(b), line 4).

TABLE 17 - RESERVE REQUIREMENTS

YEAR	RESERVE REQUIREMENT (MW)
2014	978
2015	976
2016	993
2017	1,016
2018	1,039
2019	1,063
2020	1,093
2021	1,196
2022	1,236
2023	1,275
2024	1,310
2025	1,349
2026	1,388
2027	1,426
2028	1,466
2029	1,505

[28]Additional information regarding SRSG can be found at www.srsg.org.

TRANSMISSION AND DISTRIBUTION RELIABILITY

APS follows the Institute of Electrical and Electronics Engineers (IEEE) 1366 - 2003, "Guide for Electric Power Distribution Reliability Indices" for measuring reliability. Three of the most common indicators used for measuring reliability are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI).

Forecasts for transmission and distribution reliability are provided in Attachment D.1.(b) and include the following key messages:

- Transmission reliability represents projections of the portion of total SAIFI, SAIDI, and CAIDI, respectively, due to outages at the transmission level and illustrates a general trend of improvement in transmission reliability during the 15-year Planning Period.
- Distribution reliability represents projections of the portion of total SAIFI, SAIDI, and CAIDI, respectively, due to outages at the distribution level and illustrates a general trend of improvement to APS's reliability. Forecast vs. actual data may vary depending upon weather patterns and unusual events. New distribution facilities are generally constructed underground due to local zoning rules. As underground facilities increase as a percentage of total facilities, the length of time it takes to locate, repair, and restore from the outage also increases due to the nature of underground facilities versus overhead facilities.

RULE D.1(B) - B.2(F)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(f): Purchase and sale prices, averaged by month, for the aggregate of all purchases and sales related to short-term contracts.

APS does not forecast specific short-term purchase or sales contracts in the 15-year forecast; however, APS does anticipate a certain level of short-term market purchases during the first five years as depicted in Attachment F.9(b) at line 31. These are assumed to be four-month summer purchases (June to September) with capacity and energy prices based on anticipated available market generation costs as indicated in Table 18. These purchases provide added flexibility to the resource plan and may be procured a year at a time, if needed, in the year prior to the need.

TABLE 18 - COSTS OF FORECASTED SHORT-TERM MARKET PURCHASES

YEAR	CAPACITY (MW)	DEMAND COST ($/KW-YR)	ENERGY COST ($/MWH)
2014	0	N/A	N/A
2015	0	N/A	N/A
2016	0	N/A	N/A
2017	364	$96.70	$33.70
2018	240	$99.90	$35.00

Notes: (1) Currently there are no contracts in place for the capacity shown
(2) The capacity is assumed to be available from June to September each year (3) The demand costs are based on merchant CC capacity pricing (4) The energy costs are based on fuel and O&M costs for a merchant CC

RULE D.1(B) - B.2(G)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(g): Energy losses.

Energy losses for the 15-year forecast are provided in Attachment C.1.(b) on the line labeled "Energy Losses".

RULE D.1(C)

A 15-year resource plan, providing for each year: (d) The escalation levels assumed for each component of cost, such as, but not limited to, operating and maintenance, environmental compliance, system integration, backup capacity, and transmission delivery, for each generating unit and purchased power source.

The current estimate of future inflation is 2.5% per year, which is representative of inflation levels over the past ten years. Capital and O&M components of environmental compliance costs are also assumed to escalate at the general rate of inflation. Exceptions are: (1) fuel prices which are determined either through the forward market or contractual terms; (2) purchased power prices that are determined through contractual terms; (3) solar photovoltaic capital costs, which are expected to decline (in real terms) through 2029 as the technology matures, then escalate at the rate of inflation; and, (4) property taxes on generation and transmission resources which are assumed to escalate at 1% per year.

RULE D.1(E)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(g): Energy losses.

A 15-year resource plan, providing for each year: (e) If discontinuation, decommissioning, or mothballing of any power source or permanent derating of any generating facility is expected: (i) Identification of each power source or generating unit involved; (ii) The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating; and (iii) The reasons for discontinuation, decommissioning, mothballing, or derating.

I. Identification of each power source or generating unit involved:
   Four Corners 1-2-3 were retired December 31, 2013, Saguaro Steam 1-2 were retired June 30, 2013, and Ocotillo Steam 1-2 are expected to be retired in 2018. Cholla 1-2-3 could potentially be retired in the 15-year Planning Period.

II. The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating

   The cost to decommission Four Corners Units 1-3 is estimated to be $55 million in 2014 dollars. APS expects to start dismantling the Units upon closure and fully demolish the site along with Units 4-5, which is beyond the time frame of the Planning Period.

   The estimated cost to decommission the Saguaro Steam units is approximately $5.2 M.

   The estimated cost to decommission the Ocotillo Steam units is approximately $5.1 M.

III. The reasons for discontinuing, decommissioning, or mothballing, or derating

   The retirement of Four Corners Units 1-3 was part of a plan that included APS purchasing SCE's share of Four Corners 4-5. Details of that transaction are provided in Decision No. 73130[29]. Four Corners Units 1-3 were retired 1) so that APS ownership in coal would not increase appreciably as a result of the transaction, 2) to satisfy BART provisions with the EPA, and 3) APS does not have enough transmission to deliver its new share of Units 4-5 plus Units 1-3.

   The Saguaro Steam units were constructed in 1954 and 1955 and have reached the end of their useful life. The units are old, inefficient technology that had become increasingly difficult to maintain. APS anticipates preserving the site for remaining generation and for potential new generation in the future.

   The Ocotillo Steam units were installed in 1960, and have also reached the end of their useful lives. It is becoming increasingly difficult to maintain and to acquire necessary parts for repair. Due to the importance of the location of the power plant in the Valley and its impact on ability to serve Valley load, new generating units will be built on the site.

   Though Cholla 1-2-3 are currently shown in the resource plan throughout the Planning Period, the plant is facing expensive environmental upgrade costs as described in D.17. APS is continuing to evaluate its options related to Cholla, and will inform the Commission upon making any decisions regarding the treatment of Cholla.

[29]ACC Decision No. 73130 (April 24, 2012)

RULE D.1(F)

A 15-year resource plan, providing for each year: (f) The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period. An explanation of capital and O&M costs for transmission, subtransmission and distribution facilities is provided below.

TABLE 19 - O&M COSTS FOR NEW OR REFURBISHED TRANSMISSION

YEAR	O&M ($000)
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2028	
2029	

Transmission

A list of transmission projects which includes capital costs for new or refurbished transmission facilities is provided in Attachment D.1.(f). O&M costs are not assigned to individual projects and are planned as a total of all projected transmission O&M during budgeting activities as shown in Table 19. As new transmission facilities are added to the system, they are incorporated into normal activities per APS's various processes. The O&M costs shown are those associated with the newly added transmission facilities.

Subtransmission

APS annually conducts an analysis of its 69kV subtransmission. 69kV system changes are necessitated due to electric load changes. Load changes require elements to have increased capacity or additional elements to be constructed. O&M costs are not assigned to individual projects and are planned as a total projected subtransmission O&M during budgeting activities. As new subtransmission facilities are added to the system, they are incorporated into normal activities. Subtransmission O&M costs are included with the transmission O&M costs provided above.

TABLE 20 - DISTRIBUTION PLANNED IMPROVEMENT EXPENDITURES

YEAR	CAPITAL ($000)	O&M ($000)
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		

Distribution

APS plans its distribution system on a three-year basis. Because the dynamics of a distribution system are so heavily dependent on the level and location of electric load growth or reduction, forecasting with a high degree of accuracy beyond the three-year time frame is difficult and subject to the variations of economic activity. Also, distribution system improvements must be made in a very small geographic location so pinpointing exactly where the load changes will occur is problematic very far into the future. The forecasted expenditures for capital and O&M provided in Table 20 were developed based upon APS's past expenditures and its system coincident peak load forecast for 2014 to 2029. O&M costs are not assigned to individual projects and are planned as a total projected distribution O&M during budgeting activities. As new distribution facilities are added to the system, they are incorporated into normal activities per APS's various processes. The O&M costs shown are those associated with the newly added distribution facilities.

Advanced Grid Technology

APS is likely to invest $300M in new grid technologies through 2025 to support reliability, integrate distributed energy and emerging technologies. A list of technologies includes but is not limited to, Advanced Operational Platforms, Automated Switches, Communicating Fault Indicators, Advanced Analytics, Substation Health Monitors, Communication Infrastructure, Downed Conductor Detection, Advanced Metering Infrastructure, Phasor Measurement Units, and Network Protectors. These technologies are described in Chapter 2.

RULE D.1(G)

A 15-year resource plan, providing for each year: (g) An explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona.

An explanation of the need for and purpose of all expected new or refurbished transmission is provided in Attachment D.1(f). The need and purpose of distribution facilities is discussed in response to D.1(f) above.

RULE D.1(H)

A 15-year resource plan, providing for each year: (h) Cost analyses and cost projections, including the cost of compliance with existing and expected environmental regulations.

Cost analyses and projections for the 2014 Resource Plan are provided in Attachment D.10. The cost of existing and expected environmental regulations is embedded within the capital, O&M and emissions figures.

RULE D.2

Documentation of the data, assumptions, and methods or models used to forecast production costs and power production for the 15-year resource plan, including the method by which the forecast was benchmarked.

Production Model

Data and assumptions related to resource dispatch and O&M costs as well as other system assumptions are well documented in response to Rule D.1(a) and D.1(b) above.

As an initial step, APS used Ventyx's PROVIEW resource optimizer to develop four portfolios as described in Chapter 4. PROVIEW developed and evaluated thousands of resource expansion plans designed to meet APS's forecasted load growth while meeting or exceeding reserve margin constraints. As part of the optimization process, the model calculated revenue requirements for each of the plans developed, including estimated power production and production costs for the Planning Period. Portfolios with the lowest NPV of revenue requirements were selected for further study using the much more detailed and accurate production model, PROMOD IV. PROMOD IV is one of the most widely used production simulation models in the United States by electric utilities. It was first developed in the 1970s and has been continually enhanced to keep up with utility dispatch methods. Inputs to PROMOD IV include hourly load, unit characteristics (including capacity inputs, heat rates, startup energy costs, and maintenance), fuel prices, environmental constraints, and transactions (including forward products with fixed volume and price, hourly or block options with strike prices, purchased dispatchable units, and non-dispatchable resource generation patterns and costs). PROMOD IV provides hourly system production costs, unit costs, and operating statistics (startups, energy output, runtime, capacity factor, fuel consumption and cost, emissions production and cost, and variable and fixed O&M).

Benchmarks

APS benchmarks the production simulation against the Company's budgeting tool, which itself is reconciled with actual system operations and production costs on a monthly basis. One important difference between resource planning and budgeting is that resource planning does not model the interchange market, which changes significantly from one year to the next and over which APS has no control. Decisions are made to optimize resources within the Company's control to serve native load. In real-time, however, APS of course takes advantage of market opportunities for the benefit of customers.

Assumptions

Data and system assumptions related to resource dispatch, fuel, and O&M costs are thoroughly documented in the response to Rules D.1(a) and D.1(b). Resource capital costs are documented in the response to Rule D.3. Financial assumptions and emissions costs used to forecast production costs and power production for the 2014 Resource Plan are included in the tables below.

TABLE 21 - FINANCIAL AND ECONOMIC ASSUMPTIONS

FINANCIAL AND ECONOMIC ASSUMPTIONS – 2014 RESOURCE PLAN
COST OF CAPITAL

	CAPITAL RATIO	COST RATE	WEIGHTED COST OF CAPITAL	AFTER-TAX WEIGHTED COST OF CAPITAL
Debt	46.06%	6.50%	2.99%	1.81%
Equity	53.94%	10.00%	5.39%	5.39%
Totals	100%		8.38%	7.20%
AFUDC Rate	8.54%			
Composite Income Tax Rate	39.51%			

TABLE 22 - FINANCIAL AND ECONOMIC ASSUMPTIONS

DEPRECIATION

	BOOK LIFE	TAX LIFE
Coal	32 Years	20 Years
Nuclear	32 Years	15 Years
Combined Cycle	32 Years	20 Years
Combustion Turbine	32 Years	15 Years
Transmission	50 Years	20 Years
Solar	20-32.6 Years	5 Years
Biomass / Wind	20 Years	5 Years
Geothermal	30 Years	5 Years

TABLE 23 - FINANCIAL AND ECONOMIC ASSUMPTIONS

TAX CREDITS

	ITC	ITC EXPIRES
Solar1	30%	12/31/2016
Wind	N/A	N/A
Geothermal	10%	N/A
Biomass	N/A	N/A

Notes: (1) 30% ITC is reduced to 10% for solar after 12/31/2016

TABLE 24 - EMISSIONS COSTS

YEAR	SO2 COST ($/TON) 1	CO2 COST ($/METRIC TON) 2
2014	$2.0	$0.0
2015	$2.0	$0.0
2016	$2.0	$0.0
2017	$2.1	$0.0
2018	$2.1	$0.0
2019	$2.2	$0.0
2020	$2.3	$0.0
2021	$2.3	$13.0
2022	$2.4	$13.3
2023	$2.6	$13.6
2024	$2.7	$14.0
2025	$2.8	$14.3
2026	$2.9	$14.7
2027	$3.0	$15.0
2028	$3.1	$15.4
2029	$3.2	$15.8

Notes: (1) SO2 numbers are based on the 9/30/2013 Forward SO2 Market Curve
(2) CO2 numbers based on CA 2016 CO2 cost escalated at 2.5% (begin in 2021)

RULE D.3

A description of each potential power source that was rejected; the capital costs, operating costs, and maintenance costs of each rejected source; and an explanation of the reasons for rejecting each source.

APS estimated the delivered cost of a broad spectrum of potential power sources, including conventional baseload, intermediate, peaking and energy storage resources as well as renewable solar, wind, geothermal and biomass/biogas resources. A number of those are represented in the 2014 Resource Plan based on resource need, economics, diversity, and operational characteristics. Attachment D.3 includes the description, capital costs, O&M costs, and performance characteristics for the resource technologies that were selected to be included in the 2014 Resource Plan as well as those technologies that were not selected.

Actual power sources will be acquired through the competitive procurement process. Furthermore, actual power sources procured may be different than those currently represented in the plan. The reasons that some of the resource options listed in Attachment D.3 are not represented in the 2014 Resource Plan are as follows:

- APS plans to meet or exceed the RES using a diverse set of renewable resources. Renewable resources represented in the 2014 Resource Plan include solar photovoltaic, solar thermal (trough with storage), wind, geothermal, and biomass/biogas. Though not specifically represented, solar thermal tower technologies could potentially become part of the APS resource mix by 2029, depending on technology development and the outcome of competitive procurement processes. This technology is not currently included due to lack of commercial operational experience.
- APS does not plan to construct new coal or nuclear resources during the Planning Period. New coal and nuclear technologies were considered by the resource optimization program (PROVIEW), but were rejected due to economics and other considerations.
- Energy storage technologies including battery storage, compressed air energy storage, pumped storage and flywheels were also considered. They are not included in the 2014 Resource Plan due to their current high cost and/or they are not considered to be commercially available and proven technologies. These technologies could become cost effective in the future as a means to integrate a high penetration of renewable/variable generation. APS will continue to monitor development and deploy initial technologies for consideration in meeting customers needs and inclusion in future resource plans.

Attachment D.3 also provides cost and performance estimates for a variety of peaking combustion turbines. Because of the peaked nature of APS's load, as well as the need to integrate renewable generation included in the 2014 Resource Plan into the APS system, a significant increase in highly flexible peaking resources will be required by 2029. For natural gas-fired peaking resources, APS models LMS100 combustion turbines. They are more flexible in their operational characteristics in terms of their ability to quickly start/stop than the other natural gas resources considered. Selection of specific natural gas resources will be made through competitive procurement processes, and may be different than those represented in the plan.

RULE D.4

A 15-year forecast of self generation by customers of the load-serving entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours).

The 15-year forecast of self generation in terms of annual peak production (MW) is provided in Attachment F.9(b) on line 23 of the Loads & Resources table. The forecast of annual energy production (MWh) is provided in Attachment C.1(b) on the line labeled "Distributed Energy Programs."

RULE D.5

Disaggregation of the forecast of subsection (D)(4) into two components, one reflecting the self generation projected if no additional efforts are made to encourage self generation, and one reflecting the self generation projected to result from the load-serving entity's institution of additional forecasted self generation measures.

At this time, APS does not offer an up-front cash incentive for self-generation. The response provided in Rule D.4, labeled "IRP Current Path Scenario" in Figure 31, depicts compliance requirement levels of self-generation by continuing utility support through the use of programs such as net metering and/or incentives.

The D.5 Response Scenario depicted in Table 25, and shown as "D.5 Response Scenario" in Figure 31, assumes an ECT-2 type rate for residential customers. Commercial/industrial customers are left unchanged from current rate structures.

The D5 Response Scenario illustrates customer adoption rates in an (upfront) incentive-free market place but with limited net metering remaining. The increased adoption is mainly driven by the expectation of a continued decline in photovoltaic system costs during the same time period. This D5 Response Scenario is based upon the best information available to APS at this time; however, the future of DE penetration is highly uncertain. Adoption could continue to occur even in the face of reduced and/or eliminated incentives due to market conditions, embedded rate off-sets and declining PV prices.

TABLE 25 - D5 RESPONSE SCENARIO

YEAR	MW	MWh
2014	380	648,949
2015	416	661,166
2016	425	673,293
2017	433	685,422
2018	441	720,303
2019	463	767,867
2020	495	830,673
2021	536	908,808
2022	588	1,077,333
2023	699	1,165,864
2024	758	1,253,486
2025	816	1,341,235
2026	874	1,418,044
2027	925	1,494,225
2028	975	1,570,047
2029	1,025	1,640,790

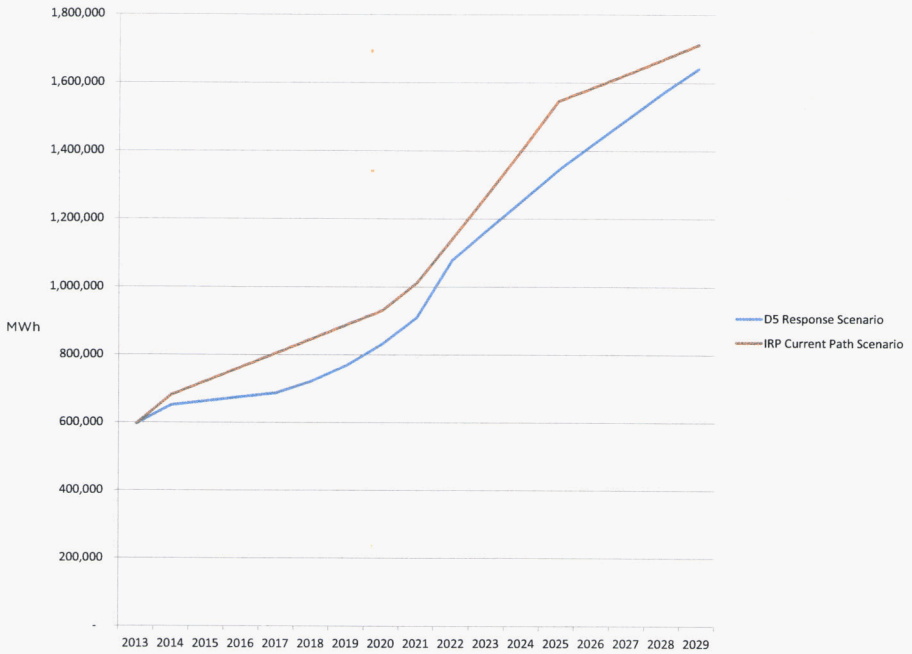


FIGURE 31 - SENSITIVITY ANALYSIS OF PROJECTED LEVELS OF SELF-GENERATION

RULE D.6

A 15-year forecast of the annual capital costs and operating and maintenance costs of the self generation identified under subsections (D)(4) and (D)(5).

A forecast of total annual customer costs, with and without incentives continuing, that may potentially be incurred by customer investments[30] in self generation during the 15-year Planning Period are provided in Table 26[31].

TABLE 26 - FORECAST OF ANNUAL SELF-GENERATION COSTS INCURRED BY APS CUSTOMERS

	CURRENT PATH		D5 RESPONSE SCENARIO	
	Capital	O&M	Capital	O&M
Year				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				

RULE D.7

Documentation of the analysis of the self generation under subsections (D)(4) through (6).

The 2014 Resource Plan reflects the estimation of the energy output reflected in this case and is contingent upon meeting the state-mandated RES rules as set forth in A.A.C. R14-2-1804. The D5 Response Scenario estimates the projected level of self-generation if APS were to discontinue all incentive programs, including net metering benefits in 2014 through 2029. The development of the D5 Response Scenario was based upon the best information available to APS at the time; however, the future of DE penetration is highly uncertain. Capacity and energy for both the renewable energy projected in the APS 2014 Resource Plan along with the scenario estimating the D5 Response Scenario are visually represented in the response to Rule D.5.

It is important to note that while the tax credit assumptions included in this analysis carry considerable weight, that component is not assumed to change from the current plan. Federal tax credits for solar are authorized through 2016 and assumed to revert to 10% thereafter.

For each response given to Rules D.4 through D.6, APS assumes self-generation to be solely renewable-based. APS does not forecast the penetration of diesel- or natural gas-fired standby and emergency generation at this time.

[30]$/Watt represents the average cost between residential and commercial

[31]Capital costs represent new installations per year. O&M costs include costs incurred for installations that occurred in previous years. All costs are in real dollars.

RULE D.8

A plan that considers using a wide range of resources and promotes fuel and technology diversity within its portfolio.

The APS 2014 Resource Plan employs a wide range of resources, both supply and demand side, and promotes fuel and technology diversity within the portfolio. On the supply side, the plan includes new renewable resources such as solar photovoltaic, wind, and geothermal; new natural gas resources such as combustion turbines and combined cycles; a wide variety of energy efficiency measures; and, demand response. The natural gas technologies reflect state-of-the-art power plants – new combined cycle resources are assumed to employ dry-cooling, and new combustion turbines will be highly efficient and operationally very flexible. As illustrated in Figure 32, the 2014 Resource Plan reflects a significant increase in resource diversity over the current energy mix.

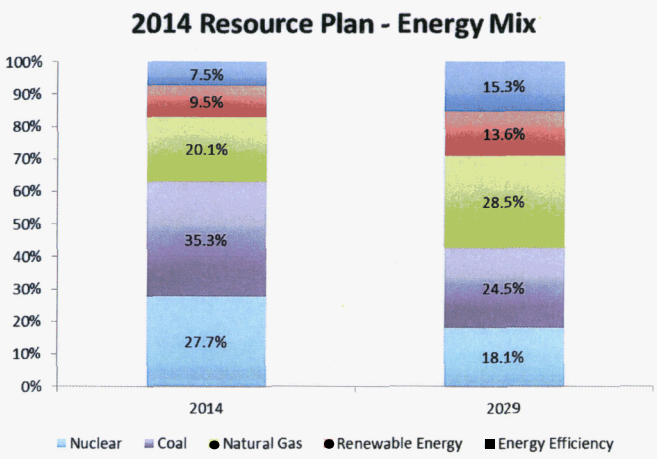


FIGURE 32 - ENERGY MIX (2014-2029)

RULE D.9

A calculation of the benefits of generation using renewable energy resources.

The estimated benefits of renewable energy resources (including distributed energy as well as energy from renewable contracts and resources) are listed in Table 27.

TABLE 27 - RENEWABLE ENERGY BENEFITS

	TOTAL RENEWABLE			AVOIDED EMISSIONS						
	Peak Capacity (MW)	Energy (GWh)	Avoided Gas Burn (BCF)	CO2 (Metric Tons)	SO2 (Tons)	CO (Tons)	NOx (Tons)	PM10 (Tons)	HG (Lbs)	Water Usage (Acre Feet)
2014	701	3,182	23	1,280,869	7	162	146	40	6	3,066
2015	744	3,355	25	1,350,452	8	171	153	42	6	3,233
2016	775	3,492	26	1,405,597	8	178	160	43	7	3,365
2017	786	3,526	26	1,419,337	8	180	161	44	7	3,398
2018	798	3,566	26	1,435,664	8	182	163	44	7	3,437
2019	810	3,607	27	1,452,019	8	184	165	45	7	3,476
2020	863	3,934	29	1,583,558	9	200	180	49	7	3,791
2021	911	4,268	31	1,718,118	10	217	195	53	8	4,113
2022	960	4,656	34	1,874,185	10	237	213	58	9	4,486
2023	1,052	5,323	39	2,142,811	12	271	243	66	10	5,129
2024	1,095	5,706	42	2,296,957	13	291	261	71	11	5,498
2025	1,139	6,138	45	2,470,889	14	313	281	76	12	5,915
2026	1,157	6,230	46	2,507,865	14	317	285	77	12	6,003
2027	1,168	6,270	46	2,523,886	14	319	287	78	12	6,042
2028	1,256	6,915	51	2,783,504	15	352	316	86	13	6,663
2029	1,268	6,944	51	2,795,214	16	354	318	86	13	6,691
		TOTAL	**567**	**31,040,924**	**173**	**3,927**	**3,527**	**959**	**145**	**74,305**

RULE D.10

A plan that factors in the delivered cost of all resource options, including costs associated with environmental compliance, system integration, backup capacity, and transmission delivery.

Revenue requirements for the 2014 Resource Plan are shown in Attachment D.10 and include the delivered costs of all the resource options as described above.

The attached revenue requirements reflect the annual revenue level required to supply APS customers' energy needs, including: (1) carrying costs on existing and future generation, future transmission over and above APS Ten Year Transmission Plan, and capital expenditures on existing generation; (2) fuel costs (commodity and fixed transport); (3) purchase power costs; (4) operating and maintenance costs for existing and future generation; (5) energy efficiency and distributed energy program and incentive costs; and, (6) power plant emission costs including SO2 and CO2. Revenue requirements as used in the resource plan filing do not include costs associated with existing transmission, existing and future distribution, or sales tax on retail electric sales.

Environmental compliance costs are embedded within the capital and O&M figures, and system integration costs are embedded in the purchased power costs for solar photovoltaic and wind technologies. The loads and resources plan factors in backup capacity and those costs are included within the total revenue requirement costs.

RULE D.11

Analysis of integration costs for intermittent resources.

System integration costs may be incurred by operation of some non-dispatchable resources such as wind or solar. Due to their intermittent and/or unpredictable nature, additional operating reserves may need to be carried on the rest of the system to effectively follow APS load and meet NERC reliability requirements. System integration costs depend upon many factors, including the accuracy of forecasting the variable generation on a day-ahead and hour-ahead basis, real-time fluctuations, penetration levels of the variable resources on the utility system, resource mix, and fuel prices of the utility system. Based on the penetration represented in APS 2014 Resource Plan, integration cost for solar photovoltaic is estimated to be $2/MWh in 2020 and $3/MWH in 2030, in a report prepared for APS by Black and Veatch in November 2012[32]. Integration cost for wind is based on a study performed by Northern Arizona University under the direction of Dr. Tom Acker for the APS system, and is estimated to be $3.25/MWh[33]. APS will reevaluate integration costs as renewable penetration increases and more experience is gained in dealing with the integration of intermittent or variable generation.

[32]Solar Photovoltaic (PV) Integration Cost Study, Black & Veatch, November, 2012.
[33]APS/NAU Wind Integration Study, 2007.

RULE D.12

A plan to increase the efficiency of the load-serving entity's generation using fossil fuel.

APS operates and maintains the fleet of generating units to optimize efficiency by balancing expenditures with benefits achieved by those expenditures. Opportunities to increase unit efficiency are evaluated on a regular basis from both economic justification and environmental permitting perspectives.

APS's objective is to ensure unit reliability is maintained so that the units are available to meet the load demand. O&M and capital expenditures are planned to maximize equipment reliability, thus reducing the amount of time the units are unavailable due to equipment failures. For baseload units this reduces fuel costs that are incurred during unplanned startups and shutdowns. In addition, proper and timely maintenance reduces replacement power costs that can be incurred during forced outage events.

Plant components are maintained with the objective of meeting the original design performance specifications. When O&M expenditures to maintain the equipment become too high or the component condition is showing signs of degradation that may threaten unit reliability, the component will be evaluated for replacement. In these circumstances, the component will be evaluated for any changes that can be made that will result in improved unit efficiency. This evaluation considers environmental permit impacts to ensure compliance with regulatory requirements.

APS also increases the efficiency of its fossil generation fleet by its resource decisions going forward. As APS adds new natural gas generation to its system, it considers adding generation that is more efficient than previous models. For example, the existing Ocotillo Steam units have full load heat rates of about 10,500 Btu/kWh, and in the modernization project, they will be replaced with state-of-the-art LMS100 combustion turbines expected to have heat rates of approximately 9,100 Btu/kWh. This will significantly increase the efficiency of the site and of APS generation portfolio in general. As APS installs or acquires or contracts for natural gas generation represented in the 2014Resource Plan, APS will continue to consider high efficiency power plants. Actual models and efficiencies will be determined through a competitive procurement process, and will be selected based on cost efficiency. As these higher efficiency units are added to the system, they will operate before the older less efficient units in the dispatch order, and result in more efficient use of natural gas.

Another aspect of efficiency applies to water consumption. One example of this is the improvement in water use rates that are expected with the Ocotillo Modernization Project. The current steam units consume 1,002 gal/MWh while the new CT's are expected to have a water use efficiency of 141 gal/MWh. Additionally, if APS constructs new combined cycle generation as envisioned in the Resource Plan, the new combined cycle units will likely have about the same heat rates as APS's West Phoenix and Redhawk combined cycle generating units. It is anticipated that the new combined cycle units will most likely utilize alternative cooling technologies as opposed to conventional cooling towers which will result in water savings. The parasitic load associated with operating air-cooled condensers causes a heat rate penalty in summer operating conditions such that the net effect is expected to be a heat rate comparable to the most recently installed combined cycle plants while using much less water. Although potential alternative cooling technologies do save water the water savings comes at the cost of reduced net plant efficiency which increases greenhouse gas emissions on a pounds per MWh basis.

A forecast of the reduction in water intensity measured as gallons per MWh for the Resource Plan is included in the response to Rule D.17. Many of the new technologies represented in the Resource Plan consume little to no water. Energy efficiency and wind generation consume none, while solar photovoltaic and future combustion turbines will have very low consumption rates.

RULE D.13

Data to support technology choices for supply-side resources.

Data to support technology choices for supply-side resources has been provided in Attachment D.3.

RULE D.14(A)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (a) How and when the program or measure will be implemented.

CURRENT PROGRAMS

There are currently fifteen EE programs and twenty DR programs (including eighteen rates). This included nineteen residential programs and sixteen non-residential programs. These programs are detailed in Attachment D.14(a).

FUTURE PROGRAMS

The Company will continue to evaluate existing and emerging technologies and measures to identify cost-effective programs that will deliver annual compliance with EE and DR targets and long-term resource planning needs. Because of the rapidly increasing targets, constant evaluation will be required. When new, unproven measures or technologies are identified, APS may request approval of new programs, measures, or pilots to assist APS in quantifying the resource potential to support future resource planning needs, as well as assist in refining the resource cost-effectiveness calculations. Through pilots, APS will be able to gather data regarding the societal and program costs and benefits that can then be used to more accurately depict the program cost-effectiveness and viability.

APS has identified standby generation as a potentially cost-effective DR program. However, APS does not need new capacity, until the 2017 (and beyond) timeframe. Standby generation may therefore be targeted for deployment in 2017 and beyond.

Similarly, APS will be evaluating the results of its the Home Energy Information (HEI) Pilot in 2014.

RULE D.14(B)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (b) The projected participation level by customer class for the program or measure.

The projected participation level by customer class for energy efficiency programs and measures is extremely difficult to quantify due to the characteristics and nature of the program in question. For example, for the residential lighting program involving Compact Fluorescent Lamp (CFL) bulbs (where APS has sold over 21 million bulbs since the program's inception), measuring the participation level by customer would involve making assumptions on the number of bulbs the "average" customer would purchase in a given year. As these programs may not exist 15 years into the future, or their components may be markedly different, projecting customer participation is not currently feasible. However, APS does estimate the number of measures installed needed to be undertaken to meet its goal for each year on a going-forward basis in the DSM Implementation Plan. Actual 2013 participation on a measure level is provided at Attachment D.14(b).

Projected demand response and time-of-use program participation is forecast at Table 28 and Table 29.

TABLE 28 - EXPECTED RESIDENTIAL DR PROGRAM PARTICIPATION

2014 RESIDENTIAL DR PROGRAMS

	EXPECTED PARTICIPANTS	
Time-Differentiated Rates	**2014**	**15 Year Horizon**
1. ET-SP Time Advantage Super Peak	1,000	5,000
2. ET-1 Time Advantage (9am -9pm)	141,872	N/A
3. ECT-1R Combined Advantage (9am-9pm)	27,459	N/A
4. ET-2 Time Advantage (Noon - 7pm)	291,901	736,903
5. ECT-2 Combined Advantage (Noon - 7pm)	87,364	194,876
6. ET-EV Experimental Electric Vehicle Charging Rate Schedule[1]	91	155
7. Peak Event Pricing[2]	1,000	5,000
8. Peak Time Rebate[3]	1,000	5,000
9. Home Energy Information Pilot	450	20,000

Notes: (1) Range provided is based on low-to-high EV and plug-in hybrid EV (PHEV) sales projections. (2) Customers are included in the parent rate schedule. (3) Customers are included in the parent rate

TABLE 29 - EXPECTED NON-RESIDENTIAL DR PROGRAM PARTICIPATION

2014 NON-RESIDENTIAL DR PROGRAMS

	EXPECTED PARTICIPANTS	
Time-Differentiated Rates	**2014***	**15 Year Horizon**
1. E-20	412	412
2. E-221-8T	59	54
3. E-32 XS TOU	471	698
4. E-32 S TOU	471	698
5. E-32 M TOU	471	698
6. E-32 L TOU	471	698
7. E-35	38	38
8. GS-Schools M	102	152
9. GS-Schools L	102	152
10. Interruptible Rate[1]	N/A	8
11. Peak Solutions[2]	1,800	N/A
12. Standby Generation	0	150

***Total participants as of December, 2013**

Notes: (1) Not expected until 2013, when APS anticipates 3 participants. Customers included in the parent rate schedule (2) The underlying contract that supports this program expires at the end of 2024.

RULE D.14(C)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (c) The expected change in peak demand and energy consumption resulting from the program or measure.

Depicted in Table 30 are the capacity and annual energy savings for 2013 energy efficiency programs. As related in response to Rule D.14(b), projecting a programmatic breakdown out 15 years into the future is not currently feasible; however, Attachments C.1(a) and C.1(b) provide annual aggregate capacity and energy savings forecasts.

Projections of future demand response and time-of-use impacts are located in Table 31.

TABLE 30 – ENERGY EFFICIENCY CAPACITY AND ENERGY CONTRIBUTIONS

2013 RESIDENTIAL AND NON-RESIDENTIAL EE PROGRAMS [1]

PROGRAM NAME	CAPACITY SAVINGS (MW)	ANNUAL ENERGY SAVINGS (MWH)
Residential		
Consumer Products	**16.2**	**154,233**
Existing Homes	10.9	17,466
New Construction	**9.7**	**19,427**
Appliance Recycling	1.3	8,787
Low Income	**0.2**	**1,491**
Conservation Behavior	4.3	24,944
Multifamily	**0.9**	**9,487**
Shade Trees	0.1	351
Residential Sub-Total	**43.6**	**236,186**
Non-Residential		
Large Existing Facilities	**26.2**	**184,207**
New Construction	5.8	15,513
Small Business	**3.9**	**14,155**
Schools	4.7	13,481
Energy Information System	**1.7**	**25**
Non-Residential Sub-Total	42.3	227,381
Codes & Standards	**4.8**	**22,224**
Total	**90.7**	**485,791**

Notes: (1) Numbers represent peak demand and energy reduction goals, with DR contribution, for 2013 as reported in the 2013 APS DSM Annual Progress Report filed with the ACC on February 28, 2014.

TABLE 31 - EXPECTED DR PROGRAM ENERGY AND DEMAND CONTRIBUTIONS

2013 RESIDENTIAL AND NON-RESIDENTIAL DR PROGRAMS

	2013		15 YEAR HORIZON	
Program Name	**Peak Demand Reduction (MW)**	**Annual Energy Reduction (MWh)[1]**	**Peak Demand Reduction (MW)**	**Annual Energy Reduction (MWh)**
Residential				
Future Direct Load Control	N/A	N/A	50	2250[2]
Non-Residential				
Peak Solutions[3]	*28*	N/A	N/A	N/A
Standby Generation	**N/A**	**N/A**	**75**	**N/A[4]**
Future Programs	N/A	N/A	N/A	N/A
Unspecified Future Programs	N/A	N/A	125	N/A
Time-of-Use Rates[5]	117	75	N/A	N/A

Notes: (1) Assumes 90 hours of events and 50% snapback; 50 MW x 90 hrs x 0.5 = 2250 MWh. (2) While not all demand response programs are anticipated to provide energy savings, they are allowed to contribute towards the EE Standard. Pursuant to R14-2-2402(C), the credit for demand response and load management peak reductions shall not exceed 10% of the EE standard for any year. The annual energy reduction calculation for energy savings is calculated as follows: Energy Savings (MWh) = Load reduction MW x 8,760 x 50% load factor. (3) Expires prior to the end of the Planning Period. (4) Standby generation, while it reduces the utility's peak load observed on the system, does not result in less energy consumed by the Customer. (5) Demand reductions are estimated for all current residential rates, and energy reduction is estimated only for ET-SP,CPP-RES and PTR. APS has not at this time completed energy reduction analyses for the remaining residential rates, and has not conducted energy or demand reduction analyses for the non-residential rates.

RULE D.14(D)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (d) The expected reductions in environmental impacts including air emissions, solid waste, and water consumption attributable to the program or measure.

EE programs as well as APS's non-residential load control and demand response pricing programs are all assumed to displace natural gas-fired generation. Because DR programs are designed to reduce only the top 1-2% of hours in the year, the impact is very small compared to EE programs that would encompass all hours.

Table 32 provides estimates of 2013 energy efficiency environmental impacts. The estimated impacts on air emissions for the experimental residential peak event pricing and super peak programs are shown in Table 33.

TABLE 32 – 2013 EE ESTIMATED ENVIRONMENTAL IMPACT

2013 RESIDENTIAL AND NON-RESIDENTIAL EE PROGRAMS
REDUCTION OF ENVIRONMENTAL IMPACT

	WATER	SOX	NOx	CO2	PM10
	(Mil Gal)	**(lbs)**	**(lbs)**	**(Mil lbs)**	**(lbs)**
Residential					
Consumer Products	313	4,389	83,384	887	24,360
Existing Homes	72	1,011	19,202	204	5,610
New Construction	123	1,729	32,852	349	9,597
Appliance Recycling	17	235	4,457	47	1,302
Low Income Weatherization	8	116	2,205	23	644
Conservation Behavior Pilot	8	111	2,109	22	616
Multi-Family Construction	32	456	8,668	92	2,532
Shade Tree	3	47	889	9	260
TOTAL - Residential	577	8,093	153,767	1,635	44,921
Non-Residential					
Large Existing Facilities	797	11,188	212,571	2,260	62,099
New Construction	69	970	18,424	196	5,382
Small Business	59	828	15,729	167	4,595
Schools	56	785	14,920	159	4,359
Energy Information Systems	0	1	10	0	3
TOTAL - Non-Residential	981	13,771	261,654	2,782	76,438

TABLE 33 - ESTIMATED ENVIRONMENTAL IMPACT FROM SELECT RATES

2013 RESIDENTIAL PEAK EVENT PRICING AND SUPER PEAK PRICING PROGRAMS
ESTIMATED REDUCTION IN AIR EMISSIONS

	WATER	SOX	NOX	CO2	PM10
	(Mil Gal)	**(lbs)**	**(lbs)**	**(Mil lbs)**	**(lbs)**
Peak Event Pricing	0.358	5.1	104.2	1.01	28.3
Time Advantage Super Peak	0.529	7.55	154.3	1.49	41.9
Peak Solutions	0.045	0.636	13	0.126	3.5
TOTAL	0.932	13.29	271.5	2.63	73.8

RULE D.14(E)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (e) The expected societal benefits, societal costs, and cost-effectiveness of the program or measure.

Pursuant to R-14-2-2412(B), APS uses the Societal Cost Test (SCT) to measure cost-effectiveness. In addition, Decision No. 73089 required APS to use the same input values and methodology as Staff for calculating the present value benefits and costs to determine benefit-cost ratios.

Table 34 provides details on the societal benefits, societal costs, and cost-effectiveness of the existing EE programs.

The Low Income Weatherization results and analysis are consistent with Commission Decision No. 68647.

In 2013, the Home Performance with ENERGY STAR program (which is part of the Existing Homes Program) and Shade Trees program had a benefit cost ratio of less than 1.0.

APS believes that the reduction in cost effectiveness for these programs is a temporary situation, and that there are several solutions that APS has already put in place and will continue working on to make the programs cost effective for 2014 and beyond.

TABLE 34 - BENEFIT-COST RATIOS FOR EE PROGRAMS

2013 RESIDENTIAL AND NON-RESIDENTIAL EE PROGRAMS
SOCIETAL COSTS, BENEFITS AND COST-EFFECTIVENESS

	SOCIETAL BENEFITS	SOCIETAL COSTS	NET BENEFITS	BENEFIT -COST
	($1000)	($1000)	($1000)	Ratio
Residential				
Consumer Products	34,629	11,629	23,000	2.9
Existing Homes	**13,119**	**13,651**	**(532)**	**0.96**
New Construction	17,125	14,942	2,183	1.15
Appliance Recycling	**1,907**	**793**	**1,114**	**2.4**
Low Income Weatherization	2,242	2,242		1
Conservation Behavior Pilot	**868**	**814**	**54**	**1.07**
Multi-Family Construction	3,124	1,986	1,138	1.57
Shade Tree	**333**	**380**	**(47)**	**0.88**
Total-Residential	73,347	46,436	26,911	1.58
Non-Residential				
Large Existing Facilities	**75,554**	**43,405**	**32,149**	**1.74**
New Construction	8,377	3,850	4,527	2.18
Small Business	**6,342**	**4,037**	**2,306**	**1.57**
Schools	6,439	5,879	560	1.10
Energy Information Systems	**299**	**66**	**233**	**4.53**
Total-Non-Residential	97,011	57,237	39,774	1.69

TABLE 35 - APS PEAK SOLUTIONS BENEFIT-COST RATIO

APS PEAK SOLUTIONS PROGRAM
SOCIETAL COSTS, BENEFITS AND COST-EFFECTIVENESS

	SOCIETAL BENEFITS	SOCIETAL COSTS	NET BENEFITS	BENEFIT-COST
	($1,000s)	($1,000s)	($1,000s)	Ratio
APS Peak Solutions	**72,186**	**52,987**	**19,198**	**1.36**

RULE D.14(F)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (f) The expected life of the measure.

Demand response pricing programs do not have a "measure life"; however, the established rate plans are expected to be in place throughout the Planning Period. The APS Peak Solutions program has been contracted through 2024. Table 36 presents the estimated measure life (in years) by EE program.

TABLE 36 - EXPECTED LIFE OF EE PROGRAMS

2013 RESIDENTIAL AND
NON-RESIDENTIAL EE PROGRAMS
PROGRAM AND MEASURE LIFE

RESIDENTIAL	YEARS
1. Consumer Products	6
2. Existing Homes	13.47
3. New Construction	19.9
4. Appliance Recycling	6
5. Low Income Weatherization	18.4
6. Conservation Behavior Pilot	1
7. Multi-Family Construction	9.5
8. Shade Tree	30

NON-RESIDENTIAL	YEARS
1. Large Existing Facilities	13.5
2. New Construction	14.4
3. Small Business	13.9
4. Schools	14.1
5. Energy Information Systems	15

RULE D.14(G)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (g)The capital costs, operating costs, and maintenance costs of the measure, and the program costs.

The estimated costs for EE programs are included in Table 37.

The APS Peak Solutions program is administered through a contract with a third-party provider through 2024 that includes both energy and capacity payments. The expected program costs through the term of the Peak Solutions contract can be found in the Table 38.

Capital and O&M costs for potential customer load management and generation programs such as residential direct load control, thermal energy storage, or standby generation have been identified as a potentially cost-effective resource. Once completed, the HEI Pilot[34] will assist in quantifying the expected capital and O&M costs for future residential demand response and energy efficiency programs.

TABLE 37 - EE PROGRAM COSTS

2013 RESIDENTIAL AND NON-RESIDENTIAL EE PROGRAMS[1] PROGRAM COSTS

	PROGRAM COST ($1000)
Residential	
1. Consumer Products	**8,558**
2. Existing Homes	8,391
3. New Construction	**5,207**
4. Appliance Recycling	1,006
5. Low Income Weatherization	**2,382**
6. Conservation Behavior Pilot	872
7. Multi-Family Construction	**1,295**
8. Shade Tree	169
TOTAL:	**27,880**
Non-Residential	
1. Large Existing Facilities	14,293
2. New Construction	**1,831**
3. Small Business	2,469
4. Schools	**2,453**
5. Energy Information Systems	57
TOTAL:	**21,104**

Notes: (1) MER costs are an additional $2,500,000; the EE Performance Incentive is an additional $9,550,000.

TABLE 38 - FORECASTED COSTS FOR APS PEAK SOLUTIONS

PEAK SOLUTIONS PROGRAM COSTS
PROGRAM COSTS ($1,000)

YEAR	PROGRAM COSTS ($1,000)
2013	[redacted]
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	

[34]Approved in Commission Decision No. 72214.

RULE D.15

For each demand management measure that was considered but rejected:

(a) A description of the measure; (b) The estimated change in peak demand and energy consumption from the measure; (c) The estimated cost-effectiveness of the measure; (d) The capital costs, operating costs and maintenance costs of the measure, and the program costs; and, (e) The reasons for rejecting the measure.

As required by the EE Rules, the SCT was applied to all measures. If the benefit-cost ratio was not greater than 1.0, the measure was rejected by APS. Table 39 - Rejected EE Measures and Programs details the response to Rules D.15(a) through D.15(d) for the EE measures that were considered, but rejected at the time of initial screening. In response to D.15(e), all of the measures listed were not approved due to their not passing the SCT. APS will continue to reevaluate beneficial measures and propose those that improve the DSM portfolio in subsequent DSM filings.

Demand Response Programs

To date, no specific DR program has been rejected.

TABLE 39 - REJECTED EE MEASURES AND PROGRAMS

RESIDENTIAL AND NON-RESIDENTIAL EE PROGRAMS
REJECTED MEASURES AND PROGRAMS

RULE D.15(A)	RULE D.15(B)		RULE D.15(C)	RULE D.15(D)
Description	Peak Demand Savings (kW/unit)	Energy Savings (kWh/unit)	Estimated cost-effectiveness (SCT result)	Incremental Measure Cost ($/unit)
Residential				
Clothes Washer Tier 1 (existing)[1]	0.02	163	0.2	$301.20
Clothes Washer Tier 2 (existing)	0.03	202	0.4	$364.46
Clothes Washer Tier 3 (existing)	0.03	232	0.5	$427.72
Clothes Washer Advanced (proposed)[2]	0.04	280	0.7	$467.33
Evaporative Cooled Air Conditioners	0.68	2986	0.8	$1,867
Energy Star Refrigerators	0.06	243	0.9	$131
Window Film	0.28	527	0.8	$537
Heat Pump Water Heaters	0.15	1,350	0.9	$1,191.62
Non-Residential				
Window Films	0	3	0.9	$5.00
Gaskets	0.01	104	0.8	$11.50

Notes: (1) Existing clothes washer refers to clothes washers that are currently available on the market. (2) Proposed clothes washer refers to the next generation of clothes washers that are not commercially-available today.

RULE D.16

Analysis of future fuel supplies that are part of the resource plan.

A thorough and comprehensive fuel supply outlook for the period of 2011-2035 was prepared by IHS CERA for APS in preparation for the 2012 Integrated Resource Plan filing. IHS CERA's outlook for the North American gas and power sectors encompassed the fundamental technological, environmental, and economic factors driving the expectations for natural gas, coal, uranium, renewable energy, emissions costs, supply, demand, and prices from 2011 to 2035. In addition to the report providing an outlook for North America (48 states and Canada) as a whole, there is also added detail for the U.S. Western Region (comprising the Rocky Mountain states and states to the West), and the AZNMNV (Arizona-New Mexico-Nevada) sub-region. APS maintains that this analysis of nuclear and coal fuel price and availability is still relevant, though the quickly evolving natural gas markets suggested additional studies were prudent to ensure adequate source and delivery infrastructure.

In addition to the previously prepared IHS CERA fuel supply outlook, Bentek prepared a study for APS reviewing the Southwest Natural Gas Market for the period of 2013-2029. This study evaluated apparent fundamental shifts in projected supply/demand balance and potential increased gas exports to Mexico or via LNG exports. Bentek's study encompassed demand changes due to non-gas generation retirements, shifting production source locations and expected additional gas-fired generating facilities. Plans to mitigate gas shortfalls are explained in response to Rule E.1(f) – E.3(f).

Additionally, APS has been actively involved in the 2013-2014 Western Interstate Energy Board's Natural Gas-Electric Interdependency study conducted with Energy and Environmental Economics. This study was initiated in response to FERC and NERC directed inquiries into issues related to gas-electric coordination to mitigate potential threats to reliability.

In planning for future gas use, APS produced a 2014 Gas Transportation Analysis summary for the selected resource plan. This analysis is designed to first project peak seasonal natural gas use based on production modeling and then identifies the source of gas for each of these seasonal peaks throughout the Planning Period. Natural gas sources include existing contract capacity, future extension of existing contracts, additional seasonal and annual contracts as well as short term contracts. All APS natural gas contracts are firm fixed delivery to assure adequate gas supply for peak seasonal demands. An example of this analysis can be found in Attachment D.16.

Based on these extensive studies, APS reaffirms that the ongoing practice of procuring firm fixed gas fuel delivery contracts is appropriate and adequately addresses potential fuel supply or delivery issues during the Planning Period.

RULE D.17

A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

Plans to reduce environmental impacts related to air emissions and solid waste are provided in Figure 33. Regulations impacting water, and the plan for reducing impacts are included in Figure 34.

AIR EMISSIONS AND SOLID WASTE REGULATIONS

Regulations impacting water, and a plan for reducing impacts are included in Figure 34.

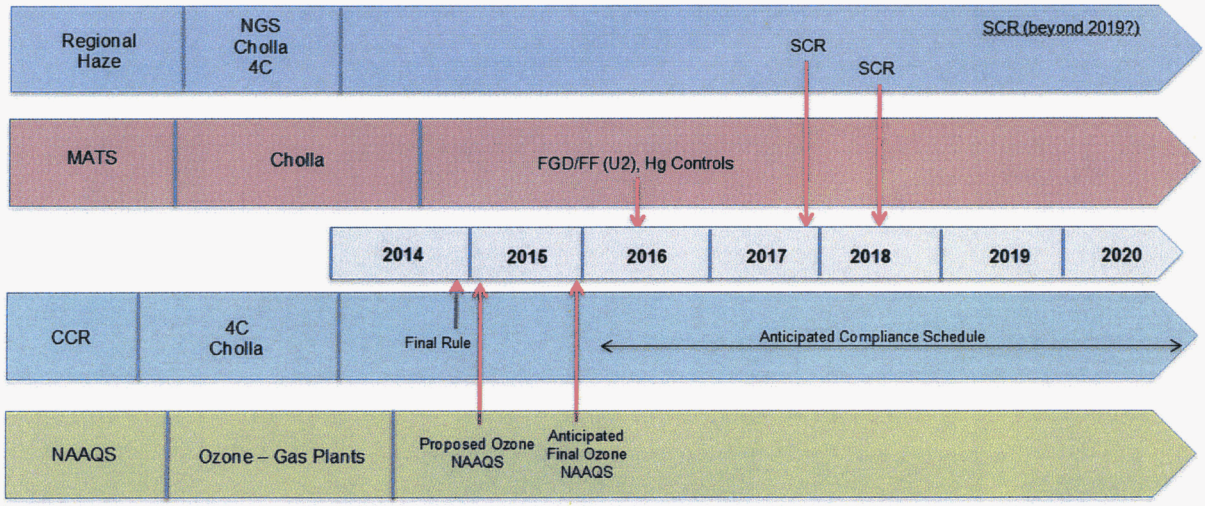


FIGURE 33 - PLAN FOR REDUCING AIR AND SOLID WASTE ENVIRONMENTAL IMPACTS

WATER REGULATIONS

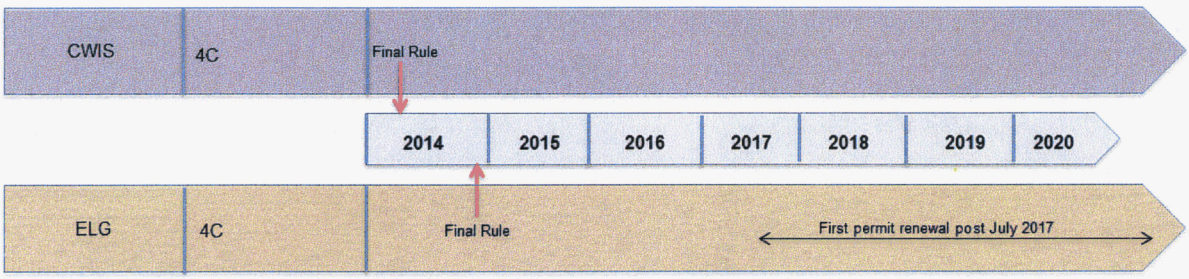


FIGURE 34 - REDUCTION OF ENVIRONMENTAL IMPACTS TO WATER

COMPANY RESPONSE TO CLIMATE CHANGE INITIATIVES

APS has undertaken a number of initiatives to address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency.

APS prepares an inventory of GHG emissions from its operations. This inventory is reported to EPA under the EPA GHG Reporting Program and is voluntarily communicated to the public in Pinnacle West's annual Corporate Responsibility Report, which is available on the Pinnacle West website (www.pinnaclewest.com). The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance.

EPA ENVIRONMENTAL REGULATIONS

REGIONAL HAZE RULES

In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal lands, EPA) to determine what pollution control technologies constitute the Best Available Retrofit Technology (BART) for certain older major stationary sources. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis.

CHOLLA

On December 5, 2012, EPA issued a final BART rule applicable to Cholla. EPA approved ADEQ's BART emission limits for sulfur dioxide (SO2) and emissions of particulate matter (PM), but added an SO2 removal efficiency requirement of 95%. In addition, EPA disapproved ADEQ's BART determinations for oxides of nitrogen (NOx) on which Arizona's state implementation plan (SIP) was based and promulgated a federal implementation plan (FIP) establishing a new, more stringent "bubbled" NOx emission rate applicable to the two BART-eligible Cholla units owned by APS and a third BART-eligible unit owned by PacifiCorp. In order to comply with this new rate, APS will be required to install selective catalytic reduction (SCR) technology on the three BART-eligible units at Cholla (Unit 1 is not BART eligible). The SCR controls would necessitate additional equipment, such as economizer bypasses and dry sorbent injection (DSI) to reduce acid gas emissions from the SCR controls. APS's total costs for these post-combustion NOx controls would be approximately $200 million. Under the FIP, APS has five years from December 2012 to complete installation of the equipment and achieve the BART emission limit for NOx.

APS believes that EPA's final rule as it applies to Cholla is unsupported and that EPA had no basis for disapproving Arizona's SIP and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. The state of Arizona and three other utilities also filed similar petitions. Briefing in the case concluded on February 21, 2014, and the parties are waiting for the court to schedule oral argument.

FOUR CORNERS

On August 6, 2012, EPA issued its final BART determination for Four Corners. The rule included two compliance options. On December 30, 2013, on behalf of itself and the Four Corners co-owners, APS notified EPA that the co-owners selected the BART alternative, which required APS to permanently shut down Four Corners Units 1-3 by January 1, 2014 and install and operate SCR control technology on Units 4 and 5 by July 31, 2018. Consistent with this alternative, APS retired Units 1-3 on December 30, 2013. APS's 63% share of the costs for these controls is estimated to be approximately $350 million.

NAVAJO

APS's total costs for post-combustion NOx controls at the Navajo Generating Station could be up to approximately $200 million. EPA's proposal includes an alternative to BART, which would provide the Navajo Plant with additional time to install the SCR technology. Under this "better-than-BART" alternative, the Navajo Generating Station participants would be required to install SCR technology on one unit per year in 2021, 2022, and 2023. On July 26, 2013, a group of stakeholders, including Salt River Project Agricultural Improvement and Power District (SRP), the operating agent for the Navajo Plant, submitted to EPA two suggested alternatives to BART, which would achieve greater NOx emission reductions than EPA's proposed BART rule. If the rule is finalized as proposed, depending on which alternate operating scenario the Navajo Plant participants ultimately chose, the required NOx emission reductions could be achieved by either closing one of the three 750 MW units at the Navajo Plant or curtailing energy production across all three units such that the emission reductions are commensurate with the closure of approximately one of the Navajo Plant units. On September 25, 2013, EPA issued a supplemental BART proposal proposing to determine that these alternatives are "better than BART" because NOx emissions that would be achieved thereunder would result in greater reasonable progress toward the national visibility goal than EPA's proposed BART determination.

MERCURY AND OTHER HAZARDOUS AIR POLLUTANTS

On December 16, 2011, EPA issued the final Mercury and Air Toxics Standards (MATS) rule, which established maximum achievable control technology (MACT) standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired power plants. Generally, plants will have three years after the effective date of the rule to achieve compliance. In the case of Cholla, APS will have a total of four years after the MATS rule's effective date to comply with the new MACT standards, because on September 24, 2012, the permitting authority granted APS's request for a one-year compliance date extension.

The MATS will require APS to install additional pollution control equipment. APS has already installed certain of the equipment necessary to meet the anticipated standards. APS currently estimates that the cost for the remaining equipment necessary to meet these standards is approximately $125 million for Cholla Units 1-3. At this time, APS anticipates minimal additional costs for compliance with MATS on Four Corners Units 4 and 5. APS are monitoring mercury emissions with mercury Continuous Emissions Monitoring Systems (CEMS) to make a final determination. Installation of SCR controls under BART could affect mercury removal. SCR controls can oxidize mercury, making it easier to remove in the fabric filter baghouse and SO2 scrubber. However, SCR controls can also oxidize SO2 to SO3, which can interfere with the ability of activated carbon injection (ACI) to remove mercury. Until APS actually operates the SCR controls and ACI, it is impossible to determine the net effect. APS's contingency plan for the possible interference of SO3 on ACI is DSI to control SO3.

COOLING WATER INTAKE STRUCTURES

EPA issued its proposed cooling water intake structures rule on April 20, 2011, which provides national standards applicable to certain cooling water intake structures at existing power plants and other facilities pursuant to Section 316(b) of the Clean Water Act. The proposed standards are intended to protect fish and other aquatic organisms by minimizing impingement mortality (the capture of aquatic wildlife on intake structures or against screens) and entrainment mortality (the capture of fish or shellfish in water flow entering and passing through intake structures). To minimize impingement mortality, the proposed rule would require facilities, such as Four Corners and the Navajo Generating Station, to either demonstrate that impingement mortality at their cooling water intakes does not exceed a specified rate or to reduce the flow at those structures to less than a specified velocity, and to take certain protective measures with respect to impinged fish. To minimize entrainment mortality, the proposed rule would also require these facilities to conduct a "structured site-specific analysis" to determine what site-specific controls, if any, should be required. Additional studies and a peer review process would also be required at these facilities. As proposed, existing facilities subject to the rule would have to comply with the impingement mortality requirements as soon as possible, but in no event later than eight years after the effective date of the rule, and would have to comply with the entrainment requirements as soon as possible under a schedule of compliance established by the permitting authority[35]. EPA is working to finalize the standards by April 17, 2014.

APS is performing analyses to determine the costs of compliance with the proposed rule at Four Corners.

[35]APS 2012 Annual Report "Momentum", p. 20-21.

COAL COMBUSTION RESIDUALS (CCR)

On June 21, 2010, EPA released its proposed regulations governing the handling and disposal of coal combustion residuals (CCR), such as fly ash and bottom ash. APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners, and also sells a portion of its fly ash for beneficial reuse as a constituent in concrete production. EPA proposes regulating CCR as either non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) or hazardous waste under Subtitle C of RCRA and requested comments on three different alternatives. The Subtitle C proposal would phase out the use of ash ponds for disposal of CCR. The other two proposals, which would be promulgated under Subtitle D, would regulate CCR as non-hazardous waste and impose performance standards for ash disposal. One of these proposals Subtitle D would require retrofitting or closure of currently unlined ash ponds, while the other proposal, known as Subtitle D prime, would not require the installation of liners or pond closures. EPA has not yet indicated a preference for any of the alternatives.

On April 5, 2012, a coalition of environmental groups filed suit to compel EPA to finalize its proposed CCR rule. Soon thereafter, coal ash recyclers filed similar lawsuits against EPA, which were consolidated with the environmental groups' lawsuits. On January 29, 2014, the parties in the CCR deadline litigation filed a consent decree with the court obligating EPA to make a final decision by December 19, 2014 whether or not to adopt the Subtitle D option for CCR. The consent decree does not foreclose EPA from adopting the Subtitle C option. APS cannot currently predict the timing or content of EPA's final rule or whether this action will have a material adverse impact on our financial position, results of operations, or cash flows.

EFFLUENT LIMITATION GUIDELINES

On April 19, 2013, EPA proposed revised effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil-fired electric generating units. EPA's proposal offers numerous options (four of which are "preferred alternatives") that target metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and non-chemical metal cleaning wastes operations. The preferred alternatives differ with respect to the scope of requirements that would be applicable to existing discharges of pollutants found in wastestreams generated at existing power plants. All four alternatives would establish a "zero discharge" effluent limit for all pollutants in fly ash transport water. However, requirements governing bottom ash transport water differ depending on which alternative EPA ultimately chooses and could range from effluent limits based on Best Available Technology Economically Achievable to "zero discharge" effluent limits. Depending on which alternative EPA finalizes, Four Corners may be required to change equipment and operating practices affecting boilers and ash handling systems, as well as change its waste disposal techniques. We cannot currently predict the shape of EPA's final rule or whether this action will have a material adverse impact on our financial position, results of operations, or cash flows. EPA is currently subject to a consent decree deadline to finalize the revised guidelines by May 2014, although it is in negotiations to obtain an extension of time.

OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS

In March 2008, EPA adopted new, more stringent eight-hour ozone standards, known as National Ambient Air Quality Standards (NAAQS). In January 2010, EPA proposed to adopt an even more stringent eight-hour ozone NAAQS. However, on September 2, 2011, President Obama decided to withdraw EPA's revised ozone standards until completion of the next review. EPA had a March 2013 deadline to complete its review of the 2008 ozone NAAQS, but failed to meet it. In a February 25, 2014 filing with the United States District Court for the Northern District of California opposing environmental plaintiffs' motion asking the court to impose a schedule on EPA requiring it to complete its review of the ozone NAAQS by a certain date, EPA indicated that it would need until January 15, 2015 to propose an action completing the ozone NAAQS review and until November 15, 2015 to take final action. As ozone standards become more stringent, APS fossil generation units may come under increasing pressure to reduce emissions of nitrogen oxides and volatile organic compounds or generate emission offsets for new projects and facility expansions in ozone nonattainment areas.

NEW SOURCE REVIEW

In August 2009, APS responded to a request from EPA seeking detailed information regarding projects at and operations of Four Corners pursuant to Section 114 of the Clean Air Act. This request is part of an enforcement initiative that EPA has undertaken under the New Source Review (NSR) provisions of the Clean Air Act. EPA has taken the position that many utilities have made certain physical or operational changes at their plants that should have triggered additional regulatory requirements under the NSR provisions of the Clean Air Act. EPA contends that APS has violated NSR rules at Four Corners, but has not listed any specific violations. Other electric utilities have received and responded to similar Section 114 requests, and several of them have been the subject of notices of violation and lawsuits by EPA. EPA has not responded to APS's response.

WATER SUPPLY

Water is used for power generation primarily to cool the steam-cycle by removing waste heat. It is also used for power augmentation, emissions control, auxiliary cooling, supporting chemical treatment processes, domestic purposes, and for other miscellaneous plant uses. APS manages water resources using a multi-layered approach to reduce water intensity. APS's plan for reducing water consumption includes the following actions:

- Employment of alternative cooling technologies for new generating resources;
- Improve the efficiency of water utilization at APS's existing facilities; and
- Increase reliance on energy efficiency and renewable energy resources.

EMPLOYMENT OF ALTERNATIVE COOLING TECHNOLOGIES FOR NEW RESOURCES

For new facilities, APS evaluates alternative cooling technologies, water sources, and operating strategies in the best interests of the state, environment, and customers on a case-by-case basis; however, the use of alternative water supplies, such as effluent and alternative cooling technologies to reduce potable water usage comes with an additional cost in terms of capital investment and O&M costs, and may have an impact on unit efficiency. The factors influencing these decisions are diverse, including location, generator type, and renewable and alternative water availability. APS is developing a water supply portfolio that will provide a reliable mix of traditional, renewable, and reclaimed sources, minimizing where possible usage of groundwater and other potable water sources in favor of more sustainable resources. This approach is aimed at providing secure water supplies for power generation while fostering responsible water use.

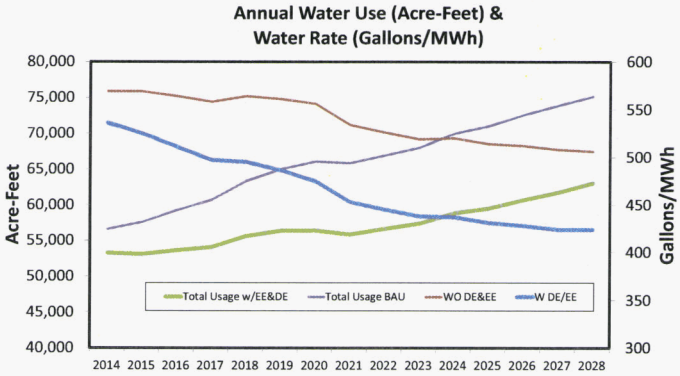


FIGURE 35 - FORECAST OF WATER CONSUMPTION AND INTENSITY

Even though energy consumption is forecast to significantly increase during the Planning Period, water consumption will only see a minimal increase. In addition, due to the energy efficiency and renewable energy resources envisioned in the 2014 Resource Plan, the rate of water usage declines dramatically over the course of the Planning Period.

When new power plant generating unit options are being evaluated, the water consumption rates for each technology option are considered and evaluated. The most significant water-saving device that can be installed on new power plants with steam turbines is air-cooled condensers in lieu of conventional wet-cooling towers. Technology for new dry-cooled combined cycle plants is estimated to use 15 gallons/MWh as compared to wet-cooled combined cycle plants such as Redhawk, which use approximately 300 gallons/MWh. APS, in conjunction with SRP and Tucson Electric Power Company performed a detailed estimate of the equipment cost for an air-cooled condenser and determined the cost difference to be about $60 million based on a nominal 600 MW combined cycle power plant constructed in the Arizona desert.

To reduce water consumption, APS's future cost estimates and performance projections assume dry or hybrid cooling for newly constructed combined cycle generating units. Reduced water consumption, however, comes at the cost of reduced unit output, higher fuel consumption, and higher capital costs. The additional costs for combined cycle air-cooled condensers have been included in the 2014 Resource Plan.

APS also evaluates utilizing hybrid cooling technology at future plants to reduce water consumption. Utilizing hybrid cooling technology at future generating plants can come with tradeoffs. The actual tradeoffs for hybrid cooling technology are dependent on the supply of water available. The dry portion of the hybrid system would be sized to achieve a certain level of water savings, primarily achieved during the cooler months. An informal estimate provided by an architect-engineering firm has projected that the use of hybrid cooling technology could result in an increase in total project capital costs of up to 15%.

RETIREMENT OF FOUR CORNERS UNITS 1-3

In addition to evaluating alternative cooling technologies, further reductions in regional water consumption were achieved through the retirement of Four Corners Units 1-3, effective December 30, 2013. Retirement of these three units will save approximately 3,000 – 5,000 acre-feet of water annually.

IMPROVING THE EFFICIENCY OF WATER USE AT EXISTING FACILITIES

APS manages water resources using a multi-layered approach to reduce water intensity. One approach has been to pursue projects targeted to improve the efficiency of water utilization at APS's existing plants. A primary example is Palo Verde Nuclear Generating Station, which not only uses reclaimed wastewater effluent as its cooling water source, but has focused on continual improvement in water treatment and operations to achieve over 23 cycles of concentration (on average) through the cooling water system. Redhawk, APS's newest combined cycle facility, also operates its cooling system using reclaimed water, achieving similar levels of efficiency. In 2013, 64% of all water used by APS was reclaimed water.

When considering water use and water efficiencies at power plants, APS considers not only the cost of projects, but also the potential impacts on society and the local environment. Understanding local and regional water use and trends is important to this decision-making. With that in mind, in 2009, APS formed its Water Resource Planning Department, consolidating many existing water-oriented functions and experience into a centralized, enterprise-wide function. The vision of this department is "to secure a sustainable and cost-effective supply of water to enable reliable energy production for APS customers." A primary initiative of the Water Resource Planning Department is to create a decision modeling center, consisting of a powerful database and computing infrastructure to allow modeling of groundwater supplies, surface water availability, and the characteristics of other water sources in conjunction with a variety of long-term energy production forecasts. By utilizing this quantitative approach in conjunction with geographic information systems, analysts and stakeholders can interactively examine and contextualize the impacts of various decisions and scenarios.

APS has also become more integrated into the Arizona water community. Participation in the U.S. Bureau of Reclamation's Colorado River Basin Study Group, the Joint Legislative Committee on Water Salinity Issues, the Arizona Department of Water Resources' (ADWR) Water Resources Development Commission, the governor's Blue Ribbon Panel on Water, and the Central Arizona Project's Acquisition, Development and Delivery Water program are five examples of activities where involvement is enabling improved communication with other water stakeholders, including regulators, municipalities, agricultural users, and other industries. APS is a representative on the Phoenix Active Management Area's (AMA) Groundwater Users Advisory Council (GUAC). This council makes recommendations to ADWR's Phoenix AMA director on groundwater management and policy in the AMA. The Phoenix GUAC is the primary mechanism for public comment and review during ADWR's development of the Phoenix AMA's Fourth Management Plan, which was initiated in 2013 and will be completed in 2014. This integration into the broader water community has opened communication and facilitated partnering opportunities for the future.

ENERGY EFFICIENCY AND RENEWABLE ENERGY RESOURCES

Demand-side management programs and renewable energy resources generally consume little or no water. The expansion of these programs in the 2014 Resource Plan contributes to a reduction in water consumption per MWh over the Planning Period.

RESPONSE TO RULES SECTION E - RISK

Response to Rules Section E - Risk

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(E), which specifically requires information related to risk analysis and mitigation.

E.1(A)

Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis: (a) demand forecasts.

The risks involved with developing a demand forecast involve uncertainties related to: (1) customer growth; (2) electricity usage; and, (3) weather. Table 40 illustrates the results of a probabilistic approach.

TABLE 40 - PROBABILISTIC ANALYSIS OF PEAK DEMAND FORECAST

APS SYSTEM PEAK DEMAND FORECAST (PROBABILISTIC ANALYSIS)

Percentile	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
10th	6,929	7,031	7,270	7,547	7,854	8,159	8,369	8,675	8,916	9,180	9,508	9,740	9,999	10,234	10,583	10,840
20th	6,992	7,122	7,372	7,652	7,973	8,263	8,500	8,798	9,084	9,329	9,654	9,934	10,209	10,491	10,776	11,059
30th	7,055	7,191	7,457	7,745	8,041	8,354	8,603	8,880	9,181	9,457	9,757	10,063	10,358	10,640	10,909	11,208
40th	7,102	7,244	7,516	7,820	8,106	8,432	8,705	8,971	9,284	9,577	9,855	10,170	10,455	10,765	11,045	11,360
Forecast	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
60th	7,190	7,353	7,633	7,950	8,253	8,551	8,830	9,157	9,453	9,762	10,069	10,374	10,667	10,983	11,297	11,597
70th	7,237	7,409	7,696	8,025	8,325	8,622	8,906	9,249	9,522	9,847	10,195	10,491	10,790	11,109	11,447	11,714
80th	7,287	7,463	7,771	8,082	8,408	8,720	9,004	9,366	9,637	9,993	10,307	10,641	10,953	11,235	11,591	11,873
90th	7,338	7,554	7,867	8,167	8,520	8,853	9,173	9,485	9,807	10,231	10,473	10,843	11,179	11,464	11,816	12,099

RULE E.2(A)

A description and analysis of available means for managing the errors, risks, and uncertainties identified and analyzed in subsection (E)(1), such as obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects: (a) demand forecasts.

A probabilistic analysis can be used to understand risk by providing a range of demand scenarios consistent with historical variations that APS has seen in customer growth, electricity consumption, and weather. Levels of demand can be illustrated by using percentiles ranging from 10% to 90%. The 10th percentile represents the likelihood of a lower demand outcome which would minimize the costs associated with procuring additional resources but contains a risk of not building a sufficient amount of resources if the actual demand exceeded the forecast. At the other end of the spectrum is the 90th percentile, a scenario with a higher demand outcome than is currently planned for and greater costs for procuring additional resources, which carries the risk of building too many resources than what might be needed if the actual demand was less than the forecast.

In the near term, weather presents the greatest risk to the forecast. Peak demand typically occurs during July or August when temperatures can reach 114°F. In the last ten years, the temperature on peak day has been as high as 118°F and as low as 113°F. The 90th percentile is 116°F. Temperatures 2°F above the 10 year average of 114°F can add nearly 200 MW to peak.

Customer growth and changes in use per customer are the most important long-term risks to the demand forecast. Population growth, business investment, and new technology development and deployment over the next 15 years could be quite different from the assumptions in the current forecast. The current forecast assumes a compound annual growth rate in residential customers of 2.8%.

Methods for managing these risks and uncertainties include utilizing resource options that have relatively shorter development lead times. Shorter development lead times allow utilities to respond quickly to changes in demand scenarios. Also, timely updates to the forecast with new information help ensure forecasts remain current. Lastly, having access to liquid wholesale power market trading hubs allows utilities to either buy or sell energy as needed to balance energy demands with resources.

RULE E.3(A)

A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (E)(1): (a) demand forecasts.

APS manages demand forecast risk using three key methods. The APS 2014 Resource Plan envisions short-lead-time resources such as solar PV and natural gas combustion turbines. The development time for these resource types can be anywhere from one to five years. Utilizing short-lead-time resources allows APS to respond quickly as demand scenarios change. APS also carries a 15% reserve margin of additional capacity, over the amount of demand actually forecast, to be available should customer demand exceed expectations or generating units not perform as designed. Furthermore, APS benefits from transmission access to the Palo Verde wholesale trading hub. Because there are many wholesale market participants with access to Palo Verde, APS buys and sells capacity as needed to balance demand with resources.

RULE E.1(B)

Risk Identification: (b) the costs of demand management measures and power supply.

Demand Management Measures

Within the DSM market, the cost trajectory will vary depending on the program or measure, and timing. It is expected that as a whole, the cost per unit of energy saved through EE programs and measures will increase over time; the rate at which it increases will vary depending on technical developments, progression of building codes and appliance standards, persistence of behavioral changes after incentives disappear, and overall market penetration. That said, as future EE programs are designed and proposed, cost-effectiveness must still be proven, which will likely change the landscape of future EE measures as the "low-hanging fruit" with shorter measure lives (e.g., CFLs) are replaced by the next-generation, more efficient products (e.g., LEDs).

As with EE measures, the cost volatility of load management and demand response solutions continues to be an identified risk. Costs will be largely influenced by development of new communication standards, increased technical efficiencies, and environmental considerations.

Home-area networks and distribution system communications are an emerging sector within the demand response arena. Communication standards and protocols are being developed to ensure seamless communication between utilities and load behind the customer meter. As these specifications mature, networks and consumer products will need to be updated to ensure compatibility and functionality, and will require financial investments from the utility and the customer. In the near-term of the Planning Period, utilities may experience an increase in IT costs, though the identified system efficiencies and customer services gained are expected to be positive investments from a finance, customer, and technical perspective. These investments can provide an IT backbone to help improve reliability, decrease outage and response time, and provide tailored energy management solutions for customers.

Other customer load response resources, such as standby generation, have demonstrated a downward trend in equipment and integration costs. The costs for new generators and harvesting existing generators have trended downward despite increased emission regulations and fuel costs. Harvesting is when APS works with customers who have existing on-site standby generators (e.g., hospitals for emergency back-up) that can be paralleled to the grid so that APS can have access to the generators in times of peak demand and the generators are not in use by the customer. In return for granting APS permission to dispatch the generator during peak events, customers can receive O&M, fuel, or other financial incentives from APS. When harvesting generators, APS would retrofit the technologies as necessary to ensure compliance with current emissions regulations.

Power Supply

Analyses to identify construction cost- and fuel cost-related risks and uncertainties are addressed in subsequent sections.

Other risks associated with costs of power supply involve surplus or shortfalls in meeting reserve requirements. APS manages three types of reserves at three different time intervals: planning reserves – these are the reserve requirements calculated at annual timescales and encapsulated in Attachment F.9(b) line 4; contingency reserves – these are made up of spin- and non-spin reserves and are managed on an hourly basis, and; frequency reserves – these are managed at a sub-minute level and manage frequency on the regional transmission system. Surplus and shortfalls in any of these categories can bring about financial risk in terms of surplus variable or capacity costs, if reserves are in surplus, or risk of overpaying during states of emergency or from paying fines for failing to meet requirements, if reserves are too low.

Though APS has always had cost risk related to surplus or shortfalls in reserve requirements, solar penetration has increased the magnitude of risk related to contingency and frequency reserve requirements and distributed generation has added an element of uncertainty when developing planning reserves. Descriptions of these three risks follow:

Frequency Reserves: Cost risk can occur when frequency reserves are in surplus or below minimum requirement levels. Operations disruptions from unplanned generation or transmission line outages – have historically posed the greatest challenges. However, more recently, intermittency related to solar generation adds an additional level of cost risk as generation output can vary at short time intervals due to cloud movement.

Contingency Reserves: Likewise, power supply cost risk may result from forecast error. APS utilizes various forecasting tools to minimize risks to over- or under-generation. These forecasts include demand, weather and load- and utility-side renewable production. The potential magnitude of load- and utility-side renewable production forecast error is expected to increase with additions of wind and/or solar to the APS system.

Planning Reserves: As a generation source, distributed energy receives the same level of planning reserve treatment as other resources. However, APS does not have full control over the timing of adding or removing this generation resource. This could put planning reserves at risk of being over- or under their 15% target, which could have cost implications to APS and its customers.

RULE E.2(B)

Risk Analysis: (b) the costs of demand management measures and power supply.

Demand Management Measures

Annually, on-going analyses will be performed to ensure that proposed and existing DSM programs are cost-effective and advantageous for APS and its customers.

Power Supply

Specific methods to manage construction cost and fuel cost-related risks and uncertainties of the costs of power supply are addressed in subsequent sections.

Real-time operations power supply cost risks have traditionally been managed through NERC reliability requirements. Many compliance costs associated with these NERC requirements have been managed through APS's participation in regional reserve sharing groups, such as the Southwest Reserve Sharing Group. That said, increasing amounts of intermittent generation, such as wind and solar, on the electric grid are expected to increase frequency and contingency reserve-related costs. APS employed Black and Veatch to analyze solar integration costs and Northern Arizona University to analyze wind integration costs in order to quantify cost impacts related to carrying additional operations reserves. These analyses are discussed in more detail in response to Rule D.11. As a general rule, integration costs increase with increased levels of solar and/or wind penetration. Integration costs increase because the magnitude of potential power supply disruptions increase with more MW of solar and/or wind.

Power supply cost impacts related to forecast error is often situation dependent and are expected to increase with increasing additions of solar and wind generation. APS analyzes weather, load and renewable forecast error on a daily basis and analyzes patterns so that forecasts can be improved and cost-related error reduced. That said, renewable production forecasting is a relatively new practice and therefore renewable production forecast practices throughout the industry are expected to advance during the Planning Period. Until renewable forecasting methodologies improve, error from these forecasts is likely to be substantial.

Planning reserve cost impacts depend upon the magnitude and direction of the difference in annual forecasted distributed energy additions and actual.

RULE E.3(B)

Risk Mitigation Plan: (b) the costs of demand management measures and power supply.

Demand Management Measures

Embedded within the EE Standard is the cost-effectiveness requirement which acts as a mechanism to ensure that all DSM programs that are implemented provide a net benefit to APS and its customers. Annually, APS seeks to manage EE program costs by exploring innovative incentive models, creating additional technology options, and conducting Measurement and Evaluation Research (MER) on the programs.

Due to the varied nature of load management and demand response solutions, cost volatility can be more closely managed by strategically timing deployment of resources and diversifying procurement methods. The APS Peak Solutions program is managed through a long-term contract (through 2024) that has fixed energy and capacity payments through the term of the agreement. Customer load response solutions, such as standby generation, offer options to harvest existing equipment or deploy new, utility-owned assets, which have different economic benefits that APS can capitalize on.

Additionally, time-differentiated rate schedules and tariffs are eligible to be re-filed as necessary to assist in managing customer and Company impact. APS will have the opportunity to revisit these rates in the annual DSM Implementation Plan filings or through rate cases.

Power Supply

Risk mitigation plans for construction cost- and fuel cost-related risks and uncertainties are addressed in subsequent sections.

To mitigate the risks associated with forecast error-related costs of power supply, APS optimizes the use of its resources to serve native load in the most economical manner possible, while maintaining grid reliability. The process begins by forecasting the load, load-side renewable production, and utility-side renewable production on a day-ahead basis. The load forecast is entered into a unit commitment and dispatch model (PCI GenTrader®/ GenPortal®) that determines the most economic unit commitment plan for serving load, taking into account generating unit capabilities, intermittent resource production forecasts (wind/solar), fuel prices, and transmission constraints. This commitment plan shows the units to be committed each hour, their projected loading level, and the quantity of natural gas to be scheduled. As part of the process, the model calculates prices for blocks of energy to help determine if it would be cheaper to buy power from the market rather than running generating units.

To mitigate risks associated with renewable forecast error, APS actively assesses forecast error, scans relevant available industry sources, consults renewable forecast providers, and participates in various renewable energy forecasting forums in order to improve its methodologies.

A minimum margin is built into transactions to account for unexpected risk factors. If there should be an unforeseen event, the model can be adjusted in real-time, which would in turn adjust the base cost/base value for future transactions.

APS also has access to the Palo Verde Hub, a major trading point in the Western Interconnection that provides access to a multitude of resources.

A risk-mitigation plan for the long-term cost of power supply includes strategies such as developing hedge programs to mitigate the volatility associated with natural gas prices and establishing long-term fuel agreements for coal and nuclear, as well as having a diversified portfolio of resources. Additionally, planning reserve margins and distributed energy MW additions are assessed several times a year.

RULE E.1(C)

Risk Identification: (c) the availability of sources of power.

Risks involved in the availability of sources of power include the availability of the supply resource itself, availability of new generation equipment, timing of construction schedules, availability of credit-worthy counterparties, the commercial viability of certain technologies, and the availability of adequate transmission capacity to move the power to the load center where it is needed.

RULE E.2(C)

Risk Analysis: (c) the availability of sources of power.

One of the key risks that APS addresses on a daily basis is the potential of reduced generating availability and outages in the fleet of existing supply resources. This risk of an equipment or plant malfunction and unplanned shutdown is present on a continuous basis but is generally minimized through high standards in plant maintenance and operations. In addition, APS plant designs incorporate a reasonable level of redundancy at the equipment level so that single failures do not generally result in plant outages.

Providing for an allowance in the timing of construction schedules for planned generation is one way the construction schedule risk can be mitigated. When planning for summer peak resource requirements, an allowance can be made for the level of capacity a particular resource is allowed to contribute toward meeting that summer peak demand. For projects that are anticipated to reach commercial operation during the summer period of June - September, a risk-reducing strategy may be to not rely upon those projects' capacity for meeting that particular summer peak. In this way, construction schedule risk is mitigated.

Having additional resources available is another means of managing risk in the availability of sources of power. Utilities carry capacity reserve margins (surplus reserve capacity) in the event of resources being unavailable or customer demand being higher than anticipated. Capacity reserve margins are an effective means to help ensure sufficient power sources are available when needed.

Following robust procurement practices is another way to mitigate risk of availability of sources of power. Soliciting bids from a large number of third-party developers allows the Company to select projects that are more likely to be completed on time. Developers often may already own property, have permits in place, and have good queue positions for equipment.

When procuring energy from third-party vendors, an analysis of vendor credit quality is crucial to the success of a transaction. Poor credit quality or the inability of a vendor to obtain cost-effective and timely financing for their project will, in most circumstances, exclude that vendor from being considered. A thorough analysis of vendor credit quality helps mitigate these impacts.

Consideration of a wide range of technologies increases resource diversity and reduces technology performance risk. Being overly dependent on a single technology or depending on technologies that have yet to be proven in commercial applications may increase performance risk.

One of the single best, and most simple, means of managing risk in sources of power is resource diversity (i.e., not being overly reliant on one fuel source). Utilities with diverse sources of power supply are situated better when unforeseen problems emerge because they have other alternative sources of power to rely upon.

To optimize the economic alternatives of running generating units versus procuring energy from the market, having transmission access to liquid trading hubs is another means of helping to ensure availability of sources of power.

RULE E.3(C)

Risk Mitigation Plan: (c) the availability of sources of power.

Existing plant availability is maintained at very high levels through the application of effective preventative and predictive equipment maintenance. APS maintains an operational staff which is capable and highly trained. Programs are in place which promote the capture of data and evaluation of equipment failures and operational incidents to help prevent recurrence and reduce the risk of unexpected outages.

APS mitigates risk due to the timing of construction schedules by not including those projects' capacity as contributing toward meeting summer peak demand when their initial commercial operation date is anticipated to be during the summer (June - September). By mitigating construction schedule risk in this manner, system reliability is not compromised if projects are delayed.

As described in response to Rules E.1(a) - E.3(a), APS plans to carry a minimum 15% planning capacity reserve requirement that helps ensure sufficient power sources are available. APS's capacity reserve requirement for 2014 is 978 MW, as shown on line 4 of Attachment F.9(b).

The Company also mitigates risk by engaging in best practice procurement procedures. Whether APS signs a purchase power agreement, purchases an existing asset, or constructs new generation, the best projects are identified through broad market participation.

APS employs credit risk management practices that ensure the creditworthiness of all counterparties in energy procurement transactions has been thoroughly analyzed prior to making a transaction. In addition to determining the credit quality of potential counterparties, APS also may require a letter of credit, guarantee, or some other form of acceptable collateral prior to completing a transaction. In this manner, if a counterparty were to default on their contractual obligations, APS could retain the collateral of the defaulting counterparty to help offset any damages APS may have incurred as a result of the counterparty default.

APS employs a wide range of resources and is not overly dependent on any one specific resource, as illustrated by the diversity of the supply-side resources included in the 2014 Resource Plan. APS limits risk exposure by considering only sources of power reasonably believed to be commercially available within the planning time frame.

APS has taken steps to promote a contingency planning process that is designed to identify uncertainties in the existing resource plan and develop options for new resources and transmission capacity, which can be implemented in the identified timeframes. These options are intended to be executable compensatory measures in the event of failure of specific elements of the current resource plan.

In terms of renewable energy, the 2014 Resource Plan includes solar thermal, solar photovoltaic, wind, geothermal, biogas, and biomass. By considering commercially available resources such as those mentioned, APS mitigates technology performance risk.

To meet the new natural gas generation needs identified in APS 2014 Resource Plan, APS could choose to contract with or purchase available market generation, or construct new combustion turbines or combined cycle units. There are currently four market generators located near the Palo Verde hub with a total of about 5,000 MW of capacity[36]. This market capacity could potentially fill some of the natural gas generation needs identified in the 2014 Resource Plan by 2029. When APS chooses to construct new capacity, it is anticipated that there will be many manufacturers and many technology options to choose from, along with sufficient availability of new equipment.

Through its ownership interest in PVNGS, APS benefits from transmission access to the wholesale power market at the Palo Verde hub. Many market participants, as well as merchant generators, buy and sell wholesale power at the Palo Verde hub making access to that facility one of the means APS uses to manage the risk of power source availability.

[36]APS has two purchase power agreements from these generators that will be expiring during the Planning Period.

RULE E.1(D)

Risk Identification: (d) the costs of compliance with existing and expected environmental regulations.

EPA is currently in various stages of promulgating environmental regulations, which are expected to impact APS. Factors that will impact future costs of compliance include:

- Capital and O&M costs pertaining to existing regulations are subject to cost increases triggered by inflation or limited supply;
- Existing regulations may change during the Planning Period;
- The requirements to comply with many of the proposed regulations have not been finalized, so it is difficult to estimate precise costs of unknown regulations; and
- New technology may be required to achieve compliance with proposed regulations, and the cost of the new technology may be unknown.
- Costs provided in response to Rule D.17 are subject to change if the scope of the regulation changes requirements.

APS monitors the regulatory landscape as potential environmental regulations evolve and become better defined. Throughout this process, APS environmental engineers develop refined cost analyses using scenarios containing a range of potential technology requirements to forecast the cost of possible outcomes.

ANALYSIS OF UNCERTAINTY PERTAINING TO REGIONAL HAZE REGULATIONS (BART)

EPA proposed a new rule regarding regional haze, which includes decreasing NOx, SO2, and PM emissions at the Four Corners and Cholla Power Plants. The focus is mainly on NOx emissions. Many scenarios are currently being evaluated to reduce the costs of compliance, but still provide reliable generation. APS has conservatively assumed the installation of SCR controls at Cholla, as required under EPA's BART rule. If APS prevails in its lawsuit with EPA, these costs could be reduced or delayed. The risk for additional costs from BART at Cholla lies mainly in the cost estimate for economizer bypasses and reagent usage.

On September 25, 2013, EPA issued a supplemental rule proposing additional alternatives to BART at the Navajo Plant. If the rule is finalized as proposed, depending on which BART alternative is ultimately selected, installation of BART controls at the Navajo Plant could be delayed until December 31, 2030. This alternative would require the permanent closure of one of the units at the Navajo Plant by December 31, 2019. The biggest risk to increases in BART compliance costs at Navajo would be if a fabric filter baghouse were required in addition to SCR controls.

ANALYSIS OF UNCERTAINTY PERTAINING TO MERCURY AND AIR TOXICS STANDARDS (MATS) REGULATIONS

In 2012, EPA finalized new regulations to control mercury and other hazardous air pollutants (HAPS). Coal units will be most affected by this rule. Cost and performance estimates for mercury control technologies are determined by utilizing information from the Electrical Power Research Institute (EPRI), discussions with technology vendors, discussions with other utilities, and in-house testing and evaluations. Except in the case of Cholla Unit 2, which would require a fabric filter baghouse and SO2 scrubber upgrades, the additional capital costs for complying with MATS are minimal. The bulk of the costs for MATS, and also the greatest uncertainty, are related to reagent usage. The amount of reagent required to achieve a given mercury limit is very site-specific and difficult to determine accurately without testing. The addition of SCR controls will complicate matters as they can convert SO2 to SO3, which can interfere with the effectiveness of activated carbon for mercury control. APS is planning to test reagents at Cholla to determine the most cost-effective reagent.

ANALYSIS OF RCRA SUBTITLE C PROPOSAL

Proposed regulations for RCRA include two different scenarios—Subtitle C (hazardous) and Subtitle D (non-hazardous). For planning purposes, APS has assumed EPA will choose to regulate CCR under Subtitle D and has included cost estimates in the 2014 Resource Plan for Four Corners and Cholla. To manage the uncertainty of the cost of compliance, APS also evaluated the requirements under the proposed Subtitle C regulations. While the requirements for Subtitle D were discussed in the response to Rule D.17, an analysis is provided below of the potential impacts based upon proposed compliance requirements for Subtitle C.

Under the Subtitle C option, EPA is proposing to regulate CCR as a hazardous waste, which is the most stringent and costly option available to EPA under federal law. Due to the stigma associated with hazardous waste, this option would likely eliminate the beneficial reuse of CCR and harm small businesses, such as coal ash marketers and end-users of CCR.

The inflexible nature of RCRA's hazardous waste regulations would result in the regulation of many aspects of power plant operations at Four Corners, Cholla, and the Navajo Plant , not just the CCR disposal operations. Under the Subtitle C proposal, within five years from the effective date of the rule, APS would be required to close its existing surface impoundments (used for wet disposal of CCR) and convert all CCR handling systems to dry handling and dispose of CCR in engineered, lined landfills at both plants. The plants would also be required to obtain federal permits for the handling and disposal of CCR, and all CCR handling operations would be required to meet very stringent hazardous waste requirements.

Historically, a portion of the ash produced at Cholla and Four Corners was beneficially reused in the manufacture of concrete and other applications; however, because of the liabilities associated with hazardous waste, it is unlikely that APS could continue to market fly ash for beneficial reuse. In such an event, APS would have to dispose of the material in permitted landfills.

ANALYSIS OF UNCERTAINTY PERTAINING TO NATIONAL AMBIENT AIR QUALITY STANDARD (NAAQS) REGULATIONS

Because the proposed ozone NAAQS were withdrawn by EPA and the agency has yet to establish new NAAQS for ozone, it is difficult to estimate the impact of new standards on APS's system. With respect to coal plants on which SCR controls are required under BART, it is unlikely that any additional NOx controls will be required during the first regional haze planning period, which will end in 2018. However, there is a possibility that SCR controls may be required on some of the natural gas combustion turbines in Maricopa County. Capacity factor will likely be a significant factor in deciding which units would require the installation of SCR controls. Because APS's higher capacity factor combustion turbines already have SCR controls, there are only a few existing units that might be at risk.

