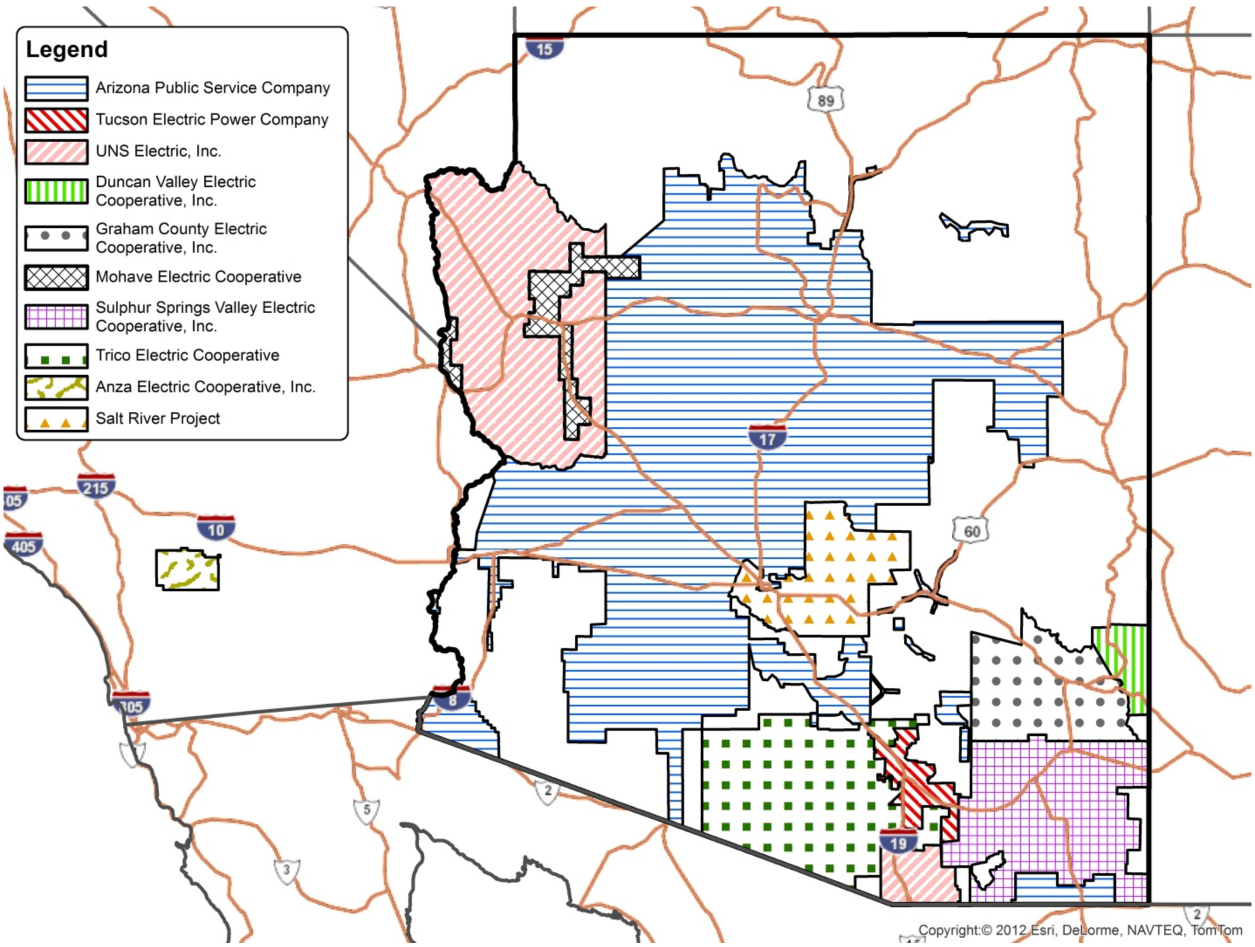
ASSESSMENT OF THE 2012 INTEGRATED RESOURCE PLANS OF THE ARIZONA ELECTRIC UTILITIES

ACC DOCKET NO. E-00000A-11-0113

DECEMBER 11, 2012



PREPARED ON BEHALF OF THE STAFF OF THE ARIZONA CORPORATION COMMISSION BY

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I. Executive Summary

A. Introduction

The purpose of this report is to satisfy the requirements of the Arizona Corporation Commission's ("Commission") Resource Planning and Procurement rules requiring the Commission's Utilities Division ("Staff") to file a report containing Staff's analysis and conclusions concerning Staff's statewide review and assessments of the Integrated Resource Plans ("IRPs") filed with the Commission. Four load-serving entities - Arizona Public Service Company ("APS"), Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNSE") and Arizona Electric Power Cooperative, Inc. ("AEPCo") are required to submit 15-year IRPs to the Commission in each evenly numbered year. The first IRPs were required to be filed with the Commission on April 1, 2012. These initial IRPs are the subject of this report.

A load-serving entity is defined in the Commission's rules as "a public service corporation that provides electricity generation service and operates or owns, in whole or in part, a generating facility or facilities with capacity of at least 50 megawatts combined"[1]. APS, UNSE and TEP are investor-owned electric utilities subject to the rules and regulations of the Commission, each owning and operating generating facilities in excess of 50 megawatts. AEPCo owns and operates, on behalf of its distribution cooperatives, the Apache generating station, which has a total capacity of 555 megawatts. AEPCo's distribution cooperatives do not currently own or operate generating facilities. The second largest electric utility in Arizona, Salt River Project ("SRP"), is not subject to these rules and regulations of the Commission and is not required to file an IRP. However, certain publicly available information and additional information voluntarily supplied by SRP is included in this report.

An IRP is essentially the utility's plan to meet the future electric needs of its customers in a way that considers environmental impacts along with the concerns of customers, regulators, stockholders and all other stakeholders. Within the IRP, the selection of ways to reduce, or shift electric usage (demand-side resources) are weighed in an equitable fashion against ways to increase the production of electricity (supply-side resources). The bottom line of an IRP is a schedule of demand-side and supply-side resources that will provide for the continued reliable delivery of electricity to all customers in Arizona.

The Commission's rules include certain filing requirements and require the Commission to determine whether each IRP complies with the requirements of the rules and is reasonable and in the public interest based on the information available to the Commission at the time, considering the following factors[2,3]:

[1] Arizona Administrative Code ("A.A.C.") R14-2-701(26).
[2] A.A.C. R-14-2-704(B).

1. The total cost of electric energy services;
2. The degree to which the factors that affect demand, including demand management, have been taken into account;
3. The degree to which supply alternatives, such as self generation, have been taken into account;
4. Uncertainty in demand and supply analyses, forecasts, and plan, and whether plans are sufficiently flexible to enable the utility to respond to unforeseen changes in supply and demand factors;
5. The reliability of power supplies, including fuel diversity and non-cost considerations;
6. The reliability of the transmission grid;
7. The environmental impacts of resource choices and alternatives;
8. The degree to which the load-serving entity considered all relevant resources, risks, and uncertainties;
9. The degree to which the load-serving entity's plan for future resources is in the best interest of its customers;
10. The best combination of expected costs and associated risks for the load-serving entity and its customers; and
11. The degree to which the load-serving entity's resource plan allows for coordinated efforts with other load-serving entities.[4]

In addition, each IRP (other than AEPCo's) must meet the requirements of the Annual Renewable Energy Requirement,[5] the Distributed Renewable Energy Requirement,[6] and the Energy Efficiency Standard.[7]

Under the Renewable Energy Requirement, each load-serving entity (excluding AEPCo) must supply energy from eligible renewable energy resources (or obtain renewable energy credits) sufficient to supply the following annual percentages of retail energy sold by the load-serving entity during that calendar year[8]:

2012	3.50%
2013	4.00%
2014	4.50%
2015	5.00%
2016	6.00%

[3] The Staff Report and the Commission's acknowledgement are in no way intended to replace the normal prudency review that the Commission undertakes during ratemaking proceedings.

[4] A.A.C. R14-2-704.

[5] A.A.C. R14-2-1804.

[6] A.A.C. R14-2-1805.

[7] A.A.C. R14-2-2404.

[8] A.A.C. R14-2-1804.

2017	7.00%
2018	8.00%
2019	9.00%
2020	10.00%
2021	11.00%
2022	12.00%
2023	13.00%
2024	14.00%
After 2024	15.00%

The Distributed Renewable Energy Requirement essentially requires that at least 30% of the load-serving entity's Renewable Energy Requirement must be supplied by distributed (or customer-owned) renewable energy resources[9].

Under the Energy Efficiency Standard, each load-serving entity (excluding AEPCo) must achieve the cumulative annual energy savings from cost-effective demand-side energy efficiency programs, as a percentage of the retail energy sales in the previous calendar year, shown in the following table[10]:

2012	3.00%
2013	5.00%
2014	7.25%
2015	9.50%
2016	12.00%
2017	14.50%
2018	17.00%
2019	19.50%
2020	22.00%

B. Major Findings

We have found that, for the most part, the 2012 Integrated Resource Plans filed by APS, TEP and UNSE are reasonable and in the public interest, based upon the information available to Staff when it prepared its report, and comply with the Commission's requirements, and thus recommend that the Commission acknowledge the APS, TEP and UNSE IRPs. We also request that the Commission recommend that APS, TEP and UNSE correct all issues identified by Staff in this report in all future IRP filings.

We have also found that the 2012 Integrated Resource Plan filed by AEPCo and amended on September 5, 2012, fails to satisfy the Commission's IRP requirements. Our recommendation is that the Commission not acknowledge AEPCo's 2012 IRP.

[9] A.A.C. R14-2-1805.
[10] A.A.C. R14-2-2404.

II. Integrated Resource Planning

A. General Overview & History

The Integrated Resource Planning process was developed with three primary purposes in mind: (a) to provide an opportunity for public input and participation in the long-term planning processes of the utilities; (b) to cause utilities to evaluate demand-side management ("DSM") resources and supply-side resources on an equal footing; and (c) to allow for the evaluation and consideration of the environmental and societal impacts of the actions of the utilities.

Prior to the implementation of Integrated Resource Planning in the 1980's, electric utilities performed long-term planning in a vacuum – with little or no input from the public or regulatory bodies. During this period, the model for electric utilities was to capitalize on the economies of scale derived by building large central station plants. These large plants contributed to the falling real price of electricity that had been evolving for years since the Second World War. Because of the low prices for electricity, the public was encouraged to consume as much power as they cared to use, with little or no consideration for making efficient use of the energy. Utilities responded by initiating large power plant construction programs.

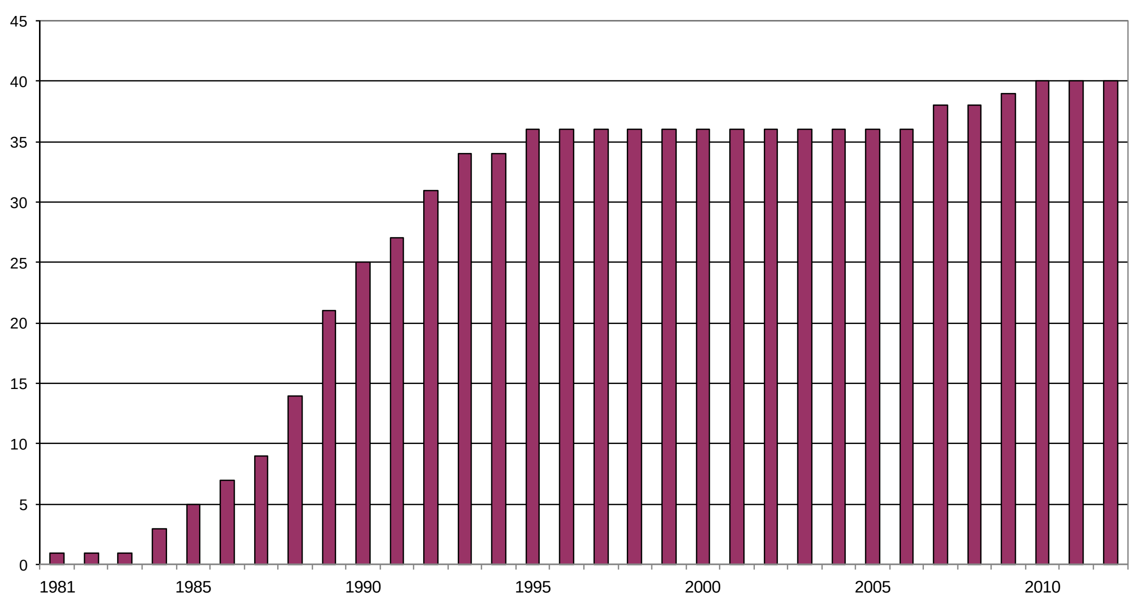
As a result of the boom in power plant construction, with very little public or regulatory oversight, the certification of new resources (generating plant) was often made after-the-fact, that is, after the construction of the generating plant was underway or even complete. This did not cause a major problem prior to the regulatory disallowance of the excessive costs of some nuclear generating plants. These nuclear disallowances were a major factor in the move to Integrated Resource Planning. With IRP, rather than planning in a vacuum, all stakeholders, including the utility's customers, the Commission and others participate in the decision-making process.

The high cost of imported oil and the resulting uncertainty of the future price of oil in the 1970's, as a result of the Arab Oil Embargo, also played a major role in the move to IRP. Rates for electricity were moving upward and regulators wanted to ensure that all options to meet the growing demand for electricity were fairly considered. Energy efficiency improvements were seen as a way to help lower costs and preserve precious energy resources. Although it is counter to the natural tendencies of electric utilities, the IRP process requires utilities to fairly consider DSM as a way to meet growing electric requirements. A DSM resource is a program that modifies the customer's need for electricity. An example is a program that encourages (through cash incentives) residential homeowners to add insulation to their homes. The added insulation reduces the use of air conditioning in the summer and electric heat in the winter, thus reducing the utility's need to generate electricity, and results in a more efficient use of electricity in the home.

The final major factor that resulted in the IRP process was the concern with the impact of generating plants on the environment. During the 1980's people became much more aware and concerned about the environmental impacts of pollution. Coal-fired plants are the main culprits, producing large emissions of sulfur dioxide (SO2), nitrous oxides (NOx), particulates, heavy metals, carbon dioxide (CO2), and other greenhouse gases. The Clean Air Act Amendments of 1990 resulted in national restrictions on the production of SO2 and NOx. In southwestern states such as Arizona, water is a scarce and valuable resource, so the consumption of water by generating facilities must also be a consideration. Through the IRP process, the levels of likely future emissions and water consumption can be estimated and alternative plans that result in reduced emissions and water consumption can be considered.

As shown in the following chart, the number of states that require electric utilities to file IRPs has grown steadily since 1981. Today, forty states require IRPs.

Number of States Requiring IRPs



Sources - NARUC Compilation of Utility Regulatory Policy 1995-1996 and
A Brief Survey of State Integrated Resource Planning Rules and Requirements - Synapse

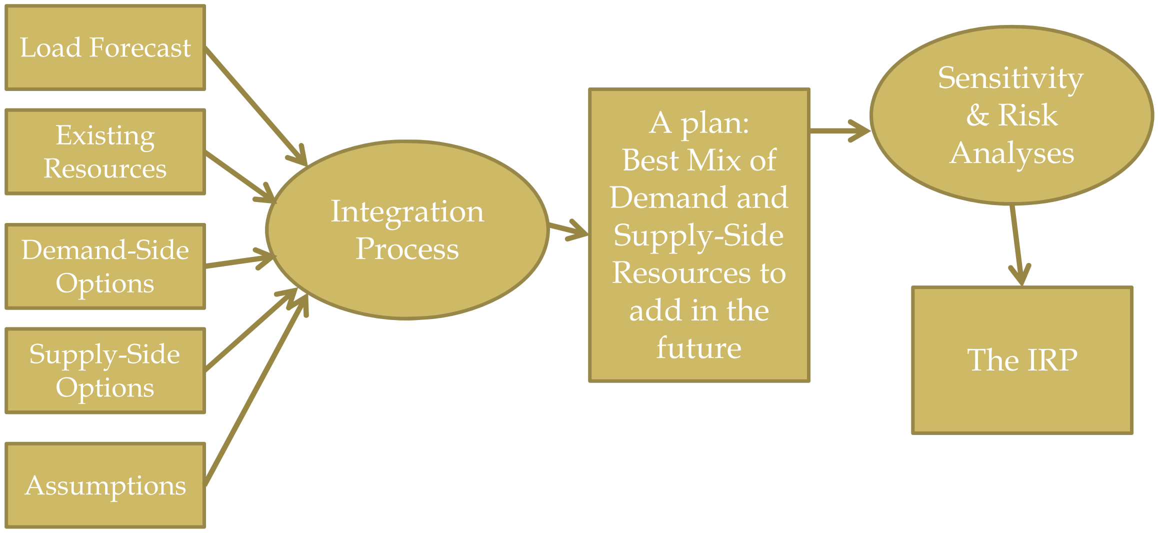
B. Overview & History of IRP in Arizona

The Commission originally adopted the Resource Planning and Procurement Rules ("IRP Rules") on February 3rd, 1989. The IRP Rules required all electric utilities owning generation facilities to file 10-year resource plans every three years. Plans were filed and reviewed by the Commission in the 1990-1991 period and also in the 1992-1993 period. In 1995, resource plans were filed, but no hearings were held and in 1997, some of the IRP Rules were suspended for one year. Then in 1999, a procedural order suspended the IRP Rules until further order of the Commission. However, that portion of the IRP Rules that required the filing of historical data remained in effect.

The 2005 APS settlement agreement (approved in Decision No. 67744) required Staff to schedule workshops on resource planning issues which would focus on developing needed infrastructure and a flexible, timely and fair competitive procurement process. In addition, the workshops were to consider whether and to what extent the competitive procurement process should include consideration of a diverse portfolio of short, medium and long-term purchased power; renewables; demand-side management; and distributed generation. The workshops were to be open to all stakeholders and the public and if necessary, were to be followed with a rulemaking.

Workshops initiated by the 2005 APS settlement agreement were held in 2005, 2006, 2007 and 2008. Written comments were filed and Staff developed draft rule modifications which were distributed to all stakeholders. Written comments on the draft rule modifications were submitted and hearings were held in February 2010. The Commission, by final rulemaking, amended the IRP Rules, effective December 20, 2010. The IRP Rules are found in the Arizona Administrative Code ("AAC") at Title 14, Chapter 2, Article 7 "Resource Planning and Procurement", et seq. The AAC is available on the Commission's Home website found at www.azcc.gov under "Laws and Rules Governing the Commission".

C. Basic Elements of an IRP



An IRP is the utility's long-term plan to meet the future electric needs of its customers. While each utility may perform an IRP study using different approaches, all IRP studies generally contain the following basic elements:

Load Forecast
Examination of Existing Resources
Development of Potential DSM Options
Development of Potential Supply-Side Options
Assumptions
Integration Process
Sensitivity & Risk Analysis
IRP Selection

The **Load Forecast** is the utility's estimate of the future electric requirements of its customers. Commission rules require utilities to forecast for at least 15 years into the future. It includes a forecast of the annual peak demand - the single highest hourly electric usage during the year and a forecast of the annual energy requirements - the total annual production of electricity required to meet the needs of all customers.

The next step in the IRP process is the **Development of Potential DSM Options**. In this step, the utility identifies all potential demand-side options that could be utilized to meet the future needs of its customers. Several qualitative and quantitative screenings are applied to the original list of options to produce a reasonable number of remaining options for inclusion in the Integration step. The screenings are usually based on a viability test and application of the standard ratios – the Total Resource Cost (TRC) test, the Utility Cost Test, the Participant Test and the Rate Impact Measure (RIM) test. Arizona jurisdictional utilities are required to use the Societal Test, which is similar to the TRC test, but includes societal benefits and costs.

The next step is the **Development of Potential Supply-Side Options**. Here, just as in the previous step, a comprehensive catalog of potential supply-side options is developed and then screened for viability and cost-effectiveness. The normal screening process is a comparison of the total busbar costs of each of the viable options at various operating levels. Busbar costs are construction costs, fixed and variable operating and maintenance costs, and fuel costs expressed as an average cost per unit of electricity produced ($/MWh). Those options that have the best busbar costs are passed on to the **Integration Process**.

Certain base **Assumptions** must be made, such as the assumed planning reserve margin, inflation, wind and solar integration costs, and future costs of natural gas, coal and other fuels.

The **Integration Process** selects the "best" mix of DSM and supply-side options to meet the load forecast. "Best" may mean lowest total revenue requirements, least environmental impact, lowest customer bills, and/or some other measures selected by the utility. If environmental impacts are monetized in this step, then the resulting plan will minimize total costs that include capital, fuel, Operating & Maintenance expense (O&M), and environmental costs. It is generally accepted that the IRP should include several potential plans; for example, a plan that minimizes total revenue requirements, a plan that includes monetized environmental impacts and a plan that minimizes customer bills. This will allow customers and regulators to more fully understand how the costs, benefits, rates, environmental impacts, etc. are affected by different resource plans.

Environmental consequences of each plan developed in the Integration Process should be included in the IRP. The annual production of all harmful emissions in each possible plan should be reported to provide customers and regulators information necessary for the proper evaluation of each plan. An assessment of environmental impacts should be performed even if environmental costs are not monetized as part of the Integration Process. Consideration should also be given to the impact of potential environmental legislation, such as the taxing of CO2 emissions, that is under consideration by the Environmental Protection Agency and the Arizona Department of Environmental Quality.

A **Sensitivity and Risk Analysis** is normally utilized to ensure that the selected plan will perform well should assumptions change. For example, a risk analysis will identify the potential dollar risk inherent in the plan if actual fuel prices turn out to be dramatically different than what had been forecasted. Several types of risk analysis studies exist. The most frequently used types are Sensitivity Analysis and Scenario Analysis. Sensitivity Analysis is primarily concerned with determining how a particular expansion plan would be impacted by the change in a single variable (such as fuel costs). Scenario Analysis looks at the impacts on the selected expansion plan considering the possibility that future conditions might influence the change in more than one variable. For example, a higher load growth scenario might also suggest that fuel costs and capital costs would be higher due to higher rates of inflation.

Finally, the results of the **Integration Process** and the **Sensitivity and Risk Analysis** are evaluated and the utility reaches a decision regarding its preferred IRP.

D. The Commission IRP Proceedings and Workshops

On March 10, 2011, the Utilities Division Staff requested that a Docket be opened for the purposed of Resource Planning and Procurement in 2011 and 2012. Docket No. E-00000A-11-0113 was established for this purpose. All plans and reports required by the Rules (R14-2-701 through -706) for 2011 and 2012 were required to be filed in the Docket. The first Historical Planning reports for 2010 and 2011 were filed by APS, AEPCO, UNSE, and TEP pursuant to A.A.C. R14-2-703 in the first quarter of 2011 and the first quarter of 2012, respectively. The first required IRPs were filed in this Docket by APS, TEP, UNSE and AEPCo in April, 2012.

The Commission sponsored two IRP workshops, open to the public and all other stakeholders, on August 22nd and October 25th, 2012. The presentation materials from the workshops are available on the Commission web site at http://www.azcc.gov.

At the first workshop, Commission Staff made a presentation concerning the history of IRP, the methodology for development of an IRP and the Commission's rules concerning IRPs. Each of the load-serving entities (APS, TEP, UNSE and AEPCo) then presented its IRP and discussed the development of its IRP. This was followed by a presentation by the Southwest Energy Efficiency Project entitled "Energy Efficiency and Resource Planning". Western Resource Advocates then presented "A Path Forward – Western Resource Advocates' Review of APS's Resource Plan". The last presentation was made by the Solar Reserve and concerned recent accomplishments in the development of solar power generation.

The second workshop began with a brief discussion by Staff on the state of Staff's draft report to the Commission. The Arizona Competitive Power Alliance then made a presentation entitled "Integrated Resource Planning", which was followed by Staff's presentation of its draft report and draft recommendations. The workshop ended with a presentation made by AARP Arizona concerning the implications of retail competition in the gas and electricity markets within Arizona.

E. Comments Received

Comments on the 2012 IRPs were received from the following parties:

Western Resource Advocates APS Comments – Western Resource advocates ("WRA") submitted written comments on September 7, 2012 concerning APS' 2012 IRP. A summary of WRA's comments follows:

In general, resource planning has multiple objectives:

- Reasonable societal costs over the long run as determined by comparing cost estimates for a variety of portfolio options
- Consideration of a wide range of resource options including supply and demand side resources and customer owned resources
- Maintenance of a reliable system
- Compatibility of power production and delivery with environmental values
- Long run risk management
- Incorporation of public input

In Arizona, there are several overarching issues that must be considered by utilities and the Commission in preparing and reviewing electric utility resource plans:

- **Wasted energy.** Consumers waste large amounts of energy, resulting in higher fuel costs and investments in unnecessary generation capacity additions. These costs are paid by all customers to produce electricity that is wasted.
- **Pollution.** The current power supply system emits huge quantities of pollutants into the atmosphere, resulting in adverse health and other environmental impacts.
- **Fuel price risk.** The current power system is vulnerable to fuel price increases and fuel price volatility.
- **Water supply risk.** Conventional steam generation technology is vulnerable to water scarcity in an arid region.
- **Resource flexibility.** Resource flexibility refers to the capability of the electric system to adjust to rapid changes in the supply of and demand for electricity.
- **Reasonable cost.** The reasonableness of costs can be determined by comparing estimated costs of a variety of options, keeping in mind the uncertainties inherent in long term projections.

WRA reviewed APS' IRP in light of these issues and concluded that: APS' intent to meet the Commission's Energy Efficiency Standard will significantly reduce wasted energy; coal plant retirements will greatly reduce air pollution; increased reliance on stably priced renewable energy and energy efficiency will hedge against higher fossil fuel costs; use of dry cooling as proposed by APS will help manage the risk of water scarcity; energy storage facilities can improve system flexibility; and pursuing a plan consistent with these findings can be accomplished at a cost that is about the same as the cost of APS' preferred (Base Case) plan.

Therefore, WRA recommends that**:**

- The Commission approve APS's 3 year action plan (APS resource plan, pp. 147-154).
- The Commission acknowledge APS's enhanced renewable energy and coal retirement portfolios and direct APS to prepare an option for the next resource plan filing that blends the enhanced renewable energy and coal retirement portfolios.
- The Commission employ a workshop process to establish a basis for early adoption of energy storage projects and services.

Sierra Club APS Comments – Sierra Club submitted written comments on September 14, 2012 concerning APS' 2012 IRP. A summary of Sierra Club's comments follows:

APS presented four portfolios in its IRP – a Base Case, a Four Corners Contingency Case, an Enhanced Renewables case, and a Coal Retirement Case. APS plans to meet the Energy Efficiency Standard requirements in each case. This is encouraging in that energy efficiency is the cheapest and cleanest energy resource. However, APS did not indicate the magnitude of savings attributable to the Energy Efficiency Standard nor did it present a scenario that exceeds the energy efficiency standard requirements.

The coal retirement portfolio is excessively dependent on generation of electricity with natural gas. Sierra Club recommends that, in its next IRP, APS include a new coal retirement portfolio that also incorporates significant amounts of renewable energy. A realistic coal retirement strategy makes sense on many levels - coal is bad for our health; burning coal releases toxic mercury that pollutes rivers and streams; coal emits more than 30 percent of the United States' annual carbon dioxide emissions; and coal mining has devastating consequences for our natural resources.

The retirement of the Four Corners units 1-3 has been approved and the units are expected to be retired by the beginning of 2014. We now know that the EPA is requiring Selective Catalytic Reduction for the Cholla plant. It would be appropriate for APS to identify and evaluate logical retirement dates for the Cholla and the Navajo generating stations within the next three to five years in its next IRP.

Currently, there is limited regulation or oversight of coal ash in Arizona, but regulation of coal ash as a hazardous waste is still under consideration by the EPA and is another potential cost associated with coal-fired power plants. Sierra Club asks that APS evaluate the costs of coal ash regulation relative to continued operation of its coal fleet to better reflect the true costs associated with coal generation.

According to APS' IRP, APS power plants emit about 15.3 million metric tons of carbon dioxide each year. Under the Base Case portfolio, APS forecasts a reduction in the emission rate, but an increase over current levels of emissions. APS should pursue plans that result in real emissions reductions as that is the only way to address climate disruption.

Sierra Club recommends that the Commission direct APS, in the next IRP filing, to modify the current Coal Retirement portfolio to substitute more renewable energy for natural gas generation. They also recommend that the Commission direct APS, in its next IRP filing, to analyze the potential for and impacts of an effort to exceed the Energy Efficiency Standard. Finally, they recommend that the Commission direct APS to include in its next IRP the analyses of coal plant retirements described above.

Solar Energy Industries Association APS Comments – Solar Energy Industries Association ("SEIA") submitted written comments on October 11, 2012 concerning APS' 2012 IRP. A summary of SEIA's comments follows:

SElA believes that it is of the upmost importance to identify the great strides the solar energy industry has made in cost reductions and work to integrate solar into the IRP as a traditional resource. For wholesale DG projects (1-20 MW) and traditional utility scale projects, SElA recommends that the level of solar energy adoption be adjusted to better reflect market and pricing dynamics, rather than be locked into one of the specific plans put forth in the APS IRP document. In other words, there should be market based trigger mechanisms that provide the opportunity to sensibly ratchet up solar energy deployment.

SEIA's policy recommendations are as follows:

- Adopt the Enhanced Renewable Portfolio or incorporate market based triggers to ratchet up solar energy deployment within the Planning Period to hedge against fuel price spikes, supply shocks, and water scarcity. The REST should be treated as a floor now that solar energy is increasingly cost competitive with other new forms of generation.
- Reinstatement of the Small Generator RFP program to generate cost effective and unique solar projects that benefit the state of Arizona and continue our momentum as a top tier solar state.

NextEra Energy Resources and LS Power APS Comments – NextEra Energy Resources and LS Power submitted written comments on October 15, 2012 concerning APS' 2012 IRP. A summary of the comments follows:

NextEra and LS Power commend APS on the thoughtful and comprehensive set of options it presented in its IRP filing to the Commission. APS included four scenarios: 1) the base case; 2) the four corners contingency; 3) the enhanced renewable energy scenario; and 4) coal retirement. The enhanced renewable energy scenario provides the best means of risk mitigation. NextEra and LS Power encourage the Commission to consider the tradeoffs in each scenario and weigh the risk mitigation advantages of the enhanced renewable energy scenario against the relatively small incremental cost of this scenario.

The Commission should also consider the different policy drivers that will affect renewable energy development and costs in the coming years, including the Investment Tax Credit ("ITC"). The ITC represents a 30% discount to renewable energy costs and a transfer of that value from the federal government to Arizona. Even if the ITC expires as currently envisioned in 2016, it greatly affects the economic tradeoffs. NextEra and LS Power encourage the Commission to consider the procurement rules and commercial arrangements that should be in place prior to the ITC expiration so that developers and load-serving entities can maximize the ITC for Arizona consumers.