ANALYSIS OF UNCERTAINTY PERTAINING TO NEW SOURCE REVIEW (NSR) REGULATIONS

Under the NSR rules, a project at an existing unit triggers pre-construction permitting and additional control requirements if it is a physical or operational change that would result in a significant net emission increase. Projects considered to be "routine maintenance, repair, and replacement" are categorically excluded. In the late 1990s, EPA started an NSR "enforcement initiative" against the utility industry. The enforcement actions are based on a theory of universal liability, under which every utility in the nation has violated NSR repeatedly in the past three decades, in virtually every outage that involved major repairs and replacements. EPA asserts in the enforcement cases that "routine" must be judged by reference to activities commonly undertaken at the specific unit in question, or at a "typical" unit in the industry, so any boiler component replacement project of substantial size is not "routine," because it occurs only once or twice in the life of any unit. On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners co-owners alleging NSR violations; however, APS are currently unable to determine a range of potential losses that are reasonably possible of occurring.

ANALYSIS OF UNCERTAINTY PERTAINING TO GREENHOUSE GAS (GHG) NEW SOURCE PERFORMANCE STANDARDS (NSPS) REGULATIONS

On September 20, 2013, EPA issued proposed an NSPS for emissions of CO2 for new affected fossil fuel-fired electric utility generating units. EPA has not yet proposed standards of performance for GHG emissions from existing power plants. The president directed EPA to propose such standards for modified and existing units by June 1, 2014 and to finalize them by June 1, 2015. The inclusion of a cost for CO2 emissions has been debated for years, and many variations of such a program have been proposed in Congress over the last 20 years. Given these factors, it is difficult to forecast what final form that regulation may take. Nonetheless, APS has included in its analysis the potential for carbon pricing in the form of three carbon price forecasts. Refer to Chapter 4 for a description of these forecasts.

ANALYSIS OF UNCERTAINTY RELATED TO EFFLUENT LIMITATION GUIDELINES (ELG)

The Clean Water Act (CWA) regulates discharges to "waters of the U.S." through water quality standards and technology-based standards. Effluent Limitation Guidelines (ELG) are technology-based standards developed by EPA on an industry-by-industry basis. The CWA requires EPA to review periodically and revise these standards as appropriate. On April 19, 2013, EPA proposed revised ELG wastewater discharge limitations for fossil-fired electric generating units. EPA's proposal offers eight options that target metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and non-chemical metal cleaning wastes operations. The alternatives differ with respect to the scope of requirements that would be applicable to discharges of pollutants found in waste streams generated at existing power plants.

The ELG will impact the Four Corners, West Phoenix, and Ocotillo power plants, because these facilities have permitted industrial discharges. Four Corners discharges directly into a water of the U.S. at two locations. West Phoenix and Ocotillo are permitted to discharge into municipal sewer systems, which are in turn permitted to discharge directly into a water of the U.S. In addition, West Phoenix is permitted to discharge directly into an adjacent irrigation canal, but as a normal practice does not use this discharge point.

Any revisions to the ELG would impact the discharge limits at APS Four Corners, West Phoenix, and Ocotillo power plants. Accordingly, these plants may be faced with increased capital and O&M expenses to achieve and maintain compliance; however, the precise nature and magnitude of those impacts cannot be assessed until EPA selects one of the eight options in its forthcoming final rule, which is expected in late 2015.

RULE E.2(D)

Risk Analysis: (d) the costs of compliance with existing and expected environmental regulations.

Available means for managing errors, risks, and uncertainties include the following strategies:

- Obtain current information from sources, such as federal and state agencies, industry publications, vendor presentations, discussions with other utilities, market research, and third-party consulting organizations, to maintain awareness of proposed changes to existing and expected regulations, which will impact technology choices and cost;
- Serve on environmental control technology committees within industry organizations;
- Analyze commercially-viable options for technologies that will enable environmental compliance;
- Negotiate solutions with government agencies that balance cost and compliance;
- Update costs of technology needed for compliance throughout the development of the regulation and as expected regulations become finalized, including increases in cost due to inflation or limited supply; and
- Pursue an expanded portfolio of non-emitting resources that includes energy efficiency, demand response, and renewable energy to defer the cost of additional environmental control technology by delaying new conventional fossil generation.

RULE E.3(D)

Risk Mitigation Plan: (d) the costs of compliance with existing and expected environmental regulations.

To manage risks and uncertainties with the cost of existing and expected environmental regulations, APS uses a multi-faceted plan, which includes a combination of the following:

- **Obtain information from sources such as federal and state agencies and third-party consulting firms to maintain awareness of proposed changes and to evaluate commercially-viable options for technology:**

  For example, APS has used Black & Veatch, a global engineering consulting firm, to provide an initial evaluation and subsequent updates for commercially-viable technology that may be required for SCR controls installation at the Four Corners Power Plant, as well as to provide cost estimates. As a risk mitigation strategy, APS also conducts market research to mitigate uncertainties when evaluating new and changing technologies to ensure that the most reasonable technologies are selected to balance cost while meeting environmental standards.

- **Serve on environmental control technology committees:**

  EPRI and the Utility Air Regulatory Group are two organizations in which APS participates as members of committees involved with environmental control technologies. Membership in these committees also provides contacts at other utilities who can share their experiences with us.

- **Negotiate solutions with government agencies that balance cost and compliance:**

  APS worked with EPA to develop a solution for controlling NOx and SO2 emissions at the Four Corners Power Plant, which balanced environmental impacts with the cost of compliance (see response to Rule D.17).

- **Review and update cost estimates based on the latest information available:**

  Throughout the process of developing environmental regulations, more rigorous cost estimates are continually produced by APS to reduce cost uncertainty.

- **Defer the cost of additional environmental control technology by pursuing a diverse portfolio of resources that includes energy efficiency, demand response, and renewable energy:**

  As illustrated in the 2014 Resource Plan, APS is managing the risk of environmental regulations by ramping up non-emitting resources, such as energy efficiency, demand response, and renewable generation. This strategy defers the cost of additional environmental control technology by delaying the need to add conventional fossil generation.

- **Analyze portfolio cost risks related to existing and expected environmental regulations:**

  APS includes the Base, Coal Reduction and Coal-to-Gas Conversion Portfolios in order to measure cost impacts of various levels of compliance with MATS and BART. Results from these analyses will help APS evaluate and decide on future emission control investment strategies at Cholla and Navajo facilities.

RULE E.1(E)

Risk Identification: (e) any analysis by the load-serving entity to identify and assess errors, risks, and uncertainties in anticipation of potential new or enhanced environmental regulations.

An analysis of several potential new environmental regulations, which would require capital and O&M expenditures for environmental control equipment was discussed in detail in the response to Rules D.17 and E(d). In addition, an implementation plan was included in response D.17, Figure 33, which identified the potential technology and time frame for design and installation based on the most current information available as of October 2013. As previously discussed, most of these potential regulations are only partially defined at this time, and some may not be finalized for years. Over the 15-year Planning Period, these regulations could be modified further resulting in changes to the technology needed for compliance, which would impact the forecast for compliance costs.

In addition to proposed regulations of which APS is currently aware, there are potential new regulations, such as another round of regional haze rules (a new EPA long-term strategy planning period starts in 2019) and GHG regulations, which may be promulgated during the Planning Period. Compliance costs could increase to an extent that is unknown at this time.

ANALYSIS OF UNCERTAINTY RELATED TO CO2 CAPTURE AND SEQUESTRATION (CCS) REGULATIONS

EPA proposed NSPS for new coal plants and natural gas combustion turbines. The rules for natural gas units are based on high efficiency combined cycle units. Low capacity factor combustion turbines would be exempted. APS anticipates constructing simple cycle natural gas combustion turbines in the near future, but they are expected to have a low capacity factor and thus not be affected by the NSPS. The rules for coal units are based on CO2 capture and sequestration (CCS). APS does not anticipate constructing any coal plants in the near future, so there should be no impact.

EPA is expected to propose GHG standards of performance for existing power plants by June 2014. APS does not know what these regulations will require. The cost of CCS for existing units could be prohibitive.

RULE E.2(E)

Risk Analysis: (e) a description and analysis of available means for managing errors, risks and uncertainties of potential new or enhanced environmental regulations.

Available means for managing the risks and uncertainties with the analysis of new environmental regulations includes the following strategies:

- Obtain information from sources, including federal and state agencies, industry publications, market research, and third-party consulting organizations, to maintain awareness of proposed changes to existing and expected regulations that will impact technology choices and cost;
- Evaluate commercially viable options for technologies that will enable environmental compliance;
- Serve on environmental control committees within industry organizations;
- Negotiate solutions with government agencies that balance cost and environmental impact;
- Update costs of technology needed for compliance as better information becomes available;
- Monitor legislative activities related to CO2 and develop cost sensitivities to evaluate the potential impact;
- Develop additional options, including scenarios containing minimum and maximum technology requirements to evaluate the range of possible outcomes; and
- Incorporate a hypothetical carbon cost into resource planning analytics.

RULE E.3(E)

Risk Mitigation Plan: (e) a plan to manage the errors, risks and uncertainties identified of potential new or enhanced environmental regulations.

APS monitors the regulatory landscape as potential environmental regulations evolve and become more clearly defined. APS reviews and updates cost estimates based on the latest information available and utilizes the services of outside engineering firms as appropriate. APS also comments, both through industry groups and independently, on regulations when they are proposed in order to help influence the final form of the regulation. As previously mentioned, APS has included a hypothetical cost of CO2 described in Chapter 4 of the 2014 Resource Plan. That cost based upon the current California market Cap and Trade prices, because Congress has not yet taken action on this issue. As decision dates for finalized regulations approach, consistently more rigorous cost estimates are produced to mitigate the risk of uncertainty relating to potential new environmental regulations.

APS is also partially insulated from the impacts of these regulations by its focus on advancing renewable energy resources. These zero-emissions sources help diversify the APS portfolio and mitigate the dependency on fossil-fueled generation. In addition, the retirement of Four Corners Units 1-3, coupled with APS's acquisition of SCE's 48% share, helps mitigate against the uncertain costs that would be associated with the installation of additional controls needed on Four Corners Units 1-3 to meet these future regulations.

RULE E.1(F)

Risk Identification: (f) changes in fuel prices and availability.

As discussed in the response to Rule D.16, APS engaged the services of IHS CERA, and Bentek, and Energy and Environmental Economics (as a joint effort with the Western Interstate Energy Board) to analyze future fuel supply and price.

Coal for APS power plants is currently purchased under long-term contracts with fixed prices and inflation-related escalators. Should APS choose to decrease coal deliveries to a level below coal contract terms, APS could be subject to liquidated damages for the amount of the coal that was contracted, but not taken. Risks for coal supply to power plants include rail service interruptions and mine permit extensions.

Uranium is an international commodity that is projected to be sufficient at current rates of extraction to last 100 years at the current rate of extraction. The primary risk for disruption of supply includes contractual performance of suppliers of the unprocessed fuel as well as performance of vendors in the processing of uranium into usable fuel.

Current natural gas supplies in North America are projected to last over 100 years at the current levels of consumption[37]. The primary reliability risk for natural gas supplies would be a disruption in natural gas pipeline transportation between the production basins and APS power plants. A disruption could involve extreme weather events and subsequent well-head freeze-off, pipeline rupture or lack of pipeline compression needed to move fuel through pipelines.

Natural gas prices present the greatest fuel price risk to APS. While natural gas prices have begun to stabilize, recent weather events in the Northeast and Midwest have induced continued volatility and unpredictable behavior. APS natural gas price forecast expectations are shown in Figure 18, Chapter 4.

In order to quantify how natural gas price fluctuation risk would impact the portfolios, APS performs gas price sensitivity analyses. APS evaluates natural gas generation assuming 30% higher and lower natural gas prices in order to evaluate changes in relative position of natural gas units to other technologies. Results of this analysis can be found in *Chapter 4 - Determining the Most Reasonable Plan.*

[37]IHS CERA "Fuel Supply Outlook 2011-2035" December 21, 2011

RULE E.2(F)

Risk Analysis: (f) changes in fuel prices and availability.

The primary means for managing fuel price and supply risk include contracting for longer periods, contracting under fixed price arrangements, utilizing multiple vendors, and engaging in hedging activity. The primary means for managing exposure to any one particular type of fuel is to develop and maintain a diverse portfolio of resources that does not overly depend on any one fuel source.

Coal is typically contracted for under longer-term supply arrangements. Occasionally, utilities may choose to purchase a portion of their coal supply under long-term contract, and then rely upon shorter-term "spot" markets for the remainder of supply. While engaging in the spot market may add flexibility in the amount of coal purchased, the spot market prices are typically more volatile and there are no guarantees that supplies in the spot market will always be available.

Uranium fuel supplies and processing are typically contracted for using multiple vendors for longer terms. Utilizing multiple vendors reduces concentration risk in the event a supplier fails to perform their contractual obligations. Prices for uranium supplies and processing are typically contracted for under fixed prices but may include escalators tied to various indices. While it may theoretically be possible to hedge price risk associated with uranium linked to indices, finding other credit-worthy counterparties may be problematic.

Natural gas supply is typically contracted for under shorter-term fuel supply arrangements. Even though natural gas supplies are typically contracted on a shorter-term basis, prices may be locked in for longer periods of time using forward financial swap instruments or futures contracts that lock in prices for specified delivery periods in the future.

Natural gas transportation is typically contracted for using fixed rates under longer-term arrangements. Additional gas transport capabilities are developed as necessary based on as-needed firm contract requests. The sequence of pipeline infrastructure build-out follows this general sequence:

- Gas customer recognizes a need for additional transport need. An APS example may be due to the construction of a new natural gas generation facility.
- The gas customer makes a decision on whether this new gas capability should be a firm delivery or interruptible based on a variety of factors including economics, reliability requirements, appetite for volatility of prices or delivery. APS contracts for only firm transport based on APS business model and reliability responsibilities.
- The gas customer negotiates with gas transportation supplier(s) for the appropriate services based on each suppliers list of services and customer needs. These services differ based on carrier.
- When a firm transport contract is requested that is beyond the existing natural gas infrastructure capabilities, it triggers an infrastructure build-out study and balance of cost, capability, type, etc. Typical examples include adding additional horsepower to existing compressor stations, adding compressor stations or adding new transport pipeline.
- The lead time and cost of additions is dependent on the stated need (firm contract request), availability of options to satisfy the need, and securing needed regulatory permits or approvals.

Given this general process, and recognizing that APS projected additional firm contract needs begin to require additional capacity in the summer of 2021, APS will begin to start discussions with gas providers in the 2016-2018 timeframe to balance the timing of contract additions and associated costs. APS and the gas pipeline need to allow enough time to enhance the pipeline if necessary, while minimizing over-conservative and early construction costs that would be unnecessary.

RULE E.3(F)

Risk Mitigation Plan: (f) changes in fuel prices and availability.

Coal for APS power plants is currently purchased under long-term contracts with fixed price adjustments. APS benefits from coal suppliers having sources with proven reserves well in excess of what could be burned even beyond the Planning Period. Disruption of coal supply due to rail interruptions is managed by keeping additional inventory of coal on power plant sites. In order to accommodate interruptions in coal supply, APS typically maintains a 45-day reserve of coal at the Cholla plant, a 60-day reserve of coal at the Four Corners plant, and a 30-day reserve at NGS (operated by Salt River Project).

For the Cholla Power Plant, transportation for coal is provided through firm long-term contracts with the Burlington Northern Santa Fe Railway. In the case of the Four Corners Power Plant, coal transportation is not required given the coal mine is located adjacent to Four Corners, thereby mitigating the risk of rail disruptions. Transportation of coal from the Kayenta mine to the Navajo Generating Station is provided by a dedicated rail owned by the co-owners of NGS and operated by the Salt River Project.

APS mitigates the risk of disruption in gas supply due to pipeline interruptions by contracting for natural gas transportation through long-term firm contracts over three separate pipelines – El Paso Natural Gas, TransCanada (North Baja), and Transwestern, to transport 100% of the gas needed to meet the system peak generation demand. An example of this planning can be found in Attachment D.16. In addition, APS benefits from dual pipeline supply capability at the following power plants: Redhawk, Yucca, Gila River (long-term PPA), and Sundance. All other power plants are served by the El Paso pipeline. Individual pipeline risk to those plants is mitigated since El Paso pipeline utilizes a redundant system that consists of multiple pipes. Additional pipes mitigate risk of a single pipe rupture since remaining pipes could continue operating.

In order to manage natural gas price volatility risk, APS employs a three-year hedge plan. The hedging parameters are 85% for year 1, 50 to 60% for year 2, and 30 to 40% for year 3. In hedging fuel supplies and prices, APS utilizes many different creditworthy counterparties to reduce concentration risk of a counterparty failing to perform their contractual obligations.

Uranium is an international commodity that is projected to be sufficient at current rates of extraction to last for 100 years[37]. To mitigate supply as well as price risk, APS hedges uranium fuel supply under long-term contracts and utilizes multiple suppliers. Not only does APS hedge uranium fuel supplies through longer-term contracts, the Company also hedges fuel processing services directly with suppliers. In order to ensure fuel supplies are ready when needed, APS requires fuel suppliers to deliver fuel to Palo Verde 45 to 90 days in advance of an outage to help ensure fuel is ready when needed. This advanced delivery also allows APS time to inspect fuel assemblies prior to loading them into a unit.

Nuclear refueling outages normally avoid the summer months to meet the peak demand for power. Sufficient fuel is maintained on-site to meet the summer peak demand periods.

[37]IHS CERA "Fuel Supply Outlook 2011-2035" December 21, 2011

RULE E.1(G)

Risk Identification: (g) construction costs, capital costs, and operating costs.

The primary construction, capital, and operating cost risks are associated with the engineering, procurement, and construction (EPC) of new generating units. Engineering, procurement, and construction of modifications to generating units also have similar risks but the total costs at risk are typically smaller.

There are many factors that have the potential to negatively impact cost, scope, and schedule of construction projects. These factors include but are not limited to the following:

- Escalating material or labor costs beyond what has been anticipated;
- Force majeure, inclement weather, labor strikes, craft availability, and productivity risks;
- Quality assurance failure of one-of-a-kind engineered equipment or failure to pass customer and factory acceptance tests;
- Major equipment performance failure to operate at minimum guaranteed ratings;
- Material availability issues; and,
- Contractor non-performance.

In addition, if land acquisition is a prerequisite to a construction project, there are potential risks. Acquisition of private land is systematic and is approached with an offer letter, appraisal, and negotiations. Timing is critical to managing risk if condemnation is necessary and a court settlement is required. Generally, a timeframe of 2 years is estimated for land acquisition if condemnation is necessary.

Federal and state lands are secured through leases, or rights-of-way with each agency. Federal lands require a NEPA process that includes archaeological and biological studies for project impacts to threatened and endangered species. The estimated processing timeframe for a typical right-of-way application with Arizona State Land Department requires 24 months. A federal application (such as with the Forest Service or Bureau of Land Management) will typically require 36 months or longer, depending on impacts to species or archaeological sites.

RULE E.2(G)

Risk Analysis: (g) construction costs, capital costs, and operating costs.

Methods for managing risks and uncertainties include requiring liquidated damage provisions in contracts for EPC activities so as to mitigate the risk of various scenarios that may impact cost and schedule. Not all schedule impacts may be mitigated, however, especially if the impact is due to one-of-a-kind specifically engineered and manufactured equipment being damaged beyond repair or lost during shipping. This risk may be mitigated through purchasing of insurance for compensation of loss. It may also be beneficial to include project milestones to document progress and determine contractor performance to those milestones.

To ensure vendors have the capability to perform the scope of work expected, a vendor analysis may be completed prior to contracting for services. Vendor analysis includes an examination of experience and capability to perform, as well as a thorough credit analysis to help determine which vendors have the financial capability to perform. As a result of this review, it may be appropriate to request letters of credit or other performance guarantees to serve as collateral from vendors. If a vendor fails to perform required services, they must forfeit any collateral they have provided.

When it is determined that equipment replacement or modifications are needed, it is important that project processes and controls are in place, well documented, and communicated in order to guide project work, set expectations, and measure progress against project milestones. Project control documents that are well communicated and measured against help serve to mitigate project cost and schedule risk.

In addition to vendor analysis and project control documents, it is also possible to conduct sensitivity analyses on project component costs to determine the overall magnitude of potential cost uncertainty. Sensitivities may be helpful in highlighting those cost components with the greatest potential to impact overall project cost uncertainty.

RULE E.3(G)

Risk Mitigation Plan: (g) construction costs, capital costs, and operating costs.

In the event of a delay in completing individual project tasks or in receiving project components, APS analyzes the overall project schedule to determine if the schedule can be reworked to avoid direct impact on the overall project completion date. Schedules are regularly analyzed for existing or potential problems that would affect the schedule or cost. The frequency of schedule analysis will vary from as often as daily to as infrequently as monthly depending on the type, complexity, and phase of the project. APS uses schedule analysis and progress measurement to identify potential risks as early as possible. Identifying potential delays as early as possible improves the probability that a corrective action or contingency plan will have the desired effect of maintaining originally scheduled completion dates.

EXAMPLES OF SCHEDULE IMPACTS AND ACTIONS TO MITIGATE

- **Construction completion after contract completion date:** This risk is normally mitigated by regular schedule reviews and progress milestone measurement. APS also mitigates this risk by including contract provisions for liquidated damages, whereby vendors must forfeit collateral to APS in the event of missing contractually-agreed-to milestones or completion dates.
- **Contractor productivity less than planned due to factors such as inclement weather, labor strikes, and craft availability:** In many instances, this risk is mitigated by requesting an increase in the number of critical craft personnel on site or the number of shifts being worked to return to the original completion schedule.
- **Equipment delivery delays:** Some negative schedule impacts cannot be totally recovered. Examples are when one-of-a-kind specifically engineered and manufactured equipment is lost or damaged during shipping to the construction site. To mitigate this risk, APS purchases insurance to compensate for a potential loss of this nature.

Impacts from uncertainties in cost are mitigated by the regular review and updating of cost estimates based on the latest industry information available. As the project start date approaches, consistently more rigorous cost estimates are produced to reduce the level of cost uncertainty.

In addition to assessing capital cost risk pertaining to the construction and installation of facilities, as well as land, land rights, structures, and equipment, APS also includes an allowance for funds used during construction in its capital cost estimates.

When it is determined that equipment replacements or modifications at existing power plants are required to improve plant efficiency or reliability, or to comply with new environmental regulations, APS has guidelines which are used to establish consistent, orderly, and efficient inter-discipline and inter-department communication for these projects. The project guidelines establish the level of project control needed to reduce the project risks, which could in turn increase costs or delay project completion.

Very large projects of sufficient size are controlled in a similar fashion; however, these projects may be so large and demanding that a new project organization with a separate dedicated staff will be created for the duration of the project.

Where capital or fuel costs can represent up to 75% of the total delivered cost of power for many technologies, non-fuel operating costs generally represent less than 10% of the delivered cost. Consequently, the sensitivity of power costs to non-fuel operating costs is typically far less than it is to capital or fuel.

RESPONSE TO RULES SECTION F – 2014 IRP

Response to Rules Section F – 2014 IRP

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(F), which specifically requires information related to the selected 15-year resource plan.

RULE E.1(H)

Risk Identification: (h) other factors the load-serving entity wishes to consider.

Several risks, uncertainties and errors have been discussed independently in Rules E(a) through E(g) above. APS has chosen to consider these and other parameters in tandem with each other by creating six scenarios. These scenarios try to capture potential correlation between variables as described in *Chapter 4 - Determining the Most Reasonable Plan*. Assumptions were varied around the following parameters: economic outlook including load growth, inflation rate, and interest rates; capital costs of conventional and renewable generation technologies, environmental costs including potential carbon and emission control costs, federal tax policy, fuel prices, and customer programs.

RULE E.2(H)

Risk Analysis: (h) other factors the load-serving entity wishes to consider.

Four resource portfolios were each evaluated under all six scenarios in order to assess their robustness, or ability to perform under different circumstances. They were evaluated in terms of their fuel diversity, capital expenditure requirements, gas burn, revenue requirements, carbon emissions and water consumption. Please see Chapter 4 for results of the risk analysis.

RULE E.3(H)

Risk Mitigation Plan: (h) other factors the load-serving entity wishes to consider.

The risks inherent in future scenarios may be mitigated by the choosing the appropriate resource portfolio. APS's Base Portfolio Plan performed well in most scenarios, potentially mitigating a wide range of risks. Risks can be further mitigated by altering the resource portfolio in the future as the APS gains clarity around the uncertain variables and gains recognition of which scenario may be becoming reality. For a full discussion about the portfolios, scenarios or risks, APS analysis and results, please refer to Chapter 4.

RULE F.1

Selects a portfolio of resources based upon comprehensive consideration of a wide range of supply- and demand-side options.

In creating the 2014 Resource Plan, APS analyzed six distinct portfolios for consideration composed of a mixture of technologies (as described further in Attachment D.3). APS monitored how each portfolio performed based on certain key metrics, including: natural gas burn; NPV of revenue requirements; cumulative capital expenditures; carbon emissions; water use; and, portfolio diversity. APS then created scenarios and stressed several key input variables on four of the six portfolios, such as natural gas prices, carbon costs, tax credits, inflation rates, load growth, interest rates, technology capital costs and environmental compliance costs, to determine the robustness of each portfolio. The results of the analytics can be found at:

Attachment F.1(a) - Analysis of Six Portfolios (Loads and Resources Tables and Energy Mixes)

Attachment F.1(b) - Analysis of Six Portfolios (Key Metrics)

Attachment F.1(c) - Analysis of Scenarios (Loads and Resources Tables, Energy Mixes, and Key Metrics)

Description of portfolios can be found in Chapter 4, with one exception. The Alternative Portfolio is described in Other Compliance Requirements, Part C.

RULE F.2

Will result in the load-serving entity's reliably serving the demand for electric energy services.

The APS 2014 Resource Plan is designed to provide reliable power to its customers with the required operating reserves while allowing for unforeseen events such as higher-than-forecast customer demand and forced outages of several generators at one time. APS uses an LOLP reliability criterion of one event in ten years to provide the desired level of reliability. While there is not a standard prescribed by the WECC or NERC, a 1-in-10 LOLP is a common standard in the industry. APS has found that designing resource portfolios based on a 15% reserve margin provides better than 1-in-10 LOLP. APS's 2014 Resource Plan maintains a 15% or greater planning reserve margin for each year of the 15-year Planning Period as indicated in response to Rule D.1(b)-B.2(e).

In addition to the reliability discussed above, APS also performs a Reliability Must Run (RMR) study of its Phoenix and Yuma load pockets every two years as part of the ACC's Biennial Transmission Assessment. This study specifically looks at transmission-constrained load pockets, and is done in conjunction with Southwest Area Transmission and other Arizona utilities. The last report, filed in January 2012, indicated that planned transmission along with existing transmission and local generation will be sufficient to provide better than 1-in-10 LOLP for the years studied. Because conditions had not changed appreciably since the 2012 filing, a RMR study was not required for the 2014 filing.

RULE F.3

Will address the adverse environmental impacts of power production.

The APS 2014 Resource Plan includes in its base assumptions a hypothetical cost for carbon emissions implemented in 2021. In addition, and as further described in response to Rule D.17, APS has planned for several power plant emissions upgrades over the next decade to ensure full compliance with any potential new or enhanced environmental regulations. The Resource Plan includes a significant amount of energy efficiency and renewable energy – resources that provide energy to APS with limited adverse environmental impacts. This allows APS to face more than a 50% increase in customer load sales (prior to energy efficiency and distributed energy), while CO2 emission intensity and annual water use intensity decreases 14% and 24%, respectively, over the 15-year Planning Period. Finally, APS has quantified the rates for multiple emissions for the reference plan, as depicted in Attachment D.1(a)(8).

RULE F.4

Will include renewable energy resources so as to meet or exceed the greater of the Annual Renewable Energy Requirement in R14-2-1804 or the following annual percentages of retail kWh sold by the load-serving entity.

As indicated in Table 41, the 2014 Resource Plan exceeds the amount of renewable energy required under the ACC RES for all years during the Planning Period. Note that in addition to the RES requirement, APS is required to achieve 1,700,000 MWh of incremental renewable generation by December 31, 2015, per ACC Decision No. 71448.

TABLE 41 - RENEWABLE GENERATION INCLUDED IN 2014 RESOURCE PLAN (% OF RETAIL SALES)

CALENDAR YEAR	ACC RES REQUIREMENT (PERCENT OF RETAIL SALES DURING CALENDAR YEAR)	RENEWABLE GENERATION IN APS 2014 RESOURCE PLAN
2014	4.5%	11.4%
2015	5.0%	12.0%
2016	6.0%	11.9%
2017	7.0%	11.8%
2018	8.0%	11.7%
2019	9.0%	11.6%
2020	10.0%	12.4%
2021	11.0%	13.2%
2022	12.0%	13.9%
2023	13.0%	15.5%
2024	14.0%	16.2%
2025	15.0%	17.0%
2026	15.0%	16.9%
2027	15.0%	16.5%
2028	15.0%	17.8%
2029	15.0%	17.4%

RULE F.5

Will include distributed generation energy resources so as to meet or exceed the greater of the Distributed Renewable Energy Requirement in R14-2-1805 or the following annual percentages as applied to the load-serving entity's Annual Renewable Energy Requirement:

The Distributed Renewable Energy Requirement in R14-2-1805 and the annual percentages in the Resource Planning Rules are the same. As indicated in Table 43, the distributed energy represented in the 2014 Resource Plan meets or exceeds the requirements in all years of the Planning Period.

TABLE 42 - DISTRIBUTED RENEWABLE ENERGY REQUIREMENTS

CALENDAR YEAR	DISTRIBUTED RENEWABLE ENERGY REQUIREMENTS
2007	5%
2008	10%
2009	15%
2010	20%
2011	25%
After 2011	30%

TABLE 43 - DISTRIBUTED RENEWABLE ENERGY INCLUDED IN 2014 RESOURCE PLAN

CALENDAR YEAR	DISTRIBUTED GENERATION REQUIREMENT (PERCENT OF ANNUAL RENEWABLE REQUIREMENT)	DISTRIBUTED GENERATION IN APS 2014 RESOURCE PLAN (PERCENT OF ANNUAL RENEWABLE REQUIREMENT)
2014	30%	65%
2015	30%	62%
2016	30%	54%
2017	30%	47%
2018	30%	42%
2019	30%	38%
2020	30%	35%
2021	30%	33%
2022	30%	32%
2023	30%	32%
2024	30%	31%
2025	30%	31%
2026	30%	32%
2027	30%	32%
2028	30%	32%
2029	30%	32%

RULE F.6

Will address energy efficiency so as to meet any requirements set in rule by the Commission, or in an order of the Commission.

ACC Decision No. 71819 set forth Energy Efficiency Requirements, which became effective January 1, 2011. As indicated in Table 44, Energy Efficiency represented in the 2014 Resource Plan meets the EE Standard in all years of the Planning Period.

TABLE 44 - CUMULATIVE EE BY CALENDAR YEAR (% OF RETAIL SALES)

APS SYSTEM PEAK DEMAND FORECAST (PROBABILISTIC ANALYSIS)

CALENDAR YEAR	ACC DECISION NO. 71819 EE STANDARD (PERCENTAGE OF RETAIL SALES)	EE INCLUDED IN APS 2014 RESOURCE PLAN
2014	7.25%	7.28%
2015	9.50%	9.50%
2016	12.00%	12.00%
2017	14.50%	14.50%
2018	17.00%	17.00%
2019	19.50%	19.50%
2020	22.00%	22.00%
2021	22.00%	22.00%
2022	22.00%	22.00%
2023	22.00%	22.00%
2024	22.00%	22.00%
2025	22.00%	22.00%
2026	22.00%	22.00%
2027	22.00%	22.00%
2028	22.00%	22.00%
2029	22.00%	22.00%

RULE F.7

Will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors.

As described in response to Rule F.1, APS performed a rigorous series of analytics on all of the potential portfolios under consideration. This effort was driven specifically towards identifying the most robust portfolio that would both provide a low-cost set of resources for customers while simultaneously mitigating potential future risks. The 2014 Resource Plan accomplishes both of these criteria. By maintaining a position in multiple fuel sources, APS has the ability to modify its dispatch of resources depending upon future price conditions. For example, should natural gas prices follow a lower trajectory than currently predicted, APS could increase its natural gas-fired generation to capitalize on this trend; conversely, should natural gas prices rise unexpectedly, APS could mitigate this exposure by increasing output at its more stably-priced coal-fired generation fleet. APS also manages future cost and environmental risks by assuming compliance with the EE Standard and the RES. Finally, APS has significant flexibility in how it meets future load forecast fluctuations by relying on resources that have relatively short development lead times, such as solar PV and natural gas plants, as well as relying upon the 15% reserve margin.

RULE F.8

Will achieve a reasonable long-term total cost, taking into consideration the objectives set forth in subsections (F)(2)-(7) and the uncertainty of future costs.

APS's 2014 Resource Plan, as outlined in Attachment F.9(b), meets the objectives set forth in Rules F.2 thru F.7 of the Resource Planning Rules, and is expected to achieve a reasonable long-term cost as shown in Attachment D.10. This plan is a fuel- and technology-diverse portfolio of resources that meets or exceeds reliability criteria, the EE Standard, the RES, and manages risks through the planning of flexible resource options and limiting exposure to natural gas prices and carbon emissions. As the future unfolds and conditions change, this plan can be easily modified to address changes. It provides a road map for the future, and will guide APS procurement efforts. Those efforts will ultimately result in the specific choices of resources to meet APS customer energy needs in a manner that balances reliability, cost, the environment, and risk.

RULE F.9(A)

Contains all of the following: (a) a complete description and documentation of the plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized.

A complete description and documentation of the plan are contained in the following sections of this report:

- Supply Conditions: All of the elements of APS's existing resource portfolio, including owned generation and purchase power contracts, are described and documented in the responses to Rule D.1. Information related to energy efficiency measures is included in the responses to Rule D.14.
- Demand Conditions: Customer demand conditions are provided and documented in the responses to Rules C.1, C.2, and C.3.
- Availability of Transmission: Transmission necessary to ensure availability for resource delivery is discussed in the responses to Rules D.1(b), D.1(d), D.1(f), D.1(g), and D.10.
- Costs: Costs of individual supply-side resource technologies are contained in the response to Rules D.1 and D.3, while costs of individual demand side management measures are contained in the response to Rule D.14. Costs and system revenue requirements associated with the 2014 Resource Plan are contained in Attachment D.10.
- Discount Rate: APS uses 7.20%, the Company's after-tax weighted cost of capital, as its discount rate.

RULE F.9(B)

Contains all of the following: (b) a comprehensive, self-explanatory load and resources table summarizing the plan.

The loads and resources table is provided at Attachment F.9(b).

RULE F.9(C)

Contains all of the following: (c) a brief executive summary.

The Executive Summary is included at the beginning of this document.

RULE F.9(D)

Contains all of the following: (d) an index to indicate where the responses to each filing requirement of these rules can be found.

APS has included a high-level Table of Contents for this document and its related Attachments and Appendices, as well as a detailed Index at the end of this document.

RULE F.9(E)

Contains all of the following: (e) definitions of the terms used in the plan.

The definitions of the terms used in the filing are contained in the Glossary included herein.

RESPONSE TO RULES SECTION H – 2014-2018 ACTION PLAN

Response to Rules Section H – Action Plan

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(H), which specifically requires information related to the action plan for the following three-year period.

RULES H.1-H.3

Includes a summary of actions to be taken on future resource acquisitions; Includes details on resource types, resources capacity, and resource timing; Covers the three-year period following the Commission's acknowledgement of the resource plan.

This response is included in Chapter 5.

RESPONSE TO RULES SECTION I – OTHER FACTORS

Response to Rules Section I – Other Factors

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(I), which allows the utility to provide additional information related to environmental impacts for the Commission's considerations.

RULE I

A load-serving entity or any interested parties may also provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be developed and reviewed by the Commission in other proceedings or stakeholder workshops.

APS has included data related to environmental impacts of its 2014 Resource Plan in multiple locations within this document. Environmental issues are discussed in Chapters 3 and 4. Water usage (expressed in annual Acre-Feet) has been included in all of APS's analytics discussed in Chapter 4. Environmental plans are discussed at length in response to Rules D.17, E.1(d)-E.3(d), and E.1(e)-E.3(e). A table of emissions for each generator is found at Attachment D.1(a)(8). Attachments F.1(b) and F.1(c) contain the backup information for all of the model runs performed in support of this resource plan.

APS also created a scenario that modeled environmental restrictions and associated costs that go well beyond today's expectations. The Increased Environmental Scenario and impact on portfolio analysis is described in Chapter 4. It includes "high" carbon costs plus additional environmental control related costs assumed to be required for continued operation of coal generation.

RESPONSE TO RULES – OTHER COMPLIANCE REQUIREMENTS

Response to Rules - Other Compliance Requirements

The ACC included compliance requirements in APS's 2012 IRP Decision and Four Corners Transaction Decision, Dockets Numbered E-00000A-11-0113 Decision No. 73884 and E-01345A-10-0474 Decision No. 73130, respectively. APS Responses are addressed in the following.

APS'S 2012 IRP DECISION[38]

It is further ordered that Arizona Public Service Company, shall address the issues identified in the 2012 Integrated Resource Planning Assessment and incorporate the appropriate responses in the 2014 Integrated Resource Plans:

A. APS, TEP AND UNSE

I. **Conversion of Coal Plants to Natural Gas**
APS included the Coal-to-Gas Conversion Portfolio in its portfolio analysis. Results of this analysis can be found in Chapter 4 and Attachments F.1(a)-(c).

II. **Consideration of Jointly Developed Generation**
APS appreciates the cost savings potential attributed to jointly owned generation facilities and is a joint participant of its nuclear and coal assets. Going forward, new generation assets will likely require operational flexibility that is not inherent in coal and nuclear facilities where joint ownership constructs and sizeable (often upwards of 1,000 MW per plant) projects prevail. Should APS reconsider the addition of a low-flexible sizeable resource, the Company will examine joint ownership opportunities at that time. That said, APS participates in several regional planning efforts, discussed in Chapter 3, that seek to optimize resource usage and ultimately decrease operating costs for utility customers.

III. **Reliance on Future Short-Term Market Purchases**
The Portfolios, which can be found in Chapter 4 and Attachments F.1(a)-(c) include demand-side management programs, supply-side resources, short-term purchases inside the five-year window only, and long-term purchased power in the future resource mixes.

IV. **Failure to Consider All Resource Options**
See Chapter 2 and Attachment D.3 for a discussion of resource options that were considered in the 2014 IRP.

B. APS

I. **Manual Selection of Resources**
This process has been addressed by employing the use of Ventyx's resource expansion plan optimizing software, PROVIEW. See Chapter 4 for additional discussion.

II. **No Load Growth Sensitivity**
Load growth was evaluated through the use of scenario planning. Specific information on Load Growth Forecasting can be found in Chapter 2 and response to Rules C.1-C.3. Load growth scenarios are discussed in Chapter 4.

C. ALTERNATIVE PORTFOLIO

Decision No. 73884 also states:
"Each load-serving entity with possible extra capacity resulting in a reserve margin beyond 20% over a period of two years shall include an alternative scenario in which any incremental additions of capacity, mandated or not, that contribute to the possible extra capacity are delayed until such additions do not contribute to the possible extra capacity. Each load-serving entity's IRP shall also include a comparison of all projected costs under this alternative scenario relative to the load-serving entity's other resource scenarios in the plan, including a comparison of projected revenue requirements."

Due to commitments made prior to the recession, APS 2014 Resource Plan reserve margins are above 20% for 2014 – 2016. In order to comply with the above order, an alternative resource plan was developed which removed uncommitted energy efficiency and distributed generation completely in 2014 and 2015, and enough in 2016 to get the reserve margin under 20%. In 2017 and beyond, the energy efficiency and distributed generation is restored to the levels included in the 2014 Resource Plan. The Alternative Resource Plan may be found at Attachment F.1(a), and the revenue requirements at Attachment F.1(b). Under the Alternative Resource Plan scenario, APS would not meet compliance with the current EE Standard in 2014-2016.

[38]Docket Number E-00000A-11-0113 Decision No. 73884 (May 8, 2013)

Four Corners Transaction Decision[39]

ADDITIONAL RETIREMENTS OF COAL-FIRED POWER PLANTS

"It is further ordered that Arizona Public Service Company shall undertake a systematic review of options for managing its resource risks and include additional retirements of coal-fired power plants as options in future resource plans."

As part of the 2014 IRP, APS evaluated retiring the Cholla Coal Power Plant. Results of this analysis can be found in Chapter 4 and Attachments F.1(a)-(c).

REPLACEMENT OF COAL-FIRED POWER PLANTS WITH RENEWABLE ENERGY

"It is further ordered that if Arizona Public Service Company acquires Southern California Edison's interest in Four Comers Units 4 and 5, Arizona Public Service Company shall undertake a comprehensive planning process to evaluate the retirement of additional coal-fired power plants (in addition to Four Comers Units 1, 2 and 3) within the next ten years and include these coal-fired plant retirement options in its resource plans, beginning no later than its 2014 resource plan filing. These options shall include portfolios of clean renewable energy, to replace the retired coal-fired energy and capacity."

As part of the 2014 IRP, APS evaluated retiring the Cholla Coal Power Plant and used the Resource Optimizer Model to choose resources to replace Cholla, including renewable energy. Results of this analysis can be found in Chapter 4 and Attachments F.1(a)-(c).

EVALUATE SOLAR-COAL HYBRID

"It is further ordered that if Arizona Public Service Company acquires Southern California Edison's interest in Four Comers Units 4 and 5, Arizona Public Service Company shall evaluate a solar-coal hybrid at Four Comers Units 4 and 5 or other coal fired power plant. The evaluation shall conclude within one year of the Commission's Decision in this docket and Arizona Public Service Company shall propose to the Commission in its 2014 resource plan filing how Arizona Public Service Company plans to proceed with a coal-solar hybrid facility."

[39]Docket E-01345A-10-0474 Decision No. 73130 (April 24, 2012)

SUMMARY OVERVIEW

Several references were used to determine the viability of adaptation of solar augmentation to a coal facility. These include a detailed study performed for solar augmentation to an APS combined cycle[40] (Redhawk) and research and various studies performed by the Electric Power Research Institute on behalf of the industry.[41,42,43] In all the cases studied, the cost for these projects was significant. Thus, independent of all other factors discussed below, the capital investment needed to achieve even small savings in fuel is significant and were not deemed cost-effective.

TECHNOLOGY

There are three CSP technologies which could be integrated into a coal plant. These methods are described in the APS-CH2M Hill report (see footnote 53). These are the parabolic trough, the linear Fresnel, and the power tower. Of the three technologies identified, the parabolic trough is generally the technology that has been considered more viable than the others although not exclusively. Mainly this is because the parabolic trough has the greater operating experience in the industry with fairly consistent results. The next method which has operating experience and lower cost is the compact linear Fresnel reflector (CLFR) and was adapted into a coal fired system in Australia; however, the currently tested designs produce a lower energy than the parabolic trough. Advances in the design could alter the performance capability but as yet are not tested. The power tower has the least amount of experience commercially but does show promise in that it may be able to provide higher temperature input to the system. The capital cost for installation is higher than the other technologies but could result in better steam conditions for better efficiency results. The largest power tower in operation to date is 20 MW-energy but is a direct conversion facility (does not provide augmentation), but larger scale power towers are under construction. This minimal performance data leads to higher risk and, therefore, lower financing capability. Therefore, the technology used in all the reference studies was the parabolic trough.

CAPITAL COST

In all the studies referenced the capital cost for the construction of a parabolic trough ranged between 3000 $/kW to 4200 $/kW. The higher costs generally reflected more complicated site preparation issues. The Escalante (Prewitt, New Mexico) study indicates a capital cost closer to a value reached in the APS-CH2M Hill study which was about 3400 $/kW and more closely approximates the solar resource for the Four Corners Power Plant 100 miles to the northwest.[44] More specifically, the Escalante design evaluated was for a solar field of 96 MW thermal peak or an equivalent 36 MW electric peak with a capital cost of $107.9 million. The Solar to Electric efficiency (MWh/DNI) achieved by the design was 18.8%.

A 30 year payback period was used for the Escalante project. As a co-operative, the owner is tax-exempt and benefits from lower interest rate loans though they are not eligible for any tax incentives. Even with these advantages, however, the project provided insufficient operating cash flow to payback the capital cost. In every other case study performed, using owners capable of utilizing tax incentives, the result was the same; that is, the projects provided insufficient operating cash flow to payback the capital cost.

[40] "Redhawk Power Station Concentrated Solar Power Augmentation Study." CH2MHill for APS, September 2011.

[41] "Solar Augmented Steam Cycles for Coal Plants: Conceptual Design Study." EPRI, Palo Alto, CA: 2010. 1018648

[42] "Solar Augmented Steam Cycles for Coal Plants: Development Guideline Manual for Mayo Electric Generating Plant." EPRI, Palo Alto, CA, American Electric Power, Columbus, OH, Progress Energy, Raleigh, NC, Southern Company, Birmingham, AL, and Tri-State Generation & Transmission Association, Westminster, CO: 2009. 1018649

[43] "Solar Augmented Steam Cycles for Coal Plants: Development Guideline Manual for Escalante Generating Station." EPRI, Palo Alto, CA, American Electric Power, Columbus, OH, Progress Energy, Raleigh, NC, Southern Company, Birmingham, AL, and Tri-State Generation & Transmission Association, Westminster, CO: 2009. 1018650

[44] "Concentrating Solar Power Prospects of New Mexico." http://www.nrel.gov/csp/images/3pct_csp_nm.jpg, NREL, 2007.

OPERATING COSTS AND CONSIDERATIONS

Operating the solar augmentation facility requires addition of staff and operating knowledge which must be incorporated into the operating and maintenance practices. In the referenced material the additional costs were $700,000 for 29.5 MW-thermal to as much as $1.72 mm for 69 MW-thermal. These are somewhat higher than the Redhawk study at about $800,000 for about 120 Mwt, but these higher costs also include the increased amounts of water and cleaning man-hours necessary when the mirrors are located next to a coal plant.

Water must be available and be used for mirror cleaning on a CSP no matter what the application. It is recommended from years of operation at the SEGS plant in California that reflectivity of the mirrors be maintained greater than 90%.[45] The Redhawk study indicated that almost 3,000,000 gallons of de-mineralized water per year would be needed; however, this is when the facility is adjacent to a combined cycle. A coal fired facility will require much more water as frequency of cleanings increases from the coal dust and flyash and amount required for the same area will increase to assure thorough removal. Coal dust and flyash when wetted can form a high acidic residue that can pit and damage the mirrors. A high volume method (power wash) uses about 50 gallons of water per solar collection assembly (SCA) per wash but uses less man-hours whereas the low volume method uses about 25 gallons of water per SCA per wash but is much more man power intensive with opportunity for breakage of the SCA.

Any modification to the steam cycle will require a full analysis of the cycle mass flows and thermodynamic characteristic changes. Addition of the piping necessary to add the solar developed energy is very invasive and, for the higher energy addition points, would need to tie into ASME code boundaries. Some designs may require a change in design to the steam turbine or cycle components (feedwater heaters, pumps, etc.) to accommodate higher flows even if the boiler firing is modified to reduce coal usage. This can add to the cost and to the complication of operation. All steam cycle control systems will need to be changed, and the boiler response to changes in energy addition from the solar field variability must be compatible. While both Cholla and Four Corners controls have been modified to a newer control system, additional modifications would be required.

The National Renewable Energy Lab study on solar augmentation for fossil fueled plants, facilities older than 30 years old were not considered due to the probable need to upgrade emissions control systems for continued operation.[46] The expenses of this plus added expense for solar augmentation modifications would likely jeopardize needed long term operation of the plant necessary for any payback to the project.

FOUR CORNERS SPECIFIC CONSIDERATIONS

The Four Corners 4 & 5 units were built in 1969 and 1970, respectively. The units and common facilities are jointly owned with APS. Any modifications or additions to the units and facilities would need to be approved by the Operating Committee. If benefits and costs were to be shared among the owners, as is currently the practice, these would also likely need approval from the PUCs of each owner. Another consideration is that the Four Corners facility occupies leased property from the Navajo and has insufficient space available to build a CSP augmentation facility of a size that would provide any significant quantity of energy. This means that additional properties would need to be negotiated and leased from the Navajo. These lease costs, along with additional Navajo Nation taxes, are not known. Any property leased will be at some distance from the plant proper resulting in added heat losses through the extended piping distances thereby lowering efficiency/ energy gained.

One of the strongest considerations is that the Four Corners 4 & 5 units are supercritical boiler technology. No CSP is designed or under consideration today that will be able to be compatible with the high pressure, supercritical steam conditions and only the power tower technology would potentially be able to meet intermediate pressure steam conditions. As was discussed, power tower technology is still untested at utility scale and is the more expensive option. This means that all energy would need to be added at the lower energy points in the system which reduces the efficiency gains in the cycle. The power tower also requires more land for the same energy.

[45]"Final Report on the Operation and Maintenance Improvement for Concentrating Solar Power Plant." KJC Operating Company, SAND99-1290 (1991).

[46]Solar-Augmented Potential of US Fossil-Fired Power Plants, Table 1: Ranking Criteria." NREL / TP-5500-50597, Feb 2011.

CHOLLA SPECIFIC CONSIDERATIONS

Cholla 1,2, and 3 are owned by APS, but Cholla 3, built in 1980 and the newest, is used as the model for this discussion. Since it is APS solely owned, any changes to unit 3 would not require other owners to approve of them. However, any increase in usage of shared facilities would need consideration from the owner of Cholla 4 with APS responsible for any of the costs associated with their usage. This would be items like water processing, land usage, electrical usage, and so forth. There is limited land available (west and east) although much of this land is under consideration for future usage. This would limit how much energy could be produced by CSP Augmentation. More land is available to properties south but have complications for use. First, these lands are bordered by other owners requiring easement rights through the properties. Additionally, these lands are two to three miles away from the facility resulting in piping lengths as much as three to four miles (not a direct line) with resultant heat losses. Also, the piping would need to cross the Little Colorado River and flood plain which can be an environmental challenge.

Cholla Unit 3 is a subcritical boiler technology. Again, it is probable that the solar power tower could meet these steam temperatures for the highest energy gains but would have challenges in use for the reasons previously discussed. The other technologies would provide energy at either the intermediate or lower energy states for moderate to low energy efficiency gains in the cycle.

In fact, the Cholla 3 steam cycle is close to the conditions of a combined cycle or similar to the Redhawk cycle conditions. All the options evaluated in the Redhawk study were not cost effective.

CONCLUSION

For the reasons discussed above, the investment in a solar augmentation facility would not be cost effective.

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ACRONYMS & GLOSSARY

Table of Acronyms

AAC	Arizona Administrative Code
ACC	Arizona Corporation Commission
ACI	Activated Carbon Injection
ADEQ	Arizona Department of Environmental Quality
ADMS	Advanced Distribution Management System
ADWR	Arizona Department of Water Resources
AFUDC	Allowance for Funds Used During Construction
AMA	Active Management Area
AMI	Advanced Metering Infrastructure
APP	Aquifer Protection Permit
APS	Arizona Public Service
ARS	Arizona Revised Statutes
AZNMNV	Arizona-New Mexico-Nevada
BART	Best Available Retrofit Technology
BCF	Billion Cubic Feet
BNCC	BHP Navajo Coal Company
BTA	Biennial Transmission Assessment
Btu	British Thermal Unit
CAA	Clean Air Act
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CC	Combined Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture & Sequestration
CDA	Conditional Demand Analysis
CEMS	Continuous Emissions Monitoring Systems
CFI	Communicating Fault Indicators
CFL	Compact Fluorescent Lamp
CLFR	Compact Linear Fresnel Reflector
CO	Carbon Monoxide
CO2	Carbon Dioxide
Commission	Arizona Corporation Commission
Company	Arizona Public Service
CP	Coincident Peak
CPP-RES	Critical Peak Pricing for Residential Customers
CSP	Concentrating Solar Power
CT	Combustion Turbine
CWA	Clean Water Act
CWIS	Cooling Water Intake Structures
DA	Distribution Automation
DAM	Distribution Asset Monitoring
DE	Distributed Energy
DLN	Dry Low NOx
DMS	Distribution Management System
DOE	U.S. Department of Energy
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSM	Demand Side Management
EA	Environmental Assessment

EE	Energy Efficiency
EHV	Extra High Voltage
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIS	Environmental Impact Statement
ELG	Effluent Limitations Guidelines
EMS	Energy Management System
EPA	Environmental Protection Agency
EPC	Engineer-Procure-Construct
EPRI	Electric Power Research Institute
ET-1	Time Advantage (9 am - 9 pm)
ET-2	Time Advantage (Noon - 7 pm)
ET-EV	Experimental Electric Vehicle Charging Rate Schedule
ET-SP	Time Advantage Super Peak
EV	Electric Vehicle
FC	Four Corners Power Plant
FERC	Federal Energy Regulatory Commission
FM	Fire Mitigation
GHG	Greenhouse Gas
GUAC	Groundwater Users Advisory Council
GWh	Gigawatt-Hours
HAP	Hazardous Air Pollutant
HEI	Home Energy Information
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
IRP	Integrated Resource Plan
IRR	Interruptible Rate Rider
ITC	Investment Tax Credit
IVVC	Integrated Volt/VAR Control
KAF	Thousand Acre Feet
kW	Kilowatt
kWh	Kilowatt-Hour
LAER	Lowest Achievable Emission Rate
LOLP	Loss of Load Probability
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MCAQD	Maricopa County Air Quality Department
MER	Measurement and Evaluation Research
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-Hour
NAAQS	National Ambient Air Quality Standards
NAS	National Academies of Science
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation

NGS	Navajo Generating Station
NNSR	Nonattainment New Source Review
NOx	Nitrogen Oxide
NP	Network Protector
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NSPR	New Source Performance Review
NSPS	New Source Performance Standards
NSR	New Source Review
NTEC	Navajo Transitional Energy Company, LLC
NTTR	Northern Tier Transmission Group
NWPP MC	Northwest Power Pool Market Assessment Committee
O&M	Operation & Maintenance
OATT	Open Access Transmission Tariff
OMS	Outage Management System
PHEV	Plug-in Hybrid Electric Vehicle
PM	Particulate Matter
PMUS	Phasor Measurement Units
PPA	Purchased Power Agreement
PPH	People Per Household
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PTR	Peak Time Rebate
PV	Photovoltaic
PVNGS	Palo Verde Nuclear Generating Station
RCRA	Resource Conservation & Recovery Act
RES	Renewable Energy Standard
RFP	Request for Proposal
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SEER	Seasonal Energy Efficiency Ratio
SCA	Solar Collection Assembly
SCE	Southern California Edison Company
SCR	Selective Catalytic Reduction
SCT	Societal Cost Test
SHM	Substation Health Monitoring
SIP	State Implementation Plan
SO2	Sulfur Dioxide
SRP	Salt River Project Agricultural Improvement and Power District
SRSG	Southwest Reserve Sharing Group
SVERI	Southwest Variable Energy Resource Initiative
SWAT	Southwest Area Transmission
TES	Thermal Energy Storage
TRC	Total Resource Cost Test
TOU	Time of Use
VAR	Volt-Ampere Reactive
VOC	Volatile Organic Compounds
WECC	Western Electricity Coordinating Council

Glossary

2014 Resource Plan (or 2014 Integrated Resource Plan or IRP)	Represents the documented process APS undertakes to select an energy resource portfolio for the 2014-2029 period based upon a wide range of supply- and demand-side options.
Acre-Foot	The volume of water that will cover an area of 1 acre to a depth of 1 foot. 1.0 acre foot equals approximately 325,851 gallons.
Action Plan	Material actions anticipated to occur during the Action Plan Period.
Action Plan Period	For the purposes of this filing, the timeframe of 2014-2018.
Activated Carbon Injection System (ACI)	An engineered mercury control system from which powdered activated carbon (PAC) is pneumatically injected from a storage silo into the flue gas ductwork of a coal-fired power plant or industrial boiler. The PAC adsorbs the vaporized mercury from the flue gas and is then collected with the fly ash in the facility's particulate collection device.
Alternative Portfolio	Portfolio that reduces the reserve margin below 20% during the 2014-2016 timeframe. This portfolio does not meet the ACC requirements for acknowledgement, i.e., meeting the EE Standard.
Aquifer Protection Permit Program in Arizona	An ADEQ program designed to protect the quality of Arizona drinking water. Includes two key requirements: (1) meet Aquifer Water Quality Standards at the Point of Compliance; and (2) demonstrate Best Available Demonstrated Control Technology.
Arizona Administrative Code (AAC)	The official compilation of rules that govern the state of Arizona's agencies, boards, and commissions.
Arizona Corporation Commission (ACC or Commission)	The Arizona Corporation Commission is comprised of five publically-elected persons who have full power to make reasonable rules, regulations and orders by which public service corporations shall be governed in doing business within the state of Arizona.
Arizona Department of Environmental Quality (ADEQ)	Administers a variety of programs to improve the health and welfare of citizens and ensure the quality of Arizona's air, land, and water resources meet healthful, regulatory standards.
Baghouse	An air pollution abatement device that traps particulates (dust) by forcing gas streams through large filter bags, usually made of fiberglass or other synthetic fabrics and coatings.

Base Portfolio	Portfolio of resources assuming Ocotillo modernization, continued coal operations and compliance with ACC RE and EE Standards. Differs from Selected Portfolio in years 2017-2018 only.
Baseload Plant	An electric generating plant devoted to the production of electricity on a relatively continuous basis. Baseload plants are typically operated for the majority of the hours during a given year and are taken off-line relatively infrequently. Baseload plants usually have a low variable production cost relative to other production facilities available to the system.
Best Available Retrofit Technology (BART)	Under the Clean Air Act, states must require the installation of the best retrofit emission controls available as part of state strategies for meeting the regional haze rule. The BART requirement applies to facilities built between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollution.
Biogas	Otherwise known as biomass gas, a medium Btu gas containing methane and carbon dioxide, resulting from the action of microorganisms on organic materials such as a landfill.
Biomass	Organic non-fossil material of biological origin constituting a renewable energy source that can be either processed into synthetic fuels or burned directly to produce steam or electricity.
British Thermal Unit (Btu)	Used to describe the heat content of fuel. The price of fuel is typically expressed in terms of dollars per million Btu (or $/MMBtu).
Cap-and-Trade	An approach used to control emissions by providing economic incentives for achieving reductions. A central authority (usually a government or international body) sets a limit or cap on the amount that can be emitted. Companies or other groups are issued emission permits and are required to hold an equivalent number of allowances (or credits) which represent the right to emit a specific amount. The total amount of allowances cannot exceed the cap, limiting total emissions to that level. Companies that need to increase their emissions must buy allowances from those that emit less. The transfer of allowances is referred to as a trade. In effect, the buyer is paying a charge for emitting, while the seller is being rewarded for having reduced emissions by more than was needed.
Capacity	The maximum amount of electricity a generation source can produce in any given moment. Capacity is usually measured in units of megawatts. It should be noted that most generation sources are not operated at their maximum capacity rating during all hours that they are generating electricity. *See Capacity Factor*

Capacity Factor	A value used to express the average production level of a generating unit over a given period of time. Capacity factor is expressed as a percentage of the maximum possible production if the generating unit had operated at its maximum capacity rating for all hours during the period. For example, a generating facility which operates at an average of 60% of its maximum capacity over a measured period has a capacity factor of 60% for that period.
Capacity Value	A resource's ability to reliably serve load during APS's top 90 load duration hours. Capacity value is calculated by dividing the average net capacity of the resource during APS's top 90 load hours by the resource's maximum hourly capacity.
Carbon Capture & Sequestration (CCS)	A technology under development to limit emissions of carbon by capturing and storing it away from the atmosphere.
Carbon Dioxide (CO_2)	A naturally occurring gas, and also a by-product of burning fossil fuels and biomass, as well as land-use changes and other industrial processes. It is the principal greenhouse gas that affects the Earth's radiative balance. See Greenhouse Gas, Emissions
Carbon Monoxide (CO)	A colorless, odorless, toxic gas produced by the incomplete combustion of carbon-containing substances. One of the major air pollutants, it is emitted in large quantities by exhaust of gasoline-powered vehicles.
Carrying Charges (or Carrying Costs)	Annual costs associated with investment in assets including depreciation, debt interest, equity return, income taxes, and property taxes.
Class-Based Hourly Load Models	Methods for identifying the hourly pattern of electricity demand for groups of customers with similar characteristics.
Cholla Generating Station	1,027 MW Coal Generating Facility located in northeastern Arizona. APS operates the plant and owns Units 1, 2 and 3, which are capable of producing 647 MW of electricity. PacifiCorp owns the 380 MW Unit 4
Clean Air Act (CAA)	The primary federal law enacted by the U.S. Congress to govern the regulation of emissions into the atmosphere on a national level. The primary responsibility for administering the CAA was given to EPA which develops and enforces regulations to protect the general public from exposure to airborne contaminants.
Coal Combustion Residual (CCR)	Referred to as coal ash, CCRs are currently considered exempt wastes under the Beville amendment to the Resource Conservation and Recovery Act (RCRA). They are residues from the combustion of coal in power plants and captured by pollution control technologies, such as scrubbers.

Coal Reduction Portfolio	Shows the impact of retiring Cholla Generating Station and replacing it with a combination of renewables and gas generation during the planning period.
Coal-to-gas Conversion Portfolio	Shows the impact of converting Cholla Generating Station to gas operations during the planning period.
Combined Cycle (CC)	Twin-stage natural gas-fired power plants that deliver higher fuel efficiency. In the first stage, a gaseous fuel source (natural gas, gaseous coal, etc.) is combusted in a gas turbine. The turbine is used to drive an electric generator. In the second stage, waste heat is captured from the gas turbine's hot exhaust gases in a heat recovery steam generator (HRSG). The steam that is produced in the HRSG is used to drive a steam turbine and produce additional electricity. This beneficial use of the residual heat content in the gas turbine's exhaust stream contributes to the excellent fuel efficiency of the combined cycle power plant.
Combustion Turbines (CT)	Also referred to as a simple cycle gas turbine, these electric generators operate on a principle similar to the engines on jet airplanes. Ambient air is compressed to high pressures in the compressor section of the machine. A gaseous fuel source is added to this compressed air and combusted in the combustor section. The resulting hot gases are then expanded through a turbine section that provides the driving force for both an electric generator and the compressor section.
Commercial Operation Date (COD)	The date when an operating utility formally declares a new generation resource to be available for the regular production of electricity.
Commodity Hedging Strategies	*See Hedging*
Compact Fluorescent Lamp (CFL)	A type of fluorescent lamp. Compared to incandescent lamps giving the same amount of visible light, CFLs use less power and have a longer rated life.
Competitive Procurement Procedure	Any solicitation process initiated to meet APS energy requirements. The Competitive Procurement Process shall include, as appropriate, preparing and conducting the solicitation, bid evaluation and selection, and negotiating the definitive agreement(s), but shall not include management or implementation of such agreement(s) after their execution.
Concentrated Solar Power	Technologies that concentrate solar energy to generate electricity. This class of solar technologies includes solar trough, power towers, dish stirling, and concentrating photovoltaics.

Conditional Demand Analysis (CDA)	Statistical approach that allocates total household electricity demand during a period into components associated with a particular electricity-using appliance or end-use.
Consumption (Energy Use)	The total amount of electricity consumed over a period of time. Consumption varies from demand in that demand is the rate at which electricity is being used at any one given time.
Conventional Resources	Conventional generating resources include a broad class of technologies that use coal, nuclear, natural gas, or fuel oil to generate electricity.
Cooling Degree-day	A measure of how warm a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the base temperature (65 degrees) from the average of the day's high and low temperatures, with negative values set equal to zero. Each day's cooling degree-days are summed to create a cooling degree-day measure for a specified reference period. Cooling degree-days are used in energy analysis as an indicator of air conditioning energy requirements or use.
Critical Peak Pricing (CPP)	Time-of-use rate plan (also known as Peak Event Pricing) that provides an extremely high price signal during a limited number of hours on critical days (such as periods of high electrical demands, extreme temperatures, system outages, or other abnormal grid-related events).
Customer Average Interruption Duration Index (CAIDI)	The average outage duration for those customers experiencing an outage.
Customer Resources (or customer-sited resources)	Resource options which rely upon active participation by customers to produce either a reduction in energy consumption or peak demand. These customer-side resource programs include energy efficiency programs, demand response programs, and alternative rate schedules. Energy efficiency programs are directed at achieving reductions in customer energy consumption through more efficient equipment or improvements to a building's thermal envelope. Demand response programs generally target reductions during the highest usage periods of the year through special rate schedules (such as time-of-use prices), energy storage options, or other similar programs.
Day-Ahead Trader	Trader that engages in forward markets that cover a 24-hour period in advance of a given day.
Delivered Cost	Refers to the cost of power produced by a generating unit (or a purchased power contract) where the cost of delivering the electric power from the generating source to the load center (area of customer consumption) has also been included in the cost.

Demand	The rate at which electricity is being used at any given time. Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time.
Demand Response (DR)	Mechanisms designed to provide incentives to customers to reduce their load in response to high electric market prices or electric system reliability concerns. Demand response measures could include direct load control programs, such as cycling of air conditioner load, or customer-initiated load reductions. Price response programs include real-time pricing, dynamic pricing, critical peak pricing, time-of-use rates, and demand bidding or buyback programs.
Demand-Side Management (DSM)	The planning, implementation, and monitoring of utility activities designed to encourage residential and business customers to modify patterns of electricity usage, including the timing and level of electricity demand.
Discount Rate	An interest rate used to convert future cash flows to present values.
Dispatchable	Generating units (or purchased power contracts) whose rate of power production can be adjusted or varied based upon economic or other considerations. Different types of generating units have varying degrees of dispatchability either for technical or economic reasons.
Distributed Energy	A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid or the customer's electrical system. Distributed generation can serve as a primary or backup energy source and can use various technologies, including combustion turbines, reciprocating engines, fuel cells, wind generators, and solar photovoltaics.
Distribution	The delivery of energy to retail customers.
Dry Cooling	The typical steam power plant requires cooling water to improve overall cycle efficiency by returning the exhaust steam to a liquid state that can then be returned to the boiler to produce more steam. In a dry-cooled power plant, the exhaust steam is cooled by use of air-cooled condensers thereby eliminating the use of water from this portion of the power production process; however, the air-cooled condensers are more expensive and overall plant efficiency is reduced versus water-cooled plants.
DSM Implementation Plan	Annual filing required for compliance with the Arizona Corporation Commission's Electric Energy Efficiency Standards, codified at A.A.C. RI4-2-2401, which includes the implementation strategy APS will use to achieve compliance with the EE Standard.

Effluent	Wastewater, treated or untreated, that flows out of a treatment plant, sewer, or industrial outfall. Generally refers to wastes discharged into surface waters.
Electric Generating Units (EGU)	A solid fuel-fired steam generating unit that serves a generator who produces electricity for sale to the electric grid.
Emissions	Discharges into the atmosphere from stacks, other vents, and surface areas of commercial and industrial facilities; from residential chimneys; and from motor vehicle, locomotive, or aircraft exhaust.
Energy	The amount of electricity a generation resource produces, or an end user consumes, in any given period of time. It is usually measured in units of kilowatt-hours, megawatt-hours, or gigawatt-hours.
Energy Efficiency	In the context of resource planning, energy efficiency refers to actions taken by consumers to reduce their overall consumption of electric energy. These reductions could be the result of installation of more efficient equipment, improvements to the thermal envelopes of structures, or behavioral changes. Energy efficiency improvements can be encouraged through utility-sponsored programs, mandated by building codes or other standards or simply implemented by the customer.
Energy Efficiency Standard (EE Standard)	Requirement codified in A.A.C. R14-2-2404 to achieve an accumulated energy savings equivalent to 22% of retail sales by the year 2020.
Energy Savings	A reduction in the amount of electricity used by end users as a result of participation in energy efficiency programs and load management programs.
Enhanced Renewable Portfolio	Portfolio that shows the impacts of increasing the contribution of renewable energy to 25% of retail sales by 2025. This portfolio envisions that 74% of future energy growth is met by emissions-free resources.
Environmental Protection Agency	A governmental agency established in 1970 to research, monitor, establish standards, and enforce activities to establish a cleaner, healthier environment.
Externalities	Occurs when an entity is engaged in an activity that creates harm or benefits for others as a byproduct, but that entity does not pay the costs of, or receive compensation for, the harm or benefits created. An example would be water use and water consumption.
Federal Energy Regulatory Commission	A governmental agency that regulates the interstate transmission of natural gas, oil, and electricity and wholesale power transactions. FERC also regulates natural gas and hydropower projects.

Federal Poverty Guidelines	Issued each year in the Federal Register by the Department of Health and Human Services. The guidelines are a simplification of the poverty thresholds for use for administrative purposes — for instance, determining financial eligibility for certain federal programs.
Flexible Resource	Dispatchable generation resource capable of reaching full capacity in under an hour from cold start.
Force Majeure	Disruptions in service caused by natural disasters (earthquakes, hurricanes, floods, etc.); wars, riots, or other major upheaval; or, performance failures of parties outside the control of the contracting party.
Geothermal	Energy produced below the Earth's crust in a layer of hot and molten rock called magma, heating nearby rock and water that has seeped deep into the Earth. At geothermal power plants, wells are drilled into the rock to more effectively capture the hot water and steam to be used to drive electric generators.
Greenhouse Gas (GHG)	A collection of gaseous substances, primarily consisting of carbon dioxide, methane, and nitrogen oxides, which have been shown to warm the earth's atmosphere by trapping solar radiation. Greenhouse gases also include chlorofluorocarbons, a group of chemicals used primarily in cooling systems and which are now either outlawed or severely restricted by most industrialized nations.
(Power or electric) Grid	An interconnected network of electric power transmission lines. The United States power grid, which covers most of the country as well as parts of Canada and Mexico, is made up the Eastern Interconnection, Western Interconnection, and Texas Interconnection. These networks include extra-high-voltage connections between individual utilities, which transfer electrical energy from one part of the network to another. The Interconnects distribute electricity in their respective areas via a network of smaller units that enable better management of power distribution.
Hazardous Air Pollutants (HAP)	Substances covered by air quality criteria, which may cause or contribute to illness or death.
Heat Rate	A measure of the amount of thermal energy required to produce a given amount of electric energy. It is usually expressed in British thermal units per kilowatt-hour (Btu/kWh). The performance of a power plant is measured by its fuel consumption rate (Btu/hr) and the corresponding amount of electric energy generated; thus, heat rate can be used to indicate the efficiency with which thermal energy is converted into electric energy.

Heating Degree-day	A measure of how cold a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the average of the day's high and low temperatures from the base temperature (65 degrees), with negative values set equal to zero. Each day's heating degree-days are summed to create a heating degree-day measure for a specified reference period. Heating degree-days are used in energy analysis as an indicator of space heating energy requirements or use.
Heating, Ventilating and Air Conditioning (HVAC)	Technology which provides indoor air comfort.
Hedging	The attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks. For example, a company that has an obligation to purchase fuel oil in six months may want to eliminate the risk that prices will increase before that time. In this case, the company could hedge, or reduce, that risk by purchasing a futures contract that provides the right to purchase fuel oil at a fixed price. Any profit or loss on the futures contract should offset the effects of higher or lower oil prices at the time the company needs to buy oil.
Hg (Mercury)	See Mercury
Hub	In the context of the electric grid, a hub is a location on the transmission network having a high concentration of interconnected transmission lines, generating sources, and/or counterparties willing to transact power trades such that this becomes a location having a great deal of commercial activity.
Hybrid Cooling	A type of technology that utilizes a combination of water cooling and dry cooling techniques. The relative contribution from each is dependent upon the plant design, weather conditions, and water consumption policies. *See also Dry Cooling.*
Integrated Gasification Combined Cycle (IGCC)	A power generation technology which allows a reduction of emissions by combining two technologies: (1) coal gasification, which uses coal to create a clean-burning gas; and, (2) combined cycle generation.
Intensity	Metric employed to characterize the emission of pollutants, relative to the power produced. For example, tons of CO2 emitted per MWh or gallons of water used per MWh can be used to help characterize the energy intensity of the system resources independent of load growth.
Interconnection	A connection between two electric systems permitting the transfer of electric energy in either direction. Additionally, an interconnection refers to the facilities that connect a generator to a system.

Intermediate Resource	Generation resources that usually fulfill a somewhat flexible role in the generating system. During some times of the year, these generating units will be started in the morning hours, used to meet daytime peak loads and then brought off-line in the evening. The operation may change during heavier load times of the year when these units may operate in more of a baseload manner and remain on-line for all hours of the day.
Intermittent (or Variable [Energy]) Resource	Generating resources that have some degree of variability in the production pattern, typically due to weather conditions. An example of an intermittent generating source is a wind project. The power output from the wind project is entirely dependent upon the wind conditions and will fluctuate with changes in wind conditions.
Investment Tax Credit (ITC)	Allows taxpayers to take a dollar-for-dollar reduction in the amount of federal income taxes that must be paid. Certain qualified facilities are characterized as energy property and are eligible for a 10% or 30% ITC, depending on the technology. A taxpayer cannot take both an ITC and PTC for a facility that could qualify for both; one must elect to receive either an ITC or PTC for each project.
Kilowatt (kW)	Unit of measure for demand. One thousand Watts.
Kilowatt-Hour (kWh)	Unit of measure for energy. The equivalent of one thousand Watts used steadily for one hour.
Landfill gas	Gas that is generated by decomposition of organic material at landfill disposal sites. The methane in landfill gas may be vented, flared, combusted to generate electricity, or used as thermal energy on-site.
Light-Emitting Diode (LED)	A semiconductor light source increasingly used for lighting. LEDs present many advantages over incandescent light sources including lower energy consumption, improved robustness, smaller size, faster switching, and greater durability and reliability.
Load	The moment-to-moment measurement of the power requirement in the entire system.
Load Center	A point at which the load of a given area is assumed to be concentrated.
Load Pocket	A geographic area that has a high demand of energy constrained by transmission import limitations. For example, the metro Phoenix area is considered a load pocket.
Loads & Resources Table	Presents the annual expected resource needs and additions.
Loss of Load Probability (LOLP)	Analysis performed to measure the ability of a system to reliably maintain service to load.

Losses on Peak	Total electric energy losses during the hour of greatest energy demand. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution equipment (wire, transformers, etc.).
Low NOx Burner (LNB)	A type of burner that is typically used in utility boilers to produce steam. Air used for combustion is split into two or more parts. The initial combustion, which occurs at a high temperature, takes place in an oxygen-deficient condition to form molecular nitrogen (N_2) instead of NOx. Further down the flame, additional air is added to complete the combustion after the nitrogen has been driven out of the coal as N_2.
Lowest Achievable Emission Rate (LAER)	The most stringent emission limitation derived from either of the following: (a) the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or, (b) the most stringent emission limitation achieved in practice by such class or category of source. The emissions rate may result from a combination of emissions-limiting measures such as: (1) a change in the raw material processed; (2) a process modification; and, (3) add-on controls.
Major Modification	Any physical change or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.
Major Sources	Term used to determine applicability of permitting regulation to stationary sources. For Title V of the Clean Air Act, refers to sources of air pollution that emit or have the potential to emit 100 tons per year or more of any criteria air pollutant.
Maximum Achievable Control Technology (MACT)	The standards which are established by EPA to require the maximum degree of emission reduction that EPA determines to be achievable for hazardous air pollutants. These standards are authorized by Section 112 of the Clean Air Act.
Megawatt (MW)	One megawatt equals one million watts. See Watt
Megawatt-Hour (MWh)	One million watt-hours See Watt-Hour
Mercury	A naturally-occurring element that is found in air, water and soil. Coal contains mercury and when coal is burned, mercury is released into the environment.
Nameplate Rating (or Nameplate Capacity or Nameplate)	A rating for each generating unit that specifies the maximum expected output of the generating unit. This nameplate rating could be dependent upon specified conditions (like ambient temperature).

National Ambient Air Quality Standards (NAAQS)	The standards established by EPA under authority of the Clean Air Act that apply to outdoor air throughout the country. Primary standards are designed to protect human health, with an adequate margin of safety.
National Environmental Policy Act (NEPA)	Establishes a process by which federal agencies must study the environmental effects of their actions, so these effects can be taken into consideration during federal decision-making.
Net Present Value (NPV)	Method for evaluating the cost or profitability of an investment. Individual future cash amounts are discounted back to their present values and then summed.
New Source Performance Standards (NSPS)	Pollution control standards issued by the Environmental Protection Agency.
New Source Review (NSR)	A permitting program that was established by Congress as part of the 1977 Clean Air Act Amendments. NSR is a preconstruction permitting program to ensure air quality is not significantly degraded from the addition of new and modified factories, boilers, and power plants and that advances in pollution control occur with industrial expansion.
Nitrogen Oxide (NOx)	Compounds of nitrogen and oxygen formed by combustion under high temperature and high pressure and a major contributor to the formation of ozone.
Non-Spinning Reserves	A generating reserve not connected to the system but capable of serving demand within a specified time.
North American Electric Reliability Corporation (NERC)	NERC is a non-government organization which has statutory responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices.
Nuclear Regulatory Commission (NRC)	The federal agency responsible for the regulation and inspection of nuclear power plants to assure safety.
Nuclear Fuel	Fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.
Off-Peak	Period of relatively low system demand. These periods often occur in daily, weekly, and seasonal patterns.
On-Peak	Periods of relatively high system demand. These periods often occur in daily, weekly, and seasonal patterns.

Operating Reserves (or reserves or Contingency Reserves)	A combination of spinning and non-spinning reserves. Operating reserve is the portion of all reserves APS is required to carry over and above firm system demand to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. APS carries a 15% reserve margin.
Operation & Maintenance (O&M)	Actions taken after construction to ensure that facilities constructed will maintain performance by being properly operated and maintained to achieve normative efficiency levels in an optimum manner.
Ozone	Ozone, the triatomic form of oxygen (O_3), is a gaseous atmospheric constituent. In the troposphere, it is created both naturally and by photochemical reactions involving gases resulting from human activities (photochemical smog). The layer of ozone that begins approximately 15 km above Earth and thins to an almost negligible amount at about 50 km, shields the Earth from harmful ultraviolet radiation from the sun.
Palo Verde Hub	An energy hub (***see*** *Hub*) in the area of PVNGS located west of Phoenix, Arizona, where numerous regional counterparties engage in power transactions which form the basis for various indices. For example, the Dow Jones Palo Verde Electricity Price Indexes are volume-weighted averages of specifically-defined bilateral, wholesale, and physical transactions in the hub quoted in either $/MWh or $/MW.
Particulate Matter	Particle pollution in the air that includes a mixture of solid particles and liquid droplets.
Peak Demand (or Peak Load or Peak)	The greatest demand that occurred or is expected to occur during a prescribed time period.
Peaking Resources	Technologies used to respond to high customer demands during the hot summer afternoons. These could include combustion turbines and DR measures and may include short-term market purchases.
Peaking Units	These generation units usually see relatively infrequent service during the non-summer months. During the summer, peaking units are used during the hot summer afternoons in response to high customer demands. It is not unusual for peaking units to operate less than 10% of the hours during the year.
Photovoltaic	The technology used to convert the sun's rays directly into electricity.
Planning Period	For the purpose of this filing, the timeframe of 2014-2029.
PM10	Particles with diameters that are 10 micrometers or smaller. Sources of particles include combustion, crushing or grinding operations, and dust from paved or unpaved roads.

Preference Power	Federal hydropower and resources from the Colorado River system.
Prevention of Significant Deterioration (PSD)	EPA program in which state and/or federal permits are required in order to restrict emissions from new or modified sources in places where air quality already meets or exceeds primary and secondary ambient air quality standards.
Production Tax Credit (PTC)	Allows a tax credit for the generation of qualified energy from qualified facilities. The PTC amounts, credit periods, and definitions of qualified facilities are technology-specific. Qualified energy resources include: wind, closed-loop biomass, open-loop biomass, geothermal, solar, small irrigation power, municipal solid waste, qualified hydropower production, and marine and hydrokinetic renewable energy. A taxpayer cannot take both an ITC and a PTC for a facility that could qualify for both – one must elect to receive either an ITC or PTC for each project.
PROMOD IV	A generator and portfolio modeling system developed by Ventyx which incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations.
Purchased Power Agreement (PPA)	A contractual agreement between two entities for the sale of electric energy and capacity from a specific generating unit, utility system, or unspecified wholesale market sources.
Real-Time Operations	Operational activity which manages the economic commitment of APS's generation resources to match the system load on a real-time basis. Requires making decisions to optimize system operation to provide lowest cost, reliable power to APS customers.
Real-Time Traders	Individuals involved solely in commodity trading of power, specifically electricity.
Regional Haze Rule	Requirements established by EPA to address source-by-source visibility impairment.
Regression Models	A statistical technique used to find relationships between variables for the purpose of predicting future values.
Renewable Energy	An energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.
Renewable Energy Standard (RES)	Requirement codified at A.A.C. R14-2-1804 which requires regulated electric utilities within Arizona to generate 15 percent of their energy from renewable resources by 2025.

Renewable Energy Standard Implementation Plan	Requirement for Arizona'sv regulated utility companies to file annual implementation plans describing how they will comply with the Renewable Energy Standard rules.
Request for Proposal (RFP)	A competitive solicitation for suppliers, often through a bidding process, to submit a proposal on a specific commodity or service.
Residential Direct Load Control	Demand response programs where the utility or a third-party contractor can remotely control customer-specific loads and reduce or cycle the energy consumption for a specified period of time.
Resource Conservation and Recovery Act	Gives EPA the authority to control hazardous waste from the "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also set forth a framework for the management of non-hazardous solid wastes.
Resource Planning Rules	Codified at A.A.C. R14-2-703, the Resource Planning Rules require regulated electric utilities to file a plan for future generation needs.
Revenue Requirements	Annual revenue level required to supply customers energy needs, including: (1) carrying charges on existing and future generation, future transmission over and above APS Ten Year Transmission Plan, and capital expenditures on existing generation; (2) fuel costs; (3) purchase power costs; (4) operating and maintenance costs for existing and future generation; (5) energy efficiency program and incentive costs; (6) distributed energy program and incentive costs; and, (7) power plant emissions costs including SO2 and CO2. Revenue requirements as used in the resource plan filing do not include costs associated with existing transmission, existing and future distribution, or sales tax on retail electric sales.
Scenario Analysis	Refers to the grouping together of a set of assumptions of key uncertain variables that could potentially all occur in tandem. The goal of scenario analysis is to illustrate the impact to the portfolios of multiple key variables being stressed in a plausible manner. Results of these studies provide information on diversity, cost, environmental impacts, robustness and overall risk to assist in the selection of a resource plan.
Selected Portfolio	The best-fitting plan chosen by APS that comprehensively considers a wide range of supply- and demand-side options
Selective Catalytic Reduction (SCR) Controls	A post-combustion pollution control technology that removes NOx emissions from an air stream. Ammonia (NH_3) is injected into the flue gas downstream from the combustion process and upstream from a catalyst bed. The NH_3 reacts with the NOx on the catalyst surface to form nitrogen (N_2) and water vapor (H_2O).

Simple Cycle	***See*** *Combustion Turbine*
Societal Cost Test (SCT)	A variant of the Total Resource Cost Test. It measures the impacts of DSM on society as a whole by including externality costs of power generation not captured by the market.
Solar Photovoltaic (PV, or Solar PV)	A method of generating electrical power by converting solar radiation directly into electricity.
Solar Thermal	A method for harnessing solar energy for thermal energy.
Southern California Edison (SCE)	One of the largest electric utilities in California, serving more than 14 million people in a 50,000 square-mile area of central, coastal and Southern California, excluding the City of Los Angeles and certain other cities.
Southwest Reserve Sharing Group (SRSG)	A NERC-registered entity. SRSG participants share contingency reserves to maximize generator dispatch efficiency and contribute to electric reliability in the Western Interconnection.
Spinning Reserves	Available generating capacity that is synchronously connected to the electric grid and capable of automatically responding to frequency deviations on the system.
Spot Market	A commodities or securities market in which goods are sold for cash and delivered immediately.
Standby Generation	Customer-owned generation resources, typically diesel- or gas-fired, that provide customers with a guaranteed source of power in the event that either power quality or reliability issues occur with their local utility.
State Implementation Plan (SIP)	Plans developed by state and local air quality management agencies and submitted for approval to EPA to comply with the federal Clean Air Act.
Sulfur Dioxide (SO_2)	A colorless gas of compounds of sulfur and oxygen that is produced primarily by the combustion of fossil fuel.
Summer Peak	***See*** *Peak Demand*
System Average Interruption Duration Index (SAIDI)	Used as a reliability indicator by electric power utilities. SAIDI is the average annual outage duration experienced by the average customer.
System Average Interruption Frequency Index (SAIFI)	Used as a reliability indicator by electric power utilities. SAIFI is the average annual outage frequency experienced by the average customer.
Thermal Energy Storage (TES) Cooling Programs	Systems that utilize a storage medium, such as chilled water or ice, which is "charged" during off-peak hours and then used as the cooling energy source during on-peak hours, offsetting the need to operate high-demand refrigeration equipment.

Total Own Load Peak	The greatest demand for energy during a specified time period by customers that APS has a requirement to serve.
Total Resource Cost Test (TRCT)	Measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's.
Transmission	The transportation of bulk energy along a network or grid of power lines. It is often intended to refer specifically to high-voltage (69,000 volts or higher) electricity of the type bought and sold on the wholesale market. An additional stage of service, referred to as distribution, is required to actually deliver usable low-voltage energy to an end-use customer.
Utility-Scale	A resource that is sized to provide power to a utility and not directly to an on-site customer.
Volatile Organic Compounds (VOC)	Types of organic compounds which have significant vapor pressures (evaporate easily, forming a gas) and which can affect the environment and human health.
Watt-Hour	The total amount of energy used in one hour by a device that requires one watt of power for continuous operation. Electric energy sold to retail customers is commonly measured in kilowatt-hours.
Watt	The electrical unit of real power or rate of doing work; specifically, the rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor.
WestConnect	WestConnect is composed of utility companies providing electric transmission in the U.S. Members work collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to Western wholesale electricity markets.
Western Electricity Coordinating Council (WECC)	The regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.
Western Interconnection	The interconnected electrical systems that encompass the region of the Western Electricity Coordinating Council of the North American Electric Reliability Council. The region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California (Mexico), and all or portions of the 14 western states in between.
Western Interstate Energy Board (WIEB)	Organization of 11 western states and three western Canadian provinces. Board Members are appointed by state governors. The Board provides the instruments and framework for cooperative state efforts to "enhance the economy of the West and contribute to the well-being of the region's people."

Wholesale Customer	Any party who purchases electricity in bulk for resale to end-use customers. Wholesale customers may include marketers, utilities and distribution companies, co-ops, and any other entity engaged in energy resale.

ATTACHMENTS

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Attachment C.1 (a) - Coincident Peak Demand by Month and Customer Class

PEAK DEMAND (MW)													
Year 2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	**1,764**	**1,772**	**1,387**	**1,666**	**2,476**	**2,995**	**3,418**	**3,418**	**3,074**	**2,147**	**1,580**	**1,820**	**3,418**
Comm+Ind <3 MW	1,572	1,504	1,610	1,629	2,001	2,043	2,424	2,424	2,205	1,927	1,476	1,477	2,424
Comm+Ind >3 MW	**356**	**320**	**336**	**365**	**404**	**414**	**381**	**381**	**406**	**385**	**351**	**354**	**381**
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5	5
Streetlights	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**39**	**0**	**0**
Resale (x/off-system sales)	40	32	33	44	66	90	170	170	55	48	35	42	170
System Peak Prior to Losses	**3,735**	**3,631**	**3,370**	**3,710**	**4,952**	**5,547**	**6,397**	**6,397**	**5,745**	**4,513**	**3,485**	**3,697**	**6,397**
Losses On Peak	437	425	394	434	579	649	748	748	672	528	408	433	748
Total Own Load Peak	**4,172**	**4,056**	**3,764**	**4,144**	**5,531**	**6,196**	**7,146**	**7,146**	**6,417**	**5,041**	**3,893**	**4,130**	**7,146**
Energy Efficiency Programs	**(65)**	**(63)**	**(65)**	**(73)**	**(80)**	**(101)**	**(111)**	**(109)**	**(93)**	**(80)**	**(56)**	**(65)**	**(109)**
Distributed Energy Programs	0	(0)	0	(22)	(25)	(26)	(23)	(23)	(17)	(11)	0	(0)	(23)
Own Load After EE/ DE	**4,106**	**3,993**	**3,699**	**4,048**	**5,426**	**6,069**	**7,011**	**7,014**	**6,308**	**4,950**	**3,836**	**4,065**	**7,014**

PEAK DEMAND (MW)													
Year 2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	**1,836**	**1,831**	**1,439**	**1,718**	**2,559**	**3,118**	**3,504**	**3,504**	**3,204**	**2,240**	**1,652**	**1,906**	**3,504**
Comm+Ind <3 MW	1,632	1,548	1,664	1,670	2,065	2,120	2,495	2,495	2,266	1,987	1,526	1,530	2,495
Comm+Ind >3 MW	**356**	**320**	**336**	**365**	**404**	**414**	**373**	**373**	**406**	**385**	**351**	**354**	**373**
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5	5
Streetlights	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**39**	**0**	**0**
Resale (x/off-system sales)	10	11	9	9	11	12	152	152	4	6	6	7	152
System Peak Prior to Losses	**3,837**	**3,713**	**3,452**	**3,766**	**5,043**	**5,669**	**6,528**	**6,528**	**5,886**	**4,623**	**3,578**	**3,801**	**6,528**
Losses On Peak	449	434	404	441	590	663	764	764	689	541	419	445	764
Total Own Load Peak	**4,286**	**4,147**	**3,855**	**4,207**	**5,634**	**6,332**	**7,292**	**7,292**	**6,574**	**5,164**	**3,997**	**4,246**	**7,292**
Energy Efficiency Programs	**(127)**	**(121)**	**(130)**	**(163)**	**(182)**	**(243)**	**(277)**	**(267)**	**(222)**	**(180)**	**(115)**	**(126)**	**(267)**
Distributed Energy Programs	0	(0)	0	(28)	(40)	(48)	(37)	(37)	(27)	(18)	0	(0)	(37)
Own Load After EE/ DE	**4,159**	**4,026**	**3,725**	**4,015**	**5,411**	**6,040**	**6,977**	**6,988**	**6,325**	**4,966**	**3,882**	**4,120**	**6,988**

Attachment C.1 (a) - Coincident Peak Demand by Month and Customer Class

PEAK DEMAND (MW)													
Year 2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	1,914	1,875	1,476	1,800	2,678	3,257	3,639	3,639	3,372	2,343	1,724	1,992	3,639
Comm+Ind <3 MW	1,689	1,568	1,697	1,733	2,156	2,200	2,612	2,612	2,357	2,054	1,573	1,581	2,612
Comm+Ind >3 MW	353	317	333	362	401	410	373	373	402	381	348	351	373
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5	5
Streetlights	0	0	0	0	0	0	0	0	0	0	39	0	0
Resale (x/off-system sales)	10	11	9	9	11	26	152	152	3	4	4	6	152
System Peak Prior to Losses	3,970	3,774	3,519	3,910	5,250	5,899	6,780	6,780	6,139	4,788	3,692	3,935	6,780
Losses On Peak	464	442	412	457	614	690	793	793	718	560	432	460	793
Total Own Load Peak	4,434	4,216	3,930	4,367	5,865	6,589	7,573	7,573	6,858	5,348	4,124	4,396	7,573
Energy Efficiency Programs	(190)	(182)	(197)	(258)	(290)	(396)	(453)	(434)	(359)	(285)	(175)	(188)	(434)
Distributed Energy Programs	(0)	(0)	(0)	(22)	(50)	(62)	(46)	(46)	(34)	(23)	(0)	(0)	(46)
Own Load After EE/ DE	4,244	4,034	3,733	4,087	5,526	6,131	7,074	7,093	6,465	5,040	3,949	4,207	7,093

PEAK DEMAND (MW)													
Year 2017	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	2,005	1,988	1,573	1,880	2,797	3,402	3,849	3,849	3,517	2,440	1,808	2,079	3,849
Comm+Ind <3 MW	1,755	1,653	1,790	1,792	2,245	2,284	2,759	2,759	2,422	2,118	1,637	1,636	2,759
Comm+Ind >3 MW	354	318	334	362	401	410	373	373	402	381	348	351	373
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5	5
Streetlights	0	0	0	0	0	0	0	0	0	0	39	0	0
Resale (x/off-system sales)	6	5	4	3	3	4	70	70	3	4	4	6	70
System Peak Prior to Losses	4,123	3,967	3,705	4,042	5,452	6,105	7,056	7,056	6,350	4,948	3,841	4,076	7,056
Losses On Peak	482	464	433	473	638	714	826	826	743	579	449	477	826
Total Own Load Peak	4,606	4,431	4,138	4,515	6,090	6,820	7,881	7,881	7,093	5,527	4,291	4,553	7,881
Energy Efficiency Programs	(250)	(239)	(261)	(348)	(392)	(553)	(620)	(594)	(490)	(387)	(233)	(247)	(594)
Distributed Energy Programs	(0)	(0)	(0)	(3)	(59)	(62)	(55)	(55)	(41)	(27)	(0)	(0)	(55)
Own Load After EE/ DE	4,356	4,192	3,877	4,164	5,638	6,205	7,206	7,232	6,562	5,112	4,058	4,306	7,232

Attachment C.1 (a) - Coincident Peak Demand by Month and Customer Class

PEAK DEMAND (MW)													
Year 2018	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	**2,097**	**2,076**	**1,639**	**1,964**	**2,903**	**3,544**	**4,020**	**4,020**	**3,673**	**2,556**	**1,887**	**2,165**	**4,020**
Comm+Ind <3 MW	1,815	1,708	1,846	1,850	2,313	2,356	2,856	2,856	2,492	2,194	1,689	1,686	2,856
Comm+Ind >3 MW	**354**	**318**	**334**	**362**	**401**	**410**	**373**	**373**	**402**	**381**	**348**	**351**	**373**
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5	5
Streetlights	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**40**	**0**	**0**
Resale (x/off-system sales)	1	2	1	0	0	0	70	70	0	0	0	0	70
System Peak Prior to Losses	**4,271**	**4,108**	**3,824**	**4,181**	**5,622**	**6,316**	**7,323**	**7,323**	**6,572**	**5,137**	**3,970**	**4,207**	**7,323**
Losses On Peak	500	481	447	489	658	739	857	857	769	601	464	492	857
Total Own Load Peak	**4,771**	**4,588**	**4,271**	**4,670**	**6,280**	**7,055**	**8,180**	**8,180**	**7,341**	**5,738**	**4,434**	**4,699**	**8,180**
Energy Efficiency Programs	**(307)**	**(293)**	**(321)**	**(430)**	**(488)**	**(690)**	**(773)**	**(738)**	**(610)**	**(480)**	**(287)**	**(303)**	**(738)**
Distributed Energy Programs	0	(0)	0	0	(69)	(72)	(85)	(67)	(48)	(32)	0	(0)	(67)
Own Load After EE/ DE	**4,465**	**4,295**	**3,951**	**4,240**	**5,723**	**6,294**	**7,322**	**7,375**	**6,683**	**5,226**	**4,147**	**4,396**	**7,375**

PEAK DEMAND (MW)													
Year 2019	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	**2,191**	**2,165**	**1,703**	**2,057**	**3,024**	**3,686**	**4,196**	**4,196**	**3,845**	**2,672**	**1,965**	**2,254**	**4,196**
Comm+Ind <3 MW	1,875	1,761	1,899	1,915	2,393	2,425	2,949	2,949	2,575	2,268	1,739	1,737	2,949
Comm+Ind >3 MW	**354**	**318**	**334**	**362**	**401**	**410**	**373**	**373**	**402**	**381**	**348**	**351**	**373**
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4	4
Streetlights	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**41**	**0**	**0**
Resale (x/off-system sales)	1	2	1	0	0	0	70	70	0	0	0	0	70
System Peak Prior to Losses	**4,424**	**4,249**	**3,940**	**4,338**	**5,821**	**6,526**	**7,592**	**7,592**	**6,826**	**5,326**	**4,096**	**4,346**	**7,592**
Losses On Peak	518	497	461	508	681	764	888	888	799	623	479	508	888
Total Own Load Peak	**4,942**	**4,746**	**4,401**	**4,846**	**6,502**	**7,289**	**8,481**	**8,481**	**7,625**	**5,949**	**4,575**	**4,854**	**8,481**
Energy Efficiency Programs	**(363)**	**(347)**	**(381)**	**(516)**	**(580)**	**(817)**	**(915)**	**(877)**	**(724)**	**(569)**	**(300)**	**(358)**	**(877)**
Distributed Energy Programs	(0)	(0)	(0)	(60)	(78)	(82)	(74)	(74)	(54)	(37)	(0)	(0)	(74)
Own Load After EE/ DE	**4,579**	**4,399**	**4,020**	**4,270**	**5,844**	**6,391**	**7,492**	**7,530**	**6,846**	**5,342**	**4,275**	**4,496**	**7,530**

Attachment C.1 (a) - Coincident Peak Demand by Month and Customer Class

PEAK DEMAND (MW)													
Year 2020	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	2,277	2,210	1,738	2,131	3,132	3,848	4,373	4,373	3,989	2,775	2,048	2,348	4,373
Comm+Ind <3 MW	1,928	1,771	1,923	1,961	2,463	2,518	3,042	3,042	2,635	2,330	1,795	1,794	3,042
Comm+Ind >3 MW	354	318	334	362	401	410	373	373	402	381	348	351	373
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	42	0	0
Resale (x/off-system sales)	1	2	1	0	0	0	62	62	0	0	0	0	62
System Peak Prior to Losses	4,563	4,304	3,999	4,458	6,000	6,781	7,853	7,853	7,031	5,490	4,236	4,497	7,853
Losses On Peak	534	504	468	522	702	793	919	919	823	642	496	526	919
Total Own Load Peak	5,096	4,807	4,467	4,979	6,701	7,574	8,772	8,772	7,853	6,133	4,732	5,023	8,772
Energy Efficiency Programs	(417)	(399)	(440)	(568)	(673)	(928)	(1,061)	(1,008)	(839)	(660)	(396)	(412)	(1,008)
Distributed Energy Programs	0	(0)	0	0	(88)	(112)	(104)	(92)	(61)	(42)	0	(0)	(92)
Own Load After EE/ DE	4,679	4,408	4,028	4,411	5,941	6,534	7,607	7,672	6,953	5,431	4,336	4,611	7,672

PEAK DEMAND (MW)													
Year 2021	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	2,355	2,506	1,989	2,387	3,504	4,295	4,950	4,950	4,469	3,085	2,286	2,610	4,950
Comm+Ind <3 MW	1,975	1,959	2,138	2,129	2,712	2,747	3,331	3,331	2,849	2,514	1,948	1,940	3,331
Comm+Ind >3 MW	354	318	334	362	401	410	373	373	402	381	348	351	373
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	44	0	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,687	4,786	4,465	4,882	6,621	7,456	8,658	8,658	7,724	5,984	4,630	4,906	8,658
Losses On Peak	548	255	236	257	297	361	413	413	424	349	229	272	413
Total Own Load Peak	5,236	5,041	4,701	5,140	6,919	7,817	9,071	9,071	8,147	6,333	4,859	5,177	9,071
Energy Efficiency Programs	(454)	(434)	(478)	(579)	(733)	(1,031)	(1,155)	(1,096)	(914)	(721)	(431)	(448)	(1,096)
Distributed Energy Programs	0	(0)	0	0	(102)	(107)	(142)	(107)	(71)	(49)	0	(0)	(107)
Own Load After EE/ DE	4,782	4,606	4,222	4,560	6,084	6,679	7,775	7,868	7,162	5,564	4,428	4,729	7,868

Attachment C.1 (a) - Coincident Peak Demand by Month and Customer Class

PEAK DEMAND (MW)													
Year 2022	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	**2,453**	**2,417**	**1,918**	**2,304**	**3,379**	**4,142**	**4,733**	**4,733**	**4,325**	**2,987**	**2,197**	**2,521**	**4,733**
Comm+Ind <3 MW	2,037	1,909	2,081	2,079	2,632	2,671	3,220	3,220	2,798	2,463	1,891	1,894	3,220
Comm+Ind >3 MW	**354**	**318**	**334**	**362**	**401**	**410**	**373**	**373**	**402**	**381**	**348**	**351**	**373**
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4	4
Streetlights	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**44**	**0**	**0**
Resale (x/off-system sales)	0	0	0	0	0	0	62	62	0	0	0	0	62
System Peak Prior to Losses	**4,847**	**4,648**	**4,337**	**4,749**	**6,415**	**7,227**	**8,392**	**8,392**	**7,529**	**5,836**	**4,484**	**4,771**	**8,392**
Losses On Peak	567	544	507	556	751	846	982	982	881	683	525	558	982
Total Own Load Peak	**5,414**	**5,192**	**4,844**	**5,305**	**7,166**	**8,073**	**9,373**	**9,373**	**8,410**	**6,518**	**5,009**	**5,329**	**9,373**
Energy Efficiency Programs	**(467)**	**(447)**	**(493)**	**(641)**	**(755)**	**(1,042)**	**(1,190)**	**(1,130)**	**(942)**	**(742)**	**(444)**	**(462)**	**(1,130)**
Distributed Energy Programs	0	(1)	0	0	(127)	(155)	(137)	(131)	(88)	(60)	0	(0)	(131)
Own Load After EE/ DE	**4,947**	**4,744**	**4,351**	**4,664**	**6,283**	**6,876**	**8,046**	**8,112**	**7,380**	**5,717**	**4,565**	**4,867**	**8,112**

PEAK DEMAND (MW)													
Year 2023	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	**2,542**	**2,506**	**1,989**	**2,387**	**3,504**	**4,295**	**4,950**	**4,950**	**4,469**	**3,085**	**2,286**	**2,610**	**4,950**
Comm+Ind <3 MW	2,089	1,959	2,138	2,129	2,712	2,747	3,331	3,331	2,849	2,514	1,948	1,940	3,331
Comm+Ind >3 MW	**354**	**318**	**334**	**362**	**401**	**410**	**373**	**373**	**402**	**381**	**348**	**351**	**373**
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4	4
Streetlights	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**44**	**0**	**0**
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	**4,988**	**4,786**	**4,465**	**4,882**	**6,621**	**7,456**	**8,658**	**8,658**	**7,724**	**5,984**	**4,630**	**4,906**	**8,658**
Losses On Peak	584	560	522	571	775	872	1,013	1,013	904	700	542	574	1,013
Total Own Load Peak	**5,572**	**5,346**	**4,987**	**5,454**	**7,396**	**8,328**	**9,671**	**9,671**	**8,628**	**6,684**	**5,172**	**5,479**	**9,671**
Energy Efficiency Programs	**(485)**	**(464)**	**(512)**	**(658)**	**(785)**	**(1,105)**	**(1,237)**	**(1,174)**	**(979)**	**(773)**	**(462)**	**(479)**	**(1,174)**
Distributed Energy Programs	0	(1)	0	0	(158)	(165)	(154)	(160)	(109)	(53)	0	(0)	(160)
Own Load After EE/ DE	**5,087**	**4,881**	**4,475**	**4,796**	**6,452**	**7,059**	**8,280**	**8,336**	**7,539**	**5,858**	**4,710**	**5,000**	**8,336**

Attachment C.1 (a) - Coincident Peak Demand by Month and Customer Class

PEAK DEMAND (MW)													
Year 2024	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	2,637	2,560	2,012	2,482	3,612	4,428	5,139	5,139	4,638	3,212	2,362	2,698	5,139
Comm+Ind <3 MW	2,143	1,971	2,143	2,189	2,771	2,798	3,405	3,405	2,921	2,591	1,991	1,984	3,405
Comm+Ind >3 MW	354	318	334	362	401	410	373	373	402	381	348	351	373
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	45	0	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,137	4,852	4,493	5,037	6,787	7,641	8,922	8,922	7,966	6,189	4,750	5,037	8,922
Losses On Peak	601	568	526	589	794	894	1,044	1,044	932	724	556	589	1,044
Total Own Load Peak	5,738	5,420	5,018	5,626	7,581	8,535	9,965	9,965	8,898	6,913	5,306	5,627	9,965
Energy Efficiency Programs	(503)	(481)	(531)	(727)	(815)	(1,146)	(1,283)	(1,230)	(1,016)	(800)	(413)	(497)	(1,230)
Distributed Energy Programs	(0)	(1)	(0)	(94)	(190)	(185)	(173)	(178)	(131)	(74)	(0)	(0)	(178)
Own Load After EE/ DE	5,236	4,938	4,487	4,805	6,576	7,203	8,509	8,557	7,750	6,039	4,893	5,130	8,557

PEAK DEMAND (MW)													
Year 2025	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	2,731	2,689	2,121	2,570	3,731	4,594	5,331	5,331	4,790	3,324	2,449	2,793	5,331
Comm+Ind <3 MW	2,195	2,057	2,233	2,240	2,838	2,880	3,478	3,478	2,972	2,650	2,042	2,031	3,478
Comm+Ind >3 MW	354	318	334	362	401	410	373	373	402	381	348	351	373
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	46	0	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,284	5,067	4,691	5,176	6,974	7,888	9,185	9,185	8,168	6,359	4,889	5,180	9,185
Losses On Peak	618	593	549	606	816	923	1,075	1,075	956	744	572	606	1,075
Energy Efficiency Programs	(521)	(499)	(551)	(736)	(846)	(1,189)	(1,331)	(1,264)	(1,055)	(830)	(425)	(515)	(1,264)
Distributed Energy Programs	0	(1)	0	0	(223)	(206)	(193)	(222)	(153)	(75)	0	(0)	(222)
Own Load After EE/ DE	5,381	5,160	4,690	5,046	6,722	7,417	8,736	8,774	7,916	6,198	5,036	5,270	8,774

Attachment C.1 (a) - Coincident Peak Demand by Month and Customer Class

PEAK DEMAND (MW)													
Year 2026	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	2,816	2,779	2,199	2,646	3,849	4,758	5,525	5,525	4,956	3,435	2,536	2,892	5,525
Comm+Ind <3 MW	2,236	2,102	2,291	2,278	2,903	2,956	3,551	3,551	3,035	2,707	2,090	2,081	3,551
Comm+Ind >3 MW	354	318	334	362	401	410	373	373	402	381	348	351	373
Irrigation	2	2	3	3	3	3	3	3	3	3	3	3	3
Streetlights	0	0	0	0	0	0	0	0	0	0	47	0	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,408	5,201	4,827	5,289	7,156	8,128	9,452	9,452	8,396	6,526	5,023	5,327	9,452
Losses On Peak	633	609	565	619	837	951	1,106	1,106	982	763	588	623	1,106
Total Own Load Peak	6,041	5,810	5,391	5,908	7,993	9,079	10,558	10,558	9,378	7,289	5,611	5,951	10,558
Energy Efficiency Programs	(538)	(515)	(569)	(731)	(875)	(1,206)	(1,376)	(1,307)	(1,090)	(859)	(514)	(532)	(1,307)
Distributed Energy Programs	0	(1)	0	0	(238)	(280)	(206)	(242)	(168)	(71)	0	(0)	(242)
Own Load After EE/DE	5,502	5,293	4,822	5,178	6,880	7,593	8,976	9,009	8,120	6,360	5,097	5,419	9,009

PEAK DEMAND (MW)													
Year 2027	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	2,907	2,865	2,277	2,738	3,973	4,910	5,724	5,724	5,142	3,552	2,609	2,985	5,724
Comm+Ind <3 MW	2,283	2,143	2,348	2,330	2,972	3,021	3,623	3,623	3,117	2,769	2,125	2,125	3,623
Comm+Ind >3 MW	354	318	334	362	401	410	373	373	402	381	348	351	373
Irrigation	2	2	3	3	3	3	3	3	3	3	3	3	3
Streetlights	0	0	0	0	0	0	0	0	0	0	48	0	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,546	5,329	4,961	5,434	7,349	8,345	9,722	9,722	8,664	6,705	5,133	5,464	9,722
Losses On Peak	649	623	580	636	860	976	1,138	1,138	1,014	785	601	639	1,138
Total Own Load Peak	6,195	5,952	5,542	6,070	8,209	9,321	10,860	10,860	9,678	7,490	5,734	6,103	10,860
Energy Efficiency Programs	(557)	(533)	(589)	(736)	(905)	(1,271)	(1,423)	(1,351)	(1,128)	(890)	(532)	(550)	(1,351)
Distributed Energy Programs	0	(1)	0	0	(246)	(227)	(287)	(252)	(174)	(57)	0	(0)	(252)
Own Load After EE/DE	5,639	5,418	4,953	5,334	7,058	7,822	9,150	9,257	8,376	6,542	5,202	5,553	9,257

Attachment C.1 (a) - Coincident Peak Demand by Month and Customer Class

PEAK DEMAND (MW)													
Year 2028	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	3,010	2,910	2,306	2,829	4,121	5,074	5,926	5,926	5,296	3,649	2,705	3,078	5,926
Comm+Ind <3 MW	2,341	2,142	2,356	2,381	3,064	3,094	3,695	3,695	3,163	2,809	2,181	2,166	3,695
Comm+Ind >3 MW	354	318	334	362	401	410	373	373	402	381	348	351	373
Irrigation	2	2	3	3	3	3	3	3	3	3	3	3	3
Streetlights	0	0	0	0	0	0	0	0	0	0	49	0	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,707	5,373	4,998	5,575	7,589	8,581	9,997	9,997	8,864	6,843	5,286	5,598	9,997
Losses On Peak	668	629	585	652	888	1,004	1,170	1,170	1,037	801	618	655	1,170
Total Own Load Peak	6,375	6,001	5,583	6,227	8,476	9,585	11,167	11,167	9,901	7,644	5,904	6,253	11,167
Energy Efficiency Programs	(575)	(550)	(608)	(783)	(935)	(1,313)	(1,470)	(1,396)	(1,165)	(919)	(549)	(568)	(1,396)
Distributed Energy Programs	0	(1)	0	0	(264)	(235)	(219)	(262)	(181)	(57)	0	(0)	(262)
Own Load After EE/ DE	5,800	5,450	4,975	5,444	7,278	8,037	9,477	9,509	8,555	6,667	5,355	5,685	9,509

PEAK DEMAND (MW)													
Year 2029	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual CP
Residential	3,110	3,053	2,423	2,920	4,233	5,227	6,131	6,131	5,463	3,779	2,791	3,173	6,131
Comm+Ind <3 MW	2,394	2,237	2,452	2,432	3,119	3,155	3,768	3,768	3,221	2,881	2,228	2,209	3,768
Comm+Ind >3 MW	354	318	334	362	401	410	373	373	402	381	348	351	373
Irrigation	2	2	3	3	3	3	3	3	3	3	3	3	3
Streetlights	0	0	0	0	0	0	0	0	0	0	49	0	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,860	5,611	5,211	5,717	7,756	8,795	10,275	10,275	9,089	7,044	5,419	5,735	10,275
Losses On Peak	686	656	610	669	907	1,029	1,202	1,202	1,063	824	634	671	1,202
Total Own Load Peak	6,546	6,267	5,821	6,386	8,663	9,824	11,477	11,477	10,153	7,868	6,053	6,406	11,477
Energy Efficiency Programs	(596)	(571)	(630)	(820)	(970)	(1,362)	(1,525)	(1,447)	(1,208)	(952)	(569)	(589)	(1,447)
Distributed Energy Programs	0	(1)	0	0	(261)	(243)	(228)	(272)	(188)	(79)	0	(0)	(272)
Own Load After EE/ DE	5,950	5,696	5,190	5,566	7,432	8,219	9,725	9,758	8,756	6,837	5,484	5,817	9,758

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

ARIZONA PUBLIC SERVICE COMPANY ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2014

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	995,277	818,842	822,816	800,833	1,057,686	1,454,089
Comm+Ind <3 MW	852,434	792,960	906,778	918,873	1,071,079	1,031,194
Comm+Ind >3 MW	259,241	239,986	256,827	256,879	271,537	281,323
Irrigation	627	619	946	951	1,573	1,649
Streetlights	11,903	12,091	12,820	12,302	13,025	11,316
Resale (x/off-system sales)	26,361	30,381	32,096	35,733	49,544	60,387
Sales Prior to EE/DE	2,145,843	1,894,879	2,032,283	2,025,571	2,464,444	2,839,958
Energy Efficiency Programs	(46,995)	(28,200)	(37,892)	(39,064)	(45,765)	(52,707)
Distributed Energy Programs	(8,356)	(6,884)	(10,324)	(11,804)	(12,642)	(10,208)
Total Sales	2,090,492	1,859,795	1,984,067	1,974,703	2,406,037	2,777,043
Energy Losses	130,144	109,183	126,443	122,595	146,228	194,220
Total Own Load Energy	2,220,636	1,968,978	2,110,510	2,097,298	2,552,265	2,971,263

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,833,225	1,741,132	1,421,828	969,424	775,534	1,038,612	13,729,298
Comm+Ind <3 MW	1,155,317	1,195,892	1,087,250	980,173	892,623	839,592	11,724,165
Comm+Ind >3 MW	299,374	299,715	294,495	278,293	264,887	263,846	3,266,403
Irrigation	1,409	1,339	1,159	1,135	779	377	12,563
Streetlights	10,978	12,237	10,736	12,780	12,193	12,351	144,732
Resale (x/off-system sales)	62,849	60,881	43,780	34,163	25,903	27,010	489,088
Sales Prior to EE/DE	3,363,152	3,311,196	2,859,248	2,275,968	1,971,919	2,181,788	29,366,249
Energy Efficiency Programs	(59,330)	(54,927)	(35,863)	(38,215)	(30,363)	(32,580)	(501,901)
Distributed Energy Programs	(9,927)	(9,918)	(7,530)	(8,004)	(5,472)	(4,874)	(105,943)
Total Sales	3,293,895	3,246,351	2,815,855	2,229,749	1,936,084	2,144,334	28,758,405
Energy Losses	213,401	224,077	156,308	141,038	111,201	143,275	1,818,113
Total Own Load Energy	3,507,296	3,470,428	2,972,163	2,370,787	2,047,285	2,287,609	30,576,518

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

ARIZONA PUBLIC SERVICE COMPANY ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2015

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,039,006	850,935	856,758	834,402	1,103,261	1,517,764
Comm+Ind <3 MW	894,416	821,872	938,241	951,620	1,107,979	1,068,306
Comm+Ind >3 MW	257,184	238,011	254,426	255,025	269,232	278,953
Irrigation	603	597	914	912	1,515	1,588
Streetlights	12,396	12,342	13,089	12,560	13,296	11,554
Resale (x/off-system sales)	6,521	10,221	8,784	6,933	7,880	8,067
Sales Prior to EE/DE	2,210,126	1,933,978	2,072,212	2,061,452	2,503,163	2,886,232
Energy Efficiency Programs	(79,367)	(58,078)	(77,372)	(82,374)	(98,166)	(127,013)
Distributed Energy Programs	(11,036)	(11,080)	(16,629)	(19,031)	(20,387)	(16,466)
Total Sales	2,119,723	1,864,820	1,978,211	1,960,047	2,384,610	2,742,753
Energy Losses	119,890	107,355	137,223	119,558	150,723	208,486
Total Own Load Energy	2,239,613	1,972,175	2,115,434	2,079,605	2,535,333	2,951,239

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,917,943	1,820,742	1,487,192	1,017,428	811,636	1,086,663	14,343,730
Comm+Ind <3 MW	1,196,928	1,238,525	1,127,479	1,015,225	924,623	870,263	12,155,477
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,237,263
Irrigation	1,366	1,293	1,118	1,096	753	364	12,119
Streetlights	11,206	12,476	10,953	13,035	12,436	12,598	147,941
Resale (x/off-system sales)	8,785	6,817	3,460	4,403	4,303	4,690	80,864
Sales Prior to EE/DE	3,432,780	3,376,358	2,921,755	2,326,567	2,016,152	2,236,619	29,977,394
Energy Efficiency Programs	(142,038)	(127,100)	(77,981)	(78,239)	(60,171)	(64,975)	(1,072,874)
Distributed Energy Programs	(16,004)	(15,985)	(12,126)	(12,879)	(8,796)	(7,834)	(168,253)
Total Sales	3,274,738	3,233,273	2,831,648	2,235,449	1,947,185	2,163,810	28,736,267
Energy Losses	213,212	224,694	140,339	134,799	112,048	147,243	1,815,570
Total Own Load Energy	3,487,950	3,457,967	2,971,987	2,370,248	2,059,233	2,311,053	30,551,837

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2016

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,081,798	888,493	895,485	872,955	1,155,138	1,589,401
Comm+Ind <3 MW	928,330	851,886	971,540	985,124	1,146,967	1,106,973
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	590	582	891	890	1,483	1,554
Streetlights	12,636	12,586	13,345	12,807	13,558	11,781
Resale (x/off-system sales)	6,521	10,221	8,784	6,933	7,880	17,725
Sales Prior to EE/DE	2,288,102	2,002,722	2,145,515	2,133,734	2,594,258	3,006,387
Energy Efficiency Programs	(113,031)	(94,183)	(117,584)	(126,862)	(154,102)	(205,060)
Distributed Energy Programs	(12,425)	(14,797)	(20,598)	(23,692)	(25,304)	(20,408)
Total Sales	2,162,646	1,893,742	2,007,333	1,983,180	2,414,852	2,780,919
Energy Losses	117,948	145,093	107,380	127,837	173,258	218,230
Total Own Load Energy	2,280,594	2,038,835	2,114,713	2,111,017	2,588,110	2,999,149

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,008,609	1,907,241	1,557,158	1,066,388	850,283	1,137,486	15,010,435
Comm+Ind <3 MW	1,240,425	1,283,219	1,169,048	1,051,890	957,905	901,895	12,595,202
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,337	1,266	1,094	1,079	738	356	11,860
Streetlights	11,425	12,723	11,166	13,292	12,680	12,846	150,845
Resale (x/off-system sales)	3,204	2,974	2,605	2,814	2,846	3,606	76,113
Sales Prior to EE/DE	3,561,552	3,503,928	3,032,624	2,410,843	2,086,853	2,318,230	31,084,748
Energy Efficiency Programs	(228,847)	(204,766)	(121,723)	(119,516)	(91,568)	(97,844)	(1,675,086)
Distributed Energy Programs	(19,898)	(19,933)	(15,203)	(16,231)	(11,146)	(9,961)	(209,596)
Total Sales	3,312,807	3,279,229	2,895,698	2,275,096	1,984,139	2,210,425	29,200,066
Energy Losses	204,058	223,748	142,514	130,871	103,070	146,093	1,840,100
Total Own Load Energy	3,516,865	3,502,977	3,038,212	2,405,967	2,087,209	2,356,518	31,040,166

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2017

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,132,341	930,031	937,352	914,596	1,210,684	1,665,768
Comm+Ind <3 MW	963,923	884,250	1,007,248	1,021,699	1,188,913	1,148,578
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	579	572	874	883	1,467	1,539
Streetlights	12,919	12,853	13,632	13,081	13,849	12,031
Resale (x/off-system sales)	3,828	4,355	3,407	2,535	2,531	2,708
Sales Prior to EE/DE	2,371,817	2,071,015	2,217,983	2,207,819	2,686,676	3,109,577
Energy Efficiency Programs	(145,654)	(118,983)	(158,501)	(169,245)	(208,348)	(279,660)
Distributed Energy Programs	(15,624)	(16,740)	(24,946)	(28,352)	(30,211)	(24,343)
Total Sales	2,210,539	1,935,292	2,034,536	2,010,222	2,448,117	2,805,574
Energy Losses	124,457	102,583	157,175	131,369	191,639	232,159
Total Own Load Energy	2,334,996	2,037,875	2,191,711	2,141,591	2,639,756	3,037,733

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,103,923	1,998,281	1,630,697	1,116,865	889,115	1,187,926	15,717,579
Comm+Ind <3 MW	1,287,222	1,331,305	1,213,773	1,091,338	993,714	935,925	13,067,888
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,323	1,252	1,083	1,066	730	352	11,720
Streetlights	11,670	12,995	11,406	13,577	12,951	13,120	154,084
Resale (x/off-system sales)	3,204	2,974	2,605	2,814	2,846	3,606	37,413
Sales Prior to EE/DE	3,703,894	3,643,312	3,151,117	2,501,040	2,161,757	2,402,970	32,228,977
Energy Efficiency Programs	(312,657)	(278,296)	(163,526)	(160,595)	(120,955)	(129,109)	(2,245,529)
Distributed Energy Programs	(23,788)	(23,878)	(18,276)	(19,579)	(13,497)	(12,083)	(251,317)
Total Sales	3,367,449	3,341,138	2,969,315	2,320,866	2,027,305	2,261,778	29,732,131
Energy Losses	213,060	234,859	115,139	119,013	110,670	146,308	1,878,431
Total Own Load Energy	3,580,509	3,575,997	3,084,454	2,439,879	2,137,975	2,408,086	31,610,562

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2018

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,184,358	972,170	980,063	956,860	1,267,477	1,743,635
Comm+Ind <3 MW	995,671	914,864	1,041,021	1,056,294	1,228,592	1,187,927
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	569	563	861	868	1,447	1,516
Streetlights	13,210	13,139	13,933	13,372	14,156	12,299
Resale (x/off-system sales)	515	1,613	801	0	0	0
Sales Prior to EE/DE	2,452,550	2,141,303	2,292,149	2,282,419	2,780,904	3,224,330
Energy Efficiency Programs	(176,950)	(146,873)	(195,010)	(211,179)	(258,246)	(347,143)
Distributed Energy Programs	(18,124)	(19,569)	(29,102)	(33,002)	(35,115)	(28,274)
Total Sales	2,257,476	1,974,861	2,068,037	2,038,238	2,487,543	2,848,913
Energy Losses	130,054	105,964	160,784	138,072	190,674	235,177
Total Own Load Energy	2,387,530	2,080,825	2,228,821	2,176,310	2,678,217	3,084,090

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,201,102	2,090,925	1,705,395	1,168,255	928,748	1,239,278	16,438,266
Comm+Ind <3 MW	1,331,489	1,376,792	1,256,077	1,128,652	1,027,585	968,117	13,513,081
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,303	1,242	1,070	1,054	722	348	11,563
Streetlights	11,928	13,284	11,660	13,878	13,239	13,411	157,509
Resale (x/off-system sales)	0	0	35	0	0	0	2,964
Sales Prior to EE/DE	3,842,374	3,778,748	3,265,790	2,587,219	2,232,695	2,483,195	33,363,676
Energy Efficiency Programs	(390,615)	(346,321)	(202,476)	(200,058)	(148,943)	(159,308)	(2,783,122)
Distributed Energy Programs	(27,672)	(27,818)	(21,346)	(22,926)	(15,843)	(14,204)	(292,995)
Total Sales	3,424,087	3,404,609	3,041,968	2,364,235	2,067,909	2,309,683	30,287,559
Energy Losses	235,134	240,203	99,323	128,581	110,182	144,511	1,918,659
Total Own Load Energy	3,659,221	3,644,812	3,141,291	2,492,816	2,178,091	2,454,194	32,206,218

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2019

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,235,852	1,014,309	1,023,020	999,083	1,323,958	1,821,322
Comm+Ind <3 MW	1,026,285	944,197	1,073,384	1,089,445	1,266,611	1,225,633
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	563	555	852	859	1,430	1,499
Streetlights	13,472	13,407	14,218	13,647	14,445	12,533
Resale (x/off-system sales)	515	1,613	801	0	0	0
Sales Prior to EE/DE	2,534,914	2,213,035	2,367,745	2,358,059	2,875,676	3,339,940
Energy Efficiency Programs	(207,482)	(174,513)	(230,789)	(252,648)	(306,583)	(409,899)
Distributed Energy Programs	(20,629)	(22,399)	(33,259)	(37,659)	(40,026)	(32,208)
Total Sales	2,306,803	2,016,123	2,103,697	2,067,752	2,529,067	2,897,833
Energy Losses	137,138	108,295	160,648	153,083	204,183	235,822
Total Own Load Energy	2,443,941	2,124,418	2,264,345	2,220,835	2,733,250	3,133,655

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,297,550	2,182,790	1,779,769	1,219,179	968,236	1,290,487	17,155,555
Comm+Ind <3 MW	1,373,905	1,420,376	1,296,614	1,164,405	1,060,041	998,961	13,939,857
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,297	1,232	1,062	1,046	717	345	11,457
Streetlights	12,162	13,545	11,888	14,150	13,497	13,674	160,638
Resale (x/off-system sales)	0	0	35	0	0	0	2,964
Sales Prior to EE/DE	3,981,466	3,914,448	3,380,921	2,674,160	2,304,892	2,565,508	34,510,764
Energy Efficiency Programs	(464,083)	(409,404)	(241,766)	(237,666)	(176,033)	(190,642)	(3,301,508)
Distributed Energy Programs	(31,563)	(31,762)	(24,420)	(26,272)	(18,197)	(16,328)	(334,722)
Total Sales	3,485,820	3,473,282	3,114,735	2,410,222	2,110,662	2,358,538	30,874,534
Energy Losses	231,976	234,495	101,606	136,374	107,576	146,905	1,958,101
Total Own Load Energy	3,717,796	3,707,777	3,216,341	2,546,596	2,218,238	2,505,443	32,832,635

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2020

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,284,970	1,055,158	1,064,284	1,039,972	1,378,405	1,896,274
Comm+Ind <3 MW	1,056,348	972,770	1,104,910	1,121,735	1,303,645	1,262,365
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	562	553	848	856	1,425	1,494
Streetlights	13,701	13,648	14,472	13,889	14,703	12,756
Resale (x/off-system sales)	515	1,613	801	0	0	0
Sales Prior to EE/DE	2,614,323	2,282,696	2,440,785	2,431,477	2,967,410	3,451,842
Energy Efficiency Programs	(237,521)	(211,812)	(266,248)	(292,225)	(352,520)	(479,970)
Distributed Energy Programs	(21,876)	(26,844)	(37,066)	(42,325)	(44,941)	(36,150)
Total Sales	2,354,926	2,044,040	2,137,471	2,096,927	2,569,949	2,935,722
Energy Losses	136,844	153,961	124,740	153,794	209,107	267,430
Total Own Load Energy	2,491,770	2,198,001	2,262,211	2,250,721	2,779,056	3,203,152

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,390,626	2,271,574	1,851,336	1,268,313	1,006,315	1,340,070	17,847,297
Comm+Ind <3 MW	1,415,223	1,462,831	1,336,100	1,199,234	1,091,657	1,029,007	14,355,825
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,293	1,234	1,062	1,046	717	345	11,435
Streetlights	12,379	13,786	12,100	14,402	13,740	13,918	163,494
Resale (x/off-system sales)	0	0	35	0	0	0	2,964
Sales Prior to EE/DE	4,116,073	4,045,930	3,492,186	2,758,375	2,374,830	2,645,381	35,621,308
Energy Efficiency Programs	(536,230)	(472,851)	(281,493)	(273,529)	(204,268)	(221,810)	(3,830,477)
Distributed Energy Programs	(35,453)	(35,712)	(27,497)	(29,626)	(20,547)	(18,457)	(376,494)
Total Sales	3,544,390	3,537,367	3,183,196	2,455,220	2,150,015	2,405,114	31,414,337
Energy Losses	237,444	230,967	81,895	133,643	116,163	159,229	2,005,217
Total Own Load Energy	3,781,834	3,768,334	3,265,091	2,588,863	2,266,178	2,564,343	33,419,554

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2021

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,336,936	1,096,947	1,106,574	1,081,716	1,434,175	1,972,511
Comm+Ind <3 MW	1,089,084	1,002,824	1,138,065	1,155,698	1,342,595	1,300,997
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	562	553	848	856	1,425	1,494
Streetlights	13,981	13,914	14,756	14,162	14,992	13,005
Resale (x/off-system sales)	0	0	0	0	0	0
Sales Prior to EE/DE	2,698,790	2,353,192	2,515,713	2,507,457	3,062,419	3,566,960
Energy Efficiency Programs	(249,139)	(221,011)	(294,620)	(317,716)	(383,900)	(522,516)
Distributed Energy Programs	(27,223)	(29,386)	(43,585)	(49,304)	(52,357)	(42,116)
Total Sales	2,422,428	2,102,795	2,177,508	2,140,437	2,626,162	3,002,328
Energy Losses	121,509	108,537	188,401	158,592	218,889	272,950
Total Own Load Energy	2,543,937	2,211,332	2,365,909	2,299,029	2,845,051	3,275,278

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,485,708	2,362,108	1,924,333	1,318,380	1,045,304	1,390,734	18,555,426
Comm+Ind <3 MW	1,458,677	1,507,484	1,377,629	1,235,866	1,124,909	1,060,607	14,794,435
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,293	1,234	1,062	1,046	717	345	11,435
Streetlights	12,622	14,056	12,339	14,685	14,009	14,190	166,711
Resale (x/off-system sales)	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,254,852	4,181,387	3,606,916	2,845,357	2,447,340	2,727,917	36,768,300
Energy Efficiency Programs	(582,914)	(516,730)	(305,982)	(296,217)	(224,465)	(239,558)	(4,154,768)
Distributed Energy Programs	(41,302)	(41,599)	(32,026)	(34,499)	(23,923)	(21,485)	(438,805)
Total Sales	3,630,636	3,623,058	3,268,908	2,514,641	2,198,952	2,466,874	32,174,727
Energy Losses	239,334	234,077	93,461	137,337	108,449	160,154	2,041,690
Total Own Load Energy	3,869,970	3,857,135	3,362,369	2,651,978	2,307,401	2,627,028	34,216,417

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2022

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,389,907	1,139,590	1,149,744	1,124,127	1,490,800	2,049,989
Comm+Ind <3 MW	1,120,425	1,032,448	1,170,746	1,189,176	1,380,989	1,339,075
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	562	553	848	856	1,425	1,494
Streetlights	14,238	14,175	15,031	14,427	15,273	13,250
Resale (x/off-system sales)	0	0	0	0	0	0
Sales Prior to EE/DE	2,783,359	2,425,720	2,591,839	2,583,611	3,157,719	3,682,761
Energy Efficiency Programs	(252,999)	(227,382)	(303,836)	(325,955)	(397,938)	(537,989)
Distributed Energy Programs	(34,283)	(36,395)	(54,076)	(61,273)	(65,149)	(52,440)
Total Sales	2,496,077	2,161,943	2,233,927	2,196,383	2,694,632	3,092,332
Energy Losses	128,667	108,755	195,437	167,976	242,231	280,145
Total Own Load Energy	2,624,744	2,270,698	2,429,364	2,364,359	2,936,863	3,372,477

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,582,295	2,454,273	1,998,731	1,369,327	1,084,727	1,441,960	19,275,470
Comm+Ind <3 MW	1,501,512	1,551,498	1,418,566	1,271,970	1,157,685	1,091,756	15,225,846
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,293	1,234	1,062	1,046	717	345	11,435
Streetlights	12,858	14,319	12,570	14,960	14,271	14,456	169,828
Resale (x/off-system sales)	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,394,510	4,317,829	3,722,482	2,932,683	2,519,801	2,810,558	37,922,872
Energy Efficiency Programs	(599,911)	(534,636)	(314,917)	(305,437)	(231,437)	(246,924)	(4,279,361)
Distributed Energy Programs	(51,358)	(51,665)	(39,690)	(42,671)	(29,527)	(26,486)	(545,013)
Total Sales	3,743,241	3,731,528	3,367,875	2,584,575	2,258,837	2,537,148	33,098,498
Energy Losses	232,511	241,034	95,147	137,264	113,930	161,123	2,104,220
Total Own Load Energy	3,975,752	3,972,562	3,463,022	2,721,839	2,372,767	2,698,271	35,202,718

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2023

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,442,221	1,182,179	1,193,019	1,166,966	1,547,599	2,128,104
Comm+Ind <3 MW	1,149,347	1,060,380	1,201,563	1,220,742	1,417,193	1,374,980
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	562	553	848	856	1,425	1,494
Streetlights	14,486	14,429	15,299	14,685	15,545	13,485
Resale (x/off-system sales)	0	0	0	0	0	0
Sales Prior to EE/DE	2,864,843	2,496,495	2,666,199	2,658,274	3,250,994	3,797,016
Energy Efficiency Programs	(263,924)	(236,316)	(315,903)	(337,131)	(415,873)	(558,458)
Distributed Energy Programs	(42,305)	(45,024)	(67,011)	(76,057)	(80,974)	(65,214)
Total Sales	2,558,614	2,215,155	2,283,285	2,245,086	2,754,147	3,173,344
Energy Losses	133,106	112,621	204,361	170,702	260,271	289,968
Total Own Load Energy	2,691,720	2,327,776	2,487,646	2,415,788	3,014,418	3,463,312

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,679,512	2,546,900	2,073,607	1,420,720	1,124,754	1,494,198	19,999,779
Comm+Ind <3 MW	1,541,902	1,592,998	1,457,167	1,306,017	1,188,591	1,121,127	15,632,007
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,293	1,234	1,062	1,046	717	345	11,435
Streetlights	13,088	14,574	12,778	15,214	14,514	14,702	172,799
Resale (x/off-system sales)	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,532,347	4,452,211	3,836,167	3,018,377	2,590,977	2,892,413	39,056,313
Energy Efficiency Programs	(623,348)	(555,618)	(326,377)	(319,538)	(240,059)	(255,060)	(4,447,605)
Distributed Energy Programs	(63,785)	(64,090)	(49,129)	(52,713)	(36,398)	(32,610)	(675,310)
Total Sales	3,845,214	3,832,503	3,460,661	2,646,126	2,314,520	2,604,743	33,933,398
Energy Losses	241,822	258,194	75,799	128,142	126,375	161,652	2,163,013
Total Own Load Energy	4,087,036	4,090,697	3,536,460	2,774,268	2,440,895	2,766,395	36,096,411

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2024

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,494,632	1,224,898	1,236,407	1,209,675	1,604,539	2,206,368
Comm+Ind <3 MW	1,177,191	1,087,087	1,231,028	1,250,923	1,451,807	1,409,312
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	562	553	848	856	1,425	1,494
Streetlights	14,786	14,712	15,598	14,974	15,850	13,747
Resale (x/off-system sales)	0	0	0	0	0	0
Sales Prior to EE/DE	2,945,398	2,566,204	2,739,351	2,731,453	3,342,853	3,909,874
Energy Efficiency Programs	(275,850)	(258,082)	(320,244)	(354,525)	(430,351)	(574,604)
Distributed Energy Programs	(47,328)	(57,286)	(79,494)	(91,183)	(97,162)	(78,284)
Total Sales	2,622,220	2,250,836	2,339,613	2,285,745	2,815,340	3,256,986
Energy Losses	139,524	179,702	145,149	187,628	256,207	275,578
Total Own Load Energy	2,761,744	2,430,538	2,484,762	2,473,373	3,071,547	3,532,564

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,777,027	2,639,898	2,148,646	1,472,174	1,164,674	1,546,099	20,725,037
Comm+Ind <3 MW	1,580,519	1,632,681	1,494,073	1,338,570	1,218,140	1,149,210	16,020,541
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,293	1,234	1,062	1,046	717	345	11,435
Streetlights	13,345	14,859	13,028	15,513	14,798	14,990	176,200
Resale (x/off-system sales)	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,668,736	4,585,177	3,948,362	3,102,683	2,660,730	2,972,685	40,173,506
Energy Efficiency Programs	(650,243)	(573,957)	(339,246)	(333,429)	(246,831)	(266,764)	(4,624,126)
Distributed Energy Programs	(76,502)	(76,798)	(58,788)	(62,988)	(43,423)	(38,876)	(808,112)
Total Sales	3,941,991	3,934,422	3,550,328	2,706,266	2,370,476	2,667,045	34,741,268
Energy Losses	257,992	257,628	83,660	152,154	124,213	163,044	2,222,479
Total Own Load Energy	4,199,983	4,192,050	3,633,988	2,858,420	2,494,689	2,830,089	36,963,747

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2025

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,547,568	1,268,052	1,280,136	1,252,843	1,662,075	2,285,511
Comm+Ind <3 MW	1,204,677	1,113,176	1,259,812	1,280,406	1,485,621	1,442,849
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	562	553	848	856	1,425	1,494
Streetlights	15,040	14,975	15,876	15,241	16,133	13,993
Resale (x/off-system sales)	0	0	0	0	0	0
Sales Prior to EE/DE	3,026,074	2,635,710	2,812,142	2,804,371	3,434,486	4,022,800
Energy Efficiency Programs	(285,814)	(253,935)	(336,377)	(367,996)	(444,892)	(599,369)
Distributed Energy Programs	(57,984)	(62,958)	(93,894)	(106,776)	(113,857)	(91,759)
Total Sales	2,682,276	2,318,817	2,381,871	2,329,599	2,875,737	3,331,672
Energy Losses	148,453	124,862	205,546	198,101	264,502	298,299
Total Own Load Energy	2,830,729	2,443,679	2,587,417	2,527,700	3,140,239	3,629,971

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,875,755	2,734,076	2,224,544	1,524,460	1,205,059	1,598,724	21,458,803
Comm+Ind <3 MW	1,618,245	1,671,445	1,530,125	1,370,370	1,247,008	1,176,643	16,400,377
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,293	1,234	1,062	1,046	717	345	11,435
Streetlights	13,583	15,124	13,261	15,790	15,064	15,257	179,337
Resale (x/off-system sales)	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,805,428	4,718,384	4,060,545	3,187,046	2,730,249	3,053,010	41,290,245
Energy Efficiency Programs	(673,813)	(593,696)	(353,779)	(345,759)	(254,439)	(279,118)	(4,788,987)
Distributed Energy Programs	(89,614)	(89,906)	(68,747)	(73,583)	(50,674)	(45,337)	(945,089)
Total Sales	4,042,001	4,034,782	3,638,019	2,767,704	2,425,136	2,728,555	35,556,169
Energy Losses	261,276	250,475	70,861	155,563	134,053	171,142	2,283,133
Total Own Load Energy	4,303,277	4,285,257	3,708,880	2,923,267	2,559,189	2,899,697	37,839,302

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2026

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,601,159	1,311,732	1,324,507	1,296,577	1,720,399	2,365,766
Comm+Ind <3 MW	1,232,489	1,139,282	1,288,612	1,309,908	1,519,455	1,476,405
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	562	553	848	856	1,425	1,494
Streetlights	15,289	15,229	16,147	15,499	16,410	14,229
Resale (x/off-system sales)	0	0	0	0	0	0
Sales Prior to EE/DE	3,107,726	2,705,750	2,885,584	2,877,865	3,526,921	4,136,847
Energy Efficiency Programs	(292,618)	(263,145)	(349,873)	(379,813)	(458,232)	(622,811)
Distributed Energy Programs	(62,027)	(68,907)	(102,815)	(116,970)	(124,767)	(100,568)
Total Sales	2,753,081	2,373,698	2,432,896	2,381,082	2,943,922	3,413,468
Energy Losses	138,639	128,061	220,233	194,530	268,282	315,353
Total Own Load Energy	2,891,720	2,501,759	2,653,129	2,575,612	3,212,204	3,728,821

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	2,975,780	2,829,573	2,301,683	1,577,324	1,246,291	1,652,368	22,203,159
Comm+Ind <3 MW	1,655,992	1,710,232	1,566,201	1,402,189	1,275,891	1,204,093	16,780,749
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,293	1,234	1,062	1,046	717	345	11,435
Streetlights	13,814	15,381	13,486	16,058	15,320	15,517	182,379
Resale (x/off-system sales)	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,943,431	4,852,925	4,173,985	3,271,997	2,800,620	3,134,364	42,418,015
Energy Efficiency Programs	(695,625)	(613,726)	(365,788)	(355,523)	(265,494)	(287,982)	(4,950,630)
Distributed Energy Programs	(98,185)	(98,471)	(75,257)	(80,506)	(55,412)	(49,562)	(1,033,447)
Total Sales	4,149,621	4,140,728	3,732,940	2,835,968	2,479,714	2,796,820	36,433,938
Energy Losses	268,169	261,827	70,352	156,919	142,471	180,520	2,345,356
Total Own Load Energy	4,417,790	4,402,555	3,803,292	2,992,887	2,622,185	2,977,340	38,779,294

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2027

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,655,568	1,356,075	1,369,455	1,340,923	1,779,666	2,446,975
Comm+Ind <3 MW	1,260,870	1,165,757	1,317,821	1,339,828	1,553,769	1,510,436
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	562	553	848	856	1,425	1,494
Streetlights	15,547	15,490	16,420	15,764	16,688	14,472
Resale (x/off-system sales)	0	0	0	0	0	0
Sales Prior to EE/DE	3,190,774	2,776,829	2,960,014	2,952,396	3,620,780	4,252,330
Energy Efficiency Programs	(300,815)	(272,749)	(364,012)	(392,227)	(473,937)	(644,099)
Distributed Energy Programs	(63,210)	(71,597)	(106,846)	(121,581)	(129,699)	(104,553)
Total Sales	2,826,749	2,432,483	2,489,156	2,438,588	3,017,144	3,503,678
Energy Losses	136,710	126,722	233,237	198,962	277,148	319,463
Total Own Load Energy	2,963,459	2,559,205	2,722,393	2,637,550	3,294,292	3,823,141

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	3,077,496	2,926,372	2,380,107	1,631,285	1,288,102	1,706,720	22,958,744
Comm+Ind <3 MW	1,694,275	1,749,569	1,602,786	1,434,458	1,305,183	1,231,934	17,166,686
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,293	1,234	1,062	1,046	717	345	11,435
Streetlights	14,048	15,643	13,715	16,332	15,580	15,781	185,480
Resale (x/off-system sales)	0	0	0	0	0	0	0
Sales Prior to EE/DE	5,083,664	4,989,323	4,289,223	3,358,501	2,871,983	3,216,821	43,562,638
Energy Efficiency Programs	(718,487)	(637,098)	(377,673)	(365,695)	(277,098)	(295,445)	(5,119,335)
Distributed Energy Programs	(102,057)	(102,345)	(78,200)	(83,635)	(57,552)	(51,468)	(1,072,743)
Total Sales	4,263,120	4,249,880	3,833,350	2,909,171	2,537,333	2,869,908	37,370,560
Energy Losses	269,893	266,834	89,695	162,938	135,887	181,544	2,399,033
Total Own Load Energy	4,533,013	4,516,714	3,923,045	3,072,109	2,673,220	3,051,452	39,769,593

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2028

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,710,506	1,400,973	1,415,157	1,385,802	1,840,090	2,529,475
Comm+Ind <3 MW	1,289,423	1,192,460	1,347,281	1,370,004	1,588,378	1,544,762
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	562	553	848	856	1,425	1,494
Streetlights	15,813	15,752	16,698	16,033	16,970	14,720
Resale (x/off-system sales)	0	0	0	0	0	0
Sales Prior to EE/DE	3,274,531	2,848,692	3,035,454	3,027,720	3,716,095	4,369,404
Energy Efficiency Programs	(313,184)	(296,592)	(371,651)	(401,136)	(494,872)	(663,799)
Distributed Energy Programs	(61,947)	(79,117)	(109,981)	(126,350)	(134,804)	(108,676)
Total Sales	2,899,400	2,472,983	2,553,822	2,500,234	3,086,419	3,596,929
Energy Losses	146,300	191,588	176,691	204,383	311,806	330,606
Total Own Load Energy	3,045,700	2,664,571	2,730,513	2,704,617	3,398,225	3,927,535

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	3,180,850	3,025,100	2,459,784	1,685,982	1,330,650	1,762,178	23,726,547
Comm+Ind <3 MW	1,732,887	1,789,244	1,639,688	1,467,005	1,334,729	1,260,012	17,555,873
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,293	1,234	1,062	1,046	717	345	11,435
Streetlights	14,288	15,909	13,947	16,610	15,844	16,049	188,633
Resale (x/off-system sales)	0	0	0	0	0	0	0
Sales Prior to EE/DE	5,225,870	5,127,992	4,406,034	3,446,023	2,944,341	3,300,625	44,722,781
Energy Efficiency Programs	(741,028)	(660,565)	(388,256)	(380,242)	(285,610)	(303,351)	(5,300,286)
Distributed Energy Programs	(106,069)	(106,351)	(81,243)	(86,874)	(59,767)	(53,441)	(1,114,620)
Total Sales	4,378,773	4,361,076	3,936,535	2,978,907	2,598,964	2,943,833	38,307,875
Energy Losses	266,818	286,913	70,738	147,860	151,833	180,484	2,466,020
Total Own Load Energy	4,645,591	4,647,989	4,007,273	3,126,767	2,750,797	3,124,317	40,773,895

Attachment C.1 (b) - Energy Consumption by Month and Customer Class

APS ENERGY DEMAND BY MONTH BY CUSTOMER CLASS

YEAR: 2029

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Residential	1,766,273	1,446,630	1,461,458	1,431,554	1,901,210	2,613,516
Comm+Ind <3 MW	1,318,209	1,219,383	1,376,985	1,400,430	1,623,273	1,579,370
Comm+Ind >3 MW	258,227	238,954	255,470	255,025	269,232	278,953
Irrigation	559	552	844	853	1,418	1,489
Streetlights	16,081	16,019	16,983	16,305	17,259	14,969
Resale (x/off-system sales)	0	0	0	0	0	0
Sales Prior to EE/DE	3,359,349	2,921,538	3,111,740	3,104,167	3,812,392	4,488,297
Energy Efficiency Programs	(328,159)	(291,028)	(387,816)	(418,908)	(512,693)	(685,660)
Distributed Energy Programs	(68,120)	(77,211)	(115,265)	(131,208)	(140,002)	(112,872)
Total Sales	2,963,070	2,553,299	2,608,659	2,554,051	3,159,697	3,689,765
Energy Losses	158,693	133,824	242,121	211,726	304,378	328,190
Total Own Load Energy	3,121,763	2,687,123	2,850,780	2,765,777	3,464,075	4,017,955

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	3,286,038	3,125,253	2,540,625	1,741,546	1,373,746	1,818,410	24,506,259
Comm+Ind <3 MW	1,771,816	1,829,247	1,676,892	1,499,821	1,364,518	1,288,320	17,948,264
Comm+Ind >3 MW	296,552	296,505	291,553	275,380	262,401	262,041	3,240,293
Irrigation	1,288	1,229	1,058	1,042	715	343	11,390
Streetlights	14,530	16,179	14,186	16,893	16,113	16,321	191,838
Resale (x/off-system sales)	0	0	0	0	0	0	0
Sales Prior to EE/DE	5,370,224	5,268,413	4,524,314	3,534,682	3,017,493	3,385,435	45,898,044
Energy Efficiency Programs	(770,742)	(684,970)	(401,454)	(397,035)	(295,576)	(314,685)	(5,488,726)
Distributed Energy Programs	(110,150)	(110,433)	(84,343)	(90,170)	(62,020)	(55,451)	(1,157,245)
Total Sales	4,489,332	4,473,010	4,038,517	3,047,477	2,659,897	3,015,299	39,252,073
Energy Losses	296,092	297,354	63,885	165,908	155,501	180,476	2,538,148
Total Own Load Energy	4,785,424	4,770,364	4,102,402	3,213,385	2,815,398	3,195,775	41,790,221

Attachment C.2 - Coincident Peak Demand Disaggregated by DSM

APS COINCIDENT PEAK DEMAND BY MONTH AND YEAR AGGREGATED BY DEMAND MANAGEMENT

YEAR: 2014

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	4,172	4,056	3,764	4,144	5,531	6,196
Distributed Energy Programs	0	(0)	0	(22)	(25)	(26)
Own Load Peak - After DE Before EE/DR	4,172	4,055	3,764	4,121	5,506	6,170
Energy Efficiency Programs	(65)	(63)	(65)	(73)	(80)	(101)
Demand Response Programs	0	0	0	0	0	(21)
Own Load Peak After EE/DR/DE	4,106	3,993	3,699	4,048	5,426	6,049

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	7,146	7,146	6,417	5,041	3,893	4,130	7,146
Distributed Energy Programs	(23)	(23)	(17)	(11)	0	(0)	(23)
Own Load Peak - After DE Before EE/DR	7,123	7,123	6,401	5,030	3,893	4,130	7,123
Energy Efficiency Programs	(111)	(109)	(93)	(80)	(56)	(65)	(109)
Demand Response Programs	(21)	(21)	(21)	0	0	0	(21)
Own Load Peak After EE/DR/DE	6,991	6,993	6,287	4,950	3,836	4,065	6,993

YEAR: 2015

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	4,286	4,147	3,855	4,207	5,634	6,332
Distributed Energy Programs	0	(0)	0	(28)	(40)	(48)
Own Load Peak - After DE Before EE/DR	4,286	4,147	3,855	4,178	5,594	6,284
Energy Efficiency Programs	(127)	(121)	(130)	(163)	(182)	(243)
Demand Response Programs	0	0	0	0	0	(21)
Own Load Peak After EE/DR/DE	4,159	4,026	3,725	4,015	5,411	6,020

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	7,292	7,292	6,574	5,164	3,997	4,246	7,292
Distributed Energy Programs	(37)	(37)	(27)	(18)	0	(0)	(37)
Own Load Peak - After DE Before EE/DR	7,255	7,255	6,547	5,146	3,997	4,246	7,255
Energy Efficiency Programs	(277)	(267)	(222)	(180)	(115)	(126)	(267)
Demand Response Programs	(21)	(21)	(21)	0	0	0	(21)
Own Load Peak After EE/DR/DE	6,957	6,967	6,304	4,966	3,882	4,120	6,967

Attachment C.2 - Coincident Peak Demand Disaggregated by DSM

APS COINCIDENT PEAK DEMAND BY MONTH AND YEAR AGGREGATED BY DEMAND MANAGEMENT

YEAR: 2016

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	4,434	4,216	3,930	4,367	5,865	6,589
Distributed Energy Programs	(0)	(0)	(0)	(22)	(50)	(62)
Own Load Peak - After DE Before EE/DR	4,434	4,216	3,930	4,344	5,815	6,527
Energy Efficiency Programs	(190)	(182)	(197)	(258)	(290)	(396)
Demand Response Programs	0	0	0	0	0	(26)
Own Load Peak After EE/DR/DE	4,244	4,034	3,733	4,087	5,526	6,105

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	7,573	7,573	6,858	5,348	4,124	4,396	7,573
Distributed Energy Programs	(46)	(46)	(34)	(23)	(0)	(0)	(46)
Own Load Peak - After DE Before EE/DR	7,527	7,527	6,824	5,325	4,124	4,396	7,527
Energy Efficiency Programs	(453)	(434)	(359)	(285)	(175)	(188)	(434)
Demand Response Programs	(26)	(26)	(26)	0	0	0	(26)
Own Load Peak After EE/DR/DE	7,048	7,066	6,438	5,040	3,949	4,207	7,066

YEAR: 2017

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	4,606	4,431	4,138	4,515	6,090	6,820
Distributed Energy Programs	(0)	(0)	(0)	(3)	(59)	(62)
Own Load Peak - After DE Before EE/DR	4,606	4,431	4,138	4,512	6,031	6,758
Energy Efficiency Programs	(250)	(239)	(261)	(348)	(392)	(553)
Demand Response Programs	0	0	0	0	0	(26)
Own Load Peak After EE/DR/DE	4,356	4,192	3,877	4,164	5,638	6,178

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	7,881	7,881	7,093	5,527	4,291	4,553	7,881
Distributed Energy Programs	(55)	(55)	(41)	(27)	(0)	(0)	(55)
Own Load Peak - After DE Before EE/DR	7,826	7,826	7,052	5,499	4,291	4,553	7,826
Energy Efficiency Programs	(620)	(594)	(490)	(387)	(233)	(247)	(594)
Demand Response Programs	(26)	(26)	(26)	0	0	0	(26)
Own Load Peak After EE/DR/DE	7,180	7,206	6,536	5,112	4,058	4,306	7,206

Attachment C.2 - Coincident Peak Demand Disaggregated by DSM

APS COINCIDENT PEAK DEMAND BY MONTH AND YEAR AGGREGATED BY DEMAND MANAGEMENT

YEAR: 2018

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	4,771	4,588	4,271	4,670	6,280	7,055
Distributed Energy Programs	0	(0)	0	0	(69)	(72)
Own Load Peak - After DE Before EE/DR	4,771	4,588	4,271	4,670	6,211	6,983
Energy Efficiency Programs	(307)	(293)	(321)	(430)	(488)	(690)
Demand Response Programs	0	0	0	0	0	(26)
Own Load Peak After EE/DR/DE	4,465	4,295	3,951	4,240	5,723	6,267

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	8,180	8,180	7,341	5,738	4,434	4,699	8,180
Distributed Energy Programs	(85)	(67)	(48)	(32)	0	(0)	(67)
Own Load Peak - After DE Before EE/DR	8,095	8,113	7,293	5,706	4,434	4,699	8,113
Energy Efficiency Programs	(773)	(738)	(610)	(480)	(287)	(303)	(738)
Demand Response Programs	(26)	(26)	(26)	0	0	0	(26)
Own Load Peak After EE/DR/DE	7,296	7,349	6,657	5,226	4,147	4,396	7,349

YEAR: 2019

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	4,942	4,746	4,401	4,846	6,502	7,289
Distributed Energy Programs	(0)	(0)	(0)	(60)	(78)	(82)
Own Load Peak - After DE Before EE/DR	4,942	4,746	4,401	4,785	6,424	7,208
Energy Efficiency Programs	(363)	(347)	(381)	(516)	(580)	(817)
Demand Response Programs	0	0	0	0	0	(26)
Own Load Peak After EE/DR/DE	4,579	4,399	4,020	4,270	5,844	6,364

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	8,481	8,481	7,625	5,949	4,575	4,854	8,481
Distributed Energy Programs	(74)	(74)	(54)	(37)	(0)	(0)	(74)
Own Load Peak - After DE Before EE/DR	8,407	8,407	7,570	5,912	4,575	4,854	8,407
Energy Efficiency Programs	(915)	(877)	(724)	(569)	(300)	(358)	(877)
Demand Response Programs	(26)	(26)	(26)	0	0	0	(26)
Own Load Peak After EE/DR/DE	7,466	7,503	6,820	5,342	4,275	4,496	7,503

Attachment C.2 - Coincident Peak Demand Disaggregated by DSM

APS COINCIDENT PEAK DEMAND BY MONTH AND YEAR AGGREGATED BY DEMAND MANAGEMENT

YEAR: 2020

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	5,096	4,807	4,467	4,979	6,701	7,574
Distributed Energy Programs	0	(0)	0	0	(88)	(112)
Own Load Peak - After DE Before EE/DR	5,096	4,807	4,467	4,979	6,614	7,463
Energy Efficiency Programs	(417)	(399)	(440)	(568)	(673)	(928)
Demand Response Programs	0	0	0	0	0	(51)
Own Load Peak After EE/DR/DE	4,679	4,408	4,028	4,411	5,941	6,483

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	8,772	8,772	7,853	6,133	4,732	5,023	8,772
Distributed Energy Programs	(104)	(92)	(61)	(42)	0	(0)	(92)
Own Load Peak - After DE Before EE/DR	8,668	8,680	7,792	6,091	4,732	5,023	8,680
Energy Efficiency Programs	(1,061)	(1,008)	(839)	(660)	(396)	(412)	(1,008)
Demand Response Programs	(51)	(51)	(51)	0	0	0	(51)
Own Load Peak After EE/DR/DE	7,556	7,621	6,902	5,431	4,336	4,611	7,621

YEAR: 2021

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	5,236	5,041	4,701	5,140	6,919	7,817
Distributed Energy Programs	0	(0)	0	0	(102)	(107)
Own Load Peak - After DE Before EE/DR	5,236	5,041	4,701	5,140	6,817	7,710
Energy Efficiency Programs	(454)	(434)	(478)	(579)	(733)	(1,031)
Demand Response Programs	0	0	0	0	0	(76)
Own Load Peak After EE/DR/DE	4,782	4,606	4,222	4,560	6,084	6,603

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	9,071	9,071	8,147	6,333	4,859	5,177	9,071
Distributed Energy Programs	(142)	(107)	(71)	(49)	0	(0)	(107)
Own Load Peak - After DE Before EE/DR	8,930	8,964	8,076	6,285	4,859	5,177	8,964
Energy Efficiency Programs	(1,155)	(1,096)	(914)	(721)	(431)	(448)	(1,096)
Demand Response Programs	(76)	(76)	(76)	0	0	0	(76)
Own Load Peak After EE/DR/DE	7,699	7,792	7,086	5,564	4,428	4,729	7,792

Attachment C.2 - Coincident Peak Demand Disaggregated by DSM

APS COINCIDENT PEAK DEMAND BY MONTH AND YEAR AGGREGATED BY DEMAND MANAGEMENT

YEAR: 2022

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	5,414	5,192	4,844	5,305	7,166	8,073
Distributed Energy Programs	0	(1)	0	0	(127)	(155)
Own Load Peak - After DE Before EE/DR	5,414	5,191	4,844	5,305	7,039	7,918
Energy Efficiency Programs	(467)	(447)	(493)	(641)	(755)	(1,042)
Demand Response Programs	0	0	0	0	0	(126)
Own Load Peak After EE/DR/DE	4,947	4,744	4,351	4,664	6,283	6,750

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	9,373	9,373	8,410	6,518	5,009	5,329	9,373
Distributed Energy Programs	(137)	(131)	(88)	(60)	0	(0)	(131)
Own Load Peak - After DE Before EE/DR	9,236	9,243	8,322	6,458	5,009	5,329	9,243
Energy Efficiency Programs	(1,190)	(1,130)	(942)	(742)	(444)	(462)	(1,130)
Demand Response Programs	(126)	(126)	(126)	0	0	0	(126)
Own Load Peak After EE/DR/DE	7,920	7,986	7,253	5,717	4,565	4,867	7,986

YEAR: 2023

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	5,572	5,346	4,987	5,454	7,396	8,328
Distributed Energy Programs	0	(1)	0	0	(158)	(165)
Own Load Peak - After DE Before EE/DR	5,572	5,345	4,987	5,454	7,238	8,163
Energy Efficiency Programs	(485)	(464)	(512)	(658)	(785)	(1,105)
Demand Response Programs	0	0	0	0	0	(151)
Own Load Peak After EE/DR/DE	5,087	4,881	4,475	4,796	6,452	6,908

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	9,671	9,671	8,628	6,684	5,172	5,479	9,671
Distributed Energy Programs	(154)	(160)	(109)	(53)	0	(0)	(160)
Own Load Peak - After DE Before EE/DR	9,517	9,511	8,518	6,631	5,172	5,479	9,511
Energy Efficiency Programs	(1,237)	(1,174)	(979)	(773)	(462)	(479)	(1,174)
Demand Response Programs	(151)	(151)	(151)	0	0	0	(151)
Own Load Peak After EE/DR/DE	8,129	8,185	7,387	5,858	4,710	5,000	8,185

Attachment C.2 - Coincident Peak Demand Disaggregated by DSM

APS COINCIDENT PEAK DEMAND BY MONTH AND YEAR AGGREGATED BY DEMAND MANAGEMENT

YEAR: 2024

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	5,738	5,420	5,018	5,626	7,581	8,535
Distributed Energy Programs	(0)	(1)	(0)	(94)	(190)	(185)
Own Load Peak - After DE Before EE/DR	5,738	5,419	5,018	5,532	7,391	8,349
Energy Efficiency Programs	(503)	(481)	(531)	(727)	(815)	(1,146)
Demand Response Programs	0	0	0	0	0	(176)
Own Load Peak After EE/DR/DE	5,236	4,938	4,487	4,805	6,576	7,027

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	9,965	9,965	8,898	6,913	5,306	5,627	9,965
Distributed Energy Programs	(173)	(178)	(131)	(74)	(0)	(0)	(178)
Own Load Peak - After DE Before EE/DR	9,792	9,787	8,767	6,839	5,306	5,626	9,787
Energy Efficiency Programs	(1,283)	(1,230)	(1,016)	(800)	(413)	(497)	(1,230)
Demand Response Programs	(176)	(176)	(176)	0	0	0	(176)
Own Load Peak After EE/DR/DE	8,333	8,380	7,574	6,039	4,893	5,130	8,380

YEAR: 2025

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	5,902	5,660	5,240	5,781	7,790	8,811
Distributed Energy Programs	0	(1)	0	0	(223)	(206)
Own Load Peak - After DE Before EE/DR	5,902	5,659	5,240	5,781	7,568	8,606
Energy Efficiency Programs	(521)	(499)	(551)	(736)	(846)	(1,189)
Demand Response Programs	0	0	0	0	0	(175)
Own Load Peak After EE/DR/DE	5,381	5,160	4,690	5,046	6,722	7,242

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	10,260	10,260	9,124	7,103	5,461	5,786	10,260
Distributed Energy Programs	(193)	(222)	(153)	(75)	0	(0)	(222)
Own Load Peak - After DE Before EE/DR	10,068	10,038	8,971	7,028	5,461	5,785	10,038
Energy Efficiency Programs	(1,331)	(1,264)	(1,055)	(830)	(425)	(515)	(1,264)
Demand Response Programs	(175)	(175)	(175)	0	0	0	(175)
Own Load Peak After EE/DR/DE	8,561	8,599	7,741	6,198	5,036	5,270	8,599

Attachment C.2 - Coincident Peak Demand Disaggregated by DSM

APS COINCIDENT PEAK DEMAND BY MONTH AND YEAR AGGREGATED BY DEMAND MANAGEMENT

YEAR: 2026

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	6,041	5,810	5,391	5,908	7,993	9,079
Distributed Energy Programs	0	(1)	0	0	(238)	(280)
Own Load Peak - After DE Before EE/DR	6,041	5,809	5,391	5,908	7,754	8,799
Energy Efficiency Programs	(538)	(515)	(569)	(731)	(875)	(1,206)
Demand Response Programs	0	0	0	0	0	(200)
Own Load Peak After EE/DR/DE	5,502	5,293	4,822	5,178	6,880	7,393

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	10,558	10,558	9,378	7,289	5,611	5,951	10,558
Distributed Energy Programs	(206)	(242)	(168)	(71)	0	(0)	(242)
Own Load Peak - After DE Before EE/DR	10,352	10,316	9,210	7,219	5,611	5,950	10,316
Energy Efficiency Programs	(1,376)	(1,307)	(1,090)	(859)	(514)	(532)	(1,307)
Demand Response Programs	(200)	(200)	(200)	0	0	0	(200)
Own Load Peak After EE/DR/DE	8,776	8,809	7,920	6,360	5,097	5,419	8,809

YEAR: 2027

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	6,195	5,952	5,542	6,070	8,209	9,321
Distributed Energy Programs	0	(1)	0	0	(246)	(227)
Own Load Peak - After DE Before EE/DR	6,195	5,951	5,542	6,070	7,963	9,094
Energy Efficiency Programs	(557)	(533)	(589)	(736)	(905)	(1,271)
Demand Response Programs	0	0	0	0	0	(225)
Own Load Peak After EE/DR/DE	5,639	5,418	4,953	5,334	7,058	7,597

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	10,860	10,860	9,678	7,490	5,734	6,103	10,860
Distributed Energy Programs	(287)	(252)	(174)	(57)	0	(0)	(252)
Own Load Peak - After DE Before EE/DR	10,573	10,608	9,504	7,433	5,734	6,103	10,608
Energy Efficiency Programs	(1,423)	(1,351)	(1,128)	(890)	(532)	(550)	(1,351)
Demand Response Programs	(225)	(225)	(225)	0	0	0	(225)
Own Load Peak After EE/DR/DE	8,925	9,032	8,151	6,542	5,202	5,553	9,032

Attachment C.2 - Coincident Peak Demand Disaggregated by DSM

APS COINCIDENT PEAK DEMAND BY MONTH AND YEAR AGGREGATED BY DEMAND MANAGEMENT

YEAR: 2028

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	6,375	6,001	5,583	6,227	8,476	9,585
Distributed Energy Programs	0	(1)	0	0	(264)	(235)
Own Load Peak - After DE Before EE/DR	6,375	6,000	5,583	6,227	8,213	9,350
Energy Efficiency Programs	(575)	(550)	(608)	(783)	(935)	(1,313)
Demand Response Programs	0	0	0	0	0	(250)
Own Load Peak After EE/DR/DE	5,800	5,450	4,975	5,444	7,278	7,787

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	11,167	11,167	9,901	7,644	5,904	6,253	11,167
Distributed Energy Programs	(219)	(262)	(181)	(57)	0	(0)	(262)
Own Load Peak - After DE Before EE/DR	10,947	10,905	9,719	7,587	5,904	6,253	10,905
Energy Efficiency Programs	(1,470)	(1,396)	(1,165)	(919)	(549)	(568)	(1,396)
Demand Response Programs	(250)	(250)	(250)	0	0	0	(250)
Own Load Peak After EE/DR/DE	9,227	9,259	8,305	6,667	5,355	5,685	9,259

YEAR: 2029

JANUARY - JUNE	JAN	FEB	MAR	APR	MAY	JUN
Total Own Load Peak	6,546	6,267	5,821	6,386	8,663	9,824
Distributed Energy Programs	0	(1)	0	0	(261)	(243)
Own Load Peak - After DE Before EE/DR	6,546	6,266	5,821	6,386	8,402	9,581
Energy Efficiency Programs	(596)	(571)	(630)	(820)	(970)	(1,362)
Demand Response Programs	0	0	0	0	0	(275)
Own Load Peak After EE/DR/DE	5,950	5,696	5,190	5,566	7,432	7,944

JULY - DECEMBER	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	11,477	11,477	10,153	7,868	6,053	6,406	11,477
Distributed Energy Programs	(228)	(272)	(188)	(79)	0	(0)	(272)
Own Load Peak - After DE Before EE/DR	11,249	11,206	9,965	7,789	6,053	6,406	11,206
Energy Efficiency Programs	(1,525)	(1,447)	(1,208)	(952)	(569)	(589)	(1,447)
Demand Response Programs	(275)	(275)	(275)	0	0	0	(275)
Own Load Peak After EE/DR/DE	9,450	9,483	8,481	6,837	5,484	5,817	9,483

Attachment D.1(a) (1) - Power Supply

POWER SUPPLY ESTIMATES FOR 2014 - 2029

	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/ MWh) 1	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking
Unit 1	1986	2044	Steam	382	1,311	382	382					Uranium	382	Must Run	Baseload
Unit 2	1986	2045	Steam	382	1,314	382	382					Uranium	382	Must Run	Baseload
Unit 3	1988	2047	Steam	382	1,312	382	382					Uranium	382	Must Run	Baseload
Unit 4	1969	2038	Steam	485	770	485	485					Coal	364	Must Run	Baseload
Unit 5	1970	2038	Steam	485	770	485	485					Coal	364	Must Run	Baseload
Unit 1	1974	2026	Steam	105	750	105	105					Coal	50	Must Run	Baseload
Unit 2	1974	2026	Steam	105	750	105	105					Coal	50	Must Run	Baseload
Unit 3	1975	2026	Steam	105	750	105	105					Coal	50	Must Run	Baseload
Unit 1	1962	2028	Steam	116	116	116	116					Coal	30	No	Baseload
Unit 2	1978	2033	Steam	260	260	260	260					Coal	75	No	Baseload
Unit 3	1980	2035	Steam	271	271	271	271					Coal	75	No	Baseload
Unit 1 ST	1960	2020	Steam	110	110	110	110					Gas	25	No	Peaking
Unit 2 ST	1960	2020	Steam	110	110	110	110					Gas	25	No	Peaking
Unit 1 CT	1972	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 2 CT	1973	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 3-7 CT	2018	2050	Combustion Turbine	520	522	522	511					Gas	51	No	Peaking

Notes:
(1) Fuel not included
(2) Consist of 5 units of 102 MW each
(3) Consist of 2 units of 102 MW each
(4) Consists of several small solar projects of 17.36 yrs book life
(5) Jun - Sep Summer months only
(6) For purposes of compliance with Rule B.1(o), intermittent is considered intermediate.

Attachment D.1(a) (1) - Power Supply

POWER SUPPLY ESTIMATES FOR 2014 - 2029

	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)			B.1(h)	B.1(i)	B.1(j)	B.1(n)	B.1(o)
Plant/Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) 1	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking.*
Unit 1 CT	1972	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 2 CT	1973	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 3 CT	2002	2037	Combustion Turbine	79	79	79	76					Gas	40	No	Peaking
Unit 1 CC	1976	2028	Combined Cycle	88	92	92	85					Gas	10	No	Intermediate
Unit 2 CC	1976	2028	Combined Cycle	88	92	92	85					Gas	10	No	Intermediate
Unit 3 CC	1976	2028	Combined Cycle	88	92	92	85					Gas	50	No	Intermediate
Unit 4 CC	2001	2036	Combined Cycle	117	123	123	110					Gas	77	No	Intermediate
Unit 5 CC	2003	2038	Combined Cycle	506	568	568	533					Gas	270	No	Intermediate
Unit 1 CT	1972	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 2 CT	1973	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 1 CC	2002	2037	Combined Cycle	492	532	532	500					Gas	250	No	Intermediate
Unit 2 CC	2002	2037	Combined Cycle	492	532	532	500					Gas	250	No	Intermediate

Notes:
(1) Fuel not included
(2) Consist of 5 units of 102 MW each
(3) Consist of 2 units of 102 MW each
(4) Consists of several small solar projects of 17.36 yrs book life
(5) Jun - Sep Summer months only
(6) For purposes of compliance with Rule B.1(o), intermittent is considered intermediate.

Attachment D.1(a) (1) - Power Supply

POWER SUPPLY ESTIMATES FOR 2014 - 2029

	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)			B.1(h)	B.1(i)	B.1(m)	B.1(n)	B.1(o)
Plant/Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/ kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/ MWh) 1	Fuel	Min Cap (MW)	Must Run?	Base load Intermediate Peaking?
Unit 1 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 2 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 3 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 4 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 5 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 6 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 7 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 8 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 9 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 10 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 1 CT	1971	2043	Combustion Turbine	19	22	22	18					Gas	2	No	Peaking
Unit 2 CT	1971	2043	Combustion Turbine	19	22	22	18					Gas	2	No	Peaking
Unit 3 CT	1973	2043	Combustion Turbine	55	62	62	52					Gas	5	No	Peaking
Unit 4 CT	1974	2043	Combustion Turbine	54	61	61	51					Oil	5	No	Peaking
Unit 5 CT	2008	2043	Combustion Turbine	48	49	49	47					Gas	20	No	Peaking
Unit 6 CT	2008	2043	Combustion Turbine	48	49	49	47					Gas	20	No	Peaking
Unit 1 CT	1972	2020	Combustion Turbine	16	19	19	15					Oil	2	No	Peaking

Notes:
(1) Fuel not included
(2) Consist of 5 units of 102 MW each
(3) Consist of 2 units of 102 MW each
(4) Consists of several small solar projects of 17.36 yrs book life
(5) Jun - Sep Summer months only
(6) For purposes of compliance with Rule B.1(c), intermittent is considered intermediate.

Attachment D.1(a) (1) - Power Supply

POWER SUPPLY ESTIMATES FOR 2014 - 2029

	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(e)			B.1(h)	B.1(i)	B.1(m)	B.1(n)	B.1(o)
Plant/Unit/ Contract	In Service Year	Book Life Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/ MWh) 1	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking
Unit 1 CC	2019	2051	Combined Cycle	541	541	541	501					Gas	230	No	Intermediate
Unit 2 CC	2020	2052	Combined Cycle	541	541	541	501					Gas	230	No	Intermediate
Unit 3 CC	2021	2053	Combined Cycle	541	541	541	501					Gas	230	No	Intermediate
Unit 4 CC	2025	2057	Combined Cycle	672	716	716	665					Gas	159	No	Intermediate
Unit 1-2 CT [3]	2020	2052	Combustion Turbine	208	209	209	204					Gas	47	No	Peaking
Unit 3-4 CT [3]	2021	2053	Combustion Turbine	208	209	209	204					Gas	47	No	Peaking
Unit 5-6 CT [3]	2022	2054	Combustion Turbine	208	209	209	204					Gas	47	No	Peaking
Unit 7-8 CT [3]	2023	2055	Combustion Turbine	208	209	209	204					Gas	47	No	Peaking
Unit 9-10 CT [3]	2024	2056	Combustion Turbine	208	209	209	204					Gas	47	No	Peaking
Unit 11 CT	2027	2059	Combustion Turbine	104	104	104	102					Gas	47	No	Peaking
Unit 12-13 CT [3]	2028	2060	Combustion Turbine	208	209	209	204					Gas	47	No	Peaking
Unit 14-15 CT [3]	2029	2061	Combustion Turbine	208	209	209	204					Gas	47	No	Peaking
APS Solar [4]	1997-2006	2013-2023	Renewable	5	5	2	2					Solar	N/A	No	Intermittent
Aragonne Mesa Wind (Superior) RFP Renew	2007	2027	Renewable	87	90	16	18					Wind	N/A	No	Intermittent
Salton Sea CE Turbo	2006	2029	Renewable	10	10	10	10					Geothermal	N/A	No	Intermittent
SWMP Biomass (Abitibi)	2008	2023	Renewable	14	14	13	13					Biomass	N/A	No	Baseload
High Lonesome Wind - NM	2009	2039	Renewable	97	100	17	17					Wind	N/A	No	Intermittent
Sexton - City of Glendale Landfill	2010	2030	Renewable	3	3	3	3					Biogas	N/A	No	Baseload

Notes:
(1) Fuel not included
(2) Consist of 5 units of 102 MW each
(3) Consist of 2 units of 102 MW each
(4) Consists of several small solar projects of 17.36 yrs book life
(5) Jun - Sep Summer months only
(6) For purposes of compliance with Rule B.1(o), intermittent is considered intermediate.

Attachment D.1(a) (1) - Power Supply

POWER SUPPLY ESTIMATES FOR 2014 - 2029

	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/ MWh) 1	Fuel	Min Cap (MW)	Must Run2	Baseload Intermediate Peaking 6
Solana CSP	2013	2043	Renewable	250	270	0	270					Solar	N/A	No	Intermittent
New Geothermal	2023	2045	Renewable	75	75	75	75					Geothermal	N/A	No	Baseload
New Geothermal	2028	2060	Renewable	75	75	75	75					Geothermal	N/A	No	Baseload
WIND PPA	2027	2051	Renewable	90	87	16	16					Wind	N/A	No	Intermittent
WIND NM	2025	2049	Renewable	100	100	18	18					Wind	N/A	No	Intermittent
PERRIN RANCH WIND	2012	2037	Renewable	99	99	20	20					Wind	N/A	No	Intermittent
AZ Sun: Cotton Center	2011	2041	Renewable	18	18	0	11.5					Solar	N/A	No	Intermittent
AZ Sun: Hyder I	2011	2041	Renewable	15	15	0	10.5					Solar	N/A	No	Intermittent
AZ Sun: Paloma	2011	2041	Renewable	17	17	0	9.4					Solar	N/A	No	Intermittent
AZ Sun: Chino Valley	2012	2042	Renewable	20	20	0	9.7					Solar	N/A	No	Intermittent
AZ Sun: Hyder II	2013	2043	Renewable	15	15	0	12.1					Solar	N/A	No	Intermittent
AZ Sun: Yuma Foothills	2013	2043	Renewable	35	35	0	27.2					Solar	N/A	No	Intermittent
AZ Sun: Gila Bend	2014	2044	Renewable	32	32	0	22.1					Solar	N/A	No	Intermittent
AZ Sun2: PV Future Project 1	2015	2045	Renewable	10	10	0	6.8					Solar	N/A	No	Intermittent
AZ Sun2: PV Future Project 2	2015	2045	Renewable	10	10	0	6.5					Solar	N/A	No	Intermittent
AZ Sun2: PV Future Project 3	2015	2045	Renewable	30	30	0	19.5					Solar	N/A	No	Intermittent

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(4) Consists of several small solar projects of 17.36 yrs book life
(5) Jun - Sep Summer months only
(6) For purposes of compliance with Rule B.1(o), intermittent is considered intermediate.

Attachment D.1(a) (1) - Power Supply

POWER SUPPLY ESTIMATES FOR 2014 - 2029

	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)			B.1(h)	B.1(i)	B.1(m)	B.1(n)	B.1(o)
Plant/Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/ kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/ MWh) 1	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking(6)
Solar Owned New (SAT) PV	2020	2049	Renewable	100	60	0	60					Solar	N/A	No	Intermittent
Solar Owned New (SAT) PV	2021	2050	Renewable	100	54	0	54					Solar	N/A	No	Intermittent
Solar PPA New (SAT) PV	2022	2051	Renewable	100	49	0	49					Solar	N/A	No	Intermittent
Solar PPA New (SAT) PV	2024	2053	Renewable	100	45	0	45					Solar	N/A	No	Intermittent
Small Gen RFP (Ajo S)	2011	2036	Renewable	4	4	0	3					Solar	N/A	No	Intermittent
Small Gen RFP (Prescott S)	2011	2041	Renewable	10	10	0	5					Solar	N/A	No	Intermittent
Small Gen RFP (Tonopah)	2012	2032	Renewable	3	3	3	3					Biogas	N/A	No	Baseload
Small Gen RFP (WM Landfil)	2012	2042	Renewable	14	14	0	9					Solar	N/A	No	Intermittent
Badger-Desert Sky	2013	2043	Renewable	15	14	0	11					Solar	N/A	No	Intermittent
Recurrent Gillepie (SAT PV)	2013	2043	Renewable	15	14	0	10					Solar	N/A	No	Intermittent
SRP - Firm / Eastern Mining Load	1955	2020	Contract	38	38	38	38					N/A	N/A	No	Base
PACIFICORP Div Exch	1990	2020	Contract	480	480	(480)	480					N/A	N/A	No	Intermediate
DR Contract (On Peak)	2020	2029	Contract	275	275	0	275					N/A	N/A	No	Peaking
CC Tolling # 1 1A	2007	2017	Tolling	248	248	248	228					Gas	165	No	Intermediate
CC Tolling # 1 2A	2007	2017	Tolling	248	248	248	228					Gas	165	No	Intermediate
CC Tolling # 1 3A	2007	2017	Tolling	45	45	45	45					Gas	45	No	Intermediate

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(5) Jun - Sep Summer months only
(6) For purposes of compliance with Rule B.1(o), intermittent is considered intermediate.

Attachment D.1(a) (1) - Power Supply

POWER SUPPLY ESTIMATES FOR 2014 - 2029

	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/ kWh)	75% Load Heat Rate (Btu/ kWh)	100% Load Heat Rate (Btu/ kWh)	Variable O&M Cost ($/ MWh) 1	Fuel	Min Cap (MW)	Must Run?	Base Load Intermediate Peaking
CC Tolling # 2 1A	2010	2019	Tolling	250	250	0	250					Gas	150	No	Intermediate
CC Tolling # 2 2A	2010	2019	Tolling	250	250	0	250					Gas	150	No	Intermediate
CC Tolling # 2 3A	2010	2019	Tolling	79	79	0	79					Gas	79	No	Intermediate
Market Call Option [5]	2007	2015	Call Option	150	150	0	150					Gas	25	No	Peaking
Market Call Option [5]	2007	2015	Call Option	50	50	0	50					Gas	25	No	Peaking
Market Call Option [5]	2008	2015	Call Option	75	75	0	75					Gas	25	No	Peaking
Market Call Option [5]	2008	2015	Call Option	225	225	0	225					Gas	25	No	Peaking
Gas Call Option	2007	2016	Call Option	150	150	0	150					Gas	50	No	Peaking

Notes:
(1) Fuel not included
(2) Consist of 5 units of 102 MW each
(3) Consist of 2 units of 102 MW each
(4) Consists of several small solar projects of 17.36 yrs book life
(5) Jun - Sep Summer months only
(6) For purposes of compliance with Rule B.1(o), intermittent is considered intermediate.