Interwest Energy Alliance APS Comments – Interwest Energy Alliance ("Interwest") submitted written comments on October 22, 2012 concerning APS' 2012 IRP. A summary of the comments follows:

Interwest recommends the Commission acknowledge the APS IRP and instruct APS to pursue the Enhanced Renewables case. The Enhanced Renewables case will provide a hedge against future fossil fuel price increases, and it creates the most balanced energy portfolio which increases supply diversity and reduces risks. Interwest believes there are ten substantive and compelling reasons to support pursuit of the Enhanced Renewables procurement plan:

1. The Enhanced Renewable Energy portfolio reduces exposure to fluctuating and rising fuel costs by reducing the consumption of natural gas.
2. The Enhanced Renewable Energy portfolio is the most balanced portfolio.
3. The Enhanced Renewable Energy portfolio increases energy security.
4. The Enhanced Renewable Energy portfolio increases economic development and jobs in Arizona.
5. The Enhanced Renewable Energy portfolio helps to build a stably-priced electric system.
6. The Enhanced Renewable Energy portfolio is the best economic deal for consumers.
7. The Enhanced Renewable Energy portfolio relies on resources with declining costs.
8. The Enhanced Renewable Energy portfolio will use less water and produce less pollution.
9. Operational changes can greatly reduce the cost of renewable energy integration.
10. Arizona customers prefer increased amounts of renewable energy.

Interstate Renewable Energy Council APS and TEP Comments – The Interstate Renewable Energy Council ("IREC") submitted written comments on November 2, 2012 concerning APS' 2012 IRP and TEP's 2012 IRP. A summary of the comments follows:

APS and TEP should be commended for their work on providing thoughtful and detailed IRPs. While not disputing the companies' general approach, several issues have emerged from the plans and subsequent meetings that deserve additional attention:

1. The Commission should acknowledge APS' and TEP's IRPs with modifications. In APS' case, this acknowledgement should recognize the support among stakeholders for the "Enhanced Renewables" option.
2. APS' resource cost comparison conflates different resource attributes (energy, capacity and operational flexibility) that should each be considered separately.
3. APS should clarify for stakeholders that the addition of renewable resources does not on its face, lead to a need for additional conventional resources as backup reserves.
4. APS overestimates firming and integration costs for renewable resources in its IRP.
5. Overestimating firming and integration costs could significantly harm ratepayer interests and lead to higher rates than necessary.
6. Each IRP should include information about the costs and benefits of an Energy Imbalance Market ("EIM"), Dynamic Transfers, and Intra-hour Scheduling on future integration costs.
7. APS' levelized cost comparison is appropriate, but also obscures some implications resource choices may have on future customer rates and investor returns.
8. APS' consideration of "diminished capacity value" for solar requires further detail to be considered relevant to the current IRP process.
9. Distributed energy deployment is not fully considered in APS' plan.
10. The alternative scenarios evaluated in APS' IRP are insufficiently distinct from the Base Case.

Sierra Club TEP Comments – The Sierra Club submitted written comments on November 26, 2012 concerning TEP's 2012 IRP. A summary of the comments follows:

TEP plans to meet the Arizona Renewable Energy Standard (RES) by 2020 as indicated in its IRP. Sierra Club supports TEP's focus on energy efficiency, since it could mean a decrease in their annual energy requirement by 1,700 GWh by 2020. Energy efficiency is the most cost-effective energy resource and it is clearly a very clean energy resource. However, we also think TEP should complement its efficiency efforts with an aggressive program to promote renewable energy resources and to retire coal combustion facilities. As you know from the IRP, 84 percent of TEP's energy generation is dependent on the combustion of dirty, toxic coal. There is obvious room for improvement. Money saved on costly coal emission retrofits can instead be invested in distributed generation (DG) and utility-scale solar and wind projects. Clean, local, renewable energy created through solar and wind generation provides green jobs, cuts pollution and greenhouse gas emissions, saves water, and improves public health.

According to the IRP, TEP may face as much as $ 486 million in purchase and retrofit costs for coal units over the next six years, with annual operating costs associated with these retrofits increasing as much as approximately $1.5 million to $2.5 million annually. This is a staggering sum to invest in a technology that is outdated, toxic, and expensive. Local clean energy generation and storage investment would ultimately provide TEP customers with lower rates, not only on their monthly electric bills, but also on their health care costs.

The IRP concludes that “TEP’s continued participation in its existing coal facilities represents a cost-effective solution for TEP customers,” even while recognizing that “40% of TEPs coal capacity may be at risk for early retirement by forces outside TEP’s control.” The future of coal is uncertain and risky, and TEP will need to approach the challenges of tomorrow with more creative thinking and dynamic planning than can be found in their 2012 IRP. We encourage the Arizona Corporation Commission to ask TEP to evaluate a coal retirement portfolio in its future resource plans.

On November 21, 2012 a draft version of this report was provided to all interested parties via email, with a request that any comments on the draft be submitted by November 30, 2012. In addition to comments concerning the draft report, several parties provided comments on Global Energy & Water Consulting, LLC and Evans Power Consulting, Inc.’s (“Staff Consultants”) presentation at the second IRP workshop. Whenever possible, these comments have been utilized to make appropriate improvements in the final report. Comments on the Staff Consultants’ presentations at the workshops or on the Staff Consultants’ draft report were received by the following parties:

TEP – TEP presented written comments via email on November 30, 2012 concerning a correction to TEP’s 2011 peak demand value in the draft report. The requested change was made.

SRP – SRP provided written comments on November 30, 2012 addressing primarily factual issues concerning SRP within the draft report. For the most part, the requested changes were made.

APS – APS submitted comments on November 16, 2012 concerning the Staff Consultants’ presentation materials at the second IRP workshop. On November 30, 2012, APS provided written comments on the draft report. The APS comments provided corrections to certain factual statements concerning APS and also discussed in detail the recommendations regarding the APS IRP. For the most part, requested changes were made.

AEPCo – AEPCo provided written comments on November 29, 2012 and December 4, 2012 concerning certain factual information on AEPCo contained in the draft report, and also Staff’s and its Consultant’s conclusions regarding AEPCo’s IRP. All changes requested concerning factual information were made, and the conclusions regarding AEPCo’s IRP were modified.

WRA and Interwest – WRA and Interwest jointly supplied on October 31, 2012, written comments on the Staff Consultants' presentation materials used in the second IRP workshop. A summary of the comments follows:

Staff is to be commended for preparing a comprehensive compilation of the four utilities' resource plans to provide a statewide picture. Our comments address three issues inherent in the consultants' presentation and provide recommendations on how to proceed.

The consultants presented a graph intending to show several utilities' cumulative energy efficiency savings as a proportion of the utilities' previous year's electricity sales. While the concept of the graph is useful, the underlying data from EIA Form 861 are problematic. Staff could attempt to correct errors in the data but we recommend that Staff simply eliminate the graph from its report. The graph is not really necessary.

Staff's presentation emphasized preparation of comprehensive and consistent calculations. We agree that solid analysis is important. However, we believe that the Commission should be primarily concerned with the general direction utilities are going in a dynamic and uncertain world. There are long term issues in air pollution, water scarcity, fuel price uncertainty, and other matters that call for in-depth discussion and creative solutions. At this point, additional model runs may be less instructive in providing direction to the utilities than focusing on long run fundamentals.

Acknowledgement of a plan pertains to Commission decisions and guidance on the general structure of the future mix of resources to meet the demand for electric energy services and, ultimately, deployment of planned resources. The consultants' presentation and Staff's comments, however, indicated that the Commission should acknowledge the utilities' resource plans as long as all the required calculations have been performed. A.A.C. R14-2-704(B) indicates that the Commission shall order an acknowledgment of a resource plan if the Commission determines that the resource plan complies with the requirements of A.A.C. R14-2-701 et seq. that the load-serving entity's resource plan is reasonable and in the public interest, based on the information available to the Commission and considering a list of economic, environmental, risk management, and other factors set forth in the rule. We believe it is essential for the Commission to hear parties' assessments of utilities' plans with respect to these factors and to base its acknowledgement decision on these factors.

WRA and lnterwest appreciated the two workshops held to date on the resource plans as well as the utilities' stakeholder meetings. The structure of the meetings allowed for dialogue among all participants. We especially appreciated the participation of the Commissioners in the two meetings at the Commission. However, additional discussion is desirable prior to the Commission acting on the resource plans. Therefore, we recommend that, after completion of the draft Staff report, Staff conduct another workshop to provide an opportunity to discuss the merits of each scenario relative to the state's challenges, including each party's assessment of the factors listed in A.A.C. R14-2-704(8). A comprehensive summary of the discussion should either be incorporated into

Staff's final report or prepared by Staff as a separate document. In either case, the summary would be available to the Commissioners for consideration in their review of the resource plans. The additional workshop and summary should not delay the schedule for the Commission's review of the resource plans in early 2013, however.

WRA – WRA supplied comments concerning the draft report on November 30, 2012. The factual concerns mentioned by WRA were addressed in the final report. WRA also provided the following additional comments on the draft report:

Staff states that "The APS approach of selecting 'best' IRPs manually is not the most reasonable or preferred approach. The manual method makes risk and sensitivity analyses virtually impossible, and brings into question any IRP produced. APS and AEPCO should be required to utilize software, whether developed internally or leased from a software provider, to select a 'best' set of resources for each IRP development." As presented, this statement appears to run counter to the best advice from planning and business and appears to be unduly narrow in its conceptualization of how to plan. Experience in planning, business, and the military indicates that the best way to explore alternatives and possible outcomes in a dynamic and uncertain environment is to obtain imaginative ideas from a variety of sources, including those from outside the company, that encompass options and scenarios that are very different from the status quo and conventional thinking. APS solicited suggested resource mixes from stakeholders and evaluated them. Modeling numerous similar scenarios and resource mixes as proposed in the Staff report is no substitute for imagination and could lull one into missing significant factors affecting the supply of and demand for electricity.

Staff's report does not consider the institutional context of many resource decisions. For example, Staff indicates that APS did not include energy storage as an option but does not offer any proposal or policies that would overcome barriers to deployment of energy storage. Just telling APS to consider energy storage won't result in beneficial energy storage.

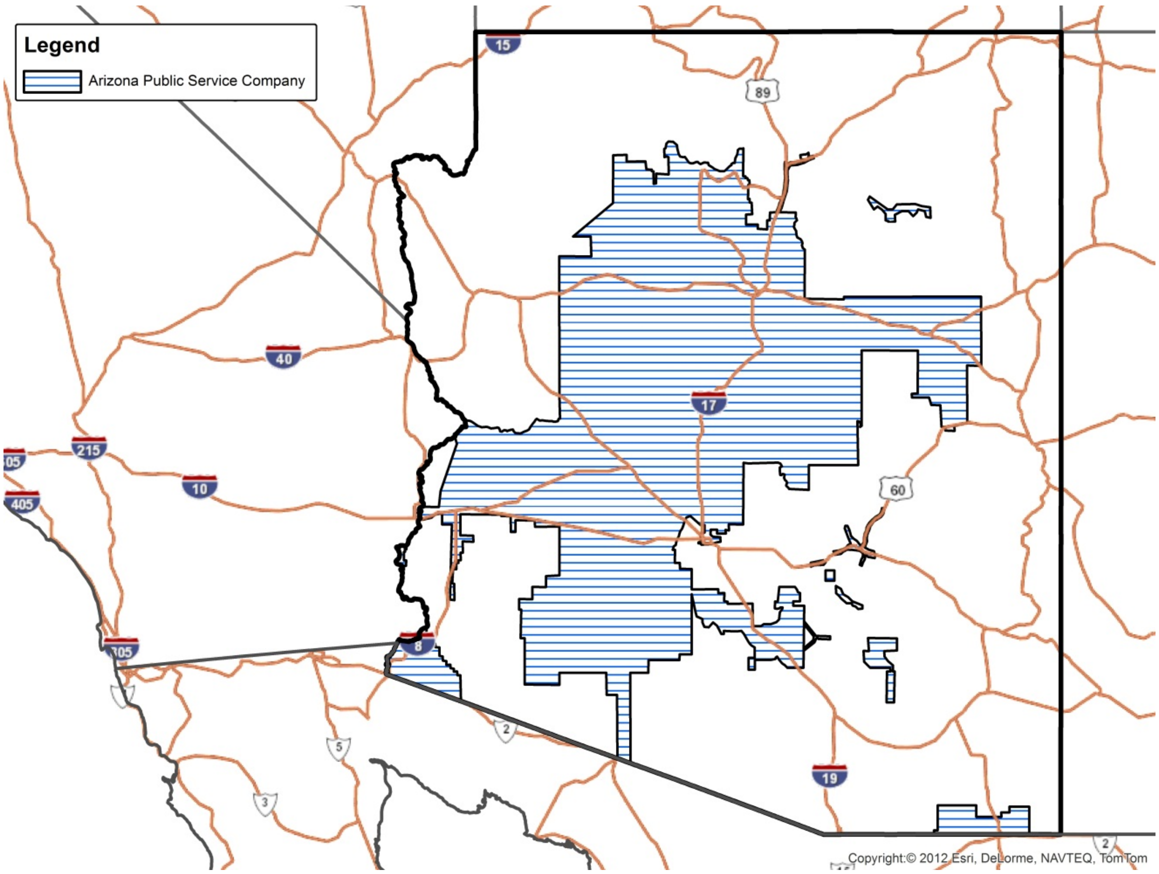
While the Staff report summarizes current and projected water consumption information provided by the utilities, we could not find a discussion about whether water consumption by power plants presents any risks and how those risks might be managed. The report should provide context for the risks associated with water shortages such as the experience of other utilities during droughts. The report should also discuss ways to manage water scarcity risk such as APS's plan to utilize dry or hybrid cooling in new power plants requiring condensation of steam.

While the Staff report mentions uncertainties about future natural gas prices, indicates that the utilities have conducted sensitivity analyses, and broadly describes methods for analyzing risk, the report does not provide the Commission with any sense of the magnitude of price risks associated with natural gas, coal, and uranium fuels or how to manage those risks. The report should provide some context for understanding fuel price risk.

The report has surprisingly little discussion of the costs of the utilities' resource plans and the uncertainties around those cost projections. The rate impact summary is a very limited presentation of cost trajectories. There should be a more complete compilation of the utilities' cost projections and Staff's assessment of the associated uncertainties.

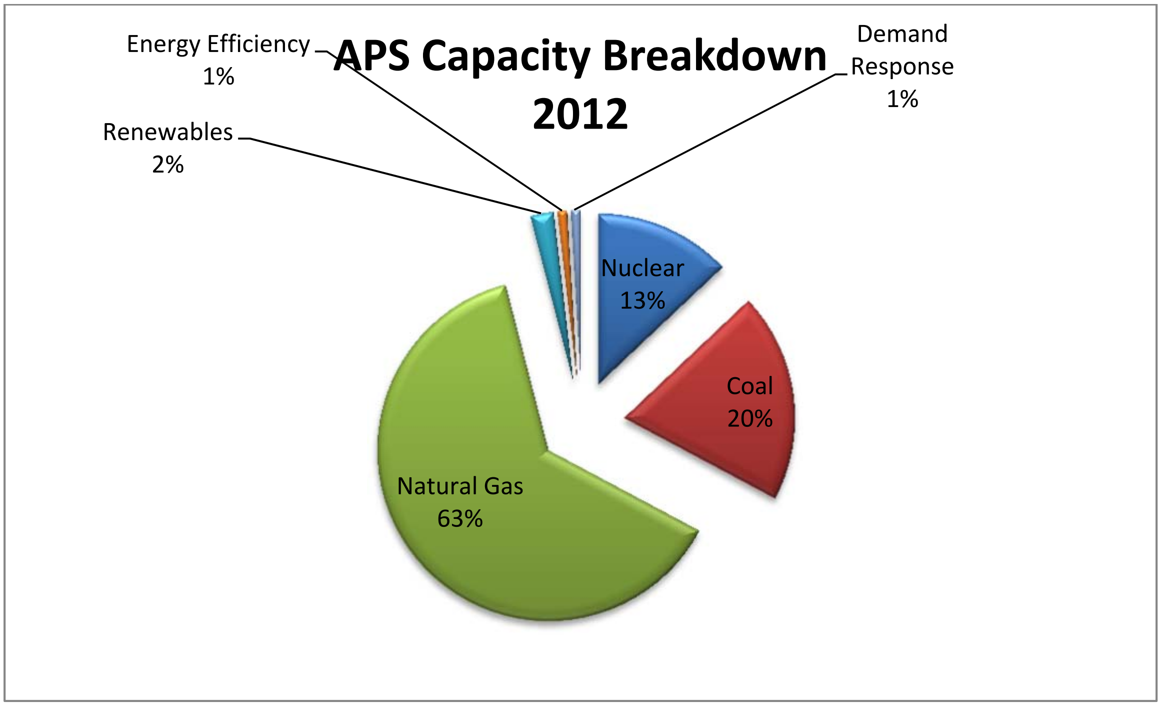
III. The Arizona Electric Utilities

A. Arizona Public Service Company ("APS")

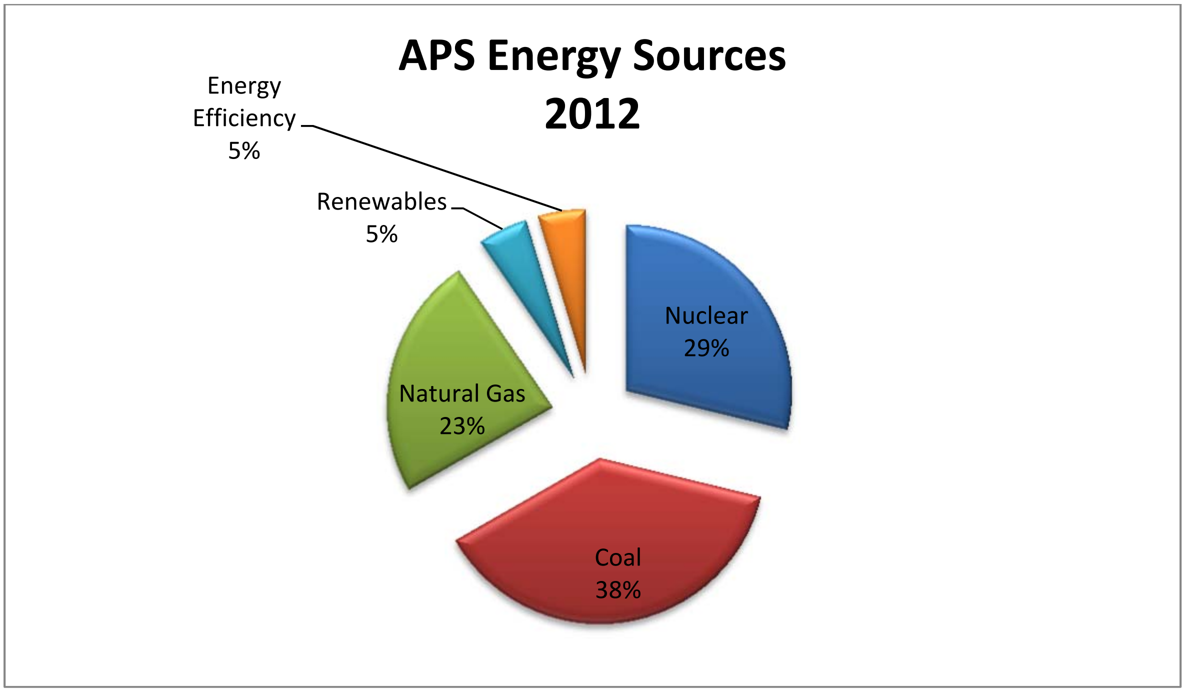


APS is the largest electric utility in Arizona, with a service territory that covers some 35,000 square miles and encompasses a portion of Phoenix. APS's 2011 peak demand was 7,087 megawatts and its total installed generating capacity in 2011 was 6,340 megawatts. APS forecasts a peak demand for 2012 of 7,234 megawatts (actual peak demand data for 2012 is not yet available). The total installed capacity (generating capacity plus purchased power) in 2012 was 8,840 megawatts.

The breakdown of 2012 installed capacity by fuel type, based on contributions to system peak demand, is shown in the following chart:



Renewables include distributed generation, renewable purchases and APS owned renewable generation. Approximately 40% of natural gas capacity is procured through purchased power contracts. The following chart shows the forecasted 2012 breakdown in energy produced by fuel type:

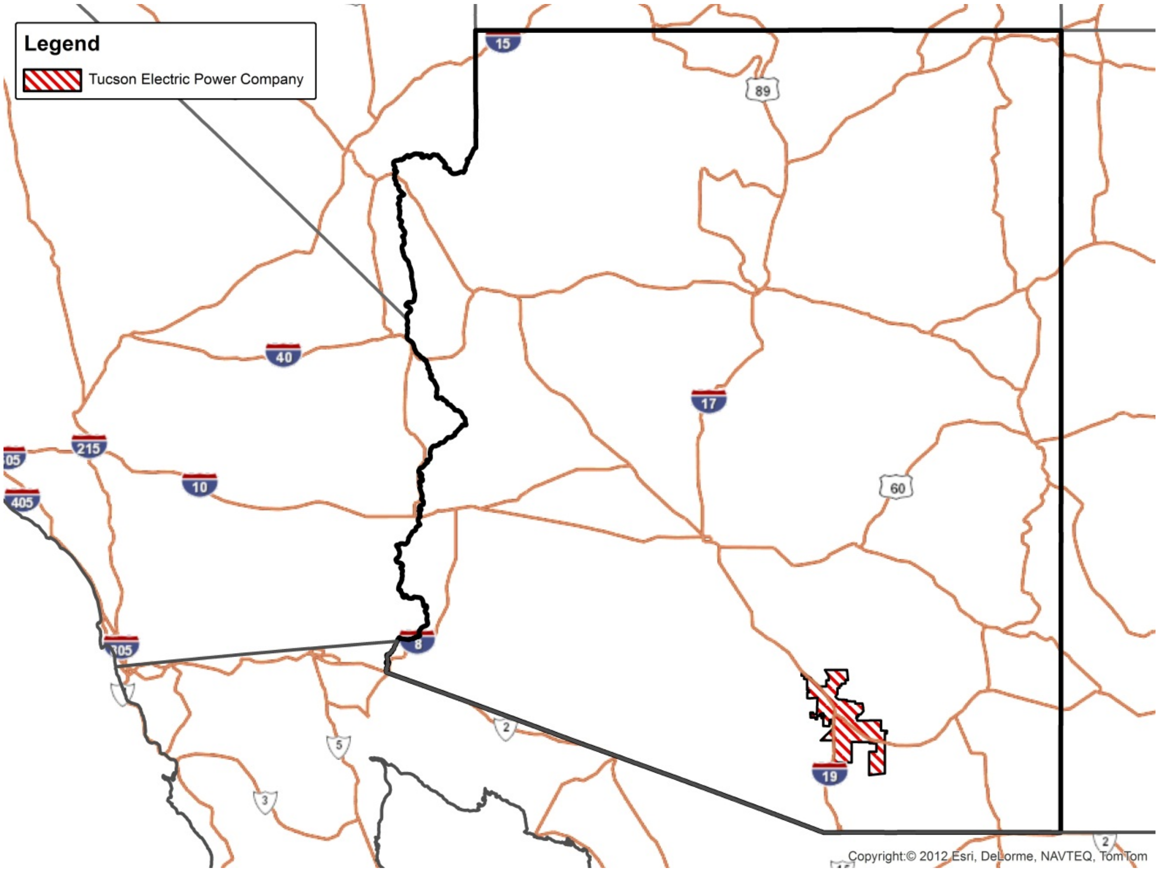


APS co-owns and operates the Palo Verde Nuclear Generating Station ("PVNGS"), which is the largest nuclear generating station in the United States. APS also co-owns and operates the Four Corners Power Plant, a 2,100 megawatt coal-fired facility located on the Navajo Indian Reservation.

A major issue facing APS is the future status of the Four Corners plant. On November 22, 2010, APS filed an application with the Commission for authorization to acquire Southern California Edison's ownership interest in Units 4 and 5 and for an accounting order to defer for possible later recovery through rates, certain costs of owning, operating, and maintaining the acquired interests in Units 4 and 5, as well as all unrecovered costs associated with Units 1, 2, and 3, including the costs incurred in connection with the closure of Units 1, 2, and 3[11]. In Commission Decision No. 73130, issued on April 24, 2012, the Commission authorized APS to pursue the acquisition of Southern California Edison's interest in Units 4 and 5 along with the retirement of Units 1, 2 and 3. However, the decision also retained the Commission's authority to review the acquisition at an appropriate time in the future and to make disallowances due to imprudence, errors or inappropriate application of the Commission's decision in that matter. APS's proposed plan for Four Corners would result in a net increase of 179 megawatts of coal capacity for APS.

[11] Docket No. E-01345A-10-0474.

B. Tucson Electric Power Company ("TEP")



TEP is the second largest investor-owned electric utility in Arizona, serving more than 400,000 customers in the Tucson metropolitan area (Pima County). Both TEP and UNS Electric, Inc. are subsidiaries of Unisource Energy Corporation. TEP's 2011 peak demand was 2,334 megawatts and the total installed generating capacity in 2011 was 2,216 megawatts. TEP forecasts a peak demand in 2012 of 2,369 megawatts (actual peak demand for 2012 is not yet available). Total installed capacity (generating capacity plus power purchases) for 2012 is 2,859 megawatts.

The breakdown of TEP's 2012 capacity, based on contribution to system peak demand, is shown in the following chart:

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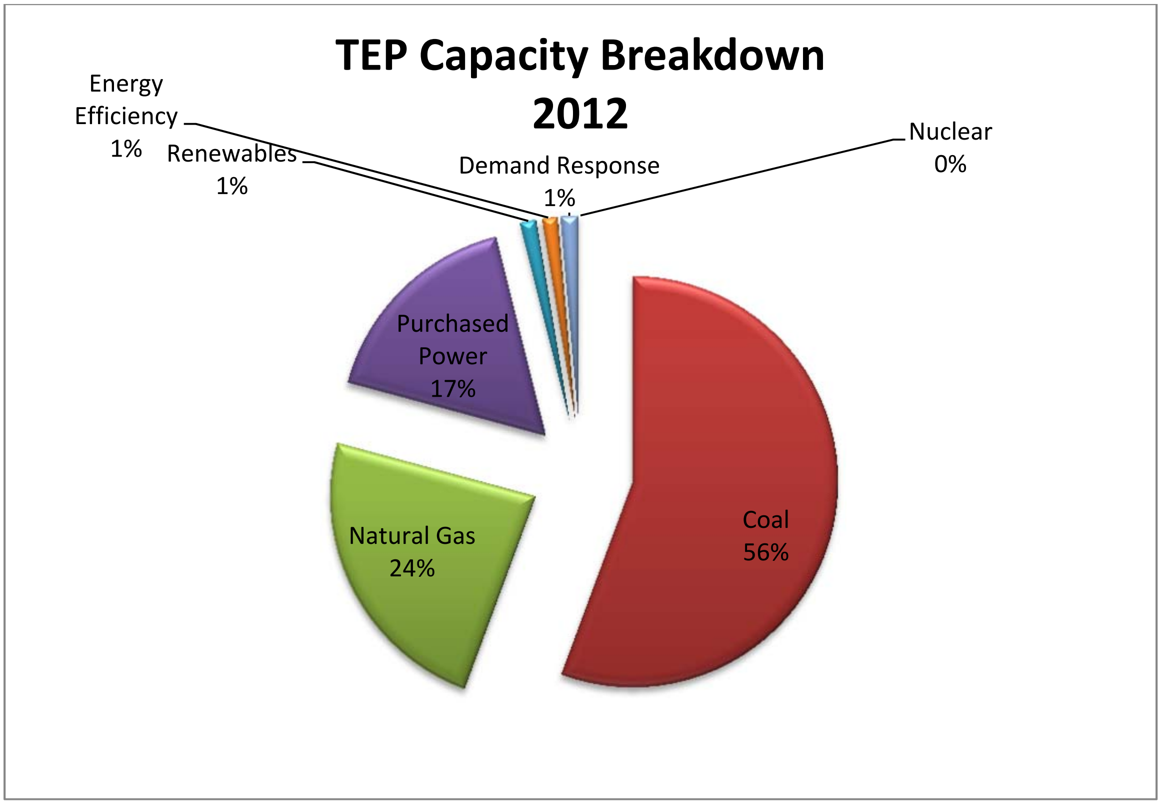
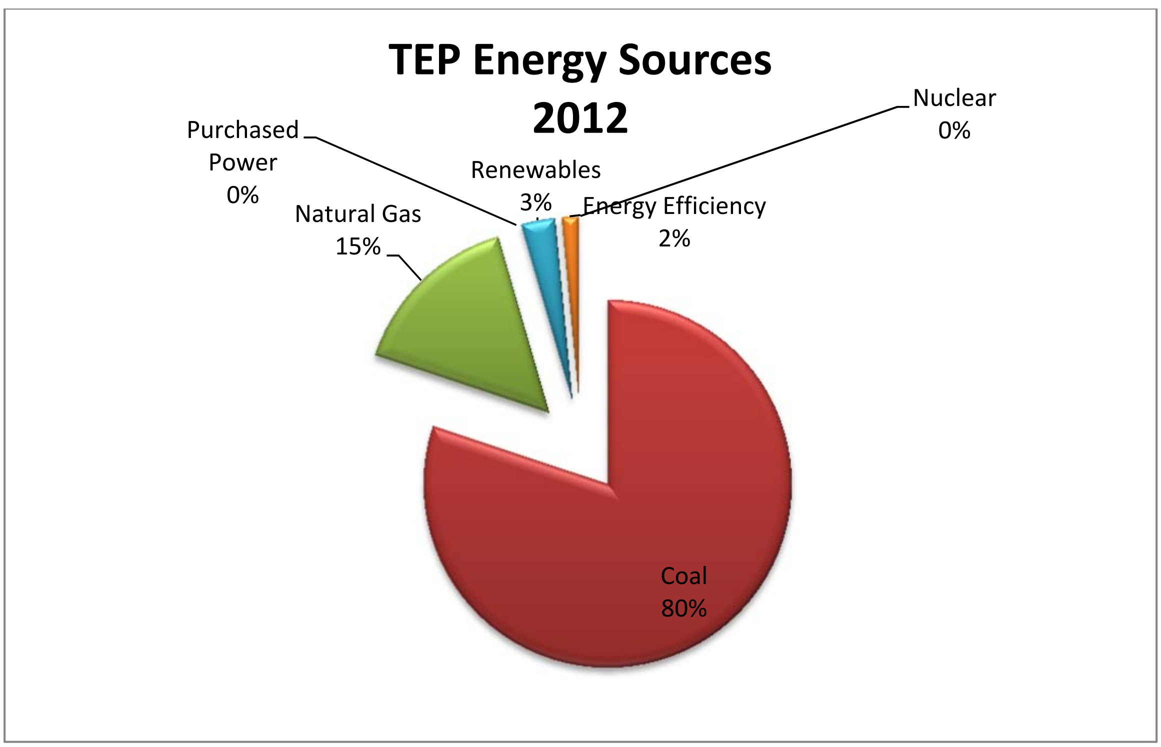
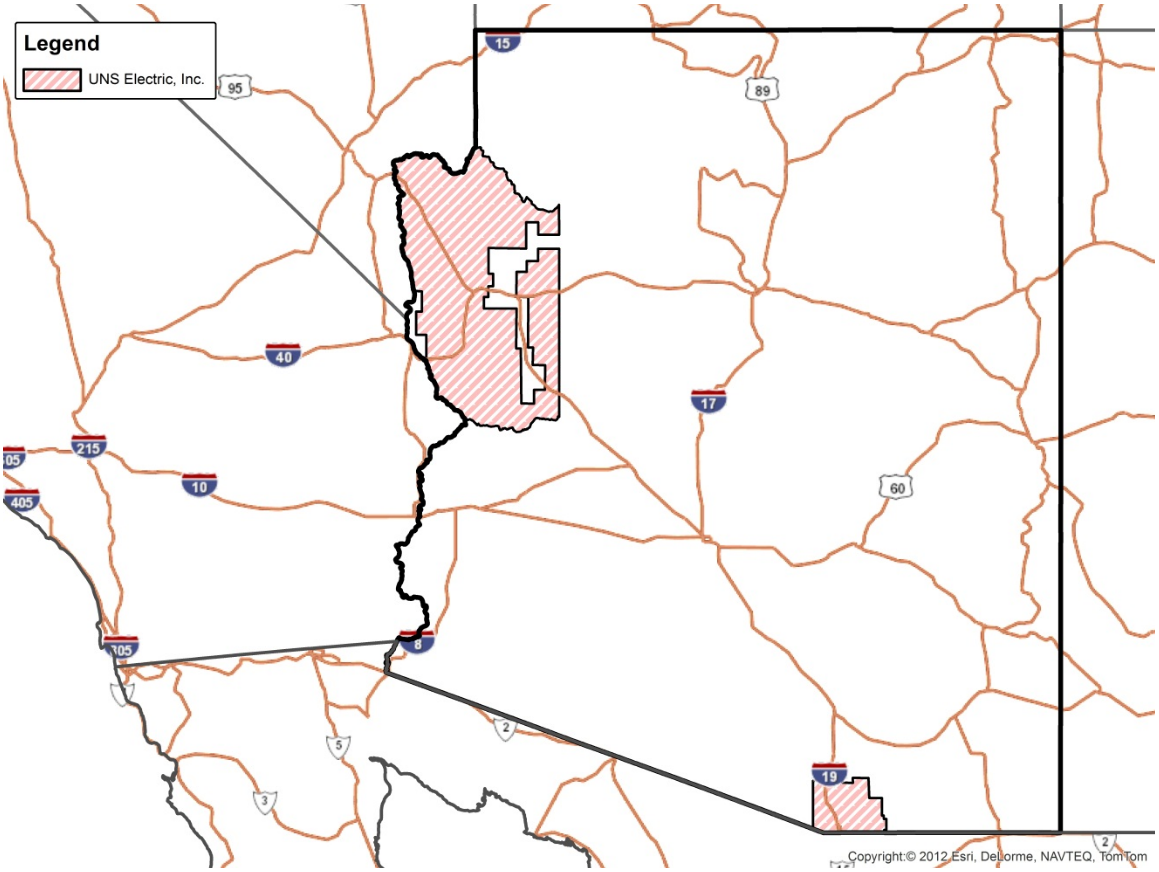


Renewables include distributed generation, renewable purchases and TEP owned renewable generation. The following chart shows the forecasted 2012 breakdown of TEP energy produced by resource type:



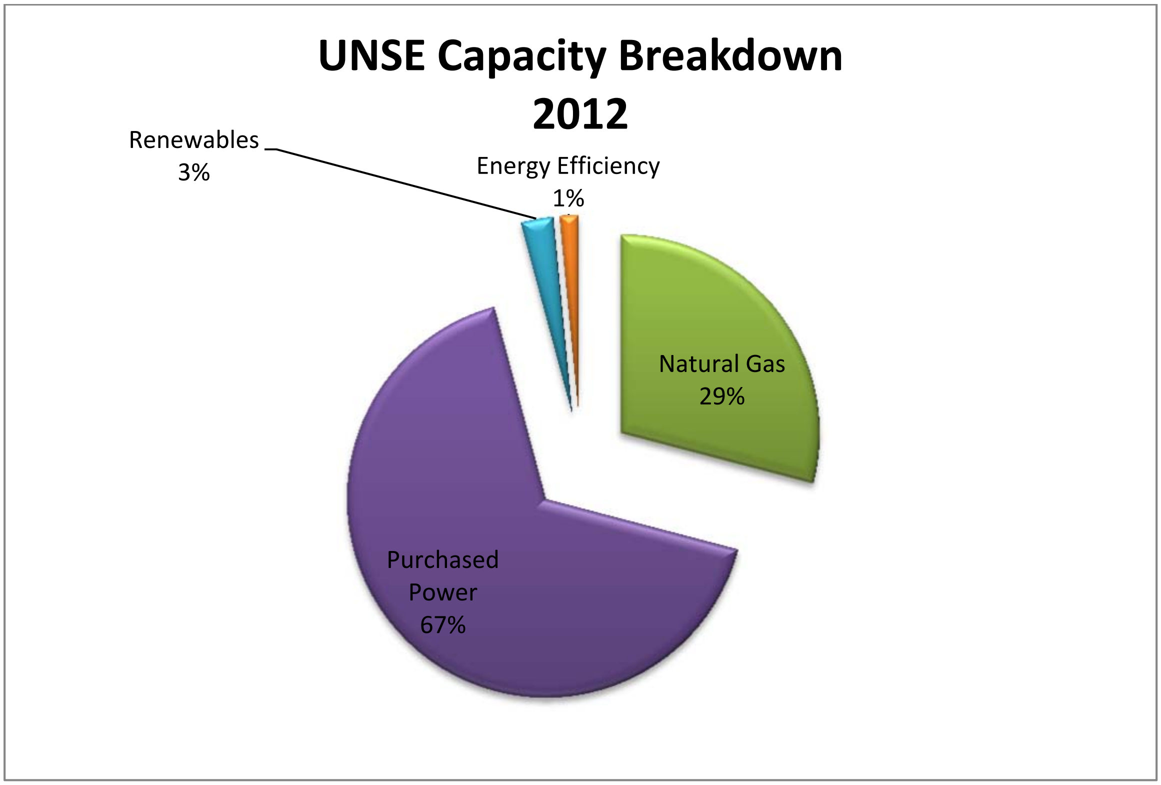
Although TEP's capacity includes significant purchased power resources, it estimates that the purchased power contracts will not result in significant energy purchases in 2012. As demonstrated in the above chart, TEP is currently highly dependent on coal generation, owning or leasing portions of the Sundt, Springerville, San Juan, Four Corners and Navajo coal-fired power plants. Environmental issues concerning coal generation will be a major factor in TEP's IRP.

C. UNS Electric, Inc. ("UNSE")

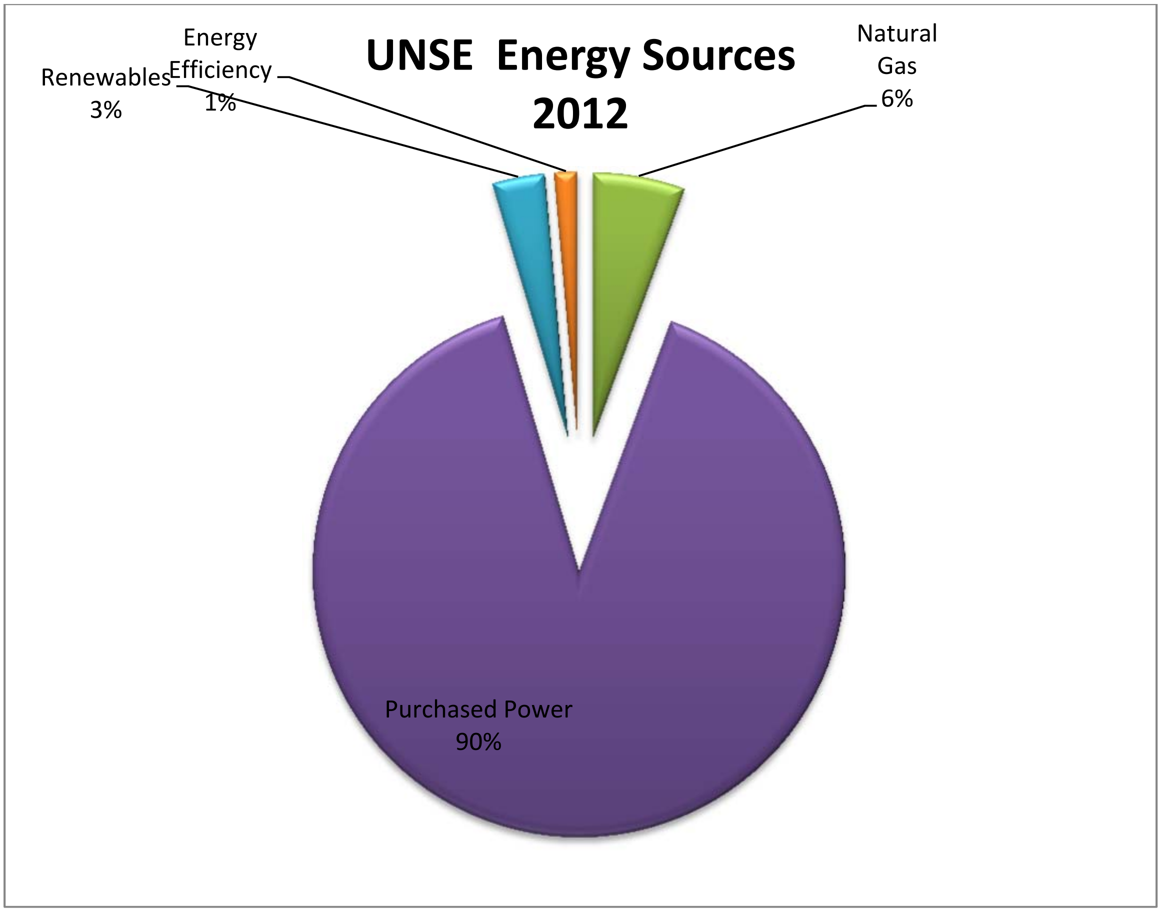


UNSE serves approximately 90,000 customers in two distinct geographic areas – Mohave County in northwest Arizona and Santa Cruz County in southern Arizona. The Mohave County portion of the UNSE service territory includes the Kingman and Lake Havasu City areas. The southern territory encompasses the Nogales area. UNS's 2011 peak demand was 437 megawatts, served by 153 megawatts of installed generating capacity, supplemented by purchased power. UNSE forecasts a 2012 peak demand of 458 megawatts and 526 megawatts of installed capacity (generating capacity plus purchased power).

UNSE's 2012 capacity mix, based on contribution to system peak demand, is shown in the following chart:

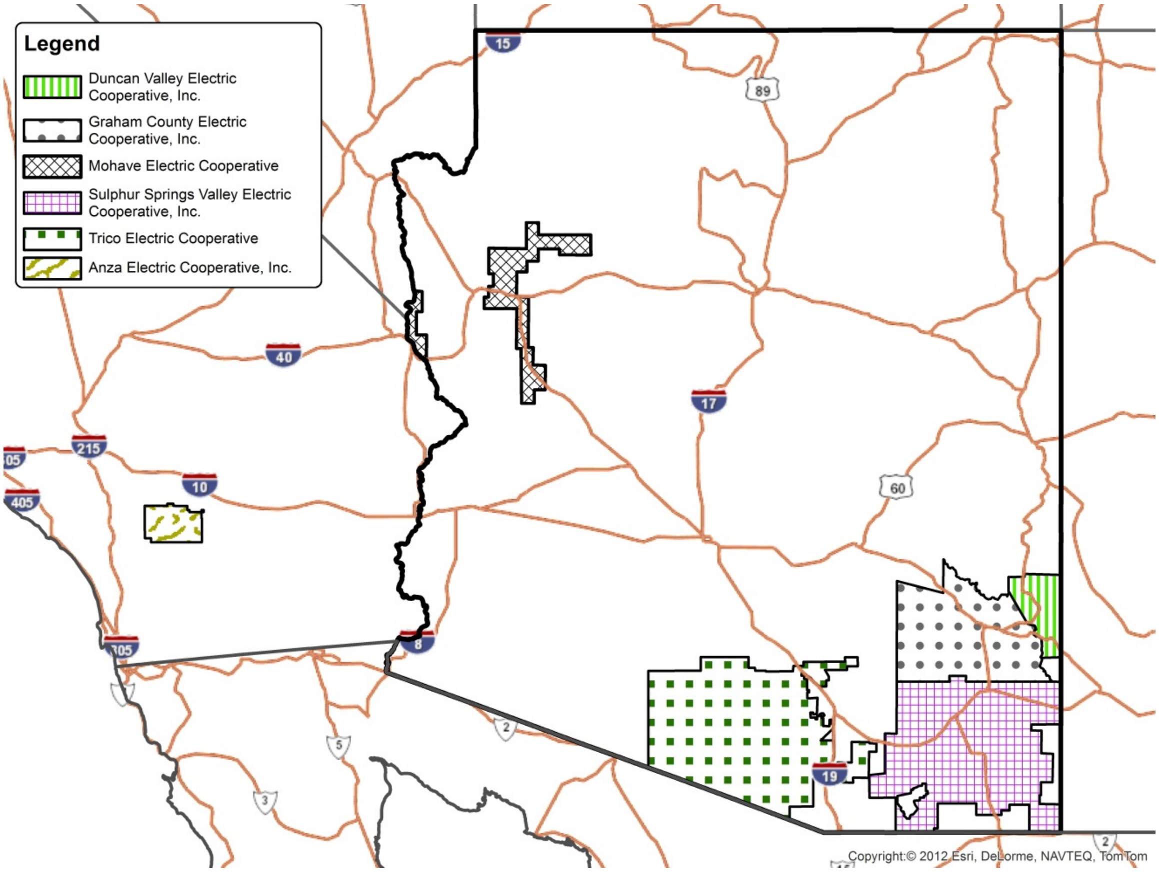


Renewables include distributed generation, renewable purchases and UNSE owned renewable generation. The following chart shows the 2012 breakdown of UNSE energy produced by resource type:



As shown in these charts, UNSE is highly dependent on purchased power, a large portion of which comes from the wholesale power markets.

D. Arizona Electric Power Cooperative, Inc. ("AEPCo")



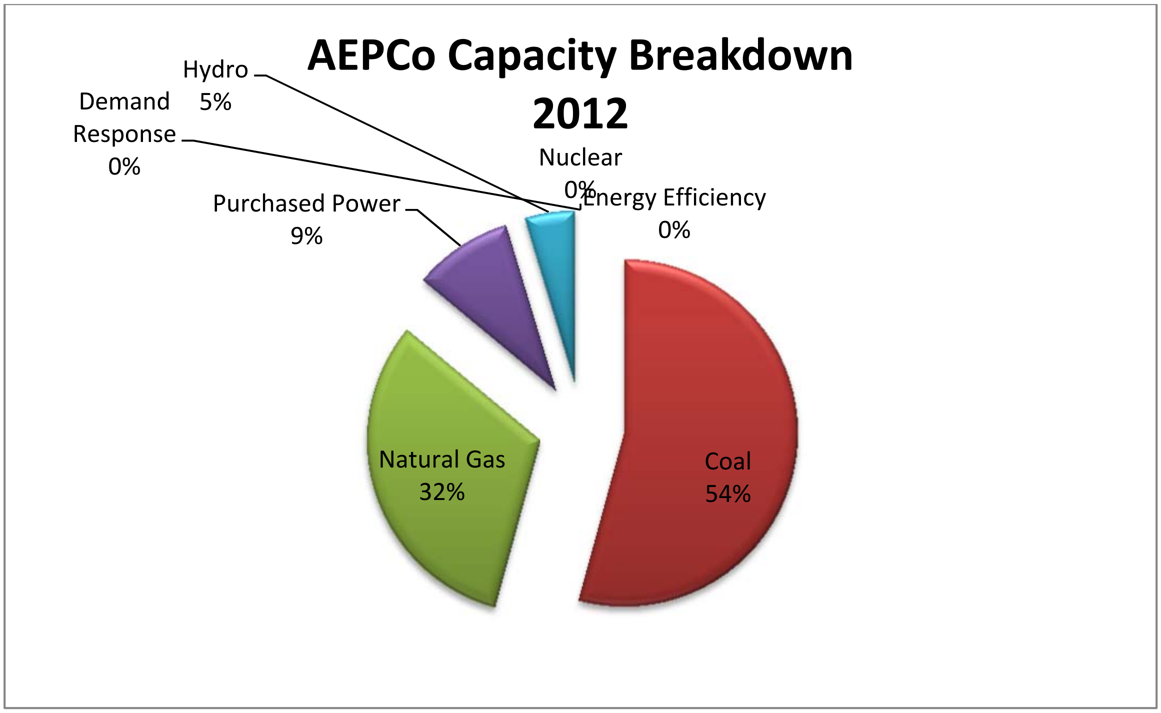
AEPCo is the generation cooperative serving six distribution cooperatives - Duncan Valley Electric Cooperative ("DVEC"), Graham County Electric Cooperative ("GCEC"), Mohave Electric Cooperative ("MEC"), Sulphur Springs Valley Electric Cooperative ("SSVEC"), Trico Electric Cooperative ("TEC"), and Anza Electric Cooperative ("AEC"). Each of these distribution cooperatives is located in Arizona, except for AEC, which is located in California.[12]

Three of the distribution cooperatives served by AEPCo, namely DVEC, GCEC and AEC are all-requirements members, meaning AEPCo is responsible for planning and providing all current and future power and energy needs for these members. The remaining members are partial-requirements members. According to AEPCo, pursuant to contracts most recently approved by the Commission in Decision No. 72055 (January 6, 2011), its only responsibility to the partial-requirements members is to provide the capacity and associated energy from existing resources that are allocated to these members. However, AEPCo is assisting its partial requirements members in studying the feasibility of potential future resources.

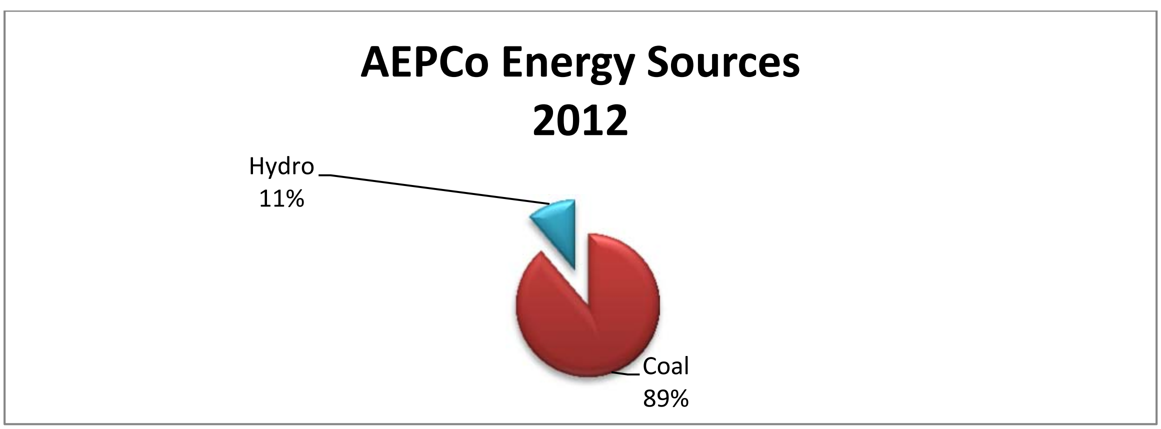
[12] DVEC provides service to Arizona and portions of New Mexico.

Due to the nature of AEPCo's relationships with its member cooperatives, AEPCo's IRP only addresses the needs of its all-requirements members. The potential needs of AEPCo's partial-requirements members are not included within AEPCo's IRP.

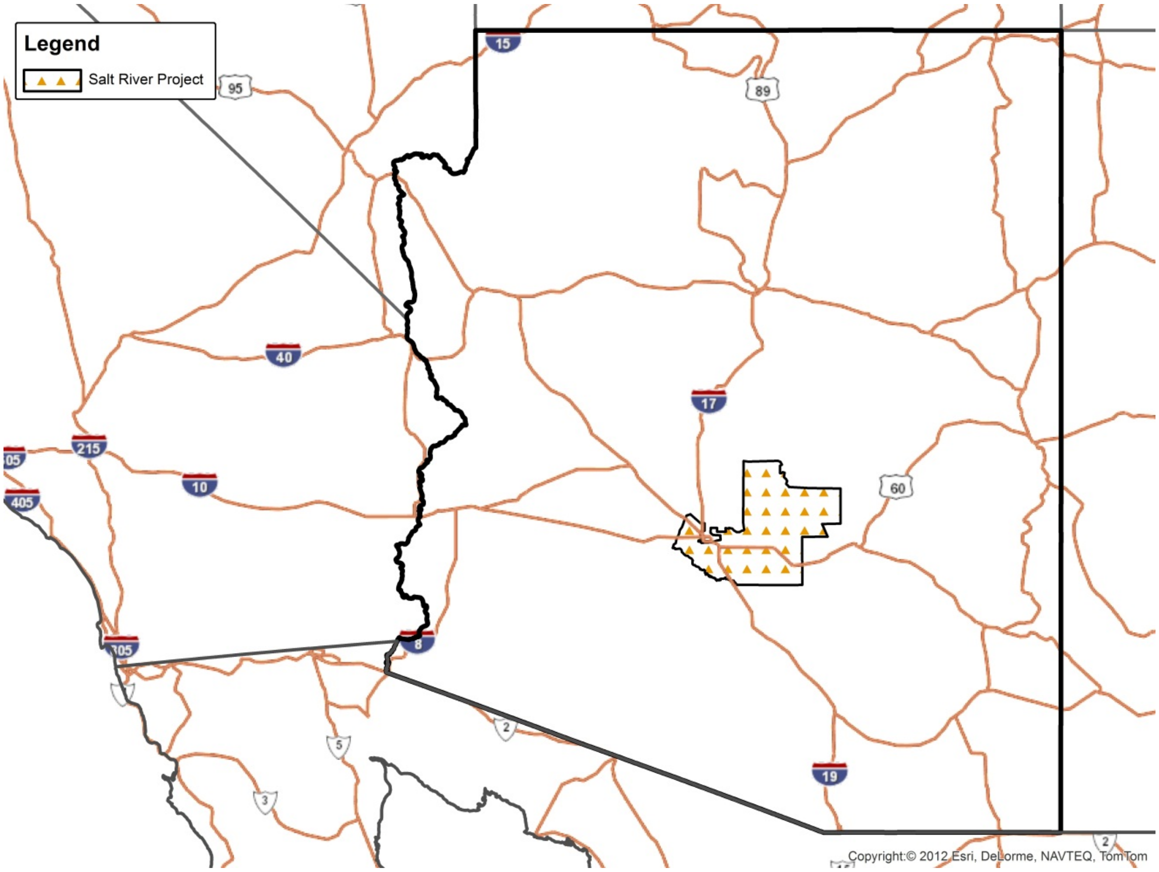
AEPCo owns and operates the Apache generating station in Cochise County, which consists of 350 megawatts of coal-fired generation and 205 megawatts of gas-fired generation. In addition, AEPCo has some 30 megawatts of federal hydro allocation, and small amounts of purchased power. AEPCo's 2012 capacity mix, based on contribution to system peak demand, is shown in the following chart:



AEPCo's coal generation is also capable of operating on natural gas. The following chart provides estimated energy production by resource type in 2012. AEPCo does not forecast utilization of its natural gas generation in 2012.



E. Salt River Project (“SRP”)

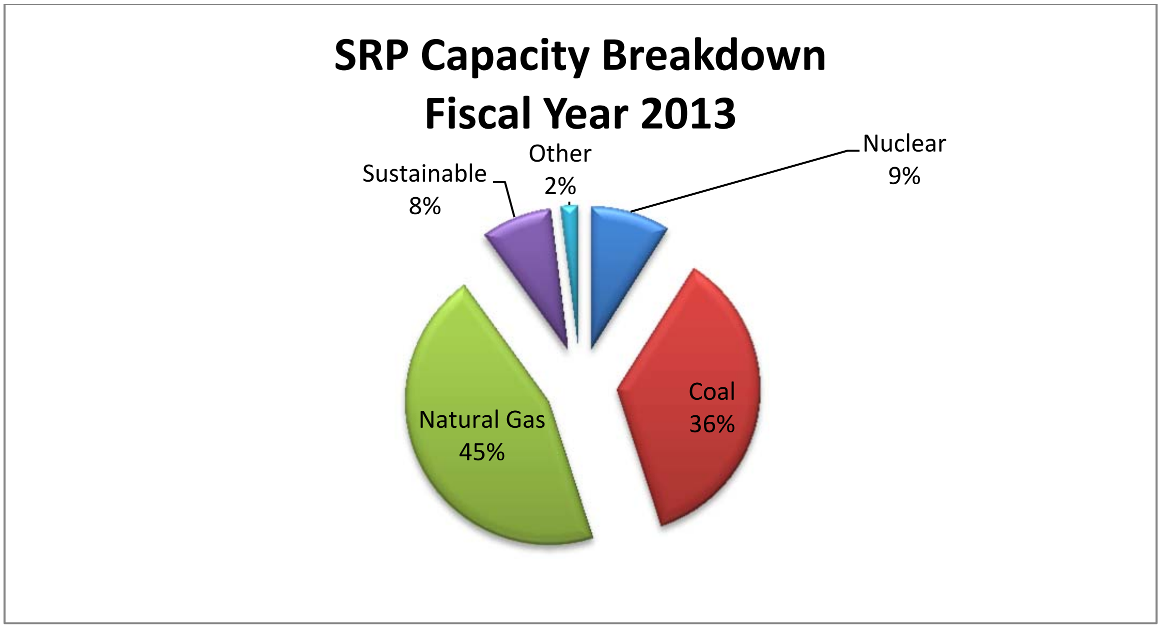


SRP provides electricity to over 950,000 customers in central Arizona, in and near Phoenix. SRP is not subject to the Commission’s IRP rules and thus has no obligation to file an IRP with the Commission. SRP was invited to participate in the two IRP public workshops, but respectfully declined to participate. Publicly available information was extracted from SRP’s web site and other publicly available sources and included in the Staff presentation at the second IRP workshop. After the conclusion of the second IRP workshop, SRP voluntarily provided updated information for inclusion in this report. Staff has utilized the updated information provided by SRP to augment the publicly available information gathered previously. Additional information concerning SRP was extracted from the “Integrated Resource Plan FY 2013, Joint Filing to the Western Area Power Administration by Salt River Project, Town of Gilbert, Fort McDowell Yavapai Nation, and Salt River Pima-Maricopa Indian Community” (“SRP IRP FY2013”) [13].

[13] SRP prepared an Integrated Resource Plan for fiscal year 2013 for submittal to the Western Area Power Administration. This IRP was prepared and made available for public comment and review pursuant to Section 114 of the Energy Policy Act of 1992 (P.L. 102-486) and 10 CFR Part 905. This SRP IRP FY2013 has been prepared and will be submitted to the Western Area Power Administration on behalf of SRP, Town of

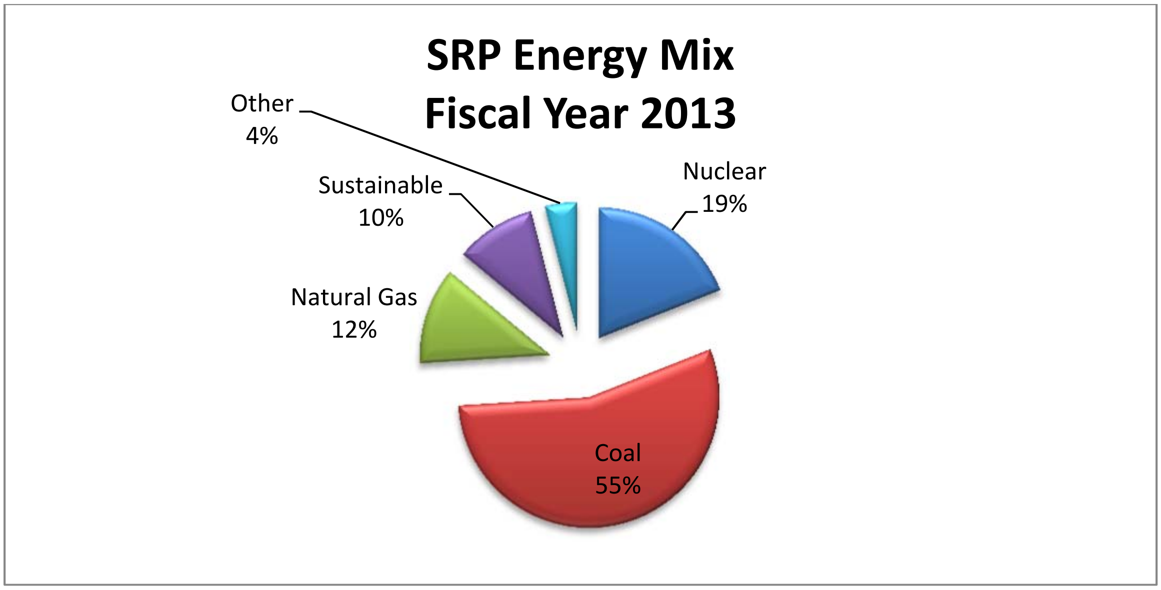
SRP experienced a total system peak demand in 2011 of 7,072 megawatts, a retail system peak of 6,369 megawatts, and had resources available to serve the peak demand totaling 8,284 megawatts. SRP forecasts for 2012 a retail peak demand of 6,926 megawatts (actual peak demand for 2012 is not yet available).

SRP owns and operates the Agua Fria, Kyrene, Desert Basin, and Santan natural gas-fired generating stations, the Coronado coal-fired generating station and several hydro-electric facilities. In addition, SRP is part owner of the PVNGS, and the Hayden, Navajo, Craig, Four Corners coal-fired generating stations. SRP also owns Unit 4 of the Springerville coal-fired generating station, purchases a portion of the output of Springerville Unit 3, purchases 100% of the output of the Coolidge gas-fired generating station, and operates the Navajo generating station. The breakdown of SRP's sources for capacity, based on contribution to system peak demand, is shown in the following chart:



SRP's Fiscal Year 2013 is the period May 1, 2012 through April 30, 2013. Grouped within the "Sustainable" capacity are renewables, energy efficiency, demand response and hydro. The "Other" category includes purchased power and Colorado River Storage Project power purchases. The energy production by resource type is shown in the following chart:

Gilbert, Fort McDowell Yavapai Nation, and Salt River Pima-Maricopa Indian Community in December 2012.


SRP Energy Mix
Fiscal Year 2013
Other
4%
Sustainable
10%
Nuclear
19%
Natural Gas
12%
Coal
55%

IV. The Arizona IRPs

A. Load Forecasts

1. Methodology

There are three basic methodologies available for load forecasting – Econometric, End-use and Trending. The econometric method uses regression techniques to forecast energy use and peak demand. A regression approach develops a series of equations that relate a desired output to a series of input variables. For example, energy sales can be the desired output and can be determined in an equation based on a relationship to other variables such as real disposable income, demographic data, weather patterns, etc.

End-use forecasting is a much more detailed load forecasting method, and is essentially a "bottoms-up" approach that builds up a total forecast from individual components such as the number of residential electric appliances in use. The advantage of end-use forecasting is that it provides valuable information that can be used in the analysis of DSM programs.

The last method, Trending, although popular in the past, is not widely used today. Trending simply develops a forecast from previous growth trends. The following table identifies the load forecasting methodologies employed by the four load-serving entities:

	Econometric	End-use	Trending
APS	Yes	Yes	Yes
TEP	Yes	No	No
UNSE	Yes	No	No
AEPCo	Yes	No	No

APS – APS forecasts the future needs of each customer class separately. For residential customers, APS forecasts the growth in the number of residential customers using a forecasted growth in population, anticipated changes in migration rates, the age distribution of the population, and the regional location of new households. This information is combined with an end-use model that estimates the electricity consumed by each household to arrive at the residential load forecast. An econometric method is utilized to forecast the loads of small commercial and industrial customers (less than 3 megawatts), based on economic growth, occupied floor space, the price of electricity and weather. The forecast for large commercial and industrial customers is developed through interviews with those customers. Finally, the estimated load growth for irrigation and street lighting is based on a trending analysis.