Attachment D.1(a) (2) - Annual Capacity Factor

ANNUAL CAPACITY FACTOR - B.1(e)

UNIT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1																
Unit 2																
Unit 3																
Unit 4																
Unit 5																
Unit 1																
Unit 2																
Unit 3																
Unit 1																
Unit 2																
Unit 3																
Unit 1 ST																
Unit 2 ST																
Unit 1 CT																
Unit 2 CT																
Unit 3 CT																
Unit 4 CT																
Unit 5 CT																
Unit 6 CT																
Unit 7 CT																
Unit 1 CT																
Unit 2 CT																
Unit 3 CT																

Attachment D.1(a) (2) - Annual Capacity Factor

ANNUAL CAPACITY FACTOR - B.1(e)

UNIT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CC																
Unit 2 CC																
Unit 3 CC																
Unit 4 CC																
Unit 5 CC																
Unit 1 CT																
Unit 2 CT																
Unit 1 CC																
Unit 2 CC																
Unit 1 CT																
Unit 2 CT																
Unit 3 CT																
Unit 4 CT																
Unit 5 CT																
Unit 6 CT																
Unit 7 CT																
Unit 8 CT																
Unit 9 CT																
Unit 10 CT																
Unit 1 CT																
Unit 2 CT																
Unit 3 CT																
Unit 4 CT																
Unit 5 CT																
Unit 6 CT																

Attachment D.1(a) (2) - Annual Capacity Factor

ANNUAL CAPACITY FACTOR - B.1(e)

UNIT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT																
Unit 1 CC																
Unit 2 CC																
Unit 3 CC																
Unit 4 CC																
Unit 1 CT																
Unit 2 CT																
Unit 3 CT																
Unit 4 CT																
Unit 5 CT																
Unit 6 CT																
Unit 7 CT																
Unit 8 CT																
Unit 9 CT																
Unit 10 CT																
Unit 11 CT																
Unit 12 CT																
Unit 13 CT																
Unit 14 CT																
Unit 15 CT																
APS Solar, Saguaro Solar																
Aragonne Mesa Wind (Superior) RFP Renew																
Salton Sea CE Turbo #1																
SWMP Biomass (Abitibi)																
High Lonesome Wind - NM																

Attachment D.1(a) (2) - Annual Capacity Factor

ANNUAL CAPACITY FACTOR - B.1(e)

UNIT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Sexton - City of Glendale Landfill																
Solana CSP																
New Geothermal																
WIND NM																
Perrin Ranch Wind																
AZ Sun: Cotton Center																
AZ Sun: Hyder I																
AZ Sun: Chino Valley																
AZ Sun: Paloma																
AZ Sun: Hyder II																
AZ Sun: Yuma Foothills																
AZ Sun2: BV Overland Gila Bend																
AZ Sun2: PV Future Project 1																
AZ Sun2: PV Future Project 2																
AZ Sun2: PV Future Project 3																
APS Future Solar SAT PV																
Small Gen RFP (Ajo S)																
Small Gen RFP (Prescott S)																
Small Gen RFP (Tonopah)																
Small Gen RFP (WM Landfil)																

Attachment D.1(a) (2) - Annual Capacity Factor

ANNUAL CAPACITY FACTOR - B.1(e)

UNIT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Badger-Desert Sky																
Recurrent Gillepie (SAT PV)																
SRP - Firm / Eastern Mining Load																
PACIFICORP Div Exch																
APS OWNED SCHOOLS/ GOV'T DE																
CC Tolling # 1																
CC Tolling # 2																
Market Call Option																
Gas Call Option																
Short term Purchases																
Recurrent Bagdad SAT PV-DE Contract																

Attachment D.1(a) (3) - Average Heat Rate

AVERAGE HEAT RATE - B.1 (f) (Btu/kWh)

UNIT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385
Unit 2	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361
Unit 3	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377
Unit 4	9,739	9,743	9,712	9,766	9,771	9,766	9,775	9,774	9,769	9,768	9,783	9,776	9,764	9,767	9,771	9,785
Unit 5	9,763	9,732	9,746	9,733	9,795	9,779	9,793	9,787	9,796	9,798	9,793	9,795	9,774	9,796	9,813	9,775
Unit 1	10,098	10,084	10,108	10,095	10,108	10,101	10,080	10,095	10,095	10,114	10,103	10,096	10,093	10,092	10,094	10,086
Unit 2	10,084	10,079	10,080	10,069	10,074	10,101	10,095	10,086	10,074	10,080	10,080	10,079	10,079	10,070	10,074	10,074
Unit 3	10,105	10,102	10,088	10,092	10,097	10,084	10,087	10,095	10,085	10,097	10,095	10,103	10,093	10,085	10,100	10,112
Unit 1	10,347	10,343	10,418	10,380	10,376	10,379	10,379	10,546	10,519	10,504	10,450	10,425	10,414	10,403	10,407	10,426
Unit 2	10,723	10,706	10,777	10,784	10,759	10,756	10,756	10,814	10,801	10,776	10,741	10,721	10,731	10,708	10,706	10,729
Unit 3	10,595	10,584	10,675	10,650	10,627	10,629	10,626	10,839	10,806	10,769	10,735	10,704	10,709	10,696	10,699	10,704
Unit 1 ST	14,700	12,615	15,447	14,121	-	-	-	-	-	-	-	-	-	-	-	-
Unit 2 ST	13,926	12,440	15,567	14,820	-	-	-	-	-	-	-	-	-	-	-	-
Unit 1 CT	-	-	-	16,124	15,108	23,042	15,010	14,956	-	-	16,942	-	-	-	-	-
Unit 2 CT	-	-	-	15,531	15,148	22,261	15,259	14,832	15,182	17,356	15,259	-	-	-	20,677	16,254
Unit 3 CT	-	-	-	10,974	10,415	10,388	10,382	10,235	9,571	10,076	9,970	10,393	10,030	10,495	9,986	9,911
Unit 4 CT	-	-	-	11,038	10,393	10,314	10,284	10,077	9,882	10,113	10,136	10,504	10,018	10,643	9,995	9,927
Unit 5 CT	-	-	-	-	10,422	10,330	10,227	9,972	9,883	9,998	10,386	10,986	10,135	10,676	9,582	9,994
Unit 6 CT	-	-	-	-	10,498	10,420	10,112	10,098	9,901	10,237	10,418	11,406	10,118	10,591	10,261	10,230
Unit 7 CT	-	-	-	-	10,319	10,395	10,014	9,814	10,107	10,315	10,458	11,406	10,314	10,568	10,450	10,863

Attachment D.1(a) (3) - Average Heat Rate

AVERAGE HEAT RATE - B.1 (f) (Btu/kWh)

UNIT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT	-	-	-	16,701	15,148	22,261	15,259	15,467	15,715	-	-	-	-	-	-	-
Unit 2 CT	-	-	-	15,295	15,368	16,356	16,037	15,552	28,375	-	-	-	-	-	-	-
Unit 3 CT	13,911	-	13,305	12,428	12,529	14,648	14,765	14,738	15,641	15,106	15,641	-	15,641	-	15,641	15,391
Unit 1 CC	11,145	11,317	11,649	10,480	10,508	10,460	10,040	9,903	10,125	9,964	10,076	10,300	10,132	10,107	10,090	9,991
Unit 2 CC	11,372	11,390	12,202	10,507	10,528	10,435	10,048	9,936	10,127	9,945	10,061	10,306	10,139	10,141	10,163	9,955
Unit 3 CC	10,214	10,554	10,576	9,922	9,951	10,106	10,071	9,879	10,008	9,844	9,864	10,101	9,998	9,936	9,933	9,815
Unit 4 CC	8,912	9,182	9,041	8,760	8,814	8,879	8,838	8,716	8,748	8,680	8,721	8,823	8,738	8,805	8,706	8,689
Unit 5 CC	7,987	8,031	7,963	7,824	7,881	7,881	7,854	7,803	7,816	7,809	7,824	7,845	7,813	7,792	7,793	7,787
Unit 1 CT	-	-	-	14,906	15,060	-	15,591	14,892	15,259	16,254	16,254	-	-	-	-	-
Unit 2 CT	-	-	-	15,210	14,861	-	15,259	15,060	15,805	-	-	-	-	-	-	-
Unit 1 CC	7,781	7,840	7,785	7,605	7,633	7,709	7,811	7,363	7,386	7,375	7,407	7,433	7,394	7,376	7,381	7,343
Unit 2 CC	7,797	7,792	7,803	7,575	7,654	7,705	7,810	7,476	7,470	7,489	7,518	7,536	7,500	7,460	7,461	7,426
Unit 1 CT	12,021	11,277	12,429	11,680	12,672	12,680	12,449	12,362	12,393	12,771	12,740	12,824	12,672	12,823	12,445	12,478
Unit 2 CT	11,913	11,188	12,331	11,721	12,665	12,626	12,397	12,371	12,407	12,615	12,823	12,824	12,725	12,490	12,474	12,490
Unit 3 CT	11,765	11,162	12,345	11,737	12,710	12,860	12,375	12,331	12,421	12,740	12,672	13,240	12,952	12,490	12,507	12,531
Unit 4 CT	11,819	11,205	12,473	11,817	12,788	12,845	12,431	12,303	12,421	12,657	12,740	-	12,990	12,490	12,567	12,562
Unit 5 CT	11,746	10,995	12,142	11,975	12,704	12,990	12,445	12,303	12,453	12,704	12,740	-	13,101	12,615	12,642	12,615
Unit 6 CT	11,623	11,969	12,615	12,442	12,666	13,009	12,421	12,311	12,490	12,759	12,740	-	13,062	12,615	12,823	12,759
Unit 7 CT	11,541	11,644	12,459	12,449	12,635	13,084	12,471	12,369	12,534	12,823	12,823	-	13,062	12,615	12,823	12,786
Unit 8 CT	11,235	11,405	12,063	12,438	12,759	12,740	12,642	10,744	11,845	12,990	12,928	-	12,824	12,824	12,615	10,749
Unit 9 CT	11,024	11,206	11,990	12,043	12,318	12,824	11,317	10,374	10,933	12,359	10,686	-	14,490	10,772	11,269	11,335
Unit 10 CT	10,844	10,749	11,530	11,185	11,387	12,823	12,101	10,599	10,896	12,704	10,971	-	14,490	12,412	11,544	12,504

Attachment D.1(a) (3) - Average Heat Rate

AVERAGE HEAT RATE - B.1 (f) (Btu/kWh)

UNIT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT	14,830	15,038	-	14,632	14,465	-	-	15,365	17,491	-	-	-	-	-	-	-
Unit 2 CT	-	14,517	-	15,232	14,465	-	-	15,359	16,220	-	-	-	-	-	-	-
Unit 3 CT	14,535	13,778	-	14,063	13,849	13,972	14,479	14,508	13,959	14,676	22,504	-	-	-	20,079	-
Unit 4 CT	-	-	-	15,391	14,510	-	-	15,051	25,373	-	-	-	-	-	-	-
Unit 5 CT	11,409	11,565	12,071	11,584	12,211	12,575	11,548	11,649	12,691	12,804	12,999	13,266	13,155	13,323	13,102	13,058
Unit 6 CT	11,397	11,317	11,812	11,477	12,260	12,834	11,989	10,889	11,859	12,557	12,661	13,266	12,947	13,266	12,702	13,049
Unit 1 CT	-	-	-	23,544	16,774	-	-	15,517	-	-	-	-	-	-	-	-
Unit 1 CC	-	-	-	-	-	7,761	7,771	7,665	7,682	7,671	7,719	7,749	7,691	7,692	7,707	7,652
Unit 2 CC	-	-	-	-	-	-	7,656	7,612	7,642	7,645	7,680	7,712	7,672	7,663	7,659	7,630
Unit 3 CC	-	-	-	-	-	-	-	7,583	7,637	7,617	7,664	7,687	7,644	7,632	7,615	7,638
Unit 4 CC	-	-	-	-	-	-	-	-	-	-	-	7,847	7,935	7,909	7,881	7,818
Unit 1 CT	-	-	-	-	-	-	10,378	10,052	10,260	10,021	10,120	10,383	10,094	10,048	10,022	9,892
Unit 2 CT	-	-	-	-	-	-	10,276	10,058	10,338	10,044	10,033	10,399	10,165	10,103	9,982	9,882
Unit 3 CT	-	-	-	-	-	-	-	10,175	10,342	10,102	10,139	10,438	10,237	10,109	10,029	9,933
Unit 4 CT	-	-	-	-	-	-	-	10,191	10,397	10,202	10,127	10,341	10,146	10,109	10,061	9,987
Unit 5 CT	-	-	-	-	-	-	-	-	10,205	10,189	10,018	10,343	10,035	10,033	10,023	9,975
Unit 6 CT	-	-	-	-	-	-	-	-	10,070	9,894	10,080	10,050	9,956	9,899	9,879	9,820
Unit 7 CT	-	-	-	-	-	-	-	-	-	9,947	10,006	9,915	9,862	9,828	9,727	9,705
Unit 8 CT	-	-	-	-	-	-	-	-	-	9,974	9,792	9,931	9,903	9,831	9,656	9,725
Unit 9 CT	-	-	-	-	-	-	-	-	-	-	9,896	10,025	10,040	10,016	9,766	9,759
Unit 10 CT	-	-	-	-	-	-	-	-	-	-	9,934	10,224	10,125	10,240	9,820	9,582
Unit 11 CT	-	-	-	-	-	-	-	-	-	-	-	-	-	10,402	9,926	9,813
Unit 12 CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,954	9,833
Unit 13 CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,005	9,810
Unit 14 CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,869
Unit 15 CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,883

Attachment D.1(a) (4) - Average Fuel Cost

AVERAGE FUEL COST - B.1(g) ($/MMBTU)

FUEL	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Uranium																
Coal - Four Corners																
Coal - NGS																
Coal - Cholla																
Gas	4.04	4.21	4.32	4.48	4.65	4.90	5.21	5.55	5.88	6.22	6.56	6.90	7.04	7.20	7.35	7.51

Attachment D.1(a) (5) - Purchased Power Energy Costs for Long-Term Contracts

ENERGY COST FOR LONG-TERM CONTRACT B.1(i) ($/MWh)

UNIT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Aragonne Mesa Wind (Superior) RFP Renew																
Salton Sea CE Turbo #1																
SWMP Biomass (Abitibi)																
High Lonesome Wind - NM																
Sexton - City of Glendale Landfill																
Solana CSP																
Perrin Ranch Wind																
Small Gen RFP (Ajo S)																
Small Gen RFP (Prescott S)																
Small Gen RFP (Tonopah)																
Small Gen RFP (WM Landfil)																
Badger-Desert Sky																
Recurrent Gillepie (SAT PV)																
Recurrent Bagdad SAT PV - DE Contract																
SRP - Firm / Eastern Mining Load [1]																
CC Tolling # 1 [2]																
CC Tolling # 2 [2]																
Market Call Option [2]																
Gas Call Option [2]																
Gas Call Option [2]																
Gas Call Option [2]																
AG1 Load																

Notes
(1) Based on Palo Verde Day-Ahead Index
(2) Based on gas price

Attachment D.1(a) (6) - Fixed O&M

FIXED OPERATING AND MAINTENANCE - B.1(j) ($/kW)

PLANT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Palo Verde 1, 2, 3																
Four Corners 4, 5																
NGS 1, 2, 3																
Cholla																
Ocotillo ST 1,2																
Ocotillo CT 1,2																
Saguaro / Douglas CT																
West Phoenix CC 1, 2, 3																
West Phoenix CC 4																
West Phoenix CC 5																
West Phoenix CT 1, 2																
Redhawk																
Sundance																
Yucca CT 1, 2, 3, 4																
Yucca CT 5, 6																
AZ Sun: Hyder II																
AZ Sun: Cotton Center																
AZ Sun: Hyder I																
AZ Sun: Chino Valley																
AZ Sun - Paloma																
AZ Sun2 PV - Yuma Foothills																
AZ Sun2 PV - BV Gila Bend																
AZ Sun2 PV - Future Project 1																
AZ Sun2 PV - Future Project 2																
AZ Sun2 PV - Future Project 3																
Solar Owned New (SAT) PV																
Solar Owned New (SAT) PV																
Future Unit 1 CC																
Future Unit 1 CT																

Attachment D.1(a) (6) - Fixed O&M

FIXED OPERATING AND MAINTENANCE - B.1(j) ($/MW)

PLANT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Palo Verde 1, 2, 3																
Four Corners 4, 5																
NGS 1, 2, 3																
Cholla																
Ocotillo ST 1,2																
Ocotillo CT 1,2																
Saguaro / Douglas CT																
West Phoenix CC 1, 2, 3																
West Phoenix CC 4																
West Phoenix CC 5																
West Phoenix CT 1, 2																
Redhawk																
Sundance																
Yucca CT 1, 2, 3, 4																
Yucca CT 5, 6																
AZ Sun: Hyder II																
AZ Sun: Cotton Center																
AZ Sun: Hyder I																
AZ Sun: Chino Valley																
AZ Sun - Paloma																
AZ Sun2 PV - Yuma Foothills																
AZ Sun2 PV - BV Gila Bend																
AZ Sun2 PV - Future Project 1																
AZ Sun2 PV - Future Project 2																
AZ Sun2 PV - Future Project 3																
Solar Owned New (SAT) PV																
Solar Owned New (SAT) PV																
Future Unit 1 CC																
Future Unit 1 CT																

Attachment D.1(a) (7) - Demand Charges for Purchased Power

DEMAND CHARGES FOR PURCHASED POWER - B.1(k) ($/kW-Yr)

CONTRACT	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CC Tolling # 1																
CC Tolling # 2 [1]																
Market Call Option																
Market Call Option																
Market Call Option																
Market Call Option																
Gas Call Option																
SRP - Firm / Eastern Mining Load [2]																

CO2 EMISSIONS - B.1(p) (METRIC TONS)

UNIT	RATE[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 4																	
Unit 5																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	

Attachment D.1(a) (8) - Environmental Impacts

CO2 EMISSIONS - B.1(p) (METRIC TONS)

UNIT	RATE[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
W. Phx. CC 5																	
Unit 1 CT																	
Unit 2 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	

CO2 EMISSIONS - B.1(p) (METRIC TONS)

UNIT	RATE[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [2]																	
Total		14,273,104	14,181,996	14,490,585	14,229,229	14,977,113	15,680,452	15,753,740	15,304,069	15,740,868	15,587,697	16,304,501	16,775,086	17,310,066	17,754,025	17,940,817	18,031,994

Notes:

(1) Emission rates are as of 2014

CO EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 4																	
Unit 5																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	

CO EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	

CO EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts[2]																	
Total		1,743	1,741	1,794	1,786	1,867	1,940	1,950	1,903	1,950	1,909	2,000	2,023	2,052	2,097	2,113	2,101

Notes:

(1) Emission rates are as of 2014

VOC EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 4																	
Unit 5																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	

VOC EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	

VOC EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [2]																	
Total		111	108	104	117	128	124	124	116	119	126	132	127	134	139	141	147

Notes:

(1) Emission rates are as of 2014

Attachment D.1(a) (8) - Environmental Impacts

NOx EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 4 [3]																	
Unit 5 [3]																	
Unit 1 [4]																	
Unit 2 [4]																	
Unit 3 [4]																	
Unit 1 [5]																	
Unit 2 [5]																	
Unit 3 [5]																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	

NOx EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	

Attachment D.1(a) (8) - Environmental Impacts

NOx EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	

NOx EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [2]																	
Total		19,001	19,214	19,715	18,910	7,271	7,010	6,907	6,342	5,038	4,814	5,121	5,256	5,319	5,436	5,479	5,285

Notes:

(1) Emission rates are as of 2014

SO2 EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 4 [2]																	
Unit 5 [2]																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1																	
Unit 2 [3]																	
Unit 3																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	

SO2 EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	

Attachment D.1(a) (8) - Environmental Impacts

SO2 EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	

SO2 EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [4]																	
Total																	

Notes:

(1) Emission rates are as of 2014

Attachment D.1(a) (8) - Environmental Impacts

Hg EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ Trillion Btu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 4																	
Unit 5																	
Unit 1 [2]																	
Unit 2 [3]																	
Unit 3 [4]																	
Unit 1 [5]																	
Unit 2 [6]																	
Unit 3 [7]																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	

Hg EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ Trillion Btu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	

Hg EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ Trillion Btu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	

Hg EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ Trillion Btu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [8]																	
Total		0.184	0.183	0.073	0.066	0.070	0.073	0.073	0.069	0.070	0.068	0.073	0.074	0.076	0.078	0.078	0.076

Notes:

(1) Emission rates are as of 2014

PM10 EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 4																	
Unit 5																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1																	
Unit 2 [2]																	
Unit 3																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	

PM10 EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 1 CC																	
Unit 2 CC																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	

PM10 EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 1 CT	[redacted]																
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Unit 11 CT	[redacted]																
Unit 12 CT	[redacted]																
Unit 13 CT	[redacted]																
Unit 14 CT	[redacted]																
Unit 15 CT	[redacted]																

PM10 EMISSIONS - B.1(p) (METRIC TONS)

Unit	Rate[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [3]																	
Total		885	882	776	769	797	817	824	764	788	793	834	850	885	897	903	904

Notes:

(1) Emission rates are as of 2014

WATER CONSUMPTION - B.1(q) (ACRE-FEET)

Plant	Rates (gal/ MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Palo Verde Units 1, 2, 3																	
Four Corners Units 4, 5																	
Navajo Generating Station Units 1, 2, 3																	
Cholla Units 1, 2, 3																	
Ocotillo Units 1, 2 ST																	
Ocotillo Units 1, 2 CT																	
Ocotillo New Units 3-7 CT																	
Saguaro Units 1, 2, 3 CT																	
West Phoenix Units 1, 2, 3, 4, 5 CC																	
West Phoenix Units 1, 2 CT																	
Redhawk Units 1, 2 CC																	
Sundance Units 1-10 CT																	
Yucca Units 1, 2, 3 CT																	
Yucca Units 5, 6 CT																	

WATER CONSUMPTION - B.1(q) (ACRE-FEET)

Plant	Rates (gal/ MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Douglas																	
Future Unit 1 CC																	
Future Unit 2 CC																	
Future Unit 3 CC																	
Future Unit 4 CC																	
Future Unit 1 CT																	
Future Unit 1-15 CT																	
Salton Sea CE Turbo #1																	
SWMP Biomass (Abitibi)																	
Sexton - City of Glendale Landfill																	
Solana CSP																	
SRP - Firm / Eastern Mining Load																	
CC Tolling # 1																	
CC Tolling # 2																	
Market Call Option																	

Attachment D.1(a) (8) - Environmental Impacts

WATER CONSUMPTION - B.1(q) (ACRE-FEET)

Plant	Rates (gal/ MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gas Call Option																	
Small GEN WM LANDFILL																	
NEW Geothermal (80MW in 2021)																	
Total		55,532	55,481	56,555	56,179	56,889	57,657	57,503	56,723	57,656	58,894	60,259	60,009	60,504	61,391	63,101	63,343

Note:

Water consumption rates are based on plant actual.

COAL FLY ASH COLLECTED - B.1(r) (METRIC TONS)

Unit	Rates[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 4																	
Unit 5																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1																	
Unit 2																	
Unit 3																	
Total		879,409	890,057	931,805	880,408	929,401	983,907	994,945	924,277	933,740	865,671	928,067	972,977	989,397	997,246	997,101	940,794

Notes:

(1) Emission rates are as of 2014

Attachment D.1(a) (8) - Environmental Impacts

COAL ASH BOTTOM COLLECTED - B.1(r) (METRIC TONS)

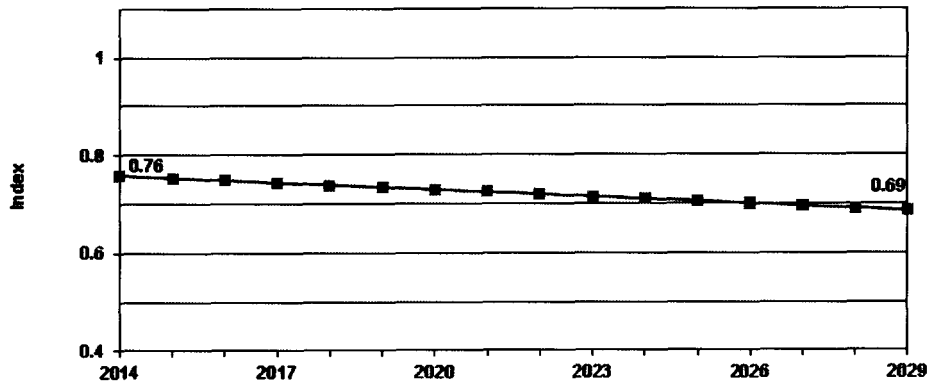
Unit	Rates[1] (lb/ MMBtu)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Unit 4																	
Unit 5																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 1																	
Unit 2																	
Unit 3																	
Total		219,840	222,502	232,938	220,090	232,338	245,964	248,724	231,057	233,423	216,407	232,005	243,232	247,337	249,299	249,262	235,187

Notes:

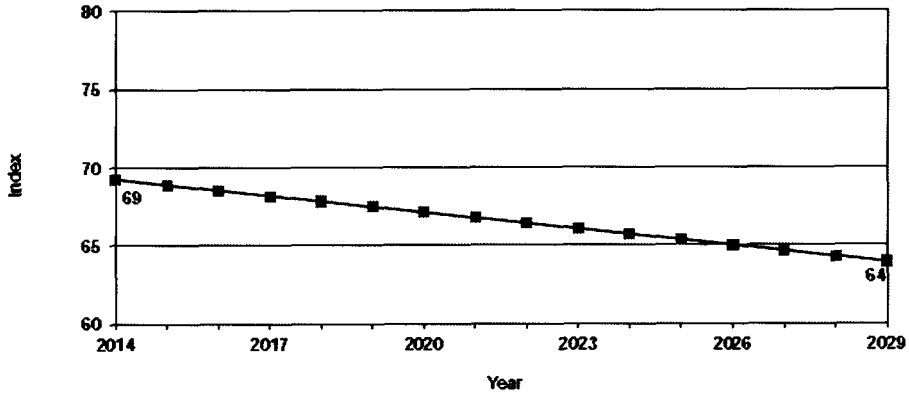
(1) Emission rates are as of 2014

Attachment D.1(b) - Transmission & Distribution Reliability

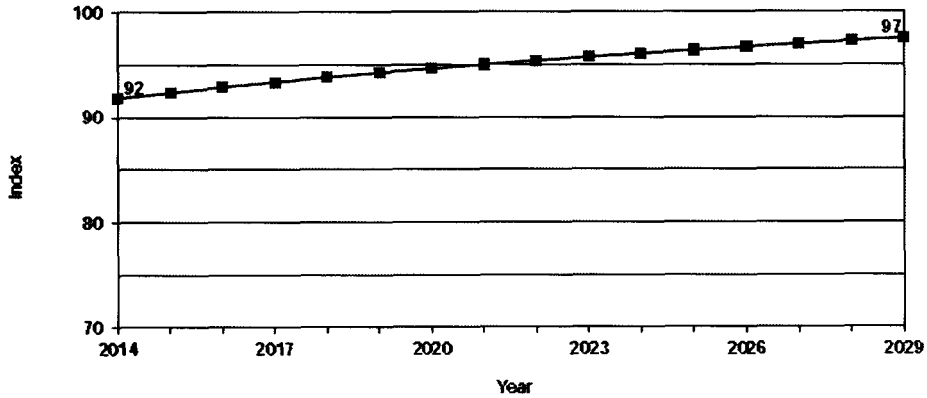
Distribution Reliability
SAIFI (Dist.)



SAIDI (Dist.)

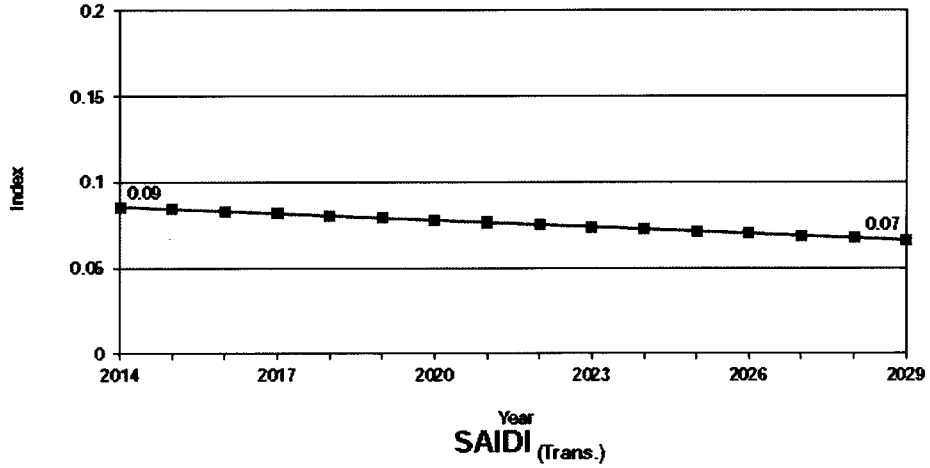


Distribution Reliability
CAIDI (Dist.)

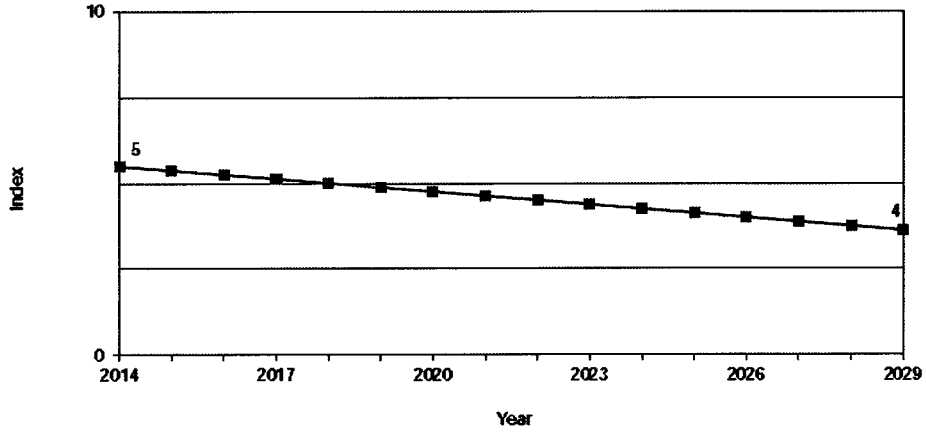


Attachment D.1(b) - Transmission & Distribution Reliability

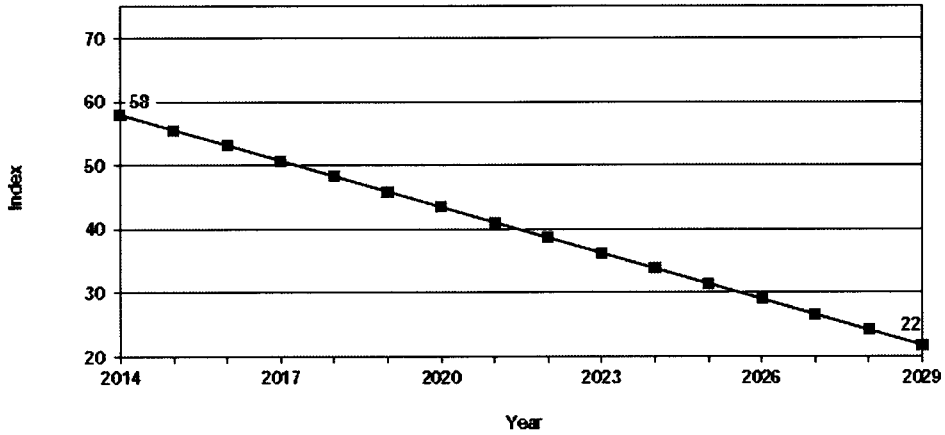
Transmission Reliability
SAIFI (Trans.)



SAIDI (Trans.)



Transmission Reliability
CAIDI (Trans.)



Attachment D.1(c) - Capital Cost and Construction Spending Schedule for New Generation

2014 RESOURCE PLAN - CAPITAL COSTS
GENERATION CONSTRUCTION CASH FLOW W/O AFUDC ($MILLIONS)

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Capital Costs Thru 2029 Total
5	Ocotillo CTs	4.2	23.2	251.6	187.8	104.8												571.5
2	Future CT	-	-	-	-	25.7	131.9	108.2										265.9
2	Future CT	-	-	-	-	-	26.4	135.2	110.9									272.5
2	Future CT	-	-	-	-	-	-	27.0	138.6	113.7								279.3
2	Future CT	-	-	-	-	-	-	-	27.7	142.1	116.5							286.3
2	Future CT	-	-	-	-	-	-	-	-	28.4	145.6	119.4						293.5
1	Future CT	-	-	-	-	-	-	-	-	-	-	-	15.3	78.4	64.3			158.0
2	Future CT	-	-	-	-	-	-	-	-	-	-	-	-	31.4	160.8	131.8		323.9
2	Future CT	-	-	-	-	-	-	-	-	-	-	-	-	-	32.2	164.8	135.1	332.0
Sub Total		4.2	23.2	251.6	187.8	130.5	158.3	270.5	277.2	284.2	262.2	119.4	15.3	109.8	257.2	296.6	135.1	2,783.0
1	Future CC	-	-	-	-	-	590.6											590.6
1	Future CC	-	-	-	-	-	-	605.3										605.3
1	Future CC	-	-	-	-	-	-	-	620.5									620.5
1	Future CC	-	-	-	-	-	-	-	-	42.3	216.7	488.8	136.6					884.4
Sub Total		-	-	-	-	-	590.6	605.3	620.5	42.3	216.7	488.8	136.6	-	-	-	-	2,700.8
	AZ Sun [1]	559.4	102.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	662.2
	Future Solar	-	-	-	-	53.9	161.1	212.9	158.4	104.6	104.0	52.0	-	-	-	-	-	846.9
	Future Wind	-	-	-	-	-	-	-	-	-	-	173.2	118.4	158.1	108.0	-	-	557.7
	Future Geothermal	-	-	-	-	-	-	-	200.7	114.3	140.6	-	-	227.0	129.3	159.0	-	970.8
Sub Total		559.4	102.8	-	-	53.9	161.1	212.9	359.1	218.9	244.5	225.2	118.4	385.1	237.3	159.0	-	3,037.6
												[illegible]	704.3	494.9	494.5	455.6	135.1	8,521.4
												[illegible]	[illegible]	[illegible]	(2,197)	1,386.7	8,521.4	

Notes:
(1) AZ Sun costs in year 2014 include all prior year capital costs.
(2) Capital Cost includes APS-owned construction of generation.

Attachment D.1(f) - Transmission Projects – Description, Capital Cost and Purpose

ARIZONA PUBLIC SERVICE COMPANY - PLANNED TRANSMISSION FACILITIES 2014 - 2023

PROJECT DESCRIPTION	I/S	PARTICIPANTS	KV	RATING (MVA)	TOTAL COST ($MILLIONS)	LENGTH (MILES)	PURPOSE
Palo Verde-Delaney line	2016	APS (90%) CAWCD (10%)	500	TBD		15	Increase the export scheduling capability from the Palo Verde area to provide access to both solar and gas resources.
Bagdad Relocation	2017	None	115	N/A		5.5	**Freeport McMoRan (HFMI) has future plans to expand the mine in the location of the existing 115kV line from Prescott.**
Delaney-Sun Valley line	2016	APS (90%) CAWCD (10%)	500	TBD		28	Serve projected need for electric energy in the area immediately north and west of the Phoenix Metropolitan area; increase import capability in the Phoenix area as well as export scheduling capability from the Palo Verde area to access solar and gas resources.
Hassayampa-North Gila #2 line	2015	None	500	1905		110	**Increase the import capability for the Yuma area and export/ scheduling capability from the Palo Verde area to provide access to both solar and gas resources.**
Mazatzal substation	2017	None	345/69	150		1	Provide the electric source and support to the subtransmission system in the area of Payson and the surrounding communities.
North Gila-Orchard line	2018	None	230	1195		13	**Serves the need for electric energy, improved reliability and continuity of service for the greater Yuma area.**
Palm Valley-TS2-Trilby Wash line	2015	None	230	1195		12	Serve the need for electric energy in the western Phoenix Metropolitan area and additional import capability into the greater Phoenix area. The proposed second 230kV source for Trilby Wash provides improved system reliability for communities such as El Mirage, Surprise, Youngtown, Goodyear and Buckeye.
Buckeye 230/69kV transformer	2016	None	230/69	188		0	**Provide additional transformer capacity to the Buckeye area**
Sun Valley-Trilby Wash line	2016	None	230	1195		15	Serve the need for electric energy in the western Phoenix Metropolitan area and additional import capability into the greater Phoenix area. The proposed second 230kV source for Trilby Wash provides improved system reliability for communities such as El Mirage, Surprise, Youngtown, Goodyear and Buckeye.
Morgan-Sun Valley line	2018	APS (90%) CAWCD(10%)	500	TBD		40	Serve the need for electric energy in the Phoenix Metropolitan area; increase the import capability to the Phoenix area; increase the export/ scheduling capability from the Palo Verde area including both solar and gas resources.

Source: 2014-2023 Transmission Ten-Year Plan dated January 2014

Attachment D.1(f) - Transmission Projects – Description, Capital Cost and Purpose

ARIZONA PUBLIC SERVICE COMPANY - PLANNED TRANSMISSION FACILITIES 2014 - 2023

PROJECT DESCRIPTION	I/S	PARTICIPANTS	KV	RATING (MVA)	TOTAL COST ($MILLIONS)	LENGTH (MILES)	PURPOSE
Raceway 230/69kV transformer	2018	None	230/69	188	[redacted]	0	Provide additional capacity in the northwest portions of the Phoenix Metropolitan area for growing loads.
Palm Valley 230/69kV transformer	2019	None	230/69	188	[redacted]	0	Provide additional capacity in the southwest portions of the Phoenix Metropolitan area for growing loads.
Scatter Wash substation	2021	None	230/69	188	[redacted]	1	Provide electric energy in the northern portions of the Phoenix Metropolitan area; increase the reliability and continuity of service for these areas.
Saguaro 230/69kV transformer	2021	None	230/69	188	[redacted]	0	Provide electric energy in the southern portions of the Southeast Division area for growing loads.
Yavapai 230/69kV transformer	2021	None	230/69	188	[redacted]	0	Provide additional capacity in the Northwest State Region area for growing loads.
CT Connect Costs	2020-2029	TBD	230-500	TBD	[redacted]	TBD	Connect new resources
CC Connect Costs	2025	TBD	230-500	TBD	[redacted]	TBD	Connect new resources

Source: 2014-2023 Transmission Ten-Year Plan dated January 2014

Attachment D.3 - Generation Technologies

2013 Q3 CONVENTIONAL GENERATION TECHNOLOGIES ASSUMPTIONS (2017 INSTALLATION)

LOCATION	ANNUAL CAPACITY (MW)	SUMMER CAPACITY (MW)	WINTER CAPACITY (MW)	CAPITAL COSTS ($MILLION)	CAPITAL COSTS ($/kW)	FIXED O&M ($/kW-Yr)	VAR O&M ($/MWh)	HEAT RATE (BTU/kWh)	LEAD TIME YEARS	CAPACITY FACTOR %	CO2 EMISSION (lbs/MWh)	WATER CONSUMPTION (gal/MWh)
Cholla	477	472	481	1,449	3,039	16.44	5.14	9,008	9	75%	1,847	491
Cholla	477	472	481	1,219	2,558	13.67	5.14	9,008	5	75%	1,847	491
Cholla	953	944	962	2,668	2,799	16.44	5.14	9,008	9	75%	1,847	491
Cholla	776	771	779	2,213	2,852	12.22	5.13	8,905	9	75%	1,826	491
Cholla	490	459	518	2,291	4,676	21.30	3.47	9,136	9	75%	1,964	491
Maricopa	203	200	209	163.1	817	4.04	5.44	10,073	3	10%	1,229	46
Maricopa	406	399	418	280.1	701	4.04	5.44	10,073	3	10%	1,229	46
Maricopa	327	319	342	314.3	985	4.14	3.47	11,911	3	10%	1,453	70
Maricopa	283	277	295	339.0	1,224	7.51	5.42	9,723	3	10%	1,186	111
Maricopa	269	266	274	346.1	1,299	7.51	5.42	9,373	3	10%	1,144	85
Maricopa	310	307	313	339.5	1,106	5.46	5.10	9,125	3	10%	1,113	207
Maricopa	310	307	313	341.3	1,113	5.46	5.10	9,138	3	10%	1,115	141
Maricopa	289	259	312	345.7	1,337	5.46	5.10	9,566	3	10%	1,167	84
Maricopa	694	681	719	620.2	910	5.12	4.54	7,216	4	75%	880	395
Maricopa	684	665	716	677.3	1,019	5.24	4.26	7,396	4	75%	902	302
Maricopa	0.5	0.5	0.5	5.0	10,000	TBD	TBD	5,688	2	98%	694	0
Redhawk	203	200	209	154.6	774	4.04	5.44	10,073	3	10%	1,229	46
Redhawk	406	399	418	270.6	678	4.04	5.44	10,073	3	10%	1,229	46
Redhawk	164	159	171	171.0	1,072	4.14	3.47	11,911	3	10%	1,453	70
Sundance	94	92	98	137.8	1,493	7.51	5.42	9,723	3	10%	1,186	111
Sundance	90	89	91	140.4	1,580	7.51	5.42	9,373	3	10%	1,144	85
Yucca	94	92	98	139.3	1,509	7.51	5.42	9,723	3	10%	1,186	111
Yucca	90	89	91	142.0	1,598	7.51	5.42	9,373	3	10%	1,144	85
Maricopa	517	511	522	528.3	1,034	5.46	5.10	9,138	3	10%	1,115	141
Maricopa	110	110	110	154.9	1,407	16.85	5.81	8,365	3	10%	1,021	0

* Efficiency
1 Costs are in year-2013 dollars.
2 Capital costs are overnight construction costs; $/kW is based on summer capacity rating.
3 Capital cost for IGCC does not include CO2 capture.
4 Lead time for Cholla 6 is contingent on Cholla 5 already built.
5 ACC- Air Cooled Condenser

Attachment D.3 - Generation Technologies

2013 Q3 CONVENTIONAL GENERATION TECHNOLOGIES ASSUMPTIONS (2017 INSTALLATION)

LOCATION	ANNUAL CAPACITY (MW)	SUMMER CAPACITY (MW)	WINTER CAPACITY (MW)	CAPITAL COSTS ($MILLION)	CAPITAL COSTS ($/KW)	FIXED O&M ($/kW-Yr)	VAR O&M ($/MWh)	HEAT RATE (BTU/kWh)	LEAD TIME YEARS	CAPACITY FACTOR %	CO2 EMISSION (lbs/MWh)	WATER CONSUMPTION (gal/MWh)
Maricopa	100	100	100	277.8	2,778	17.33	5.00	4,229	3	10%	1,148	296
Maricopa	900	900	900	2340.0	2,600	12.30	0.31	81% *	10	10%	1,051	256
Maricopa	30	30	30	153.9	5,130	25.65	3.01	90% *	1	10%	851	336
Maricopa	20	20	20	55.0	2,750	TBD	TBD	70% *	2	10%	1,289	296
Maricopa	20	20	20	166.0	8,300	TBD	TBD	75% *	2	10%	1,203	276
Palo Verde	400	400	400	1812.5	4846	52.01	0.34	10,386	10	90%	0	552
Palo Verde	200	200	200	1106.0	5,530	TBD	TBD	10,452	10	90%	0	552

* Efficiency
1 Costs are in year-2013 dollars.
2 Capital costs are overnight construction costs; $/kW is based on summer capacity rating.
3 Capital cost for IGCC does not include CO2 capture.
4 Lead time for Cholla 6 is contingent on Cholla 5 already built.
5 ACC- Air Cooled Condenser

Attachment D.3 - Generation Technologies

2013 Q3 RENEWABLE GENERATION TECHNOLOGIES ASSUMPTIONS (2017 INSTALLATION)

PLANT	CAPACITY	CAPITAL COSTS	CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-Yr)	VAR O&M ($/MWh)	WAT USE (GAL/MWh)	CAPACITY FACTOR %	CAPACITY VALUE	USEFUL LIFE YEARS	MARKET PRICE ($/MWh)	FUEL COST ($/MWh)
Residential Solar PV-Fixed	6.29 kW	$24,344	3,870	26.0	0	0	22%	45%	25		0
Commercial & Industrial Solar PV	240.53 kW	$648,457	2,696	26.0	0	0	21%	50%	25		0
Thin Film Solar PV - Fixed	38 MW	$67 M	1,754	25	0	0	30%	50%	25		0
Thin Film Solar PV - Single Axis	36 MW	$76 M	2,098	25	0	0	34%	70%	25		0
Parabolic Trough, Gas Hybrid	250 MW	$1,114 M	4,458	70	0	338	25%	100%	30		0
Parabolic Trough, Salt Storage	250 MW	$1,945 M	7,782	74	0	338	41%	100%	30		0
Central Receiver (Power Tower), Salt Storage	100 MW	$827 M	8,265	72	0	338	49%	100%	30		0
High Capacity Factor Wind	100 MW	$220 M	2,200	44	0	0	33%	20%	20		0
Arizona Wind	99 MW	$228 M	2,305	37	0	0	23%	20%	20		0
Geothermal	50 MW	$244 M	4,880	83	10	764	96%	100%	30		0
Biomass	60 MW	$129 M	2,157	145	4	764	85%	100%	20		23
Biogas	3 MW	$8 M	2,513	167	3	764	88%	100%	20		39

Notes:
Costs are in year-2013 dollars.
Capital costs ($/kW) are overnight construction in 2013 $.
PV prices are in $2013 for 2017 installation.
Thin film PV capital cost for Fixed and Single Axis Tracking is expected to decline over time and stablize by year 2026.
Market price in 2017 $/MWh is in $2013.

Attachment D.10 - 2014 Resource Plan – Total Revenue Requirements

TOTAL REVENUE REQUIREMENTS SELECTED PORTFOLIO ($ MILLIONS)						
	GENERATION					
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL
2014	625.6	470.2	50.8	412.0	19.5	1578.2
2015	634.0	469.4	51.1	441.6	42.1	1638.1
2016	687.2	471.3	54.1	376.8	65.7	1655.0
2017	700.2	566.6	60.7	387.3	75.5	1790.3
2018	880.3	650.9	68.0	395.0	76.0	2070.1
2019	1012.5	706.6	74.7	405.1	73.9	2272.8
2020	1156.6	792.4	85.7	408.8	72.6	2516.0
2021	1335.1	869.2	91.5	441.1	71.1	2808.1
2022	1414.1	938.8	98.1	445.0	71.8	2967.9
2023	1563.0	1013.0	102.7	454.5	70.3	3203.4
2024	1646.1	1065.5	110.4	460.7	68.7	3351.3
2025	1770.7	1127.5	118.0	465.3	71.4	3552.9
2026	1811.7	1200.8	124.1	492.9	72.7	3702.3
2027	1811.8	1279.5	131.7	512.3	72.0	3807.3
2028	1870.7	1333.6	137.2	524.1	70.2	3935.9
2029	1907.9	1439.2	143.8	554.8	71.6	4117.4
2030	1929.9	1542.1	153.3	560.6	71.1	4257.0
2031	1984.6	1618.2	160.9	568.5	70.5	4402.6
2032	2022.1	1715.2	169.8	575.4	69.6	4552.1
2033	2070.8	1829.3	179.0	594.7	68.7	4742.5
2034	2129.0	1934.2	188.2	610.9	68.0	4930.2
2035	2189.9	2060.4	199.2	653.3	82.5	5185.3
2036	2238.1	2185.2	210.8	665.6	107.7	5407.5
2037	2302.9	2288.6	223.0	658.9	121.8	5595.3
2038	2394.1	2446.5	238.6	725.5	141.0	5945.7
2039	2547.6	2694.5	266.3	593.5	184.5	6286.4
2040	2764.7	2839.5	283.5	575.1	227.0	6689.8
2041	2868.0	2982.6	297.4	621.3	262.2	7031.5
2042	2969.2	3115.3	313.3	654.3	274.1	7326.2
2043	3025.8	3269.4	329.2	650.3	291.8	7566.6
(2014-2029)	10764.6	7475.5	786.0	4059.3	594.5	23679.9
(2014-2043)	17277.1	13646.3	1394.6	5807.1	950.5	39075.5

Attachment D.10 - 2014 Resource Plan – Total Revenue Requirements

TOTAL REVENUE REQUIREMENTS SELECTED PORTFOLIO ($ MILLIONS)				
	PURCHASES			SALES
	DEMAND	ENERGY	SUB TOTAL	
2014	110.5	351.3	461.8	(2.0)
2015	111.2	368.4	479.6	(0.4)
2016	105.8	357.4	463.2	(0.9)
2017	124.8	321.6	446.4	(2.4)
2018	91.3	292.3	383.5	(2.3)
2019	62.3	284.8	347.0	(2.4)
2020	6.0	231.1	237.1	(2.5)
2021	5.8	234.0	239.8	0.0
2022	6.5	232.6	239.1	0.0
2023	6.4	228.7	235.2	0.0
2024	7.2	227.1	234.3	0.0
2025	8.1	230.0	238.1	0.0
2026	8.1	233.1	241.2	0.0
2027	8.1	220.1	228.1	0.0
2028	8.1	223.7	231.7	0.0
2029	8.1	226.3	234.4	0.0
2030	8.1	221.9	229.9	0.0
2031	8.0	224.4	232.4	0.0
2032	8.1	227.3	235.4	0.0
2033	8.0	228.4	236.4	0.0
2034	8.7	231.7	240.4	0.0
2035	9.0	235.2	244.2	0.0
2036	9.4	238.8	248.1	0.0
2037	9.8	222.9	232.7	0.0
2038	10.0	214.7	224.7	0.0
2039	10.5	210.1	220.6	0.0
2040	10.7	203.5	214.2	0.0
2041	11.2	206.3	217.5	0.0
2042	11.7	205.3	217.0	0.0
2043	12.5	173.2	185.8	0.0
(2014-2029)	518.1	2627.1	3145.2	(9.4)
(2014-2043)	544.5	3253.6	3798.1	(9.4)

Attachment D.10 - 2014 Resource Plan – Total Revenue Requirements

TOTAL REVENUE REQUIREMENTS SELECTED PORTFOLIO ($ MILLIONS)						
					TOTAL	
	GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	63.2	23.9	(0.1)	127.3	2252.5	73.7
2015	64.8	21.3	(0.1)	135.1	2338.4	76.5
2016	66.4	18.5	(0.1)	135.6	2337.8	75.3
2017	80.7	17.0	(0.1)	125.1	2457.1	77.7
2018	69.8	14.2	(0.1)	122.5	2657.7	82.5
2019	71.8	11.7	(0.1)	118.7	2819.6	85.9
2020	73.3	9.6	(0.1)	126.2	2959.6	88.6
2021	106.5	9.2	55.2	60.7	3279.5	95.8
2022	99.6	8.9	68.4	70.8	3454.6	98.1
2023	116.5	8.4	72.6	77.2	3713.4	102.9
2024	118.2	8.1	87.2	76.2	3875.3	104.8
2025	116.1	7.7	104.8	74.6	4094.1	108.2
2026	138.1	7.2	133.8	75.3	4298.0	110.8
2027	142.9	6.8	176.9	80.0	4442.1	111.7
2028	150.5	6.4	215.4	84.5	4624.5	113.4
2029	174.9	6.1	253.8	87.6	4874.2	116.6
2030	229.4	5.7	300.8	88.1	5110.9	119.4
2031	195.3	5.3	321.0	86.8	5243.4	119.5
2032	229.0	4.9	339.2	81.5	5442.0	121.1
2033	228.3	4.5	354.8	79.9	5646.4	122.7
2034	235.6	4.0	371.4	78.8	5860.5	124.1
2035	288.9	3.6	383.8	79.1	6184.9	127.7
2036	309.7	3.1	403.2	79.3	6451.0	129.8
2037	342.8	2.6	427.7	79.2	6680.2	131.4
2038	402.1	2.2	437.8	75.9	7088.4	136.2
2039	449.4	1.7	409.3	75.5	7443.0	139.8
2040	480.0	1.4	429.4	74.7	7889.4	144.7
2041	505.3	1.0	446.0	73.7	8275.0	148.7
2042	542.1	0.7	473.1	72.4	8631.4	151.8
2043	568.5	0.3	492.6	70.7	8884.5	153.0
(2014-2029)	870.4	123.4	470.6	982.0	29262.1	
(2014-2043)	1791.9	133.1	1562.7	1208.0	47559.8	

Attachment D.14(a) - EE and DR Program Descriptions and Deployment

PROGRAM TYPE	NAME	DEPLOYMENT	RESIDENTIAL EE PROGRAM DESCRIPTION
Residential EE	1. Consumer Products	On-going	The Consumer Products program targets deployment of energy using products at home, through partnership with local retailers. Compact fluorescent lamps (CFLs), and variable-speed pool pumps with high efficiency motors are measures incented through this program.
Residential EE	2. Existing Homes HVAC	On-going	The Existing Homes program provides incentives for heating ventilation, and air conditioning (HVAC) measures. The HVAC programs include the AC Rebate, Duct Test and Repair, and HVAC diagnostics for tuning-up existing HVAC units. The AC Rebate offers financial incentives to homeowners for buying EE equipment (≥13 SEER/10.8EER) that is installed in accordance with the program requirement for air flow, refrigerant charge, and sizing.
Residential EE	3. Home Performance with Energy Star	On-going	The HPwES program offers home owners a $99 comprehensive home energy checkup to help identify ways to improve EE and comfort throughout the home. This program element offers a direct install feature that includes up to 10 compact fluorescent lamps ("CFLs"), three faucet aerators, and one low-flow showerhead that are installed at the time of the checkup. Additional financial incentives are available for duct sealing, air sealing, insulation, and shade screens, once a home owner has completed an HPwES checkup.
Residential EE	4. New Construction	On-going	The Residential New Construction program promotes high efficiency construction practices for new homes through builder incentives. The program emphasizes the "whole building" approach to improving EE and includes field testing of homes to ensure compliance with APS performance standards that are based off the EPA ENERGY STAR Homes program. In 2012, APS updated the New Construction program to meet Version 3 ENERGY STAR requirements which will provide 80% greater savings than Version 2 in Arizona.
Residential EE	5. Appliance Recycling	On-going	The Appliance Recycling program targets the removal of functional second refrigerators and freezers in residential households. APS offers a $30 rebate with free pick-up and recycling of operable second refrigerators and freezers.
Residential EE	6. Low Income Weatherization	On-going	APS's Energy Wise Low Income Weatherization program is designed to improve the energy efficiency, safety, and health attributes of homes occupied by customers whose income falls within 200% of the Federal Poverty Guidelines. The weatherization component of this program serves low-income customers with various home improvement measures, including cooling system repair and replacement, insulation, sunscreens, water heaters, window repairs and improvements, as well as other general household repairs. These programs are administered by various community action agencies throughout APS's service territory.
Residential EE	7. Conservation Behavior Pilot	On-going	The Residential Conservation Behavior Pilot program provides participating residential customers with periodic reports containing information designed to help motivate them to adopt energy conservation behaviors. The program provides direct-mailed reports to participants to show how the energy usage in their home compares with energy efficient and other similar homes.
Residential EE	8. Multi-Family Construction	On-going	The Multi-Family Energy Efficiency Program (MEEP) is a program that targets multi-family properties and dormitories with EE measures and solutions designed to promote energy savings. The MEEP has two different approaches. The first provides CFLs, showerheads, and faucet aerators to retrofit each dwelling in a community, at no cost. The second track provides a per-unit incentive for new construction and major renovation projects that meet or exceed the EE guidelines outlined in one of the three Builder Option Packages.[1]
Residential EE	9. Shade Tree	On-going	APS's Shade Tree program is designed to provide free shade trees (maximum of 3) to all APS customers who participate in an APS Shade Tree workshop. Tree planting workshops educate customers on successful tree planting and care techniques and provide a customer-specific site map indicating the ideal tree planting location for energy efficiency.
Residential & Non-Residential EE	10. Codes & Standards	On-going	APS may count toward meeting the standard up to one third of the energy savings, resulting from energy efficiency builing codes and appliance standards, that are quantified and reported through a measurement and evaluation study.

Notes:

1. Details on the Builder Option Packages can be found in Decision No. 72060 (Docket No. E-01345A-10-0219).

Attachment D.14(a) - EE and DR Program Descriptions and Deployment

PROGRAM TYPE	NAME	DEPLOYMENT	RESIDENTIAL DR PROGRAM DESCRIPTION
Residential DR	1. ET-SP Time Advantage Super Peak	On-going	ET-SP is a static super peak time-of-use rate providing a high price signal during a small number of core peak hours and standard time-of-use pricing for other time periods. This may also be referred to as a three-part time-of-use rate in that price signals are provided for super-peak hours, on-peak hours, and off-peak hours. In addition, the pricing plan provides price signals for three seasons: Super Peak summer season which is June through August; summer season, which consists of May, September, and October; and, winter which runs November through April.
Residential DR	2. ET-1 Time Advantage (9am-9pm)	Frozen to new customers	ET-1 (Time Advantage) has an energy-only rate with an on-peak period from 9am-9pm. The program has been in place since 1982. In a previous rate case approved under A.C.C. Decision No. 71448, APS closed the series ET-1 rate to new customers. APS anticipates closing the rate to all customers within the next three years and transitioning any remaining customers to the ET-2 or ECT-2 rates.
Residential DR	3. ECT-1R Combined Advantage (9am-9pm)	Frozen to new customers	ECT-1R (Combined Advantage) includes both demand and energy charges. Similar to the ET-1 rate schedule, the peak hours are from 9am-9pm. APS anticipates closing the rate to all customers within the next three years and transitioning any remaining customers to the ET-2 or ECT-2 rates.
Residential DR	4. ET-2 Time Advantage (Noon - 7pm)	On-going	ET-2 (Time Advantage) has an energy-only rate with an on-peak period from Noon- 7:00pm.
Residential DR	5. ECT-2 Combined Advantage (Noon - 7pm)	On-going	ECT-2 (Combined Advantage) includes demand and energy charges with a peak period of Noon - 7:00pm.
Residential DR	6. ET-EV Experimental Electric Vehicle Charging Rate Schedule	On-going	ET-EV is offered to residential customers who own a qualified electric vehicle (EV) and will be charging them in the individual residence. This rate schedule provides a price signal aimed at encouraging residential customers to charge an EV during hours when demand on the distribution system is low and when the load on the secondary transformer is less, thereby reducing any potential distribution system impacts posed by the EV load.
Residential DR	7. Peak Event Pricing (also referred to as Critical Peak Pricing)	On-going	Provides a high price signal over a small number of core summer peak days and hours. The program can be called on when the Company is experiencing extreme temperatures, very high electrical demand, high market electric costs, or is experiencing a major generation or transmission disturbance. The critical peak price signal is "dynamic" in that it is callable by APS for up to 18 days and 90 hours per year, weekdays during the months June through September. APS declares a "critical event" day and notifies participants by 4:00 p.m. the prior day. During the event the customer is charged an additional $0.25 per kWh for consumption during the hours 2 p.m. to 7pm. The customer also receives a discount of approximately $0.012143 per kWh for all consumption during the June through September billing cycles. The prices are designed so that the monthly discounts equal the critical peak charges for the typical customer. Therefore, to save money, the customer must be able to reduce usage during critical hours.
Residential DR	8. PTR-RES (Peak Time Rebate)	On-going	The Peak Time Rebate program, to be available for ET-2 customers, and is similar to Peak Event Pricing in that it will have the same number of peak event days and hours, and the same customer notification process. A distinction is that instead of providing a high charge it will give an energy discount or rebate of $0.25 per kWh for all kWh reduced during the critical hours. The kWh reduction will be determined by comparing the actual metered usage during those hours with a baseline load which reflects the customer's typical or expected usage during those hours. The Company has designed a specific baseline estimation protocol, which uses the customer's actual load data for other similar hours during days when a critical event was not called. In the event the customer exceeds the baseline load during a Peak Event, the customer will receive no credit. The program has been in 2013 and will be available for two years with the option to continue the program into future years.
Residential DR	9. Home Energy Information Pilot	2012	The Home Energy Information Pilot Program (HEI Pilot), approved in ACC Decision 72214, is a comprehensive residential DR pilot designed to test available home area network technologies and determine communication devices, demand response strategies, and mix of smart home applications that can be most effectively employed in a residential setting. This information will provide essential learnings for rolling out a full-scale, residential DR program in the future.

PROGRAM TYPE	NAME	DEPLOYMENT	NON-RESIDENTIAL EE PROGRAM DESCRIPTION
Non-Residential EE	1. Large Existing Facilities	On-going	The Large Existing Facilities program targets customers with an aggregate monthly peak demand greater than 100 kW and offers prescriptive incentives to owners and operators of large non-residential facilities for EE improvements in lighting, HVAC, motors, building envelope, and refrigeration measures. Incentives are provided to customers who conduct qualifying energy studies. The largest customers (electric usage ≥40,000 MWh per year) may qualify to self direct the amount they pay toward DSM costs for their own EE projects. Custom incentives are also provided for EE measures not covered by the prescriptive incentives. Customers may also participate in the Direct Install family of measures in the areas of lighting and refrigeration for any facilities with a peak monthly demand of 400 kW and less.
Non-Residential EE	2. New Construction	On-going	The Non-Residential New Construction program includes three components: (1) design assistance; (2) prescriptive measures; and, (3) customer efficiency measures. Design assistance involves efforts to integrate EE into a customer's design process to influence equipment/system selection early on in the process. Prescriptive incentives are available for EE improvements in measures such as lighting, HVAC, motors, building envelope, and refrigeration applications. Whole Building Design is a component within the New Construction custom efficiency measures that influences customers, developers, and design professionals to design, build, and invest in higher performing building through a stepped performance incentive structure with the financial incentives increasing as the building performance improves.
Non-Residential EE	3. Small business	On-going	The Small Business program targets customers with a maximum peak aggregated demand of 100 kW or less. The program gives prescriptive incentives to small business owners for EE improvements in lighting, HVAC, motors, building envelope, and refrigeration applications. A customer in the Small Business program may participate in the Direct Install family of measures in the areas of lighting and refrigeration and may also qualify to receive APS-arranged program financing. Small Business participants may also receive incentives for energy studies and custom efficiency measures.
Non-Residential EE	4. Schools	On-going	The Schools program is designed to set aside funding for K-12 public, private, and charter school buildings. Schools can receive up to a maximum of $100,000 in incentives per year. EE incentives for Schools are the same as in the Large Existing Facilities (for existing school facilities) and New Construction (for new school construction and major renovation projects) programs. In addition, any size school may receive Direct Install measure incentives and is eligible to receive APS-arranged program financing for their EE projects.
Non-Residential EE	5. Energy Information Systems	On-going	The Energy Information Systems program is a subscription service for software that provides 15-minute interval electric usage data to large non-residential customers through a web-based energy information tool. This tool provides users with information that can be used to improve or monitor energy usage patterns, reduce energy use, reduce demands during on-peak periods, and better manage overall energy operations.

Attachment D.14(a) - EE and DR Program Descriptions and Deployment

PROGRAM TYPE	NAME	DEPLOYMENT	NON-RESIDENTIAL DR PROGRAM DESCRIPTION
Non-Residential DR	1. E-20	Frozen to new customers	Intended for houses of worship, E-20 was implemented in 1996. On-peak and off-peak charges are included for both energy and demand. This rate was frozen to new customers as of July 1, 2013.
Non-Residential DR	2. E-221-8T	On-going	Designed for water pumping customers, the E-221-8T rate was implemented in 1986. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	3. E-32 XS TOU	On-going	For business customers, the E-32TOU rates (which include extra small, small, medium, and large customers) were implemented in 2005 and are available for customers with less than 3 MW of monthly peak demand. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	4. E-32 S TOU		
Non-Residential DR	5. E-32 M TOU		
Non-Residential DR	6. E-32 L TOU		
Non-Residential DR	7. E-35	On-going	E-35 was implemented in 1988 for extra large business customers exceeding 3 MW of monthly peak demand. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	8. GS-Schools M	On-going	Designed for public and private schools providing primarily on-site K-12 education, the GS-Schools TOU rates were implemented in 2010 and are available to schools with less than 3 MW of monthly peak demand. The rates contain energy charges for three seasons including summer peak (June-August), summer shoulder (May, September and October) and winter (November through April). The demand charge is computed based on the monthly maximum demand.
Non-Residential DR	9. GS-Schools L		
Non-Residential DR	10. IRR-Interruptible Rate	On-going	The rate rider IRR was approved for July 1st 2012. IRR provides interruptible service for extra-large general service customers who can interrupt at least 500 kW of load when requested by the Company. Under this service, the customer can choose between two curtailment options, two notification options, and a one-year or five-year agreement. The customer receives capacity and energy payments for the interruptible load based on these options. The customer may also incur a penalty for failing to curtail when requested. Customers in Metro Phoenix and Yuma area are not eligible for this rate until January 1st 2015.
Non-Residential DR	11. Peak Solutions	On-going	APS Peak Solutions is a DR program approved in ACC Decision 71104 that offers financial incentives to eligible commercial and industrial customers to reduce their electricity usage during APS's summer peak periods (June through September) between 1:00 p.m. and 7:00 p.m. daily. Load reductions are often for HVAC systems, lighting, refrigeration, and industrial processes.[1]

Notes:

1. APS Peak Solutions Application filed, 11/6/2008, Docket E-01345A-08-0569.

Attachment D.14(b) - Expected EE Participation

EE PROGRAM PARTICIPATION[1]		
RESIDENTIAL PROGRAM NAME	MEASURE OR UNIT	ACTUAL PARTICIPATION IN 2013
Consumer Products	CFL Bulbs	3,195,822
	Variable Speed Pumps	6,250
Appliance Recycling	Refrigerators	6,283
	Freezers	830
Energy Star Homes	Version 3	3,446
	Second Tier - HERS 60	424
Home Performance with Energy Star	Audits	4,722
	Low Flow Shower Heads	4,722
	Low Flow Aerators	11,484
	CFL Bulbs	47,220
	Air Sealing (only)	72
	Duct Test & Repair	1,928
Residential HVAC	Insulation & Air Sealing	1,340
	Shade Screens	112
	Equipment Rebates	8,741
	Duct Test & Repair	2,843
Multi-Family	AC Diagnostic	795
	Low Flow Shower Heads	6,801
	Low Flow Aerators	11,679
	CFL Bulbs	78,932
	Builder Option Package 1	26
	Builder Option Package 2	5269
	Builder Option Package 3	679
Shade Trees	Trees Planted	4,174
Behavioral	Reports Generated	70,837
Non-Residential Program Name		
Large Existing	No. of Applications Paid	1,169
Large New Construction	No. of Applications Paid	79

[1]Additional details pertaining to EE programs were provided in the 2013 APS Annual DSM Progress Report filed with the ACC on March 1, 2014.

Attachment D.16 - Gas Transport Analysis

GAS TRANSPORT ANALYSIS										
YEAR	2015		2016		2017		2018		2019	
SEASON	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
Peak burn day (mmbtu/day)	**354,878**	**138,663**	**365,577**	**164,001**	**370,578**	**243,476**	**427,918**	**199,538**	**454,994**	**217,613**
Current firm fuel contracts										
El Paso - FT24T000	85,281	43,576	85,281	43,576	85,281	43,576	85,281	43,576	85,281	43,576
El Paso - FT39D000	**89,490**	**52,629**	**89,490**	**52,629**	**89,490**	**52,629**	**89,490**	**52,629**	**89,490**	**52,629**
El Paso - FT39E000	22,337	11,289	22,337	11,289	22,337	11,289	22,337	11,289	22,337	11,289
El Paso - FT39H000	**28,436**	**19,929**	**28,436**	**19,929**	**28,436**	**19,929**	**28,436**	**19,929**	**28,436**	**19,929**
El Paso - H822E000	28,000	25,500	28,000	25,500	28,000	25,500	28,000	25,500	28,000	25,500
Transwestern - FT-5	**182,634**	**127,096**	**182,634**	**127,096**	**182,634**	**127,096**	**182,634**	**127,096**	**182,634**	**127,096**
North Baja - A027F1 (Yuma Only)	11,000	11,000								
North Baja - YA027F1 (Yuma Only)	**62,750**	**64,895**	**62,750**	**64,895**	**62,750**	**64,895**	**62,750**	**64,895**	**62,750**	**64,895**
Total Current firm contracts[1]	**436,178**	**280,019**	**436,178**	**280,019**	**436,178**	**280,019**	**436,178**	**280,019**	**436,178**	**280,019**
Rollover ROFR firm fuel contracts										
El Paso - FT24T000										
El Paso - FT39D000										
El Paso - FT39E000										
El Paso - FT39H000										
El Paso - H822E000										
Transwestern - FT-5										
North Baja - A027F1 (Yuma Only)			11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)										
Total ROFR firm contracts[1]	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
***Future fuel contracts										
Long Term Seasonal Firm Purchases										
Short Term Purchases									19,706	
Total future contracts	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**19,706**	**0**
Total contract rights	**436,178**	**280,019**	**436,178**	**280,019**	**436,178**	**280,019**	**436,178**	**280,019**	**455,884**	**280,019**
Long/(Short) contract rights	**81,300**	**141,356**	**70,601**	**116,018**	**65,600**	**36,543**	**8,260**	**80,481**	**891**	**62,407**

[1]North Baja capacity serving only Yuma is not included in total current firm contracts.
[2]Based upon hourly optimization analysis.

Attachment D.16 - Gas Transport Analysis

GAS TRANSPORT ANALYSIS										
YEAR	2020		2021		2022		2023		2024	
SEASON	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
Peak burn day (mmbtu/day)	474,657	229,998	518,310	176,099	551,825	200,572	580,382	268,209	613,897	254,695
Current firm fuel contracts										
El Paso - FT24T000										
El Paso - FT39D000										
El Paso - FT39E000										
El Paso - FT39H000	28,436	19,929	28,436	19,929	28,436	19,929	28,436	19,929	28,436	19,929
El Paso - H822E000	28,000	25,500	28,000	25,500	28,000	25,500	28,000	25,500		
Transwestern - FT-5	182,634	127,096	182,634	127,096	182,634	127,096	182,634	127,096	182,634	127,096
North Baja - A027F1 (Yuma Only)										
North Baja - YA027F1 (Yuma Only)	62,750	64,895	62,750	64,895	62,750	64,895	62,750	64,895	62,750	64,895
Total Current firm contracts[1]	**239,070**	**172,525**	**239,070**	**172,525**	**239,070**	**172,525**	**239,070**	**172,525**	**211,070**	**147,025**
Rollover ROFR firm fuel contracts										
El Paso - FT24T000	85,281	43,576	85,281	43,576	85,281	43,576	85,281	43,576	85,281	43,576
El Paso - FT39D000	89,490	52,629	89,490	52,629	89,490	52,629	89,490	52,629	89,490	52,629
El Paso - FT39E000	22,337	11,289	22,337	11,289	22,337	11,289	22,337	11,289	22,337	11,289
El Paso - FT39H000										
El Paso - H822E000									28,000	25,500
Transwestern - FT-5										
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)										
Total ROFR firm contracts[1]	**197,108**	**107,494**	**197,108**	**107,494**	**197,108**	**107,494**	**197,108**	**107,494**	**225,108**	**132,994**
***Future fuel contracts										
Long Term Seasonal Firm Purchases			82,872		117,000		117,000		117,000	
Short Term Purchases	39,004						27,608		61,543	20,468
Total future contracts	**39,004**	**0**	**82,872**	**0**	**117,000**	**0**	**144,608**	**0**	**178,543**	**20,468**
Total contract rights	**475,182**	**280,019**	**519,050**	**280,019**	**553,178**	**280,019**	**580,786**	**280,019**	**614,721**	**300,487**
Long/(Short) contract rights	**525**	**50,021**	**740**	**103,921**	**1,353**	**79,447**	**405**	**11,810**	**824**	**45,792**

[1]North Baja capacity serving only Yuma is not included in total current firm contracts.
[2]Based upon hourly optimization analysis.

Attachment D.16 - Gas Transport Analysis

GAS TRANSPORT ANALYSIS										
YEAR	2025		2026		2027		2028		2029	
SEASON	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
Peak burn day (mmbtu/day)	649,936	240,363	694,861	311,687	697,425	280,654	743,909	296,805	802,858	369,207
Current firm fuel contracts										
El Paso - FT24T000										
El Paso - FT39D000										
El Paso - FT39E000										
El Paso - FT39H000										
El Paso - H822E000										
Transwestern - FT-5										
North Baja - A027F1 (Yuma Only)										
North Baja - YA027F1 (Yuma Only)	62,750	64,895								
Total Current firm contracts[1]	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Rollover ROFR firm fuel contracts										
El Paso - FT24T000	85,281	43,576	85,281	43,576	85,281	43,576	85,281	43,576	85,281	43,576
El Paso - FT39D000	89,490	52,629	89,490	52,629	89,490	52,629	89,490	52,629	89,490	52,629
El Paso - FT39E000	22,337	11,289	22,337	11,289	22,337	11,289	22,337	11,289	22,337	11,289
El Paso - FT39H000	28,436	19,929	28,436	19,929	28,436	19,929	28,436	19,929	28,436	19,929
El Paso - H822E000	28,000	25,500	28,000	25,500	28,000	25,500	28,000	25,500	28,000	25,500
Transwestern - FT-5	182,634	127,096	182,634	127,096	182,634	127,096	182,634	127,096	182,634	127,096
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)			62,750	64,895	62,750	64,895	62,750	64,895	62,750	64,895
Total ROFR firm contracts[1]	**436,178**	**280,019**	**436,178**	**280,019**	**436,178**	**280,019**	**436,178**	**280,019**	**436,178**	**280,019**
Future fuel contracts[2]										
Long Term Seasonal Firm Purchases	215,000		215,000	30,000	215,000	30,000	309,000	30,000	309,000	123,440
Short Term Purchases		3,010	44,332	22,147	46,870				58,115	
Total future contracts	**215,000**	**3,010**	**259,332**	**52,147**	**261,870**	**30,000**	**309,000**	**30,000**	**367,115**	**123,440**
Total contract rights	**651,178**	**283,029**	**695,510**	**332,166**	**698,048**	**310,019**	**745,178**	**310,019**	**803,293**	**403,459**
Long/(Short) contract rights	**1,242**	**42,666**	**649**	**20,479**	**623**	**29,365**	**1,269**	**13,214**	**435**	**34,252**

[1]North Baja capacity serving only Yuma is not included in total current firm contracts.
[2]Based upon hourly optimization analysis.

F.1(a)(1): Selected Portfolio

SELECTED PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	Total Load Requirements	8,124	8,268	8,566	8,897	9,219	9,543	9,864	10,268	10,610	10,946	11,276	11,609	11,945	12,286	12,632	12,982
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	463	463	464	464	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	Total Existing Resources	9,166	9,084	8,420	7,770	7,550	7,550	6,943	6,454	6,446	6,433	6,426	6,426	6,427	6,410	6,411	6,412
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	261
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	Total Customer Resources	174	350	535	706	862	1,013	1,178	1,305	1,412	1,507	1,610	1,663	1,744	1,821	1,899	1,983
29	Natural Gas	0	0	0	364	750	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CCs/CTs	0	0	0	0	510	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	364	240	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	Total Future Resources	0	32	57	420	807	1,067	1,825	2,572	2,811	3,093	3,325	4,013	4,017	4,139	4,422	4,630
37	TOTAL RESOURCES	9,340	9,467	9,012	8,897	9,219	9,630	9,945	10,331	10,668	11,033	11,361	12,102	12,188	12,371	12,732	13,025

F.1(a)(1): Selected Portfolio

ENERGY MIX
SELECTED PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,872	6,749	3,182	2,509	33,609
2015	9,297	11,963	6,479	3,355	3,120	34,214
2016	9,325	12,324	6,497	3,492	3,764	35,401
2017	9,296	11,764	7,707	3,526	4,375	36,668
2018	9,297	12,439	7,627	3,566	4,951	37,880
2019	9,297	13,034	7,661	3,607	5,505	39,105
2020	9,325	13,149	7,541	3,934	6,071	40,020
2021	9,296	12,024	9,445	4,268	6,424	41,458
2022	9,297	12,214	9,970	4,656	6,563	42,700
2023	9,297	11,514	11,035	5,323	6,743	43,912
2024	9,324	12,364	10,784	5,706	6,931	45,108
2025	9,297	12,857	10,909	6,138	7,107	46,308
2026	9,297	13,117	11,593	6,230	7,281	47,517
2027	9,297	13,215	12,489	6,270	7,461	48,732
2028	9,325	13,205	12,874	6,915	7,655	49,973
2029	9,297	12,548	14,592	6,944	7,855	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	35.3%	20.1%	9.5%	7.5%	100.0%
2015	27.2%	35.0%	18.9%	9.8%	9.1%	100.0%
2016	26.3%	34.8%	18.4%	9.9%	10.6%	100.0%
2017	25.4%	32.1%	21.0%	9.6%	11.9%	100.0%
2018	24.5%	32.8%	20.1%	9.4%	13.1%	100.0%
2019	23.8%	33.3%	19.6%	9.2%	14.1%	100.0%
2020	23.3%	32.9%	18.8%	9.8%	15.2%	100.0%
2021	22.4%	29.0%	22.8%	10.3%	15.5%	100.0%
2022	21.8%	28.6%	23.3%	10.9%	15.4%	100.0%
2023	21.2%	26.2%	25.1%	12.1%	15.4%	100.0%
2024	20.7%	27.4%	23.9%	12.6%	15.4%	100.0%
2025	20.1%	27.8%	23.6%	13.3%	15.3%	100.0%
2026	19.6%	27.6%	24.4%	13.1%	15.3%	100.0%
2027	19.1%	27.1%	25.6%	12.9%	15.3%	100.0%
2028	18.7%	26.4%	25.8%	13.8%	15.3%	100.0%
2029	18.1%	24.5%	28.5%	13.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(a)(2) - Base Portfolio

BASE PORTFOLIO - LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	463	463	464	464	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,084**	**8,420**	**7,770**	**7,550**	**7,550**	**6,943**	**6,454**	**6,446**	**6,433**	**6,426**	**6,426**	**6,427**	**6,410**	**6,411**	**6,412**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	261
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,507**	**1,610**	**1,663**	**1,744**	**1,821**	**1,899**	**1,983**
29	Natural Gas	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CCs/CTs	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,067**	**1,067**	**1,825**	**2,572**	**2,811**	**3,093**	**3,325**	**4,013**	**4,017**	**4,139**	**4,422**	**4,630**
37	**TOTAL RESOURCES**	**9,340**	**9,467**	**9,012**	**9,033**	**9,479**	**9,630**	**9,945**	**10,331**	**10,668**	**11,033**	**11,361**	**12,102**	**12,188**	**12,371**	**12,732**	**13,025**

Attachment F.1(a)(2) - Base Portfolio

ENERGY MIX
BASE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE+ DE RENEW	EE	TOT
2014	9,297	11,872	6,749	3,182	2,509	33,609
2015	9,297	11,963	6,479	3,355	3,120	34,214
2016	9,325	12,324	6,497	3,492	3,764	35,401
2017	9,296	11,576	7,895	3,526	4,375	36,668
2018	9,297	12,265	7,801	3,566	4,951	37,880
2019	9,297	13,005	7,690	3,607	5,505	39,105
2020	9,325	13,132	7,558	3,934	6,071	40,020
2021	9,296	12,015	9,454	4,268	6,424	41,458
2022	9,297	12,210	9,974	4,656	6,563	42,700
2023	9,297	11,508	11,041	5,323	6,743	43,912
2024	9,324	12,361	10,787	5,706	6,931	45,108
2025	9,297	12,860	10,906	6,138	7,107	46,308
2026	9,297	13,127	11,583	6,230	7,281	47,517
2027	9,297	13,223	12,481	6,270	7,461	48,732
2028	9,325	13,198	12,881	6,915	7,655	49,973
2029	9,297	12,541	14,599	6,944	7,855	51,236

ENERGY MIX %

	Nuclear	Coal	Gas	RE+ DE RENEW	EE	TOT
2014	27.7%	35.3%	20.1%	9.5%	7.5%	100.0%
2015	27.2%	35.0%	18.9%	9.8%	9.1%	100.0%
2016	26.3%	34.8%	18.4%	9.9%	10.6%	100.0%
2017	25.4%	31.6%	21.5%	9.6%	11.9%	100.0%
2018	24.5%	32.4%	20.6%	9.4%	13.1%	100.0%
2019	23.8%	33.3%	19.7%	9.2%	14.1%	100.0%
2020	23.3%	32.8%	18.9%	9.8%	15.2%	100.0%
2021	22.4%	29.0%	22.8%	10.3%	15.5%	100.0%
2022	21.8%	28.6%	23.4%	10.9%	15.4%	100.0%
2023	21.2%	26.2%	25.1%	12.1%	15.4%	100.0%
2024	20.7%	27.4%	23.9%	12.6%	15.4%	100.0%
2025	20.1%	27.8%	23.6%	13.3%	15.3%	100.0%
2026	19.6%	27.6%	24.4%	13.1%	15.3%	100.0%
2027	19.1%	27.1%	25.6%	12.9%	15.3%	100.0%
2028	18.7%	26.4%	25.8%	13.8%	15.3%	100.0%
2029	18.1%	24.5%	28.5%	13.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(a)(3) - Enhanced Renewable Portfolio

ENHANCED RENEWABLE PORTFOLIO - LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	470	464	464	443	426	414	403	403	388	382	380	380	363	364	364
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	397	389	384	384	363	346	333	322	323	320	314	313	313	313	314	314
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,167**	**9,085**	**8,421**	**7,771**	**7,530**	**7,513**	**6,903**	**6,412**	**6,413**	**6,397**	**6,391**	**6,390**	**6,390**	**6,373**	**6,373**	**6,374**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	96	107	116	130	154	179	201	222	235	243	251	259
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**860**	**1,010**	**1,176**	**1,303**	**1,410**	**1,505**	**1,608**	**1,661**	**1,742**	**1,819**	**1,896**	**1,981**
29	Natural Gas	0	0	0	500	1,010	1,010	1,612	2,316	2,520	2,622	2,928	3,132	3,336	4,001	4,001	4,001
30	CCs/CTs	0	0	0	500	1,010	1,010	1,612	2,316	2,520	2,622	2,928	3,132	3,336	4,001	4,001	4,001
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	150	200	226	255	337	426	448	478	561	584	667	675
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	150	200	226	255	262	276	298	310	318	326	334	342
35	Geothermal	0	0	0	0	0	0	0	0	75	150	150	150	225	225	300	300
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,160**	**1,210**	**1,838**	**2,571**	**2,857**	**3,048**	**3,376**	**3,610**	**3,897**	**4,585**	**4,668**	**4,676**
37	**TOTAL RESOURCES**	**9,341**	**9,468**	**9,013**	**9,035**	**9,551**	**9,733**	**9,917**	**10,286**	**10,680**	**10,950**	**11,375**	**11,660**	**12,028**	**12,777**	**12,938**	**13,031**

ENERGY MIX
ENHANCED RENEWABLE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE+ DE RENEW	EE	TOT
2014	9,297	11,872	6,749	3,182	2,509	33,609
2015	9,297	11,963	6,479	3,355	3,120	34,214
2016	9,325	12,324	6,497	3,492	3,764	35,401
2017	9,296	11,576	7,895	3,526	4,375	36,668
2018	9,297	12,180	7,328	4,124	4,951	37,880
2019	9,297	12,644	6,934	4,723	5,505	39,105
2020	9,325	12,578	6,714	5,332	6,071	40,020
2021	9,296	11,608	7,910	6,221	6,424	41,460
2022	9,297	11,697	8,220	6,921	6,563	42,700
2023	9,297	10,995	9,009	7,868	6,743	43,912
2024	9,324	11,570	8,468	8,816	6,931	45,108
2025	9,297	12,067	8,317	9,520	7,107	46,308
2026	9,297	12,131	8,605	10,203	7,281	47,517
2027	9,297	12,274	9,457	10,243	7,461	48,732
2028	9,325	12,386	9,711	10,897	7,655	49,973
2029	9,297	11,962	11,205	10,917	7,855	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE+ DE RENEW	EE	TOT
2014	27.7%	35.3%	20.1%	9.5%	7.5%	100.0%
2015	27.2%	35.0%	18.9%	9.8%	9.1%	100.0%
2016	26.3%	34.8%	18.4%	9.9%	10.6%	100.0%
2017	25.4%	31.6%	21.5%	9.6%	11.9%	100.0%
2018	24.5%	32.2%	19.3%	10.9%	13.1%	100.0%
2019	23.8%	32.3%	17.7%	12.1%	14.1%	100.0%
2020	23.3%	31.4%	16.8%	13.3%	15.2%	100.0%
2021	22.4%	28.0%	19.1%	15.0%	15.5%	100.0%
2022	21.8%	27.4%	19.3%	16.2%	15.4%	100.0%
2023	21.2%	25.0%	20.5%	17.9%	15.4%	100.0%
2024	20.7%	25.6%	18.8%	19.5%	15.4%	100.0%
2025	20.1%	26.1%	18.0%	20.6%	15.3%	100.0%
2026	19.6%	25.5%	18.1%	21.5%	15.3%	100.0%
2027	19.1%	25.2%	19.4%	21.0%	15.3%	100.0%
2028	18.7%	24.8%	19.4%	21.8%	15.3%	100.0%
2029	18.1%	23.3%	21.9%	21.3%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(a)(4) - Coal Reduction Portfolio

COAL REDUCTION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	463	463	464	464	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,085**	**8,160**	**7,510**	**7,290**	**7,290**	**6,683**	**6,194**	**6,186**	**6,166**	**6,159**	**5,773**	**5,774**	**5,757**	**5,759**	**5,753**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	261
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,507**	**1,610**	**1,663**	**1,744**	**1,821**	**1,899**	**1,983**
29	Natural Gas	0	0	0	704	1,214	1,214	2,020	2,622	2,826	3,030	3,234	3,899	4,103	4,409	4,613	4,817
30	CCs/CTs	0	0	0	704	1,214	1,214	2,020	2,622	2,826	3,030	3,234	3,899	4,103	4,409	4,613	4,817
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**761**	**1,271**	**1,271**	**2,131**	**2,776**	**3,015**	**3,325**	**3,548**	**4,237**	**4,448**	**4,775**	**5,061**	**5,284**
37	TOTAL RESOURCES	9,340	9,467	8,752	8,978	9,423	9,574	9,992	10,275	10,613	10,997	11,317	11,673	11,965	12,354	12,718	13,019

ENERGY MIX
COAL REDUCTION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE+ DE RENEW	EE	TOT
2014	9,297	11,872	6,749	3,182	2,509	33,609
2015	9,297	11,963	6,479	3,355	3,120	34,214
2016	9,325	11,286	7,535	3,492	3,764	35,401
2017	9,296	9,992	9,478	3,526	4,375	36,668
2018	9,297	10,626	9,440	3,566	4,951	37,880
2019	9,297	11,417	9,278	3,607	5,505	39,105
2020	9,325	11,544	9,146	3,934	6,071	40,020
2021	9,296	10,489	10,980	4,268	6,424	41,457
2022	9,297	10,795	11,388	4,656	6,563	42,700
2023	9,297	9,969	12,302	5,602	6,743	43,912
2024	9,324	10,682	12,187	5,986	6,931	45,108
2025	9,297	8,924	14,563	6,417	7,107	46,308
2026	9,297	9,053	15,378	6,509	7,281	47,517
2027	9,297	9,063	16,362	6,549	7,461	48,732
2028	9,325	9,046	16,753	7,194	7,655	49,973
2029	9,297	8,646	17,936	7,502	7,855	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE+ DE RENEW	EE	TOT
2014	27.7%	35.3%	20.1%	9.5%	7.5%	100.0%
2015	27.2%	35.0%	18.9%	9.8%	9.1%	100.0%
2016	26.3%	31.9%	21.3%	9.9%	10.6%	100.0%
2017	25.4%	27.3%	25.8%	9.6%	11.9%	100.0%
2018	24.5%	28.1%	24.9%	9.4%	13.1%	100.0%
2019	23.8%	29.2%	23.7%	9.2%	14.1%	100.0%
2020	23.3%	28.8%	22.9%	9.8%	15.2%	100.0%
2021	22.4%	25.3%	26.5%	10.3%	15.5%	100.0%
2022	21.8%	25.3%	26.7%	10.9%	15.4%	100.0%
2023	21.2%	22.7%	28.0%	12.8%	15.4%	100.0%
2024	20.7%	23.7%	27.0%	13.3%	15.4%	100.0%
2025	20.1%	19.3%	31.4%	13.9%	15.3%	100.0%
2026	19.6%	19.1%	32.4%	13.7%	15.3%	100.0%
2027	19.1%	18.6%	33.6%	13.4%	15.3%	100.0%
2028	18.7%	18.1%	33.5%	14.4%	15.3%	100.0%
2029	18.1%	16.9%	35.0%	14.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(a)(5) - Coal-to-Gas Conversion Portfolio

COAL-TO-GAS REDUCTION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	5,139	4,489	4,656	4,656	4,059	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	CT / Steam Turbines / Cholla GAS	1,254	1,254	1,514	1,514	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	463	463	464	464	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,084**	**8,420**	**7,770**	**7,550**	**7,550**	**6,943**	**6,454**	**6,446**	**6,433**	**6,426**	**6,426**	**6,427**	**6,410**	**6,411**	**6,412**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	261
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,507**	**1,610**	**1,663**	**1,744**	**1,821**	**1,899**	**1,983**
29	Natural Gas	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CCs/CTs	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,067**	**1,067**	**1,825**	**2,572**	**2,811**	**3,093**	**3,325**	**4,013**	**4,017**	**4,139**	**4,422**	**4,630**
37	**TOTAL RESOURCES**	**9,340**	**9,467**	**9,012**	**9,033**	**9,479**	**9,630**	**9,945**	**10,331**	**10,668**	**11,033**	**11,361**	**12,102**	**12,188**	**12,371**	**12,732**	**13,025**

ENERGY MIX
COAL-TO-GAS CONVERSION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE+ DE RENEW	EE	TOT
2014	9,297	11,872	6,749	3,182	2,509	33,609
2015	9,297	11,963	6,479	3,355	3,120	34,214
2016	9,325	11,243	7,578	3,492	3,764	35,401
2017	9,296	10,112	9,359	3,526	4,375	36,668
2018	9,297	8,184	11,880	3,566	4,951	37,879
2019	9,297	8,964	11,731	3,607	5,505	39,105
2020	9,325	9,114	11,576	3,934	6,071	40,020
2021	9,296	8,456	13,010	4,268	6,424	41,454
2022	9,297	8,667	13,514	4,656	6,563	42,698
2023	9,297	7,982	14,567	5,323	6,743	43,912
2024	9,324	8,338	14,811	5,706	6,931	45,108
2025	9,297	8,937	14,830	6,138	7,107	46,308
2026	9,297	9,047	15,663	6,230	7,281	47,517
2027	9,297	9,063	16,641	6,270	7,461	48,732
2028	9,325	9,056	17,022	6,915	7,655	49,973
2029	9,297	8,635	18,505	6,944	7,855	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE+ DE RENEW	EE	TOT
2014	27.7%	35.3%	20.1%	9.5%	7.5%	100.0%
2015	27.2%	35.0%	18.9%	9.8%	9.1%	100.0%
2016	26.3%	31.8%	21.4%	9.9%	10.6%	100.0%
2017	25.4%	27.6%	25.5%	9.6%	11.9%	100.0%
2018	24.5%	21.6%	31.4%	9.4%	13.1%	100.0%
2019	23.8%	22.9%	30.0%	9.2%	14.1%	100.0%
2020	23.3%	22.8%	28.9%	9.8%	15.2%	100.0%
2021	22.4%	20.4%	31.4%	10.3%	15.5%	100.0%
2022	21.8%	20.3%	31.6%	10.9%	15.4%	100.0%
2023	21.2%	18.2%	33.2%	12.1%	15.4%	100.0%
2024	20.7%	18.5%	32.8%	12.6%	15.4%	100.0%
2025	20.1%	19.3%	32.0%	13.3%	15.3%	100.0%
2026	19.6%	19.0%	33.0%	13.1%	15.3%	100.0%
2027	19.1%	18.6%	34.1%	12.9%	15.3%	100.0%
2028	18.7%	18.1%	34.1%	13.8%	15.3%	100.0%
2029	18.1%	16.9%	36.1%	13.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(a)(6) - Alternate Portfolio

ALTERNATE PORTFOLIO - LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	995	1,016	1,005	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,140**	**8,308**	**8,578**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	*Nuclear*	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	*Combined Cycle*	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	467	463	463	463	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	389	387	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,085**	**8,424**	**7,770**	**7,550**	**7,550**	**6,943**	**6,454**	**6,446**	**6,433**	**6,426**	**6,426**	**6,427**	**6,410**	**6,411**	**6,412**
22	Energy Efficiency	0	0	356	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	14	13	64	86	98	109	119	133	156	182	204	225	238	246	254	262
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**34**	**34**	**446**	**707**	**862**	**1,013**	**1,178**	**1,306**	**1,412**	**1,507**	**1,611**	**1,664**	**1,745**	**1,822**	**1,899**	**1,984**
29	Natural Gas	0	0	0	363	750	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CCs/CTs	0	0	0	0	510	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	363	240	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	39	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	39	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**39**	**420**	**807**	**1,067**	**1,825**	**2,572**	**2,811**	**3,093**	**3,325**	**4,013**	**4,017**	**4,139**	**4,422**	**4,630**
37	TOTAL RESOURCES	9,200	9,151	8,909	8,897	9,219	9,630	9,946	10,331	10,669	11,034	11,361	12,103	12,189	12,371	12,733	13,026

ENERGY MIX
ALTERNATE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,958	7,295	3,071	1,988	33,609
2015	9,297	12,107	7,656	3,167	1,988	34,214
2016	9,325	12,409	6,856	3,368	3,444	35,401
2017	9,296	11,767	7,703	3,526	4,375	36,668
2018	9,297	12,438	7,627	3,567	4,951	37,880
2019	9,297	13,034	7,661	3,607	5,505	39,105
2020	9,325	13,149	7,541	3,934	6,071	40,020
2021	9,296	12,026	9,443	4,268	6,424	41,458
2022	9,297	12,214	9,969	4,656	6,563	42,700
2023	9,297	11,513	11,036	5,323	6,743	43,912
2024	9,324	12,364	10,784	5,706	6,931	45,108
2025	9,297	12,857	10,908	6,138	7,107	46,308
2026	9,297	13,117	11,593	6,230	7,281	47,517
2027	9,297	13,215	12,489	6,270	7,461	48,732
2028	9,325	13,204	12,874	6,915	7,655	49,973
2029	9,297	12,549	14,591	6,944	7,855	51,236

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	TOT
2014	27.7%	35.6%	21.7%	9.1%	5.9%	100.0%
2015	27.2%	35.4%	22.4%	9.3%	5.8%	100.0%
2016	26.3%	35.1%	19.4%	9.5%	9.7%	100.0%
2017	25.4%	32.1%	21.0%	9.6%	11.9%	100.0%
2018	24.5%	32.8%	20.1%	9.4%	13.1%	100.0%
2019	23.8%	33.3%	19.6%	9.2%	14.1%	100.0%
2020	23.3%	32.9%	18.8%	9.8%	15.2%	100.0%
2021	22.4%	29.0%	22.8%	10.3%	15.5%	100.0%
2022	21.8%	28.6%	23.3%	10.9%	15.4%	100.0%
2023	21.2%	26.2%	25.1%	12.1%	15.4%	100.0%
2024	20.7%	27.4%	23.9%	12.7%	15.4%	100.0%
2025	20.1%	27.8%	23.6%	13.3%	15.3%	100.0%
2026	19.6%	27.6%	24.4%	13.1%	15.3%	100.0%
2027	19.1%	27.1%	25.6%	12.9%	15.3%	100.0%
2028	18.7%	26.4%	25.8%	13.8%	15.3%	100.0%
2029	18.1%	24.5%	28.5%	13.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements

TOTAL REVENUE REQUIREMENTS ($MILLIONS)						
YEAR	SELECTED PORTFOLIO	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO	ALTERNATE PORTFOLIO
2014	2,252.5	2,252.5	2,252.5	2,250.9	2,251.7	2,146.4
2015	2,338.4	2,338.4	2,338.4	2,324.2	2,337.2	2,244.7
2016	2,337.8	2,337.8	2,337.8	2,308.4	2,349.1	2,315.5
2017	2,457.1	2,518.8	2,518.8	2,540.1	2,552.2	2,748.8
2018	2,657.7	2,722.8	2,754.2	2,711.7	2,751.0	2,660.3
2019	2,819.6	2,811.4	2,898.5	2,802.9	2,839.1	2,821.7
2020	2,959.6	2,948.7	3,054.9	2,944.3	2,967.8	2,961.4
2021	3,279.5	3,269.2	3,377.0	3,252.1	3,267.1	3,281.0
2022	3,454.6	3,445.8	3,568.3	3,417.2	3,449.2	3,455.5
2023	3,713.4	3,702.9	3,811.0	3,671.9	3,698.6	3,714.1
2024	3,875.3	3,866.1	3,994.1	3,828.4	3,879.2	3,875.8
2025	4,094.1	4,085.0	4,176.8	4,045.8	4,071.7	4,094.8
2026	4,298.0	4,288.7	4,373.1	4,242.9	4,247.7	4,298.6
2027	4,442.1	4,433.4	4,626.6	4,443.5	4,394.4	4,442.7
2028	4,624.5	4,615.1	4,806.8	4,656.0	4,589.0	4,625.1
2029	4,874.2	4,867.9	4,969.4	4,889.0	4,830.5	4,874.8
2030	5,110.9	5,102.5	5,150.7	5,136.5	5,076.9	5,111.5
2031	5,243.4	5,235.1	5,263.2	5,281.3	5,223.5	5,244.1
2032	5,442.0	5,433.6	5,465.7	5,456.7	5,400.4	5,442.7
2033	5,646.4	5,638.3	5,655.7	5,673.7	5,605.1	5,647.0
2034	5,860.5	5,852.6	5,874.2	5,928.9	5,847.4	5,861.1
2035	6,184.9	6,177.7	6,199.4	6,225.1	6,161.9	6,185.4
2036	6,451.0	6,443.5	6,433.3	6,480.8	6,431.9	6,451.6
2037	6,680.2	6,672.6	6,647.0	6,733.4	6,671.5	6,680.7
2038	7,088.4	7,082.9	7,054.5	7,106.0	7,067.6	7,089.0
2039	7,443.0	7,435.1	7,392.4	7,460.1	7,409.8	7,443.5
2040	7,889.4	7,885.3	7,825.2	7,919.2	7,884.9	7,889.9
2041	8,275.0	8,270.9	8,177.4	8,270.0	8,255.9	8,275.7
2042	8,631.4	8,627.0	8,526.6	8,638.9	8,624.7	8,632.2
2043	8,884.5	8,880.6	8,758.0	8,913.8	8,900.6	8,885.3
(2014-2029)	29,262.1	29,306.1	29,939.8	29,199.9	29,334.6	29,291.7
(2014-2043)	47,559.8	47,583.7	48,192.8	47,582.0	47,569.8	47,591.1

Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements

TOTAL REVENUE REQUIREMENTS: SELECTED PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	FMIS Costs	DE-FE Costs	$Millions	$/MWh
2014	625.6	470.2	50.8	412.0	19.5	1,578.2	110.5	351.3	461.8	(2.0)	63.2	23.9	(0.1)	127.3	2,252.5	73.7
2015	634.0	469.4	51.1	441.6	42.1	1,638.1	111.2	368.4	479.6	(0.4)	64.8	21.3	(0.1)	135.1	2,338.4	76.5
2016	687.2	471.3	54.1	376.8	65.7	1,655.0	105.8	357.4	463.2	(0.9)	66.4	18.5	(0.1)	135.6	2,337.8	75.3
2017	700.2	566.6	60.7	387.3	75.5	1,790.3	124.8	321.6	446.4	(2.4)	80.7	17.0	(0.1)	125.1	2,457.1	77.7
2018	880.3	650.9	68.0	395.0	76.0	2,070.1	91.3	292.3	383.5	(2.3)	69.8	14.2	(0.1)	122.5	2,657.7	82.5
2019	1,012.5	706.6	74.7	405.1	73.9	2,272.8	62.3	284.8	347.0	(2.4)	71.8	11.7	(0.1)	118.7	2,819.6	85.9
2020	1,156.6	792.4	85.7	408.8	72.6	2,516.0	6.0	231.1	237.1	(2.5)	73.3	9.6	(0.1)	126.2	2,959.6	88.6
2021	1,335.1	869.2	91.5	441.1	71.1	2,808.1	5.8	234.0	239.8	0.0	106.5	9.2	55.2	60.7	3,279.5	95.8
2022	1,414.1	938.8	98.1	445.0	71.8	2,967.9	6.5	232.6	239.1	0.0	99.6	8.9	68.4	70.8	3,454.6	98.1
2023	1,563.0	1,013.0	102.7	454.5	70.3	3,203.4	6.4	228.7	235.2	0.0	116.5	8.4	72.6	77.2	3,713.4	102.9
2024	1,646.1	1,065.5	110.4	460.7	68.7	3,351.3	7.2	227.1	234.3	0.0	118.2	8.1	87.2	76.2	3,875.3	104.8
2025	1,770.7	1,127.5	118.0	465.3	71.4	3,552.9	8.1	230.0	238.1	0.0	116.1	7.7	104.8	74.6	4,094.1	108.2
2026	1,811.7	1,200.8	124.1	492.9	72.7	3,702.3	8.1	233.1	241.2	0.0	138.1	7.2	133.8	75.3	4,298.0	110.8
2027	1,811.8	1,279.5	131.7	512.3	72.0	3,807.3	8.1	220.1	228.1	0.0	142.9	6.8	176.9	80.0	4,442.1	111.7
2028	1,870.7	1,333.6	137.2	524.1	70.2	3,935.9	8.1	223.7	231.7	0.0	150.5	6.4	215.4	84.5	4,624.5	113.4
2029	1,907.9	1,439.2	143.8	554.8	71.6	4,117.4	8.1	226.3	234.4	0.0	174.9	6.1	253.8	87.6	4,874.2	116.6
2030	1,929.9	1,542.1	153.3	560.6	71.1	4,257.0	8.1	221.9	229.9	0.0	229.4	5.7	300.8	88.1	5,110.9	119.4
2031	1,984.6	1,618.2	160.9	568.5	70.5	4,402.6	8.0	224.4	232.4	0.0	195.3	5.3	321.0	86.8	5,243.4	119.5
2032	2,022.1	1,715.2	169.8	575.4	69.6	4,552.1	8.1	227.3	235.4	0.0	229.0	4.9	339.2	81.5	5,442.0	121.1
2033	2,070.8	1,829.3	179.0	594.7	68.7	4,742.5	8.0	228.4	236.4	0.0	228.3	4.5	354.8	79.9	5,646.4	122.7
2034	2,129.0	1,934.2	188.2	610.9	68.0	4,930.2	8.7	231.7	240.4	0.0	235.6	4.0	371.4	78.8	5,860.5	124.1
2035	2,189.9	2,060.4	199.2	653.3	82.5	5,185.3	9.0	235.2	244.2	0.0	288.9	3.6	383.8	79.1	6,184.9	127.7
2036	2,238.1	2,185.2	210.8	665.6	107.7	5,407.5	9.4	238.8	248.1	0.0	309.7	3.1	403.2	79.3	6,451.0	129.8
2037	2,302.9	2,288.6	223.0	658.9	121.8	5,595.3	9.8	222.9	232.7	0.0	342.8	2.6	427.7	79.2	6,680.2	131.4
2038	2,394.1	2,446.5	238.6	725.5	141.0	5,945.7	10.0	214.7	224.7	0.0	402.1	2.2	437.8	75.9	7,088.4	136.2
2039	2,547.6	2,694.5	266.3	593.5	184.5	6,286.4	10.5	210.1	220.6	0.0	449.4	1.7	409.3	75.5	7,443.0	139.8
2040	2,764.7	2,839.5	283.5	575.1	227.0	6,689.8	10.7	203.5	214.2	0.0	480.0	1.4	429.4	74.7	7,889.4	144.7
2041	2,868.0	2,982.6	297.4	621.3	262.2	7,031.5	11.2	206.3	217.5	0.0	505.3	1.0	446.0	73.7	8,275.0	148.7
2042	2,969.2	3,115.3	313.3	654.3	274.1	7,326.2	11.7	205.3	217.0	0.0	542.1	0.7	473.1	72.4	8,631.4	151.8
2043	3,025.8	3,269.4	329.2	650.3	291.8	7,566.6	12.5	173.2	185.8	0.0	568.5	0.3	492.6	70.7	8,884.5	153.0
(2014-2029)	10,764.6	7,475.5	786.0	4,059.3	594.5	23,679.9	518.1	2,627.1	3,145.2	(9.4)	870.4	123.4	470.6	982.0	29,262.1	
(2014-2043)	17,277.1	13,646.3	1,394.6	5,807.1	950.5	39,075.5	544.5	3,253.6	3,798.1	(9.4)	1,791.9	133.1	1,562.7	1,208.0	47,559.8	

Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements

TOTAL REVENUE REQUIREMENTS: BASE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	ENRS Costs	DE-LE Costs	$Millions	$/MWh
2014	625.6	470.2	50.8	412.0	19.5	1,578.2	110.5	351.3	461.8	(2.0)	63.2	23.9	(0.1)	127.3	2,252.5	73.7
2015	634.0	469.4	51.1	441.6	42.1	1,638.1	111.2	368.4	479.6	(0.4)	64.8	21.3	(0.1)	135.1	2,338.4	76.5
2016	687.2	471.3	54.1	376.8	65.7	1,655.0	105.8	357.4	463.2	(0.9)	66.4	18.5	(0.1)	135.6	2,337.8	75.3
2017	789.3	590.7	63.8	389.0	75.5	1,908.3	94.8	299.2	394.1	(2.4)	78.2	15.5	(0.1)	125.1	2,518.8	79.7
2018	966.6	668.7	71.7	397.9	76.0	2,180.8	62.1	276.3	338.4	(2.3)	69.8	13.6	(0.1)	122.5	2,722.8	84.5
2019	1,001.7	706.6	76.4	406.3	73.9	2,265.0	62.3	284.7	347.0	(2.4)	71.5	11.7	(0.1)	118.7	2,811.4	85.6
2020	1,145.7	792.4	85.6	408.8	72.6	2,505.0	6.0	231.1	237.1	(2.5)	73.3	9.6	(0.1)	126.2	2,948.7	88.2
2021	1,324.7	869.4	91.5	441.1	71.1	2,797.8	5.8	234.0	239.8	0.0	106.5	9.2	55.1	60.7	3,269.2	95.5
2022	1,404.0	939.1	98.1	445.0	71.8	2,958.1	6.5	233.3	239.7	0.0	100.0	8.9	68.3	70.8	3,445.8	97.9
2023	1,553.4	1,013.1	102.8	454.5	70.3	3,193.9	6.4	228.7	235.2	0.0	115.5	8.4	72.6	77.2	3,702.9	102.6
2024	1,636.7	1,065.5	110.4	460.7	68.7	3,342.0	7.2	227.1	234.3	0.0	118.2	8.1	87.2	76.2	3,866.1	104.6
2025	1,761.7	1,127.4	118.0	465.3	71.4	3,543.7	8.1	230.0	238.1	0.0	116.1	7.7	104.8	74.6	4,085.0	108.0
2026	1,802.9	1,200.4	124.0	492.9	72.7	3,693.0	8.1	233.1	241.2	0.0	138.1	7.2	133.9	75.3	4,288.7	110.6
2027	1,803.1	1,279.4	131.8	512.3	72.0	3,798.6	8.1	220.1	228.1	0.0	142.9	6.8	177.0	80.0	4,433.4	111.5
2028	1,862.2	1,333.7	137.4	524.1	70.2	3,927.5	8.1	223.7	231.7	0.0	149.5	6.4	215.3	84.5	4,615.1	113.2
2029	1,899.5	1,439.4	143.9	554.7	71.6	4,109.2	8.1	226.3	234.4	0.0	176.9	6.1	253.8	87.6	4,867.9	116.5
2030	1,921.6	1,542.0	153.4	560.6	71.1	4,248.6	8.1	221.9	229.9	0.0	229.4	5.7	300.8	88.1	5,102.5	119.2
2031	1,976.4	1,618.0	160.9	568.5	70.5	4,394.3	8.0	224.4	232.4	0.0	195.3	5.3	321.0	86.8	5,235.1	119.3
2032	2,014.0	1,715.1	169.6	575.4	69.6	4,543.8	8.1	227.3	235.4	0.0	229.0	4.9	339.1	81.5	5,433.6	120.9
2033	2,062.9	1,828.9	179.1	594.7	68.7	4,734.4	8.0	228.4	236.4	0.0	228.3	4.5	354.9	79.9	5,638.3	122.5
2034	2,121.2	1,934.0	188.1	610.9	68.0	4,922.2	8.7	231.7	240.4	0.0	235.6	4.0	371.4	78.8	5,852.6	123.9
2035	2,182.2	2,061.0	199.1	653.3	82.5	5,178.1	9.0	235.2	244.2	0.0	288.9	3.6	383.8	79.1	6,177.7	127.6
2036	2,230.6	2,185.0	211.0	665.6	107.7	5,400.0	9.4	238.8	248.1	0.0	309.7	3.1	403.3	79.3	6,443.5	129.6
2037	2,295.9	2,288.5	222.7	658.9	121.8	5,587.8	9.8	222.9	232.7	0.0	342.8	2.6	427.6	79.2	6,672.6	131.3
2038	2,388.1	2,446.8	238.8	725.5	141.0	5,940.1	10.0	214.7	224.7	0.0	402.1	2.2	437.8	75.9	7,082.9	136.1
2039	2,542.6	2,694.1	266.3	593.5	184.5	6,281.0	10.5	210.1	220.6	0.0	447.0	1.7	409.3	75.5	7,435.1	139.7
2040	2,760.0	2,840.1	283.4	575.1	227.0	6,685.6	10.7	203.5	214.2	0.0	480.1	1.4	429.4	74.7	7,885.3	144.6
2041	2,863.3	2,983.1	297.4	621.3	262.2	7,027.4	11.2	206.3	217.5	0.0	505.3	1.0	445.9	73.7	8,270.9	148.6
2042	2,964.7	3,115.3	313.3	654.3	274.1	7,321.6	11.7	205.3	217.0	0.0	542.3	0.7	473.1	72.4	8,627.0	151.8
2043	3,021.3	3,269.8	329.4	650.3	291.8	7,562.7	12.5	173.2	185.8	0.0	568.5	0.3	492.6	70.7	8,880.6	153.0
(2014-2029)	10,842.2	7,506.4	792.2	4,063.5	594.5	23,798.7	474.8	2,599.3	3,074.1	(9.4)	868.3	121.9	470.5	982.0	29,306.1	
(2014-2043)	17,334.9	13,677.3	1,400.7	5,811.2	950.5	39,174.6	501.2	3,225.7	3,726.9	(9.4)	1,789.5	131.5	1,562.6	1,208.0	47,583.7	

Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements

TOTAL REVENUE REQUIREMENTS: ENHANCED RENEWABLE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	FMIS Costs	DE-FE Costs	$Millions	$/MWh
2014	625.6	470.2	50.8	412.0	19.5	1,578.2	110.5	351.3	461.8	(2.0)	63.2	23.9	(0.1)	127.3	2,252.5	73.7
2015	634.0	469.4	51.1	441.6	42.1	1,638.1	111.2	368.4	479.6	(0.4)	64.8	21.3	(0.1)	135.1	2,338.4	76.5
2016	687.2	471.3	54.1	376.8	65.7	1,655.0	105.8	357.4	463.2	(0.9)	66.4	18.5	(0.1)	135.6	2,337.8	75.3
2017	789.3	590.7	63.8	389.0	75.5	1,908.3	94.8	299.2	394.1	(2.4)	78.2	15.5	(0.1)	125.1	2,518.8	79.7
2018	1,008.6	652.0	72.0	403.5	76.0	2,212.1	63.5	275.1	338.6	(2.3)	69.8	13.6	(0.1)	122.5	2,754.2	85.5
2019	1,110.1	673.6	75.8	417.8	73.9	2,351.2	65.1	282.8	347.9	(2.4)	71.5	11.7	(0.1)	118.7	2,898.5	88.3
2020	1,279.6	748.0	84.5	423.1	72.6	2,607.8	9.5	231.1	240.6	(2.5)	73.3	9.6	(0.1)	126.2	3,054.9	91.4
2021	1,490.1	807.1	93.3	461.5	71.1	2,923.2	10.7	231.9	242.6	0.0	98.7	9.2	42.5	60.7	3,377.0	98.7
2022	1,602.6	861.0	97.1	470.6	71.8	3,103.2	10.6	233.1	243.7	0.0	88.8	8.9	52.9	70.8	3,568.3	101.4
2023	1,754.3	919.8	102.2	483.5	70.3	3,330.0	11.3	228.7	240.1	0.0	99.8	8.4	55.5	77.2	3,811.0	105.6
2024	1,877.7	950.1	110.8	497.0	68.7	3,504.3	13.4	227.1	240.6	0.0	100.2	8.1	64.7	76.2	3,994.1	108.1
2025	1,980.7	1,003.0	115.4	504.3	67.1	3,670.5	15.1	230.0	245.1	0.0	101.6	7.7	77.3	74.6	4,176.8	110.4
2026	2,050.3	1,048.4	118.2	541.1	65.4	3,823.4	15.1	233.1	248.2	0.0	119.9	7.2	99.0	75.3	4,373.1	112.8
2027	2,164.0	1,113.9	127.3	564.7	68.4	4,038.3	15.1	220.1	235.1	0.0	121.5	6.8	144.9	80.0	4,626.6	116.3
2028	2,226.7	1,160.7	131.8	578.6	69.8	4,167.6	15.1	223.7	238.7	0.0	124.2	6.4	185.2	84.5	4,806.8	117.9
2029	2,190.0	1,252.2	140.3	609.0	71.4	4,262.7	15.0	226.3	241.4	0.0	147.1	6.1	224.6	87.6	4,969.4	118.9
2030	2,176.3	1,341.2	149.5	615.5	70.8	4,353.2	15.0	221.4	236.4	0.0	197.2	5.7	270.1	88.1	5,150.7	120.3
2031	2,221.3	1,409.8	155.6	624.7	70.3	4,481.7	15.0	224.4	239.4	0.0	159.1	5.3	290.9	86.8	5,263.2	120.0
2032	2,250.8	1,503.6	164.1	633.1	83.4	4,635.0	15.0	227.3	242.4	0.0	194.8	4.9	307.1	81.5	5,465.7	121.6
2033	2,292.8	1,598.6	174.2	653.8	91.8	4,811.2	15.0	228.4	243.4	0.0	193.4	4.5	323.4	79.9	5,655.7	122.9
2034	2,344.2	1,697.6	183.9	671.4	109.0	5,006.0	15.7	231.7	247.4	0.0	197.8	4.0	340.1	78.8	5,874.2	124.4
2035	2,398.2	1,823.8	193.1	715.4	132.5	5,262.9	16.0	235.2	251.2	0.0	251.9	3.6	350.8	79.1	6,199.4	128.0
2036	2,439.3	1,932.8	205.4	729.2	145.3	5,452.0	16.4	238.8	255.1	0.0	272.8	3.1	371.0	79.3	6,433.3	129.4
2037	2,497.2	2,029.0	215.9	724.1	163.2	5,629.5	16.7	222.9	239.6	0.0	301.8	2.6	394.4	79.2	6,647.0	130.8
2038	2,582.0	2,194.9	228.7	792.3	187.6	5,985.4	17.0	214.7	231.7	0.0	358.3	2.2	401.0	75.9	7,054.5	135.6
2039	2,728.9	2,428.7	252.7	661.9	234.5	6,306.7	17.5	210.1	227.6	0.0	407.7	1.7	373.3	75.5	7,392.4	138.9
2040	2,939.1	2,565.6	269.8	645.2	275.5	6,695.3	17.7	203.5	221.2	0.0	439.9	1.4	392.7	74.7	7,825.2	143.5
2041	3,036.0	2,704.1	282.6	693.2	292.0	7,007.9	18.2	206.3	224.4	0.0	462.0	1.0	408.2	73.7	8,177.4	147.0
2042	3,131.3	2,832.1	296.2	728.0	308.6	7,296.3	18.7	205.3	224.0	0.0	499.3	0.7	433.9	72.4	8,526.6	150.0
2043	3,170.3	2,979.9	309.2	725.9	332.2	7,517.6	19.5	173.2	192.8	0.0	524.7	0.3	451.9	70.7	8,758.0	150.9
(2014-2029)	11,994.7	6,967.3	783.4	4,233.8	588.1	24,567.3	503.4	2,595.8	3,099.2	(9.4)	801.2	121.9	377.7	982.0	29,939.8	
(2014-2043)	19,092.1	12,453.7	1,368.8	6,160.4	1,026.8	40,101.8	549.7	3,222.1	3,771.8	(9.4)	1,614.7	131.5	1,374.5	1,208.0	48,192.8	

Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements

TOTAL REVENUE REQUIREMENTS: COAL REDUCTION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWh
2014	624.1	470.2	50.8	412.0	19.5	1,576.6	110.5	351.3	461.8	(2.0)	63.2	23.9	(0.1)	127.3	2,250.9	73.6
2015	629.9	469.4	51.1	431.5	42.1	1,623.9	111.2	368.4	479.6	(0.4)	64.8	21.3	(0.1)	135.1	2,324.2	76.1
2016	660.1	474.1	51.4	363.5	65.7	1,614.9	105.8	368.1	473.9	(0.9)	66.4	18.5	(0.1)	135.6	2,308.4	74.4
2017	787.8	604.8	60.8	379.6	76.1	1,909.1	94.8	310.1	404.9	(2.4)	87.8	15.5	(0.1)	125.1	2,540.1	80.4
2018	944.4	682.4	68.0	387.5	77.0	2,159.3	62.1	279.7	341.8	(2.3)	76.9	13.6	(0.1)	122.5	2,711.7	84.2
2019	978.2	724.0	71.8	395.8	75.0	2,244.8	62.3	287.9	350.1	(2.4)	80.1	11.7	(0.1)	118.7	2,802.9	85.4
2020	1,130.6	814.7	81.1	399.1	73.2	2,498.7	6.0	231.1	237.1	(2.5)	75.2	9.6	(0.1)	126.2	2,944.3	88.1
2021	1,300.9	897.7	89.1	423.5	71.5	2,782.8	5.8	234.5	240.3	0.0	115.6	9.2	43.5	60.7	3,252.1	95.0
2022	1,365.1	967.3	95.6	433.3	71.8	2,933.1	6.5	233.3	239.8	0.0	107.4	8.9	57.2	70.8	3,417.2	97.1
2023	1,523.3	1,030.6	100.8	443.2	70.1	3,168.1	7.1	228.7	235.9	0.0	123.6	8.4	58.6	77.2	3,671.9	101.7
2024	1,609.0	1,088.3	108.0	430.6	68.5	3,304.3	7.8	227.1	235.0	0.0	132.9	8.1	71.9	76.2	3,828.4	103.6
2025	1,727.4	1,180.4	113.1	410.0	71.2	3,502.0	8.8	230.0	238.8	0.0	155.9	7.7	66.9	74.6	4,045.8	106.9
2026	1,794.2	1,254.8	118.7	417.0	73.2	3,657.9	8.8	233.1	241.9	0.0	165.9	7.2	94.7	75.3	4,242.9	109.4
2027	1,842.7	1,337.8	125.3	439.6	73.4	3,818.9	8.8	220.1	228.8	0.0	173.6	6.8	135.4	80.0	4,443.5	111.7
2028	1,918.7	1,393.2	131.0	466.3	72.5	3,981.8	8.8	223.7	232.4	0.0	179.0	6.4	171.8	84.5	4,656.0	114.2
2029	1,967.4	1,478.8	139.4	483.7	73.6	4,143.0	9.5	226.3	235.8	0.0	207.3	6.1	209.3	87.6	4,889.0	117.0
2030	1,993.8	1,588.0	147.8	483.4	72.7	4,285.8	9.4	221.2	230.6	0.0	276.6	5.7	249.6	88.1	5,136.5	120.0
2031	2,043.6	1,664.5	155.2	508.8	71.7	4,443.8	9.4	224.4	233.8	0.0	240.5	5.3	271.0	86.8	5,281.3	120.4
2032	2,076.0	1,765.6	163.1	490.9	84.7	4,580.2	9.5	227.3	236.8	0.0	267.2	4.9	286.1	81.5	5,456.7	121.4
2033	2,121.8	1,879.4	172.7	512.3	93.0	4,779.2	9.4	228.4	237.8	0.0	271.1	4.5	301.2	79.9	5,673.7	123.3
2034	2,177.2	1,985.3	182.6	547.4	110.1	5,002.6	10.1	231.7	241.8	0.0	284.8	4.0	316.8	78.8	5,928.9	125.5
2035	2,234.8	2,109.4	193.0	571.7	118.7	5,227.6	10.4	235.2	245.6	0.0	339.3	3.6	329.8	79.1	6,225.1	128.5
2036	2,281.4	2,240.2	205.1	577.9	136.7	5,441.3	10.8	238.8	249.5	0.0	363.4	3.1	344.3	79.3	6,480.8	130.4
2037	2,342.1	2,343.4	217.1	591.7	161.1	5,655.4	11.2	222.9	234.0	0.0	392.8	2.6	369.4	79.2	6,733.4	132.5
2038	2,423.0	2,507.9	232.3	630.4	174.1	5,967.7	11.4	214.7	226.1	0.0	459.7	2.2	374.5	75.9	7,106.0	136.6
2039	2,565.2	2,759.2	260.9	502.8	226.6	6,314.6	11.9	210.1	222.0	0.0	503.4	1.7	342.9	75.5	7,460.1	140.1
2040	2,780.4	2,901.2	278.6	505.6	257.6	6,723.4	12.1	203.5	215.6	0.0	542.7	1.4	361.4	74.7	7,919.2	145.2
2041	2,879.5	3,044.7	292.6	530.3	285.2	7,032.3	12.6	206.3	218.9	0.0	564.1	1.0	380.0	73.7	8,270.0	148.6
2042	2,978.8	3,187.6	308.3	555.0	308.1	7,337.7	13.1	205.3	218.4	0.0	609.5	0.7	400.2	72.4	8,638.9	152.0
2043	3,035.6	3,342.0	324.8	575.1	318.5	7,595.9	13.9	173.2	187.2	0.0	638.9	0.3	420.8	70.7	8,913.8	153.6
(2014-2029)	10,750.1	7,706.0	764.1	3,854.6	598.9	23,673.7	477.0	2,621.0	3,098.0	(9.4)	967.9	121.9	365.8	982.0	29,199.9	
(2014-2043)	17,377.7	14,032.4	1,356.4	5,377.9	1,025.2	39,169.6	507.4	3,247.2	3,754.6	(9.4)	2,035.0	131.5	1,292.7	1,208.0	47,582.0	

Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements

TOTAL REVENUE REQUIREMENTS: COAL-TO-GAS CONVERSION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWh
2014	625.0	470.2	50.8	411.9	19.5	1,577.5	110.5	351.3	461.8	(2.0)	63.2	23.9	(0.1)	127.3	2,251.7	73.6
2015	632.7	469.4	51.1	441.6	42.1	1,636.8	111.2	368.4	479.6	(0.4)	64.8	21.3	(0.1)	135.1	2,337.2	76.5
2016	684.5	474.7	51.4	379.2	65.7	1,655.5	105.8	368.2	474.0	(0.9)	66.4	18.5	(0.1)	135.6	2,349.1	75.7
2017	796.1	604.5	61.2	391.1	75.5	1,928.4	94.8	308.8	403.7	(2.4)	81.9	15.5	(0.1)	125.1	2,552.2	80.7
2018	936.8	714.7	64.7	370.6	76.0	2,162.8	62.1	286.1	348.2	(2.3)	106.3	13.6	(0.1)	122.5	2,751.0	85.4
2019	971.8	759.9	67.6	383.3	73.9	2,256.6	62.3	292.9	355.2	(2.4)	99.5	11.7	(0.1)	118.7	2,839.1	86.5
2020	1,113.6	857.5	77.3	381.6	72.6	2,502.5	6.0	231.1	237.1	(2.5)	95.0	9.6	(0.1)	126.2	2,967.8	88.8
2021	1,289.7	939.3	87.9	403.8	71.1	2,791.8	5.8	237.7	243.4	0.0	138.2	9.2	23.7	60.7	3,267.1	95.5
2022	1,366.8	1,012.9	93.8	417.3	71.8	2,962.6	6.5	235.3	241.7	0.0	129.5	8.9	35.7	70.8	3,449.2	98.0
2023	1,512.1	1,087.6	99.1	421.5	70.3	3,190.6	6.4	228.7	235.2	0.0	147.2	8.4	39.9	77.2	3,698.6	102.5
2024	1,595.4	1,159.0	104.9	421.2	68.7	3,349.1	7.2	227.1	234.3	0.0	162.5	8.1	49.0	76.2	3,879.2	104.9
2025	1,720.5	1,193.8	112.1	425.5	71.4	3,523.3	8.1	230.0	238.1	0.0	159.2	7.7	68.8	74.6	4,071.7	107.6
2026	1,760.7	1,269.7	118.3	436.5	72.7	3,657.9	8.1	233.1	241.2	0.0	169.7	7.2	96.4	75.3	4,247.7	109.5
2027	1,760.7	1,353.4	125.0	453.8	72.0	3,765.0	8.1	220.1	228.1	0.0	177.3	6.8	137.1	80.0	4,394.4	110.5
2028	1,819.4	1,408.0	131.0	479.9	70.2	3,908.5	8.1	223.7	231.7	0.0	184.1	6.4	173.7	84.5	4,589.0	112.5
2029	1,856.2	1,510.5	138.8	497.0	71.6	4,074.2	8.1	226.3	234.4	0.0	215.5	6.1	212.8	87.6	4,830.5	115.6
2030	1,878.6	1,621.4	147.4	500.6	71.1	4,219.1	8.1	223.6	231.6	0.0	279.0	5.7	253.3	88.1	5,076.9	118.6
2031	1,934.6	1,697.0	154.7	519.4	70.5	4,376.1	8.0	224.4	232.4	0.0	248.1	5.3	274.8	86.8	5,223.5	119.1
2032	1,973.2	1,799.6	163.1	507.0	69.6	4,512.4	8.1	227.3	235.4	0.0	276.3	4.9	290.0	81.5	5,400.4	120.2
2033	2,023.6	1,913.7	172.9	524.0	68.7	4,702.9	8.0	228.4	236.4	0.0	276.1	4.5	305.3	79.9	5,605.1	121.8
2034	2,083.8	2,019.2	182.7	558.9	68.0	4,912.5	8.7	231.7	240.4	0.0	290.7	4.0	320.8	78.8	5,847.4	123.8
2035	2,145.9	2,144.0	194.1	587.1	82.5	5,153.6	9.0	235.2	244.2	0.0	347.3	3.6	334.1	79.1	6,161.9	127.2
2036	2,195.7	2,276.1	205.9	597.9	107.7	5,383.3	9.4	238.8	248.1	0.0	369.5	3.1	348.7	79.3	6,431.9	129.4
2037	2,260.3	2,379.7	217.9	604.2	121.8	5,583.8	9.8	222.9	232.7	0.0	399.2	2.6	374.0	79.2	6,671.5	131.2
2038	2,345.9	2,544.4	234.0	649.2	141.0	5,914.5	10.0	214.7	224.7	0.0	471.1	2.2	379.1	75.9	7,067.6	135.8
2039	2,491.8	2,796.7	263.7	516.4	184.5	6,253.1	10.5	210.1	220.6	0.0	511.0	1.7	347.8	75.5	7,409.8	139.2
2040	2,711.6	2,939.7	281.3	518.9	227.0	6,678.5	10.7	203.5	214.2	0.0	549.7	1.4	366.4	74.7	7,884.9	144.6
2041	2,816.2	3,082.4	295.6	548.2	262.2	7,004.5	11.2	206.3	217.5	0.0	574.2	1.0	384.9	73.7	8,255.9	148.4
2042	2,918.8	3,227.7	311.6	578.2	274.1	7,310.4	11.7	205.3	217.0	0.0	618.7	0.7	405.5	72.4	8,624.7	151.7
2043	2,979.9	3,383.1	328.9	589.5	291.8	7,573.2	12.5	173.2	185.8	0.0	644.5	0.3	426.1	70.7	8,900.6	153.3
(2014-2029)	10,622.8	7,921.9	752.1	3,847.9	594.5	23,739.2	474.8	2,630.8	3,105.5	(9.4)	1,068.4	121.9	327.0	982.0	29,334.6	
(2014-2043)	16,998.3	14,349.1	1,347.2	5,414.2	950.5	39,059.4	501.2	3,257.7	3,758.9	(9.4)	2,155.2	131.5	1,266.2	1,208.0	47,569.8	

Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements

TOTAL REVENUE REQUIREMENTS: ALTERNATE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWh
2014	625.6	483.1	52.3	412.0	19.5	1,592.5	110.5	356.3	466.8	(2.0)	63.2	23.9	(0.1)	2.0	2,146.4	68.8
2015	632.0	496.2	54.7	440.8	42.1	1,665.7	111.1	380.4	491.5	(0.4)	64.8	21.3	(0.1)	1.8	2,244.7	70.5
2016	676.1	480.2	55.0	376.0	65.7	1,653.0	105.6	361.4	467.0	(0.9)	66.4	18.5	(0.1)	111.5	2,315.5	73.7
2017	692.2	566.7	60.7	387.3	75.5	1,782.4	124.8	321.5	446.3	(2.4)	80.7	17.0	(0.1)	424.8	2,748.8	87.0
2018	882.9	650.9	68.0	395.0	76.0	2,072.6	91.3	292.3	383.5	(2.3)	69.8	14.2	(0.1)	122.5	2,660.3	82.6
2019	1,014.6	706.6	74.7	405.1	73.9	2,274.9	62.3	284.8	347.0	(2.4)	71.8	11.7	(0.1)	118.7	2,821.7	85.9
2020	1,158.3	792.3	85.7	408.8	72.6	2,517.7	6.0	231.1	237.1	(2.5)	73.3	9.6	(0.1)	126.2	2,961.4	88.6
2021	1,336.6	869.2	91.5	441.1	71.1	2,809.5	5.8	234.0	239.8	0.0	106.5	9.2	55.2	60.7	3,281.0	95.9
2022	1,415.0	938.8	98.1	445.0	71.8	2,968.8	6.5	232.6	239.1	0.0	99.6	8.9	68.3	70.8	3,455.5	98.2
2023	1,563.7	1,013.0	102.7	454.5	70.3	3,204.1	6.4	228.7	235.2	0.0	116.5	8.4	72.6	77.2	3,714.1	102.9
2024	1,646.7	1,065.4	110.4	460.7	68.7	3,351.9	7.2	227.1	234.3	0.0	118.1	8.1	87.2	76.2	3,875.8	104.9
2025	1,771.3	1,127.5	118.0	465.3	71.4	3,553.5	8.1	230.0	238.1	0.0	116.1	7.7	104.8	74.6	4,094.8	108.2
2026	1,812.4	1,200.8	124.1	492.9	72.7	3,703.0	8.1	233.1	241.2	0.0	138.1	7.2	133.8	75.3	4,298.6	110.8
2027	1,812.4	1,279.5	131.7	512.3	72.0	3,808.0	8.1	220.1	228.1	0.0	142.9	6.8	176.9	80.0	4,442.7	111.7
2028	1,871.4	1,333.6	137.2	524.1	70.2	3,936.5	8.1	223.7	231.8	0.0	150.5	6.4	215.4	84.5	4,625.1	113.4
2029	1,908.6	1,439.2	143.8	554.8	71.6	4,118.0	8.1	226.3	234.4	0.0	174.9	6.1	253.8	87.6	4,874.8	116.6
2030	1,930.5	1,542.0	153.3	560.6	71.1	4,257.6	8.1	221.9	229.9	0.0	229.4	5.7	300.8	88.1	5,111.5	119.4
2031	1,985.2	1,618.2	160.9	568.5	70.5	4,403.3	8.0	224.4	232.4	0.0	195.3	5.3	321.0	86.8	5,244.1	119.6
2032	2,022.7	1,715.4	169.8	575.4	69.6	4,552.9	8.1	227.3	235.4	0.0	229.0	4.9	339.1	81.5	5,442.7	121.1
2033	2,071.4	1,829.3	179.0	594.7	68.7	4,743.1	8.0	228.4	236.4	0.0	228.3	4.5	354.8	79.9	5,647.0	122.7
2034	2,129.6	1,934.2	188.2	610.9	68.0	4,930.8	8.7	231.7	240.4	0.0	235.6	4.0	371.4	78.8	5,861.1	124.1
2035	2,190.5	2,060.4	199.2	653.3	82.5	5,185.9	9.0	235.2	244.2	0.0	288.9	3.6	383.8	79.1	6,185.4	127.7
2036	2,238.7	2,185.4	210.8	665.6	107.7	5,408.2	9.4	238.8	248.1	0.0	309.7	3.1	403.2	79.3	6,451.6	129.8
2037	2,303.5	2,288.6	223.0	658.9	121.8	5,595.8	9.8	222.9	232.7	0.0	342.8	2.6	427.7	79.2	6,680.7	131.4
2038	2,394.6	2,446.5	238.7	725.5	141.0	5,946.2	10.0	214.7	224.7	0.0	402.1	2.2	437.8	75.9	7,089.0	136.2
2039	2,548.2	2,694.5	266.3	593.5	184.5	6,286.9	10.5	210.1	220.6	0.0	449.4	1.7	409.3	75.5	7,443.5	139.8
2040	2,765.3	2,839.4	283.5	575.1	227.0	6,690.3	10.7	203.5	214.2	0.0	480.0	1.4	429.4	74.7	7,889.9	144.7
2041	2,868.7	2,982.6	297.4	621.3	262.2	7,032.1	11.2	206.3	217.5	0.0	505.3	1.0	446.0	73.7	8,275.7	148.7
2042	2,970.0	3,115.2	313.3	654.3	274.1	7,326.9	11.7	205.3	217.0	0.0	542.1	0.7	473.1	72.4	8,632.2	151.8
2043	3,026.6	3,269.4	329.2	650.3	291.8	7,567.4	12.5	173.2	185.8	0.0	568.5	0.3	492.6	70.7	8,885.3	153.1
(2014-2029)	10,755.3	7,517.9	791.4	4,058.0	594.5	23,717.1	517.9	2,645.3	3,163.2	(9.4)	870.3	123.4	470.6	956.5	29,291.7	
(2014-2043)	17,269.5	13,688.8	1,399.9	5,805.8	950.5	39,114.5	544.3	3,271.8	3,816.1	(9.4)	1,791.8	133.1	1,562.6	1,182.5	47,591.1	

Attachment F.1(b)(1) - Annual Average System Cost

ANNUAL AVERAGE SYSTEM COST ($/MWh)						
YEAR	SELECTED PORTFOLIO	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL REDUCTION PORTFOLIO	ALTERNATE PORTFOLIO
2014	73.7	73.7	73.7	73.6	73.6	68.8
2015	76.5	76.5	76.5	76.1	76.5	70.5
2016	75.3	75.3	75.3	74.4	75.7	73.7
2017	77.7	79.7	79.7	80.4	80.7	87.0
2018	82.5	84.5	85.5	84.2	85.4	82.6
2019	85.9	85.6	88.3	85.4	86.5	85.9
2020	88.6	88.2	91.4	88.1	88.8	88.6
2021	95.8	95.5	98.7	95.0	95.5	95.9
2022	98.1	97.9	101.4	97.1	98.0	98.2
2023	102.9	102.6	105.6	101.7	102.5	102.9
2024	104.8	104.6	108.1	103.6	104.9	104.9
2025	108.2	108.0	110.4	106.9	107.6	108.2
2026	110.8	110.6	112.8	109.4	109.5	110.8
2027	111.7	111.5	116.3	111.7	110.5	111.7
2028	113.4	113.2	117.9	114.2	112.5	113.4
2029	116.6	116.5	118.9	117.0	115.6	116.6

Attachment F.1(b)(2) - Cumulative Capital Spending

CUMULATIVE CAPITAL SPENDING
EXISTING AND NEW GENERATION PLUS INCREMENTAL TRANSMISSION ($MILLIONS)

YEAR	SELECTED PORTFOLIO	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO	ALTERNATE PORTFOLIO
2014	1,211.7	1,211.7	1,211.7	1,201.4	1,207.7	1,211.7
2015	1,678.9	1,678.9	1,678.9	1,641.3	1,635.6	1,678.9
2016	2,400.4	2,400.4	2,513.0	2,359.0	2,368.6	2,400.4
2017	3,094.9	3,657.0	4,104.9	3,632.9	3,589.4	3,094.9
2018	3,542.4	4,104.5	4,926.0	3,984.9	3,934.9	3,542.4
2019	4,645.9	4,617.4	5,697.2	4,528.5	4,427.0	4,645.9
2020	5,929.1	5,900.6	7,336.0	5,766.8	5,692.2	5,929.1
2021	7,441.1	7,412.6	8,998.9	7,249.6	7,181.8	7,441.1
2022	8,245.5	8,217.0	9,997.1	8,121.5	7,969.8	8,245.5
2023	9,200.7	9,172.2	11,091.3	9,059.1	8,894.4	9,200.7
2024	10,266.9	10,238.4	12,375.8	10,091.8	9,952.3	10,266.9
2025	10,844.0	10,815.5	13,425.9	10,824.9	10,522.6	10,844.0
2026	11,581.3	11,552.8	14,843.8	11,828.8	11,245.6	11,581.3
2027	12,237.9	12,209.4	15,442.5	12,653.6	11,893.1	12,237.9
2028	12,942.8	12,914.3	15,852.3	13,459.4	12,587.0	12,942.8
2029	13,616.4	13,588.0	16,387.8	14,159.1	13,248.6	13,616.4

1. Capital investment projected is regardless of whether APS constructs and owns new generation resources or whether resources are purchased by APS under long-term PPAs with market participants.

2. Capital spending excludes: (a) financial commitments to energy efficiency and distributed energy initiatives; (b) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing.

3. Capital spending includes ongoing capital investment for existing owned generation.

Attachment F.1(b)(3) - Annual Natural Gas Burns

ANNUAL NATURAL GAS BURNS (BCF)						
YEAR	SELECTED PORTFOLIO	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL REDUCTION PORTFOLIO	ALTERNATE PORTFOLIO
2014	43.1	43.1	43.1	43.1	43.1	47.2
2015	41.1	41.1	41.1	41.1	41.1	50.0
2016	45.7	45.7	45.7	53.6	53.9	48.4
2017	58.5	60.1	60.1	72.4	71.5	58.5
2018	58.1	59.5	56.0	72.1	91.3	58.1
2019	58.5	58.6	53.3	70.9	90.2	58.5
2020	58.9	59.0	53.2	71.2	90.1	58.9
2021	72.2	72.2	62.2	84.2	100.6	72.2
2022	76.5	76.5	64.9	87.5	104.5	76.5
2023	85.0	85.0	71.6	94.9	112.8	85.0
2024	83.2	83.3	68.5	94.2	114.7	83.2
2025	84.2	84.2	68.7	112.5	114.4	84.2
2026	89.5	89.4	71.4	118.7	120.8	89.5
2027	96.2	96.2	76.6	126.3	128.5	96.2
2028	99.3	99.4	78.8	129.5	131.5	99.3
2029	112.5	112.5	89.5	138.5	142.8	112.5

Attachment F.1(b)(4) - Annual CO2 Emissions

ANNUAL CO2 EMISSIONS (METRIC TONS)						
YEAR	SELECTED PORTFOLIO	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO	ALTERNATE PORTFOLIO
2014	13,736,311	13,736,311	13,736,311	13,736,311	13,736,311	14,045,630
2015	13,647,588	13,647,588	13,647,588	13,647,588	13,647,588	14,268,809
2016	14,181,078	14,181,078	14,181,078	13,562,400	13,539,017	14,409,109
2017	14,386,927	14,296,750	14,296,750	13,354,717	13,443,236	14,388,526
2018	15,050,944	14,963,126	14,692,068	13,991,972	12,143,889	15,050,618
2019	15,578,377	15,558,810	14,912,832	14,618,325	12,769,380	15,578,056
2020	15,712,360	15,701,787	14,835,550	14,754,508	12,898,586	15,712,027
2021	15,304,069	15,299,636	14,326,786	14,399,549	12,872,999	15,304,505
2022	15,740,868	15,738,953	14,579,386	14,900,716	13,283,710	15,740,641
2023	15,587,697	15,584,117	14,329,098	14,561,642	13,188,088	15,586,596
2024	16,304,501	16,302,570	14,691,257	15,202,473	13,562,851	16,304,143
2025	16,775,086	16,776,035	15,114,311	13,971,770	14,088,252	16,774,896
2026	17,310,066	17,313,242	15,314,894	14,419,311	14,531,944	17,309,776
2027	17,754,025	17,758,936	15,730,180	14,842,328	14,962,493	17,753,816
2028	17,940,817	17,936,252	15,988,276	15,018,677	15,138,125	17,940,530
2029	18,031,994	18,028,887	16,184,628	15,170,665	15,397,857	18,032,192

Attachment F.1(b)(5) - Annual Water Use

ANNUAL WATER USE (ACRE-FEET)						
YEAR	SELECTED PORTFOLIO	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL REDUCTION PORTFOLIO	ALTERNATE PORTFOLIO
2014	54,747	54,747	54,747	54,747	54,747	55,475
2015	54,524	54,524	54,524	54,524	54,524	55,977
2016	54,944	54,944	54,944	53,664	53,610	55,483
2017	55,382	55,104	55,104	53,180	53,328	55,385
2018	56,737	56,425	55,804	54,410	51,436	56,737
2019	57,514	57,437	55,964	55,455	52,447	57,513
2020	57,369	57,355	55,420	55,346	52,303	57,368
2021	56,592	56,582	54,334	54,633	52,106	56,593
2022	57,531	57,523	56,260	55,718	53,022	57,531
2023	58,765	58,758	57,276	56,507	54,268	58,763
2024	60,135	60,132	57,875	57,732	55,051	60,134
2025	59,893	59,902	58,447	54,346	54,547	59,892
2026	60,382	60,387	60,282	54,383	54,611	60,381
2027	61,270	61,264	60,255	55,227	55,504	61,270
2028	62,975	62,986	61,595	56,954	57,189	62,975
2029	63,218	63,216	62,091	57,329	57,861	63,218

Attachment F.1(c)(1) - Current Path Scenario

CURRENT PATH SCENARIO: BASE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	463	463	464	464	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,084**	**8,420**	**7,770**	**7,550**	**7,550**	**6,943**	**6,454**	**6,446**	**6,433**	**6,426**	**6,426**	**6,427**	**6,410**	**6,411**	**6,412**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	261
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,507**	**1,610**	**1,663**	**1,744**	**1,821**	**1,899**	**1,983**
29	Natural Gas	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CCs/CTs	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,067**	**1,067**	**1,825**	**2,572**	**2,811**	**3,093**	**3,325**	**4,013**	**4,017**	**4,139**	**4,422**	**4,630**
37	**TOTAL RESOURCES**	**9,340**	**9,467**	**9,012**	**9,033**	**9,479**	**9,630**	**9,945**	**10,331**	**10,668**	**11,033**	**11,361**	**12,102**	**12,188**	**12,371**	**12,732**	**13,025**

ENERGY MIX
CURRENT PATH SCENARIO: BASE PORTFOLIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	TOT
2014	9,297	11,872	6,749	3,182	2,509	33,609
2015	9,297	11,963	6,479	3,355	3,120	34,214
2016	9,325	12,324	6,497	3,492	3,764	35,401
2017	9,296	11,576	7,895	3,526	4,375	36,668
2018	9,297	12,265	7,801	3,566	4,951	37,880
2019	9,297	13,005	7,690	3,607	5,505	39,105
2020	9,325	13,132	7,558	3,934	6,071	40,020
2021	9,296	12,015	9,454	4,268	6,424	41,458
2022	9,297	12,210	9,974	4,656	6,563	42,700
2023	9,297	11,508	11,041	5,323	6,743	43,912
2024	9,324	12,361	10,787	5,706	6,931	45,108
2025	9,297	12,860	10,906	6,138	7,107	46,308
2026	9,297	13,127	11,583	6,230	7,281	47,517
2027	9,297	13,223	12,481	6,270	7,461	48,732
2028	9,325	13,198	12,881	6,915	7,655	49,973
2029	9,297	12,541	14,599	6,944	7,855	51,236

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	TOT
2014	27.7%	35.3%	20.1%	9.5%	7.5%	100.0%
2015	27.2%	35.0%	18.9%	9.8%	9.1%	100.0%
2016	26.3%	34.8%	18.4%	9.9%	10.6%	100.0%
2017	25.4%	31.6%	21.5%	9.6%	11.9%	100.0%
2018	24.5%	32.4%	20.6%	9.4%	13.1%	100.0%
2019	23.8%	33.3%	19.7%	9.2%	14.1%	100.0%
2020	23.3%	32.8%	18.9%	9.8%	15.2%	100.0%
2021	22.4%	29.0%	22.8%	10.3%	15.5%	100.0%
2022	21.8%	28.6%	23.4%	10.9%	15.4%	100.0%
2023	21.2%	26.2%	25.1%	12.1%	15.4%	100.0%
2024	20.7%	27.4%	23.9%	12.6%	15.4%	100.0%
2025	20.1%	27.8%	23.6%	13.3%	15.3%	100.0%
2026	19.6%	27.6%	24.4%	13.1%	15.3%	100.0%
2027	19.1%	27.1%	25.6%	12.9%	15.3%	100.0%
2028	18.7%	26.4%	25.8%	13.8%	15.3%	100.0%
2029	18.1%	24.5%	28.5%	13.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(1) - Current Path Scenario

CURRENT PATH SCENARIO: ENHANCED RENEWABLE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	470	464	464	443	426	414	403	403	388	382	380	380	363	364	364
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	397	389	384	384	363	346	333	322	323	320	314	313	313	313	314	314
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,167**	**9,085**	**8,421**	**7,771**	**7,530**	**7,513**	**6,903**	**6,412**	**6,413**	**6,397**	**6,391**	**6,390**	**6,390**	**6,373**	**6,373**	**6,374**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	96	107	116	130	154	179	201	222	235	243	251	259
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**860**	**1,010**	**1,176**	**1,303**	**1,410**	**1,505**	**1,608**	**1,661**	**1,742**	**1,819**	**1,896**	**1,981**
29	Natural Gas	0	0	0	500	1,010	1,010	1,612	2,316	2,520	2,622	2,928	3,132	3,336	4,001	4,001	4,001
30	CCs/CTs	0	0	0	500	1,010	1,010	1,612	2,316	2,520	2,622	2,928	3,132	3,336	4,001	4,001	4,001
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	150	200	226	255	337	426	448	478	561	584	667	675
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	150	200	226	255	262	276	298	310	318	326	334	342
35	Geothermal	0	0	0	0	0	0	0	0	75	150	150	150	225	225	300	300
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,160**	**1,210**	**1,838**	**2,571**	**2,857**	**3,048**	**3,376**	**3,610**	**3,897**	**4,585**	**4,668**	**4,676**
37	**TOTAL RESOURCES**	**9,341**	**9,468**	**9,013**	**9,035**	**9,551**	**9,733**	**9,917**	**10,286**	**10,680**	**10,950**	**11,375**	**11,660**	**12,028**	**12,777**	**12,938**	**13,031**

ENERGY MIX
CURRENT PATH SCENARIO: ENHANCED RENEWABLE PORTFOLIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	TOT
2014	9,297	11,872	6,749	3,182	2,509	33,609
2015	9,297	11,963	6,479	3,355	3,120	34,214
2016	9,325	12,324	6,497	3,492	3,764	35,401
2017	9,296	11,576	7,895	3,526	4,375	36,668
2018	9,297	12,180	7,328	4,124	4,951	37,880
2019	9,297	12,644	6,934	4,723	5,505	39,105
2020	9,325	12,578	6,714	5,332	6,071	40,020
2021	9,296	11,608	7,910	6,221	6,424	41,460
2022	9,297	11,697	8,220	6,921	6,563	42,700
2023	9,297	10,995	9,009	7,868	6,743	43,912
2024	9,324	11,570	8,468	8,816	6,931	45,108
2025	9,297	12,067	8,317	9,520	7,107	46,308
2026	9,297	12,131	8,605	10,203	7,281	47,517
2027	9,297	12,274	9,457	10,243	7,461	48,732
2028	9,325	12,386	9,711	10,897	7,655	49,973
2029	9,297	11,962	11,205	10,917	7,855	51,236

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	TOT
2014	27.7%	35.3%	20.1%	9.5%	7.5%	100.0%
2015	27.2%	35.0%	18.9%	9.8%	9.1%	100.0%
2016	26.3%	34.8%	18.4%	9.9%	10.6%	100.0%
2017	25.4%	31.6%	21.5%	9.6%	11.9%	100.0%
2018	24.5%	32.2%	19.3%	10.9%	13.1%	100.0%
2019	23.8%	32.3%	17.7%	12.1%	14.1%	100.0%
2020	23.3%	31.4%	16.8%	13.3%	15.2%	100.0%
2021	22.4%	28.0%	19.1%	15.0%	15.5%	100.0%
2022	21.8%	27.4%	19.3%	16.2%	15.4%	100.0%
2023	21.2%	25.0%	20.5%	17.9%	15.4%	100.0%
2024	20.7%	25.6%	18.8%	19.5%	15.4%	100.0%
2025	20.1%	26.1%	18.0%	20.6%	15.3%	100.0%
2026	19.6%	25.5%	18.1%	21.5%	15.3%	100.0%
2027	19.1%	25.2%	19.4%	21.0%	15.3%	100.0%
2028	18.7%	24.8%	19.4%	21.8%	15.3%	100.0%
2029	18.1%	23.3%	21.9%	21.3%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(1) - Current Path Scenario

CURRENT PATH SCENARIO: COAL REDUCTION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	469	464	464	464	464	453	444	436	417	409	410	411	395	396	390
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	364	356	349	342	343	344	345	346	340
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,085**	**8,160**	**7,510**	**7,290**	**7,290**	**6,683**	**6,194**	**6,186**	**6,166**	**6,159**	**5,773**	**5,774**	**5,757**	**5,759**	**5,753**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	260
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,506**	**1,610**	**1,663**	**1,744**	**1,821**	**1,898**	**1,983**
29	Natural Gas	0	0	0	704	1,214	1,214	2,020	2,622	2,826	3,030	3,234	3,899	4,103	4,409	4,613	4,817
30	CCs/CTs	0	0	0	704	1,214	1,214	2,020	2,622	2,826	3,030	3,234	3,899	4,103	4,409	4,613	4,817
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	295	314	338	345	366	448	467
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	220	239	245	252	258	264	283
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**761**	**1,271**	**1,271**	**2,131**	**2,776**	**3,015**	**3,325**	**3,548**	**4,237**	**4,448**	**4,775**	**5,061**	**5,284**
37	TOTAL RESOURCES	9,340	9,467	8,752	8,978	9,423	9,574	9,992	10,275	10,613	10,997	11,317	11,673	11,965	12,354	12,718	13,019

ENERGY MIX
CURRENT PATH SCENARIO: COAL REDUCTION PORTFOLIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	TOT
2014	9,297	11,872	6,749	3,182	2,509	33,609
2015	9,297	11,963	6,479	3,355	3,120	34,214
2016	9,325	11,286	7,535	3,492	3,764	35,401
2017	9,296	9,992	9,478	3,526	4,375	36,668
2018	9,297	10,626	9,440	3,566	4,951	37,880
2019	9,297	11,417	9,278	3,607	5,505	39,105
2020	9,325	11,544	9,146	3,934	6,071	40,020
2021	9,296	10,489	10,980	4,268	6,424	41,457
2022	9,297	10,795	11,388	4,656	6,563	42,700
2023	9,297	9,969	12,302	5,602	6,743	43,912
2024	9,324	10,682	12,187	5,986	6,931	45,108
2025	9,297	8,924	14,563	6,417	7,107	46,308
2026	9,297	9,053	15,378	6,509	7,281	47,517
2027	9,297	9,063	16,362	6,549	7,461	48,732
2028	9,325	9,046	16,753	7,194	7,655	49,973
2029	9,297	8,646	17,936	7,502	7,855	51,236

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	TOT
2014	27.7%	35.3%	20.1%	9.5%	7.5%	100.0%
2015	27.2%	35.0%	18.9%	9.8%	9.1%	100.0%
2016	26.3%	31.9%	21.3%	9.9%	10.6%	100.0%
2017	25.4%	27.3%	25.8%	9.6%	11.9%	100.0%
2018	24.5%	28.1%	24.9%	9.4%	13.1%	100.0%
2019	23.8%	29.2%	23.7%	9.2%	14.1%	100.0%
2020	23.3%	28.8%	22.9%	9.8%	15.2%	100.0%
2021	22.4%	25.3%	26.5%	10.3%	15.5%	100.0%
2022	21.8%	25.3%	26.7%	10.9%	15.4%	100.0%
2023	21.2%	22.7%	28.0%	12.8%	15.4%	100.0%
2024	20.7%	23.7%	27.0%	13.3%	15.4%	100.0%
2025	20.1%	19.3%	31.4%	13.9%	15.3%	100.0%
2026	19.6%	19.1%	32.4%	13.7%	15.3%	100.0%
2027	19.1%	18.6%	33.6%	13.4%	15.3%	100.0%
2028	18.7%	18.1%	33.5%	14.4%	15.3%	100.0%
2029	18.1%	16.9%	35.0%	14.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(1) - Current Path Scenario

CURRENT PATH SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	5,139	4,489	4,656	4,656	4,059	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,514	1,514	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	463	463	464	464	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,084**	**8,420**	**7,770**	**7,550**	**7,550**	**6,943**	**6,454**	**6,446**	**6,433**	**6,426**	**6,426**	**6,427**	**6,410**	**6,411**	**6,412**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	261
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,507**	**1,610**	**1,663**	**1,744**	**1,821**	**1,899**	**1,983**
29	Natural Gas	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CCs/CTs	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,067**	**1,067**	**1,825**	**2,572**	**2,811**	**3,093**	**3,325**	**4,013**	**4,017**	**4,139**	**4,422**	**4,630**
37	**TOTAL RESOURCES**	**9,340**	**9,467**	**9,012**	**9,033**	**9,479**	**9,630**	**9,945**	**10,331**	**10,668**	**11,033**	**11,361**	**12,102**	**12,188**	**12,371**	**12,732**	**13,025**

Attachment F.1(c)(1) - Current Path Scenario

ENERGY MIX
CURRENT PATH SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	TOT
2014	9,297	11,872	6,749	3,182	2,509	33,609
2015	9,297	11,963	6,479	3,355	3,120	34,214
2016	9,325	11,243	7,578	3,492	3,764	35,401
2017	9,296	10,112	9,359	3,526	4,375	36,668
2018	9,297	8,184	11,880	3,566	4,951	37,879
2019	9,297	8,964	11,731	3,607	5,505	39,105
2020	9,325	9,114	11,576	3,934	6,071	40,020
2021	9,296	8,456	13,010	4,268	6,424	41,454
2022	9,297	8,667	13,514	4,656	6,563	42,698
2023	9,297	7,982	14,567	5,323	6,743	43,912
2024	9,324	8,338	14,811	5,706	6,931	45,108
2025	9,297	8,937	14,830	6,138	7,107	46,308
2026	9,297	9,047	15,663	6,230	7,281	47,517
2027	9,297	9,063	16,641	6,270	7,461	48,732
2028	9,325	9,056	17,022	6,915	7,655	49,973
2029	9,297	8,635	18,505	6,944	7,855	51,236

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	TOT
2014	27.7%	35.3%	20.1%	9.5%	7.5%	100.0%
2015	27.2%	35.0%	18.9%	9.8%	9.1%	100.0%
2016	26.3%	31.8%	21.4%	9.9%	10.6%	100.0%
2017	25.4%	27.6%	25.5%	9.6%	11.9%	100.0%
2018	24.5%	21.6%	31.4%	9.4%	13.1%	100.0%
2019	23.8%	22.9%	30.0%	9.2%	14.1%	100.0%
2020	23.3%	22.8%	28.9%	9.8%	15.2%	100.0%
2021	22.4%	20.4%	31.4%	10.3%	15.5%	100.0%
2022	21.8%	20.3%	31.6%	10.9%	15.4%	100.0%
2023	21.2%	18.2%	33.2%	12.1%	15.4%	100.0%
2024	20.7%	18.5%	32.8%	12.6%	15.4%	100.0%
2025	20.1%	19.3%	32.0%	13.3%	15.3%	100.0%
2026	19.6%	19.0%	33.0%	13.1%	15.3%	100.0%
2027	19.1%	18.6%	34.1%	12.9%	15.3%	100.0%
2028	18.7%	18.1%	34.1%	13.8%	15.3%	100.0%
2029	18.1%	16.9%	36.1%	13.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(1) - Current Path Scenario

TOTAL REVENUE REQUIREMENTS: CURRENT PATH SCENARIO - ($MILLIONS)				
Year	Base Portfolio	Enhanced Renewable Portfolio	Coal Reduction Portfolio	Coal-to-Gas Conversion Portfolio
2014	2,252.5	2,252.5	2,250.9	2,251.7
2015	2,338.4	2,338.4	2,324.2	2,337.2
2016	2,337.8	2,337.8	2,308.4	2,349.1
2017	2,518.8	2,518.8	2,540.1	2,552.2
2018	2,722.8	2,754.2	2,711.7	2,751.0
2019	2,811.4	2,898.5	2,802.9	2,839.1
2020	2,948.7	3,054.9	2,944.3	2,967.8
2021	3,269.2	3,377.0	3,252.1	3,267.1
2022	3,445.8	3,568.3	3,417.2	3,449.2
2023	3,702.9	3,811.0	3,671.9	3,698.6
2024	3,866.1	3,994.1	3,828.4	3,879.2
2025	4,085.0	4,176.8	4,045.8	4,071.7
2026	4,288.7	4,373.1	4,242.9	4,247.7
2027	4,433.4	4,626.6	4,443.5	4,394.4
2028	4,615.1	4,806.8	4,656.0	4,589.0
2029	4,867.9	4,969.4	4,889.0	4,830.5
2030	5,102.5	5,150.7	5,136.5	5,076.9
2031	5,235.1	5,263.2	5,281.3	5,223.5
2032	5,433.6	5,465.7	5,456.7	5,400.4
2033	5,638.3	5,655.7	5,673.7	5,605.1
2034	5,852.6	5,874.2	5,928.9	5,847.4
2035	6,177.7	6,199.4	6,225.1	6,161.9
2036	6,443.5	6,433.3	6,480.8	6,431.9
2037	6,672.6	6,647.0	6,733.4	6,671.5
2038	7,082.9	7,054.5	7,106.0	7,067.6
2039	7,435.1	7,392.4	7,460.1	7,409.8
2040	7,885.3	7,825.2	7,919.2	7,884.9
2041	8,270.9	8,177.4	8,270.0	8,255.9
2042	8,627.0	8,526.6	8,638.9	8,624.7
2043	8,880.6	8,758.0	8,913.8	8,900.6
(2014-2029)	29,306.1	29,939.8	29,199.9	29,334.6
(2014-2043)	47,583.7	48,192.8	47,582.0	47,569.8

Attachment F.1(c)(1) - Current Path Scenario

TOTAL REVENUE REQUIREMENTS: CURRENT PATH SCENARIO
BASE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DF-EE Costs	$Millions	$/MWh
2014	625.6	470.2	50.8	412.0	19.5	1,578.2	110.5	351.3	461.8	(2.0)	63.2	23.9	(0.1)	127.3	2,252.5	73.7
2015	634.0	469.4	51.1	441.6	42.1	1,638.1	111.2	368.4	479.6	(0.4)	64.8	21.3	(0.1)	135.1	2,338.4	76.5
2016	687.2	471.3	54.1	376.8	65.7	1,655.0	105.8	357.4	463.2	(0.9)	66.4	18.5	(0.1)	135.6	2,337.8	75.3
2017	789.3	590.7	63.8	389.0	75.5	1,908.3	94.8	299.2	394.1	(2.4)	78.2	15.5	(0.1)	125.1	2,518.8	79.7
2018	966.6	668.7	71.7	397.9	76.0	2,180.8	62.1	276.3	338.4	(2.3)	69.8	13.6	(0.1)	122.5	2,722.8	84.5
2019	1,001.7	706.6	76.4	406.3	73.9	2,265.0	62.3	284.7	347.0	(2.4)	71.5	11.7	(0.1)	118.7	2,811.4	85.6
2020	1,145.7	792.4	85.6	408.8	72.6	2,505.0	6.0	231.1	237.1	(2.5)	73.3	9.6	(0.1)	126.2	2,948.7	88.2
2021	1,324.7	869.4	91.5	441.1	71.1	2,797.8	5.8	234.0	239.8	0.0	106.5	9.2	55.1	60.7	3,269.2	95.5
2022	1,404.0	939.1	98.1	445.0	71.8	2,958.1	6.5	233.3	239.7	0.0	100.0	8.9	68.3	70.8	3,445.8	97.9
2023	1,553.4	1,013.1	102.8	454.5	70.3	3,193.9	6.4	228.7	235.2	0.0	115.5	8.4	72.6	77.2	3,702.9	102.6
2024	1,636.7	1,065.5	110.4	460.7	68.7	3,342.0	7.2	227.1	234.3	0.0	118.2	8.1	87.2	76.2	3,866.1	104.6
2025	1,761.7	1,127.4	118.0	465.3	71.4	3,543.7	8.1	230.0	238.1	0.0	116.1	7.7	104.8	74.6	4,085.0	108.0
2026	1,802.9	1,200.4	124.0	492.9	72.7	3,693.0	8.1	233.1	241.2	0.0	138.1	7.2	133.9	75.3	4,288.7	110.6
2027	1,803.1	1,279.4	131.8	512.3	72.0	3,798.6	8.1	220.1	228.1	0.0	142.9	6.8	177.0	80.0	4,433.4	111.5
2028	1,862.2	1,333.7	137.4	524.1	70.2	3,927.5	8.1	223.7	231.7	0.0	149.5	6.4	215.3	84.5	4,615.1	113.2
2029	1,899.5	1,439.4	143.9	554.7	71.6	4,109.2	8.1	226.3	234.4	0.0	176.9	6.1	253.8	87.6	4,867.9	116.5
2030	1,921.6	1,542.0	153.4	560.6	71.1	4,248.6	8.1	221.9	229.9	0.0	229.4	5.7	300.8	88.1	5,102.5	119.2
2031	1,976.4	1,618.0	160.9	568.5	70.5	4,394.3	8.0	224.4	232.4	0.0	195.3	5.3	321.0	86.8	5,235.1	119.3
2032	2,014.0	1,715.1	169.6	575.4	69.6	4,543.8	8.1	227.3	235.4	0.0	229.0	4.9	339.1	81.5	5,433.6	120.9
2033	2,062.9	1,828.9	179.1	594.7	68.7	4,734.4	8.0	228.4	236.4	0.0	228.3	4.5	354.9	79.9	5,638.3	122.5
2034	2,121.2	1,934.0	188.1	610.9	68.0	4,922.2	8.7	231.7	240.4	0.0	235.6	4.0	371.4	78.8	5,852.6	123.9
2035	2,182.2	2,061.0	199.1	653.3	82.5	5,178.1	9.0	235.2	244.2	0.0	288.9	3.6	383.8	79.1	6,177.7	127.6
2036	2,230.6	2,185.0	211.0	665.6	107.7	5,400.0	9.4	238.8	248.1	0.0	309.7	3.1	403.3	79.3	6,443.5	129.6
2037	2,295.9	2,288.5	222.7	658.9	121.8	5,587.8	9.8	222.9	232.7	0.0	342.8	2.6	427.6	79.2	6,672.6	131.3
2038	2,388.1	2,446.8	238.8	725.5	141.0	5,940.1	10.0	214.7	224.7	0.0	402.1	2.2	437.8	75.9	7,082.9	136.1
2039	2,542.6	2,694.1	266.3	593.5	184.5	6,281.0	10.5	210.1	220.6	0.0	447.0	1.7	409.3	75.5	7,435.1	139.7
2040	2,760.0	2,840.1	283.4	575.1	227.0	6,685.6	10.7	203.5	214.2	0.0	480.1	1.4	429.4	74.7	7,885.3	144.6
2041	2,863.3	2,983.1	297.4	621.3	262.2	7,027.4	11.2	206.3	217.5	0.0	505.3	1.0	445.9	73.7	8,270.9	148.6
2042	2,964.7	3,115.3	313.3	654.3	274.1	7,321.6	11.7	205.3	217.0	0.0	542.3	0.7	473.1	72.4	8,627.0	151.8
2043	3,021.3	3,269.8	329.4	650.3	291.8	7,562.7	12.5	173.2	185.8	0.0	568.5	0.3	492.6	70.7	8,880.6	153.0
(2014-2029)	10,842.2	7,506.4	792.2	4,063.5	594.5	23,798.7	474.8	2,599.3	3,074.1	(9.4)	868.3	121.9	470.5	982.0	29,306.1	
(2014-2043)	17,334.9	13,677.3	1,400.7	5,811.2	950.5	39,174.6	501.2	3,225.7	3,726.9	(9.4)	1,789.5	131.5	1,562.6	1,208.0	47,583.7	

Attachment F.1(c)(1) - Current Path Scenario

TOTAL REVENUE REQUIREMENTS: CURRENT PATH SCENARIO
ENHANCED RENEWABLE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.6	470.2	50.8	412.0	19.5	1,578.2	110. 5	351.3	461.8	(2.0)	63.2	23.9	(0.1)	127.3	2,252.5	73.7
2015	634.0	469.4	51.1	441.6	42.1	1,638.1	111.2	368.4	479.6	(0.4)	64.8	21.3	(0.1)	135.1	2,338.4	76.5
2016	687.2	471.3	54.1	376.8	65.7	1,655.0	105.8	357.4	463.2	(0.9)	66.4	18.5	(0.1)	135.6	2,337.8	75.3
2017	789.3	590.7	63.8	389.0	75.5	1,908.3	94.8	299.2	394.1	(2.4)	78.2	15.5	(0.1)	125.1	2,518.8	79.7
2018	1,008.6	652.0	72.0	403.5	76.0	2,212.1	63.5	275.1	338.6	(2.3)	69.8	13.6	(0.1)	122.5	2,754.2	85.5
2019	1,110.1	673.6	75.8	417.8	73.9	2,351.2	65.1	282.8	347.9	(2.4)	71.5	11.7	(0.1)	118.7	2,898.5	88.3
2020	1,279.6	748.0	84.5	423.1	72.6	2,607.8	9.5	231.1	240.6	(2.5)	73.3	9.6	(0.1)	126.2	3,054.9	91.4
2021	1,490.1	807.1	93.3	461.5	71.1	2,923.2	10.7	231.9	242.6	0.0	98.7	9.2	42.5	60.7	3,377.0	98.7
2022	1,602.6	861.0	97.1	470.6	71.8	3,103.2	10.6	233.1	243.7	0.0	88.8	8.9	52.9	70.8	3,568.3	101.4
2023	1,754.3	919.8	102.2	483.5	70.3	3,330.0	11.3	228.7	240.1	0.0	99.8	8.4	55.5	77.2	3,811.0	105.6
2024	1,877.7	950.1	110.8	497.0	68.7	3,504.3	13.4	227.1	240.6	0.0	100.2	8.1	64.7	76.2	3,994.1	108.1
2025	1,980.7	1,003.0	115.4	504.3	67.1	3,670.5	15.1	230.0	245.1	0.0	101.6	7.7	77.3	74.6	4,176.8	110.4
2026	2,050.3	1,048.4	118.2	541.1	65.4	3,823.4	15.1	233.1	248.2	0.0	119.9	7.2	99.0	75.3	4,373.1	112.8
2027	2,164.0	1,113.9	127.3	564.7	68.4	4,038.3	15.1	220.1	235.1	0.0	121.5	6.8	144.9	80.0	4,626.6	116.3
2028	2,226.7	1,160.7	131.8	578.6	69.8	4,167.6	15.1	223.7	238.7	0.0	124.2	6.4	185.2	84.5	4,806.8	117.9
2029	2,190.0	1,252.2	140.3	609.0	71.4	4,262.7	15.0	226.3	241.4	0.0	147.1	6.1	224.6	87.6	4,969.4	118.9
2030	2,176.3	1,341.2	149.5	615.5	70.8	4,353.2	15.0	221.4	236.4	0.0	197.2	5.7	270.1	88.1	5,150.7	120.3
2031	2,221.3	1,409.8	155.6	624.7	70.3	4,481.7	15.0	224.4	239.4	0.0	159.1	5.3	290.9	86.8	5,263.2	120.0
2032	2,250.8	1,503.6	164.1	633.1	83.4	4,635.0	15.0	227.3	242.4	0.0	194.8	4.9	307.1	81.5	5,465.7	121.6
2033	2,292.8	1,598.6	174.2	653.8	91.8	4,811.2	15.0	228.4	243.4	0.0	193.4	4.5	323.4	79.9	5,655.7	122.9
2034	2,344.2	1,697.6	183.9	671.4	109.0	5,006.0	15.7	231.7	247.4	0.0	197.8	4.0	340.1	78.8	5,874.2	124.4
2035	2,398.2	1,823.8	193.1	715.4	132.5	5,262.9	16.0	235.2	251.2	0.0	251.9	3.6	350.8	79.1	6,199.4	128.0
2036	2,439.3	1,932.8	205.4	729.2	145.3	5,452.0	16.4	238.8	255.1	0.0	272.8	3.1	371.0	79.3	6,433.3	129.4
2037	2,497.2	2,029.0	215.9	724.1	163.2	5,629.5	16.7	222.9	239.6	0.0	301.8	2.6	394.4	79.2	6,647.0	130.8
2038	2,582.0	2,194.9	228.7	792.3	187.6	5,985.4	17.0	214.7	231.7	0.0	358.3	2.2	401.0	75.9	7,054.5	135.6
2039	2,728.9	2,428.7	252.7	661.9	234.5	6,306.7	17.5	210.1	227.6	0.0	407.7	1.7	373.3	75.5	7,392.4	138.9
2040	2,939.1	2,565.6	269.8	645.2	275.5	6,695.3	17.7	203.5	221.2	0.0	439.9	1.4	392.7	74.7	7,825.2	143.5
2041	3,036.0	2,704.1	282.6	693.2	292.0	7,007.9	18.2	206.3	224.4	0.0	462.0	1.0	408.2	73.7	8,177.4	147.0
2042	3,131.3	2,832.1	296.2	728.0	308.6	7,296.3	18.7	205.3	224.0	0.0	499.3	0.7	433.9	72.4	8,526.6	150.0
2043	3,170.3	2,979.9	309.2	725.9	332.2	7,517.6	19.5	173.2	192.8	0.0	524.7	0.3	451.9	70.7	8,758.0	150.9
(2014-2029)	11,994.7	6,967.3	783.4	4,233.8	588.1	24,567.3	503.4	2,595.8	3,099.2	(9.4)	801.2	121.9	377.7	982.0	29,939.8	
(2014-2043)	19,092.1	12,453.7	1,368.8	6,160.4	1,026.8	40,101.8	549.7	3,222.1	3,771.8	(9.4)	1,614.7	131.5	1,374.5	1,208.0	48,192.8	

TOTAL REVENUE REQUIREMENTS: CURRENT PATH SCENARIO
COAL REDUCTION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	624.1	470.2	50.8	412.0	19.5	1,576.6	110.5	351.3	461.8	(2.0)	63.2	23.9	(0.1)	127.3	2,250.9	73.6
2015	629.9	469.4	51.1	431.5	42.1	1,623.9	111.2	368.4	479.6	(0.4)	64.8	21.3	(0.1)	135.1	2,324.2	76.1
2016	660.1	474.1	51.4	363.5	65.7	1,614.9	105.8	368.1	473.9	(0.9)	66.4	18.5	(0.1)	135.6	2,308.4	74.4
2017	787.8	604.8	60.8	379.6	76.1	1,909.1	94.8	310.1	404.9	(2.4)	87.8	15.5	(0.1)	125.1	2,540.1	80.4
2018	944.4	682.4	68.0	387.5	77.0	2,159.3	62.1	279.7	341.8	(2.3)	76.9	13.6	(0.1)	122.5	2,711.7	84.2
2019	978.2	724.0	71.8	395.8	75.0	2,244.8	62.3	287.9	350.1	(2.4)	80.1	11.7	(0.1)	118.7	2,802.9	85.4
2020	1,130.6	814.7	81.1	399.1	73.2	2,498.7	6.0	231.1	237.1	(2.5)	75.2	9.6	(0.1)	126.2	2,944.3	88.1
2021	1,300.9	897.7	89.1	423.5	71.5	2,782.8	5.8	234.5	240.3	0.0	115.6	9.2	43.5	60.7	3,252.1	95.0
2022	1,365.1	967.3	95.6	433.3	71.8	2,933.1	6.5	233.3	239.8	0.0	107.4	8.9	57.2	70.8	3,417.2	97.1
2023	1,523.3	1,030.6	100.8	443.2	70.1	3,168.1	7.1	228.7	235.9	0.0	123.6	8.4	58.6	77.2	3,671.9	101.7
2024	1,609.0	1,088.3	108.0	430.6	68.5	3,304.3	7.8	227.1	235.0	0.0	132.9	8.1	71.9	76.2	3,828.4	103.6
2025	1,727.4	1,180.4	113.1	410.0	71.2	3,502.0	8.8	230.0	238.8	0.0	155.9	7.7	66.9	74.6	4,045.8	106.9
2026	1,794.2	1,254.8	118.7	417.0	73.2	3,657.9	8.8	233.1	241.9	0.0	165.9	7.2	94.7	75.3	4,242.9	109.4
2027	1,842.7	1,337.8	125.3	439.6	73.4	3,818.9	8.8	220.1	228.8	0.0	173.6	6.8	135.4	80.0	4,443.5	111.7
2028	1,918.7	1,393.2	131.0	466.3	72.5	3,981.8	8.8	223.7	232.4	0.0	179.0	6.4	171.8	84.5	4,656.0	114.2
2029	1,967.4	1,478.8	139.4	483.7	73.6	4,143.0	9.5	226.3	235.8	0.0	207.3	6.1	209.3	87.6	4,889.0	117.0
2030	1,993.8	1,588.0	147.8	483.4	72.7	4,285.8	9.4	221.2	230.6	0.0	276.6	5.7	249.6	88.1	5,136.5	120.0
2031	2,043.6	1,664.5	155.2	508.8	71.7	4,443.8	9.4	224.4	233.8	0.0	240.5	5.3	271.0	86.8	5,281.3	120.4
2032	2,076.0	1,765.6	163.1	490.9	84.7	4,580.2	9.5	227.3	236.8	0.0	267.2	4.9	286.1	81.5	5,456.7	121.4
2033	2,121.8	1,879.4	172.7	512.3	93.0	4,779.2	9.4	228.4	237.8	0.0	271.1	4.5	301.2	79.9	5,673.7	123.3
2034	2,177.2	1,985.3	182.6	547.4	110.1	5,002.6	10.1	231.7	241.8	0.0	284.8	4.0	316.8	78.8	5,928.9	125.5
2035	2,234.8	2,109.4	193.0	571.7	118.7	5,227.6	10.4	235.2	245.6	0.0	339.3	3.6	329.8	79.1	6,225.1	128.5
2036	2,281.4	2,240.2	205.1	577.9	136.7	5,441.3	10.8	238.8	249.5	0.0	363.4	3.1	344.3	79.3	6,480.8	130.4
2037	2,342.1	2,343.4	217.1	591.7	161.1	5,655.4	11.2	222.9	234.0	0.0	392.8	2.6	369.4	79.2	6,733.4	132.5
2038	2,423.0	2,507.9	232.3	630.4	174.1	5,967.7	11.4	214.7	226.1	0.0	459.7	2.2	374.5	75.9	7,106.0	136.6
2039	2,565.2	2,759.2	260.9	502.8	226.6	6,314.6	11.9	210.1	222.0	0.0	503.4	1.7	342.9	75.5	7,460.1	140.1
2040	2,780.4	2,901.2	278.6	505.6	257.6	6,723.4	12.1	203.5	215.6	0.0	542.7	1.4	361.4	74.7	7,919.2	145.2
2041	2,879.5	3,044.7	292.6	530.3	285.2	7,032.3	12.6	206.3	218.9	0.0	564.1	1.0	380.0	73.7	8,270.0	148.6
2042	2,978.8	3,187.6	308.3	555.0	308.1	7,337.7	13.1	205.3	218.4	0.0	609.5	0.7	400.2	72.4	8,638.9	152.0
2043	3,035.6	3,342.0	324.8	575.1	318.5	7,595.9	13.9	173.2	187.2	0.0	638.9	0.3	420.8	70.7	8,913.8	153.6
(2014-2029)	10,750.1	7,706.0	764.1	3,854.6	598.9	23,673.7	477.0	2,621.0	3,098.0	(9.4)	967.9	121.9	365.8	982.0	29,199.9	
(2014-2043)	17,377.7	14,032.4	1,356.4	5,377.9	1,025.2	39,169.6	507.4	3,247.2	3,754.6	(9.4)	2,035.0	131.5	1,292.7	1,208.0	47,582.0	

Attachment F.1(c)(1) - Current Path Scenario

TOTAL REVENUE REQUIREMENTS: CURRENT PATH SCENARIO
COAL-TO-GAS CONVERSION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.0	470.2	50.8	411.9	19.5	1,577.5	110.5	351.3	461.8	(2.0)	63.2	23.9	(0.1)	127.3	2,251.7	73.6
2015	632.7	469.4	51.1	441.6	42.1	1,636.8	111.2	368.4	479.6	(0.4)	64.8	21.3	(0.1)	135.1	2,337.2	76.5
2016	684.5	474.7	51.4	379.2	65.7	1,655.5	105.8	368.2	474.0	(0.9)	66.4	18.5	(0.1)	135.6	2,349.1	75.7
2017	796.1	604.5	61.2	391.1	75.5	1,928.4	94.8	308.8	403.7	(2.4)	81.9	15.5	(0.1)	125.1	2,552.2	80.7
2018	936.8	714.7	64.7	370.6	76.0	2,162.8	62.1	286.1	348.2	(2.3)	106.3	13.6	(0.1)	122.5	2,751.0	85.4
2019	971.8	759.9	67.6	383.3	73.9	2,256.6	62.3	292.9	355.2	(2.4)	99.5	11.7	(0.1)	118.7	2,839.1	86.5
2020	1,113.6	857.5	77.3	381.6	72.6	2,502.5	6.0	231.1	237.1	(2.5)	95.0	9.6	(0.1)	126.2	2,967.8	88.8
2021	1,289.7	939.3	87.9	403.8	71.1	2,791.8	5.8	237.7	243.4	0.0	138.2	9.2	23.7	60.7	3,267.1	95.5
2022	1,366.8	1,012.9	93.8	417.3	71.8	2,962.6	6.5	235.3	241.7	0.0	129.5	8.9	35.7	70.8	3,449.2	98.0
2023	1,512.1	1,087.6	99.1	421.5	70.3	3,190.6	6.4	228.7	235.2	0.0	147.2	8.4	39.9	77.2	3,698.6	102.5
2024	1,595.4	1,159.0	104.9	421.2	68.7	3,349.1	7.2	227.1	234.3	0.0	162.5	8.1	49.0	76.2	3,879.2	104.9
2025	1,720.5	1,193.8	112.1	425.5	71.4	3,523.3	8.1	230.0	238.1	0.0	159.2	7.7	68.8	74.6	4,071.7	107.6
2026	1,760.7	1,269.7	118.3	436.5	72.7	3,657.9	8.1	233.1	241.2	0.0	169.7	7.2	96.4	75.3	4,247.7	109.5
2027	1,760.7	1,353.4	125.0	453.8	72.0	3,765.0	8.1	220.1	228.1	0.0	177.3	6.8	137.1	80.0	4,394.4	110.5
2028	1,819.4	1,408.0	131.0	479.9	70.2	3,908.5	8.1	223.7	231.7	0.0	184.1	6.4	173.7	84.5	4,589.0	112.5
2029	1,856.2	1,510.5	138.8	497.0	71.6	4,074.2	8.1	226.3	234.4	0.0	215.5	6.1	212.8	87.6	4,830.5	115.6
2030	1,878.6	1,621.4	147.4	500.6	71.1	4,219.1	8.1	223.6	231.6	0.0	279.0	5.7	253.3	88.1	5,076.9	118.6
2031	1,934.6	1,697.0	154.7	519.4	70.5	4,376.1	8.0	224.4	232.4	0.0	248.1	5.3	274.8	86.8	5,223.5	119.1
2032	1,973.2	1,799.6	163.1	507.0	69.6	4,512.4	8.1	227.3	235.4	0.0	276.3	4.9	290.0	81.5	5,400.4	120.2
2033	2,023.6	1,913.7	172.9	524.0	68.7	4,702.9	8.0	228.4	236.4	0.0	276.1	4.5	305.3	79.9	5,605.1	121.8
2034	2,083.8	2,019.2	182.7	558.9	68.0	4,912.5	8.7	231.7	240.4	0.0	290.7	4.0	320.8	78.8	5,847.4	123.8
2035	2,145.9	2,144.0	194.1	587.1	82.5	5,153.6	9.0	235.2	244.2	0.0	347.3	3.6	334.1	79.1	6,161.9	127.2
2036	2,195.7	2,276.1	205.9	597.9	107.7	5,383.3	9.4	238.8	248.1	0.0	369.5	3.1	348.7	79.3	6,431.9	129.4
2037	2,260.3	2,379.7	217.9	604.2	121.8	5,583.8	9.8	222.9	232.7	0.0	399.2	2.6	374.0	79.2	6,671.5	131.2
2038	2,345.9	2,544.4	234.0	649.2	141.0	5,914.5	10.0	214.7	224.7	0.0	471.1	2.2	379.1	75.9	7,067.6	135.8
2039	2,491.8	2,796.7	263.7	516.4	184.5	6,253.1	10.5	210.1	220.6	0.0	511.0	1.7	347.8	75.5	7,409.8	139.2
2040	2,711.6	2,939.7	281.3	518.9	227.0	6,678.5	10.7	203.5	214.2	0.0	549.7	1.4	366.4	74.7	7,884.9	144.6
2041	2,816.2	3,082.4	295.6	548.2	262.2	7,004.5	11.2	206.3	217.5	0.0	574.2	1.0	384.9	73.7	8,255.9	148.4
2042	2,918.8	3,227.7	311.6	578.2	274.1	7,310.4	11.7	205.3	217.0	0.0	618.7	0.7	405.5	72.4	8,624.7	151.7
2043	2,979.9	3,383.1	328.9	589.5	291.8	7,573.2	12.5	173.2	185.8	0.0	644.5	0.3	426.1	70.7	8,900.6	153.3
(2014-2029)	10,622.8	7,921.9	752.1	3,847.9	594.5	23,739.2	474.8	2,630.8	3,105.5	(9.4)	1,068.4	121.9	327.0	982.0	29,334.6	
(2014-2043)	16,998.3	14,349.1	1,347.2	5,414.2	950.5	39,059.4	501.2	3,257.7	3,758.9	(9.4)	2,155.2	131.5	1,266.2	1,208.0	47,569.8	

Attachment F.1(c)(1) - Current Path Scenario

ANNUAL AVERAGE SYSTEM COST: CURRENT PATH SCENARIO - ($MWh)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	73.7	73.7	73.6	73.6
2015	76.5	76.5	76.1	76.5
2016	75.3	75.3	74.4	75.7
2017	79.7	79.7	80.4	80.7
2018	84.5	85.5	84.2	85.4
2019	85.6	88.3	85.4	86.5
2020	88.2	91.4	88.1	88.8
2021	95.5	98.7	95.0	95.5
2022	97.9	101.4	97.1	98.0
2023	102.6	105.6	101.7	102.5
2024	104.6	108.1	103.6	104.9
2025	108.0	110.4	106.9	107.6
2026	110.6	112.8	109.4	109.5
2027	111.5	116.3	111.7	110.5
2028	113.2	117.9	114.2	112.5
2029	116.5	118.9	117.0	115.6

Attachment F.1(c)(1) - Current Path Scenario

CUMULATIVE CAPITAL SPENDING EXISTING AND NEW GENERATION PLUS INCREMENTAL TRANSMISSION CURRENT PATH SCENARIO ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	1,211.7	1,211.7	1,201.4	1,207.7
2015	1,678.9	1,678.9	1,641.3	1,635.6
2016	2,400.4	2,513.0	2,359.0	2,368.6
2017	3,657.0	4,104.9	3,632.9	3,589.4
2018	4,104.5	4,926.0	3,984.9	3,934.9
2019	4,617.4	5,697.2	4,528.5	4,427.0
2020	5,900.6	7,336.0	5,766.8	5,692.2
2021	7,412.6	8,998.9	7,249.6	7,181.8
2022	8,217.0	9,997.1	8,121.5	7,969.8
2023	9,172.2	11,091.3	9,059.1	8,894.4
2024	10,238.4	12,375.8	10,091.8	9,952.3
2025	10,815.5	13,425.9	10,824.9	10,522.6
2026	11,552.8	14,843.8	11,828.8	11,245.6
2027	12,209.4	15,442.5	12,653.6	11,893.1
2028	12,914.3	15,852.3	13,459.4	12,587.0
2029	13,588.0	16,387.8	14,159.1	13,248.6

1. Capital investment projected is regardless of whether APS constructs and owns new generation resources or whether resources are purchased by APS under long-term PPAs with market participants.

2. Capital spending excludes: (a) financial commitments to energy efficiency and distributed energy initiatives; (b) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing.