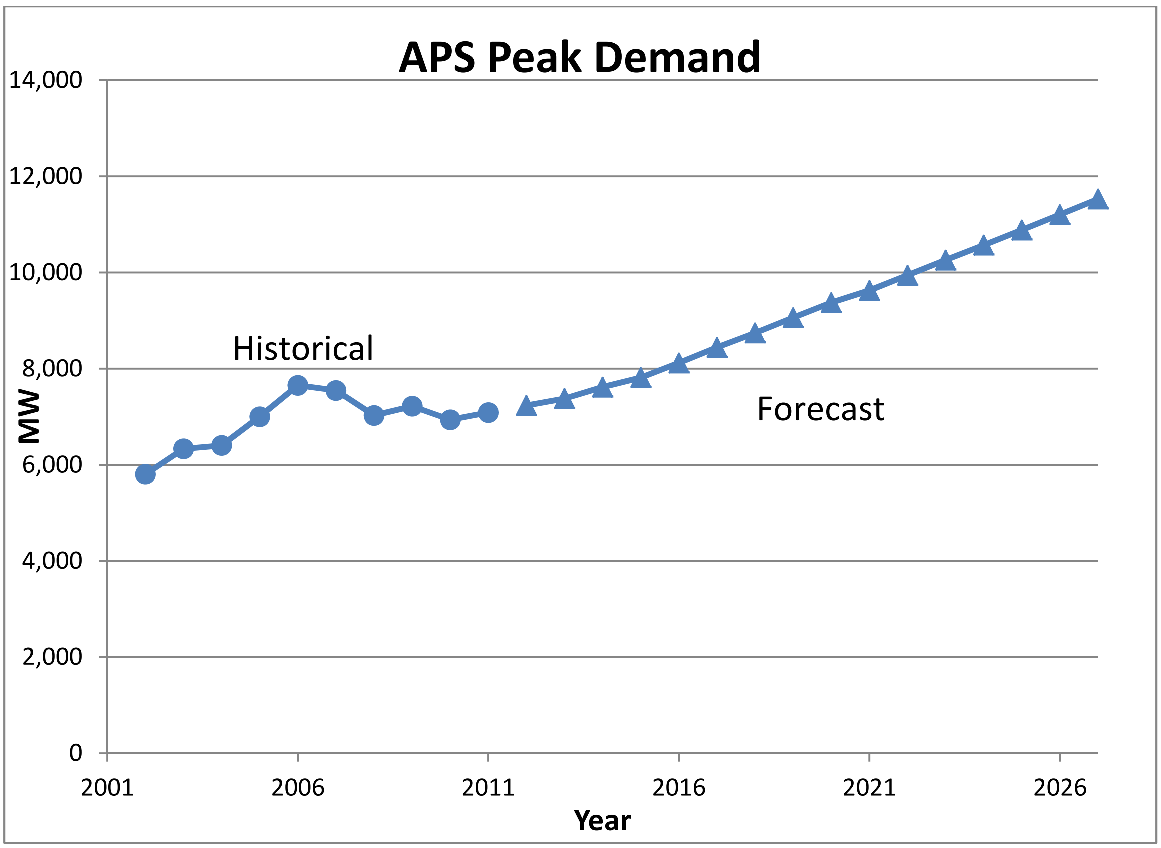
TEP – TEP develops a separate monthly energy forecast for each major rate class – residential, commercial, industrial and mining. For the residential and commercial classes, an econometric approach is utilized, based on historical usage, weather, demographic forecasts and economic conditions. For the industrial and mining classes, individual forecasts are developed for each customer based on historical usage, information from the customers on future expansions of operations and internal company resources.

UNSE – UNSE also develops a separate monthly energy forecast for each major rate class, but due to the disparate geographical sections of the UNSE service territory, also develops separate energy forecasts for three geographical areas – Kingman, Havasu City and Mohave. For the residential and commercial classes, an econometric method is applied, based on historical usage, weather, demographic forecasts and economic conditions. The forecasts of the industrial and mining classes are produced for each individual customer and are based on historical usage patterns, information from the customers, and internal company resources.

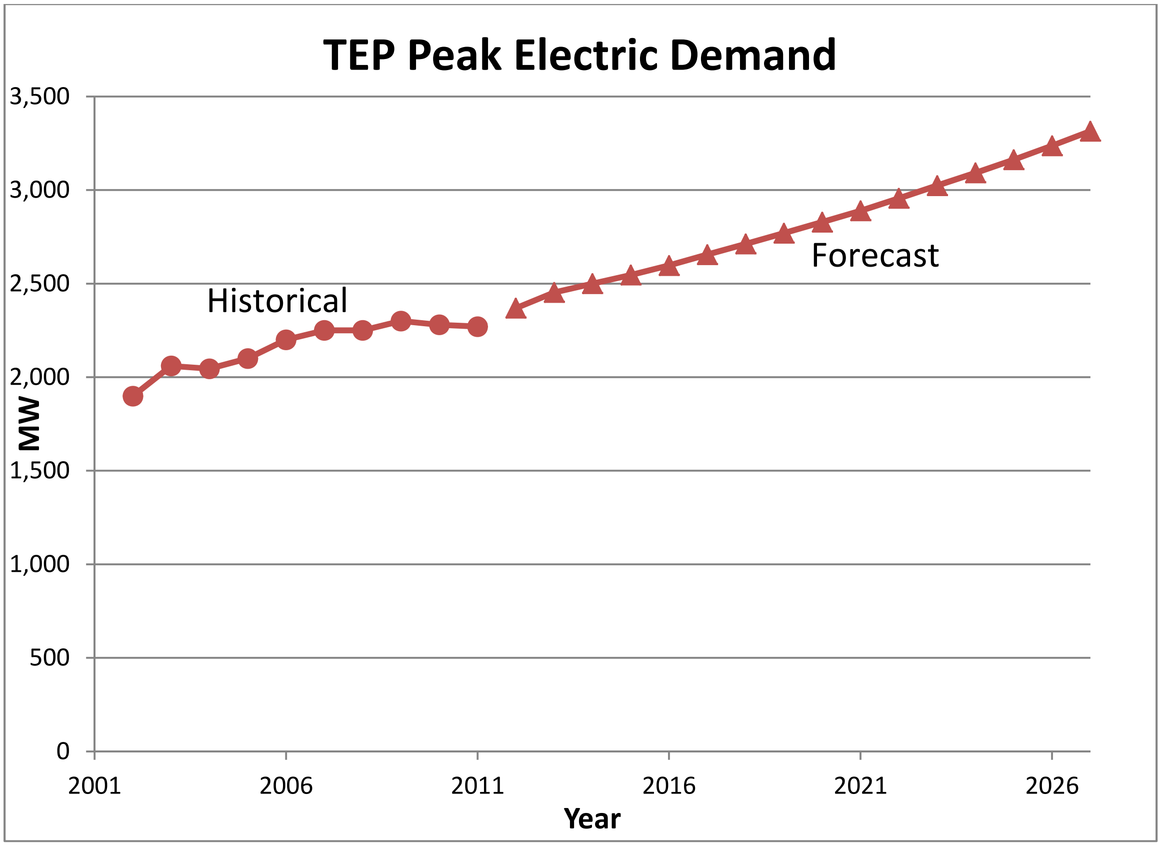
AEPCo – AEPCo developed individual load forecasts for all six of its member distribution cooperatives, using econometric methods based on population growth, economic activity, energy prices, income levels, weather and demographics. The results of the forecasts were used as stated in Exhibit C to the IRP.

2. Peak Demand Forecasts

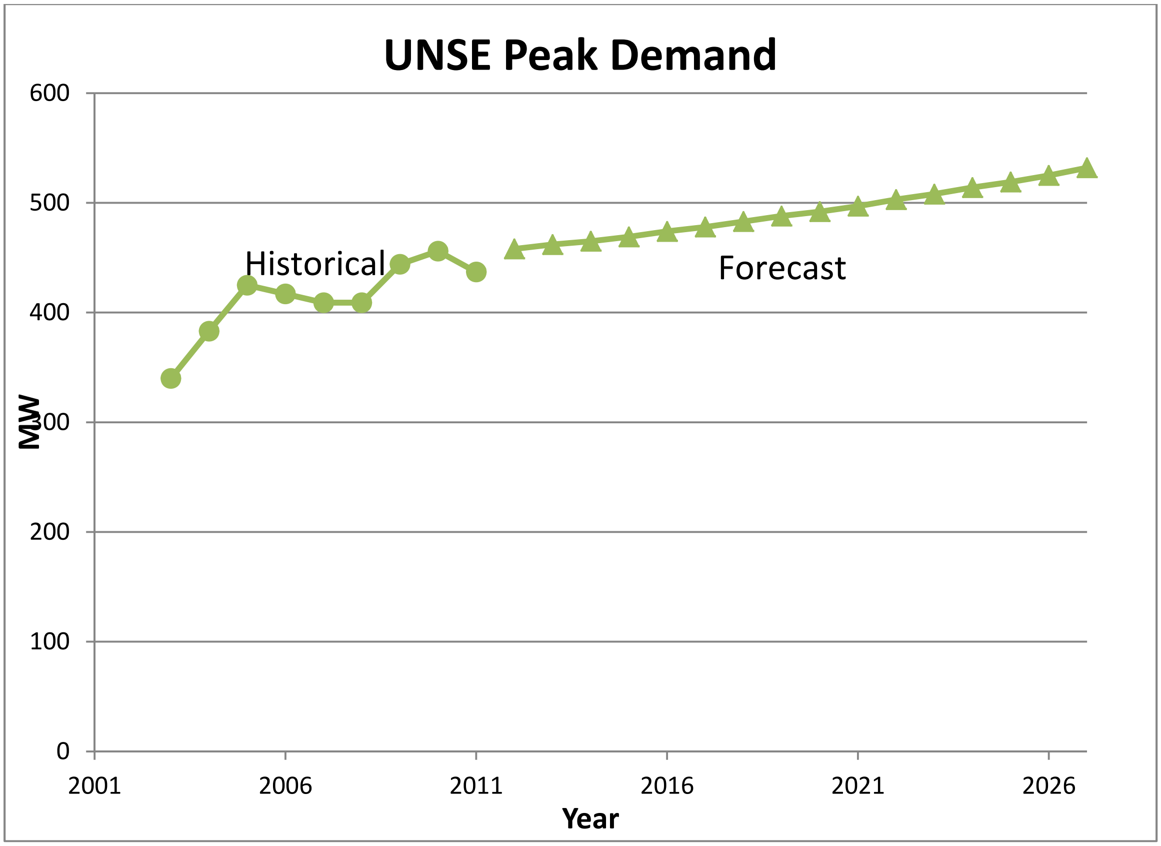
The annual forecast of peak demand (the highest one-hour need for electricity) drives each utility's need for additional resources. To maintain reliable service, each utility must maintain sufficient resources to meet the annual peak demand plus reserves. The following charts compare historical peak demands to the forecasted peak demands (prior to the impact of distributed generation and added demand-side programs) from each of the utility's IRPs.



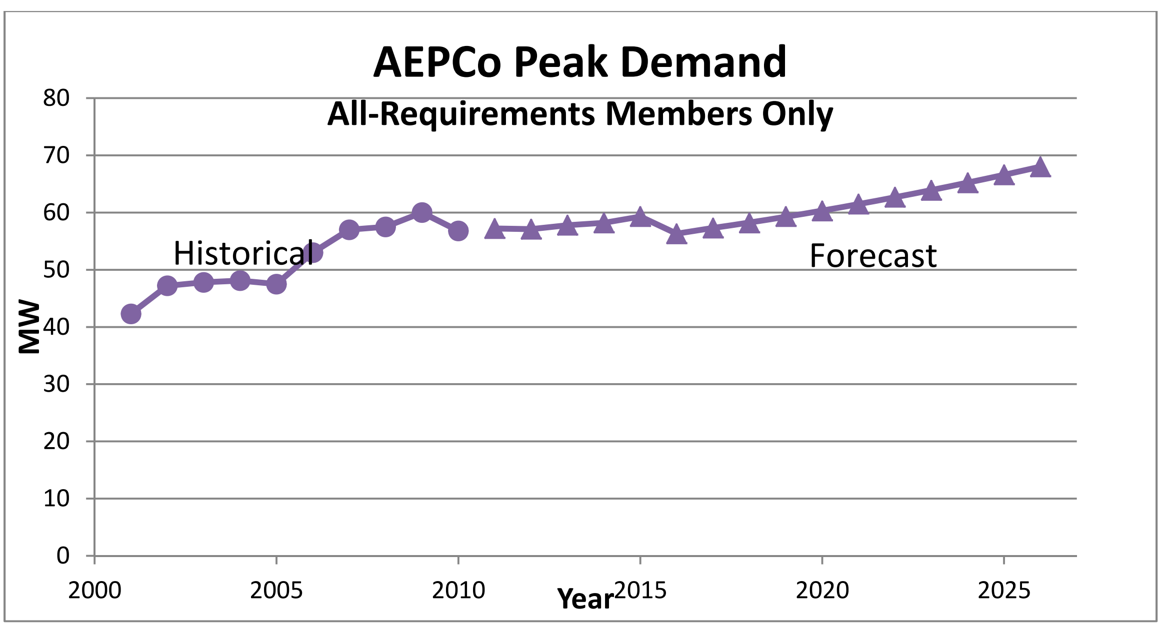
Although recent APS peak demands have dropped, due to the recession, APS is forecasting an average annual growth rate of approximately 3% from 2012 through 2027.



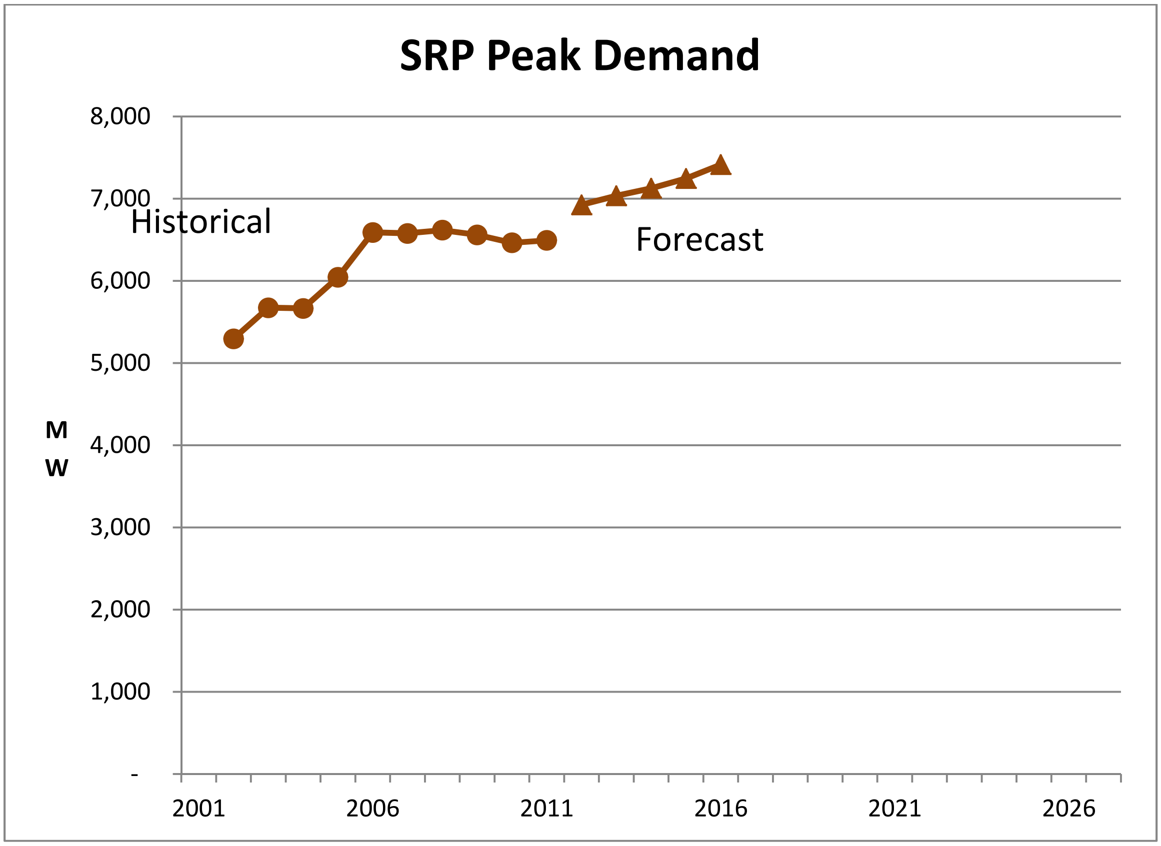
The recession has also negatively impacted TEP's recent peak demands, but it is forecasting an average annual growth rate of 2.3% for 2012 through 2027.



UNSE is forecasting an average annual growth rate of approximately 1% from 2012 through 2027.

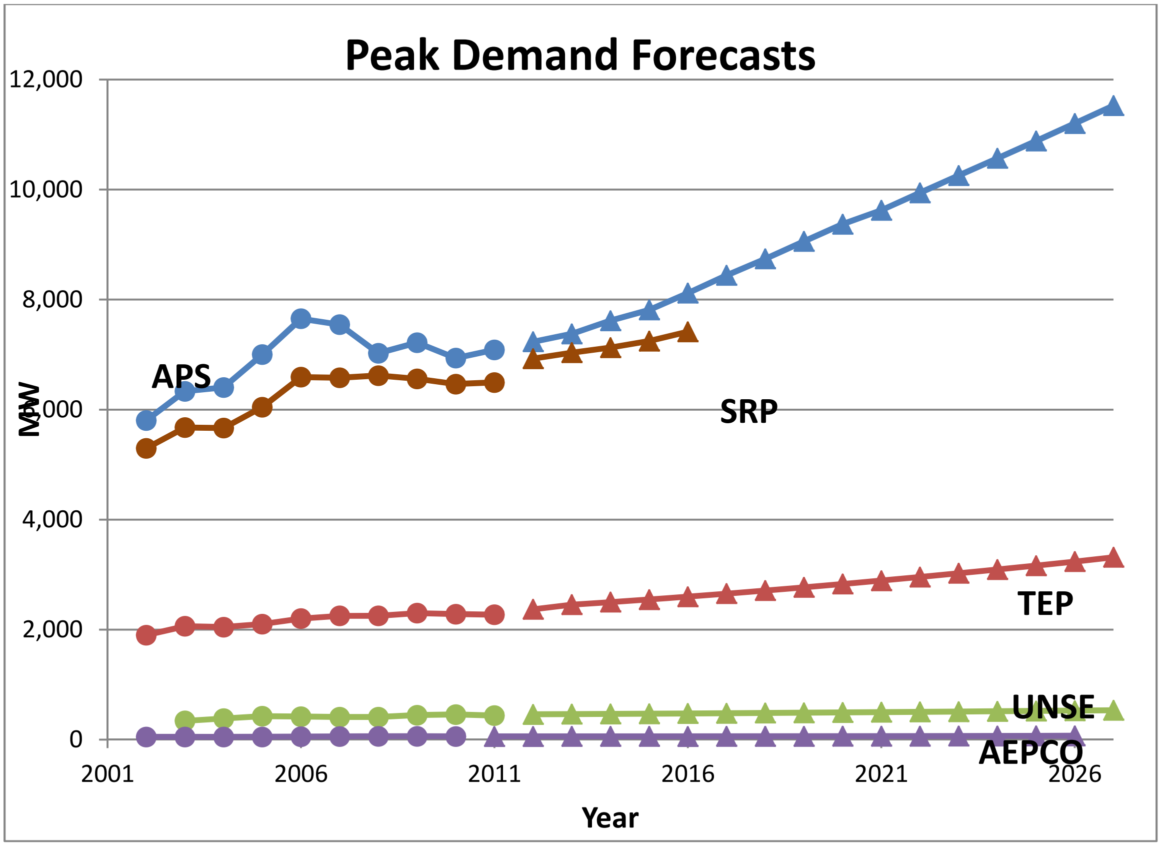


The dip in the 2016 forecasted AEPCo peak demand is due to the loss of certain customers to the City of Safford in that year. For its all-requirements members, AEPCo forecasts a 1.2% average annual growth in peak demand for the years 2012 through 2026. AEPCo's IRP forecast encompasses all six of the AEPCo member distribution cooperatives. For partial-requirements members, the load forecast in a given hour is the lesser of the AEPCo maximum base capacity available to each member and the load forecast for that hour.



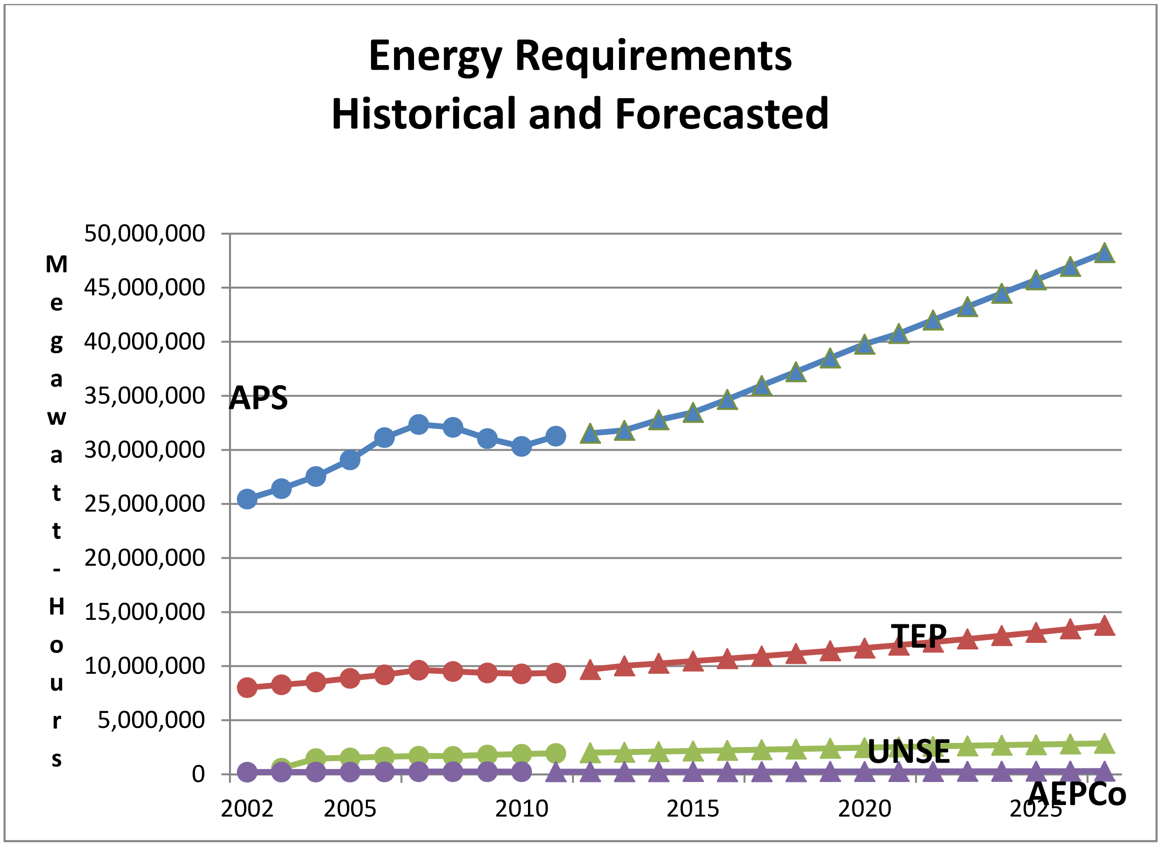
SRP IRP FY2013 only provided forecasted peak demand data prior to the impacts of distributed generation and demand-side management impacts for the years 2012 through 2016. In this period, SRP forecasts an annual average growth rate of 1.7%.

The following chart shows all of the companies load forecasts on the same scale for comparison:


Peak Demand Forecasts
12,000
10,000
8,000
6,000
4,000
2,000
0
MW
APS
SRP
TEP
UNSE
AEPCO
2001
2006
2011
2016
2021
2026
Year

3. Annual Requirements Forecasts

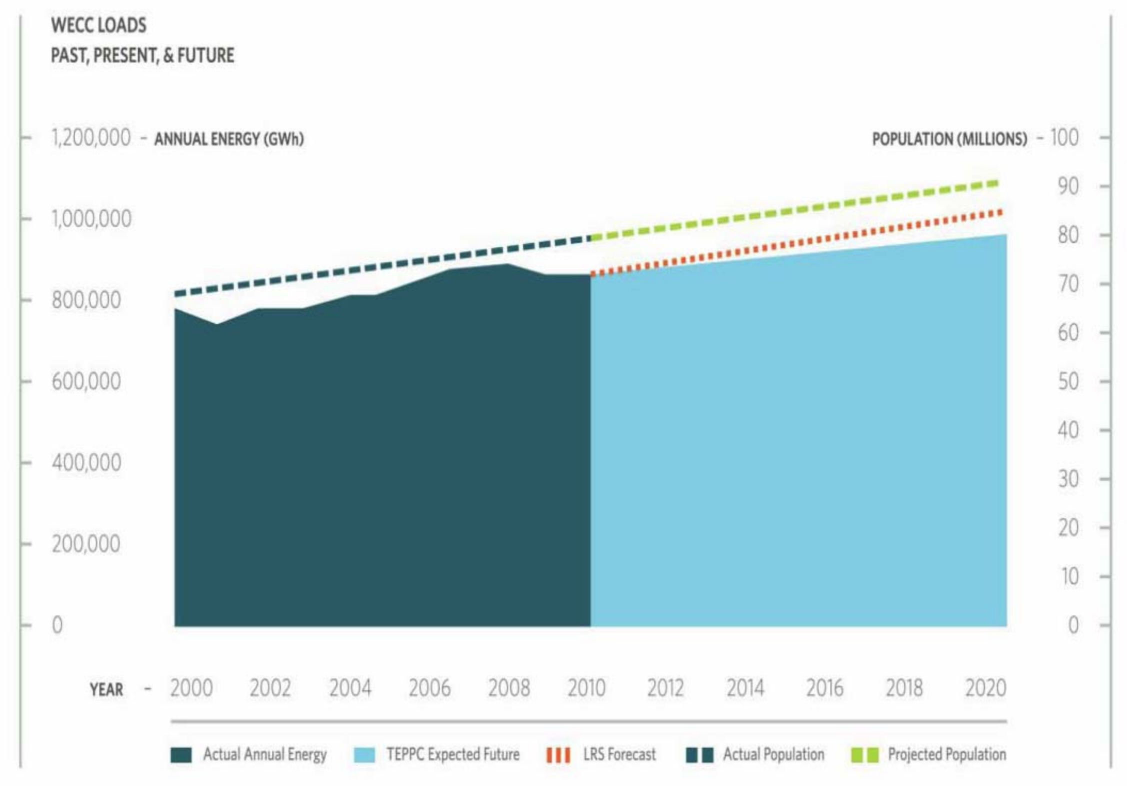
The following chart compares the historical and forecasted annual energy requirements of each utility, prior to the impacts of distributed generation and added demand-side programs:



The AEPCo information concerns only AEPCo's all-requirements members.

The predicted annual average growth rates for energy are 2.9% for APS, 2.4% for TEP, 2.4% for UNSE and 1.3% for AEPCo.

The Western Electricity Coordinating Council ("WECC"), in its September 2011 10-Year Regional Transmission Plan, included the following chart concerning load and population growth throughout the western region:



The dotted red line represents future energy requirements without the impacts of planned demand-side programs and the light blue area in the chart represents future energy requirements <u>after</u> the impacts of planned demand-side programs.

B. Demand-Side Options

1. General Considerations

The Commission’s rules require in part that each load-serving entity select a portfolio of resources based upon comprehensive consideration of a wide range of supply-side and demand-side options[14]. Demand-side options are generally grouped into two main categories – energy efficiency (“EE”) and load management or demand response (“DR”). EE programs reduce electricity usage throughout the year through programs that, for example, incent homeowners to replace older air conditioning systems with new more efficient systems. DR programs, on the other hand, target the critical periods when electricity usage is highest and provide the customers of the jurisdictional load-serving entity with incentives to reduce the usage on peak as, for example, with time of day price plans that send higher price signals during on-peak hours and programs that allow the load-serving entity to reduce the usage of residential air conditioning during on-peak hours. Typically, DR programs do not have a conservation effect. Distributed generation or customer-owned generation can also be considered a demand-side option, but will be discussed in a separate section of this report.

Each load-serving entity is required to attain certain levels of annual energy savings from demand-side options, expressed as a percentage of retail energy sales in the prior calendar year. The required percentages begin at 3% in 2012 and increase annually to 22% in 2020.

2. DSM Cost Effectiveness

The Commission’s rules require that each selected DSM program be cost-effective according to the “Societal Test”[15]. The Societal Test is a ratio defined as follows:

Societal Test = (Program Benefits) / (Program Costs)

If program benefits exceed program costs, the Societal Test will be greater than one, meaning the program is cost-effective. Program benefits include avoided supply-side capacity costs, avoided supply-side operating costs (including fuel costs) and monetized societal benefits (to the extent practical), such as avoided air pollution and avoided water usage. Program costs include utility costs to implement and administer the program, participant costs to partake in the program and monetized societal costs (if any).

[14] A.A.C. R14-2-703(F)(1).
[15] A.A.C. R14-2-2412

3. DSM Programs Considered

The following table shows the EE programs considered by each load-serving entity during the development of the 2012 IRPs. For SRP, the programs shown are those considered and currently offered by SRP. Because AEPCo does not have retail customers, AEPCo does not offer EE programs. However, the load forecasts for AEPCo's member cooperatives reflect the impacts of EE programs deployed by AEPCo's member cooperatives.

Energy Efficiency Programs Considered and Selected

	APS	TEP	UNSE	SRP
Residential Programs				
Consumer Products	◆	◆	◆	◆
Existing Homes	◆	◆	◆	◆
New Construction	◆	◆	◆	◆
Appliance Recycling	◆	◆	◆	◆
Low Income Weatherization	◆	◆	◆	◆
Conservation Behavior Pilot	◆	◆	◆	◆
Multi-Family Construction	◆	◆	◆	☒
Shade Tree	◆	◆	◆	◆
Clothes Washers	☒	☒	☒	☒
Heat Pump Water Heaters	☒			☒
Home Energy Reports	◆	◆	◆	◆
Education and Outreach	◆	◆	◆	◆
Energy Codes Enhancement Program	◆	◆	◆	◆
Residential Energy Financing	◆	◆	◆	◆
SEER Air Conditioners	◆	☒	☒	◆
LED Christmas Lights	☒			◆
Thermostatic-Controlled Showerheads	◆			◆
In Home Display	◆			◆
Non-Residential Programs				
Large Existing Facilities	◆	◆	◆	◆
New Construction	◆	◆	◆	◆
Small Business	◆	◆	◆	◆
Schools	◆	◆	◆	◆
Energy Information Systems	◆			◆
Window Films	☒			◆
Gaskets	☒			◆
Bid for Efficiency	◆	◆	◆	
Combined Heat & Power	☒	◆	◆	
Retro-Commissioning	◆	◆	◆	◆
EMS - Cold Deck Reset		☒	☒	
Refrigerated Display LED Lighting Strips	◆	☒	☒	
Compressed Air Solutions				◆

◆ Included in IRP

☒ Considered but rejected

The following table shows the DR programs considered by each load-serving entity in the development of the 2012 IRPs. For SRP, the programs shown are those considered and currently offered by SRP. AEPCo did not consider DR programs in the development of its 2012 IRP.

Demand Response Programs Considered and Selected

		APS	TEP	UNSE	SRP
Residential Programs					
	Direct Load Control	◆	◆	◆	
	Time of Use Rates	◆			◆
Non-Residential Programs					
	APS Peak Solutions	◆			
	Interruptible Rates	◆			◆
	Direct Load Control	◆	◆	◆	◆
	Time of Use Rates	◆			◆
	◆	Included in IRP			
	☒	Considered but rejected			

Because AEPCo does not have retail customers, AEPCo does not offer DR programs. However, the load forecasts for AEPCo's member cooperatives reflect the impacts of DR programs deployed by AEPCo's member cooperatives.

C. Supply-Side Options

1. Options Considered

The following table lists the supply-side options that were considered by APS, TEP, UNSE and AEPCo. AEPCo only considered short-term purchased power as a supply-side option. APS analyzed the addition of five renewable technologies that were not considered by the others. On the other hand, APS failed to consider all energy storage technologies, which could prove to be valuable resources as more renewable generation is added in the future.

SRP describes only in general terms its selected supply-side additions in its SRP IRP FY2013. SRP plans to add new renewable and natural gas generating resources.

None of the load-serving entities considered repowering existing coal-fired plants to natural gas, nor did any (other than UNSE) consider the joint development of new generating plants with the other load-serving entities.

Supply-Side Options Considered				
	APS	**TEP**	**UNSE**	**AEPCo**
Renewable Technologies:				
Wind Turbines	◆	◆	◆	
Solar Photovoltaic Fixed	◆	◆	◆	
Solar Photovoltaic Single-Axis Tracking	◆	◆	◆	
Solar Trough Concentrating without Storage	◆	◆	◆	
Solar Trough Concentrating with Storage	◆	◆	◆	
Solar Power Tower with Storage	◆			
CSP Hybrid Cooled with Storage	◆			
CSP Hybrid Cooled without Storage	◆			
Geothermal	◆			
Biomass Direct	◆	◆	◆	
Biogas	◆			
Natural Gas-Fired Generation				
Combustion Turbine - GE 7FA	◆	◆	◆	
Combustion Turbine - GE LMS100	◆	◆	◆	
Combustion Turbine - GE LM6000	◆	◆	◆	
Combined Cycle	◆	◆	◆	
Wartsila 18V50	◆			
Coal-Fired Generation				
Sub-critical Pulverized Coal	◆	◆	◆	
Integrated Gasification Combined Cycle	◆	◆	◆	
Nuclear Generation				
Advanced Boiling Water Reactor	◆	◆	◆	
Energy Storage				
Pumped Hydro		◆	◆	
Compressed Air Energy Storage	◆	◆	◆	
Batteries	◆	◆	◆	
Flywheels		◆	◆	
Ultracapacitors		◆	◆	
Purchased Power				
Long-Term	◆			
Short-Term	◆	◆	◆	◆

2. Cost Assumptions

The following table compares the capital cost assumptions utilized by APS, TEP and UNSE for the various supply-side options. AEPCo did not consider the addition of new generating facilities.

There are significant differences in the assumed capital costs for many of the supply-side additions. It is unclear why such significant differences exist, but the situation adds strength to the argument that the utilities should seriously consider joint planning of new generating facilities.

Assumed Costs - Supply-Side Options ($/KW)			
	APS	**TEP**	**UNSE**
Renewable Technologies:			
Wind Turbines	$2,190	$2,200	$2,200
Solar Photovoltaic Fixed	$1,783	$2,350	$2,350
Solar Photovoltaic Single-Axis Tracking	$1,998	$3,250	$3,250
Solar Trough Concentrating without Storage	$4,102	$4,900	$4,900
Solar Trough Concentrating with Storage	$6,196	$5,650	$5,650
Solar Power Tower with Storage	$4,585		
CSP Hybrid Cooled with Storage	$6,815		
CSP Hybrid Cooled without Storage	$4,512		
Geothermal	$4,639		
Biomass Direct	$4,783	$3,250	$3,250
Biogas	$1,536		
Natural Gas-Fired Generation			
Combustion Turbine - GE 7FA	$716	$779	$779
Combustion Turbine - GE LMS100	$1,012	$1,203	$1,203
Combustion Turbine - GE LM6000	$1,138	$1,156	$1,156
Combined Cycle	$892	$1,320	$1,320
Wartsila 18V50	$1,262		
Coal-Fired Generation			
Sub-critical Pulverized Coal	$2,846	$4,164	$4,164
Integrated Gasification Combined Cycle	$4,347	$4,448	$4,448
Nuclear Generation			
Advanced Boiling Water Reactor	$4,531	$7,532	$7,532
Energy Storage			
Pumped Hydro		$2,750	$2,750
Compressed Air Energy Storage		$1,645	$1,645
Batteries		$3,000	$3,000
Flywheels		$2,250	$2,250
Ultracapacitors		$750	$750

D. Distributed Renewable Generation

The following table shows the options considered by each load-serving entity for distributed (or customer-owned) renewable generation.

Distributed Renewable Options Considered				
	APS	TEP	UNSE	SRP
Solar Hot Water	◆	◆	◆	◆
Solar Photovoltaic	◆	◆	◆	◆
Solar Space Heating & Cooling	◆	◆	◆	
Small Hydro	◆	◆	◆	◆
Small Wind	◆	◆	◆	
Biogas or Biomass	◆	◆	◆	

APS, TEP and UNSE offer a wide spectrum of distributed renewable generation options. AEPCo does not discuss distributed renewable generation in its IRP because under Commission Rules, AEPCo is not involved in determining distributed renewable programs at the retail level. That function is reserved to its members and the Commission by R14-2-1814.

E. Assumptions

1. Basic Assumptions

The following table shows the basic assumptions made by APS, TEP and UNSE. AEPCo did not provide this information in its IRP filing.

	APS	TEP	UNSE
Planning Reserve Margin	15%	15%	15%
Inflation	2.5%	2.5%	2.5%
Wind Integration Costs per MWh	$3.25	$5.00	$5.00
Solar Integration Costs per MWh	$2.50	$4.00	$4.00

The Planning Reserve Margin establishes the utility's need to install resources above and beyond the annual peak demand for electricity. For example, if a utility expects an annual peak demand of 1,000 megawatts and has assumed a 15% reserve margin, the utility must plan to install resources that can supply 1,150 megawatts (the peak demand plus 15% of the peak demand). The Planning Reserve Margin generally covers the unexpected loss of generating resources and excessive peak demand caused by unusual weather. All three load-serving entities have established a planning reserve margin of 15%, which is a reasonable level for planning reserve margin.

All three load-serving entities have assumed a rate of inflation at 2.5%, which is also a reasonable assumption.

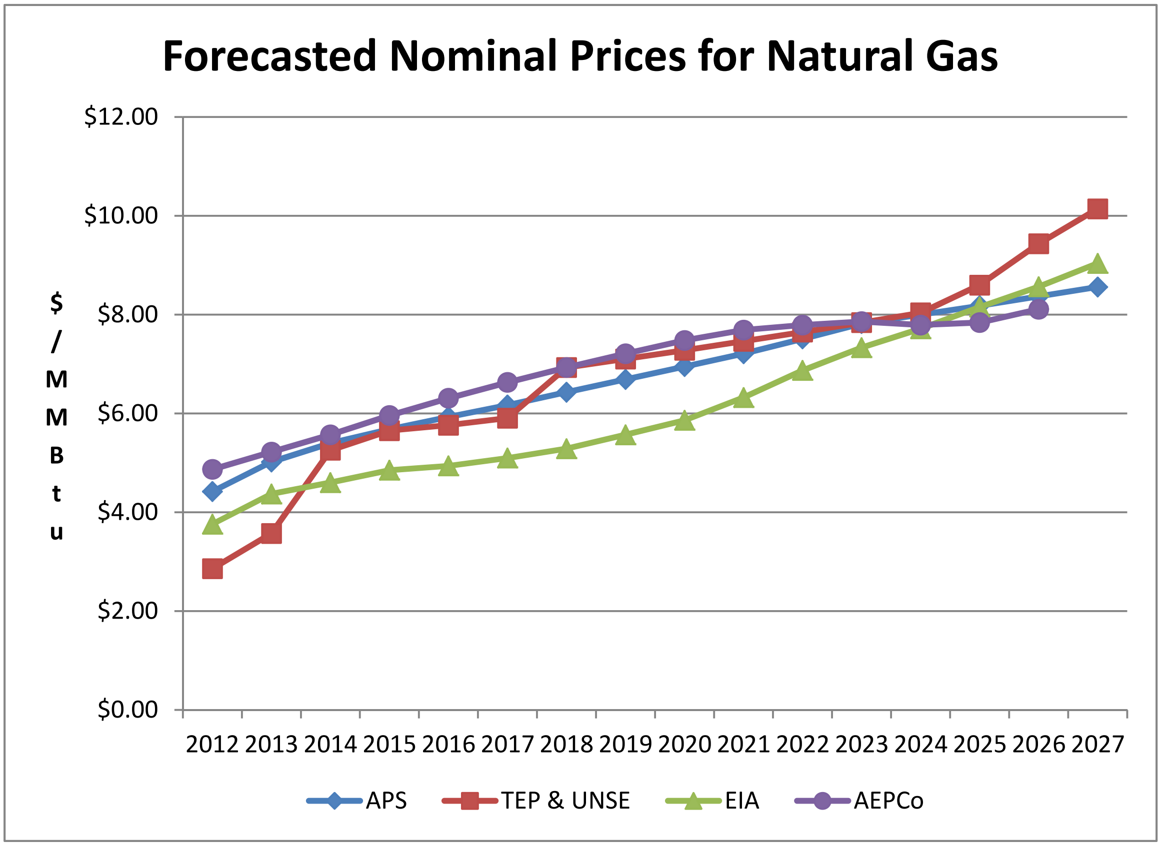
Differences arise in the assumed Wind Integration Cost and assumed Solar Integration Cost. These integration costs are estimates of the cost to assimilate the intermittent generation from wind and solar facilities into the generation system. For example, if the wind should unexpectedly cease at a wind facility, the controllable generating resources (which are generally the fossil fuel resources) must quickly increase the production of electricity to replace the unexpected loss in wind energy. So wind and solar facilities cause added stress on fossil fuel resources, and in some cases, require the utility to carry additional operating reserves. These integration costs are added to the operating costs of wind and solar facilities.

For wind integration costs, APS, TEP and UNSE relied on the APS Wind Integration Cost Impact Study conducted by Northern Arizona University in September 2007. It is unclear why the three utilities selected different levels of wind integration costs from this study. For solar integration costs, the utilities relied on several different studies, the Solar Integration Study for Public Service Company of Colorado, the Large Scale PV Integration Study conducted by Navigant Energy and the Western Governors' Association's Western Renewable Energy Zone Generation and Transmission Model. APS recently concluded a solar integration cost study, specific to the APS system, which is available to the public at http://www.aps.com/files/renewable/PVReserveReport.pdf. This study was not available prior to the development of this report, but appears to verify the solar integration costs utilized by APS in its IRP.

Solar and wind integration costs depend to a large extent on current local conditions – wind patterns in the area, local fossil generation mix, local penetration levels of intermittent resources, etc. APS has utilized integration costs that are specific to the APS system, and it would be advantageous for the other load-serving entities to conduct studies to develop wind and solar integration costs that reflect current conditions that are specific to each entity.

2. Natural Gas Price Forecasts

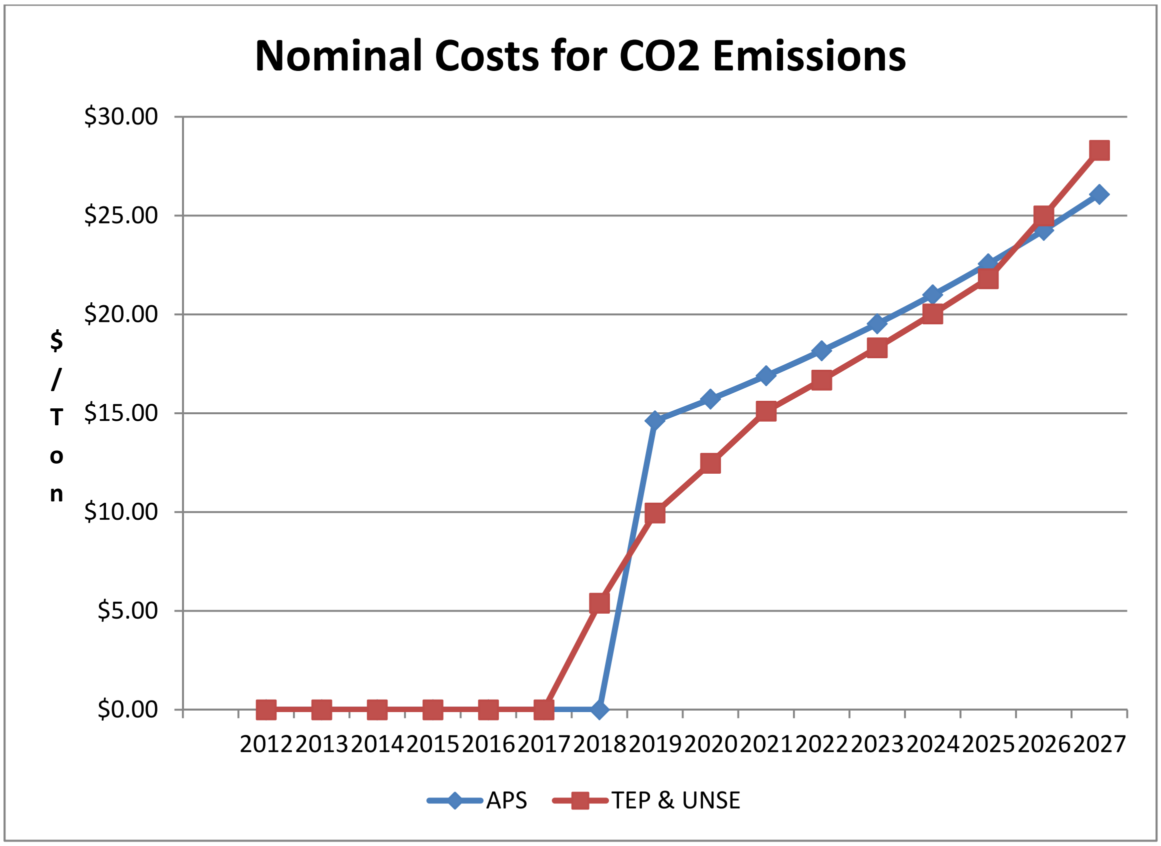
A critical assumption of IRP is the projected cost of natural gas. The base forecasted costs of natural gas utilized by APS, TEP, UNSEand AEPCo are shown in the following chart, along with the current base forecast by the Energy Information Administration ("EIA") from the EIA Annual Energy Outlook 2012.



The projections by APS, TEP, UNSE and AEPCo appear very reasonable, when compared to the EIA forecast. In addition to this base forecast for natural gas, APS, TEP and UNSE also considered higher than base and lower than base forecasts as part of the risk and sensitivity analyses.

3. CO2 Emission Cost Forecasts

Although it is still unknown whether CO2 emissions will be taxed in the future, it would be imprudent to assume that no such taxes will ever be implemented. APS, TEP and UNSE each assume that CO2 taxes will materialize in the future. The following chart compares the timing and prices assumed for the taxation of CO2 emissions. AEPCo did not provide this information in its IRP.



The assumed timing and pricing for the taxing of CO2 emissions by the utilities represents a reasonable estimate.

4. Retirements

As a base assumption, the Arizona load-serving entities assume that all existing power plants will continue to operate throughout the 15 year planning horizon, with the exception of Four Corners Units 1, 2 and 3. APS plans to retire these coal-fired generating units and acquire Southern California Edison's share of the remaining two units – Four Corners Units 4 and 5. This plan results in a 179 megawatt net gain of coal-fired capacity for APS.

This does not mean that the load-serving entities have not considered the retirement of coal-fired generating resources as a part of the development of the IRPs. APS and TEP do include studies that consider the retirement of certain coal-fired resources.

APS and UNSE do however, assume that existing long-term purchase power contracts will expire during the 15-year planning horizon, and must be replaced with other resources.

F. Software Tools for IRP Selection

The selection of a “best” mix of demand-side and supply-side resources to form an IRP is a complex task. In most cases the possibilities number in the thousands or even millions. Sifting through all the myriad possibilities to select an IRP under just one set of assumptions is a difficult task. But the selection must be repeated many times over during the risk and sensitivity analyses.

Electric utilities generally utilize a software tool to perform the selection process. TEP and UNSE both used two software tools – “Capacity Expansion” and “Planning & Risk”. Among other utilities, PacifiCorp utilizes the System Optimizer tool and Southern Company uses the Strategist capacity expansion model. These tools are commercially available products of Ventyx. APS did not use software to develop “best” IRPs, but instead developed IRPs manually, and then evaluated each IRP using PROMOD IV (also a product of Ventyx). AEPCo did not utilize any software to develop “best” IRPs, but did evaluate its IRP using PROMOD IV. SRP does not discuss the use of software in the information provided to the Commission.

The APS approach of selecting “best” IRPs manually is not the preferred approach. The manual method makes risk and sensitivity analyses much more difficult. Using a software tool, such as Strategist, System Optimizer, or Capacity Expansion would provide opportunities for the full evaluation of a much broader spectrum of potential IRPs, under a more robust set of assumptions

G. IRP Development

1. APS

APS considered four specific expansion plans, or scenarios, and performed risk and sensitivity analyses on these four scenarios:

- Base Case:
    - Four Corners 1-3 are retired and APS acquires SCE's share of Four Corners 4&5 in 2013
    - Added EE and Renewables meet load growth through 2016
    - Short-term Market purchases added in 2017-2027
    - 3,268 megawatts of natural gas-fired CTs and CCs added in 2019-2027
- Four Corners Contingency
    - Four Corners retired in 2015-2016
    - Added EE and Renewables meet load growth through 2015
    - Natural gas-fired CC added in 2016
    - Short-term market purchases added in 2017-2027
    - Total of 4,239 megawatts of natural gas-fired generation added in 2016-2027
- Enhanced Renewable Portfolio
    - Four Corners as in Base Case
    - Added EE and Renewables meet load growth through 2017
    - Short-term market purchases added in 2017-2027
    - 3,064 megawatts of natural gas-fired CTs and CCs added in 2020-2027
- Coal Retirement Portfolio
    - All coal-fired generators retired by 2025
    - Natural gas-fired CC added in 2016
    - Short-term market purchases added in 2017-2027
    - Total of 5,006 megawatts of natural gas-fired generation added in 2016-2027

Each of the four scenarios meets or exceeds the EE, Renewable Energy and Distributed Energy requirements of the Commission.

APS performed a series of single variable sensitivities, in which selected major cost assumptions were increased and decreased to test the robustness of each scenario. The cost inputs included in this sensitivity analysis were:

- Forecasted natural gas prices
- Forecasted CO2 prices
- Renewable Tax Credits
- Costs of EE programs
- Monetization of Externalities

Finally, APS evaluated each of the four scenarios under a complete set of "Low Cost Assumptions" and a complete set of "High Cost Assumptions", in which all of the major cost assumptions were set at the low values in the first case, and at the high values in the other case.

2. TEP

In the development of its IRP, TEP developed a reference case in which all coal-fired stations continue to operate and four alternative scenarios in which each of its coal-fired stations is assumed to be retired:

- Reference Case:
    - Added EE, Renewables and Short-Term Purchases cover load growth through 2017
    - 270 megawatts of natural gas-fired CTs added in 2018-2024
- Four Corners Retirement
    - 110 megawatt natural gas-fired CC added in 2016
    - 270 megawatts of natural gas-fired CTs added in 2018-2024
- Navajo Retirement:
    - 168 megawatt natural gas-fired CC added in 2017
    - 270 megawatts of natural gas-fired CTs added in 2018-2024
- San Juan Retirement
    - 340 megawatt natural gas-fired CC added in 2016
    - 270 megawatts of natural gas-fired CTs added in 2018-2024
- Springerville Retirement
    - 387 megawatt natural gas-fired CC added in 2015
    - 270 megawatts of natural gas-fired CTs added in 2018-2024

TEP evaluated each of these five scenarios using base assumptions without externalities and also with all externalities monetized. All of the cases meet or exceed the Commission's requirements for EE, Renewable Generation and Distributed Renewable Generation.

Finally, TEP evaluated each of the five cases by performing sensitivity analyses that considered high and low assumptions for the following:

- Natural Gas Prices
- Wholesale Power Prices
- Load Growth

3. UNSE

UNSE developed two cases – the Reference Case and the Combined Cycle Case:

- Reference Case:
  - Added EE, Renewables and Short-Term Purchases cover load growth through 2017
  - 110 megawatts of natural gas-fired CTs added in 2018-2024

- Combined Cycle Case:
  - Added EE, Renewables and Short-Term Purchases cover load growth through 2014
  - 150 megawatts of natural gas-fired CC added in 2015
  - 87 megawatts of natural gas-fired CTs added in 2018-2024

UNSE evaluated each of these scenarios using base assumptions without externalities and also with all externalities monetized. All of the cases meet or exceed the Commission's requirements for Renewable Generation and Distributed Renewable Generation. However, the Reference Case does not meet the Commission's requirement for Energy Efficiency.

Finally, UNSE evaluated each of the cases by performing sensitivity analyses that considered high and low assumptions for the following:

- Natural Gas Prices
- Wholesale Power Prices

4. AEPCo

In the development of its IRP, AEPCo considered only one possibility – the use of short-term market purchases to fulfill forecasted capacity shortages.

H. Environmental Considerations

1. Environmental Impacts[16]

A.A.C. R14-2-703 requires that each load-serving entity provide detailed environmental impacts for each generating unit and power purchase contract. Environmental impacts include air emission quantities (in metric tons or pounds) and rates (in quantities per mega-watt hour) for regulated air pollutants, water consumption quantities and rates, and other standards subject to current or expected future environmental regulations. The code also requires the load-serving entity to provide descriptions of programs that mitigate or manage environmental impacts and the risks and uncertainties associated with environmental impacts.

2. Current Regulations

a) National Ambient Air Quality Standards ("NAAQS")

The Clean Air Act ("CAA") established NAAQS for six pollutants: ozone, nitrogen dioxide ("NO2"), sulfur dioxide ("SO2"), particulate matter ("PM"), carbon monoxide ("CO"), and lead. These standards are set to protect public health and welfare. State Implementation Plans ("SIPs") govern how emissions from various sources within a geographical area would be limited to attain the NAAQS levels. Such plans will set maximum allowed emission limits for various sources. The CAA also requires the Environmental Protection Agency ("EPA") to periodically review those standards and adjust the NAAQS levels based on the most current scientific data.

The Arizona Department of Environmental Quality ("ADEQ") states the SIP is the cumulative record of all air pollution strategies, state statutes, state rules and local ordinances implemented under Title I of the CAA by governmental agencies within Arizona. Revisions to Arizona's SIP must be submitted to the EPA by the director of ADEQ on behalf of the governor. Once approved by EPA as published in the Federal Register the provisions contained in the SIP revision become enforceable by the federal government as well as by the appropriate governmental entities of Arizona. The cumulative and complete record of SIP revisions that have been approved by EPA and federally enforceable in Arizona is called the "applicable Arizona SIP."

The first Arizona SIP submittal was in 1972. Because there have been so many changes to federal, state and local air quality programs in the last 30 years, there is not a single definitive document that contains all of the SIP requirements.

[16] The information and documentation for the Environmental Section is compiled from information from the EPA, ADEQ, and the authors' experience.

In addition to ADEQ, there are local air planning organizations that share in the responsibility of completing SIP requirements. The Maricopa Association of Governments ("MAG") and the Pima Association of Governments ("PAG") are metropolitan planning organizations that have been delegated the responsibility to complete SIP revisions for their respective county areas.

ADEQ is in the process of posting recent SIP revisions on the Internet. However, due to the volume of information, it is expected to be a lengthy process. Hard copies of SIPs are available at the ADEQ main offices for review. SIP revisions completed by the MAG or the PAG are available at their respective offices.

b) Mercury and Air Toxics ("MATS") Rule

On December 16, 2011, the EPA signed a rule to reduce emissions of toxic air pollutants from power plants. Specifically, these mercury and air toxics standards for power plants will reduce emissions from new and existing coal and oil-fired electric utility steam generating units ("EGUs"). The MATS Rule will reduce emissions of heavy metals, including mercury ("Hg"), arsenic ("As"), chromium ("Cr"), and nickel ("Ni"); and acid gases, including hydrochloric acid ("HCl") and hydrofluoric acid ("HF"). Existing sources will have three years to comply with the rule, with the option of a one-year extension that can be granted at the discretion of the regulatory authority (ADEQ for sources located in Arizona except those on Tribal lands and EPA Region 9 for the Navajo and Four Corners generating facilities).

The requirements under the MATS Rule are as follows:

- For all existing and new coal-fired EGUs, the rule establishes numerical emission limits for mercury, PM (a surrogate for toxic non-mercury metals), and HCl (a surrogate for all toxic acid gases).
- For existing and new oil-fired EGUs, the standards establish numerical emission limits for PM (a surrogate for all toxic metals), HCl, and HF. EGUs may also show compliance with the HCl and HF limits by limiting the moisture content of their oil.
- The rule establishes alternative numeric emission standards, including SO2 (as an alternate to HCl), individual non-mercury metal air toxics (as an alternate to PM), and total non-mercury metal air toxics (as an alternate to PM) for certain subcategories of power plants.
- The standards set work practices, instead of numerical limits, to limit emissions of organic air toxics, including dioxin/furan, from existing and new coal- and oil-fired power plants. Because dioxins and furans form as a result of inefficient combustion, the work practice standards require an annual performance test program for each unit that includes inspection, adjustment, and/or maintenance and repairs to ensure optimal combustion.

- The standards also set work practices for limited-use oil-fired EGUs in the continental U.S.
- A range of widely available and economically feasible technologies, practices and compliance strategies are available to power plants to meet the emission limits, including wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and fabric filters.
- The revisions to the New Source Performance Standards ("NSPS") for fossil-fuel-fired EGUs include revised numerical emission limits for PM, SO2, and NOX.

EPA states these new standards will prevent up to thirty-five premature deaths in Arizona while creating up to $290 million in health benefits in 2016 (EPA website).

The following power plants in Arizona and New Mexico will be affected by the MATS Rule:

- Apache Station (AEPCo)
- Cholla (APS)
- Coronado (SRP)
- Four Corners (APS)
- Wilson Sundt (TEP)
- Navajo (SRP)
- Ocotillo (APS)
- Saguaro (APS)
- San Juan
- Springerville (TEP)
- Yucca (APS)

c) Toxics Release Inventory ("TRI") Program, Hydrogen Sulfide: Lifting of Administrative Stay

EPA is taking an important step to provide communities with additional information about toxic chemicals being released to the environment. The EPA is announcing that it is lifting the Administrative Stay of the Toxics Release Inventory reporting requirements for hydrogen sulfide. The Agency's review of hydrogen sulfide is part of its efforts to examine the scope of TRI chemical coverage and provide communities with more complete information on toxic chemical releases.

This action will be effective for the 2012 TRI reporting year, with the first 2012 TRI reports due from facilities by July 1, 2013.

d) Prevention of Significant Deterioration ("PSD") and Title V Operating Permit Greenhouse Gas ("GHG") Tailoring Rule Step 3 and GHG Plantwide Applicability Limits

Greenhouse gas emissions from the largest stationary sources will, for the first time, be covered by the Prevention of Significant Deterioration and Title V Operating Permit Programs. These permitting programs, required under the CAA, are proven tools for protecting air quality and the same tools will be used to reduce GHG emissions. But the thresholds established in the CAA for determining when emissions of pollutants make a source subject to these permitting programs, 100 and 250 tons per year, were based on traditional pollutants and were not designed to be applied to GHGs.

EPA's GHG Tailoring Rule, issued in May 2010, established a common sense approach to permitting GHG emissions under PSD and Title V. The rule set initial emission thresholds - known as Steps 1 and 2 of the Tailoring Rule - for PSD and Title V permitting based on carbon dioxide equivalent ("CO2e") emissions. EPA's Step 3 of the GHG Tailoring Rule, issued on June 29, 2012, continues to focus GHG permitting on the largest emitters by retaining the permitting thresholds that were established in Steps 1 and 2. In addition, the Step 3 rule improves the usefulness of plant-wide applicability limitations ("PALs") by allowing GHG PALs to be established on CO2e emissions, in addition to the already available mass emissions PALs, and to use the CO2e-based applicability thresholds for GHGs provided in the "subject to regulation" definition in setting the PAL on a CO2e basis. The rule also revises the PAL regulations to allow a source that emits or has the potential to emit at least 100,000 tons per year of CO2e, but that has minor source emissions of all other regulated NSR pollutants, to apply for a GHG PAL while still maintaining its minor source status.

State and local permitting authorities have long-standing experience working together with owners and operators of industrial facilities, and EPA believes they are best suited to issue CAA permits to sources of GHG emissions. EPA is working closely with permitting authorities to ensure that the transition to GHG permitting runs seamlessly. The following table lists contacts for Arizona Permits.

Area	Type of Permit	Permitting Authority	Regulations
All of Arizona except Maricopa County, Pima County, Pinal County and Indian Country	nonattainment minor NSR	Air Quality Division Arizona Department of Environmental Quality 1110 W. Washington St. Phoenix, AZ 85007 602 207-2308	Arizona State Implementation Plan

All of Arizona except Maricopa County, Pima County, Pinal County and Indian Country	PSD	Air Quality Division Arizona Department of Environmental Quality 1110 W. Washington St. Phoenix, AZ 85007 602 207-2308	Arizona State Implementation Plan for all pollutants except for PM_{10} which is subject to 40 CFR 52.21
Maricopa County	PSD nonattainment minor NSR	Maricopa County Environmental Services Department Air Quality Division 1001 N. Central Ave., Suite 200 Phoenix, AZ 85004 (602) 506-6010	40 CFR 52.21
Pima County	PSD nonattainment minor NSR	Pima County Department of Environmental Quality 150 W. Congress Street Tucson, AZ 85701-1332 (520) 740-3340	40 CFR 52.21
Pinal County	PSD nonattainment minor NSR	Pinal County Air Quality Control District P.O. Box 987 Florence, AZ 85232 520-866-6929	Arizona State Implementation Plan
Indian Country	PSD	Air Division U.S. EPA Region 9 75 Hawthorne Street San Francisco, CA, 94105 (415) 947-8021	40 CFR 52.21

On June 29, 2012 the EPA issued a final rule that does not revise the GHG permitting thresholds that were established in Step 1 and Step 2 of the GHG Tailoring Rule. These emissions thresholds determine when CAA permits under the New Source Review PSD and Title V Operating Permit programs are required for new and existing industrial facilities. This action became effective on August 13, 2012.