3. Capital spending includes ongoing capital investment for existing owned generation.

Attachment F.1(c)(1) - Current Path Scenario

ANNUAL NATURAL GAS BURNS CURRENT PATH SCENARIO (BCF)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	43.1	43.1	43.1	43.1
2015	41.1	41.1	41.1	41.1
2016	45.7	45.7	53.6	53.9
2017	60.1	60.1	72.4	71.5
2018	59.5	56.0	72.1	91.3
2019	58.6	53.3	70.9	90.2
2020	59.0	53.2	71.2	90.1
2021	72.2	62.2	84.2	100.6
2022	76.5	64.9	87.5	104.5
2023	85.0	71.6	94.9	112.8
2024	83.3	68.5	94.2	114.7
2025	84.2	68.7	112.5	114.4
2026	89.4	71.4	118.7	120.8
2027	96.2	76.6	126.3	128.5
2028	99.4	78.8	129.5	131.5
2029	112.5	89.5	138.5	142.8

Attachment F.1(c)(1) - Current Path Scenario

ANNUAL CO2 EMISSIONS CURRENT PATH SCENARIO (METRIC TONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	13,736,311	13,736,311	13,736,311	13,736,311
2015	13,647,588	13,647,588	13,647,588	13,647,588
2016	14,181,078	14,181,078	13,562,400	13,539,017
2017	14,296,750	14,296,750	13,354,717	13,443,236
2018	14,963,126	14,692,068	13,991,972	12,143,889
2019	15,558,810	14,912,832	14,618,325	12,769,380
2020	15,701,787	14,835,550	14,754,508	12,898,586
2021	15,299,636	14,326,786	14,399,549	12,872,999
2022	15,738,953	14,579,386	14,900,716	13,283,710
2023	15,584,117	14,329,098	14,561,642	13,188,088
2024	16,302,570	14,691,257	15,202,473	13,562,851
2025	16,776,035	15,114,311	13,971,770	14,088,252
2026	17,313,242	15,314,894	14,419,311	14,531,944
2027	17,758,936	15,730,180	14,842,328	14,962,493
2028	17,936,252	15,988,276	15,018,677	15,138,125
2029	18,028,887	16,184,628	15,170,665	15,397,857

Attachment F.1(c)(1) - Current Path Scenario

ANNUAL WATER USE CURRENT PATH SCENARIO (ACRE-FEET)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	54,747	54,747	54,747	54,747
2015	54,524	54,524	54,524	54,524
2016	54,944	54,944	53,664	53,610
2017	55,104	55,104	53,180	53,328
2018	56,425	55,804	54,410	51,436
2019	57,437	55,964	55,455	52,447
2020	57,355	55,420	55,346	52,303
2021	56,582	54,334	54,633	52,106
2022	57,523	56,260	55,718	53,022
2023	58,758	57,276	56,507	54,268
2024	60,132	57,875	57,732	55,051
2025	59,902	58,447	54,346	54,547
2026	60,387	60,282	54,383	54,611
2027	61,264	60,255	55,227	55,504
2028	62,986	61,595	56,954	57,189
2029	63,216	62,091	57,329	57,861

Attachment F.1(c)(2) - Gas Dominates Scenario

GAS DOMINATES SCENARIO: BASE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	463	463	464	464	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,084**	**8,420**	**7,770**	**7,550**	**7,550**	**6,943**	**6,454**	**6,446**	**6,433**	**6,426**	**6,426**	**6,427**	**6,410**	**6,411**	**6,412**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	261
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,507**	**1,610**	**1,663**	**1,744**	**1,821**	**1,899**	**1,983**
29	Natural Gas	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CCs/CTs	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,067**	**1,067**	**1,825**	**2,572**	**2,811**	**3,093**	**3,325**	**4,013**	**4,017**	**4,139**	**4,422**	**4,630**
37	TOTAL RESOURCES	9,340	9,467	9,012	9,033	9,479	9,630	9,945	10,331	10,668	11,033	11,361	12,102	12,188	12,371	12,732	13,025

ENERGY MIX
GAS DOMINATES SCENARIO: BASE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	9,942	8,679	3,182	2,509	33,609
2015	9,297	9,928	8,515	3,355	3,120	34,214
2016	9,325	10,450	8,371	3,492	3,764	35,401
2017	9,296	9,797	9,674	3,526	4,375	36,668
2018	9,297	9,873	10,193	3,566	4,951	37,880
2019	9,297	10,658	10,038	3,607	5,505	39,105
2020	9,325	10,965	9,725	3,934	6,071	40,020
2021	9,296	11,051	10,418	4,268	6,424	41,458
2022	9,297	11,278	10,905	4,656	6,563	42,700
2023	9,297	10,854	11,695	5,323	6,743	43,912
2024	9,324	11,636	11,512	5,706	6,931	45,108
2025	9,297	12,168	11,598	6,138	7,107	46,308
2026	9,297	12,434	12,276	6,230	7,281	47,517
2027	9,297	12,476	13,228	6,270	7,461	48,732
2028	9,325	12,439	13,640	6,915	7,655	49,973
2029	9,297	11,913	15,228	6,944	7,855	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	29.6%	25.8%	9.5%	7.5%	100.0%
2015	27.2%	29.0%	24.9%	9.8%	9.1%	100.0%
2016	26.3%	29.5%	23.6%	9.9%	10.6%	100.0%
2017	25.4%	26.7%	26.4%	9.6%	11.9%	100.0%
2018	24.5%	26.1%	26.9%	9.4%	13.1%	100.0%
2019	23.8%	27.3%	25.7%	9.2%	14.1%	100.0%
2020	23.3%	27.4%	24.3%	9.8%	15.2%	100.0%
2021	22.4%	26.7%	25.1%	10.3%	15.5%	100.0%
2022	21.8%	26.4%	25.5%	10.9%	15.4%	100.0%
2023	21.2%	24.7%	26.6%	12.1%	15.4%	100.0%
2024	20.7%	25.8%	25.5%	12.6%	15.4%	100.0%
2025	20.1%	26.3%	25.0%	13.3%	15.3%	100.0%
2026	19.6%	26.2%	25.8%	13.1%	15.3%	100.0%
2027	19.1%	25.6%	27.1%	12.9%	15.3%	100.0%
2028	18.7%	24.9%	27.3%	13.8%	15.3%	100.0%
2029	18.1%	23.3%	29.7%	13.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(2) - Gas Dominates Scenario

GAS DOMINATES SCENARIO: ENHANCED RENEWABLE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	470	464	464	443	426	414	403	403	388	382	380	380	363	364	364
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	397	389	384	384	363	346	333	322	323	320	314	313	313	313	314	314
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,167**	**9,085**	**8,421**	**7,771**	**7,530**	**7,513**	**6,903**	**6,412**	**6,413**	**6,397**	**6,391**	**6,390**	**6,390**	**6,373**	**6,373**	**6,374**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	96	107	116	130	154	179	201	222	235	243	251	259
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**860**	**1,010**	**1,176**	**1,303**	**1,410**	**1,505**	**1,608**	**1,661**	**1,742**	**1,819**	**1,896**	**1,981**
29	Natural Gas	0	0	0	500	1,010	1,010	1,612	2,316	2,520	2,622	2,928	3,132	3,336	4,001	4,001	4,001
30	CCs/CTs	0	0	0	500	1,010	1,010	1,612	2,316	2,520	2,622	2,928	3,132	3,336	4,001	4,001	4,001
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	150	200	226	255	337	426	448	478	561	584	667	675
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	150	200	226	255	262	276	298	310	318	326	334	342
35	Geothermal	0	0	0	0	0	0	0	0	75	150	150	150	225	225	300	300
36	**Total Future Resources**	0	32	57	557	1,160	1,210	1,838	2,571	2,857	3,048	3,376	3,610	3,897	4,585	4,668	4,676
37	TOTAL RESOURCES	9,341	9,468	9,013	9,035	9,551	9,733	9,917	10,286	10,680	10,950	11,375	11,660	12,028	12,777	12,938	13,031

ENERGY MIX
GAS DOMINATES SCENARIO: ENHANCED RENEWABLE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	9,942	8,679	3,182	2,509	33,609
2015	9,297	9,928	8,515	3,355	3,120	34,214
2016	9,325	10,450	8,371	3,492	3,764	35,401
2017	9,296	9,797	9,674	3,526	4,375	36,668
2018	9,297	9,813	9,695	4,124	4,951	37,880
2019	9,297	10,323	9,256	4,723	5,505	39,105
2020	9,325	10,708	8,583	5,332	6,071	40,020
2021	9,296	10,766	8,752	6,221	6,424	41,460
2022	9,297	10,914	9,003	6,921	6,563	42,700
2023	9,297	10,480	9,525	7,868	6,743	43,912
2024	9,324	11,137	8,901	8,816	6,931	45,108
2025	9,297	11,602	8,783	9,520	7,107	46,308
2026	9,297	11,661	9,075	10,203	7,281	47,517
2027	9,297	11,841	9,889	10,243	7,461	48,732
2028	9,325	11,796	10,300	10,897	7,655	49,973
2029	9,297	11,398	11,769	10,917	7,855	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	29.6%	25.8%	9.5%	7.5%	100.0%
2015	27.2%	29.0%	24.9%	9.8%	9.1%	100.0%
2016	26.3%	29.5%	23.6%	9.9%	10.6%	100.0%
2017	25.4%	26.7%	26.4%	9.6%	11.9%	100.0%
2018	24.5%	25.9%	25.6%	10.9%	13.1%	100.0%
2019	23.8%	26.4%	23.7%	12.1%	14.1%	100.0%
2020	23.3%	26.8%	21.4%	13.3%	15.2%	100.0%
2021	22.4%	26.0%	21.1%	15.0%	15.5%	100.0%
2022	21.8%	25.6%	21.1%	16.2%	15.4%	100.0%
2023	21.2%	23.9%	21.7%	17.9%	15.4%	100.0%
2024	20.7%	24.7%	19.7%	19.5%	15.4%	100.0%
2025	20.1%	25.1%	19.0%	20.6%	15.3%	100.0%
2026	19.6%	24.5%	19.1%	21.5%	15.3%	100.0%
2027	19.1%	24.3%	20.3%	21.0%	15.3%	100.0%
2028	18.7%	23.6%	20.6%	21.8%	15.3%	100.0%
2029	18.1%	22.2%	23.0%	21.3%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(2) - Gas Dominates Scenario

GAS DOMINATES SCENARIO: COAL REDUCTION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	469	464	464	464	464	453	444	436	417	409	410	411	395	396	390
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	364	356	349	342	343	344	345	346	340
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,085**	**8,160**	**7,510**	**7,290**	**7,290**	**6,683**	**6,194**	**6,186**	**6,166**	**6,159**	**5,773**	**5,774**	**5,757**	**5,759**	**5,753**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	260
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,506**	**1,610**	**1,663**	**1,744**	**1,821**	**1,898**	**1,983**
29	Natural Gas	0	0	0	704	1,214	1,214	2,020	2,622	2,826	3,030	3,234	3,899	4,103	4,409	4,613	4,817
30	CCs/CTs	0	0	0	704	1,214	1,214	2,020	2,622	2,826	3,030	3,234	3,899	4,103	4,409	4,613	4,817
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	295	314	338	345	366	448	467
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	220	239	245	252	258	264	283
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**761**	**1,271**	**1,271**	**2,131**	**2,776**	**3,015**	**3,325**	**3,548**	**4,237**	**4,448**	**4,775**	**5,061**	**5,284**
37	**TOTAL RESOURCES**	**9,340**	**9,467**	**8,752**	**8,978**	**9,423**	**9,574**	**9,992**	**10,275**	**10,613**	**10,997**	**11,317**	**11,673**	**11,965**	**12,354**	**12,718**	**13,019**

ENERGY MIX
GAS DOMINATES SCENARIO: COAL REDUCTION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	9,942	8,679	3,182	2,509	33,609
2015	9,297	9,928	8,515	3,355	3,120	34,214
2016	9,325	9,675	9,146	3,492	3,764	35,401
2017	9,296	8,541	10,930	3,526	4,375	36,668
2018	9,297	8,712	11,354	3,566	4,951	37,880
2019	9,297	9,497	11,198	3,607	5,505	39,105
2020	9,325	9,730	10,960	3,934	6,071	40,020
2021	9,296	9,714	11,755	4,268	6,424	41,457
2022	9,297	10,057	12,126	4,656	6,563	42,700
2023	9,297	9,532	12,738	5,602	6,743	43,912
2024	9,324	10,251	12,617	5,986	6,931	45,108
2025	9,297	8,767	14,720	6,417	7,107	46,308
2026	9,297	8,831	15,599	6,509	7,281	47,517
2027	9,297	8,794	16,631	6,549	7,461	48,732
2028	9,325	8,765	17,034	7,194	7,655	49,973
2029	9,297	8,376	18,206	7,502	7,855	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	29.6%	25.8%	9.5%	7.5%	100.0%
2015	27.2%	29.0%	24.9%	9.8%	9.1%	100.0%
2016	26.3%	27.3%	25.8%	9.9%	10.6%	100.0%
2017	25.4%	23.3%	29.8%	9.6%	11.9%	100.0%
2018	24.5%	23.0%	30.0%	9.4%	13.1%	100.0%
2019	23.8%	24.3%	28.6%	9.2%	14.1%	100.0%
2020	23.3%	24.3%	27.4%	9.8%	15.2%	100.0%
2021	22.4%	23.4%	28.4%	10.3%	15.5%	100.0%
2022	21.8%	23.6%	28.4%	10.9%	15.4%	100.0%
2023	21.2%	21.7%	29.0%	12.8%	15.4%	100.0%
2024	20.7%	22.7%	28.0%	13.3%	15.4%	100.0%
2025	20.1%	18.9%	31.8%	13.9%	15.3%	100.0%
2026	19.6%	18.6%	32.8%	13.7%	15.3%	100.0%
2027	19.1%	18.0%	34.1%	13.4%	15.3%	100.0%
2028	18.7%	17.5%	34.1%	14.4%	15.3%	100.0%
2029	18.1%	16.3%	35.5%	14.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(2) - Gas Dominates Scenario

GAS DOMINATES SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	5,139	4,489	4,656	4,656	4,059	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,514	1,514	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	463	463	464	464	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,084**	**8,420**	**7,770**	**7,550**	**7,550**	**6,943**	**6,454**	**6,446**	**6,433**	**6,426**	**6,426**	**6,427**	**6,410**	**6,411**	**6,412**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	261
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,507**	**1,610**	**1,663**	**1,744**	**1,821**	**1,899**	**1,983**
29	Natural Gas	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CCs/CTs	0	0	0	500	1,010	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,067**	**1,067**	**1,825**	**2,572**	**2,811**	**3,093**	**3,325**	**4,013**	**4,017**	**4,139**	**4,422**	**4,630**
37	**TOTAL RESOURCES**	**9,340**	**9,467**	**9,012**	**9,033**	**9,479**	**9,630**	**9,945**	**10,331**	**10,668**	**11,033**	**11,361**	**12,102**	**12,188**	**12,371**	**12,732**	**13,025**

ENERGY MIX
GAS DOMINATES SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	9,942	8,679	3,182	2,509	33,609
2015	9,297	9,928	8,515	3,355	3,120	34,214
2016	9,325	9,642	9,179	3,492	3,764	35,401
2017	9,296	8,614	10,856	3,526	4,375	36,668
2018	9,297	6,892	13,173	3,566	4,951	37,879
2019	9,297	7,589	13,106	3,607	5,505	39,105
2020	9,325	7,684	13,006	3,934	6,071	40,020
2021	9,296	7,709	13,756	4,268	6,424	41,454
2022	9,297	7,994	14,187	4,656	6,563	42,698
2023	9,297	7,652	14,898	5,323	6,743	43,912
2024	9,324	8,116	15,032	5,706	6,931	45,108
2025	9,297	8,782	14,984	6,138	7,107	46,308
2026	9,297	8,835	15,875	6,230	7,281	47,517
2027	9,297	8,815	16,889	6,270	7,461	48,732
2028	9,325	8,768	17,310	6,915	7,655	49,973
2029	9,297	8,364	18,777	6,944	7,855	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	29.6%	25.8%	9.5%	7.5%	100.0%
2015	27.2%	29.0%	24.9%	9.8%	9.1%	100.0%
2016	26.3%	27.2%	25.9%	9.9%	10.6%	100.0%
2017	25.4%	23.5%	29.6%	9.6%	11.9%	100.0%
2018	24.5%	18.2%	34.8%	9.4%	13.1%	100.0%
2019	23.8%	19.4%	33.5%	9.2%	14.1%	100.0%
2020	23.3%	19.2%	32.5%	9.8%	15.2%	100.0%
2021	22.4%	18.6%	33.2%	10.3%	15.5%	100.0%
2022	21.8%	18.7%	33.2%	10.9%	15.4%	100.0%
2023	21.2%	17.4%	33.9%	12.1%	15.4%	100.0%
2024	20.7%	18.0%	33.3%	12.6%	15.4%	100.0%
2025	20.1%	19.0%	32.4%	13.3%	15.3%	100.0%
2026	19.6%	18.6%	33.4%	13.1%	15.3%	100.0%
2027	19.1%	18.1%	34.7%	12.9%	15.3%	100.0%
2028	18.7%	17.5%	34.6%	13.8%	15.3%	100.0%
2029	18.1%	16.3%	36.6%	13.6%	15.3%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(2) - Gas Dominates Scenario

TOTAL REVENUE REQUIREMENTS GAS DOMINTES SCENARIO ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	2,202.7	2,202.7	2,201.1	2,202.0
2015	2,290.9	2,290.9	2,276.7	2,289.6
2016	2,274.6	2,274.6	2,237.8	2,278.0
2017	2,459.0	2,459.0	2,466.0	2,476.9
2018	2,676.5	2,710.4	2,665.1	2,665.5
2019	2,756.3	2,852.7	2,743.8	2,746.6
2020	2,907.3	3,026.8	2,900.9	2,889.0
2021	3,183.8	3,319.3	3,169.0	3,165.5
2022	3,341.2	3,497.2	3,311.5	3,329.6
2023	3,585.7	3,733.8	3,559.8	3,559.8
2024	3,730.8	3,908.1	3,692.8	3,714.1
2025	3,933.8	4,071.3	3,879.9	3,893.6
2026	4,100.9	4,243.4	4,045.5	4,031.9
2027	4,181.5	4,457.2	4,191.8	4,114.5
2028	4,317.1	4,596.5	4,361.1	4,263.0
2029	4,506.1	4,691.0	4,534.4	4,439.1
2030	4,687.6	4,818.3	4,724.0	4,627.7
2031	4,789.3	4,904.5	4,840.8	4,746.7
2032	4,958.1	5,077.9	4,986.2	4,894.6
2033	5,127.9	5,240.7	5,166.2	5,062.8
2034	5,311.4	5,430.5	5,389.5	5,274.2
2035	5,594.7	5,714.0	5,643.2	5,546.5
2036	5,830.5	5,924.5	5,856.9	5,774.8
2037	6,018.6	6,100.2	6,076.4	5,981.8
2038	6,371.8	6,446.3	6,389.4	6,319.4
2039	6,659.3	6,724.4	6,676.5	6,594.3
2040	7,083.5	7,138.9	7,114.1	7,048.1
2041	7,421.1	7,444.3	7,413.3	7,368.8
2042	7,731.4	7,748.8	7,731.2	7,686.0
2043	7,930.2	7,929.6	7,951.4	7,907.0
(2014-2029)	28,340.1	29,199.4	28,209.3	28,180.0
(2014-2043)	44,876.3	45,994.3	44,845.3	44,573.4

Attachment F.1(c)(2) - Gas Dominates Scenario

TOTAL REVENUE REQUIREMENTS: GAS DOMINTES SCENARIO
BASE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.6	432.4	44.8	412.0	19.5	1,534.3	110.5	345.4	455.9	(2.0)	63.2	23.9	(0.1)	127.3	2,202.7	72.0
2015	634.0	432.8	44.2	441.6	42.1	1,594.6	111.2	364.3	475.5	(0.4)	64.8	21.3	(0.1)	135.1	2,290.9	75.0
2016	687.2	419.8	49.2	376.8	65.7	1,598.7	105.8	350.6	456.4	(0.9)	66.4	18.5	(0.1)	135.6	2,274.6	73.3
2017	807.2	515.6	60.3	389.0	75.5	1,847.6	94.8	293.4	388.3	(2.4)	84.9	15.5	(0.1)	125.1	2,459.0	77.8
2018	996.8	596.5	66.7	397.9	76.0	2,133.9	62.1	274.2	336.3	(2.3)	72.6	13.6	(0.1)	122.5	2,676.5	83.1
2019	1,039.6	620.7	70.2	406.3	73.9	2,210.8	62.3	280.9	343.2	(2.4)	74.4	11.7	(0.1)	118.7	2,756.3	83.9
2020	1,207.4	694.5	80.4	408.8	72.6	2,463.7	6.0	231.1	237.1	(2.5)	73.3	9.6	(0.1)	126.2	2,907.3	87.0
2021	1,413.7	751.4	88.9	441.1	71.1	2,766.2	5.8	234.0	239.8	0.0	107.9	9.2	(0.1)	60.7	3,183.8	93.0
2022	1,500.0	807.4	95.4	445.0	71.8	2,919.7	6.5	233.3	239.7	0.0	102.1	8.9	(0.1)	70.8	3,341.2	94.9
2023	1,655.3	869.1	99.9	454.4	70.3	3,149.1	6.4	228.7	235.2	0.0	115.8	8.4	(0.1)	77.2	3,585.7	99.3
2024	1,744.6	913.6	106.3	460.7	68.7	3,293.9	7.2	227.1	234.3	0.0	118.4	8.1	(0.1)	76.2	3,730.8	100.9
2025	1,887.6	958.9	113.9	465.3	71.4	3,497.1	8.1	230.0	238.1	0.0	116.3	7.7	(0.1)	74.6	3,933.8	104.0
2026	1,936.9	1,015.7	120.3	492.9	72.7	3,638.6	8.1	233.1	241.2	0.0	138.6	7.2	(0.1)	75.3	4,100.9	105.8
2027	1,935.1	1,076.4	127.8	512.3	72.0	3,723.7	8.1	220.1	228.1	0.0	142.9	6.8	(0.1)	80.0	4,181.5	105.1
2028	1,997.7	1,118.7	133.9	524.1	70.2	3,844.6	8.1	223.7	231.7	0.0	149.8	6.4	(0.1)	84.5	4,317.1	105.9
2029	2,040.8	1,190.9	141.7	554.7	71.6	3,999.8	8.1	226.3	234.4	0.0	178.4	6.1	(0.1)	87.6	4,506.1	107.8
2030	2,071.9	1,279.9	150.7	560.6	71.1	4,134.2	8.1	221.9	229.9	0.0	229.8	5.7	(0.1)	88.1	4,687.6	109.5
2031	2,138.0	1,332.7	158.4	568.5	70.5	4,268.0	8.0	224.4	232.4	0.0	196.9	5.3	(0.1)	86.8	4,789.3	109.2
2032	2,186.8	1,408.1	167.2	575.4	69.6	4,407.1	8.1	227.3	235.4	0.0	229.4	4.9	(0.1)	81.5	4,958.1	110.3
2033	2,246.7	1,491.3	177.1	594.7	68.7	4,578.5	8.0	228.4	236.4	0.0	228.7	4.5	(0.1)	79.9	5,127.9	111.4
2034	2,315.9	1,570.0	187.4	610.9	68.0	4,752.1	8.7	231.7	240.4	0.0	236.1	4.0	(0.1)	78.8	5,311.4	112.5
2035	2,387.6	1,656.5	198.6	653.3	82.5	4,978.4	9.0	235.2	244.2	0.0	289.5	3.6	(0.1)	79.1	5,594.7	115.5
2036	2,446.7	1,758.5	210.8	665.6	107.7	5,189.3	9.4	238.8	248.1	0.0	310.8	3.1	(0.1)	79.3	5,830.5	117.3
2037	2,522.9	1,835.4	222.5	658.9	121.8	5,361.5	9.8	222.9	232.7	0.0	342.7	2.6	(0.1)	79.2	6,018.6	118.4
2038	2,626.4	1,935.4	238.3	725.5	141.0	5,666.6	10.0	214.7	224.7	0.0	402.5	2.2	(0.1)	75.9	6,371.8	122.5
2039	2,830.9	2,039.0	266.1	593.5	184.5	5,914.0	10.5	210.1	220.6	0.0	447.6	1.7	(0.1)	75.5	6,659.3	125.1
2040	3,085.7	2,142.1	283.2	575.1	227.0	6,313.1	10.7	203.5	214.2	0.0	480.2	1.4	(0.1)	74.7	7,083.5	129.9
2041	3,198.4	2,243.7	297.3	621.3	262.2	6,622.9	11.2	206.3	217.5	0.0	506.1	1.0	(0.1)	73.7	7,421.1	133.4
2042	3,309.5	2,347.3	312.9	654.3	274.1	6,898.1	11.7	205.3	217.0	0.0	543.4	0.7	(0.1)	72.4	7,731.4	136.0
2043	3,376.1	2,458.0	328.7	650.3	291.8	7,104.9	12.5	173.2	185.8	0.0	568.6	0.3	(0.1)	70.7	7,930.2	136.6
(2014-2029)	11,396.5	6,510.2	750.3	4,063.4	594.5	23,314.9	474.8	2,576.3	3,051.0	(9.4)	880.4	121.9	(0.7)	982.0	28,340.1	
(2014-2043)	18,526.4	11,396.4	1,355.4	5,811.2	950.5	38,040.0	501.2	3,202.7	3,703.9	(9.4)	1,803.2	131.5	(1.0)	1,208.0	44,876.3	

Attachment F.1(c)(2) - Gas Dominates Scenario

TOTAL REVENUE REQUIREMENTS: GAS DOMINTES SCENARIO
ENHANCED RENEWABLE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.6	432.4	44.8	412.0	19.5	1,534.3	110.5	345.4	455.9	(2.0)	63.2	23.9	(0.1)	127.3	2,202.7	72.0
2015	634.0	432.8	44.2	441.6	42.1	1,594.6	111.2	364.3	475.5	(0.4)	64.8	21.3	(0.1)	135.1	2,290.9	75.0
2016	687.2	419.8	49.2	376.8	65.7	1,598.7	105.8	350.6	456.4	(0.9)	66.4	18.5	(0.1)	135.6	2,274.6	73.3
2017	807.2	515.6	60.3	389.0	75.5	1,847.6	94.8	293.4	388.3	(2.4)	84.9	15.5	(0.1)	125.1	2,459.0	77.8
2018	1,038.8	584.4	66.2	403.5	76.0	2,168.9	63.5	273.7	337.2	(2.3)	70.6	13.6	(0.1)	122.5	2,710.4	84.2
2019	1,148.0	596.7	70.7	417.8	73.9	2,307.0	65.1	280.1	345.1	(2.4)	72.6	11.7	(0.1)	118.7	2,852.7	86.9
2020	1,338.6	662.4	83.0	423.1	72.6	2,579.7	9.5	231.1	240.6	(2.5)	73.3	9.6	(0.1)	126.2	3,026.8	90.6
2021	1,574.8	704.9	94.1	461.5	71.1	2,906.5	10.7	231.9	242.6	0.0	100.3	9.2	(0.1)	60.7	3,319.3	97.0
2022	1,694.4	748.4	97.9	470.6	71.8	3,083.2	10.6	233.1	243.7	0.0	90.6	8.9	(0.1)	70.8	3,497.2	99.3
2023	1,849.4	799.8	102.8	483.4	70.3	3,305.7	11.3	228.7	240.1	0.0	102.5	8.4	(0.1)	77.2	3,733.8	103.4
2024	1,979.9	825.8	111.4	497.0	68.7	3,482.9	13.4	227.1	240.6	0.0	100.4	8.1	(0.1)	76.2	3,908.1	105.7
2025	2,091.1	864.3	115.7	504.3	67.1	3,642.5	15.1	230.0	245.1	0.0	101.6	7.7	(0.1)	74.6	4,071.3	107.6
2026	2,166.7	900.7	118.6	541.1	65.4	3,792.5	15.1	233.1	248.2	0.0	120.2	7.2	(0.1)	75.3	4,243.4	109.4
2027	2,299.2	951.9	128.0	564.7	68.4	4,012.2	15.1	220.1	235.1	0.0	123.1	6.8	(0.1)	80.0	4,457.2	112.1
2028	2,370.1	990.3	132.8	578.6	69.8	4,141.7	15.1	223.7	238.7	0.0	125.2	6.4	(0.1)	84.5	4,596.5	112.7
2029	2,327.7	1,057.1	141.3	609.0	71.4	4,206.4	15.0	226.3	241.4	0.0	149.7	6.1	(0.1)	87.6	4,691.0	112.3
2030	2,318.6	1,135.2	150.2	615.5	70.8	4,290.3	15.0	221.4	236.4	0.0	197.8	5.7	(0.1)	88.1	4,818.3	112.5
2031	2,375.3	1,184.4	157.0	624.7	70.3	4,411.7	15.0	224.4	239.4	0.0	161.3	5.3	(0.1)	86.8	4,904.5	111.8
2032	2,416.4	1,256.1	164.9	633.1	83.4	4,553.8	15.0	227.3	242.4	0.0	195.5	4.9	(0.1)	81.5	5,077.9	113.0
2033	2,469.7	1,329.4	174.7	653.8	91.8	4,719.5	15.0	228.4	243.4	0.0	193.6	4.5	(0.1)	79.9	5,240.7	113.9
2034	2,532.2	1,404.3	184.5	671.4	109.0	4,901.5	15.7	231.7	247.4	0.0	198.8	4.0	(0.1)	78.8	5,430.5	115.0
2035	2,597.2	1,489.9	193.9	715.4	132.5	5,128.8	16.0	235.2	251.2	0.0	251.4	3.6	(0.1)	79.1	5,714.0	118.0
2036	2,649.4	1,584.4	205.2	729.2	145.3	5,313.4	16.4	238.8	255.1	0.0	273.7	3.1	(0.1)	79.3	5,924.5	119.2
2037	2,718.4	1,654.7	216.6	724.1	163.2	5,477.0	16.7	222.9	239.6	0.0	301.9	2.6	(0.1)	79.2	6,100.2	120.0
2038	2,814.6	1,754.6	228.8	792.3	187.6	5,777.9	17.0	214.7	231.7	0.0	358.8	2.2	(0.1)	75.9	6,446.3	123.9
2039	3,011.7	1,851.8	251.8	661.9	234.5	6,011.8	17.5	210.1	227.6	0.0	408.0	1.7	(0.1)	75.5	6,724.4	126.3
2040	3,259.5	1,952.2	269.1	645.2	275.5	6,401.7	17.7	203.5	221.2	0.0	440.0	1.4	(0.1)	74.7	7,138.9	130.9
2041	3,366.2	2,049.5	282.1	693.2	292.0	6,683.1	18.2	206.3	224.4	0.0	462.1	1.0	(0.1)	73.7	7,444.3	133.8
2042	3,471.9	2,148.1	295.5	728.0	308.6	6,952.2	18.7	205.3	224.0	0.0	499.7	0.7	(0.1)	72.4	7,748.8	136.3
2043	3,521.3	2,252.5	308.9	725.9	332.2	7,140.8	19.5	173.2	192.8	0.0	525.1	0.3	(0.1)	70.7	7,929.6	136.6
(2014-2029)	12,525.4	6,108.5	759.6	4,233.8	588.1	24,215.4	503.4	2,574.0	3,077.4	(9.4)	812.8	121.9	(0.7)	982.0	29,199.4	
(2014-2043)	20,242.1	10,512.0	1,345.9	6,160.4	1,026.8	39,287.2	549.7	3,200.3	3,750.0	(9.4)	1,627.9	131.5	(1.0)	1,208.0	45,994.3	

Attachment F.1(c)(2) - Gas Dominates Scenario

TOTAL REVENUE REQUIREMENTS: GAS DOMINTES SCENARIO
COAL REDUCTION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	624.1	432.4	44.8	412.0	19.5	1,532.8	110.5	345.4	455.9	(2.0)	63.2	23.9	(0.1)	127.3	2,201.1	72.0
2015	629.9	432.8	44.2	431.5	42.1	1,580.5	111.2	364.3	475.5	(0.4)	64.8	21.3	(0.1)	135.1	2,276.7	74.5
2016	660.1	420.0	47.7	363.5	65.7	1,557.0	105.8	354.1	459.9	(0.9)	67.7	18.5	(0.1)	135.6	2,237.8	72.1
2017	810.5	517.5	59.3	379.6	76.1	1,843.0	94.8	297.7	392.6	(2.4)	92.3	15.5	(0.1)	125.1	2,466.0	78.0
2018	982.6	598.6	66.1	387.5	77.0	2,111.8	62.1	274.5	336.6	(2.3)	82.9	13.6	(0.1)	122.5	2,665.1	82.7
2019	1,023.8	622.8	69.3	395.8	75.0	2,186.7	62.3	281.5	343.8	(2.4)	85.4	11.7	(0.1)	118.7	2,743.8	83.6
2020	1,202.4	698.7	79.7	399.1	73.2	2,453.0	6.0	231.1	237.1	(2.5)	77.6	9.6	(0.1)	126.2	2,900.9	86.8
2021	1,398.8	758.6	88.4	423.5	71.5	2,740.7	5.8	234.5	240.3	0.0	118.1	9.2	(0.1)	60.7	3,169.0	92.6
2022	1,467.7	814.4	94.5	433.3	71.8	2,881.7	6.5	233.3	239.8	0.0	110.4	8.9	(0.1)	70.8	3,311.5	94.1
2023	1,631.6	867.1	100.6	443.2	70.1	3,112.6	7.1	228.7	235.9	0.0	125.7	8.4	(0.1)	77.2	3,559.8	98.6
2024	1,722.9	911.8	106.5	430.5	68.5	3,240.3	7.8	227.1	235.0	0.0	133.3	8.1	(0.1)	76.2	3,692.8	99.9
2025	1,859.2	949.5	113.1	410.0	71.2	3,403.0	8.8	230.0	238.8	0.0	155.9	7.7	(0.1)	74.6	3,879.9	102.5
2026	1,939.9	1,006.3	119.2	417.0	73.2	3,555.5	8.8	233.1	241.9	0.0	165.5	7.2	(0.1)	75.3	4,045.5	104.3
2027	1,996.5	1,066.6	126.0	439.6	73.4	3,702.2	8.8	220.1	228.8	0.0	174.0	6.8	(0.1)	80.0	4,191.8	105.4
2028	2,079.5	1,108.4	131.7	466.3	72.5	3,858.4	8.8	223.7	232.4	0.0	179.4	6.4	(0.1)	84.5	4,361.1	107.0
2029	2,132.8	1,167.5	140.0	483.7	73.6	3,997.7	9.5	226.3	235.8	0.0	207.4	6.1	(0.1)	87.6	4,534.4	108.5
2030	2,167.3	1,251.7	148.2	483.4	72.7	4,123.3	9.4	221.2	230.6	0.0	276.4	5.7	(0.1)	88.1	4,724.0	110.3
2031	2,227.4	1,310.4	156.0	508.8	71.7	4,274.3	9.4	224.4	233.8	0.0	240.7	5.3	(0.1)	86.8	4,840.8	110.4
2032	2,270.1	1,385.8	164.2	490.9	84.7	4,395.6	9.5	227.3	236.8	0.0	267.6	4.9	(0.1)	81.5	4,986.2	111.0
2033	2,326.2	1,468.0	173.3	512.3	93.0	4,572.7	9.4	228.4	237.8	0.0	271.4	4.5	(0.1)	79.9	5,166.2	112.3
2034	2,391.7	1,547.0	183.5	547.4	110.1	4,779.7	10.1	231.7	241.8	0.0	285.3	4.0	(0.1)	78.8	5,389.5	114.1
2035	2,459.2	1,632.4	193.7	571.7	118.7	4,975.7	10.4	235.2	245.6	0.0	339.3	3.6	(0.1)	79.1	5,643.2	116.5
2036	2,515.9	1,725.3	206.0	577.9	136.7	5,161.7	10.8	238.8	249.5	0.0	363.4	3.1	(0.1)	79.3	5,856.9	117.8
2037	2,586.7	1,810.5	217.8	591.7	161.1	5,367.7	11.2	222.9	234.0	0.0	393.0	2.6	(0.1)	79.2	6,076.4	119.5
2038	2,678.0	1,910.0	232.8	630.4	174.1	5,625.3	11.4	214.7	226.1	0.0	460.0	2.2	(0.1)	75.9	6,389.4	122.8
2039	2,869.5	2,014.6	260.9	502.8	226.6	5,874.4	11.9	210.1	222.0	0.0	503.1	1.7	(0.1)	75.5	6,676.5	125.4
2040	3,121.4	2,116.6	278.7	505.6	257.6	6,279.9	12.1	203.5	215.6	0.0	542.7	1.4	(0.1)	74.7	7,114.1	130.5
2041	3,229.2	2,218.5	292.5	530.3	285.2	6,555.7	12.6	206.3	218.9	0.0	564.1	1.0	(0.2)	73.7	7,413.3	133.2
2042	3,337.6	2,321.8	308.0	555.0	308.1	6,830.4	13.1	205.3	218.4	0.0	609.5	0.7	(0.2)	72.4	7,731.2	136.0
2043	3,404.0	2,432.8	324.1	575.1	318.5	7,054.4	13.9	173.2	187.2	0.0	638.9	0.3	(0.2)	70.7	7,951.4	137.0
(2014-2029)	11,371.9	6,500.2	743.6	3,854.6	598.9	23,069.2	477.0	2,583.3	3,060.3	(9.4)	986.0	121.9	(0.7)	982.0	28,209.3	
(2014-2043)	18,690.2	11,315.2	1,337.3	5,377.9	1,025.2	37,745.9	507.4	3,209.5	3,716.9	(9.4)	2,053.4	131.5	(1.0)	1,208.0	44,845.3	

Attachment F.1(c)(2) - Gas Dominates Scenario

TOTAL REVENUE REQUIREMENTS: GAS DOMINTES SCENARIO
COAL-TO-GAS CONVERSION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.0	432.4	44.8	411.9	19.5	1,533.6	110.5	345.4	455.9	(2.0)	63.2	23.9	(0.1)	127.3	2,202.0	72.0
2015	632.7	432.8	44.2	441.6	42.1	1,593.4	111.2	364.3	475.5	(0.4)	64.8	21.3	(0.1)	135.1	2,289.6	74.9
2016	684.5	420.1	47.7	379.2	65.7	1,597.1	105.8	354.2	459.9	(0.9)	67.7	18.5	(0.1)	135.6	2,278.0	73.4
2017	813.9	518.1	59.6	391.1	75.5	1,858.3	94.8	297.1	392.0	(2.4)	88.4	15.5	(0.1)	125.1	2,476.9	78.4
2018	967.0	604.5	65.1	370.6	76.0	2,083.2	62.1	276.1	338.2	(2.3)	110.4	13.6	(0.1)	122.5	2,665.5	82.8
2019	1,009.7	632.7	68.5	383.3	73.9	2,168.2	62.3	281.9	344.2	(2.4)	106.3	11.7	(0.1)	118.7	2,746.6	83.7
2020	1,175.3	709.7	78.6	381.6	72.6	2,417.7	6.0	231.1	237.1	(2.5)	100.9	9.6	(0.1)	126.2	2,889.0	86.4
2021	1,378.7	770.7	88.2	403.8	71.1	2,712.5	5.8	237.7	243.4	0.0	139.6	9.2	(0.1)	60.7	3,165.5	92.5
2022	1,462.8	828.5	94.4	417.2	71.8	2,874.8	6.5	235.3	241.7	0.0	133.5	8.9	(0.1)	70.8	3,329.6	94.6
2023	1,614.1	886.7	99.2	421.4	70.3	3,091.7	6.4	228.7	235.2	0.0	147.3	8.4	(0.1)	77.2	3,559.8	98.6
2024	1,703.3	935.0	104.8	421.2	68.7	3,233.0	7.2	227.1	234.3	0.0	162.6	8.1	(0.1)	76.2	3,714.1	100.5
2025	1,846.5	959.2	112.1	425.5	71.4	3,414.7	8.1	230.0	238.1	0.0	158.5	7.7	(0.1)	74.6	3,893.6	102.9
2026	1,894.7	1,016.5	118.7	436.5	72.7	3,539.1	8.1	233.1	241.2	0.0	169.1	7.2	(0.1)	75.3	4,031.9	104.0
2027	1,892.8	1,077.6	125.9	453.8	72.0	3,622.1	8.1	220.1	228.1	0.0	177.6	6.8	(0.1)	80.0	4,114.5	103.5
2028	1,955.0	1,119.4	131.5	479.9	70.2	3,755.9	8.1	223.7	231.7	0.0	184.4	6.4	(0.1)	84.5	4,263.0	104.6
2029	1,997.5	1,189.7	139.4	497.0	71.6	3,895.2	8.1	226.3	234.4	0.0	215.9	6.1	(0.1)	87.6	4,439.1	106.2
2030	2,028.9	1,274.7	148.0	500.6	71.1	4,023.4	8.1	223.6	231.6	0.0	279.0	5.7	(0.1)	88.1	4,627.7	108.1
2031	2,096.2	1,332.4	155.5	519.4	70.5	4,174.0	8.0	224.4	232.4	0.0	248.3	5.3	(0.1)	86.8	4,746.7	108.2
2032	2,146.0	1,409.3	164.0	507.0	69.6	4,295.9	8.1	227.3	235.4	0.0	277.1	4.9	(0.1)	81.5	4,894.6	108.9
2033	2,207.4	1,491.4	173.9	524.0	68.7	4,465.4	8.0	228.4	236.4	0.0	276.7	4.5	(0.1)	79.9	5,062.8	110.0
2034	2,278.5	1,570.1	184.0	558.9	68.0	4,659.5	8.7	231.7	240.4	0.0	291.5	4.0	(0.1)	78.8	5,274.2	111.7
2035	2,351.2	1,656.4	194.9	587.2	82.5	4,872.2	9.0	235.2	244.2	0.0	347.5	3.6	(0.1)	79.1	5,546.5	114.5
2036	2,411.8	1,750.5	206.9	597.9	107.7	5,074.9	9.4	238.8	248.1	0.0	369.5	3.1	(0.1)	79.3	5,774.8	116.2
2037	2,487.4	1,835.7	219.0	604.2	121.8	5,268.1	9.8	222.9	232.7	0.0	399.4	2.6	(0.1)	79.2	5,981.8	117.7
2038	2,584.2	1,935.6	234.6	649.2	141.0	5,544.7	10.0	214.7	224.7	0.0	472.0	2.2	(0.1)	75.9	6,319.4	121.4
2039	2,780.1	2,041.1	263.6	516.4	184.5	5,785.7	10.5	210.1	220.6	0.0	511.0	1.7	(0.1)	75.5	6,594.3	123.9
2040	3,037.3	2,143.7	281.2	518.9	227.0	6,208.1	10.7	203.5	214.2	0.0	549.9	1.4	(0.1)	74.7	7,048.1	129.3
2041	3,151.2	2,245.5	295.4	548.2	262.2	6,502.6	11.2	206.3	217.5	0.0	574.2	1.0	(0.2)	73.7	7,368.8	132.4
2042	3,263.6	2,350.2	311.2	578.2	274.1	6,777.3	11.7	205.3	217.0	0.0	618.8	0.7	(0.2)	72.4	7,686.0	135.2
2043	3,334.7	2,461.7	328.0	589.5	291.8	7,005.8	12.5	173.2	185.8	0.0	644.5	0.3	(0.2)	70.7	7,907.0	136.2
(2014-2029)	11,177.1	6,576.9	739.5	3,847.9	594.5	22,935.9	474.8	2,587.2	3,061.9	(9.4)	1,088.4	121.9	(0.7)	982.0	28,180.0	
(2014-2043)	18,189.8	11,462.1	1,336.4	5,414.2	950.5	37,352.9	501.2	3,214.1	3,715.4	(9.4)	2,176.1	131.5	(1.0)	1,208.0	44,573.4	

Attachment F.1(c)(2) - Gas Dominates Scenario

ANNUAL AVERAGE SYSTEM COST GAS DOMINATES SCENARIO - ($/MWh)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	72.0	72.0	72.0	72.0
2015	75.0	75.0	74.5	74.9
2016	73.3	73.3	72.1	73.4
2017	77.8	77.8	78.0	78.4
2018	83.1	84.2	82.7	82.8
2019	83.9	86.9	83.6	83.7
2020	87.0	90.6	86.8	86.4
2021	93.0	97.0	92.6	92.5
2022	94.9	99.3	94.1	94.6
2023	99.3	103.4	98.6	98.6
2024	100.9	105.7	99.9	100.5
2025	104.0	107.6	102.5	102.9
2026	105.8	109.4	104.3	104.0
2027	105.1	112.1	105.4	103.5
2028	105.9	112.7	107.0	104.6
2029	107.8	112.3	108.5	106.2

CUMULATIVE CAPITAL SPENDING EXISTING AND NEW GENERATION PLUS INCREMENTAL TRANSMISSION GAS DOMINATES SCENARIO - ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	1,211.7	1,211.7	1,201.4	1,207.7
2015	1,678.9	1,678.9	1,646.1	1,635.6
2016	2,400.4	2,513.0	2,388.3	2,368.6
2017	3,769.5	4,217.3	3,794.7	3,701.8
2018	4,222.1	5,041.0	4,154.4	4,052.4
2019	4,766.7	5,830.6	4,740.2	4,576.2
2020	6,225.0	7,633.8	6,151.0	6,016.7
2021	7,916.5	9,473.5	7,802.3	7,685.7
2022	8,786.2	10,517.2	8,739.5	8,539.1
2023	9,837.3	11,672.5	9,772.9	9,559.4
2024	11,025.1	13,037.6	10,933.2	10,739.0
2025	11,632.6	14,188.3	11,733.4	11,339.6
2026	12,391.8	15,734.0	12,815.7	12,084.6
2027	13,099.9	16,361.4	13,717.7	12,783.5
2028	13,874.0	16,781.1	14,592.7	13,546.7
2029	14,635.5	17,377.4	15,380.2	14,296.1

1. Capital investment projected is regardless of whether APS constructs and owns new generation resources or whether resources are purchased by APS under long-term PPAs with market participants.

2. Capital spending excludes: (a) financial commitments to energy efficiency and distributed energy initiatives; (b) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing.

3. Capital spending includes ongoing capital investment for existing owned generation.

Attachment F.1(c)(2) - Gas Dominates Scenario

ANNUAL NATURAL GAS BURNS GAS DOMINATES SCENARIO - (BCF)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	56.3	56.3	56.3	56.3
2015	55.3	55.3	55.3	55.3
2016	59.5	59.5	65.4	65.7
2017	72.8	72.8	82.4	81.9
2018	75.5	72.2	84.9	99.9
2019	74.2	69.1	83.5	99.2
2020	73.0	65.7	82.8	99.0
2021	79.2	68.3	89.8	105.6
2022	83.4	70.6	92.9	109.0
2023	90.0	75.7	98.4	115.2
2024	89.0	72.0	97.7	116.4
2025	89.7	72.4	114.0	115.9
2026	94.9	75.1	120.6	122.7
2027	101.9	80.1	128.3	130.3
2028	105.2	83.3	131.5	133.6
2029	117.2	93.9	140.5	144.9

ANNUAL CO2 EMISSIONS GAS DOMINATES SCENARIO - (METRIC TONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	12,668,753	12,668,753	12,668,753	12,668,753
2015	12,546,928	12,546,928	12,546,928	12,546,928
2016	13,162,672	13,162,672	12,682,567	12,663,916
2017	13,323,499	13,323,499	12,540,022	12,604,303
2018	13,567,823	13,315,649	12,853,105	11,464,945
2019	14,188,268	13,554,344	13,478,384	12,038,932
2020	14,439,157	13,753,206	13,682,674	12,113,319
2021	14,842,051	13,926,169	14,029,948	12,492,398
2022	15,293,066	14,202,177	14,542,414	12,937,868
2023	15,292,149	14,119,873	14,382,780	13,044,809
2024	15,984,867	14,526,262	15,027,949	13,486,005
2025	16,476,687	14,925,912	13,936,480	14,055,963
2026	17,018,197	15,124,454	14,352,435	14,469,170
2027	17,433,575	15,571,771	14,736,522	14,867,607
2028	17,604,745	15,741,599	14,903,726	15,025,505
2029	17,754,466	15,952,025	15,063,465	15,290,909

Attachment F.1(c)(2) - Gas Dominates Scenario

ANNUAL WATER USE GAS DOMINATES SCENARIO - (ACRE-FEET)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	52,913	52,913	52,913	52,913
2015	52,638	52,638	52,638	52,638
2016	53,171	53,171	52,247	52,208
2017	53,446	53,446	51,932	52,040
2018	53,991	53,400	52,616	50,465
2019	55,098	53,654	53,698	51,432
2020	55,263	53,664	53,737	51,192
2021	55,794	53,698	54,093	51,553
2022	56,746	55,653	55,169	52,488
2023	58,298	57,006	56,336	54,145
2024	59,605	57,691	57,547	55,028
2025	59,414	58,235	54,446	54,688
2026	60,119	60,060	54,703	54,947
2027	60,976	60,117	55,351	55,674
2028	62,724	61,419	57,060	57,311
2029	63,072	61,910	57,484	57,985

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

SUSTAINED HIGH GAS PRICE SCENARIO: BASE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	*Annual Load Growth %*		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	972	983	1,004	1,026	1,047	1,073	1,176	1,216	1,254	1,288	1,328	1,366	1,404	1,443	1,481
5	**Total Load Requirements**	**8,124**	**8,263**	**8,556**	**8,885**	**9,206**	**9,527**	**9,845**	**10,247**	**10,590**	**10,925**	**11,254**	**11,588**	**11,923**	**12,264**	**12,609**	**12,959**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	*Market / Call Options / Hedges /AG-1*	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	468	462	462	462	461	461	451	442	430	430	430	431	413	413	414
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	395	387	381	381	381	381	381	370	362	362	362	363	363	363	364	364
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,165**	**9,083**	**8,419**	**7,768**	**7,548**	**7,548**	**6,951**	**6,461**	**6,452**	**6,439**	**6,439**	**6,440**	**6,440**	**6,423**	**6,423**	**6,423**
22	Energy Efficiency	109	296	501	670	825	986	1,135	1,232	1,265	1,313	1,377	1,409	1,454	1,501	1,548	1,603
23	Distributed Energy	65	108	131	146	156	165	174	186	203	221	243	263	277	287	297	306
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	*Existing DR*	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**194**	**426**	**658**	**843**	**1,007**	**1,178**	**1,361**	**1,494**	**1,594**	**1,686**	**1,796**	**1,847**	**1,931**	**2,013**	**2,095**	**2,184**
29	Natural Gas	0	0	0	500	1,010	1,010	1,510	2,214	2,418	2,622	2,826	3,491	3,491	3,593	3,797	4,001
30	CCs/CTs	0	0	0	500	1,010	1,010	1,510	2,214	2,418	2,622	2,826	3,491	3,491	3,593	3,797	4,001
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	56	56	56	56	56	110	154	232	233	253	255	272	349	350
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	56	56	56	56	56	110	154	157	158	160	162	164	165	167
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**56**	**556**	**1,066**	**1,066**	**1,566**	**2,324**	**2,572**	**2,854**	**3,059**	**3,744**	**3,746**	**3,865**	**4,146**	**4,351**
37	**TOTAL RESOURCES**	**9,359**	**9,541**	**9,133**	**9,167**	**9,622**	**9,793**	**9,878**	**10,279**	**10,619**	**10,978**	**11,295**	**12,031**	**12,117**	**12,301**	**12,663**	**12,959**

ENERGY MIX
SUSTAINED HIGH GAS PRICE SCENARIO: BASE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	12,333	6,213	3,256	2,509	33,609
2015	9,297	12,332	5,805	3,535	3,246	34,214
2016	9,325	12,740	5,564	3,735	4,037	35,401
2017	9,296	12,100	6,776	3,807	4,689	36,668
2018	9,297	12,856	6,561	3,857	5,310	37,880
2019	9,297	13,341	6,617	3,907	5,943	39,105
2020	9,325	13,439	6,695	3,964	6,597	40,020
2021	9,296	13,179	7,691	4,308	6,982	41,457
2022	9,297	13,207	8,367	4,705	7,121	42,698
2023	9,297	12,275	9,631	5,395	7,314	43,912
2024	9,324	13,125	9,609	5,532	7,518	45,108
2025	9,297	13,442	9,866	5,999	7,704	46,308
2026	9,297	13,660	10,552	6,121	7,886	47,517
2027	9,297	13,753	11,414	6,189	8,078	48,732
2028	9,325	13,778	11,726	6,860	8,284	49,973
2029	9,297	13,164	13,361	6,916	8,498	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	36.7%	18.5%	9.7%	7.5%	100.0%
2015	27.2%	36.0%	17.0%	10.3%	9.5%	100.0%
2016	26.3%	36.0%	15.7%	10.6%	11.4%	100.0%
2017	25.4%	33.0%	18.5%	10.4%	12.8%	100.0%
2018	24.5%	33.9%	17.3%	10.2%	14.0%	100.0%
2019	23.8%	34.1%	16.9%	10.0%	15.2%	100.0%
2020	23.3%	33.6%	16.7%	9.9%	16.5%	100.0%
2021	22.4%	31.8%	18.6%	10.4%	16.8%	100.0%
2022	21.8%	30.9%	19.6%	11.0%	16.7%	100.0%
2023	21.2%	28.0%	21.9%	12.3%	16.7%	100.0%
2024	20.7%	29.1%	21.3%	12.3%	16.7%	100.0%
2025	20.1%	29.0%	21.3%	13.0%	16.6%	100.0%
2026	19.6%	28.7%	22.2%	12.9%	16.6%	100.0%
2027	19.1%	28.2%	23.4%	12.7%	16.6%	100.0%
2028	18.7%	27.6%	23.5%	13.7%	16.6%	100.0%
2029	18.1%	25.7%	26.1%	13.5%	16.6%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

SUSTAINED HIGH GAS PRICE SCENARIO: ENHANCED RENEWABLE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	972	983	1,004	1,026	1,047	1,073	1,176	1,216	1,254	1,288	1,328	1,366	1,404	1,443	1,481
5	**Total Load Requirements**	**8,124**	**8,263**	**8,556**	**8,885**	**9,206**	**9,527**	**9,845**	**10,247**	**10,590**	**10,925**	**11,254**	**11,588**	**11,923**	**12,264**	**12,609**	**12,959**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	469	463	463	463	442	425	408	408	392	384	382	383	365	366	366
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	397	388	383	382	382	361	344	327	328	325	316	315	315	316	316	317
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,167**	**9,085**	**8,420**	**7,770**	**7,550**	**7,529**	**6,914**	**6,417**	**6,418**	**6,402**	**6,393**	**6,392**	**6,392**	**6,375**	**6,375**	**6,376**
22	Energy Efficiency	109	296	501	670	825	986	1,135	1,232	1,265	1,313	1,377	1,409	1,454	1,501	1,548	1,603
23	Distributed Energy	65	109	131	146	156	164	172	183	201	219	241	261	274	284	294	303
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**194**	**426**	**658**	**843**	**1,007**	**1,177**	**1,359**	**1,491**	**1,592**	**1,683**	**1,793**	**1,844**	**1,928**	**2,010**	**2,092**	**2,181**
29	Natural Gas	0	0	0	500	1,010	1,010	1,510	2,112	2,316	2,520	2,724	2,928	3,132	3,797	3,797	3,797
30	CCs/CTs	0	0	0	500	1,010	1,010	1,510	2,112	2,316	2,520	2,724	2,928	3,132	3,797	3,797	3,797
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	150	200	237	319	408	433	464	547	570	652	660
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	150	200	237	244	258	283	296	304	311	319	327
35	Geothermal	0	0	0	0	0	0	0	0	75	150	150	150	225	225	300	300
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,067**	**1,160**	**1,710**	**2,349**	**2,635**	**2,928**	**3,157**	**3,392**	**3,679**	**4,367**	**4,449**	**4,457**
37	**TOTAL RESOURCES**	**9,361**	**9,543**	**9,135**	**9,169**	**9,624**	**9,866**	**9,983**	**10,257**	**10,645**	**11,013**	**11,344**	**11,628**	**11,999**	**12,751**	**12,917**	**13,014**

ENERGY MIX
SUSTAINED HIGH GAS PRICE SCENARIO: ENHANCED RENEWABLE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	12,333	6,213	3,256	2,509	33,609
2015	9,297	12,332	5,805	3,535	3,246	34,214
2016	9,325	12,740	5,564	3,735	4,037	35,401
2017	9,296	12,100	6,776	3,807	4,689	36,668
2018	9,297	12,856	6,561	3,857	5,310	37,880
2019	9,297	13,080	6,319	4,465	5,943	39,105
2020	9,325	12,939	6,077	5,083	6,597	40,020
2021	9,296	12,529	6,669	5,983	6,982	41,459
2022	9,297	12,556	7,033	6,692	7,121	42,700
2023	9,297	11,678	7,963	7,661	7,314	43,912
2024	9,324	12,158	7,466	8,642	7,518	45,108
2025	9,297	12,538	7,389	9,381	7,704	46,308
2026	9,297	12,555	7,685	10,094	7,886	47,517
2027	9,297	12,624	8,570	10,162	8,078	48,732
2028	9,325	12,698	8,824	10,842	8,284	49,973
2029	9,297	12,353	10,200	10,889	8,498	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	36.7%	18.5%	9.7%	7.5%	100.0%
2015	27.2%	36.0%	17.0%	10.3%	9.5%	100.0%
2016	26.3%	36.0%	15.7%	10.6%	11.4%	100.0%
2017	25.4%	33.0%	18.5%	10.4%	12.8%	100.0%
2018	24.5%	33.9%	17.3%	10.2%	14.0%	100.0%
2019	23.8%	33.4%	16.2%	11.4%	15.2%	100.0%
2020	23.3%	32.3%	15.2%	12.7%	16.5%	100.0%
2021	22.4%	30.2%	16.1%	14.4%	16.8%	100.0%
2022	21.8%	29.4%	16.5%	15.7%	16.7%	100.0%
2023	21.2%	26.6%	18.1%	17.4%	16.7%	100.0%
2024	20.7%	27.0%	16.6%	19.2%	16.7%	100.0%
2025	20.1%	27.1%	16.0%	20.3%	16.6%	100.0%
2026	19.6%	26.4%	16.2%	21.2%	16.6%	100.0%
2027	19.1%	25.9%	17.6%	20.9%	16.6%	100.0%
2028	18.7%	25.4%	17.7%	21.7%	16.6%	100.0%
2029	18.1%	24.1%	19.9%	21.3%	16.6%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

SUSTAINED HIGH GAS PRICE SCENARIO: COAL REDUCTION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	972	983	1,004	1,026	1,047	1,073	1,176	1,216	1,254	1,288	1,328	1,366	1,404	1,443	1,481
5	**Total Load Requirements**	**8,124**	**8,263**	**8,556**	**8,885**	**9,206**	**9,527**	**9,845**	**10,247**	**10,590**	**10,925**	**11,254**	**11,588**	**11,923**	**12,264**	**12,609**	**12,959**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	468	462	462	462	462	462	451	443	421	422	423	423	406	407	400
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	387	382	382	381	381	381	371	362	354	354	355	356	356	357	351
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,084**	**8,159**	**7,509**	**7,289**	**7,288**	**6,691**	**6,201**	**6,192**	**6,171**	**6,172**	**5,785**	**5,786**	**5,769**	**5,769**	**5,763**
22	Energy Efficiency	109	296	501	670	825	986	1,135	1,232	1,265	1,313	1,377	1,409	1,454	1,501	1,548	1,603
23	Distributed Energy	65	108	131	146	156	165	174	186	203	221	243	263	277	287	296	305
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**194**	**426**	**658**	**843**	**1,007**	**1,178**	**1,361**	**1,494**	**1,594**	**1,685**	**1,796**	**1,847**	**1,931**	**2,012**	**2,094**	**2,183**
29	Natural Gas	0	0	0	500	1,010	1,010	1,816	2,520	2,724	2,826	3,030	3,695	4,001	4,205	4,409	4,613
30	CCs/CTs	0	0	0	500	1,010	1,010	1,816	2,520	2,724	2,826	3,030	3,695	4,001	4,205	4,409	4,613
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	56	56	57	57	57	111	155	265	268	290	293	311	389	422
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	56	56	57	57	57	111	155	190	193	197	200	203	205	239
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**56**	**556**	**1,067**	**1,067**	**1,873**	**2,631**	**2,879**	**3,091**	**3,298**	**3,985**	**4,294**	**4,516**	**4,798**	**5,035**
37	TOTAL RESOURCES	9,360	9,541	8,873	8,908	9,362	9,533	9,925	10,326	10,665	10,947	11,266	11,616	12,010	12,297	12,661	12,982

ENERGY MIX
SUSTAINED HIGH GAS PRICE SCENARIO: COAL REDUCTION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	12,333	6,213	3,256	2,509	33,609
2015	9,297	12,332	5,805	3,535	3,246	34,214
2016	9,325	11,651	6,654	3,735	4,037	35,401
2017	9,296	10,497	8,380	3,807	4,689	36,668
2018	9,297	11,188	8,228	3,857	5,310	37,880
2019	9,297	11,795	8,163	3,907	5,943	39,105
2020	9,325	11,874	8,260	3,964	6,597	40,020
2021	9,296	11,535	9,336	4,308	6,982	41,458
2022	9,297	11,652	9,924	4,705	7,121	42,700
2023	9,297	10,625	11,002	5,674	7,314	43,912
2024	9,324	11,365	11,089	5,812	7,518	45,108
2025	9,297	9,301	13,728	6,278	7,704	46,308
2026	9,297	9,392	14,541	6,400	7,886	47,517
2027	9,297	9,401	15,488	6,468	8,078	48,732
2028	9,325	9,403	15,821	7,139	8,284	49,973
2029	9,297	8,911	17,056	7,474	8,498	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	36.7%	18.5%	9.7%	7.5%	100.0%
2015	27.2%	36.0%	17.0%	10.3%	9.5%	100.0%
2016	26.3%	32.9%	18.8%	10.6%	11.4%	100.0%
2017	25.4%	28.6%	22.9%	10.4%	12.8%	100.0%
2018	24.5%	29.5%	21.7%	10.2%	14.0%	100.0%
2019	23.8%	30.2%	20.9%	10.0%	15.2%	100.0%
2020	23.3%	29.7%	20.6%	9.9%	16.5%	100.0%
2021	22.4%	27.8%	22.5%	10.4%	16.8%	100.0%
2022	21.8%	27.3%	23.2%	11.0%	16.7%	100.0%
2023	21.2%	24.2%	25.1%	12.9%	16.7%	100.0%
2024	20.7%	25.2%	24.6%	12.9%	16.7%	100.0%
2025	20.1%	20.1%	29.6%	13.6%	16.6%	100.0%
2026	19.6%	19.8%	30.6%	13.5%	16.6%	100.0%
2027	19.1%	19.3%	31.8%	13.3%	16.6%	100.0%
2028	18.7%	18.8%	31.7%	14.3%	16.6%	100.0%
2029	18.1%	17.4%	33.3%	14.6%	16.6%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

SUSTAINED HIGH GAS PRICE SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	972	983	1,004	1,026	1,047	1,073	1,176	1,216	1,254	1,288	1,328	1,366	1,404	1,443	1,481
5	**Total Load Requirements**	8,124	8,263	8,556	8,885	9,206	9,527	9,845	10,247	10,590	10,925	11,254	11,588	11,923	12,264	12,609	12,959
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	5,139	4,489	4,656	4,656	4,059	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,514	1,514	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	468	462	462	462	461	461	451	442	430	430	430	431	413	413	414
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	395	387	381	381	381	381	381	370	362	362	362	363	363	363	364	364
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	9,165	9,083	8,419	7,768	7,548	7,548	6,951	6,461	6,452	6,439	6,439	6,440	6,440	6,423	6,423	6,423
22	Energy Efficiency	109	296	501	670	825	986	1,135	1,232	1,265	1,313	1,377	1,409	1,454	1,501	1,548	1,603
23	Distributed Energy	65	108	131	146	156	165	174	186	203	221	243	263	277	287	297	306
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	194	426	658	843	1,007	1,178	1,361	1,494	1,594	1,686	1,796	1,847	1,931	2,013	2,095	2,184
29	Natural Gas	0	0	0	500	1,010	1,010	1,510	2,214	2,418	2,622	2,826	3,491	3,491	3,593	3,797	4,001
30	CCs/CTs	0	0	0	500	1,010	1,010	1,510	2,214	2,418	2,622	2,826	3,491	3,491	3,593	3,797	4,001
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	56	56	56	56	56	110	154	232	233	253	255	272	349	350
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	56	56	56	56	56	110	154	157	158	160	162	164	165	167
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	0	32	56	556	1,066	1,066	1,566	2,324	2,572	2,854	3,059	3,744	3,746	3,865	4,146	4,351
37	TOTAL RESOURCES	9,359	9,541	9,133	9,167	9,622	9,793	9,878	10,279	10,619	10,978	11,295	12,031	12,117	12,301	12,663	12,959

ENERGY MIX
SUSTAINED HIGH GAS PRICE SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	12,333	6,213	3,256	2,509	33,609
2015	9,297	12,332	5,805	3,535	3,246	34,214
2016	9,325	11,601	6,703	3,735	4,037	35,401
2017	9,296	10,610	8,266	3,807	4,689	36,668
2018	9,297	8,483	10,933	3,857	5,310	37,880
2019	9,297	9,196	10,761	3,907	5,943	39,105
2020	9,325	9,317	10,817	3,964	6,597	40,020
2021	9,296	9,062	11,804	4,308	6,982	41,454
2022	9,297	9,166	12,406	4,705	7,121	42,696
2023	9,297	8,362	13,544	5,395	7,314	43,912
2024	9,324	8,723	14,011	5,532	7,518	45,108
2025	9,297	9,304	14,004	5,999	7,704	46,308
2026	9,297	9,411	14,801	6,121	7,886	47,517
2027	9,297	9,410	15,758	6,189	8,078	48,732
2028	9,325	9,378	16,126	6,860	8,284	49,973
2029	9,297	8,939	17,586	6,916	8,498	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	36.7%	18.5%	9.7%	7.5%	100.0%
2015	27.2%	36.0%	17.0%	10.3%	9.5%	100.0%
2016	26.3%	32.8%	18.9%	10.6%	11.4%	100.0%
2017	25.4%	28.9%	22.5%	10.4%	12.8%	100.0%
2018	24.5%	22.4%	28.9%	10.2%	14.0%	100.0%
2019	23.8%	23.5%	27.5%	10.0%	15.2%	100.0%
2020	23.3%	23.3%	27.0%	9.9%	16.5%	100.0%
2021	22.4%	21.9%	28.5%	10.4%	16.8%	100.0%
2022	21.8%	21.5%	29.1%	11.0%	16.7%	100.0%
2023	21.2%	19.0%	30.8%	12.3%	16.7%	100.0%
2024	20.7%	19.3%	31.1%	12.3%	16.7%	100.0%
2025	20.1%	20.1%	30.2%	13.0%	16.6%	100.0%
2026	19.6%	19.8%	31.1%	12.9%	16.6%	100.0%
2027	19.1%	19.3%	32.3%	12.7%	16.6%	100.0%
2028	18.7%	18.8%	32.3%	13.7%	16.6%	100.0%
2029	18.1%	17.4%	34.3%	13.5%	16.6%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

TOTAL REVENUE REQUIREMENTS SUSTAINED HIGH GAS PRICE SCENARIO - ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	2,299.8	2,299.8	2,298.2	2,299.1
2015	2,420.1	2,420.1	2,405.9	2,418.8
2016	2,385.8	2,385.8	2,366.4	2,407.5
2017	2,575.5	2,575.5	2,593.1	2,623.1
2018	2,782.6	2,782.6	2,744.1	2,849.1
2019	2,879.3	2,907.2	2,841.9	2,945.1
2020	2,971.6	3,050.5	2,971.1	3,035.3
2021	3,261.8	3,349.1	3,284.1	3,304.7
2022	3,457.4	3,547.1	3,476.9	3,510.7
2023	3,733.3	3,823.6	3,739.9	3,787.5
2024	3,898.4	4,009.1	3,883.8	3,972.9
2025	4,118.8	4,187.3	4,138.6	4,164.5
2026	4,341.3	4,393.8	4,370.8	4,361.0
2027	4,505.0	4,666.4	4,586.0	4,527.3
2028	4,691.3	4,854.2	4,797.4	4,736.0
2029	4,975.0	5,032.8	5,059.1	5,005.9
2030	5,229.9	5,216.6	5,335.0	5,283.8
2031	5,368.3	5,329.2	5,482.4	5,435.9
2032	5,587.4	5,536.7	5,666.9	5,632.8
2033	5,817.6	5,733.3	5,900.0	5,866.0
2034	6,056.4	5,966.2	6,178.5	6,136.4
2035	6,394.9	6,318.0	6,505.8	6,464.3
2036	6,681.0	6,583.3	6,800.6	6,762.7
2037	6,921.2	6,808.6	7,067.1	7,012.8
2038	7,390.4	7,285.3	7,504.5	7,473.8
2039	7,893.3	7,779.1	8,011.6	7,966.8
2040	8,382.3	8,261.8	8,511.0	8,484.0
2041	8,784.6	8,650.3	8,900.4	8,870.0
2042	9,151.8	9,025.2	9,307.1	9,261.5
2043	9,448.4	9,310.7	9,622.6	9,578.6
(2014-2029)	29,761.6	30,211.4	29,829.2	30,119.9
(2014-2043)	48,810.3	49,023.0	49,206.5	49,381.2

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

TOTAL REVENUE REQUIREMENTS: SUSTAINED HIGH GAS PRICE SCENARIO
BASE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.6	492.8	53.0	412.0	19.5	1,603.0	110.5	369.7	480.2	(2.0)	63.2	23.9	(0.1)	131.6	2,299.8	75.4
2015	634.0	483.6	52.3	441.6	42.1	1,653.5	111.2	386.6	497.8	(0.4)	64.8	21.3	(0.1)	183.0	2,420.1	80.0
2016	687.2	487.3	55.5	376.8	65.7	1,672.4	105.8	375.0	480.8	(0.9)	66.4	18.5	(0.1)	148.6	2,385.8	78.2
2017	789.3	629.4	65.2	389.0	75.5	1,948.4	94.8	309.1	404.0	(2.4)	73.5	15.5	(0.1)	136.5	2,575.5	83.0
2018	966.6	702.0	75.6	397.9	76.0	2,218.0	62.1	285.5	347.6	(2.3)	69.8	13.6	(0.1)	136.0	2,782.6	88.2
2019	1,001.7	740.1	78.8	406.4	73.9	2,301.0	62.3	296.3	358.6	(2.4)	71.5	11.7	(0.1)	139.0	2,879.3	89.7
2020	1,099.4	849.8	86.4	405.1	72.0	2,512.6	5.3	231.1	236.4	(2.5)	73.3	9.6	(0.1)	142.3	2,971.6	91.2
2021	1,248.9	938.4	93.5	436.8	70.7	2,788.3	5.1	234.6	239.6	0.0	100.8	9.2	61.2	62.6	3,261.8	97.8
2022	1,333.0	1,022.6	99.0	440.6	71.5	2,966.6	5.8	234.5	240.3	0.0	93.9	8.9	73.3	74.5	3,457.4	100.8
2023	1,486.6	1,113.7	103.2	449.9	70.2	3,223.5	5.7	228.7	234.5	0.0	109.2	8.4	75.5	82.1	3,733.3	106.1
2024	1,554.0	1,186.9	110.0	452.7	68.7	3,372.4	5.8	227.1	232.9	0.0	113.9	8.1	91.5	79.6	3,898.4	108.3
2025	1,670.5	1,261.2	116.7	457.1	71.5	3,577.1	6.7	230.0	236.7	0.0	111.6	7.7	108.5	77.3	4,118.8	111.9
2026	1,717.2	1,347.8	123.1	484.6	72.8	3,745.5	6.7	233.1	239.8	0.0	133.8	7.2	136.8	78.1	4,341.3	115.1
2027	1,721.9	1,442.3	130.3	503.7	72.1	3,870.4	6.7	220.1	226.7	0.0	138.6	6.8	179.6	82.9	4,505.0	116.5
2028	1,784.8	1,502.4	135.8	515.4	70.3	4,008.6	6.7	223.7	230.4	0.0	140.5	6.4	218.0	87.4	4,691.3	118.3
2029	1,825.8	1,635.7	143.1	545.8	70.5	4,220.9	6.7	226.3	233.0	0.0	168.5	6.1	256.3	90.3	4,975.0	122.5
2030	1,851.1	1,755.3	152.1	551.4	69.9	4,379.8	6.7	221.4	228.0	0.0	222.8	5.7	302.7	90.9	5,229.9	125.7
2031	1,908.6	1,835.5	159.6	559.1	69.5	4,532.2	6.6	224.4	231.1	0.0	186.6	5.3	323.7	89.5	5,368.3	126.0
2032	1,948.8	1,952.2	168.1	565.8	68.8	4,703.7	6.7	227.3	234.0	0.0	219.6	4.9	341.1	84.1	5,587.4	128.0
2033	2,000.2	2,088.7	177.9	584.8	68.0	4,919.6	6.6	228.4	235.0	0.0	219.3	4.5	356.7	82.5	5,817.6	130.2
2034	2,044.6	2,235.6	186.7	597.4	67.3	5,131.4	6.7	231.7	238.5	0.0	226.9	4.0	374.1	81.4	6,056.4	132.0
2035	2,096.3	2,402.3	196.9	639.1	66.9	5,401.5	7.0	235.2	242.2	0.0	280.4	3.6	385.6	81.6	6,394.9	135.9
2036	2,149.7	2,550.8	209.4	651.4	82.2	5,643.4	7.4	238.8	246.2	0.0	300.4	3.1	406.3	81.7	6,681.0	138.2
2037	2,218.2	2,667.9	220.5	644.0	92.6	5,843.2	7.7	222.9	230.6	0.0	333.5	2.6	429.7	81.6	6,921.2	140.0
2038	2,312.8	2,886.1	235.7	710.2	112.6	6,257.5	8.0	214.7	222.7	0.0	391.7	2.2	438.1	78.2	7,390.4	146.0
2039	2,468.7	3,286.4	262.7	577.3	157.0	6,752.1	8.4	210.1	218.5	0.0	437.2	1.7	406.2	77.6	7,893.3	152.4
2040	2,689.9	3,466.5	279.7	559.0	200.3	7,195.3	8.7	203.5	212.1	0.0	470.2	1.4	426.6	76.7	8,382.3	157.9
2041	2,772.7	3,649.9	293.4	603.7	236.3	7,555.9	9.1	206.3	215.4	0.0	494.4	1.0	442.3	75.5	8,784.6	162.2
2042	2,858.3	3,810.6	309.0	635.4	248.9	7,862.1	9.5	205.3	214.8	0.0	530.6	0.7	469.6	74.0	9,151.8	165.4
2043	2,917.7	4,007.1	324.6	630.9	267.3	8,147.7	10.4	173.2	183.6	0.0	556.0	0.3	488.7	72.1	9,448.4	167.1
(2014-2029)	10,504.0	8,157.4	801.7	4,034.1	593.4	24,090.6	469.9	2,669.1	3,139.0	(9.4)	841.9	121.9	485.7	1,092.0	29,761.6	
(2014-2043)	16,779.2	15,422.8	1,403.7	5,744.2	910.5	40,260.4	491.3	3,295.4	3,786.7	(9.4)	1,736.6	131.5	1,579.8	1,324.7	48,810.3	

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

TOTAL REVENUE REQUIREMENTS: SUSTAINED HIGH GAS PRICE SCENARIO
ENHANCED RENEWABLE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.6	492.8	53.0	412.0	19.5	1,603.0	110.5	369.7	480.2	(2.0)	63.2	23.9	(0.1)	131.6	2,299.8	75.4
2015	634.0	483.6	52.3	441.6	42.1	1,653.5	111.2	386.6	497.8	(0.4)	64.8	21.3	(0.1)	183.0	2,420.1	80.0
2016	687.2	487.3	55.5	376.8	65.7	1,672.4	105.8	375.0	480.8	(0.9)	66.4	18.5	(0.1)	148.6	2,385.8	78.2
2017	789.3	629.4	65.2	389.0	75.5	1,948.4	94.8	309.1	404.0	(2.4)	73.5	15.5	(0.1)	136.5	2,575.5	83.0
2018	966.6	702.0	75.6	397.9	76.0	2,218.0	62.1	285.5	347.6	(2.3)	69.8	13.6	(0.1)	136.0	2,782.6	88.2
2019	1,042.7	722.3	77.7	412.1	73.9	2,328.8	63.7	295.0	358.7	(2.4)	71.5	11.7	(0.1)	139.0	2,907.2	90.6
2020	1,205.4	809.7	84.8	416.9	72.0	2,588.7	8.1	231.1	239.2	(2.5)	73.3	9.6	(0.1)	142.3	3,050.5	93.6
2021	1,399.3	875.5	92.9	454.5	70.7	2,892.9	9.3	232.7	242.0	0.0	94.2	9.2	48.2	62.6	3,349.1	100.5
2022	1,507.5	939.8	96.4	463.1	71.5	3,078.2	9.2	233.3	242.5	0.0	84.7	8.9	58.3	74.5	3,547.1	103.4
2023	1,678.9	1,012.8	101.1	476.1	70.2	3,339.1	9.9	228.7	238.7	0.0	95.8	8.4	59.4	82.1	3,823.6	108.7
2024	1,801.5	1,048.6	109.6	489.4	68.7	3,517.8	12.0	227.1	239.2	0.0	96.5	8.1	67.9	79.6	4,009.1	111.4
2025	1,896.7	1,108.8	113.6	496.1	67.2	3,682.4	13.7	230.0	243.7	0.0	96.8	7.7	79.4	77.3	4,187.3	113.7
2026	1,969.1	1,162.1	116.3	532.7	65.5	3,845.8	13.7	233.1	246.8	0.0	115.3	7.2	100.6	78.1	4,393.8	116.5
2027	2,085.6	1,243.7	125.7	556.1	68.5	4,079.7	13.7	220.1	233.7	0.0	117.1	6.8	146.2	82.9	4,666.4	120.7
2028	2,151.1	1,297.7	129.8	569.9	69.9	4,218.4	13.7	223.7	237.3	0.0	118.6	6.4	186.0	87.4	4,854.2	122.5
2029	2,117.1	1,408.7	137.9	600.0	71.4	4,335.1	13.6	226.3	240.0	0.0	135.9	6.1	225.5	90.3	5,032.8	123.9
2030	2,089.3	1,513.7	147.3	605.8	69.6	4,425.7	13.6	221.5	235.2	0.0	188.9	5.7	270.3	90.9	5,216.6	125.4
2031	2,125.8	1,591.9	153.7	614.4	69.0	4,554.9	13.6	224.4	238.0	0.0	151.0	5.3	290.5	89.5	5,329.2	125.1
2032	2,159.1	1,698.7	161.8	622.5	68.6	4,710.8	13.6	227.3	241.0	0.0	188.9	4.9	307.1	84.1	5,536.7	126.9
2033	2,204.9	1,810.6	172.0	643.0	67.9	4,898.5	13.6	228.4	242.0	0.0	182.9	4.5	322.9	82.5	5,733.3	128.3
2034	2,243.4	1,944.0	181.7	657.0	81.8	5,107.9	13.7	231.7	245.5	0.0	186.8	4.0	340.7	81.4	5,966.2	130.1
2035	2,289.3	2,104.8	191.6	700.2	106.1	5,392.1	14.0	235.2	249.1	0.0	240.3	3.6	351.3	81.6	6,318.0	134.3
2036	2,336.6	2,237.8	203.2	714.0	119.7	5,611.3	14.4	238.8	253.2	0.0	262.7	3.1	371.3	81.7	6,583.3	136.2
2037	2,398.9	2,340.5	213.7	708.2	138.4	5,799.6	14.7	222.9	237.6	0.0	292.3	2.6	395.0	81.6	6,808.6	137.8
2038	2,487.1	2,573.8	226.3	776.0	163.5	6,226.7	15.0	214.7	229.7	0.0	348.7	2.2	399.9	78.2	7,285.3	144.0
2039	2,657.8	2,941.3	250.6	645.4	211.1	6,706.2	15.4	210.1	225.5	0.0	398.1	1.7	370.0	77.6	7,779.1	150.2
2040	2,887.0	3,109.7	267.5	629.1	252.8	7,146.2	15.7	203.5	219.1	0.0	428.9	1.4	389.5	76.7	8,261.8	155.7
2041	2,985.3	3,284.9	279.7	676.3	270.0	7,496.2	16.1	206.3	222.4	0.0	450.8	1.0	404.4	75.5	8,650.3	159.7
2042	3,079.5	3,439.4	293.7	710.2	287.2	7,810.0	16.5	205.3	221.8	0.0	487.9	0.7	430.7	74.0	9,025.2	163.1
2043	3,130.8	3,630.8	306.3	707.6	311.5	8,087.0	17.4	173.2	190.6	0.0	512.8	0.3	447.8	72.1	9,310.7	164.7
(2014-2029)	11,549.4	7,562.7	787.4	4,190.8	587.4	24,677.7	495.1	2,666.6	3,161.6	(9.4)	777.8	121.9	389.9	1,092.0	30,211.4	
(2014-2043)	18,404.8	13,975.9	1,366.5	6,078.1	973.5	40,798.9	536.3	3,292.9	3,829.2	(9.4)	1,563.8	131.5	1,384.3	1,324.7	49,023.0	

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

TOTAL REVENUE REQUIREMENTS: SUSTAINED HIGH GAS PRICE SCENARIO
COAL REDUCTION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	624.1	492.8	53.0	412.0	19.5	1,601.4	110.5	369.7	480.2	(2.0)	63.2	23.9	(0.1)	131.6	2,298.2	75.3
2015	629.9	483.6	52.3	431.5	42.1	1,639.3	111.2	386.6	497.8	(0.4)	64.8	21.3	(0.1)	183.0	2,405.9	79.5
2016	660.1	496.1	52.2	363.5	65.7	1,637.7	105.8	390.4	496.1	(0.9)	66.4	18.5	(0.1)	148.6	2,366.4	77.5
2017	763.6	655.6	61.8	378.8	75.5	1,935.3	94.8	323.5	418.4	(2.4)	89.8	15.5	(0.1)	136.5	2,593.1	83.6
2018	904.0	731.9	70.8	386.2	76.0	2,168.9	62.1	291.7	353.8	(2.3)	74.3	13.6	(0.1)	136.0	2,744.1	87.0
2019	939.5	770.7	74.3	394.5	73.9	2,252.9	62.3	301.6	363.9	(2.4)	76.8	11.7	(0.1)	139.0	2,841.9	88.5
2020	1,073.3	889.1	82.2	394.8	72.6	2,512.1	5.3	231.1	236.4	(2.5)	73.3	9.6	(0.1)	142.3	2,971.1	91.2
2021	1,246.4	985.1	90.5	419.6	71.4	2,812.9	5.1	234.1	239.2	0.0	111.5	9.2	48.6	62.6	3,284.1	98.5
2022	1,323.8	1,069.7	96.0	429.5	72.0	2,991.1	5.8	232.9	238.7	0.0	102.7	8.9	61.0	74.5	3,476.9	101.3
2023	1,470.9	1,153.7	100.7	438.9	70.3	3,234.6	6.4	228.7	235.2	0.0	118.9	8.4	60.7	82.1	3,739.9	106.3
2024	1,530.1	1,230.3	106.8	422.6	68.7	3,358.5	6.5	227.1	233.6	0.0	128.5	8.1	75.5	79.6	3,883.8	107.9
2025	1,640.1	1,374.5	110.4	401.8	71.4	3,598.3	7.4	230.0	237.4	0.0	150.2	7.7	67.9	77.3	4,138.6	112.4
2026	1,727.6	1,464.3	116.6	409.1	72.7	3,790.3	7.4	233.1	240.5	0.0	159.7	7.2	95.0	78.1	4,370.8	115.9
2027	1,775.2	1,563.2	123.3	431.4	73.2	3,966.3	7.4	220.1	227.4	0.0	167.4	6.8	135.3	82.9	4,586.0	118.6
2028	1,843.5	1,626.7	129.2	457.6	72.1	4,129.0	7.4	223.7	231.1	0.0	172.0	6.4	171.5	87.4	4,797.4	121.0
2029	1,896.0	1,740.4	136.8	474.7	73.1	4,321.0	8.1	226.3	234.4	0.0	199.4	6.1	207.9	90.3	5,059.1	124.6
2030	1,925.7	1,876.2	145.4	474.2	72.0	4,493.5	8.1	221.6	229.7	0.0	267.6	5.7	247.6	90.9	5,335.0	128.2
2031	1,978.0	1,954.4	152.5	499.4	71.1	4,655.4	8.0	224.4	232.4	0.0	230.8	5.3	268.9	89.5	5,482.4	128.6
2032	2,012.8	2,075.8	160.5	481.2	70.2	4,800.5	8.1	227.3	235.4	0.0	258.2	4.9	283.7	84.1	5,666.9	129.8
2033	2,060.6	2,216.5	170.1	502.4	69.3	5,018.9	8.0	228.4	236.4	0.0	259.7	4.5	298.1	82.5	5,900.0	132.0
2034	2,101.3	2,364.8	179.8	533.8	83.1	5,262.7	8.1	231.7	239.9	0.0	276.0	4.0	314.5	81.4	6,178.5	134.7
2035	2,149.0	2,529.9	190.3	557.5	92.5	5,519.2	8.4	235.2	243.6	0.0	330.8	3.6	327.0	81.6	6,505.8	138.2
2036	2,200.6	2,695.3	201.8	563.7	111.3	5,772.5	8.8	238.8	247.6	0.0	354.4	3.1	341.3	81.7	6,800.6	140.7
2037	2,264.8	2,808.8	214.1	576.7	136.5	6,000.9	9.1	222.9	232.0	0.0	383.8	2.6	366.2	81.6	7,067.1	143.0
2038	2,348.4	3,038.0	228.6	615.1	150.1	6,380.2	9.4	214.7	224.1	0.0	449.4	2.2	370.5	78.2	7,504.5	148.3
2039	2,492.1	3,442.5	257.2	486.6	203.3	6,881.7	9.8	210.1	219.9	0.0	493.0	1.7	337.7	77.6	8,011.6	154.7
2040	2,711.1	3,621.6	274.5	489.4	235.0	7,331.6	10.1	203.5	213.5	0.0	531.8	1.4	355.9	76.7	8,511.0	160.4
2041	2,812.1	3,803.0	288.4	513.3	263.2	7,680.0	10.5	206.3	216.8	0.0	553.0	1.0	374.0	75.5	8,900.4	164.3
2042	2,910.8	3,984.6	303.9	537.2	287.5	8,024.0	10.9	205.3	216.2	0.0	598.1	0.7	394.1	74.0	9,307.1	168.2
2043	2,968.9	4,179.6	319.8	556.8	299.1	8,324.3	11.8	173.2	185.0	0.0	626.7	0.3	414.2	72.1	9,622.6	170.2
(2014-2029)	10,385.9	8,562.1	769.1	3,823.7	596.3	24,137.2	472.1	2,699.3	3,171.4	(9.4)	942.7	121.9	373.5	1,092.0	29,829.2	
(2014-2043)	16,811.9	16,219.4	1,352.4	5,309.7	971.0	40,664.4	497.5	3,325.7	3,823.2	(9.4)	1,981.7	131.5	1,290.4	1,324.7	49,206.5	

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

TOTAL REVENUE REQUIREMENTS: SUSTAINED HIGH GAS PRICE SCENARIO
COAL-TO-GAS CONVERSION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.0	492.8	53.0	411.9	19.5	1,602.2	110.5	369.7	480.2	(2.0)	63.2	23.9	(0.1)	131.6	2,299.1	75.4
2015	632.7	483.6	52.3	441.6	42.1	1,652.2	111.2	386.6	497.8	(0.4)	64.8	21.3	(0.1)	183.0	2,418.8	80.0
2016	684.5	496.6	52.1	379.2	65.7	1,678.1	105.8	391.1	496.8	(0.9)	66.4	18.5	(0.1)	148.6	2,407.5	78.9
2017	796.1	654.5	62.3	391.1	75.5	1,979.5	94.8	321.9	416.8	(2.4)	77.2	15.5	(0.1)	136.5	2,623.1	84.6
2018	936.8	794.3	64.2	370.6	76.0	2,241.9	62.1	298.9	361.0	(2.3)	98.9	13.6	(0.1)	136.0	2,849.1	90.3
2019	971.8	836.5	66.8	383.4	73.9	2,332.4	62.3	307.9	370.1	(2.4)	94.3	11.7	(0.1)	139.0	2,945.1	91.8
2020	1,067.3	964.7	76.2	377.9	72.0	2,557.9	5.3	231.1	236.4	(2.5)	91.6	9.6	(0.1)	142.3	3,035.3	93.2
2021	1,213.9	1,063.0	86.3	399.5	70.7	2,833.3	5.1	238.4	243.5	0.0	131.2	9.2	24.9	62.6	3,304.7	99.1
2022	1,295.7	1,152.6	92.3	412.8	71.5	3,024.9	5.8	236.8	242.6	0.0	123.8	8.9	36.1	74.5	3,510.7	102.3
2023	1,445.3	1,251.7	97.4	416.9	70.2	3,281.5	5.7	228.7	234.5	0.0	141.6	8.4	39.3	82.1	3,787.5	107.7
2024	1,512.6	1,348.3	102.6	413.2	68.7	3,445.4	5.8	227.2	232.9	0.0	157.4	8.1	49.6	79.6	3,972.9	110.4
2025	1,629.3	1,392.1	109.9	417.4	71.5	3,620.3	6.7	230.0	236.7	0.0	152.9	7.7	69.6	77.3	4,164.5	113.1
2026	1,675.0	1,482.9	116.3	428.1	72.8	3,775.1	6.7	233.1	239.8	0.0	164.0	7.2	96.8	78.1	4,361.0	115.6
2027	1,679.5	1,582.9	123.1	445.3	72.1	3,902.9	6.7	220.1	226.7	0.0	170.9	6.8	137.1	82.9	4,527.3	117.1
2028	1,742.0	1,649.3	128.8	471.1	70.3	4,061.5	6.7	223.7	230.4	0.0	177.1	6.4	173.2	87.4	4,736.0	119.5
2029	1,782.6	1,781.0	136.5	488.0	70.5	4,258.6	6.7	226.3	233.0	0.0	206.1	6.1	211.9	90.3	5,005.9	123.2
2030	1,808.1	1,919.1	144.8	491.4	69.9	4,433.3	6.7	223.0	229.7	0.0	272.8	5.7	251.4	90.9	5,283.8	127.0
2031	1,866.7	1,998.5	152.1	510.0	69.5	4,596.8	6.6	224.4	231.1	0.0	240.4	5.3	272.9	89.5	5,435.9	127.6
2032	1,908.0	2,121.1	160.1	497.3	68.8	4,755.3	6.7	227.5	234.1	0.0	266.6	4.9	287.7	84.1	5,632.8	129.1
2033	1,961.0	2,263.4	169.8	514.0	68.0	4,976.1	6.6	228.4	235.0	0.0	265.7	4.5	302.1	82.5	5,866.0	131.3
2034	2,007.2	2,411.3	179.6	545.4	67.3	5,210.7	6.7	231.7	238.5	0.0	283.0	4.0	318.7	81.4	6,136.4	133.8
2035	2,059.9	2,575.9	190.7	572.9	66.9	5,466.3	7.0	235.2	242.2	0.0	339.1	3.6	331.5	81.6	6,464.3	137.4
2036	2,114.7	2,742.0	202.6	583.7	82.2	5,725.3	7.4	238.8	246.2	0.0	360.6	3.1	345.9	81.7	6,762.7	139.9
2037	2,182.7	2,857.1	214.6	589.2	92.6	5,936.2	7.7	222.9	230.6	0.0	390.9	2.6	370.9	81.6	7,012.8	141.9
2038	2,270.6	3,086.5	230.6	633.9	112.6	6,334.2	8.0	214.7	222.7	0.0	461.3	2.2	375.2	78.2	7,473.8	147.7
2039	2,417.9	3,491.0	259.8	500.3	157.0	6,825.9	8.4	210.1	218.5	0.0	500.5	1.7	342.6	77.6	7,966.8	153.8
2040	2,641.5	3,671.5	277.2	502.8	200.3	7,293.3	8.7	203.5	212.1	0.0	539.6	1.4	360.9	76.7	8,484.0	159.8
2041	2,725.5	3,852.6	291.1	530.5	236.3	7,636.0	9.1	206.3	215.4	0.0	562.9	1.0	379.1	75.5	8,870.0	163.8
2042	2,812.4	4,036.5	307.1	559.3	248.9	7,964.1	9.5	205.3	214.8	0.0	608.5	0.7	399.3	74.0	9,261.5	167.3
2043	2,876.3	4,232.8	324.1	570.0	267.3	8,270.6	10.4	173.2	183.6	0.0	632.5	0.3	419.5	72.1	9,578.6	169.5
(2014-2029)	10,284.6	8,932.3	747.4	3,818.6	593.4	24,376.4	469.9	2,712.4	3,182.3	(9.4)	1,028.9	121.9	327.9	1,092.0	30,119.9	
(2014-2043)	16,442.6	16,723.1	1,333.1	5,347.2	910.5	40,756.4	491.3	3,339.2	3,830.5	(9.4)	2,090.1	131.5	1,257.5	1,324.7	49,381.2	

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

ANNUAL AVERAGE SYSTEM COST SUSTAINED HIGH GAS PRICE SCENARIO - ($/MWh)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	75.4	75.4	75.3	75.4
2015	80.0	80.0	79.5	80.0
2016	78.2	78.2	77.5	78.9
2017	83.0	83.0	83.6	84.6
2018	88.2	88.2	87.0	90.3
2019	89.7	90.6	88.5	91.8
2020	91.2	93.6	91.2	93.2
2021	97.8	100.5	98.5	99.1
2022	100.8	103.4	101.3	102.3
2023	106.1	108.7	106.3	107.7
2024	108.3	111.4	107.9	110.4
2025	111.9	113.7	112.4	113.1
2026	115.1	116.5	115.9	115.6
2027	116.5	120.7	118.6	117.1
2028	118.3	122.5	121.0	119.5
2029	122.5	123.9	124.6	123.2

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

CUMULATIVE CAPITAL SPENDING EXISTING AND NEW GENERATION PLUS INCREMENTAL TRANSMISSION SUSTAINED HIGH GAS PRICE SCENARIO - ($/MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	1,211.7	1,211.7	1,201.4	1,207.7
2015	1,678.9	1,678.9	1,617.4	1,635.6
2016	2,400.4	2,400.4	2,212.6	2,368.6
2017	3,657.0	3,767.0	3,379.1	3,589.4
2018	4,024.8	4,462.6	3,677.1	3,855.2
2019	4,297.9	5,154.6	4,126.0	4,107.4
2020	5,411.5	6,664.3	5,382.4	5,203.1
2021	6,931.1	8,293.3	6,909.9	6,700.3
2022	7,680.4	9,345.2	7,658.8	7,433.2
2023	8,534.9	10,428.0	8,434.2	8,257.0
2024	9,549.1	11,652.8	9,429.8	9,263.0
2025	10,126.2	12,702.9	10,224.2	9,833.2
2026	10,863.5	14,120.8	11,204.1	10,556.3
2027	11,520.1	14,719.5	11,973.1	11,203.7
2028	12,225.0	15,111.3	12,771.6	11,897.7
2029	12,883.8	15,550.6	13,459.4	12,544.4

1. Capital investment projected is regardless of whether APS constructs and owns new generation resources or whether resources are purchased by APS under long-term PPAs with market participants.

2. Capital spending excludes: (a) financial commitments to energy efficiency and distributed energy initiatives; (b) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing.