This is the third step in EPA's phased-in approach to GHG permitting under the CAA. Currently, new facilities with GHG emissions of at least 100,000 tons per year ("tpy") CO2e and existing facilities with at least 100,000 tpy CO2e making changes that would increase GHG emissions by at least 75,000 tpy CO2e are required to obtain PSD permits. Facilities that must obtain a PSD permit anyway, to cover other regulated pollutants, must also address GHG emissions increases of 75,000 tpy CO2e or more. New and existing sources with GHG emissions above 100,000 tpy CO2e must also obtain operating permits.

e) Final Action to Address Regional Haze

On May 30, 2012, EPA finalized a rule allowing the trading programs in the Cross-State Air Pollution Rule ("CSAPR") to serve as an alternative to determining source-by-source Best Available Retrofit Technology ("BART"). This rule provides that states in the CSAPR region can substitute participation in CSAPR for source-specific BART for sulfur dioxide and/or nitrogen oxides emissions from power plants. EPA also finalized a limited disapproval of certain states' plans that previously relied on the Clean Air Interstate Rule ("CAIR") to improve visibility and substituted a Federal Implementation Plan ("FIP") that relies on CSAPR. Although Arizona is <u>not</u> in the CSAPR region, EPA has issued a final Regional Haze FIP for the state of Arizona that will require costly additional emission controls at Coronado, Cholla and Apache generating stations, has issued a proposed Regional Haze FIP for Four Corners that would require costly additional emission controls, and has indicated that it will be issuing a proposed Regional Haze FIP for Navajo generating station in December of 2012, which could also impose costly additional emission controls.

3. Expected Regulations

a) Coal Combustion Residuals ("CCRs") – Proposed Rule

Coal Combustion Residuals, often referred to as coal ash, are currently considered exempt wastes under an amendment to the Resource Conservation and Recovery Act ("RCRA"). CCRs are residues from the combustion of coal in power plants and captured by pollution control technologies, like scrubbers. Potential environmental concerns from coal ash pertain to pollution from impoundment and landfills leaching into ground water and structural failures of impoundments, like that which occurred at the Tennessee Valley Authority's plant in Kingston, Tennessee. The need for national management criteria was emphasized by the December 2008 spill of CCRs from a surface impoundment near Kingston, Tennessee. The tragic spill flooded more than 300 acres of land with CCRs and flowed into the Emory and Clinch rivers.

EPA is proposing to regulate coal ash for the first time to address the risks from the disposal of the wastes generated by electric utilities and independent power producers. EPA is considering two possible options for the management of coal ash for public comment. Both options fall under RCRA. Under the first proposal, EPA would list these residuals as special wastes subject to regulation under subtitle C of RCRA, when destined for disposal in landfills or surface impoundments. Under the second proposal, EPA would regulate coal ash under subtitle D of RCRA, the section for non-hazardous wastes. EPA considers each proposal to have its advantages and disadvantages, and includes benefits which should be considered in the public comment period. Under both alternatives, EPA is proposing to establish dam safety requirements to address the structural integrity of surface impoundments to prevent catastrophic releases.

b) Implementation of the New Source Review ("NSR") Program for Particulate Matter Less Than 2.5 Micrometers ("PM2.5"): Amendment to the Definition "Regulated NSR Pollutant" Concerning Condensable Particulate Matter ("PM")

On March 12, 2012, the EPA proposed to amend its rules for the CAA New Source Review ("NSR") permitting program regarding the definition of "regulated NSR pollutant." This proposal would clarify when condensable PM should be measured for purposes of NSR permitting. Condensable PM is not directly measured as a solid or liquid at the stack. Instead gaseous emissions such as sulfuric acid mist, ammonium sulfate, and certain metal vapors condense upon cooling and dilution in the ambient air to form solid or liquid particles following discharge from the stack.

This proposed rule would continue to require condensable PM to be included as part of the emissions measurements for regulation of PM2.5 and PM less than 10 micrometers in diameter ("PM10"). When an industrial facility applies for a NSR permit to construct or modify an emissions source, it must show that it does not interfere with an area's ability to meet or maintain the national air quality standards. EPA has established NAAQS for PM2.5 and PM10. Condensable PM emissions contribute to monitored levels of PM2.5 and PM10. The impact of those emissions on monitored air quality levels of PM2.5 and PM10 must be considered as part of a source's permit.

This proposed action would remove the inadvertent requirement in the 2008 PM2.5 NSR Implementation Rule, that measurements of condensable PM emissions be included as part of the measurement and regulation of "PM emissions."

The terminology "PM emissions" includes particles that are significantly larger than either PM2.5 or PM10, and is used primarily to measure compliance with the EPA's existing NSPS for PM. The amount of "PM emissions" that a source has the potential to emit is not intended to be used for determining whether an area can attain or maintain either of the existing standards for particle pollution.

c) Carbon Pollution Standard for New Power Plants – Settlement Agreements to Address GHG Emissions from EGUs and Refineries

The EPA entered into two proposed settlement agreements to issue rules that will regulate GHG emissions from certain fossil fuel-fired power plants and refineries. For natural gas, oil, and coal-fired EGUs: these rules would establish NSPS for new and modified EGUs and emission guidelines for existing EGUs. Under the agreement with the States of New York, California, Connecticut, Delaware, Maine, New Mexico, Oregon, Rhode Island, Vermont, Washington, and Massachusetts; the District of Columbia and the City of New York; Natural Resources Defense Council ("NRDC"), Sierra Club, and Environmental Defense Fund ("EDF"), EPA would commit to issuing proposed regulations by September 30, 2011 and final regulations by May 26, 2012. However litigation and public involvement has continued to stall final regulations from being developed.

EPA is coordinating this action on GHGs with a number of other required regulatory actions for traditional pollutants including the Utility MACT rule, the Transport Rule and NSPS for criteria pollutants. Together, EGUs will be able to develop strategies to reduce all pollutants in a more efficient and cost-effective way than addressing these pollutants separately.

d) Proposed Carbon Pollution Standard for New Power Plants

On March 27, 2012, the EPA proposed a Carbon Pollution Standard for New Power Plants. This step under the CAA would, for the first time, set national limits on the amount of carbon pollution power plants built in the future can emit.

EPA's proposed standard reflects the ongoing trend in the power sector to build cleaner plants that take advantage of American-made technologies. The EPA's proposal, which does not apply to plants currently operating or newly permitted plants that begin construction over the next twelve months, is flexible and would help minimize carbon pollution through the deployment of the same types of modern technologies and steps that power companies are already taking to build the next generation of power plants. EPA's proposal would ensure that this progress toward a cleaner, safer and more modern power sector continues.

The proposed rule would apply only to new fossil-fuel-fired EGUs. For purposes of this rule, fossil-fuel-fired EGUs include fossil-fuel-fired boilers, integrated gasification combined cycle ("IGCC") units and stationary combined cycle turbine units that generate electricity for sale and are larger than 25 megawatts (MW). EPA is proposing that new fossil-fuel-fired power plants meet an output-based standard of 1,000 pounds of CO2 per megawatt-hour (lb CO2/MWh gross).

I. Review of IRPs for Environmental Impacts Requirements

1. Existing Air Emission Environmental Impacts

A.A.C. R14-2-703(B)(1)(p) requires the load-serving entity to provide for each generating unit and purchased power contract for the previous calendar year a description of the environmental impacts, including air emissions quantities (tons/lbs) and rates (/MWh) for CO2, nitrogen oxides (NOX), SO2, Hg, particulates (PM10 and PM2.5), and other air emissions subject to current or expected regulation.

a) APS

APS' 2011 emissions rates and quantities are located in a supplemental document of the IRP called "Historical Data." The requirements for A.A.C. R14-2-703(B)(1)(p)are in Tab V.

APS does not compare its historical rates and quantities to current or expected environmental regulations in the Historical Data document.

b) AEPCo

AEPCo provides 2011 air emissions for CO2, total PM, SO2, Hg, and NOx for their Apache Generating Station in the IRP. AEPCo does not compare these emissions to current regulations or anticipated regulations. As indicated in its IRP, AEPCo did supply additional information concerning potential EPA regulatory actions that could impact its Apache Station on October 22, 2012 as a compliance item in relation to Decision No. 72055 in Docket No. E-01773A-09-0472.

c) TEP

TEP provides 2011 air emissions data for SO2, NOx, CO2, PM, and coal ash. The historical data for 2011 is in a supplement to the Final IRP entitled "Historical Data.". TEP does not compare the historical rates and quantities to existing regulations.

d) UNSE

UNSE provides 2011 air emissions data for SO2, NOx, CO2, PM, and Hg. The historical data for 2011 is in the document "IRP Historical Data", a supplement to the Final IRP. UNSE does not compare the historical rates and quantities to existing regulations.

2. Existing Water Consumption Environmental Impacts

A.A.C. R14-2-703(B)(1)(q) requires for each generating unit and purchased power contract for the previous calendar year a description of the water consumption quantities and rates.

a) APS

APS' 2011 water consumption rates and quantities are located in a supplemental document of the IRP called "Historical Data." The requirements for A.A.C. R14-2-703(B)(1)(q) are in Tab V.

b) AEPCo

AEPCo provides the following statement regarding water consumption:

Information is not available regarding water consumption per generating unit. For all units [at Apache], an estimated total of 4,550 acre-feet of water was used in 2011 based on metered production well output.

c) TEP

TEP provides water consumption quantities and rates for 2011. The historical data for 2011 is in the "Historical Data" supplement to the Final IRP. TEP does not compare the historical rates and quantities to existing regulations.

d) UNSE

UNSE provides water consumption quantities and rates for 2011. The historical data for 2011 is in the "IRP Historical Data", supplement to the Final IRP. UNSE does not compare the historical rates and quantities to existing regulations.

3. Existing Coal Ash Environmental Impacts

A.A.C. R14-2-703(B)(1)(r) requires for the previous calendar year a description of the tons of coal ash produced per generating unit.

a) APS

APS' 2011 tons of coal ash produced per generating unit table is located in the "Historical Data" supplement of the IRP. The requirements for R14-2-703(B)(1)(r) are in Tab V. APS does not compare these values to existing regulations.

b) AEPCo

AEPCo provides the tons of coal ash produced per generating unit in 2011 in its IRP. AEPCo does not compare these values to existing regulations.

c) TEP

TEP provides the tons of coal ash produced per generating unit in 2011 in its IRP. The historical data for 2011 is in the "Historical Data" supplement to the Final IRP. TEP does not compare these values to existing regulations.

d) UNSE

UNSE provides the tons of coal ash produced per generating unit in 2011 in its IRP. The historical data for 2011 is in the "IRP Historical Data" supplement to the Final IRP. UNSE does not compare these values to existing regulations.

4. Projected Environmental Impacts

A.A.C. R14-2-703(D)(1)(a) requires projected data for each of the items listed in A.A.C. R14-2-703(B)(1), for 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. This includes air emissions, water consumption, and coal ash. Applicable sections in A.A.C. R14-2-703(B)(1) include subsections (B)(1)(p) - (r).

a) APS

Projected data for each generating unit and purchased power resource is provided in the attachments referenced in Table 7 of the IRP. APS reports for each unit CO2 emissions, CO emissions, volatile organic compounds ("VOCs"), NOx emissions, SO2 emissions, Hg emissions, PM10 emissions, coal fly ash collected, coal fly ash bottom collected, and water consumption.

In response to A.A.C. R14-2-703(D)(1)(e)(iii), APS discusses the potential possibility of discontinuing, decommissioning, or mothballing, or derating a power plant due to federal regulations including the CAA Regional Haze rules and regulations governing the disposal of CCRs, and strict emissions limitations for mercury and other hazardous air pollutants. The CAA Regional Haze rules require certain plants (including the Four Corners Plant, of which APS holds an ownership interest) to install BART to reduce haze in national parks and wilderness areas.

b) AEPCo

To comply with A.A.C. R14-2-703(B)(1)(p) as it relates to subsection D(1)(a), AEPCo provides an emissions forecast based on long-range load forecast data and past emissions performance. The emissions performance data were derived from 2011 actual measured emissions, where available, and emission factors developed for specific generating unit designs and fuels. AEPCo has no emissions data available for purchase power contracts.

Insofar as A.A.C. R14-2-703(B)(1)(q) relates to subsection D(1)(a), AEPCo states that it does not expect the amount of water usage to significantly increase as it is focusing on increasing process water reuse plant-wide as an alternative to using fresh water.

Insofar as A.A.C. R14-2-703(B)(1)(r) relates to subsection D(1)(a), AEPCo does not provide a forecast for coal ash production. AEPCo is conducting a study on the new rate designs and usage patterns and the associated environmental impacts including coal ash. The Draft Report of the Study is complete but has not been released.

c) TEP

Projected environmental impacts for each plant are provided in the supplemental workbook “Reference Case (Base) – Confidential”. TEP provides 16 years (2012 – 2027) of projections for CO2, NOx, SO2, PM, and Hg quantities and rates. TEP also provides projections for water and coal ash quantities and rates.

In Chapter 8, TEP discusses current and expected regulations and the effect they may pose on the utility. These regulations include Regional Haze, Utility MACT Rule, NAAQS, mandatory reporting of GHGs, regulation of GHGs under CAA, Federal GHG legislation, and CCRs. After reviewing the EPA MACT Rule (i.e. National Emission Standards for Hazardous Air Pollutants Rule) and the MATS Rule as described previously in this document, the IRP should reference the “MATS Rule” and not the “MACT Rule.” The MACT Rule does not pertain to power plants.

d) UNSE

Projected environmental impacts for each plant are provided in the supplemental workbook “UNSE Reference Case (Base) – Confidential”. UNSE provides 16 years (2012 – 2027) of projections for CO2, NOx, SO2, PM, and Hg. UNSE does not provide air emission rates.

In the same location as the emissions data, UNSE provides water consumption quantities forecast. UNSE does not provide water consumption rates.

5. Costs of Compliance - Existing and Expected Environmental Regulations

A.A.C. R14-2-703(D)(1)(h) requires the load serving entity to provide a 15-year resource plan, providing for each year cost analyses and cost projections, including the cost of compliance with existing and expected environmental regulations.

a) APS

In response to A.A.C. R14-2-703(D)(1)(h), APS provides cost analyses and projections in the IRP attachment D.10. The cost of existing and expected environmental regulations is embedded within the capital and operations and maintenance ("O&M") figures.

b) AEPCo

In response to A.A.C. R14-2-703(D)(1)(h), AEPCo discusses the effect of the proposed MATS Rule and NAAQS and, specifically, the new one-hour standard for SO2.

AEPCo is conducting a study on the new rate designs and usage patterns and the associated environmental impacts including known or impending regulations. The Draft Report of the Study is complete but has not been released.

c) TEP

The TEP IRP index lists the requirements of A.A.C. R14-2-703(D)(1)(h)in the Financial Report of the Reference Case (Base). The Environmental Capital Expenditures are included in this analysis. A discussion of the existing and expected environmental regulations is not included in this supplemental workbook, however it is included in the main IRP document.

d) UNSE

The UNSE IRP index lists the requirements for A.A.C. R14-2-703(D)(1)(h) in the Financial Report of the Reference Case (Base). The projected Environmental Capital Expenditures from 2012-2027 are $0, however there are discussions on costs for renewable energy in the IRP Chapters 9 and 10, Renewable Resources and Distributed Generation Resources, respectively. A discussion of the existing and expected environmental regulations is not included in this supplemental workbook; however it is included in the main IRP document.

J. Environmental Impacts Mitigation and Management

A.A.C. R14-2-703(D)(14) requires the load serving entity to provide descriptions of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure the expected reductions in environmental impacts, including air emissions, solid waste, and water consumption, attributable to the program or measure.

A.A.C. R14-2-703(D)(17) requires a plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

1. APS

Table 23, 24, and 25 of APS's IRP provides estimates of 2012 energy efficiency environmental impacts reductions by energy efficiency program. Table 24 and 25 summarize APS's Peak Pricing programs.

In response to A.A.C. R14-2-703(D)(17), APS describes in detail the plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

The APS response to A.A.C. R14-2-703(D)(17) provides information on the following issues and associated regulations in Table 32 (posted below).

Issue	Governing Regulations	IRP Section
Air Emissions	Clean Air Act Regulations 1. Visibility Protection–Regional Haze (BART) 2. Hazardous Air Pollutants – (MATS) 3. National Ambient Air Quality Standards (NAAQS) 4. Climate Change and GHG Regulations	A
Solid Waste	Resource Conservation and Recovery Act (RCRA): Coal Combustion Residuals	B
Other Factors	Clean Water Act Regulations: Section 316(b) Cooling Water Intake Structures	C
Water Consumption	Voluntary APS participation in various state and local initiatives	D

2. AEPCo

In response to A.A.C R14-2-703(D)(14)(d), AEPCo states that, because AEPCo supplies no power at retail and, therefore, has no customers for demand management programs or measures, none are included in AEPCo's plan.

In response to A.A.C R14-2-703(D)(17), AEPCo describes how it manages water consumption and air emissions environmental impacts but does not describe solid waste or other environmental factors.

3. TEP

TEP provides detailed descriptions of its energy efficiency programs in Chapter 11 of the IRP. TEP, as a result of Data Requests subsequent to the IRP filing, has provided its expected reductions in environmental impacts as required by A.A.C R14-2-703(D)(14)(d). The Table 5.1.g-1 below, extracted from TEP Data Request DPU 5.1, shows TEP's expected reductions in environmental impacts as a result of its EE program.

Table 5.1.g-1

EE Program Name	SO_X (metric tons)	NO_X (metric tons)	CO_2 (metric tons)	PM (metric tons)	Water (million gallons)
Efficient Products	405	467	345,592	15.9	231
Appliance Recycling	45	51	38,117	1.8	25
Residential New Construction	81	94	69,491	3.2	46
Existing Homes and Audit Direct Install	56	64	47,398	2.2	32
Shade Tree	20	23	17,186	0.8	11
Low Income Weatherization	4	5	3,786	0.2	3
Multi-Family	8	10	7,099	0.3	5
C&I Comprehensive Program	456	525	389,060	17.9	353
Small Business Direct Install	173	200	147,941	6.8	99
Commercial New Construction	41	47	34,766	1.6	23
Bid for Efficiency - Pilot	25	29	21,362	1.0	14
Retro-Commissioning	11	13	9,710	0.4	6
Schools Facilities	9	10	7,758	0.4	5
Home Energy Reports	17	20	14,565	0.7	10
Behavioral Comprehensive Program	68	78	57,755	2.7	39
Portfolio Total	**1,419**	**1,636**	**1,211,584**	**151**	**2186**

4. UNSE

UNSE provides detailed descriptions of its energy efficiency programs in Chapter 8 of the IRP. UNS, as a result of Data Requests subsequent to the IRP filing, has provided its expected reductions in environmental impacts as required by A.A.C R14-2-703(D)(14)(d). The Table 5.1.h-1 below, extracted from UNSE Data Request DPU 5.1, shows UNSE's expected reductions in environmental impacts as a result of its EE program.

Table 5.1.h-1

EE Program Name	SO_X (metric tons)	NO_X (metric tons)	CO_2 (metric tons)	PM (metric tons)	Water (million gallons)
Efficient Products	0.13	3.67	26,459	3.00	22.76
Appliance Recycling	0.02	0.52	3,766	0.43	3.24
Residential New Construction	0.02	0.51	3,651	0.41	3.14
Existing Homes and Audit Direct Install	0.02	0.51	3,668	0.42	3.15
Shade Tree	0.00	0.11	760	0.09	0.65
Low Income Weatherization	0.01	0.15	1,084	0.12	0.93
Multi-Family	0.01	0.18	1,294	0.15	1.11
C&I Facilities	0.06	1.60	11,512	1.30	9.90
Bid for Efficiency - Pilot	0.03	1.00	7,207	0.82	6.20
Retro-Commissioning	0.04	1.12	8,107	0.92	6.97
Schools Facilities	0.03	0.87	6,259	0.71	5.38
Home Energy Reports	0.01	0.35	2,534	0.29	2.18
Behavioral Comprehensive Program	0.04	1.06	7,654	0.87	6.58
Portfolio Total	**0.40**	**11.64**	**83,953**	**9.52**	**72.21**

K. Environmental Impacts Risks and Uncertainties

A.A.C. R14-2-703(E)(1) requires analyses to identify and assess errors, risks, and uncertainties completed using methods such as sensitivity analysis and probabilistic analysis for the costs of compliance with existing and expected environmental regulations (A.A.C. R14-2-703(E)(1)(d)) and any analysis by the load-serving entity in anticipation of potential new or enhanced environmental regulations (A.A.C. R14-2-703(E)(1)(e)).

A.A.C. R14-2-703(F)(3) requires the 15-year plan to address the adverse environmental impacts of power production. A.A.C. R14-2-703(F)(7) requires the plan to provide how the utility will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors.

1. APS

APS's IRP discusses the costs of compliance with existing environmental regulations (A.A.C. R14-2-703(E)(1)(d)) qualitatively but does not quantify the actual costs. The IRP provides a discussion on EPA's RCRA Subtitle C Proposal. Proposed regulations for RCRA include two different scenarios – Subtitle C (hazardous) and Subtitle D (non-hazardous). Under the Subtitle C option, EPA is proposing to regulate CCRs as a hazardous waste, which is the most stringent and costly option available to EPA under federal law.

APS discusses analyses in anticipation of potential new or enhanced environmental regulations in response to A.A.C. R14-2-703(E)(1)(d). The analyses are discussed in more detail in response to A.A.C. R14-2-703(D)(17). Appendix A of the APS IRP contains an *Analysis of Uncertainty Pertaining to Greenhouse Gas Regulations* that was completed by Charles River Associates.

APS addresses the adverse environmental impacts of power production in response to A.A.C. R14-2-703(F)(3) and describes how the utility will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors in response to A.A.C. R14-2-703(F)(7). The management of uncertainty and risks is also described in response to A.A.C. R14-2-703(F)(1); APS performed a rigorous series of analytics on all of the potential portfolios under consideration.

In creating its 2012 Integrated Resource Plan, APS analyzed four 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; Net Present Value ("NPV") of revenue requirements; cumulative capital expenditures; carbon emissions; water use; and, portfolio diversity. APS then stressed several key input variables, such as natural gas prices, carbon costs, energy efficiency costs, tax credits, and externalities, to determine the robustness of each portfolio (sensitivity analytics). Finally, APS combined several variables into low cost and high cost cases to see plausible boundaries on revenue requirements for each portfolio (scenario analytics). The results of the analytics for each portfolio can be found in the IRP at:

Attachment F.1(a) – Loads and Resources Tables and Energy Mixes
Attachment F.1(b) – Analysis of Four Portfolios
Attachment F.1(c) – Sensitivity Analyses
Attachment F.1(d) – Scenario Analyses

2. AEPCo

An environmental study has been completed but is only in Draft format for internal review. The study addresses the requirements of A.A.C. R14-2-703(E)(1)(d) in more detail. AEPCo does discuss cost for compliance for SO2 emissions including the anticipated NAAQS one-hour standard for SO2, carbon tax, and the proposed MATS Rule.

In response to uncertainties associated with potential new or enhanced regulations (A.A.C. R14-2-703(E)(1)(e)), AEPCo describes its anticipation of the MATS Rule, revised primary and secondary ozone NAAQS, EPA's intent to list hydrogen sulfide as a hazardous air pollutant, and EPA's upcoming Federal Implementation Plan for regional haze in Arizona. AEPCo anticipates a final rule on the management of CCRs at the end of 2012 under RCRA. AEPCo also anticipates state level programs and regulations from ADEQ including a minor New Source Review program that would increase the review of minor changes at facilities such as AEPCo.

AEPCo offers a "mission statement" relating to A.A.C. R14-2-703(F)(3) to address adverse environmental impacts of power production.

In response to A.A.C. R14-2-703(F)(7), an environmental study has been completed but is only in Draft format for internal review. The study is expected to address the requirements in more detail. AEPCo filed the study with the Commission on October 22, 2012 in Docket No. E-01773A-09-0472.

3. TEP

The TEP IRP index lists the information required by A.A.C. R14-2-703(E)(1)(d) in the IRP "Environmental Regulations, Chapter 8." In Chapter 8, the IRP discusses its plans for compliance for environmental impacts including the FIP for Regional Haze, [MACT] Rule, GHG regulations, New Mexico Cap-and-Trade Regulations, and coal combustion residuals all qualitatively. The IRP discusses carbon price assumptions quantitatively including projections of carbon emissions prices per ton through 2027. This also meets the requirements for A.A.C. R14-2-703(E)(1)(e).

The TEP IRP index lists the information required by A.A.C. R14-2-703(E)(1)(e) in the IRP "Reference Case Assumptions, Chapter 16." This should be "Modeling Assumptions, Sensitivities and Scenarios, Chapter 16" instead. This chapter also meets the requirements of A.A.C. R14-2-703(E)(1)(d). This chapter forecasts the price of natural gas, wholesale power, delivered coal, and emissions and their effect on TEP.

4. UNSE

The UNSE IRP index lists the information required by A.A.C. R14-2-703(E)(1)(d) and (e) in the IRP "Reference Case Assumptions, Chapter 16." However, there is no Chapter 16 in the IRP and the index should list Chapter 12 instead.

The UNSE IRP provides the information required by A.A.C. R14-2-703(F)(3) and (7) in "Integrated Resource Planning Results, Chapter 14." UNSE developed a 15-year plan that addresses the adverse environmental impacts of power production and how UNSE plans to manage uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors.

L. Conclusions on Environmental Issues

1. Utilities' IRPs Compliance with Arizona Administrative Code

The load-serving entities in Arizona are required to submit IRPs according to A.A.C. R14-2-703. The four load-serving entities' IRPs that have been reviewed in this report have met these criteria to varying degrees. While each entity has provided information for each criterion regarding environmental impacts, they provide varying amounts of detailed information regarding the existing and projected environmental impacts. For example, there could be more comparison between existing regulations and historical emission rates, water consumptions, and other regulated environmental impacts. However, the utilities do a fairly good job of describing proposed environmental regulations, but only marginally perform thorough quantitative emission reduction analyses expected from new management technologies and then only from an over-all expected benefit. There is no discussion of percentage saturation expected, or needed, to achieve the results provided.

From reviewing each of the load-serving entities' IRPs, the following conclusions can be made.

- All utilities may benefit from comparing their historical data to existing regulations for emissions and other environmental impacts.
- All utilities may benefit from providing quantitative projections of reduced emissions and other environmental impacts from new environmental management technologies.
- TEP and UNSE should review their indices, because there are mislabeled items (this is noted in the previous sections).
- AEPCo's environmental study was filed with the Commission on October 22, 2012 in Docket No. E-01773A-09-0472.
- UNSE should clarify the Environmental Capital Expenditure projection of $0 in its Financial Report, but UNSE provides costs for renewable resources and distributed generation in the IRP.

2. Utilities' Compliance with Expected Environmental Regulations

The four load-serving entities do a good job of discussing expected environmental regulations and management technologies. AEPCo is conducting a study that includes upcoming environmental impacts that is expected to be completed on September 30, 2012. AEPCo should supplement its IRP with this information. However, AEPCo does provide qualitative discussions on upcoming regulations and their effects on the utility. APS, TEP, and UNSE also discuss how their utilities will be affected by proposed environmental regulations as well as the associated risks and uncertainties. All four utilities could discuss how their proposed management technologies will quantitatively reduce emissions and other impacts. TEP should review the section in its IRP that discusses the MACT Rule, because it should discuss the MATS Rule. The MACT Rule does not pertain to power plants. In conclusion, the utilities are aware of upcoming regulations and the needed improvements to meet these regulations including new particulate emission requirements and mercury and air toxics standards.

M. Transmission Considerations

The transmission requirements within the IRP process of the Commission stipulates that each load-serving entity will provide "[a]n 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 [("BTA")] decision regarding the adequacy of transmission facilities in Arizona."[17] The most recently completed BTA is for the period 2010-2019. Currently, the 7th Biennial Transmission Assessment is in the process of public meetings and review.[18]

Each of the four load-serving entities, as well as SRP, make an annual transmission filing with the Commission. These filings (along with those of other transmission providers in Arizona) are assessed biennially by the Commission, most recently in the 6th BTA. In addition, transmission needs must be filed as a part of each utility'IRP filing.s As a result of variables discussed above such as economic outlook, regulatory frameworks, etc., the plans analyzed in the 6th BTA, the information filed in annual transmission plans, and information provided in the respective IRP's are not totally consistent. However, these variations in plans may be expected given the regulatory uncertainties existing with EPA regulations on power plant emissions affecting decisions on new resources and the economic downturn of the last four years. This is evidenced by the delay in constructing a number of lines or increasing the capacity of certain lines. Each of the four load-serving entities fully meets the filing requirements of the IRP.

The transmission system within Arizona is a robust and reliable system due to the significant planning processes in effect. The BTA, the annual transmission filings to the Commission and the regional planning processes provide assurances the backbone of the transmission system continues to provide safe and reliable transmission of power within and "wheeled" throughout Arizona. In-depth review of a utility's transmission plans or a specific transmission project can be accessed by visiting the BTA report or the annual transmission plans filed with the Commission.

1. General Transmission Recommendations

The current transmission analysis and policy provisions of the Commission provide a comprehensive and robust assessment of transmission current needs and future expansion needs. It is recommended the transmission planning continue with the BTA process and the annual filings of transmission plans by each utility. It is also recommended that the

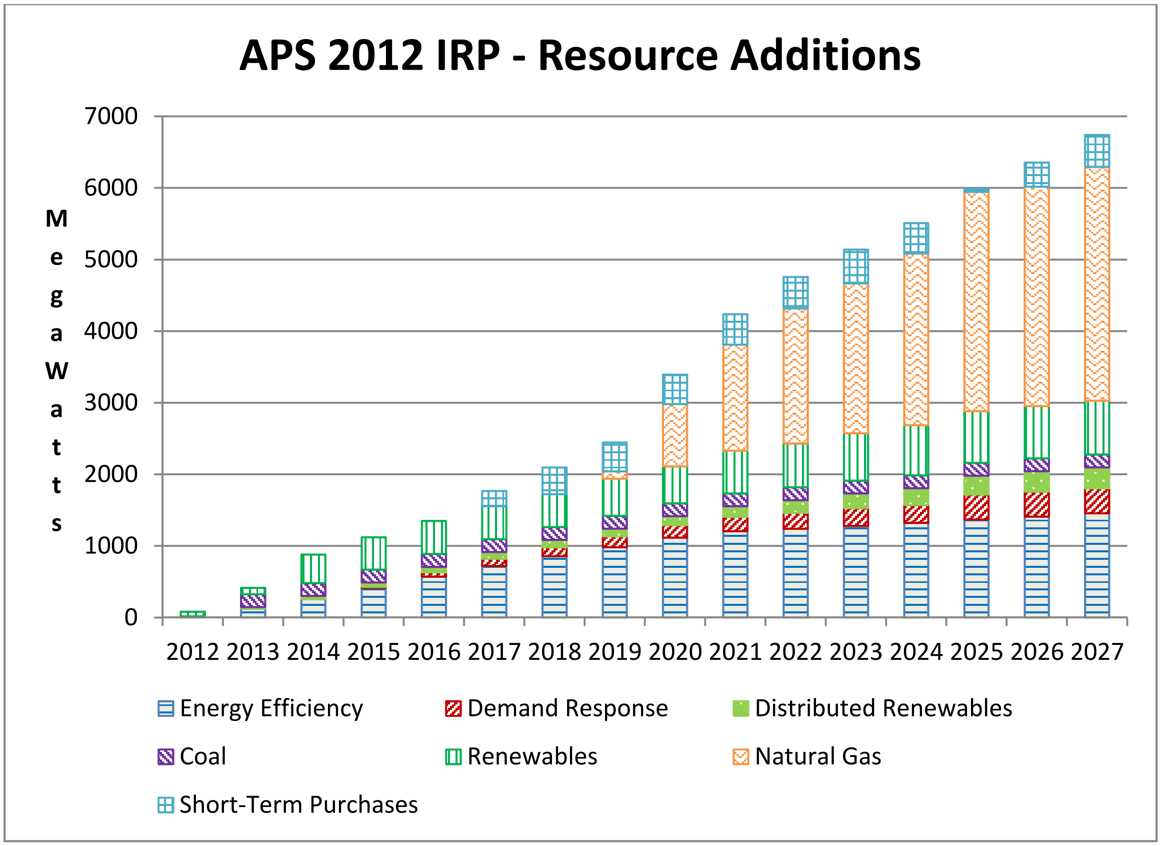
[17] *See* A.A.C. R14-2-703(D)(1)(g).
[18] *See* Docket No. E-00000D-11-0017.

results of each BTA continue to play a prominent role in the utility's filing of its IRP along with the annual filing which can and should be utilized to modify any of the BTA projects as economic or load growth dictates.

N. The 2012 Integrated Resource Plans

1. APS

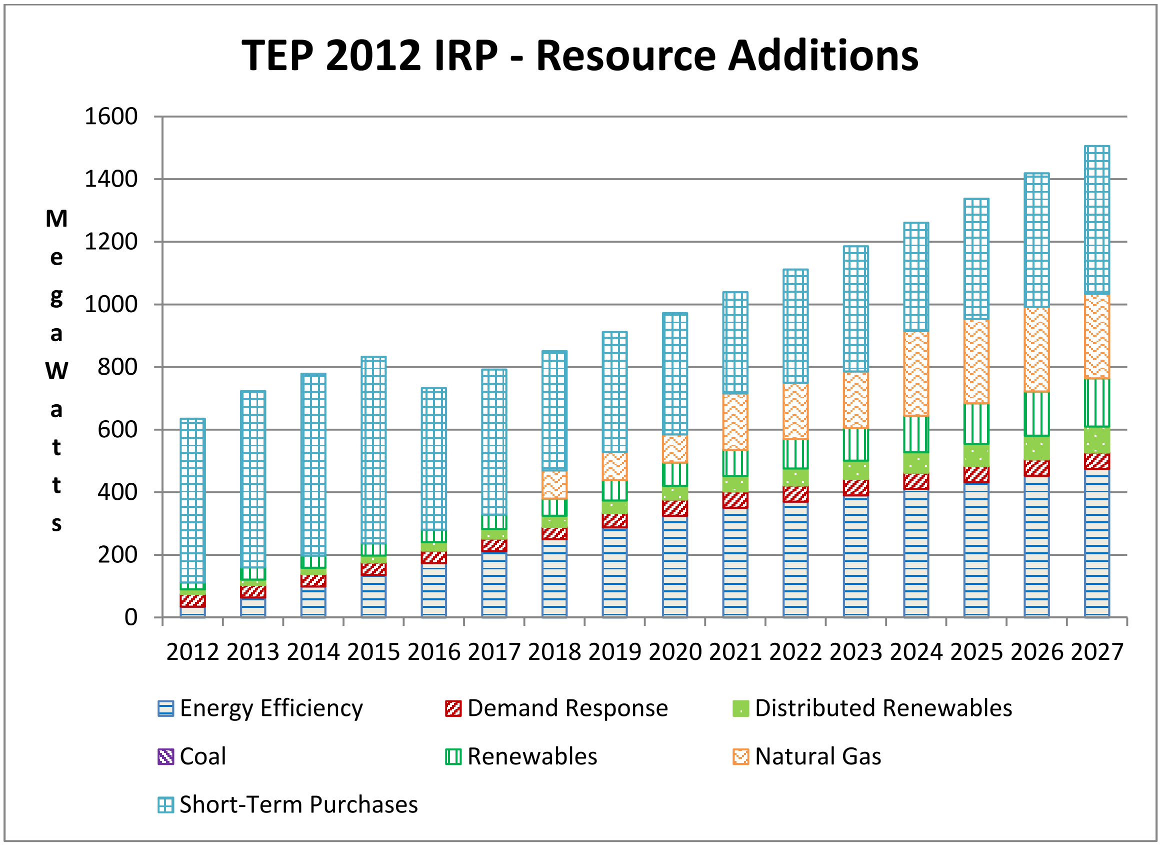
The following chart displays the resource additions selected by APS in its 2012 IRP, based on contribution to system peak demand:



APS plans to add EE programs and DR programs sufficient to meet the Commission's EE requirement, utility-scale renewable generation sufficient to meet the Commission's RE requirement, and distributed renewable generation sufficient to meet the Commission's distributed renewable energy requirement. The IRP includes the Four Corners plan to retire Four Corners Units 1-3 and acquire SCE's interest in Four Corners Units 4 and 5, resulting in a net increase of 179 megawatts of coal-fired capacity. Natural gas-fired combustion turbines and combined cycle facilities are added beginning in 2019, and short-term market purchases are added in 2017 through 2026.

2. TEP

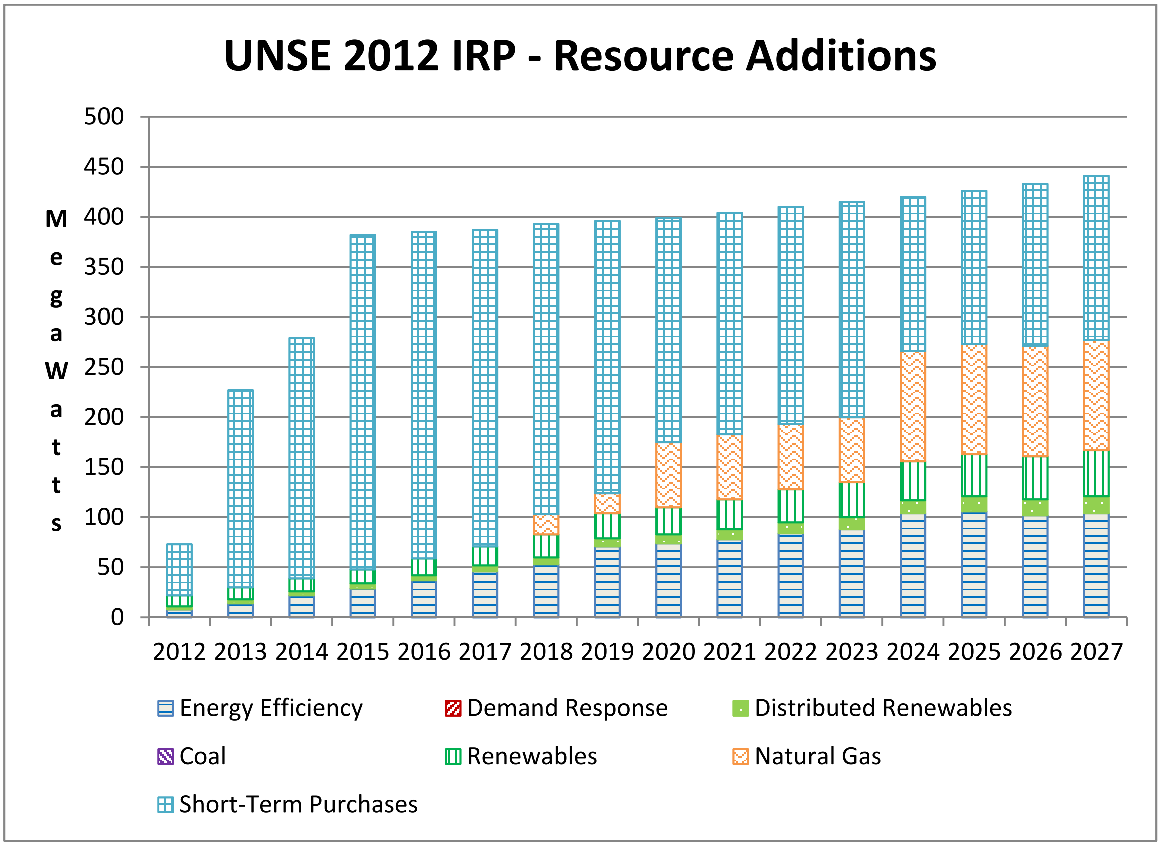
The following chart displays the resource additions selected by TEP in its 2012 IRP, based on contribution to system peak demand:



The dip in added resources in the year 2016 is due to the expiration of long-term TEP wholesale power sales contracts. TEP plans to add EE programs and DR programs sufficient to meet the Commission's EE requirement, utility-scale renewable generation sufficient to meet the Commission's RE requirement, and distributed renewable generation sufficient to meet the Commission's distributed renewable energy requirement. Beginning in 2018, the company plans to add natural gas-fired combustion turbine generation. Throughout the 15 year period, TEP includes large amounts of short-term market purchases.

3. UNSE

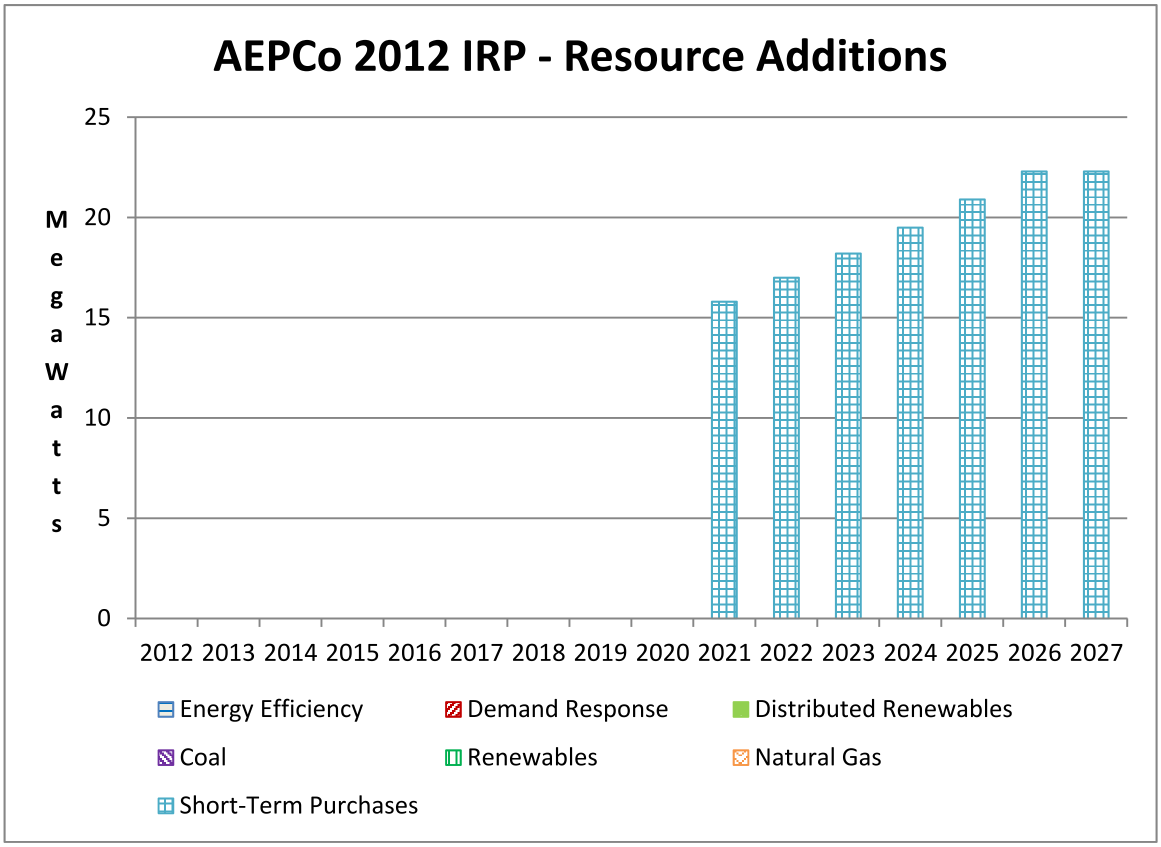
The following chart displays the resource additions selected by UNSE in its 2012 IRP, based on contribution to system peak demand:



The large increases in added resources in 2012-2015 are caused by the expiration of long-term UNSE wholesale power purchase contracts. UNSE plans to add utility-scale renewable generation sufficient to meet the Commission's RE requirement, and distributed renewable generation sufficient to meet the Commission's distributed renewable energy requirement. However, the UNSE IRP will not satisfy the Commission's EE requirement. Beginning in 2018, UNSE plans to add natural gas-fired combustion turbine generation. Throughout the 15 year period, UNSE includes large amounts of short-term market purchases.

4. AEPCo

The following chart displays the resource additions selected by AEPCo in its 2012 IRP, based on contribution to system peak demand:



The IRP produced by AEPCo only considered short-term market purchases as potential resource additions. It should be noted that the resource additions projected by AEPCo are a small fraction of the resource additions projected by the other load-serving entities,

5. SRP

Neither publicly available information nor information provided to Staff from SRP is detailed enough to produce a chart displaying annual resource additions. Based on information provided to Staff by SRP, SRP plans the following additions:

- EE programs at 5% of retail requirements (including prior years' savings)
- DR programs – up to 50 megawatts
- Interruptible programs of 126 megawatts or more
- TOU programs of 165-280 megawatts
- 415 megawatts of renewable generation
- 820 megawatts of natural gas-fired generation

6. Combined IRPs

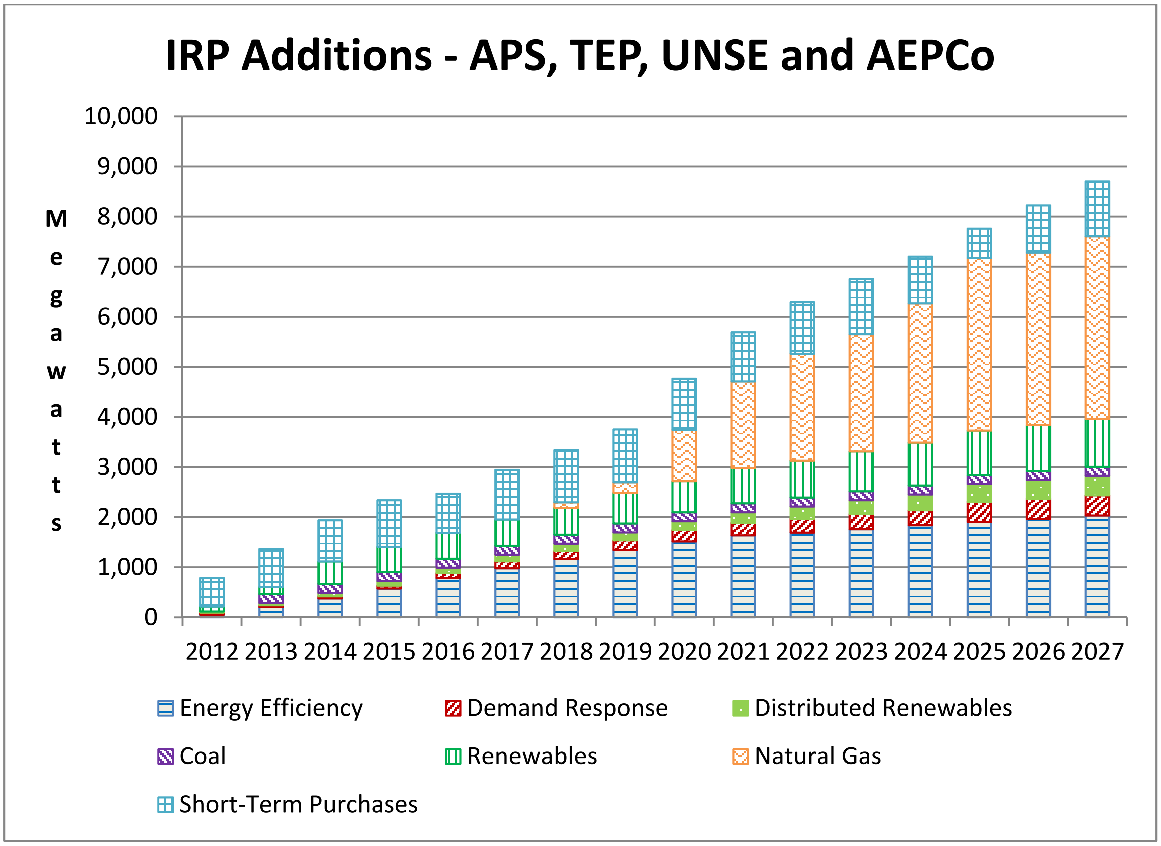
The following table shows the additional resources selected by APS, TEP, UNSE and AEPCo in their 2012 IRPs, based on contribution to system peak demand:

IRP Additions - APS, TEP, UNSE and AEPCo

Megawatts

	Energy Efficiency	Demand Response	Distributed Renewables	Coal	Renewables	Natural Gas	Short-Term Purchases
2012	54	40	23	0	98	0	574
2013	202	40	43	179	141	0	760
2014	380	40	69	179	450	0	821
2015	578	55	91	179	504	0	930
2016	783	100	109	179	519	0	778
2017	980	140	131	179	525	0	992
2018	1,160	165	146	179	537	110	1,044
2019	1,343	196	156	179	609	212	1,058
2020	1,516	227	177	179	619	979	1,023
2021	1,636	252	208	179	710	1,726	980
2022	1,693	277	241	179	739	2,134	1,028
2023	1,759	302	275	179	801	2,338	1,100
2024	1,838	302	312	179	858	2,779	935
2025	1,907	402	350	179	893	3,444	587
2026	1,966	402	376	179	914	3,444	945
2027	2,035	402	393	179	950	3,648	1,098

The same information is shown in the following chart:



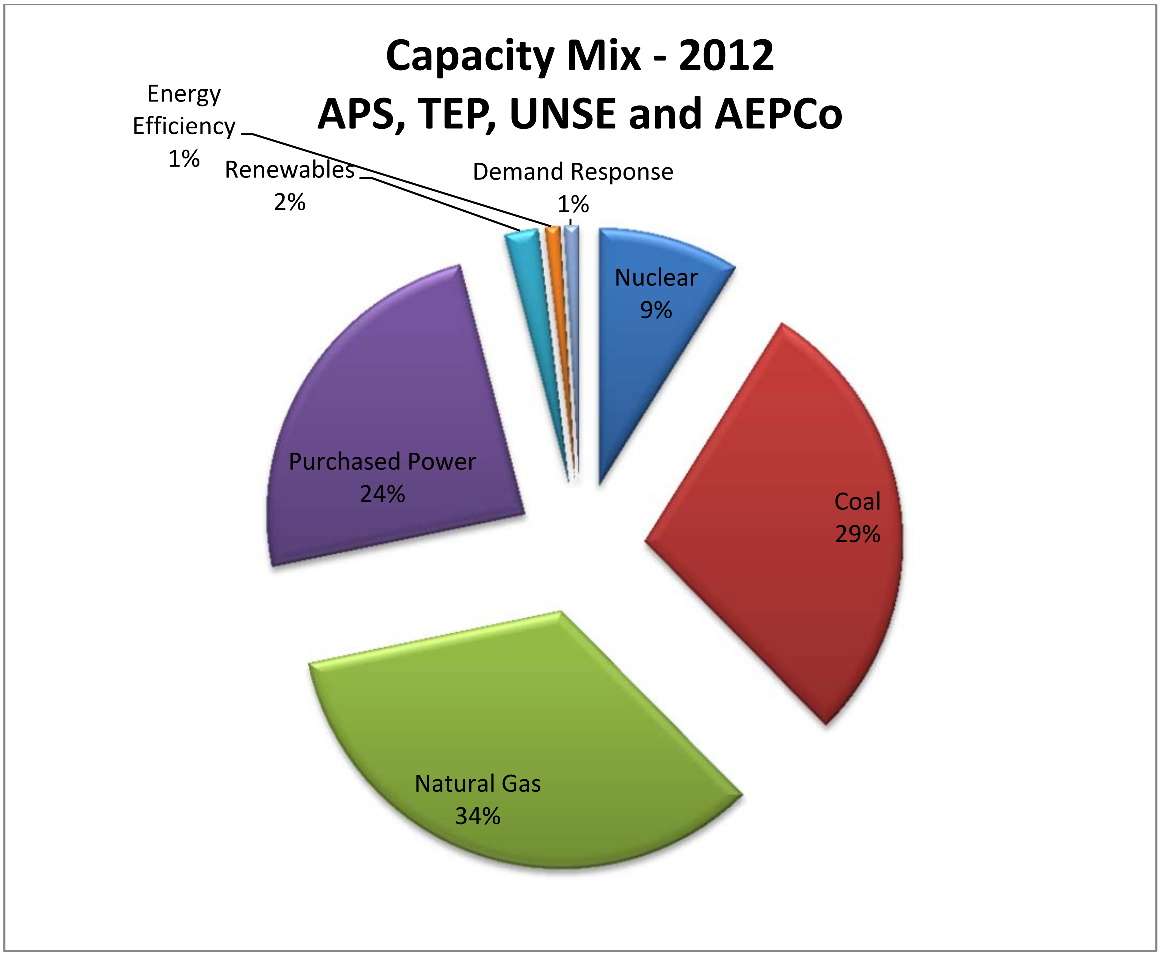
Observations:

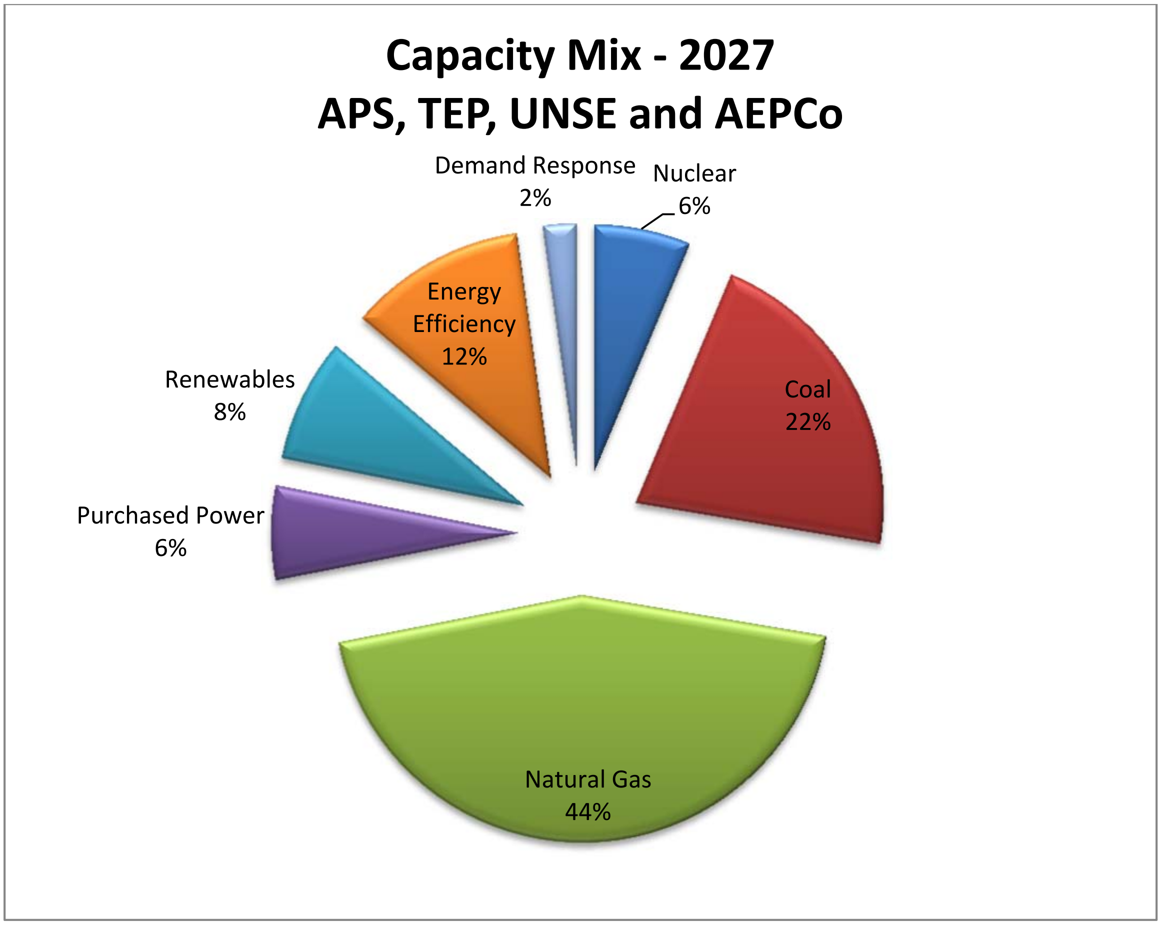
- Other than the net increase in coal capacity that is the result of the APS decision to pursue the retirement of Four Corners 1-3 and the acquisition of SCE's portion of Four Corners 4 and 5, the only new non-renewable generating plants are fired by natural gas.

- All four entities rely to some extent on short-term purchased power. Looking at the combined assumed additions of short-term purchased power, one has to wonder if the entities can rely on acquiring such large levels of short-term purchased power over the next 15 years.

7. Change in Capacity Mix

The following charts compare the capacity mix change that will occur under the 2012 IRPs filed by APS, TEP, UNSE and AEPCo, based on contribution to system peak demand:

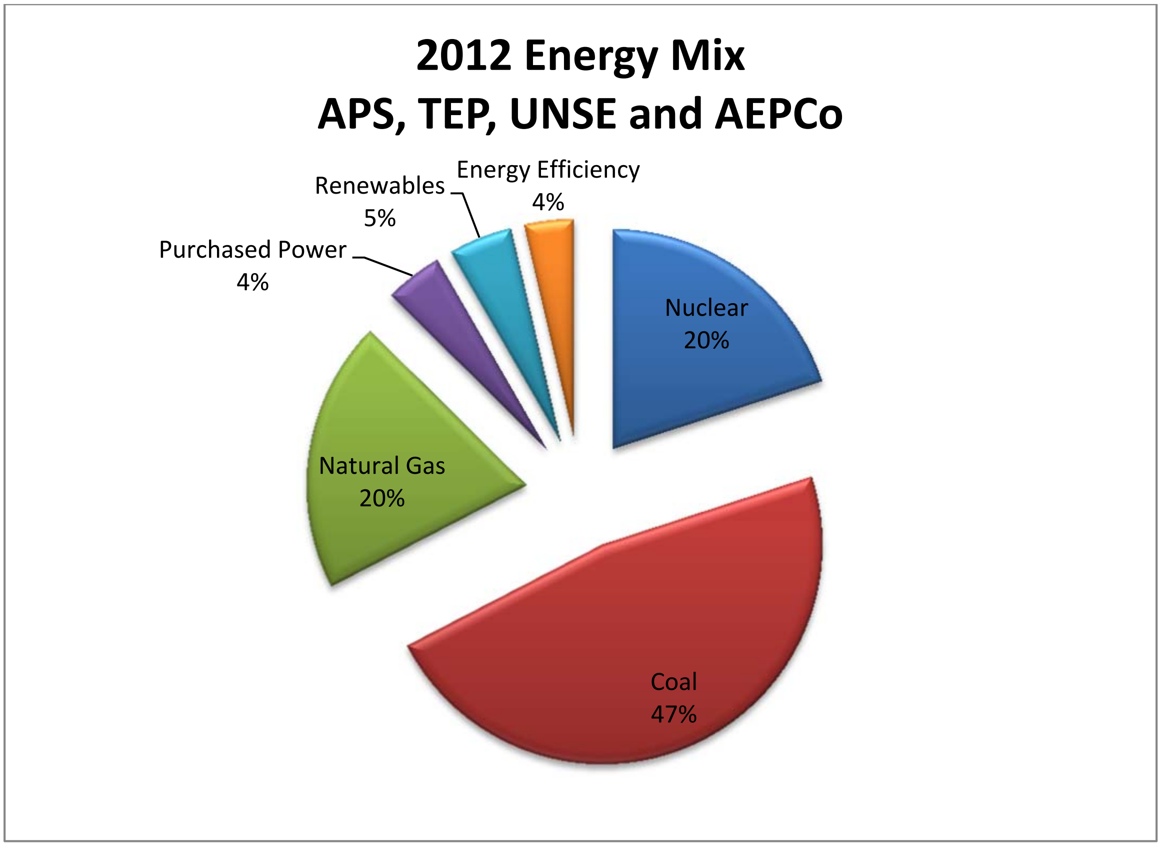


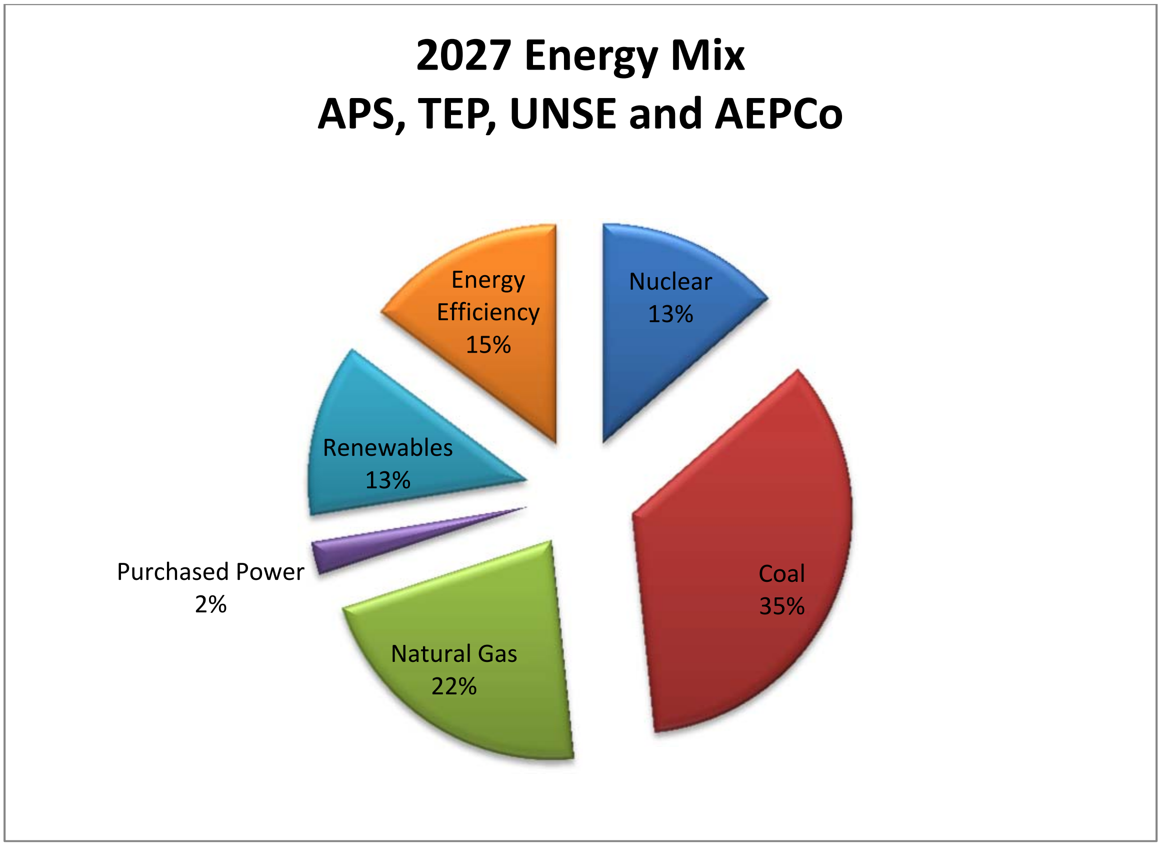


The charts reflect the major additions planned in EE programs, renewable generation (both utility-scale and distributed) and natural gas-fired generators.