3. Capital spending includes ongoing capital investment for existing owned generation.

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

ANNUAL NATURAL GAS BURNS SUSTAINED HIGH GAS PRICE SCENARIO - (BCF)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	39.4	39.4	39.4	39.4
2015	36.3	36.3	36.3	36.3
2016	38.9	38.9	47.3	47.6
2017	52.1	52.1	64.5	63.6
2018	50.5	50.5	63.3	84.4
2019	50.7	48.7	62.6	82.8
2020	52.6	48.6	64.6	84.3
2021	60.6	54.1	73.2	92.3
2022	66.0	57.3	77.8	96.8
2023	75.7	64.8	86.2	105.7
2024	75.6	62.2	86.9	109.1
2025	77.7	63.0	107.0	109.0
2026	83.0	65.8	113.1	115.1
2027	89.6	71.6	120.2	122.3
2028	92.1	73.9	123.0	125.4
2029	104.5	83.5	132.5	136.6

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

ANNUAL CO2 EMISSIONS SUSTAINED HIGH GAS PRICE SCENARIO - (METRIC TONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	13,956,845	13,956,845	13,956,845	13,956,845
2015	13,718,360	13,718,360	13,718,360	13,718,360
2016	14,194,154	14,194,154	13,557,175	13,528,175
2017	14,347,484	14,347,484	13,397,480	13,480,242
2018	15,027,415	15,027,415	14,039,888	12,035,377
2019	15,442,857	15,075,054	14,522,499	12,570,551
2020	15,646,072	14,929,300	14,710,371	12,772,121
2021	15,769,100	14,765,300	14,797,642	12,964,761
2022	16,110,752	14,982,806	15,189,107	13,315,126
2023	15,799,218	14,616,583	14,714,830	13,142,924
2024	16,612,606	14,918,003	15,462,493	13,604,974
2025	16,976,705	15,260,624	14,009,822	14,120,849
2026	17,472,599	15,425,432	14,418,686	14,544,152
2027	17,906,509	15,798,285	14,812,992	14,937,623
2028	18,094,149	16,026,209	14,980,271	15,094,666
2029	18,181,251	16,234,871	15,079,694	15,330,615

Attachment F.1(c)(3) - Sustained High Gas Price Scenario

ANNUAL WATER USE SUSTAINED HIGH GAS PRICE SCENARIO - (ACRE-FEET)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	55,093	55,093	55,093	55,093
2015	54,539	54,539	54,539	54,539
2016	54,814	54,814	53,458	53,396
2017	55,013	55,013	53,033	53,160
2018	56,361	56,361	54,259	51,011
2019	57,029	56,208	55,058	51,848
2020	57,124	55,523	55,099	51,924
2021	57,208	54,962	55,075	52,042
2022	57,952	56,812	55,952	52,834
2023	58,900	57,611	56,509	53,961
2024	60,507	58,083	57,981	54,945
2025	59,806	58,513	54,115	54,320
2026	60,253	60,281	54,116	54,377
2027	61,127	60,061	54,859	55,156
2028	62,895	61,402	56,581	56,835
2029	63,113	61,855	56,933	57,454

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

INCREASED ENVIRONMENTAL POLICY SCENARIO: BASE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	972	983	1,004	1,026	1,048	1,076	1,181	1,222	1,261	1,298	1,337	1,377	1,417	1,458	1,499
5	**Total Load Requirements**	**8,124**	**8,263**	**8,556**	**8,885**	**9,206**	**9,528**	**9,848**	**10,252**	**10,596**	**10,932**	**11,263**	**11,598**	**11,934**	**12,277**	**12,625**	**12,976**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	474	466	460	459	459	458	457	457	457	444	443	443	443	425	425	425
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	393	385	380	379	378	377	377	376	376	376	376	376	376	376	375	375
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,163**	**9,081**	**8,417**	**7,766**	**7,545**	**7,545**	**6,947**	**6,467**	**6,466**	**6,453**	**6,453**	**6,453**	**6,453**	**6,435**	**6,435**	**6,435**
22	Energy Efficiency	109	296	501	670	823	977	1,115	1,200	1,224	1,262	1,315	1,344	1,381	1,413	1,444	1,485
23	Distributed Energy	65	108	130	162	193	222	243	264	283	300	314	332	350	366	382	397
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**194**	**425**	**658**	**858**	**1,042**	**1,226**	**1,410**	**1,541**	**1,634**	**1,713**	**1,806**	**1,850**	**1,931**	**2,005**	**2,076**	**2,157**
29	Natural Gas	0	0	0	500	1,010	1,010	1,510	2,214	2,520	2,724	3,030	3,695	3,695	3,797	4,103	4,409
30	CCs/CTs	0	0	0	500	1,010	1,010	1,510	2,214	2,520	2,724	3,030	3,695	3,695	3,797	4,103	4,409
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	31	55	55	55	55	55	56	56	56	56	56	56	72	72	72
33	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	16	16	16
34	Solar	0	31	55	55	55	55	55	56	56	56	56	56	56	56	56	56
35	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	**Total Future Resources**	**0**	**31**	**55**	**555**	**1,065**	**1,065**	**1,565**	**2,270**	**2,576**	**2,780**	**3,086**	**3,751**	**3,751**	**3,869**	**4,175**	**4,481**
37	TOTAL RESOURCES	9,357	9,538	9,129	9,180	9,653	9,836	9,922	10,277	10,676	10,946	11,345	12,054	12,135	12,308	12,686	13,072

ENERGY MIX
INCREASED ENVIRONMENTAL POLICY SCENARIO: BASE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,915	6,631	3,256	2,509	33,609
2015	9,297	12,012	6,124	3,535	3,246	34,214
2016	9,325	12,408	5,896	3,735	4,037	35,401
2017	9,296	11,695	7,083	3,905	4,689	36,668
2018	9,297	12,468	6,655	4,159	5,302	37,880
2019	9,297	11,987	7,484	4,430	5,906	39,105
2020	9,325	12,095	7,368	4,717	6,515	40,020
2021	9,296	12,175	8,118	5,016	6,854	41,458
2022	9,297	12,331	8,755	5,364	6,951	42,699
2023	9,297	11,691	10,189	5,632	7,103	43,912
2024	9,324	12,587	10,051	5,875	7,271	45,108
2025	9,297	13,046	10,248	6,282	7,435	46,308
2026	9,297	13,111	10,759	6,765	7,586	47,517
2027	9,297	13,102	11,446	7,170	7,717	48,732
2028	9,325	13,175	12,065	7,553	7,856	49,973
2029	9,297	12,611	13,431	7,886	8,012	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	35.5%	19.7%	9.7%	7.5%	100.0%
2015	27.2%	35.1%	17.9%	10.3%	9.5%	100.0%
2016	26.3%	35.0%	16.7%	10.6%	11.4%	100.0%
2017	25.4%	31.9%	19.3%	10.6%	12.8%	100.0%
2018	24.5%	32.9%	17.6%	11.0%	14.0%	100.0%
2019	23.8%	30.7%	19.1%	11.3%	15.1%	100.0%
2020	23.3%	30.2%	18.4%	11.8%	16.3%	100.0%
2021	22.4%	29.4%	19.6%	12.1%	16.5%	100.0%
2022	21.8%	28.9%	20.5%	12.6%	16.3%	100.0%
2023	21.2%	26.6%	23.2%	12.8%	16.2%	100.0%
2024	20.7%	27.9%	22.3%	13.0%	16.1%	100.0%
2025	20.1%	28.2%	22.1%	13.6%	16.1%	100.0%
2026	19.6%	27.6%	22.6%	14.2%	16.0%	100.0%
2027	19.1%	26.9%	23.5%	14.7%	15.8%	100.0%
2028	18.7%	26.4%	24.1%	15.1%	15.7%	100.0%
2029	18.1%	24.6%	26.2%	15.4%	15.6%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

INCREASED ENVIRONMENTAL POLICY SCENARIO: ENHANCED RENEWABLE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	972	983	1,004	1,026	1,048	1,076	1,181	1,222	1,261	1,298	1,337	1,377	1,417	1,458	1,499
5	**Total Load Requirements**	**8,124**	**8,263**	**8,556**	**8,885**	**9,206**	**9,528**	**9,848**	**10,252**	**10,596**	**10,932**	**11,263**	**11,598**	**11,934**	**12,277**	**12,625**	**12,976**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	468	463	462	461	460	440	431	432	419	405	400	401	384	385	386
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	382	381	380	380	359	350	351	352	338	333	333	334	335	337
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,084**	**8,419**	**7,769**	**7,548**	**7,547**	**6,929**	**6,440**	**6,441**	**6,429**	**6,415**	**6,410**	**6,411**	**6,394**	**6,395**	**6,396**
22	Energy Efficiency	109	296	501	670	823	977	1,115	1,200	1,224	1,262	1,315	1,344	1,381	1,413	1,444	1,485
23	Distributed Energy	65	108	130	162	193	223	242	263	282	298	312	329	348	364	380	394
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**194**	**425**	**658**	**858**	**1,042**	**1,226**	**1,409**	**1,540**	**1,632**	**1,711**	**1,803**	**1,848**	**1,928**	**2,002**	**2,074**	**2,155**
29	Natural Gas	0	0	0	500	1,010	1,010	1,510	2,112	2,316	2,520	2,724	3,030	3,234	3,899	3,899	4,001
30	CCs/CTs	0	0	0	500	1,010	1,010	1,510	2,112	2,316	2,520	2,724	3,030	3,234	3,899	3,899	4,001
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	151	183	263	341	387	405	411	434	441	448
33	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	16	16	16
34	Solar	0	32	57	57	57	57	151	183	188	191	237	255	261	268	275	282
35	Geothermal	0	0	0	0	0	0	0	0	75	150	150	150	150	150	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**557**	**1,067**	**1,067**	**1,661**	**2,295**	**2,579**	**2,861**	**3,111**	**3,435**	**3,645**	**4,333**	**4,340**	**4,449**
37	TOTAL RESOURCES	9,360	9,542	9,134	9,184	9,657	9,840	9,999	10,275	10,652	11,002	11,329	11,692	11,984	12,729	12,809	12,999

ENERGY MIX
INCREASED ENVIRONMENTAL POLICY SCENARIO: ENHANCED RENEWABLE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,915	6,631	3,256	2,509	33,609
2015	9,297	12,012	6,124	3,535	3,246	34,214
2016	9,325	12,408	5,896	3,735	4,037	35,401
2017	9,296	11,695	7,083	3,905	4,689	36,668
2018	9,297	12,468	6,655	4,159	5,302	37,880
2019	9,297	11,987	7,484	4,430	5,906	39,105
2020	9,325	11,898	7,006	5,277	6,515	40,020
2021	9,296	11,924	7,532	5,853	6,854	41,459
2022	9,297	11,987	7,671	6,792	6,951	42,699
2023	9,297	11,228	8,632	7,652	7,103	43,912
2024	9,324	11,874	8,180	8,459	7,271	45,108
2025	9,297	12,336	8,101	9,139	7,435	46,308
2026	9,297	12,437	8,576	9,622	7,586	47,517
2027	9,297	12,463	9,227	10,027	7,717	48,732
2028	9,325	12,546	9,830	10,417	7,856	49,973
2029	9,297	12,088	11,096	10,743	8,012	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	35.5%	19.7%	9.7%	7.5%	100.0%
2015	27.2%	35.1%	17.9%	10.3%	9.5%	100.0%
2016	26.3%	35.0%	16.7%	10.6%	11.4%	100.0%
2017	25.4%	31.9%	19.3%	10.6%	12.8%	100.0%
2018	24.5%	32.9%	17.6%	11.0%	14.0%	100.0%
2019	23.8%	30.7%	19.1%	11.3%	15.1%	100.0%
2020	23.3%	29.7%	17.5%	13.2%	16.3%	100.0%
2021	22.4%	28.8%	18.2%	14.1%	16.5%	100.0%
2022	21.8%	28.1%	18.0%	15.9%	16.3%	100.0%
2023	21.2%	25.6%	19.7%	17.4%	16.2%	100.0%
2024	20.7%	26.3%	18.1%	18.8%	16.1%	100.0%
2025	20.1%	26.6%	17.5%	19.7%	16.1%	100.0%
2026	19.6%	26.2%	18.0%	20.2%	16.0%	100.0%
2027	19.1%	25.6%	18.9%	20.6%	15.8%	100.0%
2028	18.7%	25.1%	19.7%	20.8%	15.7%	100.0%
2029	18.1%	23.6%	21.7%	21.0%	15.6%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

INCREASED ENVIRONMENTAL POLICY SCENARIO: COAL REDUCTION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	972	983	1,004	1,026	1,048	1,076	1,181	1,222	1,261	1,298	1,337	1,377	1,417	1,458	1,499
5	**Total Load Requirements**	**8,124**	**8,263**	**8,556**	**8,885**	**9,206**	**9,528**	**9,848**	**10,252**	**10,596**	**10,932**	**11,263**	**11,598**	**11,934**	**12,277**	**12,625**	**12,976**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	474	466	460	459	459	458	457	457	457	444	443	443	443	425	425	425
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	393	385	380	379	378	377	377	376	376	376	376	376	376	376	375	375
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,163**	**9,081**	**8,157**	**7,506**	**7,285**	**7,285**	**6,687**	**6,207**	**6,206**	**6,193**	**6,193**	**5,806**	**5,806**	**5,788**	**5,788**	**5,788**
22	Energy Efficiency	109	296	501	670	823	977	1,115	1,200	1,224	1,262	1,315	1,344	1,381	1,413	1,444	1,485
23	Distributed Energy	65	108	130	162	193	222	243	264	283	300	314	332	350	366	382	397
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**194**	**425**	**658**	**858**	**1,042**	**1,226**	**1,410**	**1,541**	**1,634**	**1,713**	**1,806**	**1,850**	**1,931**	**2,005**	**2,076**	**2,157**
29	Natural Gas	0	0	0	500	1,010	1,010	1,714	2,520	2,724	3,030	3,234	3,899	4,205	4,511	4,715	5,021
30	CCs/CTs	0	0	0	500	1,010	1,010	1,714	2,520	2,724	3,030	3,234	3,899	4,205	4,511	4,715	5,021
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	31	55	55	55	55	55	56	56	56	56	56	56	72	72	72
33	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	16	16	16
34	Solar	0	31	55	55	55	55	55	56	56	56	56	56	56	56	56	56
35	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	**Total Future Resources**	**0**	**31**	**55**	**555**	**1,065**	**1,065**	**1,769**	**2,576**	**2,780**	**3,086**	**3,290**	**3,955**	**4,261**	**4,583**	**4,787**	**5,093**
37	TOTAL RESOURCES	9,357	9,538	8,869	8,920	9,393	9,576	9,866	10,323	10,620	10,992	11,289	11,611	11,998	12,375	12,651	13,037

ENERGY MIX
INCREASED ENVIRONMENTAL POLICY SCENARIO: COAL REDUCTION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,915	6,631	3,256	2,509	33,609
2015	9,297	12,012	6,124	3,535	3,246	34,214
2016	9,325	11,302	7,002	3,735	4,037	35,401
2017	9,296	10,155	8,624	3,905	4,689	36,668
2018	9,297	10,827	8,295	4,159	5,302	37,880
2019	9,297	10,531	8,940	4,430	5,906	39,105
2020	9,325	10,622	8,841	4,717	6,515	40,020
2021	9,296	10,662	9,631	5,016	6,854	41,459
2022	9,297	10,892	10,195	5,364	6,951	42,700
2023	9,297	10,149	11,731	5,632	7,103	43,912
2024	9,324	10,990	11,649	5,875	7,271	45,108
2025	9,297	9,225	14,069	6,282	7,435	46,308
2026	9,297	9,304	14,566	6,765	7,586	47,517
2027	9,297	9,314	15,234	7,170	7,717	48,732
2028	9,325	9,340	15,900	7,553	7,856	49,973
2029	9,297	8,895	17,146	7,886	8,012	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	35.5%	19.7%	9.7%	7.5%	100.0%
2015	27.2%	35.1%	17.9%	10.3%	9.5%	100.0%
2016	26.3%	31.9%	19.8%	10.6%	11.4%	100.0%
2017	25.4%	27.7%	23.5%	10.6%	12.8%	100.0%
2018	24.5%	28.6%	21.9%	11.0%	14.0%	100.0%
2019	23.8%	26.9%	22.9%	11.3%	15.1%	100.0%
2020	23.3%	26.5%	22.1%	11.8%	16.3%	100.0%
2021	22.4%	25.7%	23.2%	12.1%	16.5%	100.0%
2022	21.8%	25.5%	23.9%	12.6%	16.3%	100.0%
2023	21.2%	23.1%	26.7%	12.8%	16.2%	100.0%
2024	20.7%	24.4%	25.8%	13.0%	16.1%	100.0%
2025	20.1%	19.9%	30.4%	13.6%	16.1%	100.0%
2026	19.6%	19.6%	30.7%	14.2%	16.0%	100.0%
2027	19.1%	19.1%	31.3%	14.7%	15.8%	100.0%
2028	18.7%	18.7%	31.8%	15.1%	15.7%	100.0%
2029	18.1%	17.4%	33.5%	15.4%	15.6%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

INCREASED ENVIRONMENTAL POLICY SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	972	983	1,004	1,026	1,048	1,076	1,181	1,222	1,261	1,298	1,337	1,377	1,417	1,458	1,499
5	**Total Load Requirements**	**8,124**	**8,263**	**8,556**	**8,885**	**9,206**	**9,528**	**9,848**	**10,252**	**10,596**	**10,932**	**11,263**	**11,598**	**11,934**	**12,277**	**12,625**	**12,976**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	5,139	4,489	4,656	4,656	4,059	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,514	1,514	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	474	466	460	459	459	458	457	457	457	444	443	443	443	425	425	425
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	393	385	380	379	378	377	377	376	376	376	376	376	376	376	375	375
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,163**	**9,081**	**8,417**	**7,766**	**7,545**	**7,545**	**6,947**	**6,467**	**6,466**	**6,453**	**6,453**	**6,453**	**6,453**	**6,435**	**6,435**	**6,435**
22	Energy Efficiency	109	296	501	670	823	977	1,115	1,200	1,224	1,262	1,315	1,344	1,381	1,413	1,444	1,485
23	Distributed Energy	65	108	130	162	193	222	243	264	283	300	314	332	350	366	382	397
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**194**	**425**	**658**	**858**	**1,042**	**1,226**	**1,410**	**1,541**	**1,634**	**1,713**	**1,806**	**1,850**	**1,931**	**2,005**	**2,076**	**2,157**
29	Natural Gas	0	0	0	500	1,010	1,010	1,510	2,214	2,520	2,724	3,030	3,695	3,695	3,797	4,103	4,409
30	CCs/CTs	0	0	0	500	1,010	1,010	1,510	2,214	2,520	2,724	3,030	3,695	3,695	3,797	4,103	4,409
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	31	55	55	55	55	55	56	56	56	56	56	56	72	72	72
33	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	16	16	16
34	Solar	0	31	55	55	55	55	55	56	56	56	56	56	56	56	56	56
35	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	**Total Future Resources**	**0**	**31**	**55**	**555**	**1,065**	**1,065**	**1,565**	**2,270**	**2,576**	**2,780**	**3,086**	**3,751**	**3,751**	**3,869**	**4,175**	**4,481**
37	TOTAL RESOURCES	9,357	9,538	9,129	9,180	9,653	9,836	9,922	10,277	10,676	10,946	11,345	12,054	12,135	12,308	12,686	13,072

ENERGY MIX
INCREASED ENVIRONMENTAL POLICY SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,915	6,631	3,256	2,509	33,609
2015	9,297	12,012	6,124	3,535	3,246	34,214
2016	9,325	11,257	7,048	3,735	4,037	35,401
2017	9,296	10,246	8,532	3,905	4,689	36,668
2018	9,297	8,340	10,782	4,159	5,302	37,880
2019	9,297	8,447	11,025	4,430	5,906	39,105
2020	9,325	8,631	10,832	4,717	6,515	40,020
2021	9,296	8,629	11,661	5,016	6,854	41,456
2022	9,297	8,796	12,289	5,364	6,951	42,698
2023	9,297	8,134	13,746	5,632	7,103	43,912
2024	9,324	8,553	14,085	5,875	7,271	45,108
2025	9,297	9,228	14,066	6,282	7,435	46,308
2026	9,297	9,304	14,566	6,765	7,586	47,517
2027	9,297	9,313	15,235	7,170	7,717	48,732
2028	9,325	9,341	15,899	7,553	7,856	49,973
2029	9,297	8,895	17,146	7,886	8,012	51,236

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.7%	35.5%	19.7%	9.7%	7.5%	100.0%
2015	27.2%	35.1%	17.9%	10.3%	9.5%	100.0%
2016	26.3%	31.8%	19.9%	10.6%	11.4%	100.0%
2017	25.4%	27.9%	23.3%	10.6%	12.8%	100.0%
2018	24.5%	22.0%	28.5%	11.0%	14.0%	100.0%
2019	23.8%	21.6%	28.2%	11.3%	15.1%	100.0%
2020	23.3%	21.6%	27.1%	11.8%	16.3%	100.0%
2021	22.4%	20.8%	28.1%	12.1%	16.5%	100.0%
2022	21.8%	20.6%	28.8%	12.6%	16.3%	100.0%
2023	21.2%	18.5%	31.3%	12.8%	16.2%	100.0%
2024	20.7%	19.0%	31.2%	13.0%	16.1%	100.0%
2025	20.1%	19.9%	30.4%	13.6%	16.1%	100.0%
2026	19.6%	19.6%	30.7%	14.2%	16.0%	100.0%
2027	19.1%	19.1%	31.3%	14.7%	15.8%	100.0%
2028	18.7%	18.7%	31.8%	15.1%	15.7%	100.0%
2029	18.1%	17.4%	33.5%	15.4%	15.6%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

TOTAL REVENUE REQUIREMENTS INCREASED ENVIRONMENTAL POLICY SCENARIO - ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	2,257.5	2,257.5	2,256.0	2,256.8
2015	2,382.7	2,382.7	2,368.6	2,381.5
2016	2,345.5	2,345.5	2,318.5	2,359.2
2017	2,550.5	2,550.5	2,555.9	2,587.4
2018	2,772.3	2,772.3	2,722.2	2,802.6
2019	2,921.4	2,921.4	2,863.1	2,921.0
2020	3,045.4	3,071.3	3,019.9	3,036.9
2021	3,301.4	3,340.2	3,318.7	3,304.9
2022	3,501.3	3,526.6	3,511.8	3,515.2
2023	3,896.2	3,930.5	3,862.4	3,868.4
2024	4,080.1	4,120.4	4,018.8	4,069.9
2025	4,341.8	4,315.6	4,280.1	4,306.3
2026	4,582.9	4,543.1	4,547.1	4,519.9
2027	4,792.3	4,876.8	4,842.4	4,730.2
2028	5,058.1	5,136.9	5,132.5	5,018.9
2029	5,411.0	5,372.7	5,442.5	5,356.5
2030	5,723.9	5,662.3	5,781.6	5,685.8
2031	5,903.7	5,857.5	5,986.1	5,872.0
2032	6,183.7	6,132.0	6,221.1	6,121.7
2033	6,477.2	6,383.4	6,496.2	6,418.6
2034	6,801.3	6,670.8	6,842.5	6,773.7
2035	7,213.4	7,075.1	7,236.2	7,167.2
2036	7,603.9	7,446.5	7,633.0	7,565.9
2037	7,852.9	7,698.7	7,900.6	7,830.9
2038	8,336.2	8,151.3	8,363.0	8,306.9
2039	8,797.8	8,595.9	8,829.8	8,772.4
2040	9,357.3	9,151.5	9,461.2	9,361.8
2041	9,736.7	9,527.2	9,834.6	9,732.7
2042	10,188.9	9,927.2	10,260.4	10,208.4
2043	10,518.4	10,264.7	10,597.5	10,563.7
(2014-2029)	30,491.7	30,598.9	30,354.9	30,439.6
(2014-2043)	51,751.6	51,475.0	51,759.4	51,618.4

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

TOTAL REVENUE REQUIREMENTS: INCREASED ENVIRONMENTAL POLICY SCENARIO
BASE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.6	470.9	51.1	412.0	19.5	1,579.2	110.5	351.2	461.7	(2.0)	63.2	23.9	(0.1)	131.6	2,257.5	74.0
2015	634.0	467.3	50.8	441.6	42.1	1,635.7	111.2	367.1	478.3	(0.4)	64.8	21.3	(0.1)	183.0	2,382.7	78.8
2016	687.2	467.2	53.7	376.8	65.7	1,650.5	105.8	356.6	462.4	(0.9)	66.4	18.5	(0.1)	148.6	2,345.5	76.8
2017	816.1	588.8	63.0	389.0	75.5	1,932.3	94.8	297.9	392.8	(2.4)	74.1	15.5	(0.1)	138.3	2,550.5	82.5
2018	1,011.9	655.2	73.1	397.9	76.0	2,214.0	62.1	276.9	339.1	(2.3)	69.8	13.6	(0.1)	138.3	2,772.3	88.7
2019	1,058.5	691.5	73.3	406.4	73.9	2,303.6	62.3	291.3	353.6	(2.4)	71.5	11.7	42.4	141.0	2,921.4	92.4
2020	1,184.0	788.7	82.1	405.1	72.0	2,531.9	5.3	231.1	236.4	(2.5)	73.3	9.6	51.2	145.5	3,045.4	95.4
2021	1,349.5	875.7	92.7	433.8	70.7	2,822.4	4.4	233.6	238.0	0.0	98.9	9.2	65.3	67.5	3,301.4	101.6
2022	1,430.9	962.2	98.2	434.8	71.7	2,997.9	4.4	233.7	238.1	0.0	91.9	8.9	86.6	78.1	3,501.3	105.2
2023	1,675.1	1,072.8	105.4	436.3	70.3	3,359.9	4.4	228.7	233.1	0.0	109.6	8.4	100.8	84.3	3,896.2	114.6
2024	1,746.3	1,148.8	112.6	439.2	68.8	3,515.7	4.4	227.1	231.5	0.0	112.9	8.1	129.4	82.5	4,080.1	117.4
2025	1,877.5	1,235.5	120.7	437.7	71.5	3,742.9	4.3	230.0	234.3	0.0	110.8	7.7	164.6	81.5	4,341.8	122.8
2026	1,933.8	1,316.6	127.1	464.7	72.8	3,915.0	4.3	233.1	237.4	0.0	129.9	7.2	215.4	77.9	4,582.9	127.5
2027	1,956.0	1,407.0	135.3	483.3	72.1	4,053.6	4.3	220.1	224.4	0.0	133.1	6.8	295.7	78.7	4,792.3	130.9
2028	2,015.7	1,501.8	144.1	485.9	70.9	4,218.5	4.3	223.7	228.0	0.0	136.5	6.4	384.3	84.4	5,058.1	135.5
2029	2,072.3	1,632.6	152.6	516.4	72.2	4,446.1	4.3	226.3	230.6	0.0	165.8	6.1	474.3	88.1	5,411.0	142.0
2030	2,107.1	1,738.6	163.3	521.1	71.3	4,601.3	4.3	221.4	225.7	0.0	217.2	5.7	584.6	89.4	5,723.9	147.2
2031	2,167.6	1,813.6	170.3	527.7	70.4	4,749.6	4.3	224.4	228.7	0.0	179.0	5.3	652.0	89.1	5,903.7	148.6
2032	2,224.0	1,922.8	178.3	533.6	69.5	4,928.2	4.3	227.3	231.6	0.0	218.1	4.9	716.4	84.6	6,183.7	152.3
2033	2,314.7	2,040.1	189.5	552.4	68.7	5,165.3	4.3	228.4	232.6	0.0	208.3	4.5	782.9	83.6	6,477.2	156.0
2034	2,384.9	2,181.9	199.5	563.7	67.9	5,398.0	4.2	231.7	236.0	0.0	217.3	4.0	863.2	82.8	6,801.3	159.4
2035	2,437.4	2,359.9	210.1	603.1	67.6	5,678.2	4.2	235.2	239.4	0.0	274.9	3.6	934.0	83.3	7,213.4	164.7
2036	2,484.0	2,535.4	223.9	611.8	82.8	5,937.8	4.2	238.8	243.0	0.0	299.2	3.1	1,037.7	83.1	7,603.9	167.8
2037	2,559.4	2,647.4	234.7	599.1	93.8	6,134.4	3.8	222.9	226.7	0.0	328.6	2.6	1,076.6	84.0	7,852.9	170.4
2038	2,647.8	2,892.6	248.2	660.1	114.2	6,562.9	3.4	214.7	218.1	0.0	394.1	2.2	1,077.9	81.1	8,336.2	176.5
2039	2,812.1	3,299.2	275.7	520.5	158.7	7,066.3	3.0	210.1	213.1	0.0	442.8	1.7	993.0	81.0	8,797.8	181.8
2040	3,050.8	3,531.5	296.1	495.2	185.1	7,558.7	2.4	203.5	205.9	0.0	482.8	1.4	1,028.6	79.9	9,357.3	187.4
2041	3,145.8	3,700.3	308.9	535.8	209.7	7,900.5	2.4	206.3	208.7	0.0	505.9	1.0	1,040.6	80.1	9,736.7	192.2
2042	3,273.4	3,879.9	324.3	563.3	235.5	8,276.4	2.4	205.3	207.7	0.0	544.1	0.7	1,081.0	79.2	10,188.9	196.6
2043	3,330.1	4,114.2	340.3	550.6	248.6	8,583.8	2.3	173.2	175.5	0.0	574.1	0.3	1,106.7	78.0	10,518.4	198.6
(2014-2029)	11,367.8	7,828.2	800.1	3,972.0	594.4	24,562.5	462.9	2,601.2	3,064.1	(9.4)	833.5	121.9	815.3	1,103.7	30,491.7	
(2014-2043)	18,562.4	15,076.5	1,438.7	5,558.0	903.5	41,539.2	473.5	3,227.5	3,701.0	(9.4)	1,725.6	131.5	3,322.4	1,341.4	51,751.6	

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

TOTAL REVENUE REQUIREMENTS: INCREASED ENVIRONMENTAL POLICY SCENARIO
ENHANCED RENEWABLE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.6	470.9	51.1	412.0	19.5	1,579.2	110.5	351.2	461.7	(2.0)	63.2	23.9	(0.1)	131.6	2,257.5	74.0
2015	634.0	467.3	50.8	441.6	42.1	1,635.7	111.2	367.1	478.3	(0.4)	64.8	21.3	(0.1)	183.0	2,382.7	78.8
2016	687.2	467.2	53.7	376.8	65.7	1,650.5	105.8	356.6	462.4	(0.9)	66.4	18.5	(0.1)	148.6	2,345.5	76.8
2017	816.1	588.8	63.0	389.0	75.5	1,932.3	94.8	297.9	392.8	(2.4)	74.1	15.5	(0.1)	138.3	2,550.5	82.5
2018	1,011.9	655.2	73.1	397.9	76.0	2,214.0	62.1	276.9	339.1	(2.3)	69.8	13.6	(0.1)	138.3	2,772.3	88.7
2019	1,058.5	691.5	73.3	406.4	73.9	2,303.6	62.3	291.3	353.6	(2.4)	71.5	11.7	42.4	141.0	2,921.4	92.4
2020	1,224.6	772.1	81.8	411.0	72.0	2,561.4	6.7	231.1	237.8	(2.5)	73.3	9.6	46.2	145.5	3,071.3	96.2
2021	1,416.7	848.6	92.7	442.4	70.7	2,871.1	6.5	233.2	239.7	0.0	95.0	9.2	57.7	67.5	3,340.2	102.8
2022	1,514.0	908.5	96.2	450.7	71.5	3,040.8	6.5	233.8	240.2	0.0	85.2	8.9	73.5	78.1	3,526.6	106.0
2023	1,803.2	988.3	101.3	460.3	70.2	3,423.3	6.4	228.7	235.2	0.0	98.3	8.4	81.0	84.3	3,930.5	115.6
2024	1,909.0	1,037.4	110.0	469.9	68.7	3,595.1	7.8	227.1	235.0	0.0	99.0	8.1	100.8	82.5	4,120.4	118.6
2025	1,995.9	1,112.3	116.4	470.7	67.2	3,762.5	8.5	230.0	238.5	0.0	99.1	7.7	126.3	81.5	4,315.6	122.0
2026	2,047.5	1,191.8	122.0	498.4	65.5	3,925.3	8.5	233.1	241.6	0.0	119.2	7.2	171.9	77.9	4,543.1	126.4
2027	2,188.7	1,275.5	132.3	520.9	68.5	4,185.9	8.5	220.1	228.6	0.0	119.3	6.8	257.5	78.7	4,876.8	133.2
2028	2,245.4	1,365.4	139.5	524.8	69.9	4,344.9	8.5	223.7	232.2	0.0	122.0	6.4	346.9	84.4	5,136.9	137.6
2029	2,204.7	1,482.9	148.7	554.3	71.4	4,462.0	8.5	226.5	234.9	0.0	146.1	6.1	435.6	88.1	5,372.7	141.0
2030	2,227.0	1,587.7	159.4	559.7	70.8	4,604.7	8.5	221.5	230.0	0.0	191.9	5.7	540.6	89.4	5,662.3	145.6
2031	2,301.0	1,668.3	165.3	567.6	70.3	4,772.6	8.1	224.4	232.5	0.0	151.6	5.3	606.4	89.1	5,857.5	147.4
2032	2,355.1	1,768.0	173.5	574.5	69.7	4,940.7	8.1	227.3	235.4	0.0	197.1	4.9	669.3	84.6	6,132.0	151.0
2033	2,419.5	1,876.1	183.1	593.8	68.8	5,141.3	8.4	228.4	236.8	0.0	187.4	4.5	729.8	83.6	6,383.4	153.8
2034	2,471.5	2,007.5	193.7	605.8	68.1	5,346.5	8.4	231.7	240.2	0.0	191.3	4.0	806.0	82.8	6,670.8	156.4
2035	2,523.1	2,170.4	203.8	646.2	82.6	5,626.1	8.4	235.2	243.6	0.0	244.2	3.6	874.2	83.3	7,075.1	161.5
2036	2,568.5	2,334.5	217.1	656.0	92.6	5,868.7	8.4	238.8	247.2	0.0	272.8	3.1	971.6	83.1	7,446.5	164.4
2037	2,642.3	2,447.9	227.3	644.5	112.1	6,074.0	8.0	222.9	230.9	0.0	298.7	2.6	1,008.6	84.0	7,698.7	167.0
2038	2,728.5	2,675.0	240.6	706.6	121.9	6,472.6	7.6	214.7	222.3	0.0	359.4	2.2	1,013.8	81.1	8,151.3	172.6
2039	2,890.4	3,056.6	267.9	568.1	175.9	6,958.9	7.2	210.1	217.3	0.0	411.1	1.7	926.0	81.0	8,595.9	177.7
2040	3,126.8	3,279.1	287.9	544.0	208.4	7,446.3	6.6	203.5	210.1	0.0	451.9	1.4	961.9	79.9	9,151.5	183.3
2041	3,220.7	3,441.4	300.0	585.8	237.5	7,785.4	6.6	206.3	212.9	0.0	472.5	1.0	975.3	80.1	9,527.2	188.0
2042	3,318.1	3,616.9	314.5	613.9	244.8	8,108.2	6.5	205.3	211.8	0.0	512.2	0.7	1,015.1	79.2	9,927.2	191.6
2043	3,384.4	3,843.7	329.0	602.6	264.1	8,423.9	6.5	173.2	179.7	0.0	541.6	0.3	1,041.1	78.0	10,264.7	193.8
(2014-2029)	11,925.1	7,428.7	787.6	4,083.8	587.4	24,812.7	476.7	2,601.0	3,077.8	(9.4)	789.3	121.9	703.0	1,103.7	30,598.9	
(2014-2043)	19,389.2	14,125.2	1,407.4	5,794.6	920.0	41,636.3	499.0	3,227.4	3,726.4	(9.4)	1,602.2	131.5	3,046.7	1,341.4	51,475.0	

TOTAL REVENUE REQUIREMENTS: INCREASED ENVIRONMENTAL POLICY SCENARIO
COAL REDUCTION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	624.1	470.9	51.1	412.0	19.5	1,577.6	110.5	351.2	461.7	(2.0)	63.2	23.9	(0.1)	131.6	2,256.0	74.0
2015	629.9	467.3	50.8	431.5	42.1	1,621.5	111.2	367.1	478.3	(0.4)	64.8	21.3	(0.1)	183.0	2,368.6	78.3
2016	660.1	470.7	50.8	363.5	65.7	1,610.8	105.8	369.3	475.1	(0.9)	66.4	18.5	(0.1)	148.6	2,318.5	76.0
2017	790.3	604.6	60.4	378.8	75.5	1,909.7	94.8	310.2	405.0	(2.4)	89.8	15.5	(0.1)	138.3	2,555.9	82.7
2018	949.3	675.1	68.8	386.2	76.0	2,155.4	62.1	282.0	344.1	(2.3)	73.2	13.6	(0.1)	138.3	2,722.2	87.1
2019	996.3	715.5	70.4	394.5	73.9	2,250.7	62.3	295.1	357.4	(2.4)	74.9	11.7	29.8	141.0	2,863.1	90.6
2020	1,152.8	820.4	79.2	394.5	72.6	2,519.4	5.3	231.1	236.4	(2.5)	73.8	9.6	37.6	145.5	3,019.9	94.6
2021	1,355.8	911.3	90.2	416.3	71.4	2,844.9	4.4	233.2	237.6	0.0	109.4	9.2	50.1	67.5	3,318.7	102.2
2022	1,424.6	1,000.2	96.1	423.4	72.0	3,016.2	4.4	233.1	237.4	0.0	100.1	8.9	71.2	78.1	3,511.8	105.6
2023	1,619.0	1,117.9	103.1	422.3	70.3	3,332.7	4.4	228.7	233.1	0.0	120.8	8.4	83.1	84.3	3,862.4	113.6
2024	1,674.4	1,198.0	110.3	406.2	68.7	3,457.5	4.4	227.1	231.5	0.0	129.6	8.1	109.6	82.5	4,018.8	115.7
2025	1,788.6	1,339.9	117.3	379.1	71.4	3,696.3	4.3	230.0	234.3	0.0	151.5	7.7	108.7	81.5	4,280.1	121.0
2026	1,902.7	1,422.8	124.5	385.7	73.8	3,909.5	4.3	233.1	237.4	0.0	158.4	7.2	156.6	77.9	4,547.1	126.5
2027	2,003.9	1,517.2	132.7	408.0	74.4	4,136.2	4.3	220.1	224.4	0.0	164.6	6.8	231.7	78.7	4,842.4	132.3
2028	2,066.9	1,620.7	142.0	424.9	73.1	4,327.5	4.3	223.7	228.0	0.0	172.9	6.4	313.3	84.4	5,132.5	137.5
2029	2,101.0	1,754.8	150.3	438.0	73.8	4,518.0	4.3	226.3	230.6	0.0	200.3	6.1	399.4	88.1	5,442.5	142.9
2030	2,150.9	1,877.5	159.9	436.9	72.8	4,698.0	4.3	221.3	225.6	0.0	268.2	5.7	494.8	89.4	5,781.6	148.6
2031	2,224.5	1,947.1	166.9	461.1	71.8	4,871.5	4.3	224.4	228.7	0.0	230.2	5.3	561.4	89.1	5,986.1	150.6
2032	2,277.4	2,060.2	175.3	442.0	70.9	5,025.7	4.3	227.3	231.6	0.0	256.3	4.9	618.0	84.6	6,221.1	153.2
2033	2,342.0	2,182.6	185.3	462.2	70.0	5,242.0	4.3	228.4	232.6	0.0	255.4	4.5	678.0	83.6	6,496.2	156.5
2034	2,394.0	2,331.8	195.1	491.9	83.8	5,496.7	4.2	231.7	236.0	0.0	272.4	4.0	750.6	82.8	6,842.5	160.4
2035	2,444.8	2,506.5	205.2	513.0	93.1	5,762.7	4.2	235.2	239.4	0.0	327.5	3.6	819.7	83.3	7,236.2	165.2
2036	2,491.3	2,703.8	218.7	515.3	111.9	6,041.1	4.2	238.8	243.0	0.0	358.6	3.1	904.1	83.1	7,633.0	168.5
2037	2,564.1	2,815.2	230.2	523.0	122.0	6,254.5	3.8	222.9	226.7	0.0	385.2	2.6	947.7	84.0	7,900.6	171.4
2038	2,643.1	3,077.0	243.2	555.9	141.6	6,660.6	3.4	214.7	218.1	0.0	458.7	2.2	942.4	81.1	8,363.0	177.0
2039	2,797.2	3,508.0	271.7	420.4	185.2	7,182.6	3.0	210.1	213.1	0.0	503.8	1.7	847.6	81.0	8,829.8	182.5
2040	3,063.8	3,739.9	292.4	416.7	227.7	7,740.5	2.4	203.5	205.9	0.0	551.1	1.4	882.4	79.9	9,461.2	189.5
2041	3,175.4	3,910.0	306.3	436.0	245.6	8,073.4	2.4	206.3	208.7	0.0	569.3	1.0	902.0	80.1	9,834.6	194.1
2042	3,271.7	4,113.5	321.4	454.4	263.5	8,424.6	2.4	205.3	207.7	0.0	617.6	0.7	930.7	79.2	10,260.4	198.0
2043	3,309.3	4,346.5	340.6	464.9	270.3	8,731.7	2.3	173.2	175.5	0.0	650.8	0.3	961.2	78.0	10,597.5	200.1
(2014-2029)	11,150.0	8,190.6	779.4	3,750.6	597.8	24,468.4	462.9	2,626.3	3,089.2	(9.4)	939.4	121.9	641.7	1,103.7	30,354.9	
(2014-2043)	18,401.6	15,912.6	1,407.4	5,088.6	956.1	41,766.3	473.5	3,252.6	3,726.1	(9.4)	1,990.7	131.5	2,812.8	1,341.4	51,759.4	

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

TOTAL REVENUE REQUIREMENTS: INCREASED ENVIRONMENTAL POLICY SCENARIO
COAL-TO-GAS CONVERSION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMIS-SION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	625.0	470.9	51.1	411.9	19.5	1,578.4	110.5	351.2	461.7	(2.0)	63.2	23.9	(0.1)	131.6	2,256.8	74.0
2015	632.7	467.3	50.8	441.6	42.1	1,634.5	111.2	367.1	478.3	(0.4)	64.8	21.3	(0.1)	183.0	2,381.5	78.7
2016	684.5	471.0	50.8	379.2	65.7	1,651.2	105.8	369.7	475.5	(0.9)	66.4	18.5	(0.1)	148.6	2,359.2	77.3
2017	822.8	604.6	60.3	391.1	75.5	1,954.4	94.8	308.8	403.7	(2.4)	77.9	15.5	(0.1)	138.3	2,587.4	83.7
2018	982.1	716.0	63.9	370.6	76.0	2,208.7	62.1	287.5	349.6	(2.3)	94.8	13.6	(0.1)	138.3	2,802.6	89.6
2019	1,028.6	755.3	67.8	383.4	73.9	2,309.1	62.3	300.2	362.4	(2.4)	92.2	11.7	7.0	141.0	2,921.0	92.4
2020	1,151.9	868.1	78.0	377.9	72.0	2,547.9	5.3	231.1	236.4	(2.5)	86.2	9.6	13.8	145.5	3,036.9	95.2
2021	1,314.5	964.4	88.7	396.5	70.7	2,834.7	4.4	236.4	240.7	0.0	128.2	9.2	24.5	67.5	3,304.9	101.7
2022	1,393.7	1,059.4	95.0	407.0	71.7	3,026.9	4.4	235.3	239.6	0.0	119.6	8.9	42.3	78.1	3,515.2	105.7
2023	1,590.4	1,180.7	102.4	403.3	70.3	3,347.1	4.4	228.7	233.1	0.0	141.6	8.4	53.8	84.3	3,868.4	113.8
2024	1,662.5	1,279.9	108.7	399.7	68.8	3,519.6	4.4	227.1	231.5	0.0	156.4	8.1	71.8	82.5	4,069.9	117.1
2025	1,794.9	1,340.0	117.2	398.0	71.5	3,721.5	4.3	230.0	234.3	0.0	152.2	7.7	109.1	81.5	4,306.3	121.8
2026	1,851.1	1,423.3	124.6	408.2	72.8	3,880.0	4.3	233.1	237.4	0.0	160.5	7.2	156.8	77.9	4,519.9	125.8
2027	1,873.9	1,517.9	132.9	424.9	72.1	4,021.7	4.3	220.1	224.4	0.0	166.9	6.8	231.8	78.7	4,730.2	129.2
2028	1,934.8	1,621.5	142.2	441.6	70.9	4,211.1	4.3	223.7	228.0	0.0	175.5	6.4	313.5	84.4	5,018.9	134.4
2029	1,992.4	1,755.8	150.3	458.6	72.2	4,429.3	4.3	226.3	230.6	0.0	202.7	6.1	399.6	88.1	5,356.5	140.6
2030	2,028.9	1,878.6	159.9	461.2	71.3	4,600.0	4.3	222.3	226.6	0.0	269.1	5.7	495.1	89.4	5,685.8	146.2
2031	2,092.1	1,947.8	167.0	478.6	70.4	4,755.9	4.3	224.4	228.7	0.0	231.5	5.3	561.5	89.1	5,872.0	147.8
2032	2,151.1	2,061.7	175.5	465.1	69.5	4,923.0	4.3	227.4	231.7	0.0	259.5	4.9	618.1	84.6	6,121.7	150.7
2033	2,244.8	2,183.4	185.4	481.6	68.7	5,163.9	4.3	228.4	232.6	0.0	256.0	4.5	678.1	83.6	6,418.6	154.6
2034	2,318.5	2,332.1	195.1	511.8	67.9	5,425.5	4.2	231.7	236.0	0.0	274.8	4.0	750.6	82.8	6,773.7	158.8
2035	2,373.5	2,506.8	205.3	537.0	67.6	5,690.1	4.2	235.2	239.4	0.0	331.0	3.6	819.7	83.3	7,167.2	163.6
2036	2,423.0	2,704.4	218.8	544.1	82.8	5,973.2	4.2	238.8	243.0	0.0	359.3	3.1	904.2	83.1	7,565.9	167.0
2037	2,499.3	2,815.2	230.4	544.4	93.8	6,183.1	3.8	222.9	226.7	0.0	386.8	2.6	947.7	84.0	7,830.9	169.9
2038	2,582.4	3,077.0	243.1	583.8	114.2	6,600.6	3.4	214.7	218.1	0.0	462.6	2.2	942.4	81.1	8,306.9	175.9
2039	2,739.7	3,509.2	271.6	443.4	158.7	7,122.6	3.0	210.1	213.1	0.0	506.1	1.7	847.9	81.0	8,772.4	181.3
2040	2,982.4	3,741.0	292.5	439.0	185.1	7,639.9	2.4	203.5	205.9	0.0	552.0	1.4	882.7	79.9	9,361.8	187.5
2041	3,080.1	3,909.5	306.4	462.6	209.7	7,968.4	2.4	206.3	208.7	0.0	572.6	1.0	901.9	80.1	9,732.7	192.1
2042	3,210.5	4,113.5	323.5	487.2	235.5	8,370.3	2.4	205.3	207.7	0.0	619.9	0.7	930.7	79.2	10,208.4	197.0
2043	3,273.0	4,346.8	340.7	489.7	248.6	8,698.7	2.3	173.2	175.5	0.0	649.8	0.3	961.3	78.0	10,563.7	199.5
(2014-2029)	11,032.1	8,407.9	771.0	3,756.6	594.4	24,562.1	462.9	2,635.8	3,098.8	(9.4)	1,012.6	121.9	550.0	1,103.7	30,439.6	
(2014-2043)	18,032.7	16,131.7	1,399.4	5,161.1	903.5	41,628.4	473.5	3,262.4	3,736.0	(9.4)	2,069.2	131.5	2,721.5	1,341.4	51,618.4	

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

ANNUAL AVERAGE SYSTEM COST INCREASED ENVIRONMENTAL POLICY SCENARIO - ($/MWh)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	74.0	74.0	74.0	74.0
2015	78.8	78.8	78.3	78.7
2016	76.8	76.8	76.0	77.3
2017	82.5	82.5	82.7	83.7
2018	88.7	88.7	87.1	89.6
2019	92.4	92.4	90.6	92.4
2020	95.4	96.2	94.6	95.2
2021	101.6	102.8	102.2	101.7
2022	105.2	106.0	105.6	105.7
2023	114.6	115.6	113.6	113.8
2024	117.4	118.6	115.7	117.1
2025	122.8	122.0	121.0	121.8
2026	127.5	126.4	126.5	125.8
2027	130.9	133.2	132.3	129.2
2028	135.5	137.6	137.5	134.4
2029	142.0	141.0	142.9	140.6

CUMULATIVE CAPITAL SPENDING EXISTING AND NEW GENERATION PLUS INCREMENTAL TRANSMISSION INCREASED ENVIRONMENTAL POLICY SCENARIO - ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	1,211.7	1,211.7	1,201.4	1,207.7
2015	1,678.9	1,678.9	1,617.4	1,635.6
2016	2,400.4	2,400.4	2,212.6	2,368.6
2017	3,826.1	3,826.1	3,548.1	3,758.4
2018	4,194.9	4,324.4	3,842.0	4,025.3
2019	4,446.6	4,881.7	4,255.1	4,256.2
2020	5,826.8	6,590.9	5,800.0	5,618.5
2021	7,573.0	8,521.4	7,432.3	7,342.2
2022	8,494.4	9,644.9	8,214.5	8,247.2
2023	9,458.2	10,731.4	9,075.9	9,180.4
2024	10,565.0	11,762.1	10,099.9	10,278.9
2025	11,089.1	12,831.4	10,934.6	10,796.2
2026	11,717.2	14,127.1	11,980.6	11,410.0
2027	12,519.4	14,732.8	12,832.1	12,203.1
2028	13,406.8	15,161.7	13,634.2	13,079.5
2029	14,181.3	15,864.4	14,488.6	13,841.9

1. Capital investment projected is regardless of whether APS constructs and owns new generation resources or whether resources are purchased by APS under long-term PPAs with market participants.

2. Capital spending excludes: (a) financial commitments to energy efficiency and distributed energy initiatives; (b) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing.

3. Capital spending includes ongoing capital investment for existing owned generation.

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

ANNUAL NATURAL GAS BURNS INCREASED ENVIRONMENTAL POLICY SCENARIO - (BCF)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	42.3	42.3	42.3	42.3
2015	38.5	38.5	38.5	38.5
2016	41.5	41.5	49.9	50.2
2017	54.4	54.4	66.4	65.7
2018	51.1	51.1	63.9	83.4
2019	55.9	55.9	67.1	84.0
2020	56.2	54.0	67.7	83.7
2021	62.9	59.3	74.5	90.7
2022	68.2	61.3	79.2	95.6
2023	79.4	69.1	91.2	107.0
2024	78.6	66.7	90.7	109.5
2025	80.7	67.9	109.7	109.7
2026	85.1	72.5	113.7	113.8
2027	90.5	77.5	118.9	119.0
2028	95.3	82.4	124.3	124.3
2029	105.8	91.7	134.0	134.1

ANNUAL CO2 EMISSIONS INCREASED ENVIRONMENTAL POLICY SCENARIO - (METRIC TONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	13,730,855	13,730,855	13,730,855	13,730,855
2015	13,552,104	13,552,104	13,552,104	13,552,104
2016	14,020,744	14,020,744	13,369,144	13,342,170
2017	14,091,217	14,091,217	13,171,278	13,241,643
2018	14,690,815	14,690,815	13,723,421	11,851,291
2019	14,371,626	14,371,626	13,511,466	11,948,953
2020	14,495,506	14,175,323	13,629,092	12,113,295
2021	14,909,850	14,459,218	14,008,555	12,493,422
2022	15,359,925	14,636,070	14,509,704	12,919,045
2023	15,414,168	14,398,353	14,505,519	13,005,219
2024	16,215,697	14,850,221	15,272,482	13,469,784
2025	16,706,474	15,298,720	14,081,184	14,083,559
2026	17,002,404	15,645,380	14,369,893	14,373,991
2027	17,266,866	15,931,914	14,663,916	14,668,609
2028	17,629,265	16,303,881	14,994,845	15,001,480
2029	17,672,120	16,391,573	15,145,233	15,151,455

Attachment F.1(c)(4) - Increased Environmental Policy Scenario

ANNUAL WATER USE INCREASED ENVIRONMENTAL POLICY SCENARIO - (ACRE-FEET)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	54,708	54,708	54,708	54,708
2015	54,265	54,265	54,265	54,265
2016	54,508	54,508	53,142	53,084
2017	54,510	54,510	52,621	52,724
2018	55,663	55,663	53,635	50,616
2019	55,035	55,035	53,228	50,719
2020	54,972	54,252	53,145	50,724
2021	55,589	54,561	53,650	51,182
2022	56,550	56,287	54,724	52,105
2023	56,852	57,323	54,877	52,404
2024	58,374	58,090	56,318	53,334
2025	58,033	58,699	52,926	52,886
2026	57,908	59,471	52,564	52,575
2027	58,338	58,974	53,028	53,038
2028	59,056	59,116	53,667	53,683
2029	59,194	59,331	54,106	54,103

Attachment F.1(c)(5) - Economic Contraction Scenario

ECONOMIC CONTRACTION SCENARIO - BASE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,076	7,097	7,211	7,329	7,434	7,544	7,648	7,763	7,885	8,007	8,132	8,259	8,390	8,525	8,664	8,806
3	Annual Load Growth %		0.3%	1.6%	1.6%	1.4%	1.5%	1.4%	1.5%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
4	Reserve Requirements	968	948	943	940	938	940	948	1,030	1,048	1,064	1,079	1,096	1,114	1,131	1,149	1,167
5	**Total Load Requirements**	**8,044**	**8,045**	**8,153**	**8,269**	**8,372**	**8,484**	**8,596**	**8,793**	**8,932**	**9,071**	**9,210**	**9,355**	**9,504**	**9,656**	**9,813**	**9,973**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,229	4,229	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	468	462	461	461	460	460	460	448	425	416	415	415	398	398	399
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	395	387	381	381	380	380	379	379	368	357	349	348	348	348	349	349
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,165**	**9,083**	**8,419**	**7,768**	**7,767**	**7,767**	**6,949**	**6,469**	**6,458**	**6,434**	**6,426**	**6,425**	**6,425**	**6,408**	**6,408**	**6,408**
22	Energy Efficiency	109	258	409	548	661	760	846	895	900	916	940	950	967	985	1,003	1,027
23	Distributed Energy	40	50	54	60	72	86	100	108	119	139	156	172	181	185	189	193
24	Demand Response	21	21	26	26	26	26	51	76	101	126	151	150	175	200	225	225
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	75	100	125	150	175	200	225	225
27	**Total Customer Resources**	**170**	**329**	**489**	**634**	**759**	**873**	**997**	**1,079**	**1,121**	**1,182**	**1,248**	**1,273**	**1,323**	**1,370**	**1,417**	**1,445**
29	Natural Gas	0	0	0	0	0	0	612	1,214	1,316	1,316	1,418	1,418	1,520	1,622	1,724	1,928
30	CCs/CTs	0	0	0	0	0	0	612	1,214	1,316	1,316	1,418	1,418	1,520	1,622	1,724	1,928
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	56	55	55	55	55	55	106	144	174	248	250	268	270	272
33	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	16	16	16
34	Solar	0	32	56	55	55	55	55	55	106	144	174	173	175	177	179	181
35	Geothermal	0	0	0	0	0	0	0	0	0	0	0	75	75	75	75	75
36	**Total Future Resources**	**0**	**32**	**56**	**55**	**55**	**55**	**667**	**1,269**	**1,422**	**1,460**	**1,592**	**1,666**	**1,770**	**1,890**	**1,994**	**2,200**
37	**TOTAL RESOURCES**	**9,335**	**9,444**	**8,963**	**8,457**	**8,582**	**8,695**	**8,614**	**8,817**	**9,000**	**9,076**	**9,266**	**9,364**	**9,518**	**9,667**	**9,819**	**10,053**

ENERGY MIX
ECONOMIC CONTRACTION SCENARIO: BASE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,776	6,593	3,166	2,509	33,341
2015	9,297	11,773	6,005	3,307	3,084	33,465
2016	9,325	12,049	5,527	3,412	3,660	33,973
2017	9,296	11,257	6,291	3,425	4,189	34,458
2018	9,297	11,680	5,788	3,466	4,641	34,871
2019	9,297	12,131	5,326	3,518	5,035	35,308
2020	9,325	12,337	4,798	3,577	5,411	35,447
2021	9,296	12,227	5,391	3,602	5,603	36,119
2022	9,297	12,212	5,550	3,936	5,627	36,622
2023	9,297	11,383	6,487	4,255	5,691	37,113
2024	9,324	12,026	5,900	4,598	5,765	37,612
2025	9,297	12,199	5,518	5,283	5,829	38,126
2026	9,297	12,316	5,805	5,341	5,895	38,654
2027	9,297	12,340	6,227	5,357	5,969	39,190
2028	9,325	12,393	6,593	5,383	6,054	39,747
2029	9,297	11,827	7,665	5,390	6,144	40,323

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.9%	35.3%	19.8%	9.5%	7.5%	100.0%
2015	27.8%	35.2%	17.9%	9.9%	9.2%	100.0%
2016	27.4%	35.5%	16.3%	10.0%	10.8%	100.0%
2017	27.0%	32.7%	18.3%	9.9%	12.2%	100.0%
2018	26.7%	33.5%	16.6%	9.9%	13.3%	100.0%
2019	26.3%	34.4%	15.1%	10.0%	14.3%	100.0%
2020	26.3%	34.8%	13.5%	10.1%	15.3%	100.0%
2021	25.7%	33.9%	14.9%	10.0%	15.5%	100.0%
2022	25.4%	33.3%	15.2%	10.7%	15.4%	100.0%
2023	25.1%	30.7%	17.5%	11.5%	15.3%	100.0%
2024	24.8%	32.0%	15.7%	12.2%	15.3%	100.0%
2025	24.4%	32.0%	14.5%	13.9%	15.3%	100.0%
2026	24.1%	31.9%	15.0%	13.8%	15.3%	100.0%
2027	23.7%	31.5%	15.9%	13.7%	15.2%	100.0%
2028	23.5%	31.2%	16.6%	13.5%	15.2%	100.0%
2029	23.1%	29.3%	19.0%	13.4%	15.2%	100.0%

1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(5) - Economic Contraction Scenario

ECONOMIC CONTRACTION SCENARIO - ENHANCED RENEWABLE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,076	7,097	7,211	7,329	7,434	7,544	7,648	7,763	7,885	8,007	8,132	8,259	8,390	8,525	8,664	8,806
3	Annual Load Growth %		0.3%	1.6%	1.6%	1.4%	1.5%	1.4%	1.5%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
4	Reserve Requirements	968	948	943	940	938	940	948	1,030	1,048	1,064	1,079	1,096	1,114	1,131	1,149	1,167
5	**Total Load Requirements**	**8,044**	**8,045**	**8,153**	**8,269**	**8,372**	**8,484**	**8,596**	**8,793**	**8,932**	**9,071**	**9,210**	**9,355**	**9,504**	**9,656**	**9,813**	**9,973**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,229	4,229	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	469	463	462	450	429	420	408	409	396	388	382	382	365	365	365
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	382	382	370	349	340	328	328	328	320	315	315	315	315	316
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,167**	**9,084**	**8,420**	**7,769**	**7,757**	**7,736**	**6,910**	**6,418**	**6,418**	**6,405**	**6,397**	**6,392**	**6,392**	**6,374**	**6,375**	**6,375**
22	Energy Efficiency	109	258	409	548	661	760	846	895	900	916	940	950	967	985	1,003	1,027
23	Distributed Energy	41	50	54	60	71	85	98	105	117	137	155	170	179	183	187	190
24	Demand Response	21	21	26	26	26	26	51	76	101	126	151	150	175	200	225	225
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	75	100	125	150	175	200	225	225
27	**Total Customer Resources**	**170**	**329**	**489**	**634**	**759**	**871**	**995**	**1,075**	**1,118**	**1,180**	**1,246**	**1,271**	**1,321**	**1,368**	**1,415**	**1,443**
29	Natural Gas	0	0	0	0	0	0	510	1,112	1,214	1,214	1,214	1,316	1,418	1,520	1,622	1,724
30	CCs/CTs	0	0	0	0	0	0	510	1,112	1,214	1,214	1,214	1,316	1,418	1,520	1,622	1,724
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	56	56	106	166	181	203	281	359	376	391	394	413	435	438
33	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	16	33	33
34	Solar	0	32	56	56	106	166	181	203	206	209	226	241	244	248	251	255
35	Geothermal	0	0	0	0	0	0	0	0	75	150	150	150	150	150	150	150
36	**Total Future Resources**	**0**	**32**	**56**	**56**	**106**	**166**	**691**	**1,315**	**1,495**	**1,573**	**1,590**	**1,707**	**1,812**	**1,933**	**2,057**	**2,162**
37	TOTAL RESOURCES	9,336	9,446	8,965	8,459	8,621	8,773	8,596	8,808	9,032	9,158	9,234	9,370	9,525	9,675	9,847	9,980

ENERGY MIX
ECONOMIC CONTRACTION SCENARIO: ENHANCED RENEWABLE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,776	6,593	3,166	2,509	33,341
2015	9,297	11,773	6,005	3,307	3,084	33,465
2016	9,325	12,049	5,527	3,412	3,660	33,973
2017	9,296	11,257	6,291	3,425	4,189	34,458
2018	9,297	11,621	5,568	3,745	4,641	34,871
2019	9,297	11,860	4,759	4,355	5,035	35,308
2020	9,325	11,807	4,209	4,696	5,411	35,447
2021	9,296	11,493	4,454	5,276	5,603	36,122
2022	9,297	11,404	4,372	5,922	5,627	36,622
2023	9,297	10,594	4,976	6,554	5,691	37,113
2024	9,324	11,015	4,327	7,182	5,765	37,612
2025	9,297	11,322	3,851	7,828	5,829	38,126
2026	9,297	11,366	4,210	7,886	5,895	38,654
2027	9,297	11,431	4,591	7,901	5,969	39,190
2028	9,325	11,412	4,723	8,234	6,054	39,747
2029	9,297	10,995	5,653	8,234	6,144	40,323

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.9%	35.3%	19.8%	9.5%	7.5%	100.0%
2015	27.8%	35.2%	17.9%	9.9%	9.2%	100.0%
2016	27.4%	35.5%	16.3%	10.0%	10.8%	100.0%
2017	27.0%	32.7%	18.3%	9.9%	12.2%	100.0%
2018	26.7%	33.3%	16.0%	10.7%	13.3%	100.0%
2019	26.3%	33.6%	13.5%	12.3%	14.3%	100.0%
2020	26.3%	33.3%	11.9%	13.2%	15.3%	100.0%
2021	25.7%	31.8%	12.3%	14.6%	15.5%	100.0%
2022	25.4%	31.1%	11.9%	16.2%	15.4%	100.0%
2023	25.1%	28.5%	13.4%	17.7%	15.3%	100.0%
2024	24.8%	29.3%	11.5%	19.1%	15.3%	100.0%
2025	24.4%	29.7%	10.1%	20.5%	15.3%	100.0%
2026	24.1%	29.4%	10.9%	20.4%	15.3%	100.0%
2027	23.7%	29.2%	11.7%	20.2%	15.2%	100.0%
2028	23.5%	28.7%	11.9%	20.7%	15.2%	100.0%
2029	23.1%	27.3%	14.0%	20.4%	15.2%	100.0%

1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(5) - Economic Contraction Scenario

ECONOMIC CONTRACTION SCENARIO - COAL REDUCTION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,076	7,097	7,211	7,329	7,434	7,544	7,648	7,763	7,885	8,007	8,132	8,259	8,390	8,525	8,664	8,806
3	Annual Load Growth %		0.3%	1.6%	1.6%	1.4%	1.5%	1.4%	1.5%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
4	Reserve Requirements	968	948	943	940	938	940	948	1,030	1,048	1,064	1,079	1,096	1,114	1,131	1,149	1,167
5	**Total Load Requirements**	**8,044**	**8,045**	**8,153**	**8,269**	**8,372**	**8,484**	**8,596**	**8,793**	**8,932**	**9,071**	**9,210**	**9,355**	**9,504**	**9,656**	**9,813**	**9,973**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	4,879	4,229	4,229	4,229	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	468	462	461	461	460	460	460	448	425	416	415	415	398	398	399
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	395	387	381	381	380	380	379	379	368	357	349	348	348	348	349	349
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,165**	**9,083**	**8,159**	**7,508**	**7,507**	**7,507**	**6,689**	**6,209**	**6,198**	**6,174**	**6,166**	**5,778**	**5,778**	**5,761**	**5,761**	**5,761**
22	Energy Efficiency	109	258	409	548	661	760	846	895	900	916	940	950	967	985	1,003	1,027
23	Distributed Energy	40	50	54	60	72	86	100	108	119	139	156	172	181	185	189	193
24	Demand Response	21	21	26	26	26	26	51	76	101	126	151	150	175	200	225	225
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	75	100	125	150	175	200	225	225
27	**Total Customer Resources**	**170**	**329**	**489**	**634**	**759**	**873**	**997**	**1,079**	**1,121**	**1,182**	**1,248**	**1,273**	**1,323**	**1,370**	**1,417**	**1,445**
29	Natural Gas	0	0	0	102	102	102	1,112	1,612	1,612	1,612	1,714	2,122	2,224	2,326	2,428	2,530
30	CCs/CTs	0	0	0	102	102	102	1,112	1,612	1,612	1,612	1,714	2,122	2,224	2,326	2,428	2,530
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	56	55	55	55	55	55	106	144	174	248	250	268	270	272
33	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	16	16	16
34	Solar	0	32	56	55	55	55	55	55	106	144	174	173	175	177	179	181
35	Geothermal	0	0	0	0	0	0	0	0	0	0	0	75	75	75	75	75
36	**Total Future Resources**	**0**	**32**	**56**	**157**	**157**	**157**	**1,167**	**1,667**	**1,718**	**1,756**	**1,888**	**2,370**	**2,474**	**2,594**	**2,698**	**2,802**
37	**TOTAL RESOURCES**	**9,335**	**9,444**	**8,703**	**8,299**	**8,424**	**8,537**	**8,854**	**8,955**	**9,036**	**9,112**	**9,302**	**9,421**	**9,575**	**9,724**	**9,876**	**10,008**

ENERGY MIX
ECONOMIC CONTRACTION SCENARIO: COAL REDUCTION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,776	6,593	3,166	2,509	33,341
2015	9,297	11,773	6,005	3,307	3,084	33,465
2016	9,325	11,002	6,574	3,412	3,660	33,973
2017	9,296	9,748	7,800	3,425	4,189	34,458
2018	9,297	10,188	7,279	3,466	4,641	34,871
2019	9,297	10,793	6,664	3,518	5,035	35,308
2020	9,325	10,755	6,380	3,577	5,411	35,447
2021	9,296	10,614	7,007	3,602	5,603	36,121
2022	9,297	10,636	7,126	3,936	5,627	36,622
2023	9,297	9,834	8,036	4,255	5,691	37,113
2024	9,324	10,448	7,478	4,598	5,765	37,612
2025	9,297	8,709	9,008	5,283	5,829	38,126
2026	9,297	8,687	9,433	5,341	5,895	38,654
2027	9,297	8,666	9,901	5,357	5,969	39,190
2028	9,325	8,609	10,377	5,383	6,054	39,747
2029	9,297	8,178	11,314	5,390	6,144	40,323

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.9%	35.3%	19.8%	9.5%	7.5%	100.0%
2015	27.8%	35.2%	17.9%	9.9%	9.2%	100.0%
2016	27.4%	32.4%	19.4%	10.0%	10.8%	100.0%
2017	27.0%	28.3%	22.6%	9.9%	12.2%	100.0%
2018	26.7%	29.2%	20.9%	9.9%	13.3%	100.0%
2019	26.3%	30.6%	18.9%	10.0%	14.3%	100.0%
2020	26.3%	30.3%	18.0%	10.1%	15.3%	100.0%
2021	25.7%	29.4%	19.4%	10.0%	15.5%	100.0%
2022	25.4%	29.0%	19.5%	10.7%	15.4%	100.0%
2023	25.1%	26.5%	21.7%	11.5%	15.3%	100.0%
2024	24.8%	27.8%	19.9%	12.2%	15.3%	100.0%
2025	24.4%	22.8%	23.6%	13.9%	15.3%	100.0%
2026	24.1%	22.5%	24.4%	13.8%	15.3%	100.0%
2027	23.7%	22.1%	25.3%	13.7%	15.2%	100.0%
2028	23.5%	21.7%	26.1%	13.5%	15.2%	100.0%
2029	23.1%	20.3%	28.1%	13.4%	15.2%	100.0%

1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(5) - Economic Contraction Scenario

ECONOMIC CONTRACTION SCENARIO - COAL-TO-GAS CONVERSION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,076	7,097	7,211	7,329	7,434	7,544	7,648	7,763	7,885	8,007	8,132	8,259	8,390	8,525	8,664	8,806
3	Annual Load Growth %		0.3%	1.6%	1.6%	1.4%	1.5%	1.4%	1.5%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
4	Reserve Requirements	968	948	943	940	938	940	948	1,030	1,048	1,064	1,079	1,096	1,114	1,131	1,149	1,167
5	**Total Load Requirements**	**8,044**	**8,045**	**8,153**	**8,269**	**8,372**	**8,484**	**8,596**	**8,793**	**8,932**	**9,071**	**9,210**	**9,355**	**9,504**	**9,656**	**9,813**	**9,973**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	5,139	4,489	4,876	4,876	4,059	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,514	1,514	1,901	1,901	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	468	462	461	461	460	460	460	448	425	416	415	415	398	398	399
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	395	387	381	381	380	380	379	379	368	357	349	348	348	348	349	349
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,165**	**9,083**	**8,419**	**7,768**	**7,767**	**7,767**	**6,949**	**6,469**	**6,458**	**6,434**	**6,426**	**6,425**	**6,425**	**6,408**	**6,408**	**6,408**
22	Energy Efficiency	109	258	409	548	661	760	846	895	900	916	940	950	967	985	1,003	1,027
23	Distributed Energy	40	50	54	60	72	86	100	108	119	139	156	172	181	185	189	193
24	Demand Response	21	21	26	26	26	26	51	76	101	126	151	150	175	200	225	225
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	75	100	125	150	175	200	225	225
27	**Total Customer Resources**	**170**	**329**	**489**	**634**	**759**	**873**	**997**	**1,079**	**1,121**	**1,182**	**1,248**	**1,273**	**1,323**	**1,370**	**1,417**	**1,445**
29	Natural Gas	0	0	0	0	0	0	612	1,214	1,316	1,316	1,418	1,418	1,520	1,622	1,724	1,928
30	CCs/CTs	0	0	0	0	0	0	612	1,214	1,316	1,316	1,418	1,418	1,520	1,622	1,724	1,928
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	56	55	55	55	55	55	106	144	174	248	250	268	270	272
33	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	16	16	16
34	Solar	0	32	56	55	55	55	55	55	106	144	174	173	175	177	179	181
35	Geothermal	0	0	0	0	0	0	0	0	0	0	0	75	75	75	75	75
36	**Total Future Resources**	**0**	**32**	**56**	**55**	**55**	**55**	**667**	**1,269**	**1,422**	**1,460**	**1,592**	**1,666**	**1,770**	**1,890**	**1,994**	**2,200**
37	TOTAL RESOURCES	9,335	9,444	8,963	8,457	8,582	8,695	8,614	8,817	9,000	9,076	9,266	9,364	9,518	9,667	9,819	10,053

ENERGY MIX
ECONOMIC CONTRACTION SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	11,776	6,593	3,166	2,509	33,341
2015	9,297	11,773	6,005	3,307	3,084	33,465
2016	9,325	10,962	6,613	3,412	3,660	33,973
2017	9,296	9,847	7,701	3,425	4,189	34,458
2018	9,297	7,907	9,561	3,466	4,641	34,871
2019	9,297	8,577	8,880	3,518	5,035	35,308
2020	9,325	8,719	8,416	3,577	5,411	35,447
2021	9,296	8,538	9,078	3,602	5,603	36,116
2022	9,297	8,569	9,193	3,936	5,627	36,621
2023	9,297	7,959	9,911	4,255	5,691	37,113
2024	9,324	8,265	9,660	4,598	5,765	37,611
2025	9,297	8,812	8,905	5,283	5,829	38,126
2026	9,297	8,814	9,306	5,341	5,895	38,654
2027	9,297	8,805	9,762	5,357	5,969	39,190
2028	9,325	8,736	10,249	5,383	6,054	39,746
2029	9,297	8,321	11,172	5,390	6,144	40,323

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.9%	35.3%	19.8%	9.5%	7.5%	100.0%
2015	27.8%	35.2%	17.9%	9.9%	9.2%	100.0%
2016	27.4%	32.3%	19.5%	10.0%	10.8%	100.0%
2017	27.0%	28.6%	22.3%	9.9%	12.2%	100.0%
2018	26.7%	22.7%	27.4%	9.9%	13.3%	100.0%
2019	26.3%	24.3%	25.1%	10.0%	14.3%	100.0%
2020	26.3%	24.6%	23.7%	10.1%	15.3%	100.0%
2021	25.7%	23.6%	25.1%	10.0%	15.5%	100.0%
2022	25.4%	23.4%	25.1%	10.7%	15.4%	100.0%
2023	25.1%	21.4%	26.7%	11.5%	15.3%	100.0%
2024	24.8%	22.0%	25.7%	12.2%	15.3%	100.0%
2025	24.4%	23.1%	23.4%	13.9%	15.3%	100.0%
2026	24.1%	22.8%	24.1%	13.8%	15.3%	100.0%
2027	23.7%	22.5%	24.9%	13.7%	15.2%	100.0%
2028	23.5%	22.0%	25.8%	13.5%	15.2%	100.0%
2029	23.1%	20.6%	27.7%	13.4%	15.2%	100.0%

1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(5) - Economic Contraction Scenario

TOTAL REVENUE REQUIREMENTS ECONOMIC CONTRACTION SCENARIO - ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	2,210.8	2,210.8	2,209.3	2,210.1
2015	2,268.9	2,268.9	2,255.1	2,267.7
2016	2,213.8	2,213.8	2,186.2	2,224.6
2017	2,265.9	2,265.9	2,268.9	2,295.2
2018	2,414.2	2,426.9	2,374.0	2,413.1
2019	2,451.6	2,500.5	2,412.4	2,461.1
2020	2,412.8	2,482.4	2,434.1	2,407.4
2021	2,532.8	2,620.8	2,536.6	2,548.7
2022	2,601.4	2,709.0	2,581.1	2,617.4
2023	2,737.6	2,843.3	2,706.0	2,750.9
2024	2,785.4	2,890.2	2,721.7	2,807.6
2025	2,828.2	2,950.6	2,800.5	2,813.6
2026	2,889.3	3,009.7	2,871.5	2,861.1
2027	2,930.3	3,044.4	2,911.8	2,901.1
2028	2,970.7	3,093.5	2,958.3	2,951.5
2029	3,035.5	3,150.3	2,996.6	3,006.1
2030	3,120.6	3,214.1	3,087.8	3,111.4
2031	3,127.5	3,228.2	3,111.5	3,133.6
2032	3,214.3	3,296.0	3,155.8	3,178.3
2033	3,236.7	3,321.5	3,220.6	3,229.5
2034	3,311.0	3,374.0	3,298.4	3,310.2
2035	3,413.2	3,463.5	3,412.3	3,432.0
2036	3,490.3	3,525.7	3,483.8	3,513.5
2037	3,544.5	3,583.1	3,556.2	3,580.8
2038	3,709.5	3,737.9	3,705.2	3,738.2
2039	3,778.5	3,788.0	3,770.9	3,812.5
2040	3,943.3	3,952.3	3,958.1	4,000.8
2041	4,111.9	4,124.1	4,102.9	4,165.9
2042	4,232.6	4,234.9	4,233.7	4,296.8
2043	4,280.7	4,257.3	4,291.1	4,355.9
CPW @ 6.86%				
(2014-2029)	23,977.9	24,515.6	23,801.0	23,998.1
(2014-2043)	34,681.1	35,375.8	34,466.0	34,753.8

TOTAL REVENUE REQUIREMENTS: ECONOMIC CONTRACTION SCENARIO
BASE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	603.9	461.5	49.7	408.1	19.1	1,542.2	110.3	348.2	458.5	(2.0)	63.2	22.5	(0.1)	126.4	2,210.8	72.9
2015	610.9	449.9	48.1	433.4	40.7	1,583.0	110.9	359.8	470.7	(0.4)	64.8	20.1	(0.1)	130.7	2,268.9	75.9
2016	660.9	416.7	49.1	365.8	63.5	1,556.1	105.5	342.7	448.2	(0.9)	66.4	17.4	(0.1)	126.6	2,213.8	74.3
2017	672.9	520.8	54.7	371.0	73.1	1,692.5	94.9	288.2	383.0	(2.4)	68.1	14.7	(0.1)	110.1	2,265.9	76.3
2018	829.5	566.0	58.4	373.2	73.7	1,900.8	62.1	268.9	330.9	(2.3)	69.8	12.8	(0.1)	102.3	2,414.2	81.5
2019	859.0	570.5	59.4	378.6	71.7	1,939.2	62.2	275.7	338.0	(2.4)	71.5	11.0	(0.1)	94.4	2,451.6	82.8
2020	872.2	618.6	64.3	373.3	70.4	1,998.8	5.3	231.1	236.4	(2.5)	73.3	9.0	(0.1)	97.8	2,412.8	81.6
2021	966.3	658.5	69.6	396.3	69.0	2,159.6	4.4	237.5	241.8	0.0	76.9	8.7	(0.1)	45.8	2,532.8	85.0
2022	1,009.3	682.8	71.9	394.7	69.5	2,228.1	5.1	232.6	237.7	0.0	77.0	8.3	(0.1)	50.3	2,601.4	86.1
2023	1,101.5	721.5	74.3	394.0	67.9	2,359.2	5.7	228.7	234.5	0.0	79.2	8.0	(0.1)	56.8	2,737.6	89.6
2024	1,140.4	728.8	78.1	394.0	66.3	2,407.6	6.5	227.1	233.6	0.0	80.9	7.6	(0.1)	55.8	2,785.4	90.2
2025	1,175.2	735.0	77.8	394.0	64.8	2,446.7	6.4	230.0	236.4	0.0	82.9	7.2	(0.1)	54.9	2,828.2	90.6
2026	1,182.3	758.7	80.0	412.4	63.5	2,497.0	6.4	233.2	239.7	0.0	89.9	6.8	(0.1)	56.0	2,889.3	91.4
2027	1,197.0	783.0	82.5	425.1	62.1	2,549.7	6.4	220.1	226.5	0.0	87.3	6.4	(0.1)	60.5	2,930.3	91.4
2028	1,199.0	810.0	86.2	422.7	60.6	2,578.6	6.4	223.7	230.1	0.0	91.3	6.1	(0.1)	64.7	2,970.7	91.4
2029	1,202.9	842.6	87.8	443.7	61.2	2,638.2	6.4	226.3	232.7	0.0	94.9	5.7	(0.1)	64.0	3,035.5	92.1
2030	1,205.3	893.3	92.3	442.9	59.7	2,693.5	6.4	222.9	229.3	0.0	132.0	5.3	(0.1)	60.6	3,120.6	93.3
2031	1,227.4	912.3	94.9	443.3	58.2	2,736.2	6.4	224.4	230.8	0.0	96.2	5.0	(0.1)	59.5	3,127.5	92.2
2032	1,228.9	951.4	97.7	442.9	56.7	2,777.6	6.4	227.3	233.7	0.0	144.0	4.6	(0.1)	54.5	3,214.3	93.4
2033	1,232.6	991.5	101.9	452.4	55.8	2,834.2	6.4	228.4	234.7	0.0	110.7	4.2	(0.1)	53.0	3,236.7	92.7
2034	1,242.2	1,033.2	105.8	456.9	55.3	2,893.4	6.6	231.7	238.3	0.0	123.5	3.8	(0.1)	52.1	3,311.0	93.3
2035	1,249.6	1,085.1	107.6	483.8	54.7	2,980.8	6.7	235.2	241.9	0.0	134.5	3.4	(0.1)	52.7	3,413.2	94.6
2036	1,254.7	1,134.8	113.1	485.7	54.5	3,042.9	6.8	238.8	245.6	0.0	145.8	2.9	(0.1)	53.2	3,490.3	95.1
2037	1,265.3	1,170.9	118.3	471.8	54.2	3,080.6	6.9	222.9	229.8	0.0	178.2	2.4	(0.1)	53.7	3,544.5	95.2
2038	1,287.8	1,241.8	121.7	515.6	54.2	3,221.0	7.0	214.8	221.8	0.0	213.7	2.1	(0.1)	51.0	3,709.5	98.2
2039	1,322.7	1,347.9	134.5	403.8	58.9	3,267.8	7.1	210.1	217.2	0.0	240.7	1.6	(0.1)	51.4	3,778.5	98.5
2040	1,432.9	1,401.8	142.0	382.7	62.2	3,421.5	7.2	203.5	210.6	0.0	258.4	1.3	(0.1)	51.6	3,943.3	101.2
2041	1,480.8	1,462.2	146.6	409.8	63.3	3,562.7	7.4	206.3	213.7	0.0	283.0	1.0	(0.1)	51.7	4,111.9	104.1
2042	1,518.6	1,512.7	151.1	426.2	73.2	3,681.8	7.6	205.3	212.9	0.0	285.7	0.7	(0.1)	51.7	4,232.6	105.6
2043	1,525.8	1,577.2	155.6	414.7	79.5	3,752.8	8.1	173.2	181.4	0.0	294.8	0.3	(0.1)	51.5	4,280.7	105.3
(2014-2029)	8,480.2	5,782.7	613.2	3,775.0	576.7	19,227.8	473.4	2,611.1	3,084.5	(9.6)	710.6	116.8	(0.7)	848.5	23,977.9	
(2014-2043)	12,427.2	9,249.2	963.4	5,142.3	756.5	28,538.6	494.1	3,283.8	3,777.8	(9.6)	1,235.2	126.5	(1.0)	1,013.4	34,681.1	

Attachment F.1(c)(5) - Economic Contraction Scenario

TOTAL REVENUE REQUIREMENTS: ECONOMIC CONTRACTION SCENARIO
ENHANCED RENEWABLE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	603.9	461.5	49.7	408.1	19.1	1,542.2	110.3	348.2	458.5	(2.0)	63.2	22.5	(0.1)	126.4	2,210.8	72.9
2015	610.9	449.9	48.1	433.4	40.7	1,583.0	110.9	359.8	470.7	(0.4)	64.8	20.1	(0.1)	130.7	2,268.9	75.9
2016	660.9	416.7	49.1	365.8	63.5	1,556.1	105.5	342.7	448.2	(0.9)	66.4	17.4	(0.1)	126.6	2,213.8	74.3
2017	672.9	520.8	54.7	371.0	73.1	1,692.5	94.9	288.2	383.0	(2.4)	68.1	14.7	(0.1)	110.1	2,265.9	76.3
2018	846.5	559.2	58.3	375.9	73.7	1,913.6	62.8	268.0	330.8	(2.3)	69.8	12.8	(0.1)	102.3	2,426.9	82.0
2019	919.3	551.7	59.0	386.7	71.7	1,988.4	64.3	273.3	337.6	(2.4)	71.5	11.0	(0.1)	94.4	2,500.5	84.5
2020	956.4	592.3	63.1	384.0	69.8	2,065.6	8.1	231.1	239.2	(2.5)	73.3	9.0	(0.1)	97.8	2,482.4	83.9
2021	1,078.8	619.6	68.6	412.4	68.6	2,248.0	8.6	234.7	243.2	0.0	75.1	8.7	(0.1)	45.8	2,620.8	87.9
2022	1,144.5	634.2	68.8	415.3	69.4	2,332.2	8.5	232.6	241.1	0.0	77.0	8.3	(0.1)	50.3	2,709.0	89.6
2023	1,244.3	660.8	69.9	419.4	67.9	2,462.3	8.5	228.7	237.3	0.0	78.9	8.0	(0.1)	56.8	2,843.3	93.1
2024	1,284.7	661.8	73.6	422.3	66.4	2,508.8	9.9	227.1	237.1	0.0	80.9	7.6	(0.1)	55.8	2,890.2	93.6
2025	1,326.5	676.5	75.2	421.3	64.8	2,564.3	11.3	230.0	241.3	0.0	82.9	7.2	(0.1)	54.9	2,950.6	94.5
2026	1,334.2	702.5	77.2	440.3	63.3	2,617.4	11.3	233.2	244.5	0.0	85.0	6.8	(0.1)	56.0	3,009.7	95.2
2027	1,341.4	722.1	80.1	453.5	62.0	2,659.1	11.3	220.1	231.3	0.0	87.1	6.4	(0.1)	60.5	3,044.4	95.0
2028	1,359.8	738.4	81.6	457.0	60.6	2,697.5	12.3	223.7	235.9	0.0	89.3	6.1	(0.1)	64.7	3,093.5	95.2
2029	1,361.1	764.5	85.6	478.1	61.3	2,750.6	12.2	226.3	238.6	0.0	91.6	5.7	(0.1)	64.0	3,150.3	95.5
2030	1,360.5	810.8	89.1	478.0	59.8	2,798.1	12.2	221.8	234.1	0.0	116.1	5.3	(0.1)	60.6	3,214.1	96.1
2031	1,373.3	830.0	90.6	478.8	58.3	2,831.0	12.2	224.4	236.6	0.0	96.2	5.0	(0.1)	59.5	3,228.2	95.1
2032	1,373.8	865.9	93.8	479.0	56.7	2,869.2	12.2	227.3	239.6	0.0	128.2	4.6	(0.1)	54.5	3,296.0	95.8
2033	1,381.0	899.4	97.9	489.3	55.2	2,922.8	12.2	228.4	240.6	0.0	101.1	4.2	(0.1)	53.0	3,321.5	95.1
2034	1,373.8	938.4	101.6	494.0	54.5	2,962.2	12.5	231.7	244.2	0.0	111.9	3.8	(0.1)	52.1	3,374.0	95.0
2035	1,381.3	982.1	105.2	521.6	54.4	3,044.5	12.6	235.2	247.7	0.0	115.3	3.4	(0.1)	52.7	3,463.5	96.0
2036	1,378.6	1,029.7	109.3	523.9	54.1	3,095.7	12.7	238.8	251.5	0.0	122.5	2.9	(0.1)	53.2	3,525.7	96.1
2037	1,389.3	1,066.6	113.1	510.6	54.1	3,133.8	12.8	222.9	235.6	0.0	157.7	2.4	(0.1)	53.7	3,583.1	96.3
2038	1,416.8	1,128.0	117.8	555.3	53.8	3,271.8	12.8	214.7	227.5	0.0	185.6	2.1	(0.1)	51.0	3,737.9	98.9
2039	1,447.2	1,211.5	130.7	444.2	68.6	3,302.2	12.9	210.1	223.0	0.0	209.9	1.6	(0.1)	51.4	3,788.0	98.7
2040	1,552.8	1,261.2	138.4	423.6	78.3	3,454.3	13.0	203.5	216.5	0.0	228.8	1.3	(0.1)	51.6	3,952.3	101.4
2041	1,596.3	1,317.4	142.6	451.4	92.5	3,600.2	13.2	206.3	219.5	0.0	251.9	1.0	(0.1)	51.7	4,124.1	104.4
2042	1,629.8	1,366.4	146.3	468.4	98.1	3,708.9	13.4	205.3	218.7	0.0	255.1	0.7	(0.1)	51.7	4,234.9	105.7
2043	1,626.9	1,427.2	149.5	457.6	100.1	3,761.3	14.0	173.2	187.2	0.0	257.1	0.3	(0.1)	51.5	4,257.3	104.7
(2014-2029)	9,173.0	5,507.9	599.7	3,896.5	576.1	19,753.1	494.9	2,607.2	3,102.2	(9.6)	705.4	116.8	(0.7)	848.5	24,515.6	
(2014-2043)	13,525.2	8,648.6	937.8	5,380.2	770.7	29,262.4	533.5	3,279.5	3,813.0	(9.6)	1,171.0	126.5	(1.0)	1,013.4	35,375.8	

TOTAL REVENUE REQUIREMENTS: ECONOMIC CONTRACTION SCENARIO
COAL REDUCTION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	602.4	461.5	49.7	408.1	19.1	1,540.7	110.3	348.2	458.5	(2.0)	63.2	22.5	(0.1)	126.4	2,209.3	72.9
2015	607.0	449.9	48.1	423.5	40.7	1,569.2	110.9	359.8	470.7	(0.4)	64.8	20.1	(0.1)	130.7	2,255.1	75.5
2016	635.7	418.2	46.4	352.9	63.5	1,516.7	105.5	354.6	460.1	(0.9)	66.4	17.4	(0.1)	126.6	2,186.2	73.4
2017	658.1	530.6	51.6	361.6	73.6	1,675.6	94.9	300.7	395.6	(2.4)	75.3	14.7	(0.1)	110.1	2,268.9	76.4
2018	787.3	575.9	55.3	362.7	74.6	1,855.8	62.1	273.7	335.7	(2.3)	69.8	12.8	(0.1)	102.3	2,374.0	80.2
2019	816.5	582.7	56.5	368.0	72.7	1,896.5	62.2	279.3	341.5	(2.4)	71.5	11.0	(0.1)	94.4	2,412.4	81.5
2020	885.3	636.8	62.7	364.5	70.8	2,020.1	5.3	231.1	236.4	(2.5)	73.3	9.0	(0.1)	97.8	2,434.1	82.3
2021	958.0	678.4	69.5	381.0	69.0	2,155.9	4.4	235.4	239.8	0.0	86.5	8.7	(0.1)	45.8	2,536.6	85.1
2022	978.3	703.7	72.0	384.5	69.3	2,207.8	5.1	232.6	237.7	0.0	77.0	8.3	(0.1)	50.3	2,581.1	85.4
2023	1,054.0	741.5	74.4	381.3	67.7	2,318.8	5.7	228.7	234.5	0.0	87.9	8.0	(0.1)	56.8	2,706.0	88.6
2024	1,085.0	748.2	77.8	364.4	66.2	2,341.7	6.5	227.1	233.6	0.0	83.1	7.6	(0.1)	55.8	2,721.7	88.2
2025	1,159.2	764.2	75.8	343.7	64.9	2,407.9	6.4	230.0	236.4	0.0	94.2	7.2	(0.1)	54.9	2,800.5	89.7
2026	1,192.8	787.3	78.3	344.7	63.5	2,466.5	6.4	233.1	239.5	0.0	102.7	6.8	(0.1)	56.0	2,871.5	90.8
2027	1,203.6	809.5	80.6	359.5	62.0	2,515.2	6.4	220.1	226.5	0.0	103.2	6.4	(0.1)	60.5	2,911.8	90.8
2028	1,203.3	835.3	83.7	369.9	60.5	2,552.7	6.4	223.7	230.1	0.0	104.8	6.1	(0.1)	64.7	2,958.3	91.0
2029	1,191.1	864.4	86.5	376.5	61.1	2,579.6	6.4	226.3	232.7	0.0	114.7	5.7	(0.1)	64.0	2,996.6	90.9
2030	1,181.3	913.9	89.4	370.8	59.6	2,615.0	6.4	223.1	229.5	0.0	177.5	5.3	(0.1)	60.6	3,087.8	92.3
2031	1,203.8	940.5	92.0	386.3	58.1	2,680.7	6.4	224.4	230.8	0.0	135.6	5.0	(0.1)	59.5	3,111.5	91.7
2032	1,205.3	979.6	94.8	365.6	57.2	2,702.5	6.4	227.3	233.7	0.0	160.6	4.6	(0.1)	54.5	3,155.8	91.7
2033	1,221.6	1,024.1	98.1	377.8	56.5	2,778.2	6.4	228.4	234.7	0.0	150.6	4.2	(0.1)	53.0	3,220.6	92.2
2034	1,227.8	1,069.3	101.7	398.2	55.6	2,852.6	6.6	231.7	238.3	0.0	151.6	3.8	(0.1)	52.1	3,298.4	92.9
2035	1,238.2	1,120.3	104.7	411.0	55.1	2,929.4	6.7	235.2	241.9	0.0	185.1	3.4	(0.1)	52.7	3,412.3	94.6
2036	1,239.2	1,172.4	108.8	408.5	54.6	2,983.6	6.8	238.8	245.6	0.0	198.6	2.9	(0.1)	53.2	3,483.8	95.0
2037	1,251.2	1,212.5	113.4	411.4	54.6	3,043.2	6.9	222.9	229.8	0.0	227.3	2.4	(0.1)	53.7	3,556.2	95.5
2038	1,274.7	1,282.6	118.3	434.1	54.3	3,163.9	7.0	214.7	221.7	0.0	266.6	2.1	(0.1)	51.0	3,705.2	98.0
2039	1,300.5	1,389.8	131.7	326.4	59.3	3,207.6	7.1	210.1	217.2	0.0	293.3	1.6	(0.1)	51.4	3,770.9	98.3
2040	1,409.9	1,446.8	139.8	322.2	62.3	3,381.0	7.2	203.5	210.6	0.0	313.8	1.3	(0.1)	51.6	3,958.1	101.5
2041	1,442.8	1,506.6	144.5	333.0	73.8	3,500.8	7.4	206.3	213.7	0.0	335.9	1.0	(0.2)	51.7	4,102.9	103.9
2042	1,485.6	1,561.7	147.8	343.8	80.4	3,619.3	7.6	205.3	212.9	0.0	349.3	0.7	(0.2)	51.7	4,233.7	105.6
2043	1,490.3	1,627.4	152.3	350.6	82.8	3,703.4	8.1	173.2	181.4	0.0	354.6	0.3	(0.2)	51.5	4,291.1	105.6
(2014-2029)	8,317.0	5,913.5	599.5	3,573.2	578.4	18,981.6	473.4	2,635.0	3,108.4	(9.6)	755.9	116.8	(0.7)	848.5	23,801.0	
(2014-2043)	12,201.2	9,489.3	939.8	4,725.5	761.9	28,117.7	494.1	3,307.7	3,801.8	(9.6)	1,417.1	126.5	(1.1)	1,013.4	34,466.0	

Attachment F.1(c)(5) - Economic Contraction Scenario

TOTAL REVENUE REQUIREMENTS: ECONOMIC CONTRACTION SCENARIO
COAL-TO-GAS CONVERSION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	603.3	461.5	49.7	408.0	19.1	1,541.6	110.3	348.2	458.5	(2.0)	63.2	22.5	(0.1)	126.4	2,210.1	72.9
2015	609.7	449.9	48.1	433.4	40.7	1,581.8	110.9	359.8	470.7	(0.4)	64.8	20.1	(0.1)	130.7	2,267.7	75.9
2016	658.5	418.2	46.4	368.1	63.5	1,554.8	105.5	354.9	460.4	(0.9)	66.4	17.4	(0.1)	126.6	2,224.6	74.7
2017	679.2	531.1	51.9	373.1	73.1	1,708.4	94.9	299.2	394.1	(2.4)	70.4	14.7	(0.1)	110.1	2,295.2	77.3
2018	802.5	600.2	52.8	347.4	73.7	1,876.7	62.1	278.6	340.6	(2.3)	83.1	12.8	(0.1)	102.3	2,413.1	81.5
2019	831.9	612.0	53.3	357.1	71.7	1,925.9	62.2	284.1	346.4	(2.4)	85.9	11.0	(0.1)	94.4	2,461.1	83.2
2020	843.0	673.3	58.6	347.8	70.4	1,993.1	5.3	231.4	236.7	(2.5)	73.3	9.0	(0.1)	97.8	2,407.4	81.4
2021	934.5	715.1	63.0	361.7	69.0	2,143.2	4.4	240.4	244.8	0.0	106.1	8.7	(0.1)	45.8	2,548.7	85.5
2022	978.5	740.9	66.3	369.2	69.5	2,224.3	5.1	233.5	238.5	0.0	95.9	8.3	(0.1)	50.3	2,617.4	86.6
2023	1,072.1	771.9	69.5	364.0	67.9	2,345.2	5.7	228.8	234.5	0.0	106.4	8.0	(0.1)	56.8	2,750.9	90.1
2024	1,115.3	790.2	71.8	358.8	66.3	2,402.4	6.5	227.4	233.9	0.0	108.0	7.6	(0.1)	55.8	2,807.6	91.0
2025	1,151.4	766.2	72.8	358.9	64.8	2,414.1	6.4	230.0	236.4	0.0	101.0	7.2	(0.1)	54.9	2,813.6	90.1
2026	1,156.6	790.3	75.3	363.0	63.5	2,448.6	6.4	233.5	240.0	0.0	109.8	6.8	(0.1)	56.0	2,861.1	90.5
2027	1,170.2	811.8	77.7	374.5	62.1	2,496.4	6.4	220.1	226.5	0.0	111.4	6.4	(0.1)	60.5	2,901.1	90.5
2028	1,171.3	839.6	81.0	384.8	60.6	2,537.4	6.4	224.7	231.1	0.0	112.3	6.1	(0.1)	64.7	2,951.5	90.8
2029	1,174.2	867.6	83.5	394.7	61.2	2,581.2	6.4	226.3	232.7	0.0	122.6	5.7	(0.1)	64.0	3,006.1	91.2
2030	1,176.3	917.1	86.1	392.8	59.7	2,631.9	6.4	224.9	231.3	0.0	182.4	5.3	(0.1)	60.6	3,111.4	93.0
2031	1,198.9	945.0	89.1	402.7	58.2	2,694.0	6.4	224.4	230.8	0.0	144.5	5.0	(0.1)	59.5	3,133.6	92.4
2032	1,201.0	984.4	91.9	386.6	56.7	2,720.6	6.4	227.3	233.7	0.0	165.1	4.6	(0.1)	54.5	3,178.3	92.3
2033	1,205.5	1,030.0	94.5	394.8	55.8	2,780.6	6.4	228.4	234.7	0.0	157.1	4.2	(0.1)	53.0	3,229.5	92.5
2034	1,217.4	1,075.1	97.9	415.2	55.3	2,860.9	6.6	231.7	238.3	0.0	155.1	3.8	(0.1)	52.1	3,310.2	93.2
2035	1,226.5	1,125.7	101.1	431.1	54.7	2,939.2	6.7	235.2	241.9	0.0	194.9	3.4	(0.1)	52.7	3,432.0	95.1
2036	1,233.2	1,179.3	105.6	432.5	54.5	3,005.1	6.8	238.8	245.6	0.0	206.8	2.9	(0.1)	53.2	3,513.5	95.8
2037	1,245.6	1,220.5	110.3	429.3	54.2	3,059.8	6.9	222.9	229.8	0.0	235.2	2.4	(0.1)	53.7	3,580.8	96.2
2038	1,266.2	1,293.3	115.9	456.8	54.2	3,186.5	7.0	215.4	222.4	0.0	276.4	2.1	(0.1)	51.0	3,738.2	98.9
2039	1,297.6	1,406.7	131.6	345.2	58.9	3,239.9	7.1	210.2	217.3	0.0	302.5	1.6	(0.1)	51.4	3,812.5	99.4
2040	1,413.0	1,458.2	138.8	340.6	62.2	3,412.7	7.2	203.5	210.6	0.0	324.7	1.3	(0.1)	51.6	4,000.8	102.6
2041	1,463.6	1,520.7	143.6	355.4	63.3	3,546.6	7.4	206.3	213.7	0.0	353.0	1.0	(0.2)	51.7	4,165.9	105.4
2042	1,502.9	1,577.7	147.9	370.1	73.2	3,671.8	7.6	205.3	212.9	0.0	359.9	0.7	(0.2)	51.7	4,296.8	107.2
2043	1,515.8	1,641.6	152.6	370.7	79.5	3,760.3	8.1	173.2	181.4	0.0	362.6	0.3	(0.2)	51.5	4,355.9	107.2
(2014-2029)	8,310.3	6,057.8	575.1	3,575.0	576.7	19,094.8	473.4	2,645.3	3,118.7	(9.6)	829.6	116.8	(0.7)	848.5	23,998.1	
(2014-2043)	12,185.8	9,658.1	907.7	4,788.4	756.5	28,296.5	494.1	3,318.7	3,812.8	(9.6)	1,515.2	126.5	(1.1)	1,013.4	34,753.8	

Attachment F.1(c)(5) - Economic Contraction Scenario

ANNUAL AVERAGE SYSTEM COST ECONOMIC CONTRACTION SCENARIO - ($/MWh)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	72.9	72.9	72.9	72.9
2015	75.9	75.9	75.5	75.9
2016	74.3	74.3	73.4	74.7
2017	76.3	76.3	76.4	77.3
2018	81.5	82.0	80.2	81.5
2019	82.8	84.5	81.5	83.2
2020	81.6	83.9	82.3	81.4
2021	85.0	87.9	85.1	85.5
2022	86.1	89.6	85.4	86.6
2023	89.6	93.1	88.6	90.1
2024	90.2	93.6	88.2	91.0
2025	90.6	94.5	89.7	90.1
2026	91.4	95.2	90.8	90.5
2027	91.4	95.0	90.8	90.5
2028	91.4	95.2	91.0	90.8
2029	92.1	95.5	90.9	91.2

Attachment F.1(c)(5) - Economic Contraction Scenario

CUMULATIVE CAPITAL SPENDING EXISTING AND NEW GENERATION PLUS INCREMENTAL TRANSMISSION ECONOMIC CONTRACTION SCENARIO - ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	1,209.0	1,209.0	1,198.8	1,205.0
2015	1,669.6	1,669.6	1,618.5	1,627.1
2016	2,377.4	2,433.7	2,251.4	2,346.1
2017	3,052.5	3,331.4	2,885.0	2,986.6
2018	3,417.5	4,016.8	3,137.0	3,254.5
2019	3,659.7	4,533.4	3,298.6	3,477.1
2020	3,994.8	5,173.2	3,952.9	3,795.6
2021	4,939.4	6,291.6	4,781.3	4,719.4
2022	5,434.8	6,845.3	5,204.1	5,199.8
2023	5,998.3	7,473.9	5,746.5	5,735.5
2024	6,394.3	8,058.7	6,300.0	6,124.0
2025	6,784.2	8,496.8	6,842.5	6,507.9
2026	7,222.8	8,932.4	7,257.0	6,934.0
2027	7,563.1	9,395.2	7,569.4	7,266.3
2028	7,906.3	9,781.2	7,845.1	7,600.0
2029	8,267.3	10,142.2	8,134.3	7,950.7

1. Capital investment projected is regardless of whether APS constructs and owns new generation resources or whether resources are purchased by APS under long-term PPAs with market participants.

2. Capital spending excludes: (a) financial commitments to energy efficiency and distributed energy initiatives; (b) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing.