8. Change in Energy Mix

The following charts compare the energy mix change that will occur under the 2012 IRPs filed by APS, TEP, UNSE and AEPCo:

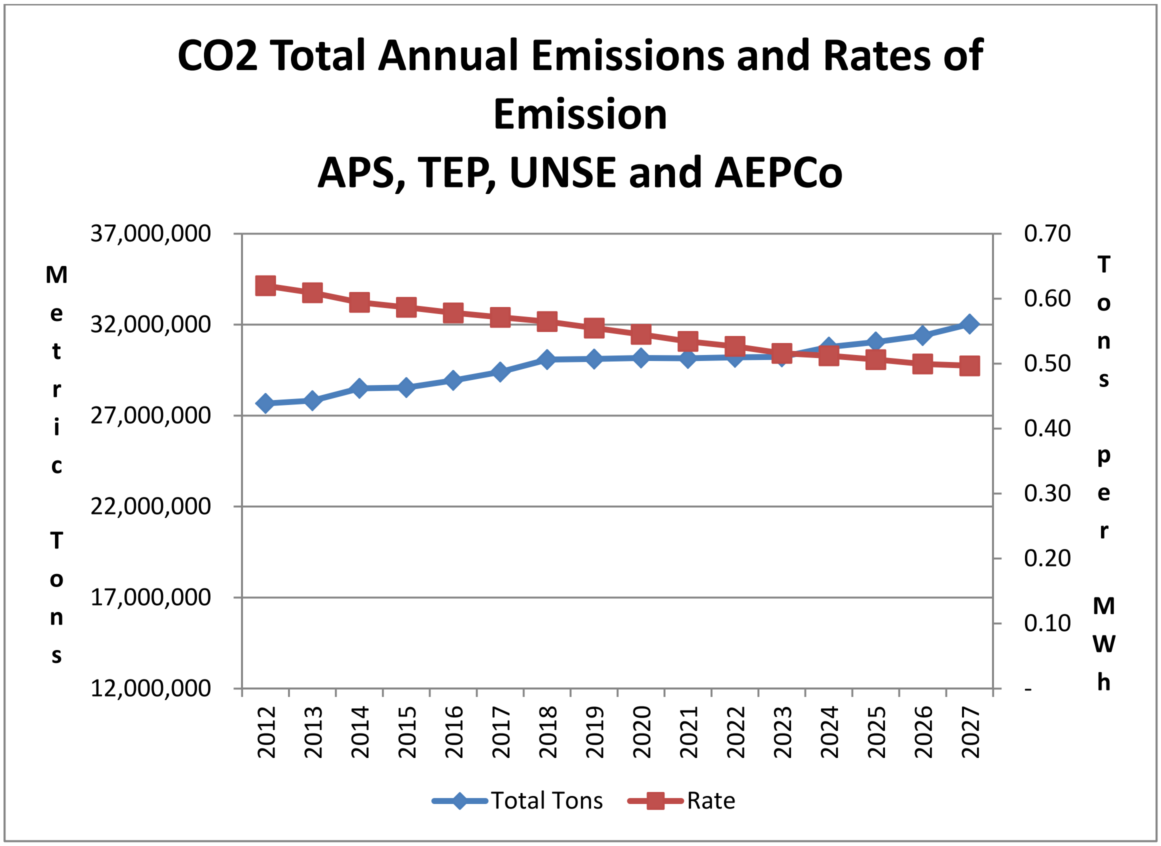


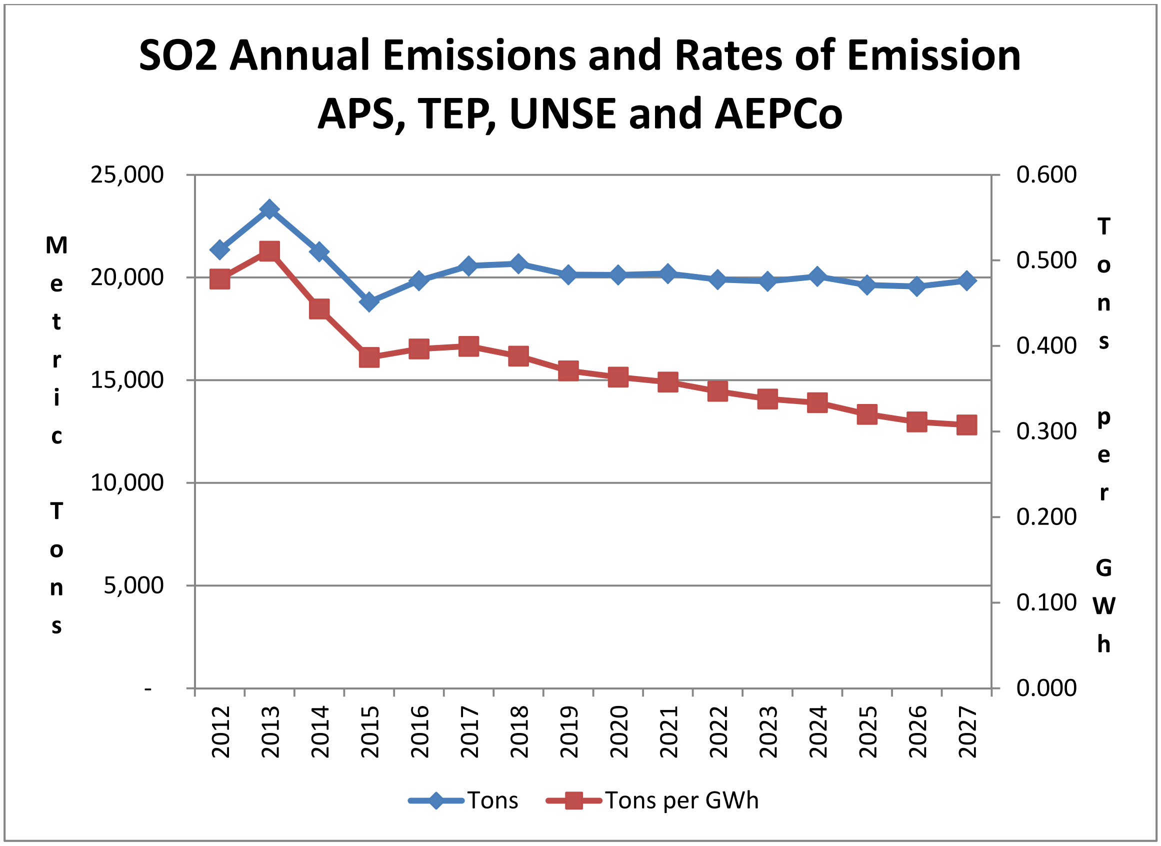


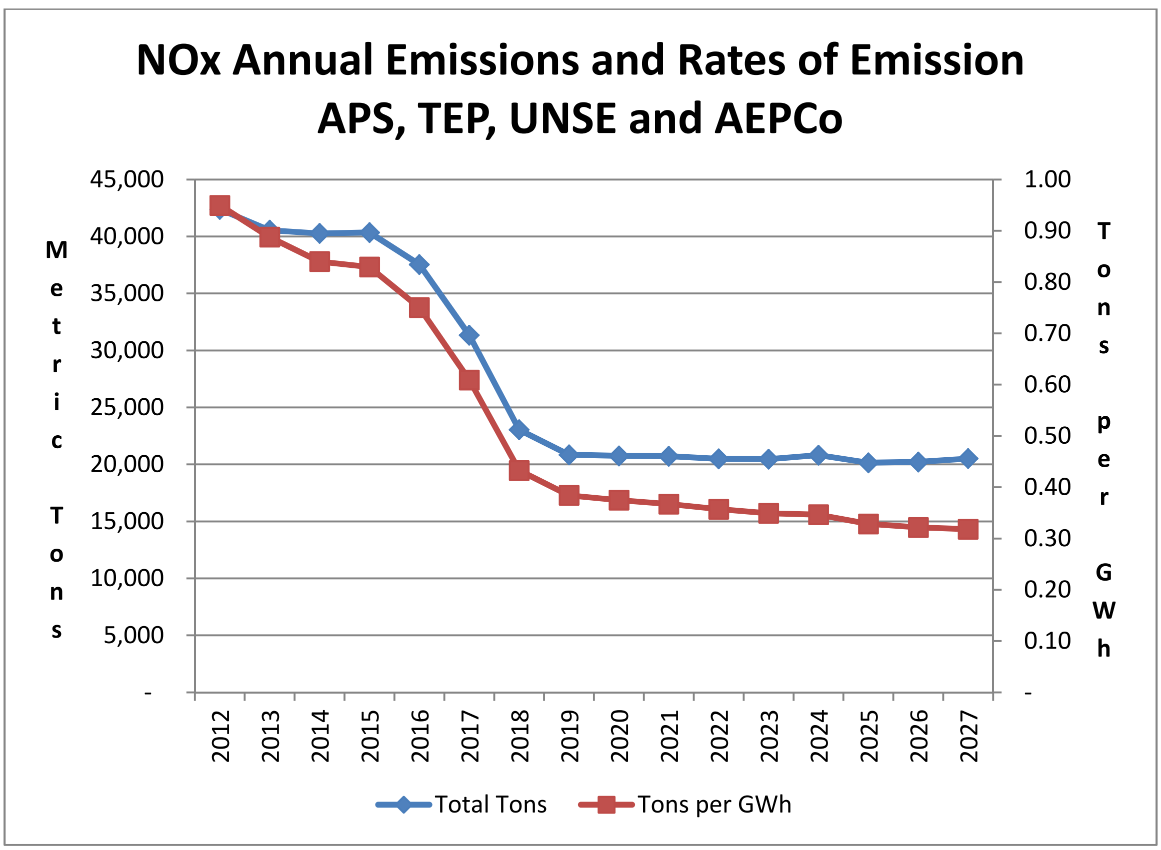
As the charts show, the 2012 IRPs cause the domination of coal-fired generation to be reduced dramatically over the 15 year horizon, with energy efficiency programs, renewable generation and natural gas-fired generation playing a much more significant role.

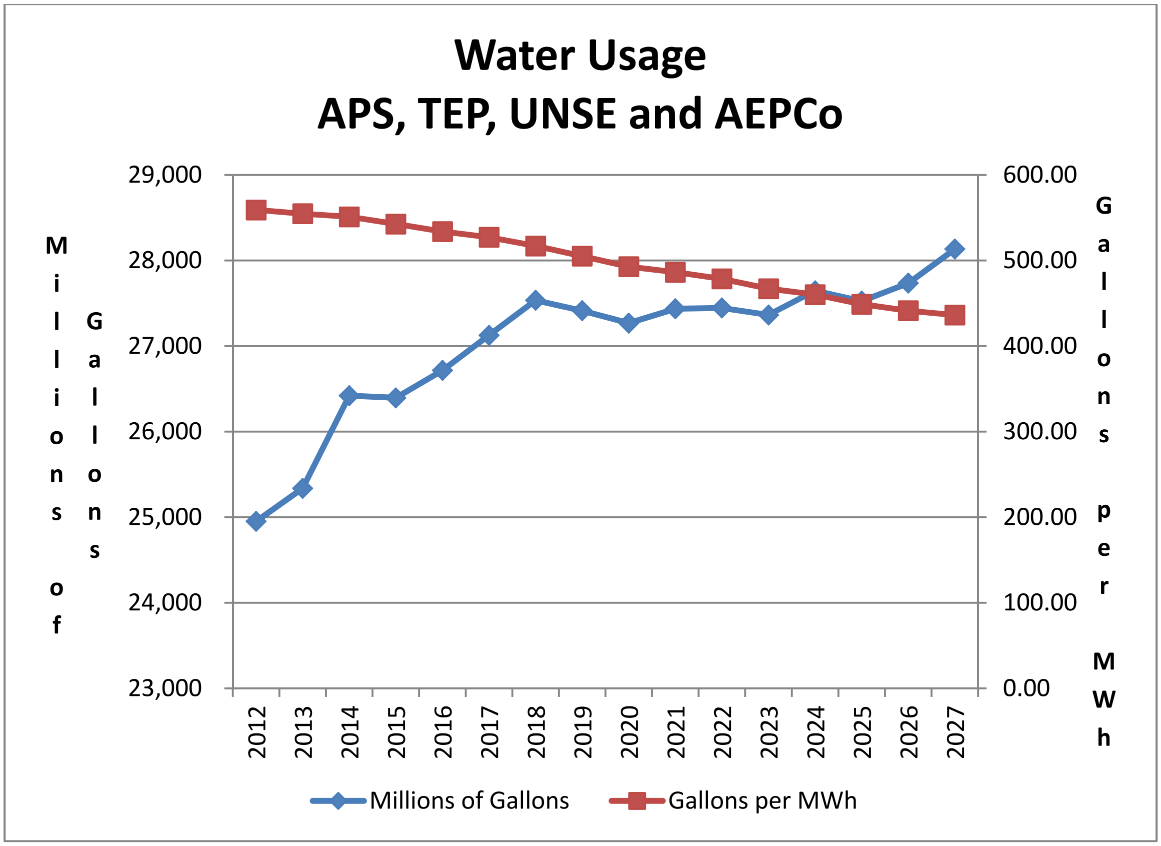
9. Impacts on Emissions and Water Usage

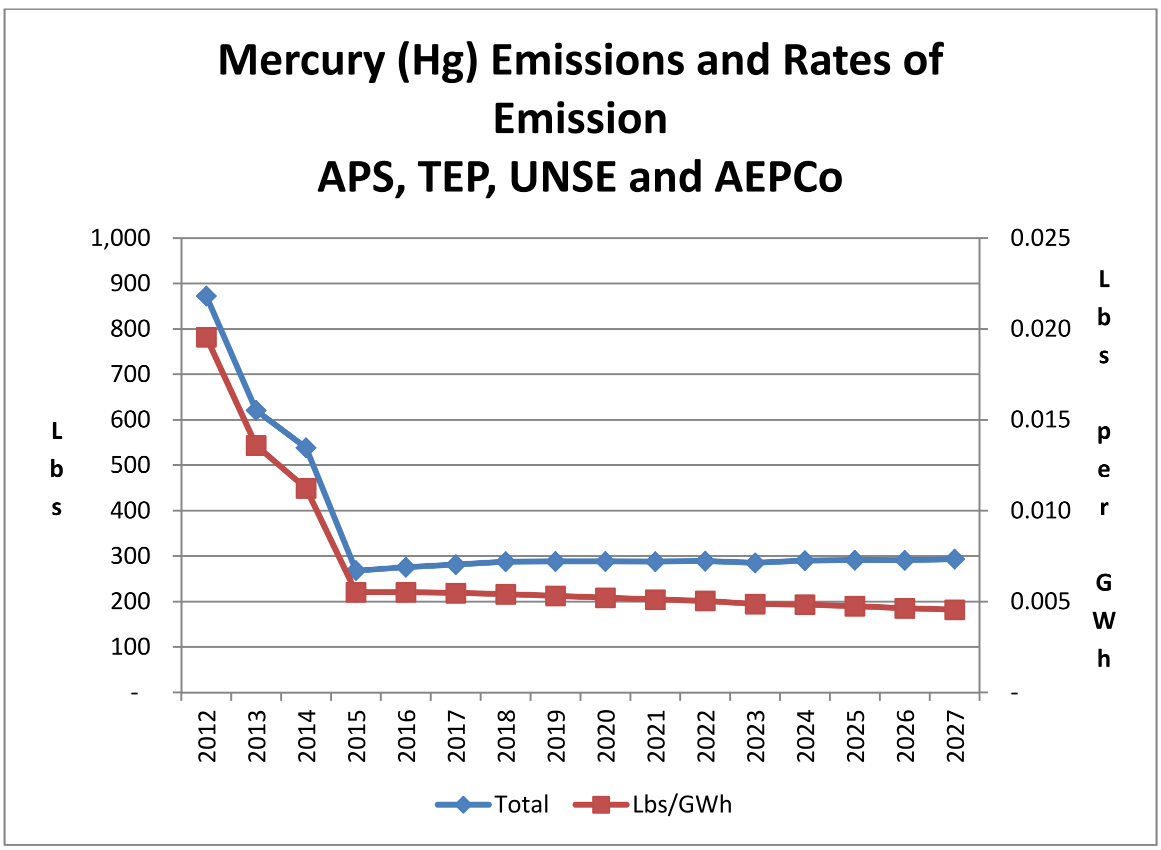
The following charts show the impact of the 2012 IRPs on CO_2, SO_2, and NO_x emissions, and water usage. These are the combined impacts of the APS, TEP, UNSE and AEPCo IRPs.

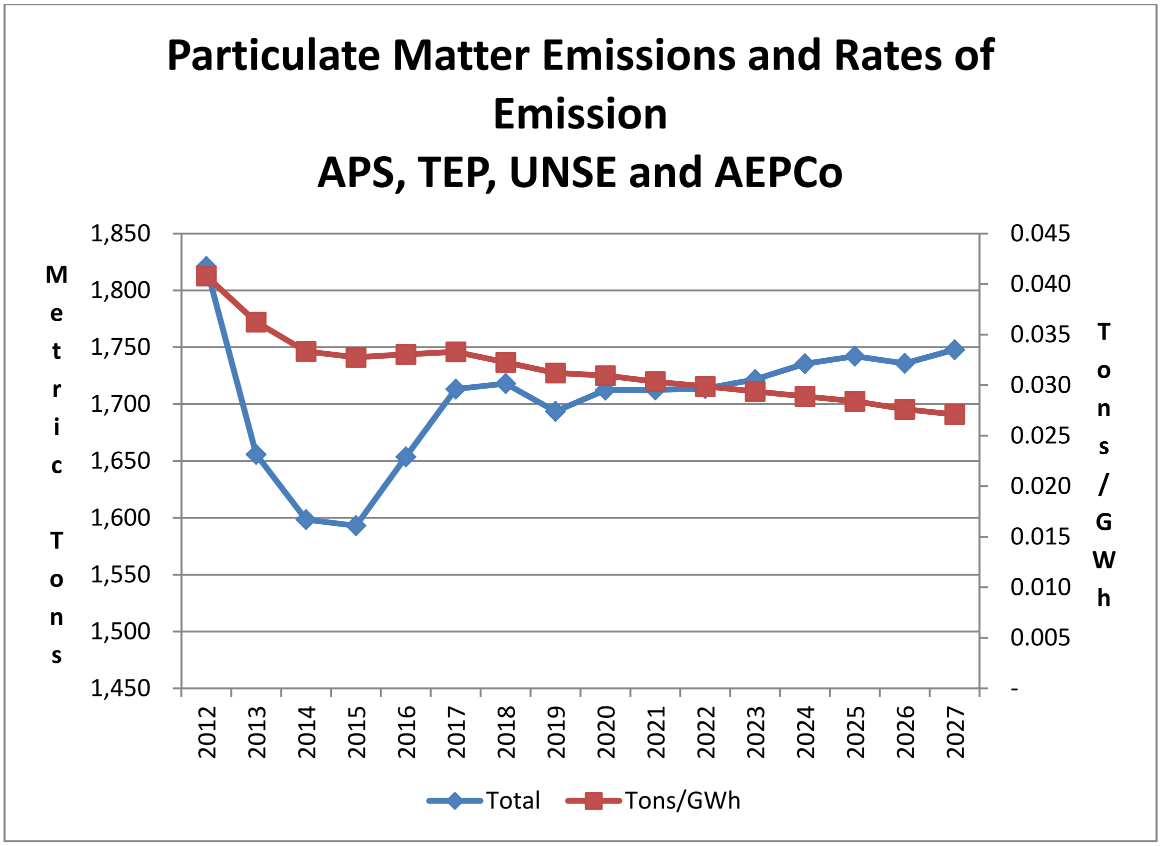


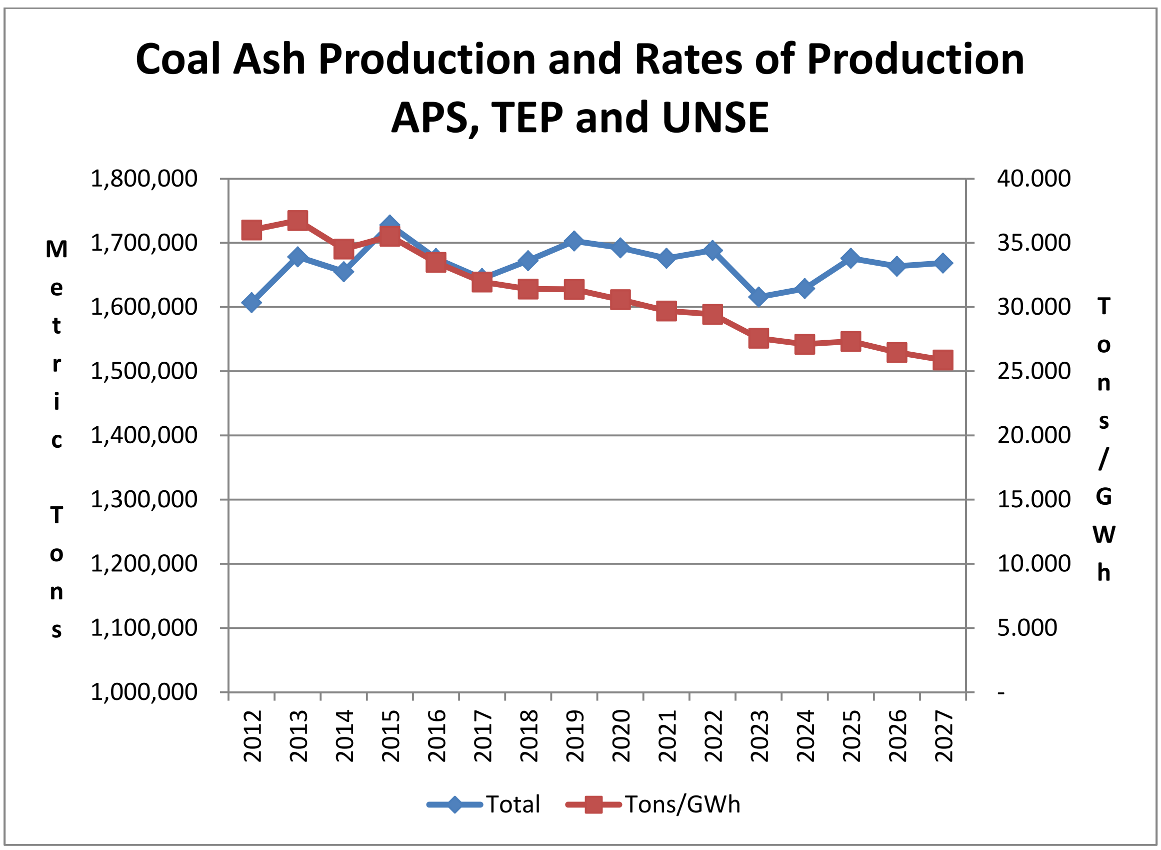

SO2 Annual Emissions and Rates of Emission
APS, TEP, UNSE and AEPCo
Metric Tons
Tons per GWh
25,000
20,000
15,000
10,000
5,000
-
0.600
0.500
0.400
0.300
0.200
0.100
0.000
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027
Tons
Tons per GWh


NOx Annual Emissions and Rates of Emission
APS, TEP, UNSE and AEPCo
Metric Tons
Tons per GWh
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027
Total Tons
Tons per GWh


Water Usage
APS, TEP, UNSE and AEPCo
Millions of Gallons
Gallons per MWh
29,000
28,000
27,000
26,000
25,000
24,000
23,000
600.00
500.00
400.00
300.00
200.00
100.00
0.00
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
Millions of Gallons
Gallons per MWh


Mercury (Hg) Emissions and Rates of Emission
APS, TEP, UNSE and AEPCo
Lbs
Lbs per GWh
1,000
900
800
700
600
500
400
300
200
100
-
0.025
0.020
0.015
0.010
0.005
-
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
Total
Lbs/GWh


Particulate Matter Emissions and Rates of Emission
APS, TEP, UNSE and AEPCo
Metric Tons
Tons/GWh
1,850
1,800
1,750
1,700
1,650
1,600
1,550
1,500
1,450
0.045
0.040
0.035
0.030
0.025
0.020
0.015
0.010
0.005
-
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
Total
Tons/GWh


Coal Ash Production and Rates of Production
APS, TEP and UNSE
Metric Tons
Tons/GWh
1,800,000
1,700,000
1,600,000
1,500,000
1,400,000
1,300,000
1,200,000
1,100,000
1,000,000
40.000
35.000
30.000
25.000
20.000
15.000
10.000
5.000
-
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
Total
Tons/GWh

Under the 2012 IRPs, the rates of production of all emissions and the rate of water usage per unit energy produced are decreasing throughout the 15-year period. This trend is largely due to the movement toward renewable energy and energy efficiency programs, and away from coal-fired generation. However, total CO2 emissions and total water usage continue to increase under the 2012 IRPs.

The large annual drops in emissions are driven primarily by planned added emissions controls:

- Post-combustion NOX controls on Four Corners 4 and 5 by the end of 2018
- Fabric filters on Cholla 2 in 2014 to control particulate matter and mercury
- Mercury controls on all coal units by 2015
- SCR systems for NOX control on San Juan by 2017
- SCR systems for NOX control on Navajo by 2017

10. Rate Impacts

The load-serving entities predict the following average annual rate increases under the 2012 IRPs:

Load-Serving Entity	Average Annual Rate Increase
APS	4.2%
TEP	3.2%
UNSE	4.7%

The average annual rate increases shown for APS reflect only estimated future generation and associated future transmission costs, and may not necessarily reflect annual rate increases.

V. Natural Gas Supply

Over the next fifteen years, the Arizona electric utilities plan to construct over 4,000 megawatts of new natural gas-fired generating facilities. A natural question arising is – can the Arizona natural gas supply and delivery infrastructure accommodate these planned facilities?

Arizona's natural gas needs are supplied by three major gas basins – the San Juan, Permian and Rockies basins. Transportation of natural gas into the state is accomplished via an extensive pipeline network that is comprised of a dual system served by El Paso and Transwestern.

Based on a fuel supply outlook prepared for APS by HIS CERA, APS concluded in its IRP that it does not "foresee any fuel supply issues during the Planning Period"[19]. TEP and UNSE both foresee sufficient natural gas supply and transportation in future years[20]. AEPCo does not include new gas-fired generating facilities in its IRP. Based on these assessments by the load-serving entities, it appears that the existing infrastructure will be sufficient to supply planned new gas-fired generators.

[19] *See* APS 2012 Integrated Resource Plan, p. 105.

[20] *See* TEP 2012 Integrated Resource Plan, chapter 17; *see also* UNSE 2012 Integrated Resource Plan, chapter 13.

VI. Conclusions and Recommendations

For the most part, the 2012 Integrated Resource Plans produced by APS, TEP and UNSE are reasonable and in the public interest, based upon the information available to the Staff at the time this report was prepared and the factors set out in R14-2-704(B). While Staff believes the IRPs of APS, TEP and UNSE meet the requirements of the Commission's IRP rules, the following issues have been identified concerning the IRPs of APS, TEP and UNSE:

- **APS, TEP and UNSE**
  - **Conversion of Coal Plants to Natural Gas** – None of the load-serving entities considered the possible conversion of existing coal generating plants to natural gas. This is a potentially viable option that would reduce the costs of emissions compliance and possibly, bring long-term savings to the ratepayers.
  - **Consideration of Jointly Developed Generation** – Although PVNGS and Four Corners generating plants, among others, were developed through joint efforts of a number of electric utilities, the load-serving entities of Arizona (excluding UNSE) did not seriously consider the joint development of new generating plants in their 2012 IRPs. Economies of scale could produce cost savings that would benefit all. For example, large solar facilities, energy storage projects, and new nuclear generation may become more feasible under the assumption that construction and operating costs would be shared among the developers.
  - **Reliance on Future Short-Term Market Purchases** – All three load-serving entities include future short-term market purchases throughout the 2012 IRPs. The cost and availability of such purchases are subject to a wide array of influences that are difficult, if not impossible, to predict. For example, if a large number of older coal-fired generating plants are retired in the western region, the availability of such purchases will decline dramatically, and the cost of such purchases will increase significantly. Reliance on short-term market purchases in a long-term plan is difficult, if not impossible, to justify. Instead, beyond a five-year horizon, the load-serving entities should only include additional DSM programs, additional supply-side resources, and long-term purchased power.
  - **Failure to Consider all Resource Options** – None of the three load-serving entities considered all reasonable resources in the development of the 2012 IRPs. For example, APS did not consider all

potential conventional energy storage facilities while TEP and UNSE failed to consider solar generators with storage capabilities.

- **<u>Wind and Solar Integration Costs</u>** – Other than APS, the load-serving entities rely on wind and solar integration costs that are not specific to the entities' service territories and the entities' existing level of wind and solar facilities. TEP and UNSE should develop wind and solar integration costs that reflect the conditions within the TEP and UNSE systems.

- **APS**

  - **<u>Manual Selection of Resources</u>** - APS used a manual process to select the "best" mix of resources for each IRP that was considered. This is not the industry-accepted practice, could possibly result in the selection of a resource mix that is not the best possible mix, and limits the utility's ability to fully evaluate a wide range of potential IRPs.

  - **<u>No Load Growth Sensitivity</u>** – APS failed to develop alternative IRPs that reflected higher than expected load growth or lower than expected load growth. This is a generally accepted requirement for the development of an IRP, and provides insight into what actions would be required, should load growth increase faster or slower than predicted.

- **UNSE**

  - **<u>EE Standard</u>** – The UNSE final selected IRP does not meet the Commission's Energy Efficiency Standard. However, UNSE has committed to meeting the EE Standard in the implementation of the IRP.

  - **<u>No Load Growth Sensitivity</u>** – UNSE also failed to develop alternative IRPs that reflected higher than expected load growth or lower than expected load growth.

<u>AEPCo</u> – Staff commends AEPCo for its efforts in providing information concerning its IRP and for its cooperative attitude, and notes that AEPCo is in a special situation regarding its member cooperatives. However, the AEPCo 2012 IRP does not satisfy the requirements of the Commission's IRP rules. For example, the Commission's rules require that the load-serving entity file an IRP that "selects a portfolio of resources based upon comprehensive consideration of a wide range of supply- and demand-side options"[21]. AEPCo considered (and selected) only short-term market purchases as a

[21] A.A.C. R14-2-703(F)(1).

potential resource to meet future needs. AEPCo also failed to provide a calculation of the benefits of generation using renewable energy resources[22], an analysis of integration costs for intermittent resources[23], or analyses to identify risks and uncertainties in the availability of sources of power[24].

We recommend that the Commission acknowledge the 2012 IRPs filed by APS, TEP and UNSE, and further, that the Commission recommend that APS, TEP and UNSE correct the issues described above in all future IRP filings.

We also recommend that the Commission not acknowledge the 2012 IRP filed by AEPCo, for the reasons stated above.

[22] A.A.C R14-2-703(D)(9)).
[23] A.A.C R14-2-703(D)(11)).
[24] A.A.C R14-2-703(E)(1)(c)).