3. Capital spending includes ongoing capital investment for existing owned generation.

Attachment F.1(c)(5) - Economic Contraction Scenario

ANNUAL NATURAL GAS BURNS ECONOMIC CONTRACTION SCENARIO - (BCF)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	41.8	41.8	41.8	41.8
2015	37.4	37.4	37.4	37.4
2016	38.5	38.5	46.5	46.8
2017	48.1	48.1	59.9	59.2
2018	44.2	42.7	55.9	74.1
2019	40.7	37.3	51.0	68.8
2020	37.7	34.5	49.8	66.6
2021	42.8	37.6	55.0	71.8
2022	44.0	37.4	56.0	72.5
2023	51.5	42.2	63.2	78.5
2024	47.1	38.2	59.1	76.4
2025	44.8	36.8	71.5	71.3
2026	46.9	39.8	74.7	74.6
2027	49.8	41.7	77.9	77.6
2028	52.7	43.1	81.6	81.7
2029	60.8	49.1	88.6	88.4

Attachment F.1(c)(5) - Economic Contraction Scenario

ANNUAL CO2 EMISSIONS ECONOMIC CONTRACTION SCENARIO - (METRIC TONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	13,580,255	13,580,255	13,580,255	13,580,255
2015	13,272,014	13,272,014	13,272,014	13,272,014
2016	13,514,485	13,514,485	12,896,342	12,871,762
2017	13,339,614	13,339,614	12,439,792	12,519,886
2018	13,578,707	13,436,893	12,691,864	10,959,172
2019	13,759,795	13,302,950	12,949,254	11,258,973
2020	13,795,460	13,090,045	12,847,765	11,263,378
2021	13,954,147	12,922,814	12,980,459	11,380,796
2022	14,020,360	12,825,102	13,072,876	11,449,586
2023	13,672,518	12,366,108	12,736,527	11,288,333
2024	14,052,814	12,537,386	13,098,678	11,400,560
2025	14,017,539	12,692,191	11,522,603	11,601,907
2026	14,244,465	12,902,516	11,672,285	11,775,219
2027	14,415,423	13,055,323	11,826,127	11,930,122
2028	14,661,931	13,139,558	11,995,503	12,112,646
2029	14,549,965	13,071,845	12,009,321	12,122,889

Attachment F.1(c)(5) - Economic Contraction Scenario

ANNUAL WATER USE ECONOMIC CONTRACTION SCENARIO - (ACRE-FEET)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	54,397	54,397	54,397	54,397
2015	53,691	53,691	53,691	53,691
2016	53,405	53,405	52,102	52,049
2017	52,981	52,981	51,135	51,269
2018	53,381	53,052	51,571	48,894
2019	53,481	52,440	51,817	49,178
2020	53,233	51,676	51,235	48,646
2021	53,291	51,002	51,209	48,598
2022	53,443	52,166	51,439	48,741
2023	52,833	52,700	50,850	48,439
2024	53,462	52,889	51,449	48,629
2025	54,451	52,898	49,946	50,052
2026	54,966	53,409	50,345	50,466
2027	55,423	53,801	50,719	50,832
2028	55,938	54,002	51,123	51,238
2029	55,948	54,064	51,339	51,441

Attachment F.1(c)(6) - Economic Boom Scenario

ECONOMIC BOOM SCENARIO - BASE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,316	7,596	7,983	8,394	8,807	9,244	9,692	10,175	10,688	11,229	11,796	12,394	13,025	13,693	14,399	15,143
3	Annual Load Growth %		3.8%	5.1%	5.1%	4.9%	5.0%	4.8%	5.0%	5.0%	5.1%	5.1%	5.1%	5.1%	5.1%	5.2%	5.2%
4	Reserve Requirements	1,004	1,022	1,054	1,089	1,127	1,169	1,218	1,345	1,413	1,482	1,553	1,632	1,713	1,799	1,890	1,985
5	**Total Load Requirements**	**8,320**	**8,618**	**9,037**	**9,483**	**9,935**	**10,413**	**10,910**	**11,519**	**12,101**	**12,711**	**13,349**	**14,026**	**14,739**	**15,492**	**16,289**	**17,128**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	469	464	464	464	464	455	447	440	429	423	418	420	398	399	401
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	389	384	384	384	384	374	367	360	361	355	350	352	348	350	351
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,167**	**9,085**	**8,421**	**7,771**	**7,551**	**7,551**	**6,945**	**6,457**	**6,450**	**6,438**	**6,432**	**6,428**	**6,429**	**6,407**	**6,409**	**6,411**
22	Energy Efficiency	109	268	443	616	775	935	1,092	1,209	1,270	1,346	1,442	1,514	1,602	1,697	1,796	1,909
23	Distributed Energy	67	114	141	160	172	185	197	213	234	260	289	319	344	364	386	409
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**196**	**402**	**610**	**802**	**974**	**1,146**	**1,341**	**1,498**	**1,630**	**1,757**	**1,907**	**2,008**	**2,146**	**2,287**	**2,432**	**2,593**
29	Natural Gas	0	0	0	1,000	1,510	1,714	2,520	3,491	3,899	4,307	4,972	5,278	5,943	6,453	6,963	7,628
30	CCs/CTs	0	0	0	1,000	1,510	1,714	2,520	3,491	3,899	4,307	4,972	5,278	5,943	6,453	6,963	7,628
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	33	58	58	58	58	115	163	204	284	321	373	382	430	516	526
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	33	58	58	58	58	115	163	204	209	246	280	289	322	332	342
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	***Total Future Resources***	**0**	**33**	**58**	**1,058**	**1,568**	**1,772**	**2,635**	**3,654**	**4,103**	**4,591**	**5,293**	**5,651**	**6,325**	**6,883**	**7,479**	**8,154**
37	**TOTAL RESOURCES**	**9,362**	**9,520**	**9,088**	**9,631**	**10,093**	**10,469**	**10,920**	**11,608**	**12,184**	**12,786**	**13,633**	**14,087**	**14,900**	**15,577**	**16,320**	**17,158**

ENERGY MIX
ECONOMIC BOOM SCENARIO: BASE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	12,019	7,315	3,262	2,509	34,403
2015	9,297	12,187	7,434	3,555	3,124	35,596
2016	9,325	12,706	7,626	3,776	3,798	37,230
2017	9,296	11,820	9,467	3,866	4,464	38,913
2018	9,297	12,565	9,704	3,929	5,101	40,596
2019	9,297	11,780	11,568	3,993	5,736	42,375
2020	9,325	11,984	11,862	4,347	6,413	43,930
2021	9,296	12,156	13,068	4,710	6,880	46,111
2022	9,297	12,479	14,185	5,129	7,129	48,219
2023	9,297	11,925	15,902	5,854	7,440	50,419
2024	9,324	12,737	16,566	6,324	7,779	52,729
2025	9,297	13,247	17,374	7,129	8,122	55,168
2026	9,297	13,343	19,302	7,319	8,480	57,741
2027	9,297	13,200	21,341	7,740	8,866	60,444
2028	9,325	12,994	23,212	8,497	9,285	63,313
2029	9,297	12,105	26,567	8,642	9,732	66,343

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.0%	34.9%	21.3%	9.5%	7.3%	100.0%
2015	26.1%	34.2%	20.9%	10.0%	8.8%	100.0%
2016	25.0%	34.1%	20.5%	10.1%	10.2%	100.0%
2017	23.9%	30.4%	24.3%	9.9%	11.5%	100.0%
2018	22.9%	31.0%	23.9%	9.7%	12.6%	100.0%
2019	21.9%	27.8%	27.3%	9.4%	13.5%	100.0%
2020	21.2%	27.3%	27.0%	9.9%	14.6%	100.0%
2021	20.2%	26.4%	28.3%	10.2%	14.9%	100.0%
2022	19.3%	25.9%	29.4%	10.6%	14.8%	100.0%
2023	18.4%	23.7%	31.5%	11.6%	14.8%	100.0%
2024	17.7%	24.2%	31.4%	12.0%	14.8%	100.0%
2025	16.9%	24.0%	31.5%	12.9%	14.7%	100.0%
2026	16.1%	23.1%	33.4%	12.7%	14.7%	100.0%
2027	15.4%	21.8%	35.3%	12.8%	14.7%	100.0%
2028	14.7%	20.5%	36.7%	13.4%	14.7%	100.0%
2029	14.0%	18.2%	40.0%	13.0%	14.7%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(6) - Economic Boom Scenario

ECONOMIC BOOM SCENARIO - ENHANCED RENEWABLE PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,316	7,596	7,983	8,394	8,807	9,244	9,692	10,175	10,688	11,229	11,796	12,394	13,025	13,693	14,399	15,143
3	Annual Load Growth %		3.8%	5.1%	5.1%	4.9%	5.0%	4.8%	5.0%	5.0%	5.1%	5.1%	5.1%	5.1%	5.1%	5.2%	5.2%
4	Reserve Requirements	1,004	1,022	1,054	1,089	1,127	1,169	1,218	1,345	1,413	1,482	1,553	1,632	1,713	1,799	1,890	1,985
5	**Total Load Requirements**	**8,320**	**8,618**	**9,037**	**9,483**	**9,935**	**10,413**	**10,910**	**11,519**	**12,101**	**12,711**	**13,349**	**14,026**	**14,739**	**15,492**	**16,289**	**17,128**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	478	470	465	465	455	430	417	406	404	389	383	381	382	364	365	365
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	397	390	385	385	374	349	337	325	323	322	316	314	315	314	315	315
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,168**	**9,086**	**8,422**	**7,772**	**7,542**	**7,517**	**6,907**	**6,415**	**6,413**	**6,399**	**6,393**	**6,391**	**6,392**	**6,373**	**6,375**	**6,374**
22	Energy Efficiency	109	268	443	616	775	935	1,092	1,209	1,270	1,346	1,442	1,514	1,602	1,697	1,796	1,909
23	Distributed Energy	67	114	141	160	172	183	195	210	232	257	287	317	342	362	384	407
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**196**	**402**	**610**	**802**	**973**	**1,144**	**1,338**	**1,495**	**1,628**	**1,755**	**1,905**	**2,006**	**2,144**	**2,285**	**2,430**	**2,591**
29	Natural Gas	0	0	0	1,000	1,510	1,612	2,418	3,389	3,695	4,103	4,768	5,074	5,739	6,147	6,759	7,424
30	CCs/CTs	0	0	0	1,000	1,510	1,612	2,418	3,389	3,695	4,103	4,768	5,074	5,739	6,147	6,759	7,424
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	33	58	58	113	216	248	282	377	471	501	619	635	748	766	790
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	33	58	58	113	216	248	282	302	321	351	376	393	414	433	457
35	Geothermal	0	0	0	0	0	0	0	0	75	150	150	225	225	300	300	300
36	**Total Future Resources**	**0**	**33**	**58**	**1,058**	**1,623**	**1,828**	**2,666**	**3,671**	**4,072**	**4,574**	**5,269**	**5,693**	**6,374**	**6,895**	**7,525**	**8,214**
37	**TOTAL RESOURCES**	**9,363**	**9,521**	**9,089**	**9,632**	**10,138**	**10,489**	**10,911**	**11,582**	**12,113**	**12,728**	**13,567**	**14,090**	**14,910**	**15,553**	**16,330**	**17,179**

ENERGY MIX
ECONOMIC BOOM SCENARIO: ENHANCED RENEWABLE PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	12,019	7,315	3,262	2,509	34,403
2015	9,297	12,187	7,434	3,555	3,124	35,596
2016	9,325	12,706	7,626	3,776	3,798	37,230
2017	9,296	11,818	9,469	3,866	4,464	38,913
2018	9,297	12,521	9,469	4,208	5,101	40,596
2019	9,297	11,695	10,537	5,110	5,736	42,375
2020	9,325	11,812	10,636	5,745	6,413	43,930
2021	9,296	12,020	11,253	6,663	6,880	46,113
2022	9,297	12,151	11,969	7,674	7,129	48,219
2023	9,297	11,520	13,483	8,678	7,440	50,419
2024	9,324	12,326	13,587	9,713	7,779	52,729
2025	9,297	12,633	13,736	11,381	8,122	55,168
2026	9,297	12,716	15,676	11,571	8,480	57,741
2027	9,297	12,581	17,117	12,583	8,866	60,444
2028	9,325	12,601	19,343	12,759	9,285	63,313
2029	9,297	11,735	22,405	13,173	9,732	66,343

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.0%	34.9%	21.3%	9.5%	7.3%	100.0%
2015	26.1%	34.2%	20.9%	10.0%	8.8%	100.0%
2016	25.0%	34.1%	20.5%	10.1%	10.2%	100.0%
2017	23.9%	30.4%	24.3%	9.9%	11.5%	100.0%
2018	22.9%	30.8%	23.3%	10.4%	12.6%	100.0%
2019	21.9%	27.6%	24.9%	12.1%	13.5%	100.0%
2020	21.2%	26.9%	24.2%	13.1%	14.6%	100.0%
2021	20.2%	26.1%	24.4%	14.4%	14.9%	100.0%
2022	19.3%	25.2%	24.8%	15.9%	14.8%	100.0%
2023	18.4%	22.8%	26.7%	17.2%	14.8%	100.0%
2024	17.7%	23.4%	25.8%	18.4%	14.8%	100.0%
2025	16.9%	22.9%	24.9%	20.6%	14.7%	100.0%
2026	16.1%	22.0%	27.1%	20.0%	14.7%	100.0%
2027	15.4%	20.8%	28.3%	20.8%	14.7%	100.0%
2028	14.7%	19.9%	30.6%	20.2%	14.7%	100.0%
2029	14.0%	17.7%	33.8%	19.9%	14.7%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(6) - Economic Boom Scenario

ECONOMIC BOOM SCENARIO - COAL REDUCTION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,316	7,596	7,983	8,394	8,807	9,244	9,692	10,175	10,688	11,229	11,796	12,394	13,025	13,693	14,399	15,143
3	Annual Load Growth %		3.8%	5.1%	5.1%	4.9%	5.0%	4.8%	5.0%	5.0%	5.1%	5.1%	5.1%	5.1%	5.1%	5.2%	5.2%
4	Reserve Requirements	1,004	1,022	1,054	1,089	1,127	1,169	1,218	1,345	1,413	1,482	1,553	1,632	1,713	1,799	1,890	1,985
5	**Total Load Requirements**	**8,320**	**8,618**	**9,037**	**9,483**	**9,935**	**10,413**	**10,910**	**11,519**	**12,101**	**12,711**	**13,349**	**14,026**	**14,739**	**15,492**	**16,289**	**17,128**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	470	464	464	464	465	455	447	441	422	416	413	414	393	394	392
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	397	389	384	384	384	384	375	367	360	354	349	345	346	344	345	343
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,167**	**9,085**	**8,161**	**7,511**	**7,291**	**7,291**	**6,685**	**6,197**	**6,190**	**6,171**	**6,166**	**5,776**	**5,776**	**5,756**	**5,757**	**5,755**
22	Energy Efficiency	109	268	443	616	775	935	1,092	1,209	1,270	1,346	1,442	1,514	1,602	1,697	1,796	1,909
23	Distributed Energy	67	114	141	160	172	185	197	213	235	259	289	319	343	364	386	408
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**196**	**402**	**610**	**802**	**974**	**1,146**	**1,341**	**1,498**	**1,630**	**1,757**	**1,907**	**2,008**	**2,146**	**2,286**	**2,432**	**2,593**
29	Natural Gas	0	0	500	1,204	1,714	2,214	2,879	3,748	4,156	4,564	4,972	5,943	6,453	7,065	7,730	8,240
30	CCs/CTs	0	0	500	1,204	1,714	2,214	2,879	3,748	4,156	4,564	4,972	5,943	6,453	7,065	7,730	8,240
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	33	58	58	58	58	115	163	204	315	346	397	404	453	536	571
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	33	58	58	58	58	115	163	204	240	271	304	311	344	352	387
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**33**	**558**	**1,262**	**1,772**	**2,272**	**2,994**	**3,911**	**4,360**	**4,879**	**5,318**	**6,340**	**6,857**	**7,518**	**8,266**	**8,811**
37	TOTAL RESOURCES	9,362	9,520	9,328	9,575	10,037	10,710	11,020	11,606	12,181	12,807	13,391	14,124	14,779	15,560	16,455	17,158

ENERGY MIX
ECONOMIC BOOM SCENARIO: COAL REDUCTION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	12,019	7,315	3,262	2,509	34,403
2015	9,297	12,187	7,434	3,555	3,124	35,596
2016	9,325	11,508	8,823	3,776	3,798	37,230
2017	9,296	10,195	11,092	3,866	4,464	38,913
2018	9,297	10,846	11,423	3,929	5,101	40,596
2019	9,297	10,232	13,116	3,993	5,736	42,375
2020	9,325	10,416	13,430	4,347	6,413	43,930
2021	9,296	10,572	14,656	4,710	6,880	46,113
2022	9,297	10,891	15,773	5,129	7,129	48,219
2023	9,297	10,144	17,405	6,134	7,440	50,419
2024	9,324	10,954	18,069	6,603	7,779	52,729
2025	9,297	9,200	21,142	7,408	8,122	55,168
2026	9,297	9,120	23,245	7,598	8,480	57,741
2027	9,297	9,100	25,162	8,019	8,866	60,444
2028	9,325	9,034	26,892	8,776	9,285	63,313
2029	9,297	8,483	29,630	9,200	9,732	66,343

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.0%	34.9%	21.3%	9.5%	7.3%	100.0%
2015	26.1%	34.2%	20.9%	10.0%	8.8%	100.0%
2016	25.0%	30.9%	23.7%	10.1%	10.2%	100.0%
2017	23.9%	26.2%	28.5%	9.9%	11.5%	100.0%
2018	22.9%	26.7%	28.1%	9.7%	12.6%	100.0%
2019	21.9%	24.1%	31.0%	9.4%	13.5%	100.0%
2020	21.2%	23.7%	30.6%	9.9%	14.6%	100.0%
2021	20.2%	22.9%	31.8%	10.2%	14.9%	100.0%
2022	19.3%	22.6%	32.7%	10.6%	14.8%	100.0%
2023	18.4%	20.1%	34.5%	12.2%	14.8%	100.0%
2024	17.7%	20.8%	34.3%	12.5%	14.8%	100.0%
2025	16.9%	16.7%	38.3%	13.4%	14.7%	100.0%
2026	16.1%	15.8%	40.3%	13.2%	14.7%	100.0%
2027	15.4%	15.1%	41.6%	13.3%	14.7%	100.0%
2028	14.7%	14.3%	42.5%	13.9%	14.7%	100.0%
2029	14.0%	12.8%	44.7%	13.9%	14.7%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(6) - Economic Boom Scenario

ECONOMIC BOOM SCENARIO - COAL-TO-GAS CONVERSION PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,316	7,596	7,983	8,394	8,807	9,244	9,692	10,175	10,688	11,229	11,796	12,394	13,025	13,693	14,399	15,143
3	Annual Load Growth %		3.8%	5.1%	5.1%	4.9%	5.0%	4.8%	5.0%	5.0%	5.1%	5.1%	5.1%	5.1%	5.1%	5.2%	5.2%
4	Reserve Requirements	1,004	1,022	1,054	1,089	1,127	1,169	1,218	1,345	1,413	1,482	1,553	1,632	1,713	1,799	1,890	1,985
5	**Total Load Requirements**	**8,320**	**8,618**	**9,037**	**9,483**	**9,935**	**10,413**	**10,910**	**11,519**	**12,101**	**12,711**	**13,349**	**14,026**	**14,739**	**15,492**	**16,289**	**17,128**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,672	1,672	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285	1,285
9	Natural Gas	5,612	5,538	5,139	4,489	4,656	4,656	4,059	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,514	1,514	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	477	469	464	464	464	464	455	447	440	429	423	418	420	398	399	401
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	389	384	384	384	384	374	367	360	361	355	350	352	348	350	351
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,167**	**9,085**	**8,421**	**7,771**	**7,551**	**7,551**	**6,945**	**6,457**	**6,450**	**6,438**	**6,432**	**6,428**	**6,429**	**6,407**	**6,409**	**6,411**
22	Energy Efficiency	109	268	443	616	775	935	1,092	1,209	1,270	1,346	1,442	1,514	1,602	1,697	1,796	1,909
23	Distributed Energy	67	114	141	160	172	185	197	213	234	260	289	319	344	364	386	409
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**196**	**402**	**610**	**802**	**974**	**1,146**	**1,341**	**1,498**	**1,630**	**1,757**	**1,907**	**2,008**	**2,146**	**2,287**	**2,432**	**2,593**
29	Natural Gas	0	0	0	1,000	1,510	1,714	2,520	3,491	3,899	4,307	4,972	5,278	5,943	6,453	6,963	7,628
30	CCs/CTs	0	0	0	1,000	1,510	1,714	2,520	3,491	3,899	4,307	4,972	5,278	5,943	6,453	6,963	7,628
31	Short-Term Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	33	58	58	58	58	115	163	204	284	321	373	382	430	516	526
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	33	58	58	58	58	115	163	204	209	246	280	289	322	332	342
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**33**	**58**	**1,058**	**1,568**	**1,772**	**2,635**	**3,654**	**4,103**	**4,591**	**5,293**	**5,651**	**6,325**	**6,883**	**7,479**	**8,154**
37	TOTAL RESOURCES	9,362	9,520	9,088	9,631	10,093	10,469	10,920	11,608	12,184	12,786	13,633	14,087	14,900	15,577	16,320	17,158

ENERGY MIX
ECONOMIC BOOM SCENARIO: COAL-TO-GAS CONVERSION PORTFOLIO

ENERGY (GWH)

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	9,297	12,019	7,315	3,262	2,509	34,403
2015	9,297	12,187	7,434	3,555	3,124	35,596
2016	9,325	11,573	8,758	3,776	3,798	37,230
2017	9,296	10,321	10,966	3,866	4,464	38,913
2018	9,297	8,293	13,974	3,929	5,101	40,594
2019	9,297	8,344	15,004	3,993	5,736	42,375
2020	9,325	8,426	15,420	4,347	6,413	43,930
2021	9,296	8,458	16,762	4,710	6,880	46,106
2022	9,297	8,597	18,066	5,129	7,129	48,218
2023	9,297	8,059	19,768	5,854	7,440	50,419
2024	9,324	8,442	20,861	6,324	7,779	52,729
2025	9,297	9,176	21,445	7,129	8,122	55,168
2026	9,297	9,140	23,505	7,319	8,480	57,741
2027	9,297	9,101	25,441	7,740	8,866	60,444
2028	9,325	9,070	27,136	8,497	9,285	63,313
2029	9,297	8,515	30,156	8,642	9,732	66,343

ENERGY MIX %

	NUCLEAR	COAL	GAS	RE + DE RENEW	EE	TOT
2014	27.0%	34.9%	21.3%	9.5%	7.3%	100.0%
2015	26.1%	34.2%	20.9%	10.0%	8.8%	100.0%
2016	25.0%	31.1%	23.5%	10.1%	10.2%	100.0%
2017	23.9%	26.5%	28.2%	9.9%	11.5%	100.0%
2018	22.9%	20.4%	34.4%	9.7%	12.6%	100.0%
2019	21.9%	19.7%	35.4%	9.4%	13.5%	100.0%
2020	21.2%	19.2%	35.1%	9.9%	14.6%	100.0%
2021	20.2%	18.3%	36.4%	10.2%	14.9%	100.0%
2022	19.3%	17.8%	37.5%	10.6%	14.8%	100.0%
2023	18.4%	16.0%	39.2%	11.6%	14.8%	100.0%
2024	17.7%	16.0%	39.6%	12.0%	14.8%	100.0%
2025	16.9%	16.6%	38.9%	12.9%	14.7%	100.0%
2026	16.1%	15.8%	40.7%	12.7%	14.7%	100.0%
2027	15.4%	15.1%	42.1%	12.8%	14.7%	100.0%
2028	14.7%	14.3%	42.9%	13.4%	14.7%	100.0%
2029	14.0%	12.8%	45.5%	13.0%	14.7%	100.0%

1. RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.

2. Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

3. Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of calendar year as a percentage of prior calendar year retail energy sales.

Attachment F.1(c)(6) - Economic Boom Scenario

TOTAL REVENUE REQUIREMENTS ECONOMIC BOOM SCENARIO - ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	2,352.6	2,352.6	2,350.8	2,351.8
2015	2,483.6	2,483.6	2,468.7	2,482.3
2016	2,503.2	2,503.2	2,594.3	2,519.5
2017	2,902.4	2,902.7	2,924.9	2,939.2
2018	3,180.6	3,201.3	3,175.1	3,215.6
2019	3,444.5	3,520.6	3,521.2	3,435.8
2020	3,752.9	3,873.6	3,737.6	3,749.6
2021	4,220.5	4,365.2	4,216.3	4,217.3
2022	4,687.7	4,843.2	4,663.1	4,696.3
2023	5,184.0	5,346.5	5,163.1	5,179.3
2024	5,658.9	5,841.8	5,576.4	5,664.8
2025	6,117.7	6,344.6	6,134.6	6,091.7
2026	6,649.5	6,915.0	6,715.0	6,587.3
2027	7,270.3	7,479.5	7,346.0	7,210.1
2028	7,930.5	8,101.0	8,022.7	7,893.7
2029	8,680.7	8,811.3	8,747.8	8,601.2
2030	9,423.0	9,545.1	9,477.2	9,352.7
2031	10,153.7	10,212.2	10,232.9	10,081.8
2032	11,019.5	11,033.1	11,048.0	10,929.6
2033	11,967.2	11,987.0	12,002.8	11,876.5
2034	12,152.2	12,175.9	12,210.7	12,087.6
2035	12,192.8	12,195.0	12,232.6	12,113.7
2036	12,165.9	12,144.8	12,185.6	12,086.0
2037	12,095.6	12,052.9	12,130.3	12,030.7
2038	12,254.0	12,189.6	12,222.1	12,163.5
2039	12,399.3	12,317.9	12,351.4	12,281.8
2040	12,671.2	12,561.7	12,640.3	12,587.3
2041	12,774.3	12,645.8	12,700.0	12,665.4
2042	12,820.1	12,679.4	12,741.0	12,709.5
2043	12,758.2	12,583.3	12,708.4	12,674.9
CPW @ 8.50%				
(2014-2029)	35,332.5	36,087.3	35,482.2	35,305.9
(2014-2043)	60,582.0	61,311.2	60,768.9	60,374.4

TOTAL REVENUE REQUIREMENTS: ECONOMIC BOOM SCENARIO
BASE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	685.4	489.5	53.1	416.2	21.2	1,665.4	110.9	357.5	468.4	(2.0)	63.2	25.6	(0.1)	131.9	2,352.6	75.2
2015	697.8	502.6	55.8	450.3	47.2	1,753.7	111.6	381.7	493.2	(0.4)	64.8	22.9	(0.1)	149.5	2,483.6	78.3
2016	759.4	505.4	59.9	387.6	74.1	1,786.4	106.2	374.3	480.6	(0.9)	66.4	19.8	(0.1)	151.0	2,503.2	76.9
2017	1,018.3	669.8	73.3	405.9	84.8	2,252.1	94.7	310.3	405.0	(2.4)	90.9	16.7	(0.1)	140.2	2,902.4	86.8
2018	1,234.7	780.2	85.0	420.5	84.9	2,605.3	62.3	282.9	345.1	(2.3)	79.1	14.6	(0.1)	138.9	3,180.6	92.4
2019	1,315.3	856.9	87.3	434.1	83.2	2,776.9	62.4	298.7	361.1	(2.4)	88.9	12.5	68.4	139.1	3,444.5	97.1
2020	1,559.6	1,000.7	99.8	442.1	81.7	3,183.9	6.0	231.1	237.1	(2.5)	88.0	10.3	84.8	151.3	3,752.9	102.6
2021	1,826.5	1,130.1	115.2	483.6	84.8	3,640.2	5.8	235.0	240.8	0.0	135.3	9.9	115.1	79.2	4,220.5	111.1
2022	2,075.3	1,266.7	127.9	493.8	88.1	4,051.9	6.5	232.6	239.1	0.0	142.0	9.5	154.1	91.2	4,687.7	118.1
2023	2,337.4	1,421.5	138.6	510.8	88.3	4,496.5	6.4	228.7	235.2	0.0	161.2	9.1	181.5	100.6	5,184.0	125.3
2024	2,569.2	1,569.2	154.2	525.2	87.6	4,905.5	7.2	227.1	234.3	0.0	177.5	8.6	231.8	101.3	5,658.9	131.2
2025	2,764.4	1,732.9	167.9	540.1	86.7	5,292.0	8.8	230.0	238.8	0.0	192.7	8.2	284.3	101.7	6,117.7	136.0
2026	2,929.9	1,921.0	187.1	579.0	104.5	5,721.5	8.8	233.1	241.9	0.0	220.2	7.8	352.9	105.1	6,649.5	141.5
2027	3,141.9	2,119.9	206.5	615.6	136.1	6,220.2	9.5	220.1	229.5	0.0	244.5	7.3	456.4	112.4	7,270.3	147.9
2028	3,377.7	2,322.6	222.8	639.3	172.1	6,734.7	9.5	223.7	233.1	0.0	265.0	6.9	571.1	119.6	7,930.5	154.1
2029	3,571.3	2,603.4	248.4	685.8	210.4	7,319.3	9.5	226.3	235.8	0.0	321.7	6.5	671.8	125.6	8,680.7	161.1
2030	3,760.1	2,880.9	277.6	704.4	248.0	7,871.0	9.4	221.2	230.6	0.0	384.9	6.1	801.6	128.8	9,423.0	167.0
2031	4,027.6	3,135.8	302.0	726.6	286.1	8,478.1	9.4	224.4	233.8	0.0	390.3	5.7	916.8	128.9	10,153.7	171.8
2032	4,328.8	3,416.6	330.6	753.9	348.3	9,178.2	10.3	227.3	237.6	0.0	443.0	5.3	1,030.7	124.8	11,019.5	177.9
2033	4,648.5	3,746.9	360.3	795.4	403.7	9,954.9	10.7	228.4	239.0	0.0	485.9	4.8	1,158.6	123.9	11,967.2	184.5
2034	4,678.7	3,838.8	372.7	820.8	422.0	10,133.0	10.8	231.7	242.5	0.0	485.3	4.3	1,165.7	121.3	12,152.2	187.3
2035	4,521.0	3,943.1	385.1	877.6	416.1	10,142.9	10.8	235.2	246.0	0.0	531.2	3.8	1,149.2	119.7	12,192.8	187.9
2036	4,356.2	4,050.7	400.8	896.7	404.0	10,108.5	10.8	238.8	249.6	0.0	535.3	3.3	1,151.6	117.6	12,165.9	187.1
2037	4,213.4	4,119.5	412.7	890.5	392.5	10,028.7	10.7	222.9	233.6	0.0	549.5	2.8	1,166.1	114.9	12,095.6	186.4
2038	4,115.5	4,267.9	431.2	977.5	381.2	10,173.3	10.5	214.7	225.3	0.0	608.0	2.3	1,136.5	108.7	12,254.0	188.9
2039	4,224.7	4,533.1	467.1	810.2	431.1	10,466.2	10.5	210.1	220.6	0.0	645.6	1.9	960.4	104.7	12,399.3	191.1
2040	4,369.0	4,645.3	490.8	788.9	461.0	10,755.0	10.5	203.5	213.9	0.0	666.8	1.5	934.1	99.9	12,671.2	194.9
2041	4,289.6	4,747.4	505.4	849.1	463.3	10,854.9	10.4	206.3	216.7	0.0	677.3	1.1	929.8	94.5	12,774.3	196.9
2042	4,197.4	4,841.6	521.7	892.0	448.9	10,901.6	10.4	205.3	215.7	0.0	683.6	0.7	930.6	87.9	12,820.1	197.6
2043	4,051.7	4,953.2	539.5	886.8	434.6	10,865.7	10.8	173.2	184.1	0.0	700.6	0.4	927.2	80.3	12,758.2	196.7
(2014-2029)	14,107.7	9,212.9	934.7	4,060.6	713.6	29,029.5	458.1	2,464.7	2,922.8	(9.0)	1,061.7	122.9	1,123.1	1,081.5	35,332.5	
(2014-2043)	23,365.7	17,640.8	1,778.5	5,834.8	1,536.0	50,155.8	480.6	2,944.3	3,424.9	(9.0)	2,196.1	131.0	3,350.5	1,332.6	60,582.0	

Attachment F.1(c)(6) - Economic Boom Scenario

TOTAL REVENUE REQUIREMENTS: ECONOMIC BOOM SCENARIO
ENHANCED RENEWABLE PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	685.4	489.5	53.1	416.2	21.2	1,665.4	110.9	357.5	468.4	(2.0)	63.2	25.6	(0.1)	131.9	2,352.6	75.2
2015	697.8	502.6	55.8	450.3	47.2	1,753.7	111.6	381.7	493.2	(0.4)	64.8	22.9	(0.1)	149.5	2,483.6	78.3
2016	759.4	505.4	59.9	387.6	74.1	1,786.4	106.2	374.3	480.6	(0.9)	66.4	19.8	(0.1)	151.0	2,503.2	76.9
2017	1,018.3	669.8	73.3	405.9	84.8	2,252.2	94.7	310.3	405.0	(2.4)	91.2	16.7	(0.1)	140.2	2,902.7	86.8
2018	1,263.6	770.5	85.1	423.5	84.9	2,627.7	62.9	282.4	345.3	(2.3)	77.3	14.6	(0.1)	138.9	3,201.3	93.0
2019	1,427.3	817.1	88.1	445.9	83.2	2,861.7	65.2	297.6	362.9	(2.4)	86.1	12.5	60.7	139.1	3,520.6	99.2
2020	1,732.6	947.5	101.2	457.1	81.4	3,319.9	9.5	231.1	240.6	(2.5)	80.0	10.3	74.0	151.3	3,873.6	105.9
2021	2,054.5	1,046.9	117.4	505.6	84.6	3,809.0	10.7	232.6	243.3	0.0	124.7	9.9	99.1	79.2	4,365.2	115.0
2022	2,357.4	1,151.6	127.0	524.7	88.1	4,248.8	11.3	232.6	243.9	0.0	120.1	9.5	129.7	91.2	4,843.2	122.0
2023	2,645.9	1,285.8	136.9	545.9	87.8	4,702.2	12.0	228.7	240.8	0.0	142.3	9.1	151.6	100.6	5,346.5	129.2
2024	2,920.2	1,392.4	154.0	568.7	104.4	5,139.7	14.1	227.1	241.3	0.0	156.6	8.6	194.4	101.3	5,841.8	135.5
2025	3,216.4	1,504.0	162.5	598.3	115.1	5,596.4	16.5	230.0	246.5	0.0	159.4	8.2	232.4	101.7	6,344.6	141.1
2026	3,411.5	1,682.0	180.3	639.2	154.9	6,068.0	16.5	233.1	249.6	0.0	186.5	7.8	298.0	105.1	6,915.0	147.1
2027	3,633.7	1,829.6	195.6	687.5	178.7	6,525.2	17.1	220.1	237.2	0.0	206.6	7.3	390.8	112.4	7,479.5	152.1
2028	3,819.5	2,050.7	214.3	703.4	204.8	6,992.8	17.2	223.7	240.8	0.0	229.3	6.9	511.5	119.6	8,101.0	157.4
2029	3,983.2	2,305.2	238.4	756.8	258.7	7,542.3	17.8	226.3	244.2	0.0	283.7	6.5	609.1	125.6	8,811.3	163.5
2030	4,171.5	2,564.0	263.3	777.9	308.9	8,085.7	17.8	221.2	239.0	0.0	348.5	6.1	737.1	128.8	9,545.1	169.2
2031	4,395.2	2,807.7	286.0	802.1	349.8	8,640.8	17.8	224.4	242.2	0.0	345.4	5.7	849.2	128.9	10,212.2	172.8
2032	4,662.8	3,082.5	313.1	831.6	409.9	9,299.9	18.7	227.3	246.0	0.0	403.5	5.3	953.6	124.8	11,033.1	178.1
2033	5,004.5	3,402.8	343.2	876.4	463.4	10,090.3	19.0	228.4	247.4	0.0	445.8	4.8	1,074.7	123.9	11,987.0	184.8
2034	5,045.9	3,485.5	354.0	905.1	479.8	10,270.3	19.2	231.7	250.9	0.0	445.7	4.3	1,083.5	121.3	12,175.9	187.7
2035	4,874.6	3,584.5	365.5	964.9	472.0	10,261.6	19.2	235.2	254.4	0.0	489.3	3.8	1,066.2	119.7	12,195.0	188.0
2036	4,697.1	3,686.5	378.1	987.1	458.2	10,206.9	19.2	238.8	258.0	0.0	491.9	3.3	1,067.2	117.6	12,144.8	186.8
2037	4,541.4	3,740.8	389.9	984.0	444.8	10,101.0	19.1	222.9	242.0	0.0	509.1	2.8	1,083.2	114.9	12,052.9	185.8
2038	4,430.3	3,892.3	405.6	1,074.3	431.7	10,234.3	18.9	214.7	233.6	0.0	560.1	2.3	1,050.6	108.7	12,189.6	187.9
2039	4,526.2	4,147.7	437.8	910.3	479.9	10,501.9	18.9	210.1	229.0	0.0	599.3	1.9	881.1	104.7	12,317.9	189.9
2040	4,657.2	4,247.1	457.9	892.6	508.0	10,762.8	18.9	203.5	222.3	0.0	617.5	1.5	857.5	99.9	12,561.7	193.2
2041	4,564.6	4,338.7	474.2	956.4	508.5	10,842.4	18.8	206.3	225.1	0.0	628.8	1.1	853.9	94.5	12,645.8	194.9
2042	4,458.8	4,430.8	488.1	1,003.1	492.3	10,873.1	18.8	205.3	224.1	0.0	637.8	0.7	855.8	87.9	12,679.4	195.4
2043	4,292.5	4,530.8	504.0	1,001.8	476.1	10,805.2	19.2	173.2	192.4	0.0	651.6	0.4	853.4	80.3	12,583.3	194.0
(2014-2029)	15,562.1	8,499.1	922.8	4,241.6	784.4	30,010.1	485.0	2,462.5	2,947.5	(9.0)	964.6	122.9	969.7	1,081.5	36,087.3	
(2014-2043)	25,553.9	16,145.7	1,719.2	6,208.0	1,726.7	51,353.5	525.7	2,942.1	3,467.7	(9.0)	2,006.1	131.0	3,029.1	1,332.6	61,311.2	

TOTAL REVENUE REQUIREMENTS: ECONOMIC BOOM SCENARIO
COAL REDUCTION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	683.6	489.5	53.1	416.3	21.2	1,663.7	110.9	357.5	468.4	(2.0)	63.2	25.6	(0.1)	131.9	2,350.8	75.1
2015	693.1	502.6	55.8	440.1	47.2	1,738.8	111.6	381.7	493.2	(0.4)	64.8	22.9	(0.1)	149.5	2,468.7	77.8
2016	845.4	513.7	58.9	375.6	74.1	1,867.7	106.2	381.4	487.6	(0.9)	69.2	19.8	(0.1)	151.0	2,594.3	79.7
2017	1,015.3	688.1	71.6	397.4	85.5	2,257.9	94.7	319.5	414.1	(2.4)	98.4	16.7	(0.1)	140.2	2,924.9	87.5
2018	1,210.3	798.5	81.1	409.7	86.1	2,585.6	62.3	285.5	347.8	(2.3)	90.6	14.6	(0.1)	138.9	3,175.1	92.3
2019	1,382.3	881.3	86.7	424.1	83.8	2,858.1	62.4	300.1	362.5	(2.4)	100.0	12.5	51.5	139.1	3,521.2	99.2
2020	1,517.4	1,027.2	100.7	432.8	86.2	3,164.3	6.0	231.1	237.1	(2.5)	101.5	10.3	75.5	151.3	3,737.6	102.2
2021	1,802.9	1,157.9	116.8	464.7	87.8	3,630.1	5.8	232.7	238.4	0.0	150.0	9.9	108.8	79.2	4,216.3	111.0
2022	2,031.5	1,297.1	129.0	481.3	89.3	4,028.2	6.5	232.6	239.1	0.0	148.6	9.5	146.6	91.2	4,663.1	117.5
2023	2,308.4	1,445.0	140.1	498.7	87.3	4,479.4	7.1	228.7	235.9	0.0	167.7	9.1	170.5	100.6	5,163.1	124.8
2024	2,497.2	1,599.2	152.5	491.0	86.5	4,826.4	7.8	227.1	235.0	0.0	192.4	8.6	212.7	101.3	5,576.4	129.3
2025	2,794.7	1,801.7	165.1	479.5	104.7	5,345.6	9.5	230.0	239.5	0.0	226.0	8.2	213.6	101.7	6,134.6	136.4
2026	3,024.8	2,001.7	182.2	494.8	135.9	5,839.4	9.5	233.1	242.6	0.0	246.7	7.8	273.3	105.1	6,715.0	142.9
2027	3,232.3	2,208.5	199.4	532.7	171.3	6,344.2	10.2	220.1	230.2	0.0	278.6	7.3	373.3	112.4	7,346.0	149.4
2028	3,506.0	2,401.2	219.8	573.2	206.4	6,906.6	10.2	223.7	233.8	0.0	294.6	6.9	461.1	119.6	8,022.7	155.9
2029	3,704.7	2,665.5	243.5	603.4	243.5	7,460.5	10.9	226.3	237.2	0.0	353.0	6.5	565.0	125.6	8,747.8	162.4
2030	3,877.1	2,951.0	268.7	613.5	280.0	7,990.4	10.8	221.2	232.0	0.0	424.4	6.1	695.5	128.8	9,477.2	168.0
2031	4,135.9	3,199.5	292.9	655.6	339.5	8,623.3	10.8	224.4	235.2	0.0	425.9	5.7	813.9	128.9	10,232.9	173.1
2032	4,428.8	3,476.9	322.7	652.3	392.6	9,273.3	11.7	227.3	239.0	0.0	483.7	5.3	922.0	124.8	11,048.0	178.4
2033	4,742.9	3,800.4	353.5	695.3	460.0	10,052.2	12.1	228.4	240.4	0.0	530.5	4.8	1,050.9	123.9	12,002.8	185.0
2034	4,767.4	3,888.1	365.9	743.0	487.4	10,251.8	12.2	231.7	243.9	0.0	530.3	4.3	1,059.1	121.3	12,210.7	188.2
2035	4,602.2	3,987.3	379.2	776.7	485.5	10,231.0	12.2	235.2	247.4	0.0	583.4	3.8	1,047.3	119.7	12,232.6	188.6
2036	4,431.1	4,103.9	393.5	787.2	471.3	10,187.0	12.2	238.8	251.0	0.0	584.3	3.3	1,042.5	117.6	12,185.6	187.4
2037	4,277.9	4,163.5	406.4	805.7	457.6	10,111.0	12.1	222.9	235.0	0.0	601.7	2.8	1,064.9	114.9	12,130.3	187.0
2038	4,159.8	4,311.3	425.3	856.5	444.2	10,197.0	11.9	214.7	226.6	0.0	659.6	2.3	1,027.8	108.7	12,222.1	188.4
2039	4,248.6	4,578.6	461.6	693.5	492.0	10,474.3	11.9	210.1	222.0	0.0	699.0	1.9	849.5	104.7	12,351.4	190.4
2040	4,389.1	4,682.2	483.1	698.7	519.9	10,772.9	11.9	203.5	215.3	0.0	724.7	1.5	825.9	99.9	12,640.3	194.4
2041	4,305.3	4,779.5	498.2	729.9	520.2	10,833.0	11.8	206.3	218.1	0.0	728.4	1.1	824.9	94.5	12,700.0	195.8
2042	4,213.0	4,874.3	514.9	760.5	503.8	10,866.6	11.8	205.3	217.1	0.0	744.0	0.7	824.7	87.9	12,741.0	196.4
2043	4,069.8	4,977.5	532.2	786.1	487.4	10,853.0	12.2	173.2	185.5	0.0	764.4	0.4	825.0	80.3	12,708.4	195.9
(2014-2029)	14,239.6	9,448.5	924.2	3,862.6	766.9	29,241.7	460.0	2,478.2	2,938.2	(9.0)	1,160.9	122.9	945.9	1,081.5	41,727.0	
(2014-2043)	23,656.9	17,986.0	1,752.3	5,424.1	1,710.3	50,529.6	485.5	2,957.8	3,443.4	(9.0)	2,398.3	131.0	2,942.9	1,332.6	60,768.9	

Attachment F.1(c)(6) - Economic Boom Scenario

TOTAL REVENUE REQUIREMENTS: ECONOMIC BOOM SCENARIO
COAL-TO-GAS CONVERSION PORTFOLIO - ($MILLIONS)

	GENERATION						PURCHASES			SALES					TOTAL	
	CAPITAL REV. REQ.	FUEL	VARIABLE O&M	FIXED FUEL + O&M	NEW TRANSMISSION	SUB TOTAL	DEMAND	ENERGY	SUB TOTAL		GAS TRANS	IMPUTED DEBT	EMIS COSTS	DE-EE COSTS	$MILLIONS	$/MWh
2014	684.7	489.5	53.1	416.1	21.2	1,664.6	110.9	357.5	468.4	(2.0)	63.2	25.6	(0.1)	131.9	2,351.8	75.2
2015	696.3	502.6	55.8	450.4	47.2	1,752.3	111.6	381.7	493.2	(0.4)	64.8	22.9	(0.1)	149.5	2,482.3	78.2
2016	755.9	511.4	57.1	390.1	74.1	1,788.6	106.2	383.8	490.0	(0.9)	71.0	19.8	(0.1)	151.0	2,519.5	77.4
2017	1,025.9	687.1	70.7	408.1	84.8	2,276.6	94.7	319.0	413.7	(2.4)	94.4	16.7	(0.1)	140.2	2,939.2	87.9
2018	1,198.1	836.3	77.5	392.0	84.9	2,588.9	62.3	291.9	354.2	(2.3)	121.4	14.6	(0.1)	138.9	3,215.6	93.5
2019	1,278.7	916.8	84.0	409.8	83.2	2,772.5	62.4	303.1	365.5	(2.4)	118.7	12.5	30.0	139.1	3,435.8	96.8
2020	1,520.4	1,073.0	97.3	413.0	81.7	3,185.5	6.0	231.1	237.1	(2.5)	124.5	10.3	43.4	151.3	3,749.6	102.5
2021	1,783.9	1,213.8	112.3	443.2	84.8	3,638.0	5.8	240.1	245.9	0.0	172.1	9.9	72.3	79.2	4,217.3	111.1
2022	2,030.2	1,364.4	122.7	463.5	88.1	4,068.9	6.5	233.8	240.3	0.0	179.9	9.5	106.6	91.2	4,696.3	118.3
2023	2,287.4	1,526.9	133.7	474.5	88.3	4,510.8	6.4	228.7	235.2	0.0	193.4	9.1	130.3	100.6	5,179.3	125.2
2024	2,519.2	1,692.6	148.1	481.4	87.6	4,928.8	7.2	227.1	234.3	0.0	219.1	8.6	172.6	101.3	5,664.8	131.4
2025	2,714.7	1,826.8	162.0	495.6	86.7	5,285.7	8.8	230.0	238.8	0.0	233.0	8.2	224.3	101.7	6,091.7	135.5
2026	2,878.9	2,020.9	180.6	515.0	104.5	5,699.8	8.8	233.1	241.9	0.0	251.0	7.8	281.7	105.1	6,587.3	140.2
2027	3,090.7	2,226.2	199.8	548.7	136.1	6,201.6	9.5	220.1	229.5	0.0	282.7	7.3	376.6	112.4	7,210.1	146.6
2028	3,326.1	2,433.2	217.0	588.1	172.1	6,736.5	9.5	223.7	233.2	0.0	311.8	6.9	485.7	119.6	7,893.7	153.4
2029	3,519.0	2,706.9	241.9	618.2	210.4	7,296.4	9.5	226.3	235.8	0.0	353.2	6.5	583.7	125.6	8,601.2	159.6
2030	3,708.1	2,993.2	270.3	633.7	248.0	7,853.3	9.4	221.3	230.7	0.0	432.1	6.1	701.7	128.8	9,352.7	165.8
2031	3,977.1	3,239.2	295.2	668.2	286.1	8,465.7	9.4	224.4	233.8	0.0	426.7	5.7	820.9	128.9	10,081.8	170.6
2032	4,279.7	3,521.0	325.3	671.5	348.3	9,145.8	10.3	227.3	237.6	0.0	486.0	5.3	930.1	124.8	10,929.6	176.5
2033	4,601.4	3,844.5	356.2	709.5	403.7	9,915.3	10.7	228.4	239.0	0.0	532.9	4.8	1,060.5	123.9	11,876.5	183.1
2034	4,634.0	3,931.4	368.4	757.0	422.0	10,112.8	10.8	231.7	242.5	0.0	537.8	4.3	1,068.9	121.3	12,087.6	186.3
2035	4,477.6	4,032.0	381.6	795.7	416.1	10,102.9	10.8	235.2	246.0	0.0	586.5	3.8	1,054.6	119.7	12,113.7	186.7
2036	4,314.6	4,147.3	397.1	812.2	404.0	10,075.2	10.8	238.8	249.6	0.0	589.6	3.3	1,050.7	117.6	12,086.0	185.9
2037	4,170.9	4,210.8	409.0	821.3	392.5	10,004.5	10.7	222.9	233.6	0.0	601.0	2.8	1,073.9	114.9	12,030.7	185.4
2038	4,063.7	4,359.6	429.1	880.4	381.2	10,114.1	10.5	214.7	225.3	0.0	675.4	2.3	1,037.8	108.7	12,163.5	187.5
2039	4,161.1	4,625.9	467.7	711.0	431.1	10,396.9	10.5	210.1	220.6	0.0	700.9	1.9	856.9	104.7	12,281.8	189.3
2040	4,308.7	4,733.8	488.1	715.9	461.0	10,707.5	10.5	203.5	213.9	0.0	729.9	1.5	834.6	99.9	12,587.3	193.6
2041	4,231.1	4,829.2	502.9	753.1	463.3	10,779.7	10.4	206.3	216.7	0.0	739.4	1.1	833.9	94.5	12,665.4	195.2
2042	4,140.7	4,924.2	519.1	791.3	448.9	10,824.2	10.4	205.3	215.7	0.0	748.4	0.7	832.6	87.9	12,709.5	195.9
2043	4,001.5	5,031.3	537.0	805.3	434.6	10,809.8	10.8	173.2	184.1	0.0	767.0	0.4	833.4	80.3	12,674.9	195.4
(2014-2029)	13,871.3	9,696.8	903.4	3,850.7	713.6	29,035.7	458.1	2,490.4	2,948.5	(9.0)	1,263.7	122.9	862.5	1,081.5	35,305.9	
(2014-2043)	23,020.7	18,332.6	1,738.3	5,452.8	1,536.0	50,080.3	480.6	2,970.0	3,450.6	(9.0)	2,511.4	131.0	2,877.4	1,332.6	60,374.4	

Attachment F.1(c)(6) - Economic Boom Scenario

AVERAGE ANNUAL SYSTEM COST ECONOMIC BOOM SCENARIO - ($/MWh)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	75.2	75.2	75.1	75.2
2015	78.3	78.3	77.8	78.2
2016	76.9	76.9	79.7	77.4
2017	86.8	86.8	87.5	87.9
2018	92.4	93.0	92.3	93.5
2019	97.1	99.2	99.2	96.8
2020	102.6	105.9	102.2	102.5
2021	111.1	115.0	111.0	111.1
2022	118.1	122.0	117.5	118.3
2023	125.3	129.2	124.8	125.2
2024	131.2	135.5	129.3	131.4
2025	136.0	141.1	136.4	135.5
2026	141.5	147.1	142.9	140.2
2027	147.9	152.1	149.4	146.6
2028	154.1	157.4	155.9	153.4
2029	161.1	163.5	162.4	159.6

Attachment F.1(c)(6) - Economic Boom Scenario

CUMULATIVE CAPITAL SPENDING EXISTING AND NEW GENERATION PLUS INCREMENTAL TRANSMISSION ECONOMIC BOOM SCENARIO - ($MILLIONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	1,214.4	1,214.4	1,204.1	1,210.4
2015	1,688.3	1,688.3	1,655.0	1,644.2
2016	2,423.7	2,491.2	3,089.2	2,391.4
2017	4,572.1	4,957.1	4,590.5	4,502.6
2018	5,276.8	6,108.9	5,211.9	5,100.2
2019	6,369.1	7,589.1	7,170.9	6,170.4
2020	8,712.6	10,485.0	8,615.1	8,494.7
2021	10,352.0	12,385.3	10,119.9	10,109.9
2022	11,854.9	14,297.4	11,580.7	11,594.9
2023	13,566.4	16,725.8	13,301.7	13,272.6
2024	15,096.3	18,751.2	15,424.6	14,793.4
2025	16,834.1	21,033.8	17,290.9	16,523.5
2026	18,849.2	22,824.2	19,774.0	18,522.4
2027	20,954.4	25,064.3	21,964.0	20,617.1
2028	22,982.5	27,165.4	23,690.6	22,632.6
2029	24,701.9	28,976.7	25,750.9	24,337.9

1. Capital investment projected is regardless of whether APS constructs and owns new generation resources or whether resources are purchased by APS under long-term PPAs with market participants.

2. Capital spending excludes: (a) financial commitments to energy efficiency and distributed energy initiatives; (b) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing.

3. Capital spending includes ongoing capital investment for existing owned generation.

Attachment F.1(c)(6) - Economic Boom Scenario

ANNUAL NATURAL GAS BURNS ECONOMIC BOOM SCENARIO - (BCF)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	47.4	47.4	47.4	47.4
2015	48.4	48.4	48.4	48.4
2016	54.5	54.5	63.4	63.0
2017	72.2	72.3	84.8	83.9
2018	74.2	72.4	87.2	107.3
2019	86.0	78.8	98.0	113.6
2020	89.4	80.9	101.0	117.6
2021	99.2	86.5	110.5	128.4
2022	107.7	92.1	118.9	138.4
2023	121.3	104.3	132.0	151.7
2024	126.1	105.2	137.3	159.2
2025	132.5	107.4	161.1	164.1
2026	146.3	121.2	176.8	178.9
2027	161.4	131.6	191.8	193.8
2028	175.5	148.0	204.0	207.3
2029	199.4	170.0	224.5	228.6

Attachment F.1(c)(6) - Economic Boom Scenario

ANNUAL CO2 EMISSIONS ECONOMIC BOOM SCENARIO - (METRIC TONS)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	14,113,325	14,113,325	14,113,325	14,113,325
2015	14,254,910	14,254,910	14,254,910	14,254,910
2016	14,996,572	14,996,572	14,284,331	14,326,055
2017	15,182,558	15,181,667	14,214,501	14,308,024
2018	16,049,375	15,910,523	15,016,151	13,115,990
2019	15,800,190	15,316,807	14,880,883	13,472,006
2020	16,182,967	15,550,384	15,230,764	13,768,393
2021	16,865,775	16,026,214	15,880,530	14,391,452
2022	17,650,962	16,473,535	16,667,715	15,072,791
2023	17,925,746	16,593,884	16,734,654	15,384,668
2024	18,962,360	17,416,960	17,799,237	16,098,928
2025	19,719,197	17,744,553	16,886,834	17,028,565
2026	20,570,856	18,584,115	17,668,234	17,801,830
2027	21,238,151	18,995,444	18,472,462	18,581,590
2028	21,835,602	19,938,615	19,096,961	19,307,702
2029	22,304,006	20,335,323	19,749,440	20,003,582

Attachment F.1(c)(6) - Economic Boom Scenario

ANNUAL WATER USE ECONOMIC BOOM SCENARIO - (ACRE-FEET)				
YEAR	BASE PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
2014	55,604	55,604	55,604	55,604
2015	55,905	55,905	55,905	55,905
2016	56,775	56,775	55,228	55,369
2017	57,060	57,054	55,048	55,227
2018	58,818	58,503	56,691	53,602
2019	58,463	57,311	56,499	54,332
2020	58,935	57,452	55,639	54,617
2021	58,870	57,051	54,755	53,989
2022	59,681	58,621	55,551	54,505
2023	61,533	60,204	56,664	56,393
2024	62,643	60,869	58,860	56,522
2025	62,870	61,816	55,551	56,997
2026	62,967	62,108	55,776	56,862
2027	63,102	63,421	56,944	57,057
2028	65,289	64,878	58,030	59,535
2029	64,457	64,254	57,943	59,259

Attachment F.9(b) - 2014 Resource Plan – Loads & Resources Forecast

SELECTED PORTFOLIO LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,260	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,236	1,275	1,310	1,349	1,388	1,426	1,466	1,505
5	**Total Load Requirements**	**8,124**	**8,268**	**8,566**	**8,897**	**9,219**	**9,543**	**9,864**	**10,268**	**10,610**	**10,946**	**11,276**	**11,609**	**11,945**	**12,286**	**12,632**	**12,982**
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,538	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market / Call Options / Hedges /AG-1	920	846	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	469	463	463	464	464	453	444	436	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	16	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	**Total Existing Resources**	**9,166**	**9,084**	**8,420**	**7,770**	**7,550**	**7,550**	**6,943**	**6,454**	**6,446**	**6,433**	**6,426**	**6,426**	**6,427**	**6,410**	**6,411**	**6,412**
22	Energy Efficiency	109	267	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	63	74	86	98	109	119	133	156	181	203	224	237	245	253	261
24	Demand Response	21	21	26	26	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	26	26	26	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	**Total Customer Resources**	**174**	**350**	**535**	**706**	**862**	**1,013**	**1,178**	**1,305**	**1,412**	**1,507**	**1,610**	**1,663**	**1,744**	**1,821**	**1,899**	**1,983**
29	Natural Gas	0	0	0	364	750	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CTs/CCs	0	0	0	0	510	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	364	240	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	**Total Future Resources**	**0**	**32**	**57**	**420**	**807**	**1,067**	**1,825**	**2,572**	**2,811**	**3,093**	**3,325**	**4,013**	**4,017**	**4,139**	**4,422**	**4,630**
37	**TOTAL RESOURCES**	**9,340**	**9,467**	**9,012**	**8,897**	**9,219**	**9,630**	**9,945**	**10,331**	**10,668**	**11,033**	**11,361**	**12,102**	**12,188**	**12,371**	**12,732**	**13,025**

APPENDIX A

Customer-Side Resources

ENERGY EFFICIENCY

RESIDENTIAL EXISTING HOMES HEATING, VENTILATION, AND AIR CONDITIONING PROGRAM ("RESIDENTIAL HVAC")

This program is divided into two distinct components: (1) HVAC measures and (2) Home Performance with ENERGY STAR® ("HPwES") measures.

The HVAC measures use a combination of financial incentives, contractor training and consumer education to promote the proper installation and maintenance of energy-efficient HVAC systems. The Air Conditioner ("AC") Rebate, Duct Test and Repair and Residential Diagnostic measures support energy-efficient residential air conditioning and heating systems along with the proper installation, maintenance and repair of these systems.

The HPwES measures promote a whole house approach to EE by offering incentives for improvements to the building envelope of existing residential homes within the APS service territory. HPwES includes measures that improve the EE of the home with air sealing, insulation, faucet aerators, and low flow showerheads.

RESIDENTIAL NEW CONSTRUCTION PROGRAM

This program promotes high-efficiency construction practices for new homes by offering incentives to builders that meet the program's EE standards. The program emphasizes the whole building approach to improving EE and includes field-testing of homes to ensure performance. Participating builders are trained to apply building science principles to ensure that high efficiency homes also have superior performance. The program also provides education for prospective homebuyers about the benefits of choosing an energy-efficient home and the features to consider.

The program takes advantage of the national ENERGY STAR® brand name, and promotes the EPA ENERGY STAR® label to prospective homebuyers. To encourage builders to meet the program's high-efficiency standards, APS provides builder incentives of $1,000 per home for ENERGY STAR version 3 compliant homes. To encourage builders to meet even higher EE standards, the program also offers a second-tier incentive of $1,500 per home for builders that meet the higher savings level of Home Energy Rating System ("HERS") 60.

CONSUMER PRODUCTS PROGRAM

This program is composed of two components: (1) Residential Lighting and (2) Residential Pool Products.

The Residential Lighting element of the program promotes high-efficiency EPA/DOE ENERGY STAR® CFLs. CFLs use an average of 75% less energy than standard incandescent bulbs and last up to ten times longer, typically saving consumers up to $40 in energy costs over the life of each bulb. The program offers discounts on CFLs through cooperative agreements with retailers and lighting manufacturers. This provides consumers with reduced retail prices for CFLs at local lighting retailers, with prices typically at or below $0.99 per bulb for standard 60 watt equivalent CFLs.

The Energy-Efficient Pool Pump element of the Consumer Products program is designed to improve the efficiency of residential pool operations while maintaining equivalent or better standards for pool sanitation and cleanliness. The program promotes the installation and optimal calibration of energy-efficient variable-speed pool pump motors.

THE APPLIANCE RECYCLING PROGRAM

This program is designed to educate APS customers about their old spare refrigerator or freezer that use a great deal of energy. By turning the working refrigerator or freezer in for recycling, they can save up to $100 per year on their electric bill.

RESIDENTIAL CONSERVATION BEHAVIOR PILOT PROGRAM

This program provides participating customers with bi-monthly reports containing information designed to motivate them to change energy usage patterns to conserve energy.

To drive conservation behavior, this program direct-mails comparative Home Energy Reports to participants that show how the energy usage in that customer's home compares with similar homes. Coupled with the comparison data, customers receive recommendations for specific and targeted actions they can take to save energy.

Derived from best practices in behavioral science research, this program uses normative messaging to engage and motivate conservation actions of targeted individuals. Comparing an individual's energy use to what is "normal" has proven to be an effective mechanism to attract attention and motivate action. Normative messaging on energy use, combined with recommendations on how to improve, is the basis of the concept for the Conservation Behavior program. The program provides a benchmark for customers to achieve, and often instills a sense of competition to produce sustained conservation behaviors.

MULTIFAMILY ENERGY EFFICIENCY PROGRAM (MEEP)

MEEP encourages EE improvements in multifamily complexes within the APS service territory. MEEP uses a three-track approach to promote EE within the multifamily market segment.

- Track 1 provides free direct install components to retrofit the residential dwellings of existing communities. Participating communities will receive enough CFLs, low flow showerheads, and faucet aerators to retrofit every community dwelling. Facility personnel, with implementation contractor field support, will conduct all direct install installations.
- Track 2 will utilize APS Solutions for business programs to provide complementary energy assessments of the community commercial facilities. The energy assessment will identify opportunities for additional EE savings and the applicable Solutions for Business incentives that are available.
- Track 3 targets new construction and major renovation multifamily projects. This track builds from the success of the APS ENERGY STAR® Homes program and encourages energy efficient building principles by paying an incentive to builders on a per unit basis for following a list of EE measures outlined in one of four builder option packages.

SHADE TREE PROGRAM

This program provides free shade trees to APS's residential customers that have attended an APS Shade Tree workshop or participated in online training. The program educates customers on successful tree planting and care techniques, and provides a customer specific site map indicating the ideal tree planting location(s) to help reduce customer-cooling needs.

APS'S ENERGY WISE LOW INCOME ASSISTANCE PROGRAM

This program is designed to improve the EE, safety and health attributes of homes for customers whose income falls within the defined federal poverty guidelines. This program serves low-income customers with various home improvements including cooling system repair and replacement, insulation, sunscreens, water heaters, window repairs and improvements as well as other general repairs. In addition, low-income families are provided crisis bill assistance. The program is administered by various community action agencies throughout APS's service territory.

LARGE EXISTING FACILITIES PROGRAM

This program provides prescriptive incentives for owners and operators of large (over 100 kW aggregated peak monthly demand) non-residential facilities for EE improvements in technologies such as lighting, HVAC, motors and refrigeration applications. The direct installation approach is available for facilities that are individually metered with a peak demand of 400 kW and less. For EE applications not covered by the prescriptive incentives, the program offers custom incentives, which are evaluated individually based on energy savings. The program also provides incentives to reduce the cost of an energy study that identifies energy saving opportunities. The program provides educational and promotional pieces designed to assist facility and business owners and operators in making decisions to improve the EE of their facilities.

NON-RESIDENTIAL NEW CONSTRUCTION AND MAJOR RENOVATIONS PROGRAM

This program includes: (1) design assistance and feasibility studies, (2) custom measures, (3) prescriptive measures and (4) whole building applications (construction & design incentives). Design incentives involve efforts to integrate EE into a customer's design process to influence equipment/systems selection and specification as early in the process as possible. Custom and prescriptive incentives are available for EE improvements in lighting, HVAC, motors and refrigeration applications. Whole-building applications are intended to promote integrated design strategies.

NON-RESIDENTIAL SMALL BUSINESS PROGRAM

This program provides prescriptive incentives for small non-residential customers (<100 kW of aggregated peak monthly demand) for EE improvements in lighting, HVAC, motors and refrigeration applications through a simple and straightforward mechanism for program participation. Small business customers are also eligible for custom incentives to implement EE measures. The program provides incentives for conducting an energy study that identifies energy saving opportunities. Direct install measures are also offered to the small business market through participating contractors.

SCHOOLS PROGRAM

This program includes a set-aside budget for K-12 schools and provides assistance in reducing the energy used in school buildings, including public, private and charter schools (K-12). The incentives available for schools include the same DSM measures that are available for all non-residential customers, including direct install measures for K-12 schools of any size.

ENERGY INFORMATION SYSTEMS (EIS) PROGRAM

The EIS Program helps large customers (>100 kW) save energy by giving them a better understanding and control of their facilities' electric use. EIS provides data not only regarding usage and demand, but also identifies when, where and how much power is used in specific areas of each facility. This detailed information allows customers to fine-tune equipment use and operations and to document the impact of those changes. Participating customers monitor their electric usage through a web-based energy information system that allows them to receive historical (up to previous day) 15-minute usage and demand graphics. This information can be used to improve or monitor energy usage patterns, reduce energy use, reduce demands during on-peak periods and better manage overall energy operations.

DEMAND RESPONSE

NON-RESIDENTIAL DEMAND RESPONSE PROGRAM

APS Peak Solutions® is a commercial and industrial demand response program for APS's Yuma and Phoenix metro customers utilizing direct load control and manual load reduction.

RESIDENTIAL TIME-OF-USE (TOU) RATES

TOU rates are designed to (1) reflect the time variation in the cost of producing electricity by more accurately matching those costs to the service being provided to encourage efficient use of energy, and (2) motivate customers to reduce consumption during peak hours or to shift energy usage to off-peak periods. APS currently offers five residential TOU rates.

DISTRIBUTED GENERATION: ROOFTOP/CUSTOMER-SITED SOLAR PV

A complete solar electric system consists of (1) solar modules that convert the sun's energy into direct current (DC) electricity, (2) an inverter which then collects DC electricity for the solar modules and converts that into alternating current (AC) electricity and (3) the mounting hardware to install the technology at the customer's site. These systems are expected to last at least 20 years with the solar PV modules requiring little maintenance over this timeframe. The power electronics (inverter and other components), represent about 30-40% of the system cost and have a standard life expectancy of 5 to 10 years, however some leading inverter manufacturers are beginning to offer 10-year standard warranties and with a few even offering up to 20-year warranties.

As of year-end 2013, APS had over 22,000 customer-owned/leased distributed PV systems with over 125 APS-owned distributed PV systems on residential customer premises as part of the Flagstaff Community Power Project. APS also has installed about 15 MW(dc) of APS-owned distributed PV systems school facilities throughout the APS service territory. In most cases, these systems are interconnected to the APS grid from the customer side of the meter and are designed to reduce the overall customer need to purchase electricity generated from their utility.

APS was one of the first utilities in the country to provide customer incentives for the installation of distributed PV in 2002. Available incentives, if any, are approved by the ACC and are reviewed and adjusted on an annual basis. The combination of declining installation costs and incentives makes rooftop PV challenging to forecast. However, based on historical market activity, the level of penetration is not expected to fall below RES Compliance Standards.

SOLAR WATER HEATING

A thermal fluid (such as water or glycol) is passed through a solar collector and heated to as high as 240°F. It is then circulated through a heat exchanger that heats water stored in the hot water tank for use when needed by the customer. A less sophisticated system simply passes water through the solar collector that preheats the water before it enters the customer's water heater. If the water is preheated, the water heater requires less energy to heat the water but is also somewhat less efficient.

APS has been providing rebates to encourage the installation of solar water heaters since 2002. As a result, there were 8,950 units installed as of the end of Q3 2013.

CONCENTRATED PHOTOVOLTAIC TECHNOLOGY (CPV)

CPV technology uses optics such as lenses to concentrate a large amount of sunlight onto a small area of solar photovoltaic materials to generate electricity. According to the photovoltaic effect, solar cells make electric energy that is proportional to the amount of light energy that falls on them. By focusing up to 300 times the amount of light on a solar panel, it is possible to produce multiple times the amount of electricity.

Though a promising technology, CPV has been challenged by performance under extreme cell temperatures, precise tracking system requirements and routine O&M to remove any soiling from modules so as not to decrease performance. These issues make the systems more complicated than a comparable fixed or single axis tracking (SAT) PV system. The resulting increased costs of the concentrated, more sophisticated PV cells and tracking system may drastically reduce the savings derived from having fewer solar cells.

GEOTHERMAL HEAT PUMPS

Geothermal heat pumps take advantage of the more constant temperatures found just under the surface of the earth by using a vertical or horizontal ground loop installed underground and a thermal exchange. The system helps heat or cool a home or other building by transferring heat to or from the air found in the home. In the summer, the system takes the warmer air out of the home and transfers its heat to the ground. In winter, the system does the opposite by transferring heat from the ground to the colder air circulating from the home.

In recent years, APS has seen many installations as a result of the Distributed Generation Incentive Program. The market for geothermal heat pumps is expected to grow slowly as efficiency increases and paybacks are reduced, provided long-term energy prices increase. Most of the systems within the APS service area are found in the Northern part of the state.

WIND (SMALL RESIDENTIAL CUSTOMER)

APS has little direct experience with distributed wind energy systems. Wind turbines used in distributed generation have been in operation for many decades. They use the kinetic energy of the wind passing over the blades mounted to a generator to produce energy. They are mounted on towers that are 50 to 200 feet high in order to avoid air flow disruption from surrounding buildings, trees and topography. These wind turbines require a minimum wind speed of 4-7 mph to begin generating power, and achieve their maximum energy output at around 25-30 mph wind velocity. There are numerous manufacturers of small distributed wind systems that can be grid connected.

Although specific markets around the world show signs of significant growth, small wind is expected to remain a niche market within the APS service territory throughout the period of 2014 to 2018.

Utility-Side Resources

MATURE TECHNOLOGIES

NUCLEAR

One example of advanced nuclear technology is Westinghouse's AP1000 which is a two-loop pressurized water reactor. The primary loop cools the nuclear core and carries the thermal energy to the steam generator heat exchangers. The steam generators transfer the thermal energy to the secondary loop to produce steam that generates electricity through the turbine-generator. The AP1000 incorporates a passive core cooling system in addition to many other safety systems in the design.

New nuclear generators have a long lead time of over 9 years. This is because new reactor licenses, which can take 2½ to 5 years to complete, must be approved by the NRC. After the review process is completed, construction may take approximately six additional years for each reactor. For most utilities, the construction of a large nuclear plant is considered a major investment due to the large capital cost and long duration to build the plant.

COAL

There are two commonly utilized coal steam boiler technologies, and one under development, differentiated by operating characteristics, available for construction. All three burn pulverized coal to produce steam in the boiler tubes at varying pressures, which then is expanded through a steam turbine and generator to produce electricity. From there, the turbine exhaust steam is condensed back to water and returned to the boiler tubes at varying pressures. Since the 1960's, APS has had experience operating two of the three types of plants.

TABLE 1 - COAL STEAM BOILER TECHNOLOGIES

COAL STEAM BOILER TECHNOLOGY	OPERATING CHARACTERISTICS		APS PLANTS
Subcritical	<3,208 psi	1,025°F	Cholla Units 1-3
Supercritical	>3,208 psi	1,000°F - 1,050°F	Four Corners Units 4&5
Future	>3,208 psi	1,100°F	None

According to the EIA, coal's share of U.S. electricity generation is expected to decline from 42% in 2011 to approximately 35% by 2040[1]. In September 2013, the EPA re-proposed the New Souwrce Performance Standard that would set an emissions limit of 1,100 pounds per MWh of electricity generated by new coal-fired power plant units. According to the Congressional Research Service's November 2013 report, *EPA Standards for Greenhouse Gas Emissions from Power Plants: Many Questions, Some Answers*, it would be impossible for coal-fired units to meet the standard without carbon, capture and sequestration technologies in place to capture about 40% of the CO2 they produce[2].

[1]http://www.eia.gov/forecasts/archive/aeo13/pdf/0383(2013).pdf

[2]https://www.fas.org/sgp/crs/misc/R43127.pdf

NATURAL GAS

A versatile fuel, natural gas can be burned or heated in numerous generation technologies. APS employs three natural gas technologies and within these subcategories of technologies, many more modern versions exist. The differences among technologies can be found in Attachment D.3. Those differences are taken into account when making resource addition decision as described in Chapter 4 of this document. Below are some of the operational highlights of each form of existing natural gas generation technology that exists on APS's side of the grid.

NATURAL GAS STEAM TURBINES

These turbines operate similarly to coal steam turbines, but utilize gas instead of pulverized coal as their fuel source. In these units, compressed natural gas is burned within the boiler to produce subcritical steam in the boiler tubes at a typical pressure of 1,450 psi and temperature of 1,000°F. The subcritical steam is expanded through a steam turbine to produce electricity. The turbine steam is exhausted into the condenser, is condensed back to water, and then pumped back into the boiler tubes at the subcritical pressure.

Over many decades APS has operated gas-fueled boilers that supply steam to turbine generators. These steam units are located at the West Phoenix, Yucca, Ocotillo and Saguaro power plants. The several small steam boilers at the West Phoenix plant were retired many years ago. The single unit at the Yucca power plant is operated by APS for the Imperial Irrigation District. The two units at the Saguaro power plant were recently retired and are in the process of being decommissioned. The Ocotillo power plant has two units that are still in use but will be replaced by 2018 with five high efficiency combustion turbines.

CONVENTIONAL AND ADVANCED COMBINED CYCLE (CC)

A CC generating unit consists of one or more combustion turbine (CT) generators equipped with heat recovery steam generators (HRSG) to capture the otherwise wasted thermal energy remaining in the turbine exhaust gases. Steam produced in the HRSG powers a steam generator to produce electric power, in addition to the power produced by the CT(s). This process significantly increases the efficiency of this electric generating unit, and additional capacity can be obtained with the use of power augmentation technologies, including turbine inlet cooling of the compressed air and duct firing at the inlet of the HRSG.

APS installed three combined-cycle units at the West Phoenix power plant in 1976. Since then, APS has added two additional units at West Phoenix and also built two units at the Redhawk power plant.

SIMPLE CYCLE COMBUSTION TURBINES (CT)

A CT generating system consists of an inlet air filter, inlet cooling system, compressor, combustor, turbine, exhaust environmental controls, stack, generator and auxiliary systems needed to support the operation of the CT. Many of the newer units are now capable of a 10-minute quick start. Most are also considered to have low emission combustion and controls, and have improved part-load performance.

Combustion turbine market growth over the last 20 years has been the result of metallurgical advances, aerodynamic and thermodynamic knowledge base advancements, and advanced computer technologies used in the design, simulation and manufacturing of combustion turbine components. The proposed CO2 emissions cap for new construction power generation units should not affect the selection and operation of potential future APS peaking units. Electric generation units operating for less than 2,920 hours per year and producing less than 219,000 MWh-net per year will be exempt from the proposed CO2 emissions cap.

APS has owned and operated CTs since the first units were installed at the Yucca power plant in 1971. Currently, the utility has 24 CTs in operation positioned around its service territory to support the local grid. Yucca, Douglas, Saguaro, Ocotillo, West Phoenix and Sundance all have CTs on-site.

RECIPROCATING ENGINES

Spark ignition reciprocating engines can range in size from a few kilowatts up to several megawatts such as the 18 MW Wartsila 50SG. Some of these engines are turbocharged or supercharged to increase their output. The units are capable of using natural gas, propane, and biogas fuels. The fuel and air mixture is introduced into combustion cylinder, and then compressed as the piston within the cylinder moves up to the top of its stroke. As it nears the top, a spark is produced that ignites the air-fuel mixture. The pressure of the hot, exploding gases drives the piston down. This energy in the moving piston is converted by the crankshaft into rotational energy that is used to generate electricity or drive a piece of equipment or machinery. An alternative application can combine heat and power in this form of unit captures some of the waste heat from the engine cooling system and exhaust gases for process heating within a facility.

The combustion process produces NOx and, depending on its level of maintenance, varying amounts of carbon monoxide, particulate, and hydrocarbon emissions. These units fall below the 25 MW size limitation of the EPA's proposed CO2 emissions regulation for new natural gas fueled power plants and would be exempt from any CO2 emissions control requirements.

APS currently has many backup power generators at electrical critical sites, including the emergency electric power requirements at the Palo Verde Nuclear Generating Station.

WIND

Wind turbines today range in size from 1-3 MW each with blade diameters up to 300 feet. Because of an individual turbine's size, wind farms typically require sizeable plots of land. Wind systems convert the wind's energy into electricity by using rotating blades, typically made of fiberglass, to collect the wind's kinetic energy. The turbines are supported by a conical steel tower that is widest at the base and tapers in diameter to just below the nacelle. The nacelle is attached to the top of the tower and contains the primary mechanical components of wind turbine. The blades are connected to a drive shaft that turns a generator to produce electricity.

APS has Power Purchase Agreements (PPAs) for three wind farms. Two are located outside of the state, in New Mexico, as spring and fall are usually the best periods for wind generation in Arizona, but also the period of lowest load on the electric grid. Additionally, energy prices for wind are directly related to wind resource capacity. The best Arizona wind resources are estimated to be class 3-4 on a Wind Power Classification scale of 1-to-7, which makes wind energy more costly for Arizona. While the wind market is expected to grow at a fairly rapid rate over the next few years compared to other renewable energy resources because of poor wind generation potential in this state, national growth is expected to outpace growth in APS's territory.

SOLAR

APS currently operates two forms of solar generation technology, which are discussed below:

SOLAR PV FIXED AND SINGLE AXIS TRACKING (SAT)

Fixed systems are typically angled at latitude for optimum production while SAT systems rotate to follow the sun from east to west. Adding SAT increases the energy output from the system by approximately 20% in comparison to a fixed system. Thousands of these modules can be connected together to form large systems connected to the grid through an inverter that converts the DC energy to AC. Utility scale inverters typically range in scale from 500 kW to over 1 MW. Many of these inverters are combined together to form multi-MW solar power systems. Standard warranties for solar modules typically last for 20-25 years. Production from panels will typically degrade at about 0.5-percent per year. The inverters, which count for about 25% of system cost, have life expectancies of about 10 years before replacement is required.

Through the AZ Sun program there are currently 118 MW in service with a further 32 MW either under construction of development. APS plans to install over 200 MW of PV solar power plants by the end of 2015. Uncertainty remains with the possible expiration of the Investment Tax Credit.

SOLAR THERMAL - TROUGH TECHNOLOGY

Parabolic trough systems are the original utility-scale solar thermal technology. Parabolic mirrors focus solar energy onto a receiver tube that contains a heat transfer fluid, typically synthetic oil. The fluid then returns to a series of heat exchangers, where it is used to generate superheated steam at about 1,450 psia and 700°F. The steam is then used to run conventional steam turbines. Spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers as condensate via the feedwater pumps. With the addition of molten salt thermal storage, such as APS's Solana Plant, or gas hybridization, these systems can extend the generation period up to six hours after sunset.

The 283 gross, 250 net MW Solana plant near Gila Bend Arizona completed construction and started commercial power production on October 7, 2013. However, the reduction in PV costs compared to CSP technology costs has made PV a more popular choice.

GEOTHERMAL

Geothermal energy is created when the heat from the earth is used to heat water which is then used as flash steam, dry (direct) steam or binary steam. The flash steam process occurs when very hot water is drawn through wells under pressure and vaporizes into steam at pressures below the reservoir via one or two flash tanks. The steam then turns a steam turbine. The dry (direct) steam process occurs when wells draw steam and routes it directly to a turbine that spins a generator. The binary steam process occurs when wells use heat from water to boil a working fluid, usually an organic compound with a low boiling point, in a heat exchanger that spins a turbine.

APS has a power purchase agreement for geothermal energy from the Salton Sea in California. APS participated in some early exploration of what is considered some of Arizona's best geothermal resources in the early 2000's and again in 2010 in the Clifton, Arizona area near Clifton Hot Springs. The exploratory research results indicated very limited energy potential. However, there is about 2,500 MW of projects in other areas of the US with confirmed geothermal resources in development over the next decade[3]. Additionally, the use of binary plants are expanding the use of lower temperature resources such as those found in Arizona, thereby potentially reducing the cost and making lower and more abundant geothermal resources more feasible and economically viable.

[3]http://geo-energy.org/pdf/reports/2013AnnualUSGeothermalPowerProductionandDevelopmentReport_Final.pdf

BIOMASS

Biomass fuels are primarily wood or wood byproducts. However, they can include dried municipal solid wastes, feedlot and dairy manure, crop wastes, and sewage digester sludge. Biomass can be converted into electricity in one of several processes. The majority of biomass electricity is generated today using a steam cycle where the biomass is burned in a boiler to produce steam. The steam turns a turbine, which is connected to a generator that produces electricity.

In smaller applications, cogeneration is used to extend the viability of the technology. An additional potential opportunity is co-firing torrefied biomass pellets with pulverized coal or through biomass gasification. Both of these technology options are either developmental or early-commercial. In addition, there are currently no utility-scale torrefied biomass pellet fuel suppliers, although there are several that are working to establish a market presence. Pellet manufacturing is a fully commercialized operation but large-scale biomass torrefaction process options are still developmental.

APS has a PPA for approximately 50% of the Snowflake biomass power plant's output. The plant has recently resumed full operation after an extended shutdown.

BIOGAS

Biogas is a low-BTU gas composed of methane (40-60%), carbon dioxide, water and miscellaneous contaminates that is produced thru anaerobic digestion processes in landfills, and wastewater treatment at municipal water plants and concentrating animal feeding operation (CAFO) farms. The gas is produced, collected, and then typically flared and/or used for on-site thermal heating. If the amount of biogas produced is sufficient to warrant the development of a biogas-to-energy project, the biogas would be cleaned and dried, and/or thermally oxidized prior to combustion. The biogas can then be converted into electricity by combustion in specific reciprocating engines, microturbines, and fuel cells that have been designed and configured to utilize low-Btu fuels.

APS currently has a PPA with the Glendale Landfill, a 2.8 MW generation facility, and the Surprise Landfill, a 3.2 MW generation facility. Landfills and other biogas generators are fairly small on a utility scale and usually represent only a few MW, with an average size of less than 5 MW. As technologies improve, these may mature into viable opportunities in the future.

POTENTIAL FUTURE TECHNOLOGIES

NUCLEAR - SMALL MODULAR REACTORS (SMR)

Potential future requirements for nuclear energy may be fulfilled by an advanced, latest-technology system. The EIA estimates that SMR will be the nuclear technology of choice after 2025 and the SMRs will have traveled the complete path to commercialization by then[4]. SMRs are smaller than 300 MW and can be built in modular arrangements in a manufacturing plant. The reactor units can be shipped to the plant site and inserted into the plant foundation structure and connected to the balance-of-plant steam and auxiliary systems. SMRs have a projected construction period of three years. Generating capacity can be added in smaller increments with a much smaller impact on transmission line capacity and need for upgrades or large increases in cooling water requirements.

COAL

ULTRA-SUPERCRITICAL STEAM TURBINES (USC)

USC steam pulverized coal power plants are still considered to be an early commercial technology. The first USC unit in the U.S. was built for AEP and completed in 2012[5]. Over the long-term there is potential for the near-zero emissions Pressurized Oxy-Combustion (POXC) technology that combusts a coal slurry and oxygen in a pressurized 'flameless' reactor. This technology is in pilot-scale testing and still needs additional thermal recovery heat rate improvements, and then demonstrated and tested to full-scale commercialization.

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

APS expects that IGCC technology will experience slow growth until it is proven to be commercially viable. IGCC plants integrate coal gasification with combined-cycle technology. Coal gasification is the partial oxidation process of converting coal and other fuel inputs into a cleaned gaseous fuel or syngas (CO+H2). The syngas (synthesis gas) produced in the coal gasifier is scrubbed and filtered before combustion in the turbine. This protects the turbine blades from damage and helps meet or exceed the current EPA pollution emission regulations. Depending on the gasification technology selected, most of the coal ash will be removed in the form of a glassy, non-leachable slag that can be used in the manufacture of roofing shingles or aggregate.

[4]http://www.eia.gov/forecasts/archive/aeo13/pdf/0383(2013).pdf

[5]http://www.powermag.com/aeps-john-w-turk-jr-power-plant-earns-powers-highest-honor/

CARBON CAPTURE AND SEQUESTRATION

CO2 can be recovered from the flue stream using an amine-based thermal swing absorption process. Steam required for the process will be pulled out of the LP turbine, which lowers its output and overall plant efficiency. The amine-based solvent process is susceptible to both thermal and oxidative degradation. Ammonium carbonate can also be used as a sorbent rather than the organic amine sorbent. Both these processes have been used for more than 70 years in industrial applications for the removal of acid gases (both CO2 and H2S). The current method of CO2 separation and capture can be costly and energy intensive. For a 600 MW power plant, the auxiliary loads for the addition of an amine-based CO2 absorption system have been estimated at 92 MW[6].

The plant efficiency was also estimated to drop from 39% down to 28%[7]. The primary means for carbon storage is injecting liquefied CO2 into geological formations with additional options such as oil and gas reservoirs, unmineable coal seams, and underground saline water formations. The amount of auxiliary energy required from the point of capture thru sequestration will in itself result in additional CO2 emissions and increased quantities of water consumption. Other concerns have been the seismic events that have resulted from geological sequestration pilot tests and the potential leakage of CO2 back to the surface.

No more than 12 large-scale demonstration plants are expected to be built by 2020[8]. Alberta, Canada has committed over $1.2 billion to two demonstration projects expected to be completed by late 2015[9].

SOLAR THERMAL - TOWER

Solar tower systems use a field array of flat mirrors, ranging from hundreds to tens of thousands, called heliostats that reflect sunlight onto a central receiver located at the top of tower. Inside the central receiver is a working fluid such as water, molten salt or air. Water is boiled to steam at about 800psi and 850°F. This steam powers a traditional turbine and generator. The steam reverts back to water through cooling, and the process repeats.

Another method uses molten salt as the working fluid. In this method, molten salt from a cold salt tank is pumped through the receiver where it is heated to about 1050°F. The heated salt is stored in a hot tank. The hot molten salt is then pumped through a heat exchanger to create steam that spins a generator. Cold salt at about 525°F flows back to the cold salt tank.

The tower market is still emerging as projects are brought online. Should this technology prove reliable, it has the potential to become competitive with thermal trough with storage.

[6]Derived from information contained in the following article: http://blogs.scientificamerican.com/guest-blog/2013/03/07/post-combustion-co2-capture-to-mitigate-climate-change-separation-costs-energy/

[7]Derived from http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

[8]http://www.powermag.com/epa-banks-on-ccs-technologies-sets-carbon-standards-for-new-coal-units/?pagenum=2

[9]http://www.technologyreview.com/news/514221/can-carbon-capture-clean-up-canadas-oil-sands/

FUEL CELLS

There are many different types of fuel cells such as Alkali (AFC), Phosphoric Acid (PAFC), Molten Carbonate (MCFC), Proton Exchange Membrane (PEM), Solid Oxide fuel cell (SOFC), and Direct Carbon (DCFC) and many more differentiated on the basis of components used and type of reaction taking place within the cell. While two require pure hydrogen, most have reformers to convert fuels such as biogas, natural gas, methanol or hydrocarbons into hydrogen and/or carbon inputs. At this time, APS does not view fuel cells as suitable for any of the Company's distributed generation or smart-grid applications until their reliability is improved, costs are reduced, and the cell-stack life is extended. The following table compares the various fuel cell technologies[4].

TABLE 2 - FUEL CELL TECHNOLOGIES

	AFC	PAFC	MCFC	PEMFC	SOFC	DCFC
Electrolyte	Potassium Hydroxide	Phosphoric Acid	Molten Carbonate	Polymer "saran wrap"	Ceramic	Several different
Catalyst	Platinumn/ Palladium	Platinum	Nickel/ Nickel-oxide	Platinum Ruthenium	Not required	Not required
Operating Temperature	150-200°C (300-400°F)	190°C (375°F)	650°C (1,200°F)	80°C (175°F)	1,000°C (1,830°F)	700°C (1,290°F)
Fuel(s)	Pure H2	H2 reformate	H2/CO reformate	H2 reformate	H2/CO/CH4 reformate	Solid Carbon
Reformer	Not applicable	External	Internal	External	Internal	Not necessary
Oxidant	Pure O2	O2 / Air	O2 / Air	O2 / Air	O2 / Air	Humidified Air
Efficiency (HHV)	70%	40-50%	50-60%	30-35%	45-55%	70-80%
Cold Startup	4-8 hours	4-8 hours	8 hours	~2 seconds	6-8 hours	8 hours

STORAGE

Storage comes in many forms of technologies. Certain technologies are better suited for grid applications while others are more suitable to address seasonal or diurnal needs. It is likely that APS will deploy a suite of storage technologies to maximize reliability as the Company integrates increasing amounts of variable generation and customer-side resources. APS evaluates these technologies as opportunities arise, in conjunction with other renewable or intermittent technologies, or for power quality applications while determining their financial and operational strengths and weaknesses. However, because their limited usage and applications, their application of choice may not be completely known at this time.

[4]http://www1.eere.energy.gov/hydrogenandfuelcells/fuelcells/pdfs/fc_comparison_chart.pdf

FLYWHEEL/ROTARY UNINTERRUPTIBLE POWER SUPPLIES (UPS) ENERGY STORAGE

Flywheels are energy storage systems used primarily for short-term energy and power support such as voltage stabilization and UPS (uninterruptable power supply). High-rpm systems store electricity in the form of kinetic energy in a flywheel that rotates at speeds of up to 16,000 rpm. To reach its operational speed, the system draws electricity from the grid to power a permanent magnet motor and spins the flywheel faster. The high-rpm flywheel can spin with great efficiency because friction and drag are reduced by the use of magnetic bearings in a vacuum-sealed environment. Because it incurs low friction, little power is required to maintain the flywheel's operating speed. The flywheel is powered up when the distribution system is operating normally, either automatically or when signaled by the operator. When voltage drops to a specified level, a signal is sent for electrical power to be provided. The momentum of the spinning high-rpm flywheel drives a generator and the kinetic energy is converted back into electrical energy for a 5-15 minute release to the grid.

High-rpm flywheel technology, as part of the energy storage market, is gaining momentum. The biggest market driver for large scale high-rpm flywheel technology is the demand for more renewable energy and the potential use as very short-term energy storage to firm up grid sags and spikes from intermittent solar and wind. It also has the potential to replace short duration battery storage technologies for frequency and voltage grid support with a higher potential energy density and a lower environmental footprint.

BATTERY STORAGE

Battery energy storage provides a means of storing energy by using energy from the utility grid to charge batteries, and then discharging the energy when needed. There are two major components to a battery energy storage system: the batteries and the power conversion system to convert the DC energy provided by the battery to AC energy that is suitable for the grid.

Battery energy storage is generally very scalable, and systems are either centralized or distributed. Centralized systems contain the entire battery system and controls at a single site, and generally support the primary distribution system. Distributed energy systems are typically smaller and support secondary level distribution. The California Public Utility Commission has mandated that the three major utilities will install a total energy storage capacity of 1.3GW by the end of 2020. This was driven by an increased focus associated with renewable resource integration and smart grid development programs[10].

The table below includes a range of battery storage systems[11].

TABLE 3 - BATTERY STORAGE SYSTEMS

STORAGE TECHNOLOGY	MAIN ADVANTAGES (RELATIVE)	MAIN DISADVANTAGES (RELATIVE)	POWER APPLICATION	ENERGY APPLICATION
Flow Batteries • Zinc Bromine (ZnBr) • Vanadium Redox (VRB)	High Capacity, Independent Power and Energy Ratings, Excellent Cycle Life	Low Energy Diversity, Moving Parts	Reasonable	Optimal
Metal-Air	Very High Energy Density	Electric Charging is Difficult	Feasible	Optimal
Sodium Sulfur (NaS)	High Power & Energy Densities, High Efficiency	High Production Cost, Safety	Optimal	Optimal
Lithium-Ion (Li-ion)	High Power & Energy Densities, High Efficiency	High Production Cost, Requires Special Charging Circuit	Optimal	Feasible
Lead-Acid	Low Capital Cost	Poor Life Cycle	Optimal	Feasible
Advanced Batteries	High Power & Energy Densities, High Efficiency	High Production Cost, Emerging Technologies	Optimal	Feasible

[10]http://www.greentechmedia.com/articles/read/california-passes-huge-grid-energy-storage-mandate

[11]http://large.stanford.edu/courses/2012/ph240/doshay1/docs/EPRI.pdf

ABOVE- AND BELOW-GROUND COMPRESSED AIR ENERGY STORAGE (CAES)

These two technologies are very similar in operations; they differ based on how the compress air is stored during off-peak periods. Above ground systems store air in tanks while below ground systems store air in caverns or aquifers, meaning geologic suitability may limit this option in many regions. The energy is recovered from storage by using the air as an input for a turbine electric generator. CAES plants operate by separating in time the compression and expansion stages of the turbine from off-peak to on-peak. However, the turbine performance may be impacted as the tank pressure bleeds down and the discharge flow slowly drops as the usable air volume is consumed. Only a partial percentage of the stored volume of air is actually usable to generate electricity. The air is reheated by fossil fuels before being put through an expander to generate power. Future advanced systems will capture, store, and use heat-of-compression energy to reheat the stored compressed air before flowing it thru the turbine to generate power.

CAES systems are not a new technology. According to an August 2013 report from Navigant Research, *Compressed Air Energy Storage*, more than 11 gigawatts of CAES capacity will be installed worldwide from 2013 to 2023 based on the heightened penetration of variable energy resources and its resulting impact on the grid[12].

LIQUEFIED AIR ENERGY STORAGE (LAES)

A large volume of air is compressed and processed into liquid air products stored in cryogenic tanks at off-peak energy periods. The energy is recovered by pressurizing the liquid with cryogenic pumps and then re-thermalizing it into a superheated gas for input to a turbo-expander electric generator. LAES plants operate by separating in time the liquefaction and expansion stages of the turbine from off-peak to peak periods. Unlike the other compressed air storage systems, this technology maintains the air pressure, temperature, and flow to the specified turbine requirements.

Several companies have each proposed demonstration projects based on their mature industrial air separation technologies, combined with commercial turbo-expander generators. The success of the projects could determine the fate of this technology and the pace of future commercialization.

[12]http://www.navigantresearch.com/newsroom/compressed-air-energy-storage-to-experience-dramatic-growth-over-the-next-10-years